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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for a rate increase for Orange-Osceola Utilities, Inc. in Osceola County, and in Bradford, Brevard, Charlotte, Citrus, Clay, Collier, Duval, Highlands, Lake, Lee, Marion, Martin, Nassau, Orange, Osceola, Pasco, Putnam, Seminole, St. Johns, St. Lucie, Volusia, and Washington Counties by Southern States Utilities, Inc.	Docket No. 950495-WS Filed: February 12, 1996

DIRECT TESTIMONY

OF

TED BIDDY

On Behalf of the Citizens of The State of Florida

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Attorney for the Citizens
of the State of Florida

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ted L. Biddy. My business address is Baskerville-Donovan, Inc. (BDI), 2878 Remington Green Circle, Tallahassee, Florida 32308.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am Vice-President of Baskerville-Donovan, Inc. and Regional Manager of the Tallahassee Office.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. I graduated from the Georgia Institute of Technology with a B.S. degree in Civil Engineering in 1963. I am a registered professional engineer and land surveyor in Florida, Georgia and Mississippi and several other states. Before joining BDI in 1991, I had operated my own civil engineering firm for 21 years. My areas of expertise include civil engineering, structural engineering, sanitary engineering, soils and foundation engineering and precise surveying. During my career, I have designed and supervised the master planning, design and construction of thousands of residential, commercial and industrial properties. My work has included: water and wastewater design; roadway design; parking lot design; stormwater facilities design; structural design; land surveys; and environmental permitting.

I have served as principal and chief designer for numerous utility projects. Among my major water and wastewater facilities designs have been a 2,000 acre development in Lake County, FL; a 1,200 acre development in Ocean Springs, MS; a 4 mile water distribution system for Talquin Electric Cooperative, Inc. and a 320 lot subdivision in Leon County, FL.

Q. WHAT ARE YOUR PROFESSIONAL AFFILIATIONS?

A. I am a member of the Florida Engineering Society, National Society of Professional Engineers, and Florida Society of Professional Land Surveyors.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION (FPSC)?

A. Yes. I have testified in the St. George Island Utilities, Ltd. case in Docket No. 940109-WU.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A STATE OR FEDERAL COURT AS AN ENGINEERING EXPERT WITNESS?

A. Yes, I have had numerous court appearances as an expert witness for cases involving roadways, utilities, drainage, stormwater, water and wastewater facilities designs.

Q. HAVE YOU REVIEWED ANY RATE FILING DOCUMENTS FILED WITH THE FLORIDA PUBLIC SERVICE COMMISSION REGARDING USED AND USEFUL ANALYSIS AND OTHER ENGINEERING ISSUES?

A. Yes, I have reviewed the FPSC staff final recommendations on engineering issues for Docket No. 920733-WS and No. 900718-WU. Docket No. 920733-WS was filed by the General Development Utilities, Inc. for its Silver Springs Shores Division which has lime softening treatment facilities. Docket No. 900718-WU was filed by Gulf Utility Company for its reverse osmosis plant expansion.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide comments on methods of used and useful analysis used by Southern States Utilities, Inc. (SSU) for this rate increase filing.

Q. WERE THE MATERIALS YOU ARE SPONSORING PREPARED BY YOU OR BY PERSONS UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. DO YOU AGREE WITH THE MARGIN RESERVE PROPOSED BY SSU FOR USED AND USEFUL CALCULATIONS?

A. No, I do not think margin reserve used by SSU in this rate filing is appropriate. Besides the testimony provided by Witness Mr. Larkin, I have some comments to add especially on 3 years and 5 years of margin reserve for water and wastewater treatment facilities, respectively. Chapter 62-600.405, Florida Administrative Code (F.A.C.) requires all wastewater utilities to submit capacity analysis reports (CAR) to the Florida Department of Environmental Protection (FDEP) at different conditions. The five year time frame mentioned in the rules is mainly used as the interval for submitting a CAR. We should not translate that five year time frame as the actual time required for new plant expansions. The rule is simply trying to mandate wastewater treatment plant (WWTP) owners to prepare plans for possible future expansion. The five year submittal will be reduced to annual update when the permitted capacity will be equaled or exceeded within the next 10 years. The utilities may have to expand WWTP quickly, it depends on how soon the flow is anticipated to reach the permitted capacity. If the wastewater flow is not anticipated to reach the permitted capacity within 10 years, on the other hand, the utilities are only required to submit a CAR every 5 years and nothing else.

FDEP has no similar rules on water treatment facilities. The need for plant expansion again is dependent upon when the future flow will reach existing capacities. Sometimes it does not take a long time to increase capacity for water treatment, such as adding a new well and filters. Therefore, the 3-year and 5-year margin reserves requested by SSU are not justified or mandated by regulation.

In addition, a well planned phased development and plant expansion can reduce and eventually eliminate the need of margin reserve. This is feasible and can be done. The construction permit DC432-219274 of Marion Oaks WWTP is a good example in this filing. In that permit, the 0.2 MGD Type I extended aeration sewage treatment plant was permitted to expand in four phases to a 1.0 MGD plant. Actually, the utility should have new customers or developers to pay for new plant expansion through contribution or prepaid CIAC (contribution in aid of construction) and other ways. Collection of these prepaid fees from future customers should render a margin reserve allowance, paid by current customers, to be unnecessary.

Under Florida conditions of tightening environmental regulation, increasing water costs and water conservation concern, it is reasonable to believe that the water consumption and wastewater generation of existing customers will not increase. Therefore, the margin reserve requested by SSU is solely for new customers. If the PSC allows margin reserve in the used and useful calculations, then it will penalize existing customers by burdening them to pay extra cost for new customers. Allowing margin reserve will further increase water and wastewater rates to existing customers. High utility rates reduce the financial ability for customers and will hinder future development. Therefore, the PSC should eliminate margin reserve allowance in used and useful analysis. The utility should recover the costs of plant addition from new customers or developers through other measures.

Q. DO YOU HAVE ANY COMMENTS ON THE FIRE FLOW REQUIREMENT SOUTHERN STATES UTILITIES, INC. (SSU) APPLIED IN USED AND USEFUL CALCULATIONS?

A. Fire flow capacity should be included in used and useful calculation only if fire flow provision was proven by sufficient fire flow test records. SSU did not provide this information in the original filing, therefore, no fire flow was applied in my used and useful calculation. However, OPC has request SSU to provide the fire flow test information. Revised used and useful calculation will be submitted if SSU does provide adequate information.

Many components of a water distribution system dictate the delivery of fire flow. They include high service pumps, distribution storage tanks (elevated or ground) and water mains. Because of economic concerns, for many systems fire flows are provided partially by high service pumps and partially by storage. See Exhibit TLB-1 excerpted from AWWA M31 Manual for examples.

No fire flow should be applied to high service pumps, finished water storage or water supply wells without confirming the fire fighting capability of each system. Installing a fire hydrant in the distribution system does not guarantee the required fire flow. As mentioned above SSU was asked to prove the fire flow capability by providing fire flow test records. However, that information was not available at the time of preparing this testimony. Therefore, no fire flow requirement requested by SSU was included in my used and useful calculations in Exhibit TLB-3. When fire flow test documentation becomes available, the used and useful schedules may be revised and provided to the Commission.

If a system is not designed or proved to provide required fire flow, it is dangerous and unfair to assume the fire flow requirement in used and useful analysis. Residents and business owners are paying higher property insurance premiums because of inadequate fire fighting provision. It is not cost effective to use source of supply to meet instantaneous demands, such as peak hourly flows and fire flows. Normally a small water system without storage tanks does not have the capability for fire fighting.

In addition, AWWA Manual M31 Page 33 states "Generally, water system components are out of service for short periods of time, so the probability of a component being out of service when a fire occurs is low. ....Fortunately, fires that severely stress a distribution system occur only a few times a year in large systems and only once every few years in small systems. Therefore, the probability of a major fire occurring while more than one water system component is out of service is so low that the utility should not be expected to meet required fire flow at such times."

Q. SSU REQUESTED A 12.5% COMPANY-WIDE LEVEL OF

UNACCOUNTED FOR WATER. DO YOU AGREE WITH THIS REQUEST?

A. No. A company-wide unaccounted for water percentage can not represent actual unaccounted for water level of each system. Some systems with high levels of unaccounted for water, like Oak Forest, St. Johns Highlands, and Stone Mountain, are averaged out by large numbers of low unaccounted for water systems. Therefore, the company-wide approach provides a shelter to high unaccounted for water systems and does not encourage operation improvement. PSC should evaluate the level of unaccounted for water on an individual basis. To achieve low levels of unaccounted for water, PSC should allow no more than 10% for each water system. Proper adjustments have been made in Exhibit TLB-3 water system used and useful calculations, to account for excess unaccounted for water.

Q. DO YOU RECOMMEND THAT A SINGLE MAXIMUM DAY FLOW SHOULD BE USED IN USED AND USEFUL CALCULATIONS?

A. No, the single maximum day flows should not be used in used and useful calculations in this filing. The single maximum day flows may include undetected or unrecorded leaks, flushing and unusual usage, in addition to the PSC allowed unaccounted for water. Normally, a water main leaks for days before detection and that amount of water loss is hard to keep track of. Main breaks and line flushing have similar situations because good records are hard to keep.

When engineers review historic flow data and evaluate for maximum daily demands, any unusual and excessive uses of water should be excluded as provided by AWWA M31, *Distribution System Requirement for Fire Protection*, on Page 16.

In this filing, SSU did not exclude any unusual and excessive water use for the single maximum day flows. Therefore, an average of the five highest maximum daily flows in the maximum month is justified and should be used for all used and useful and engineering issues. This has been the policy historically used by the Commission.

Q. IS IT JUSTIFIED TO USE THE PERMITTED CAPACITIES IN OPERATION PERMITS INSTEAD OF CONSTRUCTION PERMITS FOR USED AND USEFUL CALCULATIONS?

A. Normally the operation permit has the same capacity as construction permit for each treatment facility. However, sometimes the same treatment facility has less permit capacity in its operation permit than construction permit. For example, a one MGD contact stabilization type sewage treatment plant could be rated at 0.5 MGD for operating in extended aeration treatment. The Beacon Hills WWTP provides an actual example. According to FDEP permit number DO16-213087, that facility is permitted as a 0.836 MGD extended aeration WWTP, which can also be operated as a 1.78 MGD contact stabilization WWTP. I have adjusted the used and useful calculation for the Beacon Hill wastewater treatment plant to reflect its 1.78 MGD capacity in Exhibit TLB-4. Adjustments would be appropriate for the other systems if their plant capacities are similarly understated.

Therefore, construction permit capacities should be used unless the operation permit has permanently changed the original permit capacities. This question will not be an issue when SSU applies for permit renewals in the future. According to the 1993 Environmental Resources Permit (ERP) Program, FDEP will combine the construction and operation permits into one permit application.

Q. IS IT REASONABLE TO USE "FIRM RELIABLE CAPACITIES" TO CALCULATE USED AND USEFUL PERCENTAGES FOR SUPPLY WELLS, HIGH SERVICE PUMPS AND WATER TREATMENT FACILITIES?

A. No, it is not justified to use firm reliable capacity on more than one component. The firm reliable capacity is the total capacity of supply wells, high service pumps, filters, or other treatment plant facilities without the largest unit in operation. That largest unit is assumed to be out of service for routine maintenance or emergency repair.

Most of the time, facilities are scheduled in advance to be out of service for maintenance or repair. It is very unlikely that two facility components will be scheduled for service at the same time. The chance of having two facility breakdowns, simultaneously, is slim. Therefore, it is not economically justified to calculate used and useful percentages for supply wells, water treatment facilities and high service pumps all with "firm reliable capacity." Adjustments have been made in my used and useful calculations in Exhibit TLB-3, based on the above discussion.

Q. DO YOU HAVE ANY COMMENTS ON WATER SUPPLY WELL USED AND USEFUL CALCULATIONS PROPOSED BY SSU?

A. SSU used so called "firm reliable capacity" in calculating used and useful percentage for water supply wells. The firm reliable capacity excludes the largest well capacity by assuming it to be out of service. When there are more than ten wells, the largest two wells are assumed to be out of service. The combined capacity of remaining supply wells is the "firm reliable capacity." If a system has only supply wells and no storage facilities or high service pumps, then the well pumps also serve as high service pumping facilities. For this type water system, the "firm reliable capacity" proposed by SSU is acceptable.

However, when storage or high service pumping facilities are available, the "firm reliable capacity" method is not applicable. According to Section 3.2.1.1 Source capacity of *Recommended Standards For Water Works*:

"The total developed groundwater source capacity shall equal or exceed the design maximum day demand and equal or exceed the design average day demand with the largest producing well out of service."

This design criteria should be used to calculate used and useful percentage for supply wells. For the above reason, the "firm reliable capacity" method should not be applied to supply wells where the water system is also equipped with storage and high service pumping facilities. Adjustments have been made according to the above principles in Exhibit TLB-3.

Q. DO YOU HAVE ANY COMMENTS REGARDING USED AND USEFUL CALCULATIONS OF THE FINISHED WATER STORAGE?

A. The peak hour domestic demands calculations proposed by SSU is unjustified without document support and clear explanation. SSU assumed the peak hour demand is two times of the maximum day demand and the peak hour demand is four hours long. AWWA M32, *Distribution Network Analysis for Water Utilities*, suggests a peak factor range of 1.3 to 2.0 for peak-hour demand to maximum-day demand. I believe 1.3 should be used because it is the minimum requirement.

In MFRs Volume VI Book 1 of 2 Pages 14 and 15, "maximum day gallons pumped" was used instead of "maximum day gallons pumped/24 hours." The time unit was omitted and an abnormal large storage for domestic peak hour demand will be erroneously calculated. Though SSU did not make mistakes in this calculation, it is better to clarify that the "maximum day gallons pumped" means "maximum day gallons pumped within 24 hours" in the record. Normally to compute the required peak hour storage, a mass diagram or hydrograph indicating the hourly rate of consumption is required.

SSU requested an 8-hour emergency storage for large water systems, including: Amelia Island, Burnt Store, Citrus Springs, Deltona Lakes, Lehigh, Marco Shores, Marco Island, and Sugar Mill Country Club. Emergency storage is not a design criteria in the *Recommended Standards for Water Works*. Just as AWWA M32 stated, the amount of emergency storage is an owner option to be included within a particular water system. It depends on an assessment of risk and the desired degree of system dependability. Emergency storage is seldom included in designs because of costs. SSU was unable to confirm the emergency storage in the original plant design. Therefore, no emergency storage was applied in my used and useful calculations.

SSU also requested ten percent of the total finished water storage to be "dead storage" because of floor suction and vortexing effect. These concerns are not true for all storage facilities, especially for elevated tanks. For ground storage facilities, as-built drawings should be able to reveal the minimum operating level. It is not justified to assume 10% of the storage capacity is dead storage for every single storage tank. In addition, SSU has used more than 10% dead storage in the used and useful calculations for most of the systems. Further, SSU provides no supporting explanation to justify dead storage allowance for each storage tank.

When designing storage tanks and high service pumps, engineers have to check the available net positive suction head (NPSH) and ensure that it is greater than the net required positive suction head to avoid cavitation problems. Therefore, the vortex situation is rare because high service pumps are always placed at a low grade to obtain the maximum NPSH. Full storage tank capacity was applied in my used and useful calculations, per Exhibit TLB-2 and Exhibit TLB-3.

Q. DO YOU HAVE ANY COMMENTS TO ADD ABOUT THE PROPOSED HIGH SERVICE PUMPS USED AND USEFUL CALCULATIONS?

A. High service pumps are normally designed to handle maximum daily flows. Any demands beyond maximum daily flows should be met by distribution storage tanks (AWWA M32 P.41). Distribution storage means elevated storage tank or a ground storage tank with booster pumps in the distribution system. Distribution storage is a part of the finished water storage. Finished water storage usually means ground storage tanks that store finished water to be supplied to high service pumps which push the finished water to the distribution system. However, many water systems have elevated storage tanks in addition to the ground storage tanks to meet the system demands. According to SSU witness Mr. Bliss, Keystone Heights and

Lehigh are the only two water systems in this rate filing that have elevated storage tanks. It is not cost effective to use high service pumps to handle peak hourly flows and fire flows. If fire flows are provided by distribution storage, no fire flow should be included in high service pump used and useful calculations. However, SSU was unable to confirm whether fire flow is provided by elevated storage tanks in Keystone Heights and Lehigh. For that reason fire flow demands will be applied to high service pumps only when fire flow provision is properly proven.

A water system with no elevated distribution storage facilities is less cost effective because both high service pumps and on site finished water storage need to meet extra peak hourly demands above maximum daily flows or fire flows. Without the capability of replenishing elevated storage, high service pumps need to operate in a higher and wider range of pumping head. Therefore, the capital costs are higher and less cost effective to operate, compared to water systems with elevated storage tanks. During the peak demands, the elevated tank will first provide water to the system and high service pumps will provide the remaining excess water demands. For that reason a smaller high service pump can be used. Examples in Exhibit TLB-1 clearly address these situations.

When distribution storage is not available, but the system is designed to provide fire flows, engineers will size up high service pumps for fire flow provision. However, the design flows used should be maximum day demands (average 5 maximum days of maximum month) plus fire flows or peak hourly demands, which ever is greater. This design criteria is used in AWWA M31 because the chance of having a fire outbreak during peak hourly demands is very slim. Therefore, designing high service pumps to meet fire flows, plus peak hourly flows, is not economically justified. Adjustments have been made in my used and useful calculations in Exhibit TLB-3. See Exhibit TLB-2 for calculation key summary.

Q. DO YOU AGREE WITH THE 100% USED AND USEFUL REQUEST ON FACILITY LANDS, HYDRO TANKS, AND AUXILIARY POWER?

A. No, PSC should not grant 100% used and useful on facility lands, auxiliary power and hydro tanks without individual analysis. Every system has different sizes of facility lands, auxiliary power, and hydro tanks. The current demands and available capacities are also unique between systems. These factors all dictate the facility usage. Therefore, a used and useful calculation is really required for every facility land, auxiliary power, and hydro tank. Adjustments should be made to the used and useful percentages because all facility land, auxiliary power, and hydro tank are part of the system, and they are designed to serve the whole system. The higher the existing demand, the higher the used and useful percentage.

From the response to OPC Interrogatory No. 341, SSU stated that 50 water and 11 wastewater systems have auxiliary power equipment. Unfortunately SSU cannot specify what facilities are supported by each auxiliary power equipment. Therefore, OPC has to assume that auxiliary power has the same used and useful percentage as supply wells or wastewater treatment plants. Adjustments to auxiliary power have been made in Exhibit TLB-3 and Exhibit TLB-4. See Exhibit TLB-2 for calculation key and rationale summary. Marco Shores water system has no supply wells, and the used and useful percentage of high service pumps was used for auxiliary power equipment.

Q. IS IT APPROPRIATE TO USE HYDRAULIC ANALYSIS IN CALCULATING THE USED AND USEFUL PERCENTAGES OF WATER TRANSMISSION AND DISTRIBUTION SYSTEMS?

A. No, it is not appropriate to use hydraulic analysis modeling to calculate the used and useful percentage for water transmission and distribution system. The hydraulic analysis method indeed is a reliable design tool for designing water transmission and distribution systems. However, it does not follow that hydraulic analysis is also appropriate and applicable for the used and useful analysis in economic regulations.

The used and useful analysis for a water transmission and distribution system is not a flow measurement or flow projection technique. Used and useful analysis is about allocating construction costs fairly to both existing and future customers. Hydraulic analysis modeling proposed by SSU unfairly shifts the majority of the cost burden to existing customers, especially in new or sparsely developed areas. For example, in the same subdivision customers in densely developed areas will have to pay for water mains which are less used in newly or sparsely developed areas. The reason is that the distribution system will supply water to high demands from densely developed areas through looped water mains in sparsely developed areas. The fire flow provision also makes the water mains in sparsely developed areas highly used and useful. It is the responsibility of developers and utility owners to prevent scattered development. Utility owners should bear the risk and costs of acquiring systems serving sparse developments. Sunny Hills is a good example of the above conditions. The example below illustrates the unfair used and useful determination because the flow measurement technique utilized in a hydraulic analysis tends to inflate used and useful percentage for sparsely developed systems.

Assume a water distribution system is designed to serve 1,000 single family homes with a 750 gpm fire flow provision, and assume that the system currently serves only 100 homes with 350 gallons per home average daily consumption. Using peaking factors of 2 for maximum daily flows from average daily flows and 1.3 for peak hourly flows from maximum daily flows, the existing 100 homes will be required to pay for 58.84% of the total water mains laid for 1,000 homes. See the following calculation.

$$\text{Used and useful \%} = \frac{[(100 \times 350 \times 2 \times 1.3/1440) + 750]}{[(1000 \times 350 \times 2 \times 1.3/1440) + 750]} = 58.84\%$$

This example clearly demonstrates that the hydraulic analysis method unfairly allocates cost sharing between existing customers and future customers. In the filing, SSU has requested a 28.09% used and useful on the Sunny Hills Well 5 transmission and distribution system. In that subdivision, only four customers are connected to the system with a 491 lot capacity. Due to the inclusion of fire flow, those customers who represent less than one percent of the system, are responsible for 28.09% of the water mains cost. An economic regulatory agency like PSC should not accept such a disparity created by hydraulic analysis methods. If PSC accepts hydraulic analysis for used and useful calculations, future development will be intimidated by highly inflated rates.

Hydraulic analysis modeling is too complicated and time consuming to apply to water transmission and distribution used and useful analysis. Any change in high service pumps, distribution storage, customer demands and water main size will increase or decrease water flows in water pipes. For example, by using a larger size high service pump for build out conditions, more water will pass through the same water main. Therefore, a change in the system operating parameters will create a different hydraulic analysis result. The build out flows presented by SSU in the MFR's are not the ultimate capacities of the water mains, and they are subject to change. For examples, a lot of "dry" water mains in the original "Deltona" systems are not connected to existing distribution systems. Once the "dry" mains are connected, the build out flow of each main will be changed. If PSC accepts the use of hydraulic analysis, there will be numerous sets of used and useful percentages, and it can unduly complicate the used and useful analysis. Consequently customers will be paying more than their fair share on the water transmission and distribution system.

In addition, to validate the hydraulic analysis computer model for an existing distribution system, detailed calibrations are required, which includes comparing system pressures with computer output and checking roughness coefficient of water mains. A slight change on the roughness coefficient can affect the results significantly. Calibrating a hydraulic model basically is a trial and error process until the model prediction is close to field measurements. Trying to adopt hydraulic modeling for used and useful analysis is not appropriate because of complexity and time consumption. It is economically unfeasible for most utilities to perform hydraulic modeling for rate increase filings. Due to numerous variables, the enormous staff time required to verify hydraulic computer models is an unnecessary burden for PSC.

On the other hand, the "lot count" method allocates the water main costs evenly to all customers, after engineers have properly designed the whole system. The lot count method assigns a fair share of the total construction cost to every customer. The lot count method does not fail to recognize water main cost to accommodate fire flow and looped lines, because it allocates the total cost through used and useful percentages. Existing customers do not get a free ride because the construction costs of fire flow accommodation and looped lines are included in the total cost.

Water transmission and distribution systems are designed for all existing and future customers. The hydraulic analysis method clearly tilts the burden to existing customers. The lot count method tends to give an equal cost share to all customers. Therefore, the lot count method will not discourage future development, as opposed to the way hydraulic modeling will probably discourage future development. For some instances, however, the lot count method still favors future customers. For example, without future development, engineers would design a smaller size system for existing customers. However, most of the time water transmission and distribution mains are oversized for existing customers to accommodate future phases of development. Lot count method does not reduce the used and useful percentage for existing customers for the over sized mains. Therefore, existing customers are carrying extra costs for laying larger sizes of water mains that will be connected for future development. The burden on future customers are therefore less than existing customers.

"Fill-in-lots" should not be a problem in the lot count method. When a system is reaching built out, fill-in lots probably will be sold at appreciated values and increase the used and useful percentages. A mass development without proper phasing creates sparse development and scatters customers. Low used and useful percentages of the water transmission and distribution are apparent and unavoidable. Developers and utility owners should bear the risk for not preventing sparse development from happening. Existing customers should not pay for the consequence of low used and useful percentage on a water distribution system. SSU should recover the cost of unused water mains by collecting contributions from new customers. Adjustments have been made to appropriate systems in the Exhibit TLB-3.

Q. SHOULD RATE BASE INCLUDE WATER MAINS LAID IN THE GROUND BUT NOT CONNECTED TO THE EXISTING DISTRIBUTION SYSTEM?

A. Any water mains constructed in place but which do not connect to the existing system should be considered non-used and useful. Apparently those "dry" mains are reserved for future customers. Any investment in these "dry" water mains should be removed from rate base. When SSU provides the dollar investments in these "dry" water mains, these amounts should be removed from rate base.

Q. SHOULD EXCESS INFLOW AND INFILTRATION BE INCLUDED IN ENGINEERING SCHEDULE F-2(S) GALLONS OF WASTEWATER TREATED?

A. No. The amount of wastewater treated should not include any excessive inflow and infiltration. Engineering Schedules F-2(S) filed by SSU did not show the inflow and infiltration amount. The inflow/infiltration information should be presented to show the condition of collection system. Many guideline criteria are available and can be used for infiltration allowance on gravity sewers. In the *Recommended Standards for Wastewater Facilities,* 200 gallons per inch of pipe diameter per mile per day is the recommended guideline and that criteria is generally used by the FDEP staff.

Any excessive inflow and infiltration should be excluded from the amount of wastewater treated. The used and useful analysis should be adjusted accordingly. From the response to OPC Document Request No. 279, SSU indicated that eight out of the forty WWTP have excess inflow and infiltration, as shown by Appendix DR 279-A. The excess amounts were excluded from the used and useful calculations in Exhibit TLB-4.

Q. DO YOU AGREE THAT THE NEW RAW WATER SUPPLY SITE OF MARCO ISLAND IS 100% USED AND USEFUL WITHOUT EVALUATION?

A. No. An evaluation of total water supply capacity should be conducted before claiming 100% used and useful on the raw water supply site. Currently, it does not seem feasible that this facility will be put into service for the projected test year 1996 because no facilities have been constructed on the site. In addition, witness Mr. Terrero mentioned that SSU does not yet have the easement and right of way to connect the new water supply site and Marco Island. Therefore, the cost of 160 acres new water supply site should be eliminated from the rate base in this filing.

Q. DO YOU AGREE WITH THE 100% USED AND USEFUL REQUEST FOR ALL EFFLUENT REUSE FACILITIES WITHOUT EVALUATION?

A. No. Though effluent reuse is encouraged by environmental regulatory agencies and the utilities are allowed to recover the costs through rate structures, it does not automatically mean all effluent reuse facilities are 100% used and useful. Existing customers should not pay for extra reuse capacity, just as existing customers should not pay for excess capacities of wastewater treatment plants and percolation ponds. In addition, the effluent reuse customers also are paying costs for using the treated effluent. SSU should perform used and useful calculations on all systems that have reuse facilities: Amelia Island, Deltona Lakes, Florida Central Commerce Park, Lehigh, Marco Island, Point O'Woods, and University Shores. It is unjustified to ask existing customers to pay for future customers. Currently no specific used and useful calculations have been made due to lack of effluent reuse flow data. Under this circumstance, the used and useful percentage of reuse facilities was assumed the same percentage as used for percolation ponds.

Some systems have two or more effluent disposal measures other than reuse. For example, Marco Island wastewater system has golf course irrigation, percolation ponds, and deep injection well for its effluent disposal. Used and useful calculations may be revised when relevant information is provided by SSU.

Q. DO YOU AGREE THAT AN ADJUSTMENT SHOULD BE MADE TO THE DEEP INJECTION WELL ON MARCO ISLAND?

A. Yes. The used and useful percentage of the deep injection well on Marco Island depends on the flow data that will be provided by SSU in the near future. Proper adjustment may be made and filed to the Commission when necessary information is provided.

Q. DO YOU HAVE ANY SPECIFIC COMMENTS CONCERING THE BURNT STORE WATER SYSTEM?

A. Yes. I believe the capacity of the Burnt Store reverse osmosis water plant should be 380 gallons per minute (gpm) instead of 333 gpm. The SSU response to Staff Interrogatory No. 91 indicated that there are two membrane skids in service. Each skid is rated for 167 gpm. However, this pure product water (167 gpm) is blended with ten percent (10%) of the 223 gpm feed water. Therefore, the whole plant output capacity should be as follows:

Total Capacity = 2 x [167 gpm + (10% x 223 gpm)] = 378.6gpm

However, at his deposition SSU witness Mr. Terrero confirmed that he considered each skid to have a capacity of 190 gpm, resulting in a total capacity of 380 gpm for Burnt Store's reverse osmosis water plant. Proper adjustment has been made in my used and useful calculation in Exhibit TLB-3.

Q. DID YOU PREPARE ANY USED AND USEFUL CALCULATIONS IN THIS TESTIMONY?

A. Yes, I have recalculated the used and useful percentages for all water and wastewater systems, according to my positions on the above issues. However, some information was not provided by SSU, and I had to make many assumptions in the calculations. For example, fire flow provision was not included because no confirmation is available. Auxiliary power is normally designed to operate supply wells in water systems. In wastewater systems, auxiliary power is usually designed to operate the wastewater treatment plant.

All numbers filed by SSU were used, and assumed to be genuine and correct. The calculated used and useful percentages of water and wastewater systems are presented in Exhibit TLB-3 and Exhibit TLB-4, respectively. A summary of calculation key and rationale is also included in Exhibit TLB-2. However, these used and useful numbers are subject to change pending further responses to discovery.

Q. **DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?**

A Yes, that concludes my testimony filed on February 12, 1996.

EXHIBIT TLB-1

DISTRIBUTION SYSTEM ANALYSIS EXAMPLE

PUMPING FOR DISTRIBUTION STORAGE

The two types of distribution storage—ground and elevated—have, in turn, two types of pumping systems. One is a direct pumping system, in which the instantaneous system demand is met by pumping with no elevated storage provided. The second type is an indirect system in which the pumping station lifts water to a reservoir or elevated storage tank, which floats on the system and provides system pressure by gravity.

Direct Pumping

The direct pumping system is quite rare today, but some systems still exist. Variable-speed pumping units operated off of direct system pressure are also in use in some communities. Hydropneumatic tanks at the pumping station provide some storage. These tanks permit the pumping-station pumps to start and stop, based on a variable system pressure preset by controls operating off of the tank.

Indirect Pumping

In an indirect system, the pumping station is not associated with the demands of the major load center. It is operated from the water level difference in the reservoir or elevated storage tank, enabling the prescribed water level in the tank to be maintained. The majority of systems have an elevated storage tank or a reservoir on high ground floating on the system. This arrangement permits the pumping station to operate at a uniform rate, with the storage either making up or absorbing the difference between station discharge and system demand.

ANALYSIS OF STORAGE

Two variations of distribution storage design affect the operation and reliability of a system's fire suppression capabilities. These two variations involve placement of the storage between the supply point and the major load center or beyond the major load center. An analysis of the following storage designs will be made in the remainder of this chapter:

- system A—pumping station to major center of demand (load) with no elevated storage tank;
- system B—pumping station to major center of demand with an elevated storage tank between the supply and demand; and
- system C—pumping station to major center of demand with an elevated storage tank beyond the demand.

Model System

The model system used in the analysis has the following characteristics:

Population = 27,000	
Water demand rates	
Average day—27,000 × 150 gpcd	= 4.0 mgd
Maximum day—4.0 × 1.5	= 6.0 mgd
Maximum hour—6.0 × 1.5	= 9.0 mgd
Fire flow = 5000 gpm	= 7.2 mgd
Maximum 10-h rate	
Maximum day and fire flow—6.0 + 7.2	= 13.2 mgd
Minimum pressure at major load center	= 50 psi

System pipelines are all expressed as equivalent lengths of 24-in. pipe with a *C* factor of 120. Hydraulic gradient is the slope of the line joining the elevations to which water would rise in pipes freely vented and under atmospheric pressure.

System A—No Storage

If no storage is provided in system A (Figure 3-1) at a given demand rate, the pumping station hydraulic gradient must be sufficient to overcome system losses at a demand rate and maintain a minimum of 115 ft at the major load center. Thus, the pumping heads required to maintain 115 ft plus the head loss in 40,000 ft of equivalent pipe for the various conditions are as follows:

Demand Rates	Pumping Head Required
Average day, 4.0 mgd—115 + (0.67 × 40)	= 142 ft
Maximum day, 6.0 mgd—115 + (1.42 × 40)	= 172 ft
Maximum hour, 9.0 mgd—115 + (3.0 × 40)	= 235 ft
Maximum day and fire, 13.2 mgd—115 + (6.1 × 40)	= 359 ft

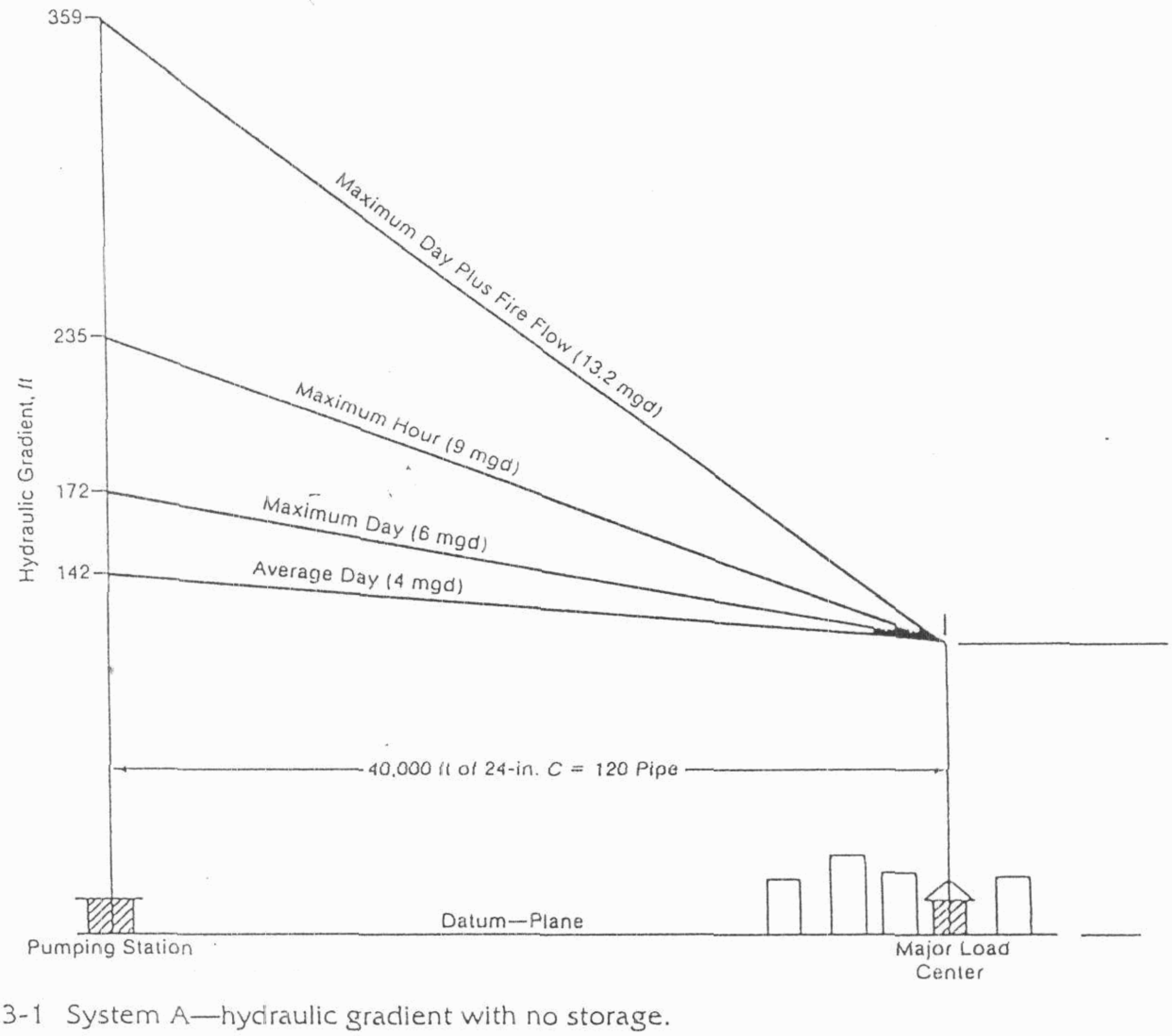

Figure 3-1 System A—hydraulic gradient with no storage.

System B—Storage Ahead of Load Center

If, as shown in Figure 3-2, a 1.75-mil gal storage tank is located 145 ft above the datum plane and at a distance of 35,000 ft from the pump station (5000 ft ahead of the major load center), the pumping head of a given pumping rate must be sufficient to pump against a head at the storage tank and overcome system losses at the pumping rate.

Average day. At the average-day demand, the required pumping rate (no water taken from storage) is 4 mgd. The pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 35,000 ft of equivalent pipe at 4 mgd, or 145 + (0.67 × 35) = 169 ft. The hydraulic gradient at the load center is the hydraulic gradient at the tank minus the head loss in 5000 ft of equivalent pipe, or 145 − (0.67 × 5) = 142 ft.

Maximum day. At the maximum-day demand, the required pumping rate is 6 mgd (no water taken from storage). The pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 35,000 ft of equivalent pipe at 6 mgd, or 145 + (1.42 × 35) = 195 ft. The hydraulic gradient at the load center is the hydraulic gradient at the tank minus the head loss in 5000 ft of equivalent pipe at 6 mgd, or 145 − (1.42 × 5) = 138 ft.

Maximum hour. At the maximum-hour demand, the flow in the 5000 ft of pipe between the tank and the load center must be 9 mgd. The hydraulic gradient at the load center is the hydraulic gradient at the tank minus the losses in 5000 ft of equivalent pipe at 9 mgd, or 145 − (3 × 5) = 130 ft. The pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 35,000 ft of equivalent pipe at the chosen pumping rate. If 3 mgd is to be supplied from the tank

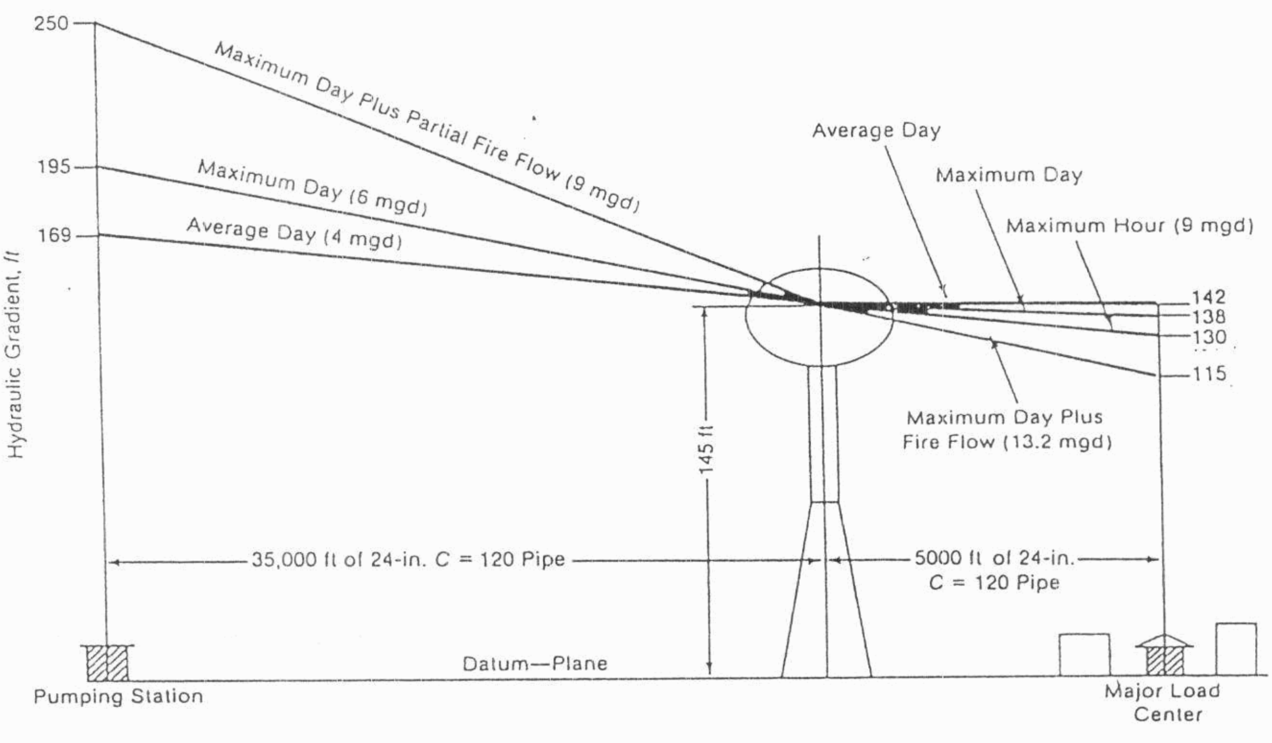

Figure 3-2 System B—hydraulic gradients with storage between pump station and load center.

storage and the remaining 6 mgd is to be supplied from pumping, the pumping head required is 145 + (1.42 × 35) = 195 ft (Figure 3-2).

Maximum day plus fire flow. At the maximum-day demand plus the fire demand, the flow in the 5000 ft of pipe between the tank and the load center must be 13.2 mgd. The hydraulic gradient at the load center is the hydraulic gradient at the tank minus the head loss of 5000 ft of equivalent pipe at 13.2 mgd, or 145 − (6.1 × 5) = 115 ft. If it is decided to supply 4.2 mgd from storage and pump the remaining 9 mgd, the pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 35,000 ft of equivalent pipe at 9 mgd, or 145 + (3 × 35) = 250 ft.

Demand Rates	Pumping Head Required
Average day, 4.0 mgd—no water from storage	= 169 ft
Maximum day, 6.0 mgd—no water from storage	= 195 ft
Maximum hour, 9.0 mgd—6.0 mgd from pumps + 3.0 mgd from storage	= 195 ft
Maximum day plus fire flow, 13.2 mgd—9.0 mgd from pumps + 4.2 mgd tank	= 250 ft

System C—Storage Beyond Load Center

In the arrangement shown in Figure 3-3, 1.75 mil gal of storage is provided 5000 ft beyond the load center (45,000 ft from the pump station) at an elevation of 119 ft above the datum plane. When no water is being taken from storage at a given demand rate, the pumping head must be sufficient to pump against the head at the tank and overcome losses between the pump station and the load center at that demand rate. When part of the demand is being supplied from storage, however, the pumping head need only be sufficient to pump against the head at the load center and overcome losses in the pipeline between the pump station and the load center.

Average day. At the average-day demand, the required pumping rate is 4 mgd (no water taken from storage). The pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 40,000 ft of equivalent pipe, or 119 + (0.67 × 40) = 146 ft. The hydraulic gradient at the load center is thus identical to that at the tank (119 ft).

Maximum day. At the maximum-day demand, the required pumping rate is 6 mgd (no water taken from storage). The pumping head required is equal to the hydraulic gradient at the tank plus the head loss in 40,000 ft of equivalent pipe at 6 mgd, or 119 + (1.42 × 40) = 176 ft. The hydraulic gradient at the load center is identical to that at the tank (119 ft).

Maximum hour. If, at the maximum-hour demand (9 mgd), it is decided to supply 3 mgd from storage and the remaining 6 mgd from pumping, the hydraulic gradient at the load center is the hydraulic gradient at the tank minus the head loss in the 5000 ft of pipe between the tank and load center at the storage discharge rate of 3 mgd, or 119 − (0.4 × 5) = 117 ft. The pumping head required is equal to the hydraulic gradient at the load center plus the head loss in 40,000 ft of equivalent pipe at 6 mgd, 117 + (1.42 × 40) = 174 ft.

Maximum day plus fire flow. In order to maintain a head of 115 ft at the load center, the flow in the 5000 ft of pipe between the load center and the tank cannot exceed that at which the head loss is 4 ft, which is 4.2 mgd. Thus the remainder of the demand (9 mgd) must be supplied from pumping. The pumping head required is equal to the hydraulic gradient at the load center (115 ft) plus the head loss in 40,000 ft of equivalent pipe, or 115 + (3 × 40) = 235 ft.

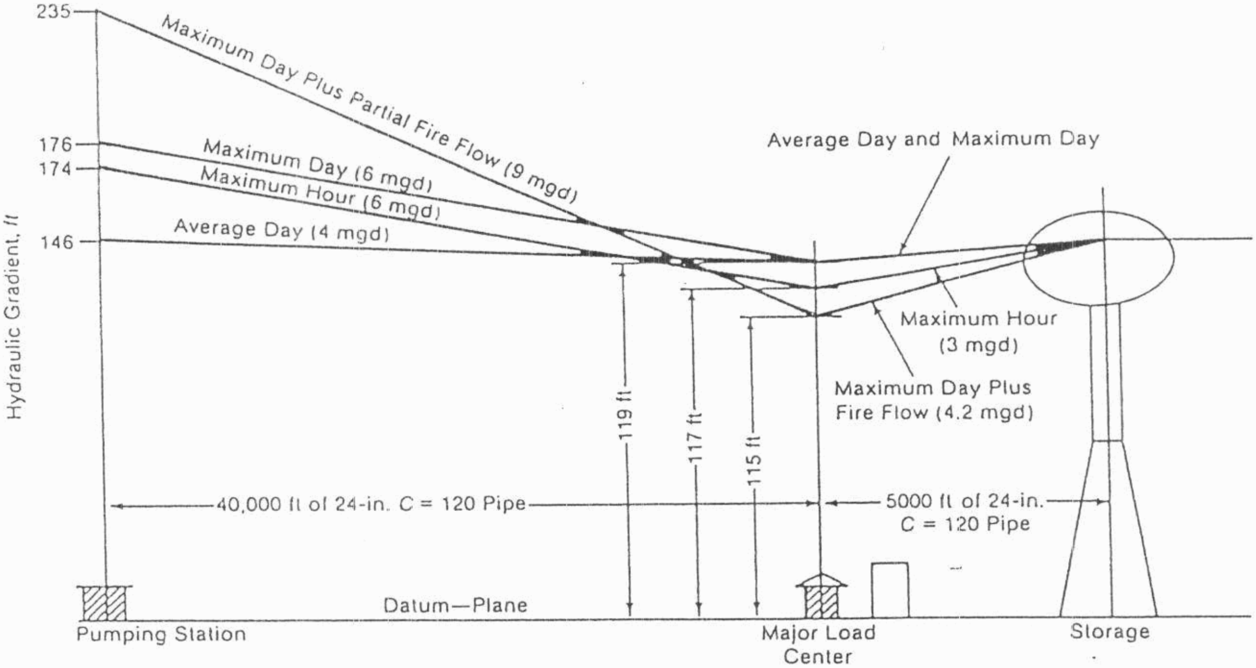

Figure 3-3 System C—hydraulic gradients with storage beyond load center.

Demand Rates	Pumping Head Required
Average day, 4.0 mgd—no water from storage	= 146 ft
Maximum day, 6.0 mgd—no water from storage	= 176 ft
Maximum hour, 9.0 mgd—6.0 mgd from pumps + 3.0 mgd from tank	= 174 ft
Maximum day plus fire flow, 13.2 mgd—9.0 mgd from pumps + 4.2 mgd from tank	= 235 ft

In the analyses above, the designer has provided 1.75 mil gal of storage for fire demands. The highest rate of flow that can be sustained for the required 10 h is 4.2 mgd. The remainder of the fire flow (3 mgd) and the maximum-day demand (6 mgd) must be supplied from pumping. The fact that the pumping rate (9 mgd) is the same as the maximum-hour demand is only a coincidence.

Comparison of System A With System C

If no storage is provided, 124 ft (359 ft − 235 ft) more pumping head is required to furnish the maximum-day demand plus fire flow than if adequate storage is provided beyond the load center. With the increased pumping rates required with no storage, the power needed is approximately 1100 hp, as opposed to 495 hp with storage, or more than twice as much. Similarly, furnishing the maximum-hour demand without storage would require 500 hp, as opposed to 245 hp, still more than twice as much.

The capacities of the pumps required under these two conditions would be 13.2 mgd at 359-ft head, as opposed to 9 mgd at 235-ft head, and 9 mgd at 235-ft head, as opposed to 6 mgd at 174-ft head. During average- and maximum-day demands, the pumping head at the source is approximately the same.

Comparison of System B With System C

In comparing storage located between the source and the load center with storage located beyond the load center, the examples illustrate that an increase in height is necessary if the storage is between the source and the load center. To secure approximately equivalent pressure results, the flow line of storage in the first instance must be 26 ft (145 ft − 119 ft) higher than if the storage feeds back to the load center from a point beyond.

Pumping heads are substantially lower under all rates of flow and pressure is more uniformly regulated, if the storage is located beyond the load center. The area served is substantially greater and the pressures are better regulated by storage located beyond the load center than by storage located between the pumping station and the load center. The additional height of 26 ft for the storage tank and the additional pumping head under all rates of flow make system B more costly when considering initial capital cost and substantially higher operating costs for electrical power.

Recommended Design

System C, using a 1.75-mil gal elevated storage tank beyond the major load center, is the recommended design, because it provides the necessary water demand flows at reasonable pressures. This system is also the most cost-effective design for capital costs and operating costs.

The design chosen is based on replenishing, within the 24 h during which a major fire occurs, all water taken from storage for fire fighting. The maximum required pumping head would be reduced from 235 ft to 182 ft if all water used for fire fighting (7.2 mgd) was provided by storage, and the pumps would only have to operate at 6 mgd. If the system was so designed, however, the tank would have to be raised 6 ft in order to maintain 115 ft of head at the load center, and the fire storage would have to be increased to 3 mil gal. Fire storage would then amount to 50 percent of the maximum day and 75 percent of the average day, and that much storage might not be economically justified. On the other hand, if the storage is not provided, an additional 3 mgd of pumping capacity is required and the production and supply works must also be capable of increased output, unless finished-water storage is provided ahead of the pump station. Therefore, an economic and engineering study should generally be made to determine the most efficient way to provide the required capacity.

References

1. *Water Distribution Operator Training Handbook.* AWWA, Denver, Colo. (1976).
2. COTE, A.E. & LINVILLE, J.L., eds. *Fire Protection Handbook.* National Fire Protection Association, Quincy, Mass. (16th ed., 1986).
3. FAIR, G.M. ET AL. *Water and Wastewater Engineering.* John Wiley and Sons, Inc., New York (1966).
4. STEEL, E.W. & MCGHEE, T.G. *Water Supply and Sewerage.* McGraw-Hill Book Co., New York (1979).

EXHIBIT TLB-2

KEY AND RATIONALE

FOR

OPC USED AND USEFUL CALCULATIONS

KEY AND RATIONALE FOR OPC USED AND USEFUL CALCULATIONS

I. SUPPLY WELL

A. Small System (without high service pumps):

Used & Useful % = **PHF/Reliable Capacity** (w/o fire flow provision)

= **(MDF + FF)/Reliable Capacity** (w/ fire flow provision)

Rationale ---- Well pumps function as high service pumps. Therefore, according to "10 States Standards", at least two pumping units shall be provided. With any pump out of service, the remaining pump or pumps shall be capable of providing the maximum daily pumping demand of the system. It is not economically justified to use PHF+FF as design flow. A peaking factor of 1.3 is applied to MDF where PHF is used in the calculations.

B. Large System (with high service pumps and storage):

Used & Useful % = **MDF/Total Capacity** or **ADF/Reliable Capacity,**

Whichever is greater.

Rationale ---- ADF/Reliable Capacity is used because the percentage is generally greater than MDF/Total Capacity. Reliable capacity should be applied once to high service pumps, not to other facilities also. The chance of having a well and a high service pump breakdown or to be out of service simultaneously is very slim. "10 States Standards" states that "the total developed groundwater source capacity shall equal or exceed the design maximum day demand and equal or exceed the design average day demand with the largest producing well out of service."

Notes: 1. PHF = Peak Hourly Flow; MDF = Avg. 5 Max Day Flows in Max Month; ADF = Annual Avg. Day Flow; FF = Fire Flow. However, no fire flow was applied because no fire flow confirmation was provided by SSU yet.

2. Water flow was adjusted for excess unaccounted for water.

3. Wastewater flow was adjusted for excess infiltration.

4. No margin reserve was included in OPC's calculations.

II. HIGH SERVICE PUMP

Used & Useful % = **(MDF + FF)/Reliable Capacity**

or **PHF/Reliable Capacity** (no fire protection)

Rationale ---- It is not economically justified to use PHF + FF as design flow, per AWWA M31 (P.16). Reliable capacity should be used per "10 States Standards." No fire flow was applied at this time. It may be included pending future discovery response. For systems with elevated storage tanks like Keystone Heights and Lehigh, the peak hour demands are provided by elevated tanks.

III. WATER TREATMENT PLANT

Used & Useful % = **MDF/Total Capacity**

Rationale ---- The chance is very small to have a high service pump and a part of treatment facilities to be out of service at the same time.

VI. FINISHED WATER STORAGE

Used & Useful % = **(1/2 ADF + FF)/Total Capacity** (with fire flow provision) or **ADF/Total Capacity** (without fire flow protection)

Rationale ---- AWWA M32 suggests that equalization storage is about 20 to 25 percent of the average day demand. Fire storage shall be included if fire flow is provided. Emergency storage is an owner option.

---- "10 States Standard" requires fire flow storage where fire protection is provided. The minimum storage capacity for systems not providing fire protection shall be equal to the average daily consumption (ADF). This requirement may be reduced when the source and treatment facilities have sufficient capacity with stand by power to supplement peak demands of the system. Emergency storage is not mentioned in this reference.

---- SSU uses a peaking factor of 2 and 4 hours of peak duration to calculate peak hour storage or equalization storage. This is a pure empirical method. SSU also requests 8 hours of ADF as emergency storage for some water systems, but no detail explanation was provided.

---- OPC believes fire storage should be included where fire protection is provided. Fire flow storage was not included because SSU has not confirmed the provision of fire protection. Fire flow is assumed stored in ground storage tanks and delivered through high service pumps.

When the system is furnishing fire flow, a half day ADF storage is used. That is more than adequate for peak hour demand storage compared with 20 to 25% ADF mentioned in the AWWA M32. The volume of a half day ADF is also close to

SSU's empirical method calculated. The excess storage can be considered as a provision for emergency storage. The one day ADF storage criteria used in "10 States Standards" was reduced to one half day because MDF design flow is used for supply wells, treatment plant and high service pumps. Fire storage will be included if it is confirmed.

No emergency storage was included because it is not yet confirmed by the original design or other supporting documents. Total capacity is used because SSU used more than 10% for dead storage without confirmation. Dead storage is not applicable to elevated storage tanks.

V. HYDROPNEUMATIC TANK

$$\text{Used \& Useful \%} = \frac{\textbf{10 x (Total Capacity - Reliable Capacity of Supply Well)}}{\textbf{Hydro Tank Capacity}}$$

Rationale ---- Hydropneumatic tanks are usually used in very small water systems with groundwater supply wells as "10 States Standards" stated. When serving more than 150 units, ground or elevated storage should be provided.

The sizing criteria is ten times the capacity of the largest well pump. The information filed is not clear on some supply wells especially for large systems because two wells were assumed out of service. However, the largest well capacity is still assumed to be the difference between total capacity and reliable capacity of supply wells.

VI. AUXILIARY POWER

A. Water System:

Used & Useful % = **(1/2 MDF)/(1/2 Total Capacity) = MDF / Total Capacity**

Rationale ---- This a FDEP requirement per Chapter 62-555.320, F.A.C. SSU cannot provide proper capacity information of auxiliary power, therefore, the used and useful percentage of supply wells was used because the cost of auxiliary power is booked under the Source of Supply as Power Generation Equipment.

B. Wastewater System:

Used & Useful % = **ADF of Max. Month/Total Capacity**

Rationale ---- FDEP has no specific requirement. Since SSU cannot provide proper capacity information to specific equipments, the same used and useful percentage of WWTP was used for auxiliary power.

VII. WASTEWATER TREATMENT PLANT

Used & Useful % = **ADF of Max. Month/Total Capacity**

Rationale ---- Though the capacity permitted is annual ADF, OPC agrees to use ADF of the maximum month because that is the PSC policy.

VIII. EFFLUENT DISPOSAL AND EFFLUENT REUSE FACILITY

Used & Useful % = **ADF of Max. Month/Total Capacity**

Rationale ---- Same as WWTP.

Note: Since no effluent reuse data was yet provided, the same used and useful percentage also was used for effluent reuse facilities for the following systems: Amelia Island, Deltona Lakes, Florida Central Commerce Park, Lehigh, Marco Island, Point O'Woods, and University Shores.

IX. WATER DISTRIBUTION SYSTEM AND WASTEWATER COLLECTION SYSTEM

Used & Useful % = **Lots Connected/Total Lots Available**

Rationale ---- See direct testimony.

X. FLOWS AND LOTS PROJECTIONS OF 1996

A. Water System:

MDF of 1996 = (ERCs of 1996/ERCs of 1994) x Avg. 5 Max. Day of 1994

B. Wastewater System:

ADF of Max. Month in 1996 = (ERCs of 1996/ERCs of 1994) x ADF of Max. Month in 1994

C. Water Distribution and Wastewater Collection Systems

Connected Lots of 1996 = (ERCs of 1996/ERCs of 1994) x Connected Lots of 1994

EXHIBIT TLB-3

OPC USED AND USEFUL CALCULATIONS

OF

WATER SYSTEMS

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.		Amelia Island	Apache Shore	Apple Valley	Bay Lake Estates	Beacon Hill	Beecher's Point	Burnt Store	Carlton Village	Chuluota
	Docket No. 950495-WS									
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]							Reverse		
	FPSC Uniform [x]; FPSC Non-Uniform [x]							Osmosis		
1	1994 MAX DAY FOR YEAR (GPD)	2,110,842	24,000	960,000	60,000	2,849,200	Water	239,040	94,000	488,000
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	1,933,972	20,200	767,715	56,348	2,731,049	Purchased	220,503	108,593	367,168
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	1,727,071	20,200	736,800	54,000	2,477,540	From	194,688	93,080	352,400
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	1,286,547	15,268	389,878	20,038	1,492,990	Town of	164,340	45,073	207,825
3	1994 ANNUAL AVG DAILY FLOW (GPD)	1,148,909	15,268	374,178	19,203	1,354,404	Welaka	145,100	38,634	199,466
4	FIRE STORAGE ACCEPTED (GAL.)	0	0	0	0	0		0	0	0
5	FIRE FLOW PROVISION (GPM)	0	0	0	0	0		0	0	0
6	Unaccounted for Water Level (%)	21.9%	11.9%	9.7%	8.5%	0.3%	17.6%	0.1%	19.9%	4.9%
7	Unaccounted for Water Allowed (%)	10.0%	10.0%	9.7%	8.5%	0.3%	10.0%	0.1%	10.0%	4.9%
8										
9	<u>SOURCE OF SUPPLY AND PUMPING:</u>									
10	**Supply Wells:**	L	S	L	S	L	S	L	S	L
11	Total Capacity (gpm)	2,800	150	1,100	275	3,850	N/A	440	300	1,300
12	Reliable Capacity (gpm)	1,400	50	500	0	2,350	N/A	220	100	800
13	OPC Calculated Used & Useful (%)	**56.22%**	**35.78%**	**54.15%**	**100.00%**	**44.12%**	**N/A**	**51.87%**	**88.33%**	**18.04%**
14	U & U Per Order (%)	67.70%	25.30%	100.00%	100.00%	58.90%	N/A	80.10%	100.00%	98.50%
15	SSU Requested U & U (%)	100.00%	66.67%	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	50.43%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided	Unavailable		Unavailable	Unavailable	Unavailable		Unavailable	Unavailable	Unavailable
19	OPC Calculated Used & Useful (%)	**56.22%**		**54.15%**	**100.00%**	**44.12%**		**51.87%**	**88.33%**	**18.04%**
20	SSU Requested U & U (%)	100.00%		100.00%	100.00%	100.00%		100.00%	100.00%	100.00%
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	5,200	N/A	2,400	N/A	5,675	N/A	2,400	N/A	1,950
24	Reliable Capacity (gpm)	2,645	N/A	1,200	N/A	4,000	N/A	900	N/A	1,450
25	OPC Calculated Used & Useful (%)	**44.73%**	**N/A**	**44.43%**	**N/A**	**47.41%**	**N/A**	**17.01%**	**N/A**	**17.58%**
26	U & U Per Order (%)	64.20%	N/A	100.00%	N/A	100.00%	N/A	100.00%	N/A	100.00%
27	SSU Requested U & U (%)	100.00%	N/A	100.00%	N/A	100.00%	N/A	100.00%	N/A	97.03%
28										
29	<u>WATER TREATMENT PLANT:</u>									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	380	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	380	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**40.30%**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	96.77%	N/A	N/A
36										
37	<u>TRANSMISSION AND DISTRIBUTION:</u>									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)	1,000,000		100,000		433,600		500,000		150,000
40	Reliable Capacity (gal.)	289,953	N/A	90,000	N/A	390,240	N/A	401,633	N/A	135,000
41	OPC Calculated Used & Useful (%)	**56.67%**	**N/A**	**100.00%**	**N/A**	**100.00%**	**N/A**	**16.43%**	**N/A**	**69.28%**
42	U & U Per Order (%)	100.00%	N/A	100.00%	N/A	100.00%	N/A	46.90%	N/A	75.00%
43	SSU Requested U & U (%)	100.00%	N/A	100.00%	N/A	100.00%	N/A	84.75%	N/A	100.00%
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	20,000	12,500	15,000	3,000	20,000	N/A	25,000	10,000	15,000
47	OPC Calculated Used & Useful (%)	**70.00%**	**8.00%**	**40.00%**	**91.67%**	**75.00%**	**N/A**	**8.80%**	**20.00%**	**33.33%**
48	U & U Per Order (%)	100.00%	81.00%	100.00%	100.00%	100.00%	N/A	100.00%	54.00%	100.00%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	100.00%
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	<u>TRANSMISSION AND DISTRIBUTION:</u>									
54	**Connected Lots in 1996 w/o M.R.**	1,601	153	982	72	3,266	52	490	147	682
55	Connected Lots in 1994 w/o M.R.	1,429	153	942	69	2,962	45	432	126	655
	Connected Lots in 1994 w/ M.R.	1,513	153	962	70	3,080	49	458	137	669
56	Number of Lots	2,467	293	1,591	100	3,178	85	4,347	343	1,055
57	OPC Calculated Used & Useful (%)	**64.88%**	**52.22%**	**61.71%**	**72.00%**	**100.00%**	**61.56%**	**11.26%**	**42.86%**	**64.67%**
58	U & U Per Order (%)	100.00%	55.00%	100.00%	64.00%	97.00%	100.00%	13.70%	31.00%	100.00%
59	SSU Requested U & U (%)	100.00%	55.00%	100.00%	73.70%	100.00%	100.00%	13.70%	45.89%	100.00%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

<u>Year</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>
1990	1,630	161	918	63	2,545	69	503	87	635
1991	1,804	160	941	64	2,660	80	561	96	653
1992	1,924	161	961	66	2,799	90	597	109	669
1993	2,027	157	982	68	3,078	92	651	118	679
1994	2,187	153	1,001	69	3,401	94	724	126	692
1995	2,315	153	1,022	70	3,536	103	767	137	707
1995.5	2,382	153	1,033	71	3,642	107	793	142	714
1996	2,449	153	1,043	72	3,749	110	820	147	721

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No		Citrus Park	Citrus Springs	Crystal River	Daetwyler Shores	Deltona Lakes	Dol Ray Manor	Druid Hills	East Lake Harris Est.	Fern Park	Fern Terrace
	Docket No. 950495-WS										
	Company: Southern States Utilities, Inc.										
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]										
	FPSC Uniform [x]; FPSC Non-Uniform [x]										
1	1994 MAX DAY FOR YEAR (GPD)	155,700	1,384,800	46,000	Water	15,981,000	66,600	299,000	40,200	92,000	93,680
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	144,583	1,018,008	40,744	Purchased	16,045,232	57,120	240,800	37,268	80,641	81,858
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	142,940	960,200	38,600	From	15,200,200	57,120	240,800	36,640	80,200	79,300
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	90,399	594,100	23,653	Orlando	6,764,274	26,158	124,771	18,026	52,101	37,835
3	1994 ANNUAL AVG DAILY FLOW (GPD)	89,372	560,364	22,408	Util. Comm.	6,408,029	26,158	124,771	17,722	51,816	36,653
4	**FIRE STORAGE ACCEPTED (GAL.)**	0	0	0		0	0	0	0	0	0
5	**FIRE FLOW PROVISION (GPM)**	0	0	0		0	0	0	0	0	0
6	Unaccounted for Water Level (%)	9.9%	17.9%	2.8%	2.0%	11.6%	0.0%	14.2%	9.9%	7.9%	4.4%
7	Unaccounted for Water Allowed (%)	9.9%	10.0%	2.8%	2.0%	10.0%	0.0%	10.0%	9.9%	7.9%	4.4%
8											
9	**SOURCE OF SUPPLY AND PUMPING:**										
10	**Supply Wells:**	S	L	S	S	L	L	L	S	L	S
11	Total Capacity (gpm)	285	1,500	390	N/A	17,230	525	550	200	259	180
12	Reliable Capacity (gpm)	137	1,000	150	N/A	14,230	250	200	0	0	0
13	OPC Calculated Used & Useful (%)	**95.27%**	**38.00%**	**24.52%**	**N/A**	**32.48%**	**7.27%**	**41.50%**	**100.00%**	**100.00%**	**100.00%**
14	U & U Per Order (%)	100.00%	100.00%	100.00%	N/A	96.00%	100.00%	100.00%	100.00%	100.00%	100.00%
15	SSU Requested U & U (%)	100.00%	100.00%	53.64%	N/A	92.85%	100.00%	100.00%	100.00%	100.00%	100.00%
16											
17	**Auxiliary Power:**										
18	Capacity (GPD), not provided	Unavailable				Unavailable		Unavailable			Unavailable
19	OPC Calculated Used & Useful (%)	**95.27%**				**32.48%**		**41.50%**			**100.00%**
20	SSU Requested U & U (%)	100.00%				100.00%		100.00%			100.00%
21											
22	**High Service Pumping:**										
23	Total Capacity (gpm)	N/A	4,500	N/A	N/A	23,300	500	500	N/A	250	N/A
24	Reliable Capacity (gpm)	N/A	3,000	N/A	N/A	21,200	250	250	N/A	0	N/A
25	OPC Calculated Used & Useful (%)	**N/A**	**21.70%**	**N/A**	**N/A**	**51.72%**	**15.87%**	**64.08%**	**N/A**	**100.00%**	**N/A**
26	U & U Per Order (%)	N/A	N/A	N/A	N/A	100.00%	100.00%	100.00%	N/A	100.00%	N/A
27	SSU Requested U & U (%)	N/A	100.00%	N/A	N/A	100.00%	37.00%	100.00%	N/A	100.00%	N/A
28											
29	**WATER TREATMENT PLANT:**										
30	**Water Treatment Equipment:**										
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36											
37	**TRANSMISSION AND DISTRIBUTION:**										
38	**Finished Water Storage:**										
39	Total Capacity (gal.)		500,000			7,000,000	8,000	30,000		17,000	
40	Reliable Capacity (gal.)	N/A	140,825	N/A	N/A	3,749,577	7,200	27,000	N/A	15,300	N/A
41	OPC Calculated Used & Useful (%)	**N/A**	**54.72%**	**N/A**	**N/A**	**47.54%**	**100.00%**	**100.00%**	**N/A**	**100.00%**	**N/A**
42	U & U Per Order (%)	N/A	N/A	N/A	N/A	100.00%	100.00%	100.00%	N/A	100.00%	N/A
43	SSU Requested U & U (%)	N/A	100.00%	N/A	N/A	100.00%	100.00%	100.00%	N/A	100.00%	N/A
44											
45	**Hydropneumatic Tanks:**										
46	Total Capacity (gal.)	4,000	16,000	2,000	N/A	25,500	5,000	7,500	3,000	4,500	3,000
47	OPC Calculated Used & Useful (%)	**37.00%**	**31.25%**	**100.00%**	**N/A**	**100.00%**	**55.00%**	**46.67%**	**66.67%**	**57.56%**	**60.00%**
48	U & U Per Order (%)	56.00%	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	70.00%	100.00%	50.00%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
50											
51	**USED AND USEFUL CALCULATIONS**										
	Water Transmission & Distribution System										
52	**Schedule F-7(W)**										
53	**TRANSMISSION AND DISTRIBUTION:**										
54	**Connected Lots in 1996 w/o M.R.**	350	1,892	76	124	23,933	59	247	177	178	126
55	Connected Lots in 1994 w/o M.R.	346	1,784	72	124	22,672	59	247	174	177	122
	Connected Lots in 1994 w/ M.R.	346	1,840	74	124	23,327	59	247	175	177	125
56	Number of Lots	335	11,667	91	138	34,940	77	335	214	208	126
57	OPC Calculated Used & Useful (%)	**100.00%**	**16.22%**	**83.52%**	**89.86%**	**68.50%**	**76.62%**	**73.73%**	**82.70%**	**85.56%**	**99.99%**
58	U & U Per Order (%)	100.00%	21.00%	100.00%	100.00%	89.30%	100.00%	100.00%	100.00%	100.00%	100.00%
59	SSU Requested U & U (%)	100.00%	42.71%	100.00%	100.00%	89.30%	100.00%	100.00%	100.00%	100.00%	100.00%
60											
	ERC CALCULATIONS (by SSU)										
	Combined Schedule of F- 8 & 9 (W)	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
	Year	ERC	ERC	ERC	ERC	ERC	ERC	ERC	ERC	ERC	ERC
	1990	333	1,719	65	136	22,190	77	333	168	180	119
	1991	326	1,810	65	133	23,064	77	331	170	180	121
	1992	328	1,864	68	130	23,651	77	330	170	181	123
	1993	340	1,898	70	130	24,301	75	330	173	180	125
	1994	348	1,960	72	131	24,895	75	331	175	182	124
	1995	348	2,021	74	131	25,614	75	331	176	182	127
	1995.5	350	2,050	75	131	25,946	75	331	177	182	128
	1996	352	2,078	76	131	26,279	75	331	178	183	128

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.		Fisherman's Haven	Fountains	Fox Run	Friendly Center	Golden Terrace	Gospel Island	Grand Terrace	Harmony Homes	Hermits Cove
	Docket No. 950495-WS									
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]									
	FPSC Uniform [x]; FPSC Non-Uniform [x]									
1	1994 MAX DAY FOR YEAR (GPD)	56,700	65,100	69,000	12,900	Water	7,000	99,500	5,900	80,800
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	41,680	50,427	62,297	9,100	Purchased	6,525	134,731	36,360	49,400
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	41,680	37,820	57,057	9,100	From	5,800	93,800	36,360	49,400
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	26,751	14,603	30,855	4,363	City of	2,271	50,119	23,078	20,043
3	1994 ANNUAL AVG DAILY FLOW (GPD)	26,751	10,952	28,260	4,363	Inverness	2,019	34,893	23,078	20,043
4	**FIRE STORAGE ACCEPTED (GAL.)**	0	0	0	0		0	0	0	0
5	**FIRE FLOW PROVISION (GPM)**	0	0	0	0		0	0	0	0
6	Unaccounted for Water Level (%)	3.1%	13.6%	1.5%	9.3%	17.6%	9.8%	4.3%	7.6%	9.8%
7	Unaccounted for Water Allowed (%)	3.1%	10.0%	1.5%	9.3%	10.0%	9.8%	4.3%	7.6%	9.8%
8										
9	**SOURCE OF SUPPLY AND PUMPING:**									
10	**Supply Wells:**	S	L	L	S	S	S	S	S	L
11	Total Capacity (gpm)	100	300	850	140	N/A	50	600	300	110
12	Reliable Capacity (gpm)	0	80	350	0	N/A	0	0	0	0
13	OPC Calculated Used & Useful (%)	**100.00%**	**12.22%**	**6.12%**	**100.00%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
14	U & U Per Order (%)	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%
15	SSU Requested U & U (%)	100.00%	100.00%	19.07%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided			Unavailable						Unavailable
19	OPC Calculated Used & Useful (%)			**6.12%**						**100.00%**
20	SSU Requested U & U (%)			100.00%						100.00%
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	N/A	1,500	850	N/A	N/A	N/A	N/A	N/A	240
24	Reliable Capacity (gpm)	N/A	1,000	500	N/A	N/A	N/A	N/A	N/A	120
25	OPC Calculated Used & Useful (%)	**N/A**	**3.38%**	**8.65%**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**37.16%**
26	U & U Per Order (%)	N/A	37.00%	100.00%	N/A	N/A	N/A	N/A	N/A	60.60%
27	SSU Requested U & U (%)	N/A	83.98%	100.00%	N/A	N/A	N/A	N/A	N/A	95.85%
28										
29	**WATER TREATMENT PLANT:**									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36										
37	**TRANSMISSION AND DISTRIBUTION:**									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)		20,000	50,000						23,000
40	Reliable Capacity (gal.)	N/A	18,000	45,000	N/A	N/A	N/A	N/A	N/A	20,700
41	OPC Calculated Used & Useful (%)	**N/A**	**35.19%**	**30.86%**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**43.57%**
42	U & U Per Order (%)	N/A	100.00%	100.00%	N/A	N/A	N/A	N/A	N/A	100.00%
43	SSU Requested U & U (%)	N/A	100.00%	100.00%	N/A	N/A	N/A	N/A	N/A	100.00%
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	10,000	13,000	4,400	3,500	N/A	600	6,000	5,000	3,000
47	OPC Calculated Used & Useful (%)	**10.00%**	**16.92%**	**100.00%**	**40.00%**	**N/A**	**83.33%**	**100.00%**	**60.00%**	**36.67%**
48	U & U Per Order (%)	15.00%	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	90.00%	75.90%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	**TRANSMISSION AND DISTRIBUTION:**									
54	**Connected Lots in 1996 w/o M.R.**	136	39	107	20	106	9	158	61	175
55	Connected Lots in 1994 w/o M.R.	136	29	98	20	105	8	110	61	175
	Connected Lots in 1994 w/ M.R.	136	32	103	20	105	9	139	61	175
56	Number of Lots	144	84	109	46	120	25	111	62	350
57	OPC Calculated Used & Useful (%)	**94.44%**	**46.18%**	**98.17%**	**43.48%**	**88.24%**	**12.34%**	**100.00%**	**98.39%**	**50.00%**
58	U & U Per Order (%)	100.00%	14.00%	100.00%	100.00%	100.00%	36.00%	100.00%	100.00%	49.40%
59	SSU Requested U & U (%)	100.00%	53.59%	100.00%	100.00%	100.00%	12.34%	100.00%	100.00%	50.41%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	133	2	82	21	118	6	38	62	173
1991	133	4	90	20	116	8	66	62	173
1992	133	6	94	21	117	8	95	62	172
1993	133	18	96	21	119	8	108	62	173
1994	136	30	98	20	119	8	110	61	176
1995	136	33	103	20	119	9	139	61	176
1995.5	136	37	105	20	120	9	148	61	176
1996	136	40	107	20	120	9	158	61	176

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.	Docket No. 950495-WS	Hobby Hills	Holiday Haven	Holiday Heights	Imperial Terrace	Inter-cession City	Interlachen/ Park Manor	Jungle Den	Keystone Heights	Kingswood
	Company: Southern States Utilities, Inc									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]									
	FPSC Uniform [x]; FPSC Non-Uniform [x]									
1	1994 MAX DAY FOR YEAR (GPD)	49,350	Water	33,000	103,000	136,190	101,400	Water	656,000	Water
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	42,540	Purchased	39,600	87,062	116,250	68,818	Purchased	549,886	Purchased
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	42,540	From	39,600	86,000	110,590	76,360	From	543,400	From
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	20,386	Astor Water	16,488	39,720	61,837	36,140	Astor Water	338,350	Brevard
3	1994 ANNUAL AVG DAILY FLOW (GPD)	20,386	Assoc.	16,488	39,236	58,826	40,101	Assoc.	334,359	County
4	FIRE STORAGE ACCEPTED (GAL.)	0		0	0	0	0		0	
5	FIRE FLOW PROVISION (GPM)	0		0	0	0	0		0	
6	Unaccounted for Water Level (%)	11.8%	21.7%	7.2%	5.8%	22.3%	24.9%	1.3%	11.8%	5.2%
7	Unaccounted for Water Allowed (%)	10.0%	10.0%	7.2%	5.8%	10.0%	10.0%	1.3%	10.0%	5.2%
8										
9	SOURCE OF SUPPLY AND PUMPING:									
10	**Supply Wells:**	S	S	S	S	S	L	S	L	S
11	Total Capacity (gpm)	325	N/A	220	550	325	340	N/A	1,230	N/A
12	Reliable Capacity (gpm)	150	N/A	0	150	75	160	N/A	680	N/A
13	OPC Calculated Used & Useful (%)	**25.14%**	**N/A**	**100.00%**	**52.40%**	**100.00%**	**13.35%**	**N/A**	**33.93%**	**N/A**
14	U & U Per Order (%)	43.20%	N/A	100.00%	100.00%	100.00%	56.30%	N/A	47.10%	N/A
15	SSU Requested U & U (%)	47.94%	N/A	100.00%	100.00%	100.00%	56.30%	N/A	70.97%	N/A
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided				Unavailable	Unavailable	Unavailable		Unavailable	
19	OPC Calculated Used & Useful (%)				**52.40%**	**100.00%**	**13.35%**		**33.93%**	
20	SSU Requested U & U (%)				100.00%	100.00%	100.00%		100.00%	
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	430	N/A	N/A	N/A
24	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	190	N/A	N/A	N/A
25	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**21.41%**	**N/A**	**N/A**	**N/A**
26	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	N/A	N/A
27	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	N/A	N/A
28										
29	WATER TREATMENT PLANT:									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36										
37	TRANSMISSION AND DISTRIBUTION:									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)						30,500		55,000	
40	Reliable Capacity (gal.)	N/A	N/A	N/A	N/A	N/A	27,450	N/A	49,500	N/A
41	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**50.42%**	**N/A**	**100.00%**	**N/A**
42	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	100.00%	N/A
43	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	100.00%	N/A
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	3,000	N/A	3,000	3,000	5,000	10,000	N/A	10,000	N/A
47	OPC Calculated Used & Useful (%)	**58.33%**	**N/A**	**73.33%**	**100.00%**	**50.00%**	**18.00%**	**N/A**	**55.00%**	**N/A**
48	U & U Per Order (%)	87.50%	N/A	100.00%	100.00%	75.00%	54.00%	N/A	71.30%	N/A
49	SSU Requested U & U (%)	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	N/A
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	TRANSMISSION AND DISTRIBUTION:									
54	**Connected Lots in 1996 w/o M.R.**	95	113	52	244	262	252	113	991	61
55	Connected Lots in 1994 w/o M.R.	95	112	52	241	249	280	113	979	61
	Connected Lots in 1994 w/ M.R.	95	113	52	243	257	250	113	984	61
56	Number of Lots	125	166	53	241	546	387	135	1,673	68
57	OPC Calculated Used & Useful (%)	**76.00%**	**68.07%**	**98.11%**	**100.00%**	**47.97%**	**65.19%**	**83.70%**	**59.22%**	**89.71%**
58	U & U Per Order (%)	100.00%	70.00%	100.00%	100.00%	44.00%	61.50%	100.00%	68.40%	100.00%
59	SSU Requested U & U (%)	100.00%	70.00%	100.00%	100.00%	49.02%	66.33%	100.00%	68.40%	100.00%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Hobby Hills Water ERC	Holiday Haven Water ERC	Holiday Heights Water ERC	Imperial Terrace Water ERC	Inter-cession City Water ERC	Interlachen/ Park Manor Water ERC	Jungle Den Water ERC	Keystone Heights Water ERC	Kingswood Water ERC
1990	94	111	51	238	236	235	112	1,148	61
1991	92	116	52	241	239	240	113	1,140	60
1992	91	116	51	242	247	243	113	1,152	59
1993	95	112	51	243	255	242	112	1,167	60
1994	96	114	52	243	254	243	113	1,173	61
1995	96	115	52	245	262	217	113	1,179	61
1995.5	96	115	52	245	265	218	113	1,183	61
1996	96	115	52	246	267	219	113	1,187	61

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No	Docket No. 950495-WS	Lake Ajay	Lake Brantley	Lake Conway	Lake Harriet	Lakeview Villas	Leilani Heights	Leisure Lakes	Marco Shores	Marion Oaks	Meredith Manor
	Company: Southern States Utilities, Inc										
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]										
	FPSC Uniform [x]; FPSC Non-Uniform [x]										
1	1994 MAX DAY FOR YEAR (GPD)	105,070	41,000	Water	140,000	12,200	381,500	66,000	479,966	1,058,000	400,300
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	131,480	31,600	Purchased	116,839	7,620	255,124	51,229	403,171	972,926	357,260
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	97,514	31,600	From	115,600	7,620	252,540	50,200	403,171	896,000	357,260
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	49,350	17,940	Orlando	73,370	2,251	142,564	24,503	135,064	601,295	232,154
3	1994 ANNUAL AVG DAILY FLOW (GPD)	36,601	17,940	Util. Comm.	72,592	2,251	141,120	24,011	135,064	553,753	232,154
4	FIRE STORAGE ACCEPTED (GAL.)	0	0		0	0	0	0	0	0	0
5	FIRE FLOW PROVISION (GPM)	0	0		0	0	0	0	0	0	0
6	Unaccounted for Water Level (%)	9.1%	5.7%	5.7%	5.1%	0.6%	9.8%	14.7%	4.3%	7.7%	2.8%
7	Unaccounted for Water Allowed (%)	9.1%	5.7%	5.7%	5.1%	0.6%	9.8%	10.0%	4.3%	7.7%	2.8%
8											
9	SOURCE OF SUPPLY AND PUMPING:										
10	**Supply Wells:**	L	L	S	L	S	S	L		L	L
11	Total Capacity (gpm)	200	100	N/A	600	25	470	350	N/A	1,500	1,380
12	Reliable Capacity (gpm)	100	0	N/A	0	0	100	50	N/A	1,000	300
13	OPC Calculated Used & Useful (%)	**34.27%**	**100.00%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**32.43%**	**N/A**	**41.76%**	**53.74%**
14	U & U Per Order (%)	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	N/A	63.70%	80.10%
15	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	92.92%
16											
17	**Auxiliary Power:**										
18	Capacity (GPD), not provided	Unavailable					Unavailable	Unavailable	navailable	Unavailable	Unavailable
19	OPC Calculated Used & Useful (%)	**34.27%**					**100.00%**	**32.43%**	**18.67%**	**41.76%**	**53.74%**
20	SSU Requested U & U (%)	100.00%					100.00%	100.00%	100.00%	100.00%	100.00%
21											
22	**High Service Pumping:**										
23	Total Capacity (gpm)	320	100	N/A	400	N/A	N/A	400	2,700	1,200	1,150
24	Reliable Capacity (gpm)	160	0	N/A	0	N/A	N/A	200	1,500	600	350
25	OPC Calculated Used & Useful (%)	**57.07%**	**100.00%**	**N/A**	**100.00%**	**N/A**	**N/A**	**16.95%**	**18.67%**	**100.00%**	**70.88%**
26	U & U Per Order (%)	100.00%	100.00%	N/A	100.00%	N/A	N/A	100.00%	68.20%	100.00%	100.00%
27	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	N/A	N/A	100.00%	100.00%	100.00%	100.00%
28											
29	WATER TREATMENT PLANT:										
30	**Water Treatment Equipment:**										
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	500	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	500	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**56.00%**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	48.00%	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	N/A
36											
37	TRANSMISSION AND DISTRIBUTION:										
38	**Finished Water Storage:**										
39	Total Capacity (gal.)	15,000	8,000		25,000			15,000	500,000	1,000,000	50,000
40	Reliable Capacity (gal.)	13,500	7,200	N/A	22,500	N/A	N/A	13,500	367,123	900,000	45,000
41	OPC Calculated Used & Useful (%)	**100.00%**	**100.00%**	**N/A**	**100.00%**	**N/A**	**N/A**	**77.84%**	**13.51%**	**30.06%**	**100.00%**
42	U & U Per Order (%)	100.00%	100.00%	N/A	100.00%	N/A	N/A	100.00%	58.90%	100.00%	100.00%
43	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	N/A	N/A	100.00%	100.00%	100.00%	100.00%
44											
45	**Hydropneumatic Tanks:**										
46	Total Capacity (gal.)	3,000	1,000	N/A	5,000	1,000	20,000	10,000	10,000	27,000	10,000
47	OPC Calculated Used & Useful (%)	**33.33%**	**100.00%**	**N/A**	**100.00%**	**25.00%**	**18.50%**	**30.00%**	**N/A**	**18.52%**	**100.00%**
48	U & U Per Order (%)	100.00%	100.00%	N/A	100.00%	30.00%	59.00%	100.00%	100.00%	100.00%	100.00%
49	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
50											
51	**USED AND USEFUL CALCULATIONS**										
	Water Transmission & Distribution System										
52	**Schedule F-7(W)**										
53	TRANSMISSION AND DISTRIBUTION:										
54	**Connected Lots in 1996 w/o M.R.**	111	67	84	282	12	395	252	518	2,709	639
55	Connected Lots in 1994 w/o M.R.	82	67	84	279	12	391	247	518	2,494	639
	Connected Lots in 1994 w/ M.R.	96	67	84	280	12	393	385	518	2,601	639
56	Number of Lots	100	73	89	302	23	413	584	584	12,262	867
57	OPC Calculated Used & Useful (%)	**100.00%**	**91.78%**	**94.38%**	**93.38%**	**52.17%**	**95.64%**	**43.16%**	**88.70%**	**22.09%**	**73.70%**
58	U & U Per Order (%)	44.35%	100.00%	97.00%	100.00%	100.00%	100.00%	75.00%	70.70%	34.40%	85.20%
59	SSU Requested U & U (%)	100.00%	100.00%	97.00%	100.00%	100.00%	100.00%	75.00%	100.00%	66.83%	85.20%
60											

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	28	65	85	273	14	385	236	417	2,181	730
1991	38	65	84	273	13	386	242	410	2,316	734
1992	54	66	85	275	13	388	243	405	2,412	730
1993	74	65	85	278	12	390	243	408	2,526	730
1994	89	67	84	280	12	391	244	432	2,644	734
1995	104	67	84	281	12	393	247	432	2,757	734
1995.5	112	67	84	282	12	394	248	432	2,814	734
1996	120	67	84	283	12	395	249	432	2,871	734

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.	Docket No. 950495-WS	Morningview	Oak Forest	Oakwood	Palisades	Palm Port	Palm Terrace	Palm Mobile Home Park	Picciola Island	Pine Ridge
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]									
	FPSC Uniform [x], FPSC Non-Uniform [x]									
1	1994 MAX DAY FOR YEAR (GPD)	28,900	140,000	Water	146,000	41,700	183,800	12,990	83,100	793,000
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	17,540	114,637	Purchased	174,771	35,218	151,912	10,574	81,324	820,099
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	17,540	111,600	From	122,100	32,560	151,660	10,574	78,420	670,000
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	11,245	46,900	Brevard	69,894	18,415	71,773	4,453	39,071	426,945
3	1994 ANNUAL AVG DAILY FLOW (GPD)	11,245	45,658	County	48,830	17,025	71,654	4,453	37,676	348,803
4	FIRE STORAGE ACCEPTED (GAL.)	0	0		0	0	0	0	0	0
5	FIRE FLOW PROVISION (GPM)	0	0		0	0	0	0	0	0
6	Unaccounted for Water Level (%)	8.0%	26.1%	4.2%	9.8%	12.4%	12.0%	2.4%	17.4%	5.7%
7	Unaccounted for Water Allowed (%)	8.0%	10.0%	4.2%	9.8%	10.0%	10.0%	2.4%	10.0%	5.7%
8										
9	SOURCE OF SUPPLY AND PUMPING:									
10	**Supply Wells:**	S	S	S	S	L	S	S	S	S
11	Total Capacity (gpm)	425	630	N/A	800	100	160	130	275	1,150
12	Reliable Capacity (gpm)	0	150	N/A	0	0	0	0	100	550
13	OPC Calculated Used & Useful (%)	**100.00%**	**44.53%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**67.98%**	**100.00%**
14	U & U Per Order (%)	100.00%	100.00%	N/A	86.80%	100.00%	100.00%	26.60%	100.00%	100.00%
15	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided		Unavailable						Unavailable	Unavailable
19	OPC Calculated Used & Useful (%)		**44.53%**						**67.98%**	**100.00%**
20	SSU Requested U & U (%)		100.00%						100.00%	100.00%
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	N/A	N/A	N/A	N/A	120	N/A	N/A	N/A	N/A
24	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	60	N/A	N/A	N/A	N/A
25	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**39.78%**	**N/A**	**N/A**	**N/A**	**N/A**
26	U & U Per Order (%)	N/A	N/A	N/A	N/A	29.50%	N/A	N/A	N/A	N/A
27	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	100.00%	N/A	N/A	N/A	N/A
28										
29	WATER TREATMENT PLANT:									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36										
37	TRANSMISSION AND DISTRIBUTION:									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)					18,000				
40	Reliable Capacity (gal.)	N/A	N/A	N/A	N/A	16,200	N/A	N/A	N/A	N/A
41	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**49.92%**	**N/A**	**N/A**	**N/A**	**N/A**
42	U & U Per Order (%)	N/A	N/A	N/A	N/A	23.60%	N/A	N/A	N/A	N/A
43	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	100.00%	N/A	N/A	N/A	N/A
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	4,500	10,000	N/A	15,000	5,000	3,000	1,500	5,000	16,000
47	OPC Calculated Used & Useful (%)	**94.44%**	**48.00%**	**N/A**	**53.33%**	**20.00%**	**53.33%**	**86.67%**	**35.00%**	**37.50%**
48	U & U Per Order (%)	100.00%	43.20%	N/A	80.00%	30.00%	80.00%	100.00%	53.00%	100.00%
49	SSU Requested U & U (%)	100.00%	100.00%	N/A	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	**TRANSMISSION AND DISTRIBUTION:**									
54	**Connected Lots in 1996 w/o M.R.**	36	145	206	49	106	1,183	59	137	818
55	Connected Lots in 1994 w/o M.R.	36	141	201	34	98	1,181	59	132	668
	Connected Lots in 1994 w/ M.R.	36	143	203	40	103	1,181	59	135	743
56	Number of Lots	42	287	191	141	137	1,213	87	213	3,828
57	OPC Calculated Used & Useful (%)	**85.71%**	**50.49%**	**100.00%**	**34.52%**	**77.37%**	**97.52%**	**67.82%**	**64.30%**	**21.36%**
58	U & U Per Order (%)	100.00%	50.70%	100.00%	6.30%	67.50%	100.00%	69.00%	100.00%	20.00%
59	SSU Requested U & U (%)	100.00%	51.28%	100.00%	40.08%	80.22%	100.00%	69.00%	100.00%	100.00%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	44	140	189	2	86	1,199	59	125	776
1991	45	140	191	4	88	1,193	60	128	948
1992	45	143	195	19	94	1,195	59	130	1,103
1993	45	145	196	34	98	1,202	58	133	1,253
1994	46	147	201	51	98	1,204	59	135	1,415
1995	46	149	203	60	103	1,204	59	138	1,574
1995.5	46	150	204	67	105	1,205	59	139	1,653
1996	46	151	206	73	106	1,206	59	140	1,732

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No		Pine Ridge Estates	Piney Woods	Point O'Woods	Ponoma Park	Postmaster Village	Quail Ridge	River Grove	River Park	Rosemont Rolling Green
	Docket No. 950495-WS									
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]									
	FPSC Uniform [x]; FPSC Non-Uniform [x]									
1	1994 MAX DAY FOR YEAR (GPD)	124,000	112,967	132,000	84,600	114,500	27,000	49,100	74,400	153,000
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	103,914	101,593	129,365	64,808	116,896	38,480	43,133	59,799	147,903
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	98,788	99,800	120,200	62,740	112,540	22,200	43,133	58,300	140,000
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	51,873	53,646	77,342	38,030	45,728	9,076	23,715	34,230	57,388
3	1994 ANNUAL AVG DAILY FLOW (GPD)	49,314	52,699	71,863	36,816	44,024	5,236	23,715	33,372	54,321
4	FIRE STORAGE ACCEPTED (GAL.)	0	0	0	0	0	0	0	0	0
5	FIRE FLOW PROVISION (GPM)	0	0	0	0	0	0	0	0	0
6	Unaccounted for Water Level (%)	11.8%	9.6%	16.2%	18.4%	10.0%	2.4%	8.2%	9.1%	8.8%
7	Unaccounted for Water Allowed (%)	10.0%	9.6%	10.0%	10.0%	10.0%	2.4%	8.2%	9.1%	8.8%
8										
9	<u>SOURCE OF SUPPLY AND PUMPING:</u>									
10	**Supply Wells:**	L	L	S	S	S	S	L	L	S
11	Total Capacity (gpm)	685	440	1,250	95	400	650	135	215	865
12	Reliable Capacity (gpm)	360	140	500	35	200	0	0	93	65
13	OPC Calculated Used & Useful (%)	**9.83%**	**26.61%**	**16.85%**	**100.00%**	**52.77%**	**100.00%**	**100.00%**	**25.56%**	**100.00%**
14	U & U Per Order (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	36.70%	100.00%
15	SSU Requested U & U (%)	34.14%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	61.55%	100.00%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable				Unavailable
19	OPC Calculated Used & Useful (%)	**9.83%**	**26.61%**	**16.85%**	**100.00%**	**52.77%**				**100.00%**
20	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%				100.00%
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	500	200	N/A	N/A	N/A	N/A	320	180	N/A
24	Reliable Capacity (gpm)	250	0	N/A	N/A	N/A	N/A	160	90	N/A
25	OPC Calculated Used & Useful (%)	**28.35%**	**100.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**18.72%**	**46.14%**	**N/A**
26	U & U Per Order (%)	100.00%	100.00%	N/A	N/A	N/A	N/A	32.30%	75.90%	N/A
27	SSU Requested U & U (%)	100.00%	100.00%	N/A	N/A	N/A	N/A	42.91%	100.00%	N/A
28										
29	<u>WATER TREATMENT PLANT:</u>									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36										
37	<u>TRANSMISSION AND DISTRIBUTION:</u>									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)	15,000	25,000					15,000	5,000	
40	Reliable Capacity (gal.)	13,500	22,500	N/A	N/A	N/A	N/A	13,500	4,500	N/A
41	OPC Calculated Used & Useful (%)	**100.00%**	**100.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**79.05%**	**100.00%**	**N/A**
42	U & U Per Order (%)	100.00%	100.00%	N/A	N/A	N/A	N/A	92.00%	100.00%	N/A
43	SSU Requested U & U (%)	100.00%	100.00%	N/A	N/A	N/A	N/A	100.00%	100.00%	N/A
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	3,500	7,000	10,000	5,000	8,000	6,500	3,000	4,500	10,000
47	OPC Calculated Used & Useful (%)	**92.86%**	**42.86%**	**75.00%**	**12.00%**	**25.00%**	**100.00%**	**45.00%**	**27.11%**	**80.00%**
48	U & U Per Order (%)	92.00%	90.00%	100.00%	18.00%	41.00%	100.00%	67.50%	83.00%	35.00%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	<u>TRANSMISSION AND DISTRIBUTION:</u>									
54	**Connected Lots in 1996 w/o M.R.**	217	170	367	172	161	26	104	359	131
55	Connected Lots in 1994 w/o M.R.	206	167	341	166	155	15	104	350	124
	Connected Lots in 1994 w/ M.R.	207	169	358	169	158	22	104	355	129
56	Number of Lots	292	215	415	535	345	114	119	754	150
57	OPC Calculated Used & Useful (%)	**74.22%**	**79.07%**	**88.43%**	**32.10%**	**46.67%**	**22.81%**	**87.39%**	**47.61%**	**87.33%**
58	U & U Per Order (%)	100.00%	76.50%	83.50%	32.00%	44.70%	15.80%	100.00%	44.80%	87.00%
59	SSU Requested U & U (%)	100.00%	79.44%	90.43%	32.72%	47.75%	26.20%	100.00%	48.11%	89.23%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	169	163	304	171	141	0	104	334	113
1991	171	165	329	171	146	6	104	339	120
1992	173	166	342	174	148	15	104	343	123
1993	186	167	342	180	151	16	104	347	124
1994	212	167	341	182	155	15	104	350	124
1995	213	169	358	185	158	22	104	355	129
1995.5	218	169	362	187	160	24	104	357	130
1996	223	170	367	188	161	26	104	359	131

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No	Docket No. 950495-WS Company: Southern States Utilities, Inc. Schedule Year Ended: 12/31/96 Projected [x] FPSC Uniform [x]; FPSC Non-Uniform [x]	Salt Springs	Samira Villas	Silver Lakes West Shores	Silver Lake Oaks	Skycrest	St. Johns Highlands	Stone Mountain	Sugar Mill	Sugarmill Woods
		1996	1996	1996	1996	1996	1996	1996	1996	1996
1	1994 MAX DAY FOR YEAR (GPD)	202,000	8,900	1,857,200	15,700	61,700	42,800	24,600	200,000	2,806,000
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	195,383	4,847	1,889,654	8,727	60,758	34,111	22,880	165,383	2,796,369
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	193,000	4,847	1,796,720	8,727	59,200	32,907	20,020	158,000	2,479,400
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	93,150	2,472	878,354	5,208	24,086	13,974	8,241	111,469	1,187,768
3	1994 ANNUAL AVG DAILY FLOW (GPD)	92,014	2,472	835,156	5,208	23,468	13,481	7,211	106,493	1,053,134
4	**FIRE STORAGE ACCEPTED (GAL.)**	0	0	0	0	0	0	0	0	0
5	**FIRE FLOW PROVISION (GPM)**	0	0	0	0	0	0	0	0	0
6	Unaccounted for Water Level (%)	3.6%	2.1%	7.3%	4.1%	17.1%	39.2%	58.8%	7.7%	6.0%
7	Unaccounted for Water Allowed (%)	3.6%	2.1%	7.3%	4.1%	10.0%	10.0%	10.0%	7.7%	6.0%
8										
9	**SOURCE OF SUPPLY AND PUMPING:**									
10	**Supply Wells:**	S	S	L	L	S	L	S	L	L
11	Total Capacity (gpm)	633	85	2,850	40	675	75	100	330	4,800
12	Reliable Capacity (gpm)	133	0	1,450	0	175	0	0	210	4,200
13	OPC Calculated Used & Useful (%)	**100.00%**	**100.00%**	**90.50%**	**100.00%**	**22.40%**	**100.00%**	**100.00%**	**36.86%**	**19.64%**
14	U & U Per Order (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	21.00%	57.00%	100.00%
15	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	77.84%	71.46%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided	Unavailable				Unavailable			Unavailable	Unavailable
19	OPC Calculated Used & Useful (%)	**100.00%**				**22.40%**			**36.86%**	**19.64%**
20	SSU Requested U & U (%)	100.00%				100.00%			100.00%	100.00%
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	N/A	N/A	3,460	140	N/A	120	N/A	2,250	3,600
24	Reliable Capacity (gpm)	N/A	N/A	2,745	70	N/A	60	N/A	1,200	2,400
25	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**47.81%**	**8.66%**	**N/A**	**27.95%**	**N/A**	**9.57%**	**80.91%**
26	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	100.00%	N/A	100.00%	N/A
27	SSU Requested U & U (%)	N/A	N/A	100.00%	31.15%	N/A	100.00%	N/A	100.00%	100.00%
28										
29	**WATER TREATMENT PLANT:**									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	350	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	350	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**32.81%**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	48.10%	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	48.10%	N/A
36										
37	**TRANSMISSION AND DISTRIBUTION:**									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)				12,000		16,000		500,000	500,000
40	Reliable Capacity (gal.)	N/A	N/A	N/A	5,400	N/A	14,400	N/A	400,564	450,000
41	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**21.70%**	**N/A**	**30.92%**	**N/A**	**11.15%**	**100.00%**
42	U & U Per Order (%)	N/A	N/A	N/A	50.00%	N/A	100.00%	N/A	73.30%	N/A
43	SSU Requested U & U (%)	N/A	N/A	N/A	100.00%	N/A	100.00%	N/A	100.00%	100.00%
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	15,000	1,500	15,000	1,000	5,000	3,000	1,000	15,000	60,000
47	OPC Calculated Used & Useful (%)	**33.33%**	**56.67%**	**93.33%**	**40.00%**	**100.00%**	**25.00%**	**100.00%**	**8.00%**	**10.00%**
48	U & U Per Order (%)	53.30%	85.00%	100.00%	60.00%	100.00%	49.00%	100.00%	100.00%	67.00%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
50										
51	**USED AND USEFUL CALCULATIONS** **Water Transmission & Distribution System**									
52	**Schedule F-7(W)**									
53	**TRANSMISSION AND DISTRIBUTION:**									
54	**Connected Lots in 1996 w/o M.R.**	115	2	1,285	26	117	85	8	648	2,632
55	Connected Lots in 1994 w/o M.R.	114	2	1,222	26	114	82	7	619	2,333
	Connected Lots in 1994 w/ M.R.	114	2	1,265	26	116	84	7	636	2,508
56	Number of Lots	160	3	1,648	53	122	118	22	661	8,252
57	OPC Calculated Used & Useful (%)	**72.13%**	**66.67%**	**77.99%**	**49.06%**	**95.90%**	**72.03%**	**36.36%**	**97.97%**	**31.89%**
58	U & U Per Order (%)	78.00%	100.00%	100.00%	50.90%	100.00%	69.80%	25.00%	86.90%	22.40%
59	SSU Requested U & U (%)	100.00%	100.00%	100.00%	50.90%	100.00%	72.46%	36.36%	99.51%	33.39%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	154	13	1,368	27	108	79	6	591	3,929
1991	158	13	1,503	26	111	79	6	624	4,250
1992	161	13	1,582	25	113	81	7	636	4,598
1993	156	13	1,472	24	113	83	7	636	4,862
1994	162	13	1,508	26	114	82	7	642	4,928
1995	162	13	1,561	26	116	84	7	660	5,297
1995.5	163	13	1,574	26	117	84	8	666	5,427
1996	164	13	1,586	26	117	85	8	672	5,558

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No	Docket No. 950495-WS	Sunny Hills (Wells 1&4)	Sunny Hills (Well 5)	Sunshine Parkway	Tropical Park	University Shores	Venetian Village	Welaka/ Saratoga Harbor	Westmont	Windsong
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]									
	FPSC Uniform [x]; FPSC Non-Uniform [x]									
1	1994 MAX DAY FOR YEAR (GPD)	311,500	19,000	186,900	187,700	1,658,600	65,600	55,000	Water	44,800
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	269,400	8,400	157,043	152,257	1,775,860	45,756	40,102	Purchased	36,088
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	269,400	8,400	118,740	151,980	1,559,860	43,500	38,940	From	35,420
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	159,592	3,000	98,981	58,412	1,071,474	26,111	17,395	Orange	16,249
3	1994 ANNUAL AVG DAILY FLOW (GPD)	159,592	3,000	74,839	58,306	941,149	24,824	16,891	County	15,948
4	FIRE STORAGE ACCEPTED (GAL.)	0	0	0	0	0	0	0		0
5	FIRE FLOW PROVISION (GPM)	0	0	0	0	0	0	0		0
6	Unaccounted for Water Level (%)	4.0%	4.0%	5.4%	13.3%	3.6%	2.9%	6.9%	12.0%	2.0%
7	Unaccounted for Water Allowed (%)	4.0%	4.0%	5.4%	10.0%	3.6%	2.9%	6.9%	10.0%	2.0%
8										
9	SOURCE OF SUPPLY AND PUMPING:									
10	**Supply Wells:**	L	S	L	S	L	S	L	S	S
11	Total Capacity (gpm)	650	200	2,000	200	5,100	310	296	N/A	180
12	Reliable Capacity (gpm)	300	0	1,000	0	3,600	100	110	N/A	0
13	OPC Calculated Used & Useful (%)	**36.94%**	**100.00%**	**6.87%**	**100.00%**	**20.67%**	**41.31%**	**10.98%**	**N/A**	**100.00%**
14	U & U Per Order (%)	63.90%	63.90%	100.00%	100.00%	100.00%	44.30%	29.80%	N/A	100.00%
15	SSU Requested U & U (%)	72.11%	100.00%	100.00%	100.00%	100.00%	100.00%	38.09%	N/A	100.00%
16										
17	**Auxiliary Power:**									
18	Capacity (GPD), not provided	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable			
19	OPC Calculated Used & Useful (%)	**36.94%**	**100.00%**	**6.87%**	**100.00%**	**20.67%**	**41.31%**			
20	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			
21										
22	**High Service Pumping:**									
23	Total Capacity (gpm)	500	N/A	3,400	N/A	7,980	N/A	300	N/A	N/A
24	Reliable Capacity (gpm)	300	N/A	2,600	N/A	3,980	N/A	150	N/A	N/A
25	OPC Calculated Used & Useful (%)	**62.36%**	**N/A**	**4.19%**	**N/A**	**30.99%**	**N/A**	**18.57%**	**N/A**	**N/A**
26	U & U Per Order (%)	100.00%	N/A	100.00%	N/A	72.30%	N/A	N/A	N/A	N/A
27	SSU Requested U & U (%)	100.00%	N/A	99.89%	N/A	100.00%	N/A	55.87%	N/A	N/A
28										
29	WATER TREATMENT PLANT:									
30	**Water Treatment Equipment:**									
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36										
37	TRANSMISSION AND DISTRIBUTION:									
38	**Finished Water Storage:**									
39	Total Capacity (gal.)	60,000		108,000		612,000		40,000		
40	Reliable Capacity (gal.)	54,000	N/A	97,200	N/A	550,800	N/A	36,000	N/A	N/A
41	OPC Calculated Used & Useful (%)	**100.00%**	**N/A**	**45.82%**	**N/A**	**87.54%**	**N/A**	**21.74%**	**N/A**	**N/A**
42	U & U Per Order (%)	100.00%	N/A	100.00%	N/A	100.00%	N/A	N/A	N/A	N/A
43	SSU Requested U & U (%)	100.00%	N/A	100.00%	N/A	100.00%	N/A	55.87%	N/A	N/A
44										
45	**Hydropneumatic Tanks:**									
46	Total Capacity (gal.)	20,000	7,500	10,000	10,000	20,000	4,000	4,500	N/A	4,000
47	OPC Calculated Used & Useful (%)	**17.50%**	**26.67%**	**100.00%**	**20.00%**	**75.00%**	**52.50%**	**41.33%**	**N/A**	**45.00%**
48	U & U Per Order (%)	93.00%	100.00%	100.00%	100.00%	100.00%	66.00%	45%/100%	N/A	56.00%
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	N/A	100.00%
50										
51	**USED AND USEFUL CALCULATIONS**									
	Water Transmission & Distribution System									
52	**Schedule F-7(W)**									
53	TRANSMISSION AND DISTRIBUTION:									
54	**Connected Lots in 1996 w/o M.R.**	435	4	14	533	3,800	142	134	137	107
55	Connected Lots in 1994 w/o M.R.	435	4	11	532	3,338	135	130	129	105
	Connected Lots in 1994 w/ M.R.	435	4	13	532	3,574	139	132	134	106
56	Number of Lots	5,377	491	40	671	5,100	223	249	167	106
57	OPC Calculated Used & Useful (%)	**8.09%**	**0.81%**	**36.01%**	**79.43%**	**74.51%**	**63.68%**	**53.79%**	**82.04%**	**100.00%**
58	U & U Per Order (%)	11.00%	N/A	100.00%	81.40%	100.00%	61.70%	54.00%	100.00%	100.00%
59	SSU Requested U & U (%)	28.09%	28.09%	100.00%	81.40%	100.00%	65.13%	54.00%	100.00%	100.00%
60										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990	619	4	39	544	2,777	123	129	117	102
1991	604	4	42	545	2,951	129	129	121	105
1992	607	4	56	544	3,233	133	130	127	105
1993	614	4	67	545	3,548	134	132	129	106
1994	602	4	62	549	3,748	135	134	129	106
1995	602	4	74	549	4,013	139	136	134	107
1995.5	602	4	78	549	4,140	141	137	136	108
1996	602	4	82	550	4,267	142	138	137	108

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.	Docket No. 950495-WS	Woodmere	Wootens	Zephyr Shores	Buenaventura Lakes	Deep Creek	Enterprise	Geneva Lake Estates	Keystone Club Estates
	Company: Southern States Utilities, Inc.								
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]								
	FPSC Uniform [x]; FPSC Non-Uniform [x]								
1	1994 MAX DAY FOR YEAR (GPD)	1,479,000	8,120	121,000	2,753,000	All Water	All Water	104,500	229,000
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	1,463,718	8,855	91,187	2,769,385	Purchased	Purchased	96,603	132,851
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	1,398,000	7,792	89,600	2,610,400	From	From	90,540	126,000
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	888,133	3,114	54,982	1,815,263	Charlotee	Deltona	39,711	39,183
3	1994 ANNUAL AVG DAILY FLOW (GPD)	848,258	2,740	54,025	1,711,052	County	Lakes	37,219	37,162
4	**FIRE STORAGE ACCEPTED (GAL.)**	0	0	0	0			0	0
5	**FIRE FLOW PROVISION (GPM)**	0	0	0	0			0	0
6	Unaccounted for Water Level (%)	38.6%	6.9%	5.0%	13.5%	2.9%	11.6%	17.2%	12.6%
7	Unaccounted for Water Allowed (%)	10.0%	6.9%	5.0%	10.0%	2.9%	10.0%	10.0%	10.0%
8									
9	<u>SOURCE OF SUPPLY AND PUMPING:</u>								
10	**Supply Wells:**	L	S	S	L	S	S	S	S
11	Total Capacity (gpm)	3,000	25	120	4,700	N/A	N/A	280	750
12	Reliable Capacity (gpm)	1,000	0	0	2,200	N/A	N/A	100	375
13	OPC Calculated Used & Useful (%)	**44.04%**	**100.00%**	**100.00%**	**55.29%**	**N/A**	**N/A**	**80.93%**	**31.15%**
14	U & U Per Order (%)	48.30%	90.00%	100.00%	63.20%	N/A	N/A	N/A	N/A
15	SSU Requested U & U (%)	100.00%	100.00%	100.00%	92.14%	N/A	N/A	100.00%	53.93%
16									
17	**Auxiliary Power:**								
18	Capacity (GPD), not provided	Unavailable			Unavailable			Unavailable	Unavailable
19	OPC Calculated Used & Useful (%)	**44.04%**			**55.29%**			**80.93%**	**31.15%**
20	SSU Requested U & U (%)	100.00%			100.00%			100.00%	100.00%
21									
22	**High Service Pumping:**								
23	Total Capacity (gpm)	3,100	N/A	N/A	7,400	N/A	N/A	N/A	N/A
24	Reliable Capacity (gpm)	2,000	N/A	N/A	4,400	N/A	N/A	N/A	N/A
25	OPC Calculated Used & Useful (%)	**36.29%**	**N/A**	**N/A**	**42.18%**	**N/A**	**N/A**	**N/A**	**N/A**
26	U & U Per Order (%)	100.00%	N/A	N/A	63.2%	N/A	N/A	N/A	N/A
27	SSU Requested U & U (%)	100.00%	N/A	N/A	100.0%	N/A	N/A	N/A	N/A
28									
29	<u>WATER TREATMENT PLANT:</u>								
30	**Water Treatment Equipment:**								
31	Total Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36									
37	<u>TRANSMISSION AND DISTRIBUTION:</u>								
38	**Finished Water Storage:**								
39	Total Capacity (gal.)	455,000			1,206,000				
40	Reliable Capacity (gal.)	409,500	N/A	N/A	1,085,400	N/A	N/A	N/A	N/A
41	OPC Calculated Used & Useful (%)	**69.68%**	**N/A**	**N/A**	**72.63%**	**N/A**	**N/A**	**N/A**	**N/A**
42	U & U Per Order (%)	100.00%	N/A	N/A	60.1%	N/A	N/A	N/A	N/A
43	SSU Requested U & U (%)	100.00%	N/A	N/A	100.0%	N/A	N/A	N/A	N/A
44									
45	**Hydropneumatic Tanks:**								
46	Total Capacity (gal.)	10,000	500	7,500	N/A	N/A	N/A	3,000	8,000
47	OPC Calculated Used & Useful (%)	**100.00%**	**50.00%**	**16.00%**	**N/A**	**N/A**	**N/A**	**60.00%**	**46.88%**
48	U & U Per Order (%)	100.00%	75.00%	17.10%	N/A	N/A	N/A	N/A	N/A
49	SSU Requested U & U (%)	100.00%	100.00%	100.00%	N/A	N/A	N/A	100.00%	100.00%
50									
51	**USED AND USEFUL CALCULATIONS**								
	Water Transmission & Distribution System								
52	**Schedule F-7(W)**								
53	<u>**TRANSMISSION AND DISTRIBUTION:**</u>								
54	**Connected Lots in 1996 w/o M.R.**	1,207	25	499	7,515	3,311	236	93	159
55	Connected Lots in 1994 w/o M.R.	1,153	22	490	7,083	2,940	216	87	151
	Connected Lots in 1994 w/ M.R.	1,172	24	495	7,287	3,166	225	90	154
56	Number of Lots	1,189	52	647	6,725	7,171	279	139	250
57	OPC Calculated Used & Useful (%)	**100.00%**	**48.08%**	**77.10%**	**100.00%**	**46.17%**	**84.71%**	**67.11%**	**63.64%**
58	U & U Per Order (%)	98.50%	28.90%	85.40%	N/A	N/A	N/A	N/A	N/A
59	SSU Requested U & U (%)	100.00%	51.25%	85.40%	100.00%	48.19%	88.78%	69.13%	65.77%
60									

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

<u>Year</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>	Water <u>ERC</u>
1990	1,235	17	479		2,801.5	202.5	96.0	139.0
1991	1,244	18	518		3,087.0	216.5	97.5	141.0
1992	1,277	20	511		3,334.5	226.3	100.5	143.5
1993	1,333	21	496		3,450.8	241.3	107.5	152.5
1994	1,404	22	508	7,075.0	3,479.0	258.3	112.0	160.0
1995	1,427	24	513	7,278.3	3,746.2	269.6	115.3	163.3
1995.5	1,448	24	515	7,395.8	3,832.1	276.4	117.4	166.0
1996	1,470	25	517	7,505.9	3,918.0	283.2	119.5	168.7

OPC USED AND USEFUL CALCULATIONS
Water Treatment Plant - Schedule F-5 (W)

Line No.		Lakeside	Lehigh	Marco Island	Palm Valley	Remington Forest	Spring Gardens	Valencia Terrace
	Docket No. 950495-WS							
	Company: Southern States Utilities, Inc.							
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996
	Projected [x]							
	FPSC Uniform [x]; FPSC Non-Uniform [x]							
1	1994 MAX DAY FOR YEAR (GPD)	544,000	1,711,000	11,871,000	All Water	87,780	55,050	224,700
2	**1996 AVG MAX 5 DAYS IN MAX MONTH (GPD)**	317,003	1,727,685	10,439,248	Purchased	96,041	52,534	218,000
2	1994 AVG MAX 5 DAYS IN MAX MONTH (GPD)	298,800	1,661,200	9,924,600	From	77,540	49,530	218,000
3	**1996 ANNUAL AVG DAILY FLOW (GPD)**	96,945	1,371,878	6,488,319	Intercoastal	37,453	24,453	133,344
3	1994 ANNUAL AVG DAILY FLOW (GPD)	91,378	1,319,085	6,168,449	Utilities	30,238	23,055	133,344
4	FIRE STORAGE ACCEPTED (GAL.)	0	0	0		0	0	0
5	FIRE FLOW PROVISION (GPM)	0	0	0		0	0	0
6	Unaccounted for Water Level (%)	100.0%	13.6%	4.0%	8.8%	15.5%	19.8%	49.7%
7	Unaccounted for Water Allowed (%)	10.0%	10.0%	4.0%	8.8%	10.0%	10.0%	10.0%
8								
9	SOURCE OF SUPPLY AND PUMPING:							
10	**Supply Wells:**	S	L	L	S	L	S	S
11	Total Capacity (gpm)	1,400	1,900	9,831	N/A	48	180	1,100
12	Reliable Capacity (gpm)	400	1,444	7,747	N/A	0	90	350
13	OPC Calculated Used & Useful (%)	**5.50%**	**63.60%**	**58.16%**	**N/A**	**100.00%**	**36.56%**	**26.08%**
14	U & U Per Order (%)	N/A	100.00%	100.00%	N/A	N/A	N/A	N/A
15	SSU Requested U & U (%)	100.00%	100.00%	95.99%	N/A	100.00%	100.00%	100.00%
16								
17	**Auxiliary Power:**							
18	Capacity (GPD), not provided	Unavailable	Unavailable	Unavailable				Unavailable
19	OPC Calculated Used & Useful (%)	**5.50%**	**63.60%**	**58.16%**				**26.08%**
20	SSU Requested U & U (%)	100.00%	100.00%	100.00%				100.00%
21								
22	**High Service Pumping:**							
23	Total Capacity (gpm)	N/A	4,250	22,700	N/A	600	N/A	N/A
24	Reliable Capacity (gpm)	N/A	3,000	17,700	N/A	220	N/A	N/A
25	OPC Calculated Used & Useful (%)	**N/A**	**38.55%**	**40.96%**	**N/A**	**28.65%**	**N/A**	**N/A**
26	U & U Per Order (%)	N/A	100.0%		N/A	N/A	N/A	N/A
27	SSU Requested U & U (%)	N/A	100.0%	100.0%	N/A	100.0%	N/A	N/A
28								
29	WATER TREATMENT PLANT:							
30	**Water Treatment Equipment:**							
31	Total Capacity (gpm)	N/A	1,736	6,944	N/A	N/A	N/A	N/A
32	Reliable Capacity (gpm)	N/A	1,736	6,944	N/A	N/A	N/A	N/A
33	OPC Calculated Used & Useful (%)	**N/A**	**66.62%**	**100.00%**	**N/A**	**N/A**	**N/A**	**N/A**
34	U & U Per Order (%)	N/A	78.30%	100.00%	N/A	N/A	N/A	N/A
35	SSU Requested U & U (%)	N/A	78.30%	100.00%	N/A	N/A	N/A	N/A
36								
37	TRANSMISSION AND DISTRIBUTION:							
38	**Finished Water Storage:**							
39	Total Capacity (gal.)		1,720,000	6,500,000		15,000		
40	Reliable Capacity (gal.)	N/A	1,048,052	3,635,143	N/A	13,500	N/A	N/A
41	OPC Calculated Used & Useful (%)	**N/A**	**38.44%**	**49.91%**	**N/A**	**100.00%**	**N/A**	**N/A**
42	U & U Per Order (%)	N/A	81.80%	100.00%	N/A	N/A	N/A	N/A
43	SSU Requested U & U (%)	N/A	88.00%	100.00%	N/A	100.00%	N/A	N/A
44								
45	**Hydropneumatic Tanks:**							
46	Total Capacity (gal.)	15,000	10,000	N/A	N/A	5,000	1,500	5,000
47	OPC Calculated Used & Useful (%)	**66.67%**	**45.60%**	**N/A**	**N/A**	**9.60%**	**60.00%**	**100.00%**
48	U & U Per Order (%)	N/A	100.00%	N/A	N/A	N/A	N/A	N/A
49	SSU Requested U & U (%)	100.00%	100.00%	N/A	N/A	100.00%	100.00%	100.00%
50								
51	**USED AND USEFUL CALCULATIONS**							
	Water Transmission & Distribution System							
52	**Schedule F-7(W)**							
53	TRANSMISSION AND DISTRIBUTION:							
54	**Connected Lots in 1996 w/o M.R.**	93	5,800	6,083	216	80	130	323
55	Connected Lots in 1994 w/o M.R.	87	5,577	5,783	201	65	122	323
	Connected Lots in 1994 w/ M.R.	90	5,681	5,986	209	70	126	323
56	Number of Lots	252	7,789	14,014	210	87	180	340
57	OPC Calculated Used & Useful (%)	**36.79%**	**74.46%**	**43.41%**	**100.00%**	**92.23%**	**72.06%**	**95.00%**
58	U & U Per Order (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
59	SSU Requested U & U (%)	37.73%	77.17%	100.00%	100.00%	100.00%	74.06%	95.00%
60								

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 9 (W)

Year	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC	Water ERC
1990		8,128.0	12,915.5	196.3	24.5		
1991		8,300.5	13,795.0	204.3	28.0		
1992		8,473.5	14,150.5	211.5	33.5		
1993		8,668.0	14,136.0	219.8	48.5		
1994	87.0	8,897.5	13,983.0	225.8	65.8	122.0	323.0
1995	89.6	9,063.8	14,473.6	234.8	71.1	125.7	323.0
1995.5	90.9	9,158.7	14509.8	238.6	76.3	127.5	323.0
1996	92.3	9,253.6	14,708.1	242.4	81.5	129.4	323.0

EXHIBIT TLB-4

OPC USED AND USEFUL CALCULATIONS

OF

WASTEWATER SYSTEMS

OPC USED AND USEFUL CALCULATIONS

Line No.	Wastewater Treatment Plant Schedule F-6 (S)	Amelia Island	Apache Shores	Apple Valley	Beacon Hill	Beecher's Point	Burnt Store	Chuluota	Citrus Park	Citrus Springs
	Docket No. 950495-WS									
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]			Treated						
	FPSC Uniform [x] & Non-Uniform [x]			by						
				Altomonte						
1	PERMITTED PLANT CAPACITY (GPD)	950,000	17,000	Springs	1,780,000	15,000	250,000	100,000	64,000	200,000
2	EFFLUENT DISPOSAL CAPACITY (GPD)	950,000	17,000	N/A	1,780,000	15,000	250,000	100,000	64,000	200,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	844,484	12,000	N/A	783,323	8,194	135,968	42,226	48,323	134,033
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	611,480	12,000	N/A	848,580	6,072	153,394	43,186	49,055	135,366
5	Response to OPC Doc. Request No. 279									
6	EXCESS Inflow/Infiltration (%), by EPA guidelines	36.4%				25.9%				
7	EXCESS INFLOW/INFILTRATION (GPD)	307,392	0		0	2,122	0	0	0	0
8										
9	TREATMENT PLANT AND EFFLUENT DISPOSAL:									
10	**Treatment Plant:**									
11	OPC Calculated Used & Useful (%)	**64.37%**	**70.59%**	N/A	**47.67%**	**40.48%**	**61.36%**	**43.19%**	**76.65%**	**67.68%**
12	U & U Per Order (%)	94.30%	69.60%	N/A	62.90%	39.60%	48.00%	71.00%	100.00%	51.60%
13	SSU Requested U & U (%)	100.00%	70.59%	N/A	100.00%	54.62%	85.97%	71.00%	100.00%	69.51%
14	**Effluent Disposal:**									
15	OPC Calculated Used & Useful (%)	**64.37%**	**70.59%**	N/A	**47.67%**	**40.48%**	**61.36%**	**43.19%**	**76.65%**	**67.68%**
16	U & U Per Order (%)	94.30%	69.60%	N/A	69.60%	39.60%	48.00%	71.00%	100.00%	51.60%
17	SSU Requested U & U (%)	100.00%	70.59%	N/A	100.00%	54.62%	85.97%	71.00%	100.00%	69.51%
18	**Reuse Facilities:**									
19	OPC Calculated Used & Useful (%)	**64.37%**								
20	SSU Requested U & U (%)	100.00%								
21										
22	**Auxiliary Power:**									
23	Capacity (GPD), not provided	navailable			Unavailable					
24	OPC Calculated Used & Useful (%)	**64.37%**			**47.67%**					
25	SSU Requested U & U (%)	100.00%			100.00%					
26										
27	USED AND USEFUL CALCULATIONS									
28	**Wastewater Collection System Schedule F-7(S)**									
29										
30	COLLECTION AND SYSTEM PUMPING PLANT:									
31	**Connected Lots in 1996 w/o M.R.**	1,450	111	163	3,085	45	418	135	136	684
32	Connected Lots in 1994 w/ M.R.	1,363	111	163	2,917	45	385	134	134	680
33	Connected Lots in 1994 w/o M.R.	1,273	111	163	2,848	45	371	132	133	677
34	Number of Lots	2,467	195	188	3,178	62	4,347	155	155	1,084
35	Calculated Used & Useful (%)	**58.77%**	**56.92%**	**86.70%**	**97.09%**	**72.58%**	**9.63%**	**87.10%**	**87.43%**	**63.09%**
36	U & U Per Order (%)	93.70%	59.55%	100.00%	91.00%	73.40%	9.20%	82.90%	82.90%	28.00%
37	SSU Requested U & U (%)	93.70%	59.50%	100.00%	100.00%	73.40%	10.40%	87.90%	100.00%	63.38%
38										
39										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC
1990	1,382.0	116.0	175.0	2,450.0	45.0	342.0	127.0	251.0	687.0
1991	1,571.0	113.0	175.0	2,524.0	45.0	379.0	130.0	247.0	693.0
1992	1,707.0	113.0	173.0	2,609.0	45.0	398.0	131.0	248.0	696.0
1993	1,783.0	112.0	175.0	2,870.0	45.0	455.0	131.0	258.0	697.0
1994	1,935.0	111.0	180.0	3,229.0	45.0	554.0	132.0	264.0	704.0
1995	2,071.0	111.0	180.0	3,307.0	45.0	575.0	134.0	265.0	707.0
1995.5	2,137.0	111.0	180.0	3,403.0	45.0	600.0	134.0	266.0	709.0
1996	2,203.0	111.0	180.0	3,498.0	45.0	625.0	135.0	268.0	711.0

OPC USED AND USEFUL CALCULATIONS

Line No		Deltona Lakes	Fisherman's Haven	Florida Central Commerce Park	Fox Run	Holiday Haven	Jungle Den	Leilani Heights	Leisure Lakes
	Wastewater Treatment Plant								
	Schedule F-6 (S)								
	Docket No. 950495-WS								
	Company: Southern States Utilities, Inc.								
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996	1996
	Projected [x]				Interconn.				
	FPSC Uniform [x] & Non-Uniform [x]				With				
					Martin				
1	PERMITTED PLANT CAPACITY (GPD)	1,200,000	25,000	95,000	County	25,000	25,000	150,000	50,000
2	EFFLUENT DISPOSAL CAPACITY (GPD)	1,400,000	25,000	95,000	Utilities	25,000	25,000	150,000	50,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	1,132,710	17,467	56,267	to Treat	18,700	16,613	172,964	18,129
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	1,207,742	17,467	71,514		18,700	16,755	145,848	18,523
5	Response to OPC Doc. Request No. 279								
6	EXCESS Inflow/Infiltration (%), by EPA guidelines							16.1%	
7	EXCESS INFLOW/INFILTRATION (GPD)	0	0	0		0	0	27,847	0
8									
9	TREATMENT PLANT AND EFFLUENT DISPOSAL:								
10	**Treatment Plant:**								
11	OPC Calculated Used & Useful (%)	**100.00%**	**69.87%**	**75.28%**	**N/A**	**74.80%**	**67.02%**	**97.23%**	**37.05%**
12	U & U Per Order (%)	95.00%	80.00%	44.00%	N/A	47.00%	65.00%	100.00%	65.70%
13	SSU Requested U & U (%)	100.00%	80.00%	100.00%	N/A	74.80%	68.61%	100.00%	65.70%
14	**Effluent Disposal:**								
15	OPC Calculated Used & Useful (%)	**86.27%**	**69.87%**	**75.28%**	**N/A**	**74.80%**	**67.02%**	**97.23%**	**37.05%**
16	U & U Per Order (%)	95.00%	80.00%	44.00%	N/A	47.00%	65.00%	100.00%	65.70%
17	SSU Requested U & U (%)	100.00%	80.00%	100.00%	N/A	74.80%	68.61%	100.00%	65.70%
18	**Reuse Facilities:**								
19	OPC Calculated Used & Useful (%)	**86.27%**		**75.28%**					
20	SSU Requested U & U (%)	100.00%		100.00%					
21									
22	**Auxiliary Power:**								
23	Capacity (GPD), not provided	Unavailable		Unavailable				Unavailable	
24	OPC Calculated Used & Useful (%)	**100.00%**		**75.28%**				**97.23%**	
25	SSU Requested U & U (%)	100.00%		100.00%				100.00%	
26									
27	**USED AND USEFUL CALCULATIONS**								
	Wastewater Collection System								
28	**Schedule F-7(S)**								
29									
30	COLLECTION AND SYSTEM PUMPING PLANT:								
31	**Connected Lots in 1996 w/o M.R.**	4,659	141	56	106	94	118	399	235
32	Connected Lots in 1994 w/ M.R.	4,619	141	51	102	94	117	398	233
33	Connected Lots in 1994 w/o M.R.	4,595	141	44	97	94	117	397	230
34	Number of Lots	5,000	144	71	109	166	135	413	385
35	Calculated Used & Useful (%)	**93.18%**	**97.92%**	**78.18%**	**97.25%**	**56.63%**	**87.41%**	**96.61%**	**61.04%**
36	U & U Per Order (%)	100.00%	100.00%	43.00%	100.00%	61.40%	100.00%	100.00%	61.60%
37	SSU Requested U & U (%)	100.00%	100.00%	84.26%	100.00%	61.40%	100.00%	100.00%	61.62%
38									
39									

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC
1990	4,860.0	142.0	86.0	82.0	95.0	114.0	393.0	221.0
1991	4,852.0	142.0	130.0	88.0	97.0	115.0	393.0	227.0
1992	4,895.0	140.0	146.0	92.0	97.0	116.0	394.0	229.0
1993	4,963.0	138.0	150.0	95.0	94.0	115.0	395.0	229.0
1994	5,025.0	141.0	155.0	97.0	96.0	117.0	397.0	230.0
1995	5,051.0	141.0	181.0	102.0	96.0	117.0	398.0	233.0
1995.5	5,073.0	141.0	189.0	104.0	96.0	118.0	398.0	234.0
1996	5,095.0	141.0	197.0	106.0	96.0	118.0	399.0	235.0

OPC USED AND USEFUL CALCULATIONS

Line No.	Wastewater Treatment Plant Schedule F-6 (S)	Marco Shores	Marion Oaks	Meredith Manor	Morning-view	Palm Port	Palm Terrace	Park Manor	Point O'Woods	Salt Springs
	Docket No. 950495-WS									
	Company: Southern States Utilities, Inc.									
	Schedule Year Ended: 12/31/96	*1996*	*1996*	*1996*	*1996*	*1996*	*1996*	*1996*	*1996*	*1996*
	Projected [x]			Interconn.						
	FPSC Uniform [x] & Non-Uniform [x]			With The						
				City of						
1	PERMITTED PLANT CAPACITY (GPD)	110,000	200,000	Altamonte	20,000	50,000	130,000	15,000	58,000	85,000
2	*EFFLUENT DISPOSAL CAPACITY (GPD)*	110,000	200,000	Springs and	20,000	50,000	130,000	15,000	58,000	34,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	62,000	170,129	Sanlando	8,710	25,233	147,742	13,194	20,226	29,129
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	64,369	172,210	Utilities	8,710	27,550	148,175	15,134	23,622	29,129
5	Response to OPC Doc. Request No. 279									
6	EXCESS Inflow/Infiltration (%), by EPA guidelines									
7	EXCESS INFLOW/INFILTRATION (GPD)	0	0	#VALUE!	0	0	0	0	0	0
8										
9	TREATMENT PLANT AND EFFLUENT DISPOSAL:									
10	**Treatment Plant:**									
11	OPC Calculated Used & Useful (%)	**58.52%**	**86.10%**	**N/A**	**43.55%**	**55.10%**	**100.00%**	**100.00%**	**40.73%**	**34.27%**
12	U & U Per Order (%)	66.80%	81.00%	N/A	77.00%	45.00%	62.50%	28.00%	28.60%	49.00%
13	*SSU Requested U & U (%)*	*94.24%*	*90.36%*	*N/A*	77.00%	63.83%	100.00%	100.00%	51.53%	49.00%
14	**Effluent Disposal:**									
15	OPC Calculated Used & Useful (%)	**58.52%**	**86.10%**	**N/A**	**43.55%**	**55.10%**	**100.00%**	**100.00%**	**40.73%**	**85.67%**
16	U & U Per Order (%)	66.80%	81.00%	N/A	77.00%	45.00%	96.00%	28.00%	28.60%	100.00%
17	SSU Requested U & U (%)	100.00%	90.36%	N/A	77.00%	63.83%	100.00%	100.00%	51.53%	100.00%
18	**Reuse Facilities:**									
19	OPC Calculated Used & Useful (%)								**40.73%**	
20	SSU Requested U & U (%)								100.00%	
21										
22	**Auxiliary Power:**									
23	Capacity (GPD), not provided									
24	OPC Calculated Used & Useful (%)									
25	SSU Requested U & U (%)									
26										
27	**USED AND USEFUL CALCULATIONS**									
28	**Wastewater Collection System Schedule F-7(S)**									
29										
30	COLLECTION AND SYSTEM PUMPING PLANT:									
31	**Connected Lots in 1996 w/o M.R.**	411	1,336	29	36	107	1,026	35	160	110
32	Connected Lots in 1994 w/ M.R.	400	1,323	28	36	103	1,024	33	152	110
33	Connected Lots in 1994 w/o M.R.	396	1,320	28	36	98	1,023	30	137	110
34	Number of Lots	584	1,610	34	48	137	1,189	35	191	185
35	Calculated Used & Useful (%)	**70.44%**	**83.00%**	**84.78%**	**75.00%**	**78.10%**	**86.29%**	**99.38%**	**83.77%**	**59.46%**
36	U & U Per Order (%)	50.20%	85.00%	100.00%	100.00%	67.00%	85.00%	96.90%	100.00%	100.00%
37	SSU Requested U & U (%)	85.62%	85.00%	100.00%	100.00%	80.40%	86.40%	100.00%	100.00%	100.00%
38										
39										

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC
1990	*274.0*	*1,335.0*	*33.0*	*46.0*	*86.0*	*1,019.0*	26.0	103.0	153.0
1991	288.0	1,333.0	33.0	46.0	89.0	1,013.0	30.0	121.0	151.0
1992	288.0	1,340.0	34.0	45.0	95.0	1,015.0	33.0	134.0	149.0
1993	294.0	1,361.0	34.0	45.0	98.0	1,023.0	33.0	137.0	146.0
1994	314.0	1,390.0	34.0	46.0	98.0	1,023.0	34.0	137.0	151.0
1995	317.0	1,393.0	34.0	46.0	103.0	1,024.0	37.0	152.0	151.0
1995.5	322.0	1,400.0	35.0	46.0	105.0	1,025.0	38.0	156.0	151.0
1996	326.0	1,407.0	35.0	46.0	107.0	1,026.0	39.0	160.0	151.0

OPC USED AND USEFUL CALCULATIONS

Line No.	Wastewater Treatment Plant Schedule F-6 (S) Docket No. 950495-WS Company: Southern States Utilities, Inc. Schedule Year Ended: 12/31/96 Projected [x] FPSC Uniform [x] & Non-Uniform [x]	Silver Lake Oaks	South Forty	Suager Mill	Sugarmill Woods	Sunny Hills	Sunshine Parkway	University Shores	Venetian Village
		1996	1996	1996	1996	1996	1996	1996	1996
1	PERMITTED PLANT CAPACITY (GPD)	12,000	50,000	270,000	400,000	50,000	250,000	1,145,000	36,000
2	EFFLUENT DISPOSAL CAPACITY (GPD)	12,000	50,000	270,000	500,000	50,000	150,000	1,145,000	36,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	7,290	35,806	160,000	261,194	29,419	86,933	1,000,226	35,581
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	7,290	13,508	167,886	293,645	29,583	3,710	1,130,484	36,808
5	Response to OPC Doc. Request No. 279								
6	EXCESS Inflow/Infiltration (%), by EPA guidelines		63.4%				96.5%		
7	EXCESS INFLOW/INFILTRATION (GPD)	0	22,701	0	0	0	83,890	0	0
8									
9	**TREATMENT PLANT AND EFFLUENT DISPOSAL:**								
10	**Treatment Plant:**								
11	OPC Calculated Used & Useful (%)	**60.75%**	**27.02%**	**62.18%**	**73.41%**	**59.17%**	**1.48%**	**98.73%**	**100.00%**
12	U & U Per Order (%)	13.00%	74.00%	78.00%	58.20%	51.00%	51.00%	93.10%	86.00%
13	SSU Requested U & U (%)	60.75%	79.88%	78.00%	90.46%	60.02%	56.78%	100.00%	100.00%
14	**Effluent Disposal:**								
15	OPC Calculated Used & Useful (%)	**60.75%**	**27.02%**	**62.18%**	**58.73%**	**59.17%**	**2.47%**	**98.73%**	**100.00%**
16	U & U Per Order (%)	13.00%	74.00%	78.00%	58.20%	51.00%	51.00%	93.10%	86.00%
17	SSU Requested U & U (%)	60.75%	79.88%	78.00%	72.36%	60.02%	94.63%	100.00%	100.00%
18	**Reuse Facilities:**								
19	OPC Calculated Used & Useful (%)							**98.73%**	
20	SSU Requested U & U (%)							100.00%	
21									
22	**Auxiliary Power:**								
23	Capacity (GPD), not provided				Unavailable	Unavailable		Unavailable	
24	OPC Calculated Used & Useful (%)				**73.41%**	**59.17%**		**98.73%**	
25	SSU Requested U & U (%)				100.00%	100.00%		100.00%	
26									
27	USED AND USEFUL CALCULATIONS								
28	**Wastewater Collection System Schedule F-7(S)**								
29									
30	COLLECTION AND SYSTEM PUMPING PLANT:								
31	**Connected Lots in 1996 w/o M.R.**	26	35	642	2,551	177	11	3,532	90
32	Connected Lots in 1994 w/ M.R.	26	34	630	2,432	176	10	3,338	89
33	Connected Lots in 1994 w/o M.R.	26	33	612	2,269	176	9	3,125	87
34	Number of Lots	53	52	661	8,252	504	56	4,275	107
35	Calculated Used & Useful (%)	**49.06%**	**66.38%**	**97.08%**	**30.91%**	**35.12%**	**18.92%**	**82.61%**	**84.11%**
36	U & U Per Order (%)	50.90%	94.00%	84.00%	21.10%	36.00%	100.00%	72.40%	81.90%
37	SSU Requested U & U (%)	50.90%	94.00%	99.00%	32.34%	36.00%	100.00%	87.12%	85.84%
38									
39									

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC
1990	27.0	55.0	576.0	3,844.0	176.0	55.0	2,545.0	80.0
1991	27.0	68.0	605.0	4,085.0	178.0	56.0	2,763.0	83.0
1992	25.0	68.0	619.0	4,422.0	178.0	67.0	2,996.0	84.0
1993	24.0	59.0	623.0	4,719.0	177.0	78.0	3,199.0	85.0
1994	26.0	65.0	629.0	4,773.0	179.0	73.0	3,371.0	87.0
1995	26.0	66.0	648.0	5,116.0	179.0	84.0	3,601.0	89.0
1995.5	26.0	67.0	654.0	5,241.0	179.0	86.0	3,706.0	89.0
1996	26.0	67.0	660.0	5,366.0	180.0	89.0	3,810.0	90.0

OPC USED AND USEFUL CALCULATIONS

Line No.	Wastewater Treatment Plant Schedule F-6 (S)	Woodmere	Zephyr Shores	Buenaventura Lakes	Deep Creek	Enterprise	Lehigh	Marco Island
	Docket No. 950495-WS							
	Company: Southern States Utilities, Inc.							
	Schedule Year Ended: 12/31/96	1996	1996	1996	1996	1996	1996	1996
	Projected [x]				All	Plant taken		
	FPSC Uniform [x] & Non-Uniform [x]				Wastewater	off line. Flow		
					Treated	goes to		
1	PERMITTED PLANT CAPACITY (GPD)	500,000	40,000	1,800,000	By	Deltona	2,100,000	3,500,000
2	EFFLUENT DISPOSAL CAPACITY (GPD)	500,000	40,000	1,800,000	Charlotte	Lakes.	2,100,000	3,500,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	466,226	27,258	1,614,839	County	45,097	1,773,710	2,438,000
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	482,889	27,744	1,713,181		59,253	1,848,001	856,291
5	Response to OPC Doc. Request No. 279							
6	EXCESS Inflow/Infiltration (%), by EPA guidelines							65.1%
7	EXCESS INFLOW/INFILTRATION (GPD)	0	0	0		0	0	1,587,138
8								
9	TREATMENT PLANT AND EFFLUENT DISPOSAL:							
10	**Treatment Plant:**							
11	OPC Calculated Used & Useful (%)	**96.58%**	**69.36%**	**89.71%**	**N/A**	N/A	**88.00%**	**24.47%**
12	U & U Per Order (%)	100.00%	86.30%	69.90%	N/A	N/A	100.00%	78.00%
13	SSU Requested U & U (%)	100.00%	86.30%	89.71%	N/A	100.00%	100.00%	78.00%
14	**Effluent Disposal:**							
15	OPC Calculated Used & Useful (%)	**96.58%**	**69.36%**	**89.71%**	**N/A**	N/A	**88.00%**	**24.47%**
16	U & U Per Order (%)	100.00%	100.00%	69.90%	N/A	N/A	81.08%	N/A
17	SSU Requested U & U (%)	100.00%	100.00%	89.71%	N/A	N/A	100.00%	100.00%
18	**Reuse Facilities:**							
19	OPC Calculated Used & Useful (%)						**88.00%**	**24.47%**
20	SSU Requested U & U (%)						100.00%	100.00%
21								
22	**Auxiliary Power:**							
23	Capacity (GPD), not provided			Unavailable			Unavailable	navailable
24	OPC Calculated Used & Useful (%)			**89.71%**			**88.00%**	**24.47%**
25	SSU Requested U & U (%)			100.00%			100.00%	100.00%
26								
27	USED AND USEFUL CALCULATIONS							
28	**Wastewater Collection System Schedule F-7(S)**							
29								
30	COLLECTION AND SYSTEM PUMPING PLANT:							
31	**Connected Lots in 1996 w/o M.R.**	1,155	496	7,437	3,414	166	4,436	1,976
32	Connected Lots in 1994 w/ M.R.	1,126	492	7,220	3,251	152	4,342	1,970
33	Connected Lots in 1994 w/o M.R.	1,115	487	7,010	2,999	126	4,257	1,964
34	Number of Lots	1,189	647	6,725	7,285	228	5,270	1,334
35	Calculated Used & Useful (%)	**97.15%**	**76.64%**	**100.00%**	**46.87%**	**72.80%**	**84.17%**	**100.00%**
36	U & U Per Order (%)	100.00%	85.30%	N/A	N/A	N/A	N/A	N/A
37	SSU Requested U & U (%)	100.00%	85.30%	100.00%	49.10%	79.19%	88.31%	100.00%
38								
39								

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC	Sewer ERC
1990	1,206.0	476.0		2,825.8	64.0	6,440.5	5,044.5
1991	1,210.0	513.0		3,178.5	129.5	6,635.0	5,228.3
1992	1,230.0	505.0		3,444.5	132.0	6,777.0	5,356.3
1993	1,279.0	493.0		3,571.0	135.5	6,888.8	5,287.3
1994	1,343.0	505.0	7,010.0	3,611.8	137.3	7,093.3	5,109.0
1995	1,356.0	510.0	7,220.3	3,915.8	165.2	7,234.5	5,125.3
1995.5	1,373.0	512.0	7,327.8	4,014.1	172.8	7,312.4	5,133.4
1996	1,391.0	514.0	7,436.9	4,112.3	180.4	7,390.4	5,141.6

OPC USED AND USEFUL CALCULATIONS

Line No.	Wastewater Treatment Plant Schedule F-6 (S)	Spring Gardens	Tropical Isle	Valencia Terrace
	Docket No. 950495-WS			
	Company: Southern States Utilities, Inc.			
	Schedule Year Ended: 12/31/96	1996	1996	1996
	Projected [x]			
	FPSC Uniform [x] & Non-Uniform [x]			
1	PERMITTED PLANT CAPACITY (GPD)	20,000	50,000	99,000
2	EFFLUENT DISPOSAL CAPACITY (GPD)	20,000	50,000	99,000
3	1994 AVG DAILY FLOW OF MAX MONTH (GPD)	87,200	35,033	78,452
4	**1996 AVG DAILY FLOW OF MAX MONTH (GPD)**	92,489	43,616	78,452
5	Response to OPC Doc. Request No. 279			
6	EXCESS Inflow/Infiltration (%), by EPA guidelines			
7	EXCESS INFLOW/INFILTRATION (GPD)	0	0	0
8				
9	TREATMENT PLANT AND EFFLUENT DISPOSAL:			
10	**Treatment Plant:**			
11	OPC Calculated Used & Useful (%)	**100.00%**	**87.23%**	**79.24%**
12	U & U Per Order (%)	N/A	N/A	N/A
13	SSU Requested U [illegible] U (%)	100.00%	100.00%	79.24%
14	**Effluent Disposal:**			
15	OPC Calculated Used & Useful (%)	**100.00%**	**87.23%**	**79.24%**
16	U & U Per Order (%)	N/A	N/A	N/A
17	SSU Requested U & U (%)	100.00%	100.00%	79.24%
18	**Reuse Facilities:**			
19	OPC Calculated Used & Useful (%)			
20	SSU Requested U & U (%)			
21				
22	**Auxiliary Power:**			
23	Capacity (GPD), not provided			
24	OPC Calculated Used & Useful (%)			
25	SSU Requested U & U (%)			
26				
27	**USED AND USEFUL CALCULATIONS**			
28	**Wastewater Collection System Schedule F-7(S)**			
29				
30	COLLECTION AND SYSTEM PUMPING PLANT:			
31	**Connected Lots in 1996 w/o M.R.**	130	274	323
32	Connected Lots in 1994 w/ M.R.	126	250	323
33	Connected Lots in 1994 w/o M.R.	122	220	323
34	Number of Lots	180	334	340
35	Calculated Used & Useful (%)	**72.06%**	**82.07%**	**95.00%**
36	U & U Per Order (%)	N/A	N/A	N/A
37	SSU Requested U & U (%)	74.06%	89.21%	95.00%
38				
39				

ERC CALCULATIONS (by SSU)
Combined Schedule of F- 8 & 10 (S)

Year	Sewer ERC	Sewer ERC	Sewer ERC
1990		126.5	
1991		154.0	
1992		180.5	
1993		207.5	
1994	122.0	220.0	323.0
1995	125.7	249.8	323.0
1995.5	127.5	261.9	323.0
1996	129.4	273.9	323.0

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for a rate increase for Orange-Osceola Utilities, Inc. in Osceola County, and in Bradford, Brevard, Charlotte, Citrus, Clay, Collier, Duval, Highlands, Lake, Lee, Marion, Martin, Nassau, Orange, Osceola, Pasco, Putnam, Seminole, St. Johns, St. Lucie, Volusia, and Washington Counties by Southern States Utilities, Inc.	Docket No. 950495-WS Filed: February 12, 1996

ORIGINAL FILE COPY

DIRECT TESTIMONY

OF

JAMES A. ROTHSCHILD

On Behalf of the Citizens of The State of Florida

ACK
AFA 3
APP
CAF
CMU
CTR
EAG
LEG 1
LIN 5 + orig
OPC
RCH
SEC 1
WAS Willis
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of the State of Florida

SOUTHERN STATES UTILITIES CO.
Docket No. 950495-WS
TESTIMONY OF JAMES A. ROTHSCHILD

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I. STATEMENT OF QUALIFICATIONS OF JAMES A. ROTHSCHILD

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James A. Rothschild and my address is 115 Scarlet Oak Drive, Wilton, Connecticut 06897.

Q. WHAT IS YOUR OCCUPATION?

A. I am a financial consultant specializing in utility regulation. I have experience in the regulation of electric, gas, telephone, sewer, and water utilities throughout the United States.

Q. PLEASE SUMMARIZE YOUR UTILITY REGULATORY EXPERIENCE.

A. I am President of Rothschild Financial Consulting and have been a consultant since 1972. From 1979 through January 1985, I was President of Georgetown Consulting Group, Inc. From 1976 to 1979, I was the President of J. Rothschild Associates. Both of these firms specialized in utility regulation. From 1972 through 1976, Touche Ross & Co., a major international accounting firm, employed me as a management consultant. Touche Ross & Co. later merged to form Deloitte Touche. Much of my consulting work done while at Touche Ross was in utility regulation. While associated with the above firms, I worked for various state utility commissions, attorneys general, and public advocates on regulatory matters relating to regulatory and financial issues. These have included rate of return, financial issues, and accounting issues. (See Appendix B.)

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received an MBA in Banking and Finance from Case Western University (1971) and a BS in Chemical Engineering from the University of Pittsburgh (1967).

II. PURPOSE AND OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY.

A. The purpose of this testimony is to derive a fair and reasonable cost of equity that should be allowed by the Commission to Southern States Utilities Co. (SSU). This testimony includes an evaluation of the applicability of the current leverage formula result to determine the cost of equity to SSU. Furthermore, the testimony provides a response to the many comments made by Dr. Morin in the testimony he has filed on behalf of SSU.

In formulating the recommendations I have made in this testimony, I have recognized that the cost of capital approved by the Commission should balance the interests of investors and ratepayers. If the allowed cost of capital is excessive, rates will be above the level they need to be for the provision of safe and adequate utility service. If the allowed cost of capital is too low, investors would be denied the profits to which they are entitled, and eventually, the company would not be able to provide the safe and adequate utility service that is critically important to ratepayers.

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS:

A. Based upon the analyses contained in this testimony, I conclude that the cost of equity the Commission should allow to SSU is 10.10%. In arriving at this result, I have followed the Commission's practice of giving equal weight to the cost of equity results indicated for water utilities and for gas distribution utilities. See Sch. JAR-1. If I had based my recommendation solely on the cost of equity indicated for water utilities, my recommendation would have been lower.

The leverage formula result that was approved by the Commission in its August 10, 1995 decision is that the cost of equity to a Florida water utility should be equal to 9.05 percent + 1.1131/Equity Ratio, with a maximum cost of equity of 11.88%, and a cost of equity to the average water utility in Florida of 10.18%[1] By applying this formula to the capital structure requested by SSU, the leverage formula indicated cost of equity is 11.78% based upon a common equity ratio of 40.7%. However, since this formula was developed, capital cost rates have dropped materially. As a result, the 11.78% leverage graph indicated result is considerably higher than the current cost of equity to SSU.

Company Witness Morin has expressed his opinion that the 11.78% cost of equity produced by the leverage formula result produces a cost of equity below that which the company would like to receive. He has recommended that the company be allowed a cost of equity of 12.25%. The evidence I present later in this testimony shows that irrespective of the relative weighting given to the result for gas distribution utilities or to water utility

[1] Page 11 of

companies, the cost of equity to SSU is now materially below 11.78%, not above 11.78%. Therefore, if any variation is to be made to the results of the leverage graph, the cost of equity to allow to SSU should be materially *lowered* rather than *increased* to 12.25% as requested by the company.

Q. HAVE YOU USED ANY METHODS OTHER THAN THE DCF METHOD TO QUANTIFY THE COST OF EQUITY?

A. Yes. As a check to the DCF results, I have also presented a risk premium method. The risk premium result is 9.76% to 10.17% based upon interest rates as of 12/31/95. Additionally, because Dr. Morin presented a CAPM method, and because the Commission expressed a desire to consider the results of a CAPM method, I have also derived a CAPM determined equity cost rate. My CAPM method indicates a cost of equity of 7.67% to 8.12%. However, even though the CAPM method that I have presented does not contain the known serious flaws in Dr. Morin's implementation of CAPM, it still is not as accurate a method as either the DCF method or the risk premium method that I have presented. As I result, my recommendation was formulated based upon the DCF result. The risk premium method was only reviewed as a check.

Q. WHAT ARE THE PROBLEMS WITH DR. MORIN'S CAPM METHOD?

A. There were substantial mathematical and theoretical errors in Dr. Morin's presentation of the CAPM method. For example, to arrive at his CAPM result, he had to violate important principles established by both the U.S. Securities and Exchange Commission (SEC), and improperly use a long-term treasury bond interest rate as a proxy for a risk-free security, i.e. a security with a zero beta. The only difference in my implementation of the CAPM and Dr. Morin's implementation of the CAPM is that I used the SEC method for quantifying historic actual returns, and used the interest rate on a 30 year U.S. treasury bond in a mathematically correct manner. A more complete discussion of the CAPM method, including the problems with Dr. Morin's implementation of the method, are contained later in this testimony.

Q. OTHER THAN DR. MORIN'S IMPROPER USE OF THE CAPM METHOD, WHAT OTHER PROBLEMS DO YOU HAVE WITH WHAT HE HAS SAID IN HIS TESTIMONY?

A. Following is a summary of the significant problems that I have with the comments made by Dr. Morin in his testimony. A detailed explanation of why these are all valid criticisms of Dr. Morin's testimony will follow later in this testimony:

1. *Hope* Decision. On page 7 of his testimony, Dr. Morin mis-states the findings of the US Supreme Court in its *Hope Natural Gas* decision. Specifically, the *Hope* decision rejects Dr. Morin's desire to allow a return on equity high enough to maintain inflated market to book ratios.

2. Water Company Risks in Florida. Dr. Morin has improperly concluded that there are higher relative risks for water utilities in Florida which cause these companies to need a higher allowed return on equity. The critical point missed by Dr. Morin is that the only risk which impacts the cost of equity is non-diversifiable risk. Factors such as size, large construction programs, regulatory risk are not only shared by water utilities throughout the country, but they are all diversifiable risks anyhow. Furthermore, even if Dr. Morin were correct that size causes an increase in the cost of equity, then his comment on page 10 of his testimony that the source of capital has no bearing on the cost of capital must be wrong. To the extent that size is relevant, it would be the size of the entity raising the capital that should be considered.

3. Direction of Change in Water Company Risk. Dr. Morin speculates on page 15 of his testimony that the risks of water utilities is increasing. Facts show that the opposite is true. If anything, the risk of an investment in water utilities has been declining in recent years.

4. Relative Risk of Gas Companies and Water Companies. Dr. Morin claims that the risk in a water utility is higher than for a gas utility. Facts show that this is not true. In the last several years, the risk of water utilities has been below that of gas distribution utilities. This is confirmed by the DCF results which indicate a higher cost of equity for gas distribution utilities than for water utilities.

5. Exclusive use of DCF method. Dr. Morin claims that it is improper to use only the DCF method to quantify the cost of equity. While a *properly applied* risk premium method can be of some additional value, all too often the risk premium method is mis-applied. The CAPM method, especially as applied by Dr. Morin, is a very inaccurate method for quantifying the cost of equity. Furthermore, as applied by Dr. Morin, the CAPM method contains an unacceptably large upward bias.

II. DETERMINATION OF THE CURRENT COST OF EQUITY FOR WATER AND GAS UTILITIES.

A. Summary

Q. HOW DID YOU DETERMINE THE COST OF EQUITY FOR WATER UTILITIES AND FOR GAS UTILITIES?

A. My primary method for determining the cost of equity was to apply the constant growth, or D/P + g version of the DCF method. In order to properly apply the constant growth version of the method, I recognized that it is *essential* to quantify growth in a manner that is consistent with the constant growth rate expectations necessary for the constant growth version of the DCF model to have any mathematical validity. In addition to using a consistently applied simplified version of the DCF model, I confirmed the result of the constant growth version of the DCF model by presenting a non-constant, or two stage, growth rate to water utilities and also checked the result of the constant growth DCF method by implementing a risk premium method and a CAPM method. Of the three methods, the DCF model should be considered the most accurate, and the risk premium next most accurate. While I was careful to present a version of the CAPM model that has corrected the mathematical errors contained in Dr. Morin's application of the CAPM, even after repairing Dr. Morin's errors, the CAPM, the method is still inferior to the accuracy obtainable by either the DCF model or the risk premium model.

B. Constant Growth DCF Model

Q. HOW DID YOU IMPLEMENT THE CONSTANT GROWTH DCF MODEL?

A. I implemented the constant growth DCF model by quantifying future sustainable growth based on "b x r" + "sv", where "b" is the retention rate that is consistent with the dividend rate used to evaluate the dividend yield, and "r" is equal to the future return on book equity expected by investors. "sv" is added to this "b x r" growth in order to recognize that in addition to growth caused by "b x r", growth is also caused by the sale of new common stock above book value.

Q. DOES THE DCF METHOD BASED UPON THE " b x r" GROWTH METHOD COMPUTE THE COST OF EQUITY WITH ABSOLUTE PRECISION?

A. No. No equity costing approach, DCF or otherwise, is capable of computing the cost of equity with absolute precision. However, a major advantage of the "b x r" approach is that if the method is applied properly, the majority of the inputs required to implement the model, such as stock price, dividend rate, and book value are subject to precise quantification. For most utility companies, the only critical input number that could have a material impact on the DCF computed cost of equity is the value chosen for "r", or the future expected return on equity. If the DCF method is properly applied, the retention rate "b" is directly derived from the value chosen for "r" and the dividend rate used to compute the dividend yield.

Q. ARE THERE RESTRICTIONS ON THE USE OF THE SIMPLIFIED VERSION OF THE DCF METHOD?

A. Yes. The simplified version of the DCF model should only be used when investors expect:

• the same future growth rate estimate in stock price, earnings per share, dividends per share, and book value per share,

and

• that future growth rate is best expressed as a constant. Note that this does not necessarily mean that future growth is expected to be constant. It means that no reason exists to expect future growth to be higher or lower than average in any one specific future year.

Q. CAN THE DCF MODEL BE USED IN A SITUATION WHERE IT IS NOT REASONABLE TO EXPECT THE ABOVE CONDITIONS TO BE MET?

A. Yes. The complex version of the DCF does not require the above simplifying expectations. This is because the complex version separately discounts each expected future cash flow. Recently, FERC has begun to prefer a two-stage DCF model to a single-stage DCF.

I have been presenting a complex form of the DCF model for years. This complex form of the DCF is readily adaptable to the two-stage approach. In order to allow this Commission to be able to also consider a properly applied two-stage DCF, my testimony in this case supplements the results of the single-stage, or constant growth DCF model with a two-stage DCF model.

Q. HOW SHOULD GROWTH FOR USE IN A CONSTANT GROWTH DCF MODEL BE DETERMINED?

A. **The most important characteristic of any approach to determining a growth rate for use in the DCF method is that it incorporate the kind of growth that can**

reasonably be expected to occur for many years into the future. Textbooks generally explain that the appropriate method to quantify the future sustainable growth required for the simplified DCF model is to use the "b x r" method. The advantage of a properly applied "b x r" is that it computes a sustainable growth rate. Therefore, when applying the "b x r" method, the result will be accurate as long as the future return on book equity, "r" that is expected by investors and the retention rate "b" that is both consistent with the value used for "r" and the dividend rate, "D", is used to compute growth. With other methods to estimate future expected growth, extreme care must be taken to be sure that they are in a form that is applicable to the simplified, or constant growth version of the DCF model. In order to be at all useful, these alternative methods usually have to be adjusted so that the indicated growth rates are consistent with the financial realities necessary to develop a growth rate that has any realistic chance of being sustainable.

Q. DO STOCK ANALYSTS USE THE "b x r" METHOD?

A. Yes. In the textbook, *Investments*, by Bodie, Kane and Marcus (Irwin, 1989) at page 478, expected growth rate of dividends is described as follows:

> How do stock analysts derive forecasts of *g*, the expected growth rate of dividends? Usually, they first assume a constant dividend payout ratio (that is, ratio of dividends to earnings), which implies that dividends will grow at the same rate as earnings. Then they try to relate the expected growth rate of earnings to the expected profitability of the firm's *future* investment opportunities.
>
> The exact relationship is
>
> $$g = b \times ROE$$
>
> where *b* is the proportion of the firm's earnings that is reinvested in the business, called the **plowback ratio** or the **earnings retention ratio,** and

> ROE is the rate of return (return on equity) on new investments. If all of the variables are specified correctly, [the] equation . . . is true by definition, . . .

Q. ARE YOU AWARE OF ANY RECENT REPORT FROM AN INVESTMENT BANKING FIRM THAT SUPPORTS THE TEXTBOOK EXPLANATION OF HOW ANALYSTS DETERMINE "g"?

A. Yes. In a report entitled "U.S. Investment Research. Electric Utilities. Five-year Financial Projections" issued by Morgan Stanley on October 24, 1995, 32 electric utilities are evaluated. In all cases, the "Total Return" is quantified by adding the "Internal Growth" rate to the dividend yield. The internal growth rate is quantified by subtracting the dividend/book ratio from the future expected return on book equity. This is algebraically identical to the "b x r" method in which "r" is equal to the future expected return on book equity and "b" is computed in a manner consistent with the inputs for "r" and for the dividend rate "D" used to compute dividend yield.

Q. HOW DID YOU COMPUTE "g"?

A. As previously stated, I used the "b x roe" method specified in the above textbook quote, although I refer to it in this testimony as the "b x r" method. In the above equation, ROE has the same meaning as "r". I computed the growth rate, "g," by using a future expected return on book equity value, or "r," of 11.25% for the *Value Line* water companies. The specific inputs, and the evaluation of those inputs, is discussed in the next section of this testimony.

My method differs from the method used in the above-referenced Morgan Stanley report only in that I have reflected additional growth for the sale of common stock in my recommended growth rate. This is consistent with the Morgan Stanley report, because Morgan Stanley specifically noted that its growth rate they have obtained is applicable "... in the absence of new equity issuances..." (P. 4).

The Morgan Stanley report also notes that "(i)f the ROE were to remain constant, this [the growth rate obtained using the equivalent of "b x r"] would be the same as the growth in earnings."

Q. DOES THE MORGAN STANLEY REPORT ADD ANY GROWTH RATES OTHER THAN THE " b x r", OR INTERNAL GROWTH RATE, TO THE DIVIDEND YIELD TO OBTAIN A "TOTAL RETURN" NUMBER?

A. Within Morgan Stanley's write-up on each individual electric company, the only growth rate added to the dividend yield is the "b x r" or "Internal Growth" rate. However, in a summary table on page 9 of the report, Morgan Stanley does also show a total return number using both the "Yield + Int. Growth" and the "Yield + Est. 5-Year Growth" in dividends per share. Page 4 of the report explains that Morgan Stanley is concerned that the "Yield + Int. Growth" rate number might overstate long-term sustainable growth because the reinvestment assumption that earnings can be re-invested to earn the expected return on book equity might be optimistic given slow growth in the industry and increasing competitive pressures.

Q. WHAT COST OF EQUITY DOES THE MORGAN STANLEY REPORT INDICATE FOR ELECTRIC UTILITIES?

A. The average total return for electric utilities based upon the Yield + Internal Growth method is shown by Morgan Stanley to have a median value of 9.1% on page 9 of the report..

Q. WHAT DOES MORGAN STANLEY SHOW AS THE COST OF EQUITY BASED UPON THE YIELD PLUS ESTIMATED FIVE YEAR DIVIDEND GROWTH RATE?

A. The median value for the cost of equity based upon projected dividends per share growth is 8.1%, also on page 9 of the report.

Q. SOME WITNESSES CLAIM THAT THE 'b x r" APPROACH TO THE DCF METHOD IS SOMEHOW CIRCULAR BECAUSE THE FUTURE EARNED RETURN ON BOOK EQUITY THAT YOU USE TO QUANTIFY GROWTH IS USED TO DETERMINE THE COST OF EQUITY, AND THE COST OF EQUITY IS THEN USED TO DETERMINE THE FUTURE RETURN ON EQUITY THAT WILL BE EARNED. IS THIS CIRCULAR?

A. No. Those who erroneously claim that the method is circular confuse the definition of "r" and the definition of "k". While "r" is defined as the future return on **book** equity anticipated by investors, "k" is the cost of equity, or the return investors expect on the **market price** investment. Since the market price is determined based upon what investors are willing to pay for a stock, and the book value is based upon the net stockholders' investment in the company, "r" usually has a different value than "k". In fact, the proper application of the DCF method relates a specific stock market price to a specific expectation of future cash flows that is created by future earned return ("r") levels. For example, if investors are willing to pay $10 a share for a company when the expectations are that the company will be able to earn 12% on its book equity in the future, if events were to occur which would cause investors to re-evaluate the 12% return expectation, the stock price should be expected to change. If investors' expectations of the future return on book equity change from 12% to 10%, and there is no corresponding change in the cost of equity, the stock price would decline. The cost of equity, however, would not decline simply because an event might occur that would cause investors to lower their estimate for "r". The cost of equity is equal to the sum of both the dividend yield and growth. Investors' estimate of "r" influences the investors estimate for growth. Changes in growth expectations cause investors to change the price they are willing to pay for stock. A change in the stock price can cause a change in the dividend yield that offsets the change in expected growth. In this way, a higher dividend yield would offset by the lower expected growth rate and leave the cost of equity, "k", unchanged.

a. Determination of Future Expected Return on Book Equity, "r"

Q. HOW DID YOU DETERMINE THE VALUE OF "r" THAT YOU USED IN YOUR RETAINED EARNINGS GROWTH COMPUTATIONS FOR THE *VALUE LINE* WATER COMPANIES?

A. I determined the 11.25% investors' expectation of the future value for "r" for the *Value Line* water companies and the 12.00% value for "r" for the gas distribution utilities by evaluating :[2]

[2]Note that the value of "r" is the investors' expected return on book equity, not the cost of equity. The cost of equity, "k" requires consideration of not only the return investors expect on book, but a

- the future returns on book equity expected by *Value Line*,
- the return on book equity consistent with the Zacks' consensus 5-year growth estimate,[3]
- absolute levels of, and trends in, allowed returns on equity to utility companies, and
- historic actual earned returns on equity.

Q. WHY DON'T YOU USE THE GROWTH RATES AS COMPILED BY ZACKS DIRECTLY IN THE SIMPLIFIED DCF FORMULA?

A. The growth rates reported by *Zacks* are five-year growth rates beginning from the most recent historic actual reported earnings per share. It would be improper to merely plug these growth rates into the D/P + g simplified version of the DCF formula because they are not sustainable growth rates. For example, if a company had an atypically good or atypically bad year in 1994, or if the earned returns on equity were, for any other reason, expected to increase (or decrease), the five-year growth rate as reported by *Zacks* would be atypically low (or high). Since the perceived abnormal nature of the earnings might be industry-wide, use of an average growth rate for the entire group would likely

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determination of whether or not the return rate investors expect on book is higher or lower than the return level required to attract capital on reasonable terms. In order to determine the adequacy of the return on book, the market price investors are willing to pay for that return on book must also be considered.

3 Zacks Research is a service that surveys professional securities analysts to determine the consensus earnings per share forecast that is expected for a company. I obtain the Zacks consensus growth rates by accessing the results for the companies of interest to me via the Dow Jones News Retrieval computer database service. Zacks is a similar service to one compiled by I/B/E/S. I use Zacks because it is the one chosen by Dow Jones for use in its database.

not solve the problem. Thus, in order to be able to use these growth rates in the D/P + g version of the DCF formula, it is necessary to compute what return on book equity will achieve the analysts' consensus growth rate. In this way, it is possible to estimate analysts' anticipated future return on book equity.

b. Determination of Retention Rate, "b"

Q. HOW HAVE YOU DETERMINED THE VALUE OF THE FUTURE EXPECTED RETENTION RATE, "b", THAT YOU USED IN YOUR SIMPLIFIED DCF ANALYSIS?

A. I have recognized that the retention rate, "b", is merely the residual of the dividend rate, "D", and the future expected return on book equity, "r." Since, by definition, "b" is the fraction of earnings not paid out as a dividend, the only correct value to use for "b" is the one that is consistent with the quantification of the other variables when implementing the DCF method. The formula to determine "b" is:

$$b = 1 - (D/E), \text{ where}$$

b = retention rate

D = Dividend rate

E = Earnings rate

However, "E" is equal to "r" times the book value per share. Book value per share is a known amount, as is "E", consistent with the future expected value for "r", and the "D" used to compute dividend yield. Therefore, to maximize the accuracy of the DCF method, quantification of the value of "b" should be done in a manner that recognizes the interdependency between the value of "b" and the values for "r" and "D". I directly computed the value of "b" based upon the values of "D", and "r".

C. Implementation of the Two-Stage or Complex Version of DCF Method

Q. WHY DO YOU ALSO PRESENT THE TWO-STAGE OR COMPLEX VERSION OF THE DCF METHOD?

A. *When constant growth is expected to be the best estimate of future anticipated growth, the two-stage or complex version of the DCF model is essentially the same as the simplified version.* I have presented a two-stage DCF model for several reasons: 1) FERC has recently begun relying upon a two-stage DCF model in recent cost of capital decisions[4]; 2) a two-stage or even more complex than two-stage version of the DCF method is helpful because it provides a framework that will work even in special situations when future payout ratios, earned returns on equity, or market-to-book ratios change; 3) a two-stage or complex version of the DCF model serves as a check to show that the growth rate used in the simplified version is credible. For example, if an analyst forecasts an unrealistically high growth rate, the complex DCF method may show that the growth rate is improper.

Q. HOW WOULD THE COMPLEX VERSION OF THE DCF METHOD SHOW WHETHER A GROWTH RATE IS CREDIBLE?

A. Computing for each year the anticipated dividends, earnings, return on book equity and market-to-book ratios permits a separate study of each of the key causes of future cash flow. If, for example, the complex DCF analysis shows that the chosen growth rate could only occur if market-to-book ratios grow to unrealistic levels, or the payout ratio goes to more than 100%, or the earned return on book equity grows to excessive levels, then the chosen growth rate must be too high. Conversely, if a detailed projection shows that payout ratios, or market-to-book ratios, or the earned return on book equity would have to decline to unrealistic levels, then the growth rate selected must be too low.

Q. HOW DID YOU IMPLEMENT THE TWO-STAGE DCF MODEL?

A. The first stage of the model is based upon *Value Line*'s estimates of dividends per share, earnings per share , and book value per share for 1995 through 1999[5]. *Value Line* does not show a specific earnings and dividend projection for every year from 1995 to 1999. Projections for years skipped by *Value Line* were made by extrapolation from the available data.

I determined future earnings in the second stage of the complex DCF model by multiplying the future book value per share by the future expected earned return on book equity. For the purposes of this case, I used the same future expected return on book equity that I used in the simplified version of the DCF model.[6] Projected book value

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[4] Ozark Gas Transmission System, Docket Nos. RP94-105-002 and RP-94-105-003 decision issued July 7, 1994, and Wyoming Interstate Co., Docket No. RP85-39-009, decision issued November 30, 1994.

[5] The estimate for 1999 is shown by *Value Line* as its estimate from 1998-2000.

equals the beginning book value plus the current year's earnings minus the current year's dividends. Book value growth projections also include the effect of sales of new common stock. The projections in the second stage of the DCF model were made up until 40 years into the future. Events longer than 40 years into the future have a minimal present value. [7]

My projections have relied on a constant dividend payout ratio.[8]

I derived the estimated future stock price from the projected book value estimating that the same market-to-book ratio would exist at the time of sale as exists today. The only cash outflow is the price paid for the stock. The complex version of the model uses both the spot stock price as of December 31, 1995, and the average stock price for the year ended December 31, 1995 to be representative of the price paid.

As summarized on Sch. JAR 2, P. 1 and 2, the two-stage complex version of the DCF model indicates a cost of equity between 10.21% and 10.59% for the *Value Line* water companies and between 10.29% and 10.72% for the gas distribution utilities.

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6 For reasons explained in the discussion of the simplified version of the DCF method, this is because I believe that is the best estimate of future earnings. However, if the use of a varying array of future expected returns on book equity were supported by the facts, rather than a constant return, the same mathematical model would still be proper to use in determining the cost of equity.

7 For example, a change in an assumption that the selling market-to-book ratio would be 0.1 lower or higher than as of the time of purchase would introduce a potential inaccuracy in the indicated cost of equity of plus or minus about 25 basis points in a 30 year analysis, but a similar change in the market-to-book ratio expectation would introduce only plus or minus about 15 basis points in a 40 year analysis. If longer than 40 years were used, the result would be even less sensitive to the future market-to-book ratio expectation.

8 As in the case of the future expected earned return on equity assumption, if there were evidence to support the use of varying payout ratios instead of a constant payout ratio, the same model could still be used to accurately quantify the cost of equity. Unlike the simplified DCF model, this model specifically accounts for the fact that a change in the payout ratio has an impact on the book value, and therefore has an impact on the earnings rate achieved in the future.

Q. YOUR EQUITY COST RATE FINDINGS FOR BOTH WATER COMPANIES AND FOR GAS DISTRIBUTION COMPANIES IS HIGHER THAN THE COST OF EQUITY YOU EXPLAINED WAS DETERMINED BY MORGAN STANLEY FOR ELECTRIC UTILITIES. IS THIS BECAUSE THE COST OF EQUITY TO ELECTRIC UTILITIES IS LESS THAN FOR WATER OR GAS DISTRIBUTION UTILITIES?

A. No. I believe that Morgan Stanley's result is too low because Morgan Stanley did not add anything for growth caused by additional sales of common stock above book value. Furthermore, I believe that the DCF based upon retention growth is more reflective of investors' long-term expectations than a DCF using a five-year dividends per share growth rate forecast. Nevertheless, the Morgan Stanley report is valuable because it confirms that my equity cost rate finding is conservatively high. It adds yet additional confirmation to the fact that Dr. Morin's 12.25% equity cost recommendation is based upon seriously flawed approaches to determining the cost of equity.

D. Risk Premium Method

Q. WHY DID YOU CONDUCT A RISK PREMIUM STUDY?

A. A properly applied DCF method has a greater accuracy than is possible to obtain from the best available risk premium method. This is primarily because the risk premium method is limited by the invalid assumption that risk premiums remain constant. Furthermore, the risk premium method requires the quantification of the cost difference between debt and equity. In order to determine this cost difference, the cost of equity has to first be computed in order to be able to implement the risk premium in the first place. Nevertheless, a properly applied risk premium method is better than an improperly applied risk premium. Therefore, since risk premium methods frequently appear in utility ratemaking proceedings and there are some people who would prefer to consider the results of a risk premium analysis, I have presented an approach to the risk premium method which maximizes the accuracy obtainable from that method.

Q. WHAT COST OF EQUITY IS INDICATED BY THE RISK PREMIUM METHOD?

A. Because there are many more electric utilities covered by *Value Line* than water utilities, I determined a risk premium based upon an analysis of the difference between the cost of debt and the cost of equity of electric companies. As shown on Sch. JAR 8, P. 1 and 2, the risk premium method based heavily on the data for electric utilities indicates a cost of equity of 9.76% to 10.17% on December 31, 1995. There is some variation between the cost of equity for an average electric company and an average water or gas distribution company. The difference between my recommended cost of equity in this case and the cost of equity indicated by the risk premium method could be explained by the industry-risk differential, or could be explained by the lower accuracy associated with a risk premium method than a properly applied DCF method.

Q. PLEASE EXPLAIN THE RISK PREMIUM METHOD.

A. The risk premium method is based upon the concept that the cost of equity is related to, but more expensive than the cost of debt. Since the cost of debt can be readily quantified, if it were possible to accurately quantify the "risk premium" demanded by investors to invest in the common stock of a particular company instead of debt, it would then be possible to determine the cost of equity merely by adding this premium to the cost of debt. However, in order to compute the difference between the cost of equity and the cost of debt, it is necessary to quantify the cost of equity in the first place. It is also necessary to assume that the risk premium today is the same as the risk premium that existed during the historic period used to quantify the risk premium.

My cost of equity recommendation in this case is based totally on the DCF method. The risk premium method was presented to show that a properly applied risk premium approach does produce a cost of equity result that is consistent with the result obtained from a properly applied DCF method.

Q. IS THE RISK PREMIUM CONSTANT?

A. No. The risk premium over the cost of US treasury debt that is demanded by investors to invest in common stock is, at a minimum, influenced by federal income tax laws. The return on stocks and the return on bonds is taxed differently, and in ways that have varied substantially over the years. When the tax law changes, the risk premium may change.

Q. YOU HAVE MENTIONED THE RISK PREMIUM IN EXCESS OF THE COST OF 30 YEAR TREASURY BONDS. COULD YOU HAVE USED UTILITY DEBT INSTEAD OF 30 YEAR TREASURY BONDS IN YOUR ANALYSIS?

A. Yes. Utility bonds are in a higher risk category than treasury bonds of the same maturity. Therefore, unless the utility bonds being studied are tax free bonds, they will have a higher interest rate than treasury bonds of the same maturity and same basic terms. Because the interest cost on utility bonds is higher, then the risk premium difference between the cost of equity and the cost of utility bonds is lower than the risk premium difference between the cost of treasury bonds and the cost of equity. If I had added a lower risk premium to a higher interest cost, it should be expected that I would have obtained the same result for the cost of equity that I have obtained by starting with treasury bonds.

Q. WHY WOULD A CHANGE IN THE INCOME TAX LAW CHANGE THE RISK PREMIUM?

A. Typically, the total return received by a bondholder is dominated by the interest income received. Interest income is taxable every year. The return received by a stockholder typically contains a capital appreciation component and a dividend component. The capital appreciation component receives favorable tax treatment in two ways. First, the capital gain is not taxable at all until the stock is sold. Second, the income tax rate charged on capital gains has often been substantially lower than the income tax rate charged on dividend and interest income. Since the 1986 tax law change, the income tax rate on capital gains and on regular income has been similar. Third, dividend income paid to stockholders is partially tax free if the stockholder is another corporation. No such exclusion exists for interest income. This means that every time there is a significant change in the federal income tax law, the "risk premium" demanded by investors to be willing to buy common stock instead of bonds could undergo a corresponding change.

Q. IS A CHANGE IN THE TAX LAW THE ONLY FACTOR THAT CAN INFLUENCE THE RISK PREMIUM?

A. No. Another important factor that could influence the "risk premium" demanded by investors is the perceived interest rate volatility. Investors who buy long-term bonds with a fixed interest rate are exposed to the risk of being locked into that bond's interest rate even if interest rates rise substantially over the life of the bond. Stockholders, especially utility company stockholders, do not share this interest rate risk. The allowed returns on equity are usually reevaluated in a rate case. When the cost of equity goes up, the allowed returns go up. When the cost of equity goes down, the allowed returns go down. Therefore, in times when investors are concerned about interest rate volatility, the "risk premium" required to buy common stock instead of a long-term bond goes down. Conversely, in times when investors are less concerned about interest rate volatility, the "risk premium" goes up.

Q. DID YOU DO ANYTHING TO MINIMIZE INACCURACIES IN THE RISK PREMIUM METHOD CAUSED BY VARIATIONS IN THE RISK PREMIUM OVER TIME?

A. Yes. I quantified the risk premium demanded by investors to invest in common stock by comparing the cost of debt and the cost of equity over the five years ended in 1993. There have been only relatively small changes in the federal income tax rates over that time period. Yet, five years is sufficient time to make it possible to examine a substantial amount of data. I am unaware of any abnormal factors which would have caused investors' perceptions about future interest rate volatility to have changed over the last five years. To the extent that there are reasons, of which I or any other analyst could be unaware, this renders the "risk premium" approach an ever weaker method.

Q. HOW DID YOU QUANTIFY THE RISK PREMIUM?

A. I compared the cost of equity to the cost of debt for each of the electric utilities covered by *Value Line*. I used the first edition of *Value Line* issued in each calendar year for the five years ended 1993. The cost of equity in each of the last five years was quantified using the DCF method. The DCF method I used to quantify the cost of equity was essentially the same as the DCF approach I use in this case, except that instead of using my own analysis to determine what return on book equity is expected by investors in the future, I simply used *Value Line*'s future return on book equity expectation as a proxy for what investors expected. The cost of equity so computed was separately compared to the interest rate on 30-year US treasury bonds, 5-year US treasury bonds, and 1-year US treasury bonds. Based upon that analysis, three separate risk premiums were quantified.

Q. ARE CHANGES IN INTEREST RATES, INCOME TAX RATES, AND INVESTORS' PERCEPTIONS ABOUT THE VOLATILITY OF FUTURE INTEREST RATES THE ONLY THINGS THAT IMPACT CHANGES IN THE COST OF EQUITY OVER TIME?

A. No. Factors such as capital structure ratios, uncertainties associated with construction projects, and the portion of earnings being paid out as dividends also impact the relative desirability of investing in the common stock of a water utility as compared to a treasury bond. As these change over time, even if other things remain equal, the risk premium will change.

E. CAPM Method

Q. WHAT COST OF EQUITY IS INDICATED BY THE CAPM METHOD?

A. As shown on Sch. JAR 9, P. 1 and 2, the CAPM method is indicating a cost of equity of 8.12% for water utilities, and 7.67% for gas distribution utilities.

Q. HOW DID YOU IMPLEMENT THE CAPM METHOD?

A. I implemented the CAPM method by using the differential between the actual earned returns on common stocks and the actual earned returns on 30-year treasury bonds from 1926 through 1994. The difference between the actual returns was then first adjusted for the risk difference between the group of common stocks and the risk of an investment in 30 year treasury bonds.

Q. IS THIS METHOD AS ACCURATE AS A PROPERLY APPLIED DCF METHOD?

A. While my approach to CAPM is substantially more accurate than the approach to the CAPM method presented by Dr. Morin, even my approach to the CAPM method is materially less accurate than a properly applied DCF method. I have presented the CAPM method because the Commission has expressed a desire to consider the results from this method. Therefore, I did not want the Commission to be left only with Dr.

Morin's highly flawed approach to the CAPM from which to make its evaluation. However, I believe it is preferable to rely on the DCF method in preference to the CAPM method.

Q. WHY IS THE CAPM METHOD NOT AS ACCURATE AS A PROPERLY APPLIED DCF METHOD?

A. The CAPM method is highly dependent upon whether or not the earned differential between common stocks and long-term bonds is consistent with the spread difference that investors expect for the future. Additionally, the CAPM method shares all of the other problems that cause uncertainty in the "risk premium" method that are discussed in the previous section of this testimony.

Q. YOUR APPROACH TO CAPM SOUNDS THE SAME AS THAT USED BY DR. MORIN, YET YOU HAVE OBTAINED A VERY DIFFERENT ANSWER. PLEASE EXPLAIN WHY.

A. Dr. Morin has made two very serious errors in his implementation of the CAPM method. First, he has incorrectly used an arithmetic averaging technique to measure historic actual returns. Second, he has reached the invalid conclusion that the risk of a 30-year treasury bond is zero. Both of these errors cannot be responsibly refuted, and both serve to materially increase the cost of equity that is indicated by the CAPM model. Another reason my result is lower than his is that he used a 7.60% interest rate for long-term treasury bonds, while I have used a rate of 6.30%. My rate is reflective of current financial conditions, and is because my testimony is able to consider more current information than was available to Dr. Morin at the time he prepared his testimony. Since he prepared his testimony, there has been a very substantial rally in the bond markets, causing the interest rate on long-term utility bonds to decline materially.

Q. YOU SAID THAT LONG-TERM TREASURY BONDS DO NOT HAVE A ZERO BETA. WHAT IS THE BETA OF LONG-TERM U.S. TREASURY BONDS?

A. The beta of long-term U.S. treasury bonds is about 0.40. This makes long-term treasury bonds in a lower risk category than an equity investment in the common stock of a gas utility, but a beta of 0.40 indicates that there is still a considerable amount of risk in a long-term treasury bond investment.

Q. CAN IT BE REASONABLE TO EXAMINE THE RISK PREMIUM DIFFERENCE BETWEEN LONG-TERM TREASURY BONDS AND COMMON STOCK EVEN THOUGH LONG-TERM TREASURY BONDS DO CONTAIN INTEREST RATE RISK?

A. Yes, but not if it is used in a CAPM model in the way that Dr. Morin has done. One of the elements of Dr. Morin's CAPM computation is that he uses the risk premium between the cost of long-term bonds and common stock as the amount he multiplies by beta. This is wrong. In order to properly quantify the risk differential that is measured by beta, it is essential to use a risk premium factor that is fully reflective of the difference between the two securities being compared.

Q. YOU SAID THAT DR. MORIN IMPROPERLY USED THE ARITHMETIC AVERAGE OF ACTUAL ANNUAL RETURNS EARNED BY COMMON STOCKS FROM 1926-1993 INSTEAD OF THE GEOMETRIC AVERAGE APPROACH. PLEASE EXPLAIN.

A. Arithmetic returns do not properly compensate for year to year volatility and therefore overstate the actual realized returns. The more variable historic growth rates have been, the more his method exaggerates actual growth rates. For example, if a company were to have a stock price of $10.00 in the beginning of the first year of the measurement period and a $5.00 stock price at the end of the first year, an arithmetic average approach would conclude that the return earned by the investor would be a loss of 50% [($5-$10)/($10)]. If, in the second year, the stock price returned to $10.00, then the arithmetic average would compute a gain of 100% in the second year [($10-$5)/($5)]. The arithmetic average approach would naively average the 50% loss in the first year with the 100% gain in the second year to arrive at the conclusion that the total return received by the investor over this two year period would be 25% per year [(-50% +100%)/2 years]. In other words, the arithmetic average approach is so inaccurate that it would conclude the average annual return over this two year period was 25% per year even though the stock price started at $10.00 and ended at $10.00. The geometric average would not make such an error. It would only consider the compound annual return from the beginning $10.00 to the ending $10.00, and correctly determine that the annual average of the total returns was not 25%, but was zero.

In order to protect investors from misleading data, the U.S. Securities and Exchange Commission (SEC) requires mutual funds to report historic returns by using the geometric average only. The arithmetic average is not permitted. The geometric average, or SEC method, has the compelling advantage of providing a true representation of the performance that would have actually been achieved by an investor who made an investment at the beginning of a period and re-invested dividends at market prices prevailing at the time the dividends were paid.

Q. DO FINANCIAL TEXTBOOKS SUPPORT THE USE OF THE GEOMETRIC AVERAGE FOR COMPUTING HISTORIC ACTUAL RETURNS?

A. Yes. For example, the textbook *Valuation. Measuring and Managing the Value of Companies*, by Copeland, Koller, and Murrin of McKinsey & Co. , John Wiley & Sons, 1994, in a description of how to use the Ibbotson Associates data states the following on pages 261-262:

> We use a geometric average of rates of return because arithmetic averages are biased by the measurement period. An arithmetic average estimates the rates of return by taking a simple average of the single period rates of return. Suppose you buy a share of a nondividend-paying stock for $50. After one year the stock is worth $100. After two years the stock falls to $50 once again. The first period return is 100 percent; the second period return is -50 percent. The arithmetic average return is 25 percent [(100 percent - 50 percent)/2]. The geometric avenge is zero. (The geometric average is the compound rate of return that equates the beginning and ending value.) **We believe that the geometric average represents a better estimate of investors' expected returns over long periods of time.**

(Emphasis added)

Similarly, in another textbook discussion that specifically addresses the use of the Ibbotson data, *Financial Market Rates & Flows*, by James C. Van Horne, Prentice Hall, 1990, states the following on page 80:

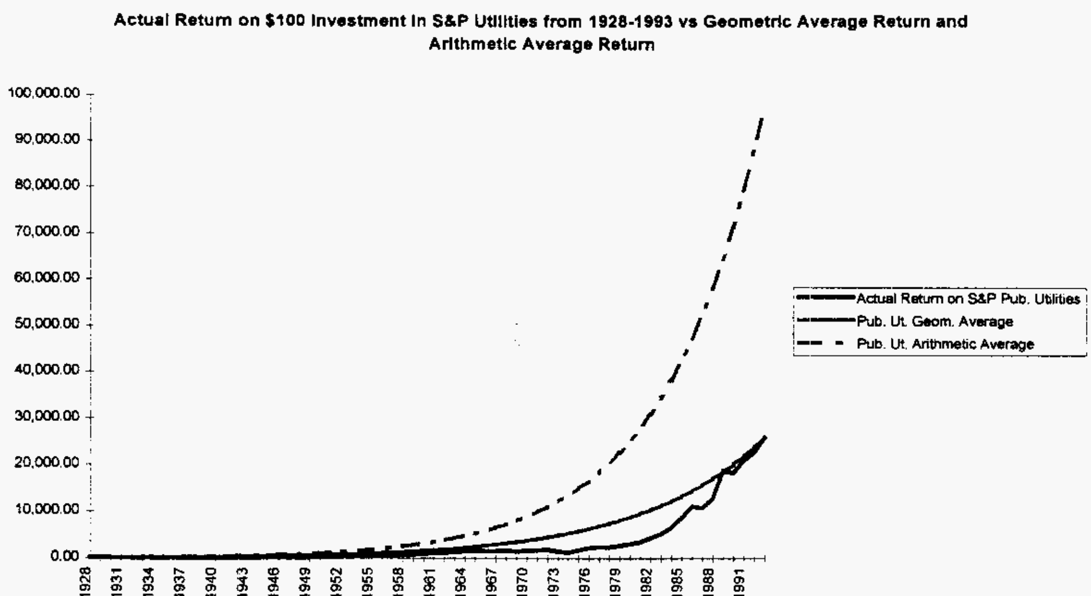
> The geometric mean is a geometric average of annual returns, whereas the arithmetic mean is an arithmetic average. For cumulative wealth changes over long sweeps of time, the geometric mean is the appropriate measure.

Q. HOW DO INVESTORS VIEW HISTORIC ACTUAL RETURNS?

A. Every time I have seen an article in popular business magazines about what returns stocks have achieved historically, reference is made to a rate that is consistent with the geometric return, not the arithmetic return. A recent example I have seen is in an article entitled "Saving at Mach Speed" on page 79 of the June 12, 1995 issue of *U.S. News and World Report*. This article states that "...10 percent (is) the long-term rate of return of the Standard & Poor's 500."

Q. HAVE YOU COMPARED GRAPHICALLY THE CAPITAL APPRECIATION GROWTH RATE USING DR. MORIN'S METHOD WITH THE CAPITAL APPRECIATION GROWTH RATE THAT IS OBTAINED USING THE SEC METHOD?

A. Yes. In the following graph I show the actual movement of the S&P Utility index from 1928 through 1993. I also show how the index would have behaved on a year-by-year basis using the average growth obtained from the SEC method and using Dr. Morin's historic growth rate methodology. The graph illustrates that Dr. Morin's calculation of historic actual returns deviates at an ever-increasing rate over time from the actual S&P Utility Index, overstating the total return from 1928-1993 by almost 400%. By contrast, the historic actual returns computed using the SEC method is a dramatically more reasonable track of the growth of the S&P utility over time and thus is a better measure of historic actual return rates realized by investors.



Q. HOW MUCH HIGHER IS THE RISK PREMIUM DIFFERENCE BASED UPON AN ARITHMETIC AVERAGE THAN IT IS BASED UPON A GEOMETRIC AVERAGE?

A. From 1928 to 1993, the arithmetic average method produced an indicated risk premium that was 1.90% higher for public utility stocks vs. public utility bonds than the risk premium indicated by using the SEC, or geometric average method.

For all of the above reasons, to the extent any weight at all is given to the CAPM method, its computation must be based upon a geometric average of historic actual returns in preference to an arithmetic average of historic actual returns.

III. HOPE NATURAL GAS DECISION

Q. ON PAGES 6-9 OF HIS DIRECT TESTIMONY, DR. MORIN DISCUSSES THE U.S. SUPREME COURT DECISION IN THE *HOPE NATURAL GAS* CASE. IS HIS EQUITY COST RECOMMENDATION CONSISTENT WITH THE REQUIREMENTS OF THE HOPE CASE?

A. No. His 12.25% equity cost recommendation is substantially higher than the return required by the implementation of the principles in the *Hope Natural Gas* case. Specifically, his recommendation is inconsistent with the following important quote from the decision:

> The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value of the property is reduced does not mean that the regulation is invalid... It does, however, indicate that "fair value" is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

The U. S. Supreme court explains in a footnote to the above paragraph that "... the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn." Therefore, when Dr. Morin says on pages 14 to 15 of his testimony that he concerned about the "... market-to-book (M/B) ratios..." of the water industry and "... falling realized returns on equity...", he has ignored the above-quoted principles. The fact is that the market-to-book ratio of the water utility industry was, on average, above 1.4 as of December 31, 1995. When the market-to-book ratio is this high, it is consistent for realized returns on equity to be allowed to drift down.

Dr. Morin again ignored the above-quoted principles from the *Hope* decision when he arrived at his erroneous conclusion on page 28 of his testimony that there is ".... questionable applicability of the [DCF] model when M/B ratios deviates substantially from 1.00...". Actually, the DCF model is specifically designed to determine the proper cost of equity irrespective of the market-to-book ratio because it determines the return investors demand on market price. Then, when other regulatory principles are properly applied, the return on the original cost rate base is set equal to the return demanded by investors on book value. In this way, the principles of the *Hope* case are specifically met.

Q. HAVE REGULATORY AGENCIES RELIED UPON THE ABOVE PORTION OF THE *HOPE NATURAL GAS* DECISION THAT YOU HAVE QUOTED?

A. Yes. For example, FERC has stated the following:

> Specifically, they claim that when a utility's market-to-book ratio is above one, applying a DCF-based allowed rate of return to a book value rate base results in earnings that are too low. Conversely, when a utility's market-to-book ratio is below one, applying a DCF-based allowed rate of return to a book value rate base results in earnings that are too high. Both commenters argue that the allowed rate of return should be applied to a market value rate based rather than to book value.
>
> The following example demonstrates the circularity of their claim. Equity capital costs generally rise as interest rates rise. Conversely, equity capital cost rates generally fall as interest rates fall. During periods of risking equity costs, utilities generally file for rate increases to cover these higher costs. This action protects utility shareholders from declines in the value of the stock. The result is a tendency to maintain a utility's existing market-to-book ratio during periods of risking equity costs.

> During periods of falling capital costs, the revenue required to meet shareholder capital costs requirements also declines. Until a utility files for new rates at the lower capital cost, it continues to charge rates based on the higher equity capital costs that existed when the current rates were set. The result is a tendency for the utility to earn more than its shareholders currently require and a concomitant increase in the price of the utility's common stock and market-to-book ratio.
>
> When capital costs are below those of the previous filing, applying the allowed rate of return to a market value rate base would perpetuate the unnecessarily high revenues that the expense of utility's customers. **Applying the allowed rate of return to a book value rate base would reduce revenue to the level required by shareholders at the new lower cost of equity. These revenues will provide the utility with an opportunity to recover all costs including the cost of capital.**
>
> The argument over the application of an allowed rate of return to a market value rate base is an old one and the problem of circularity inherent in that approach has been long and widely recognized. **The Supreme Court's statement in Federal Power Commission v. Hope Natural Gas Co. that "rates cannot be dependent upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated" reflects its recognition of that problem. The market value of an enterprise or its common stock depends upon its earnings or anticipated earnings, which in turn depends upon the rates allowed. Thus, market value is a result of the ratemaking process and may not properly be the beginning of the process as well.**

Docket RM87-35-000, P. 3348 of the Federal Register/ Vol. 53, No. 24, Friday Feb. 5, 1988. Emphasis added.

Similarly, the Federal Communications Commission (FCC) responded to an argument made by Ameritech which suggested that the FCC was "... obligated to prescribe a rate of return that will ensure continuation of the carriers' current market-to-book ratios."[9] The FCC rejected Ameritech's argument for several reasons. The reasons stated were:

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[9]Page 15 of decision FCC 90-315 dated September 19, 1990, in CC Docket No. 89-624.

> ... market-to-book ratios greater than one have been viewed traditionally as possible indicators that the company's return is greater than its required return.
>
> ...Ameritech places great reliance on its perception that unless this Commission applies the market-derived rate of return to its equity base, stockholders will see a massive decline in the value of their stock. It is true that prescription of a rate of return based on market data could lead to a decrease in the value of the stock if investors have been expecting continuation of a previously-authorized higher rate of return. On the other hand, a reduced rate of return might have no impact on stock price if, as often happens, the reduction had already been anticipated and discounted by the market. In any case, the requirement that we balance ratepayer and investor interests does not allow us to insulate investors from a diminution in the value of their stock (if in fact we could do so). **In any event, if we prescribed a rate of return above that which market data showed to be reasonable, investors would increase their expectations as to the carrier's rate of return, market value would increase, and the carrier would seek a higher rate of return authorization so that these higher expectations are not thwarted. We would be remiss in our responsibilities to balance ratepayers' and investors' interests if we implemented procedures that effectively insulated a carrier from experiencing a decrease in its authorized return. Thus, our current market-based rate of return procedures meet the Bluefield/Hope criteria notwithstanding that their application herein may adversely impact carriers' high market-to-book stock ratios.**
>
> Moreover, market-to-book ratios greater than one have been viewed traditionally as possible indicators that the company's return is greater than its required return.

(Emphasis added)

(FCC-90-315, P. 15.)

IV. WATER COMPANY RISKS IN FLORIDA

Q. DR. MORIN CLAIMS, ON PAGE 40 OF HIS TESTIMONY, THAT THE WATER UTILITIES IN FLORIDA ARE MORE RISKY THAN WATER UTILITIES ELSEWHERE BECAUSE OF THEIR SMALLER SIZE AND BECAUSE OF USED AND USEFUL ADJUSTMENTS. PLEASE COMMENT.

A. The kind of risk that impacts the cost of equity is the non-diversifiable risk. Neither of these factors impact non-diversifiable risk and therefore do not impact the cost of equity.

Q. WHY DO DIVERSIFIABLE RISKS NOT IMPACT THE COST OF EQUITY?

A. Investors have the opportunity to purchase securities as part of an overall portfolio. Unexpectedly bad results at one company whose stock is owned in the portfolio will likely be impacted by unexpectedly good results at another company so long as the portfolio is appropriately diversified. Therefore, as long as the portfolio is diversified, the predictability of the income from a portfolio is much higher and therefore the risk is much lower than if only one company were owned. Conceptually, from the perspective of divrsifiable risk, a large water company is no different than a large portfolio of small water companies.

An analogy that is helpful could be made to gambling on whether either "red" or "black" will come up on a roulette wheel at a casino in Las Vegas. If the "investor" goes to the casino with $1,000 to bet and places all $1,000 on the roulette wheel all at once, the bet would be highly risky. There is a 50% chance (before consideration of the "house" take) that the "investor" would loose the entire investment. However, if the same investor made 1,000 bets of $1.00 each, the outcome is highly predictable. Within a very narrow range, this investor would have close to $1,000 (absent considerations of the "house" take). It could be a little more, or a little less, but because the number of diversifiable bets would be very large (1,000) instead of very small (1), risk is significantly minimized.

Q. DO USED AND USEFUL ADJUSTMENTS INCREASE THE RISK OF INVESTING IN FLORIDA UTILITIES?

A. No. While a used and useful adjustment is a factor that must be considered, because the water company receives both a return of and a return on the plant that is disallowed on used and useful grounds as customers are added in the future, investors eventually receive much of the compensation associated with what was initially disallowed used and useful plant. Furthermore, the predictability of adding customers in future years is materially increased if the investor purchases the equity in the water utility as part of a diversified portfolio.

VII. DIRECTION OF CHANGE IN WATER COMPANY RISKS

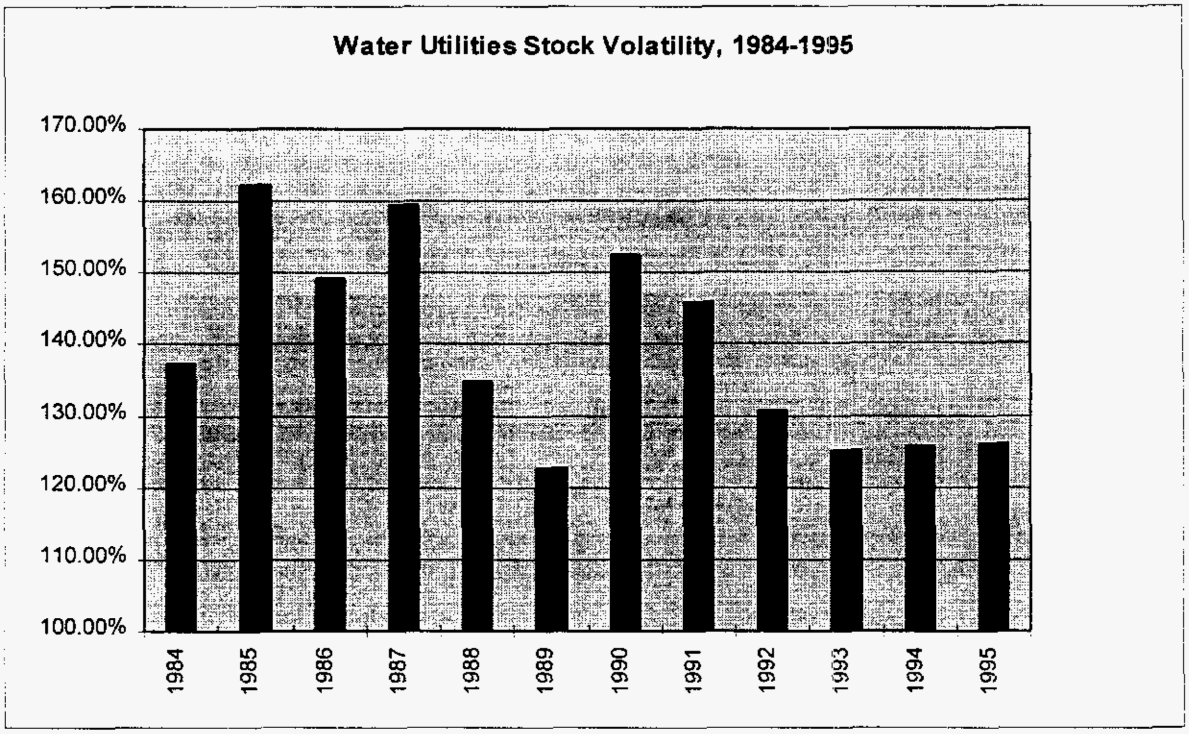
Q. ON PAGE 3 OF HIS TESTIMONY, DR. MORIN CONCLUDES THAT THE RISK OF WATER BUSINESS HAS INCREASED SUBSTANTIALLY IN RECENT YEARS. DO YOU AGREE?

A. No. My experience has shown that most company cost of capital witnesses argue that the company or industry for which they are testifying happens to have extraordinarily high risks. It is always possible to identify factors associated with any one business or any one industry which seem to cause that entity to have risk. However, risk is inherent in all businesses. This is specifically why the cost of equity for all investor owned companies is higher than the risk free interest rate. Because a simple listing of risks can make any company appear to be risky, when evaluating risks it is important to concentrate only on analytical analysis. Subjective comments relating to risk should be given minimal weight.

Q. DOES AN ANALYTICAL ANALYSIS SHOW A DIRECTION OF CHANGE IN THE RISK EXPERIENCED BY THE STOCKHOLDERS OF WATER UTILITIES?

A. Yes. One analytical method to determine how the risk of an industry is changing over time is to examine the range over which stock prices have traded. The common stock price at any one point in time is reflective of investors' expectations for the future. Risk is related to the difficulty with which future events relating to the value of a specific investment can be forecast. Therefore, the larger the range over which stock prices trade, the more significant the changes in investor expectations that were experienced over the time period that the stock price volatility was quantified.

In order to examine how investors' perceptions of risk have been changing for water utilities, I examined the difference between the high and low stock price that was achieved by the water utilities covered by Value Line for each year from 1994 to 1995. The results of this analysis are shown on Sch. JAR 12, P. 2, and are summarized on the following graph:



As shown in the above graph, the risk as indicated by stock volatility has been in a basic downtrend since 1985, and four of the five lowest volatility years since 1983 occurred in the most recent four-year period.

VI. RELATIVE RISK OF GAS COMPANIES AND WATER COMPANIES

Q. ON PAGE 39 OF HIS TESTIMONY, DR. MORIN CLAIMS THAT WATER UTILITIES ARE MORE RISKY THAN GAS UTILITIES. PLEASE COMMENT.

A. Dr. Morin is wrong. Water utilities are in a lower risk category than gas utilities. Other than air, water is the most basic commodity there is. As contrasted to natural gas, there are no substitute products available.

Standard & Poors has made it clear that it recognizes water utilities are in a lower risk category than gas utilities. This can be seen by comparing the benchmarks Standard & Poors has stated are required for a water utility to obtain an "A" bond rating and the benchmarks required for a natural gas distribution utility to obtain the same "A" rating. For example, the pre-tax interest courage required for a water utility to be within the benchmark for an "A" rating are 2.25-3.75, whereas the benchmark for a gas distribution utility to achieve an "A" rating is 3.0-4.25. Similarly, for a "BBB" bond rating, the benchmark range for water utilities is 1.25-2.75, while the benchmark range for gas distribution utilities is 2.0 to 3.25. Similarly, water utilities can use more debt in the capital structure than gas distribution companies with the same bond rating. The benchmark level of debt in the capital structure for an "A" rated water utility is 48-56%, while the benchmark level of debt in the capital structure of a gas distribution utility is 42-50% debt. A water utility can use between 54-62% debt and still be within the benchmark guidelines for a "BBB" rating, while a gas distribution utility must stay within 47-60% debt to be consistent with the guidelines for a "BBB" bond rating.

Q. DOES MARKET PRICE DATA OF COMMON STOCK MOVEMENTS SUPPORT THE FACT THAT WATER UTILITIES HAVE A LOWER RISK THAN GAS DISTRIBUTION UTILITIES?

A. Yes. As previously explained, one analytical indicator of risk is the magnitude of stock price movement within a year. As shown on Sch. JAR 12, P. 1, the difference between the high and low stock price of water utilities has been smaller than the similar movement of the stock price movement of gas distribution utilities in every year since 1991.

VII. LIQUIDITY PREMIUM

Q. ON PAGE 46 OF HIS TESTIMONY, DR. MORIN RECOMMENDS ADDING A 0.2% LIQUIDITY PREMIUM TO THE COST OF EQUITY OF SSU. PLEASE COMMENT.

A. It is inappropriate to add this liquidity premium. Not only is such an addition speculative, equity capital is raised by SSU's parent, Minnesota Power and Light. Therefore, the liquidity of the investment is related to the cost of raising equity that is incurred by Minnesota Power and Light. The common stock of Minnesota Power and Light is traded on the New York Stock Exchange and does not command any liquidity premium.

Q. IS THERE ANY FACTOR WHICH SHOULD LEAD TO A DISCOUNT RATHER THAN A PREMIUM FOR SMALL WATER UTILITIES?

A. Yes. While I do not recommend adding such a premium because quantifying it would be speculative, a smaller water company is more likely to be purchased by another water utility than is a large water utility. Frequently when such acquisitions take place, they are for a price in excess of book value. The potential for the sale of assets in excess of book value is a reason why investors might find small water company investments especially attractive and therefore might actually pay a premium to own these companies rather than require the liquidity premium penalty as recommended by Dr. Morin.

VIII. IMPACT OF WEATHER NORMALIZATION CLAUSE

Q. IF A WEATHER NORMALIZATION CLAUSE IS IMPLEMENTED FOR SSU, WHAT IMPACT SHOULD THIS HAVE ON THE OVERALL COST OF CAPITAL?

A. A weather normalization clause would increase the predictability of revenues and earnings for a water utility. An increase in revenue predictability reduces the amount of common equity and increases the amount of debt in the capital structure that a water utility can safely use. This is because a weather normalization clause increases the amount of annual interest expense that a water company can count on being able to pay each year. Therefore, if a water company does respond to the existence of a weather normalization clause by increasing the amount of debt and the result of the debt increase is to lower the overall cost of capital, then there is a net cost of capital benefit from implementing a weather normalization clause.

Other than in response to a change in the capital structure, it is unlikely that the implementation of a weather normalization clause would lower the cost of equity. This is because variation from weather is a diversifiable risk. As explained earlier in this testimony, the cost of equity is only influenced by changes in non-diversifiable risks, not diversifiable risks.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A FINANCIAL PRINCIPLES SUPPORTING THE DCF METHOD

A. Basic Principles

Q. WHY IS THE DCF METHOD VALID?

A. Investors purchase stock with current cash because they perceive the future cash received in the form of dividends and proceeds from the eventual sale of the stock as being more valuable than the current cash. The DCF method quantifies the rate of return by finding the discount rate that equates the future cash expectations to the current market price.

Common stock dividend rates are not contractual. Similarly, there is no contractually specified price at which the stock will sell in the future. Therefore, the accuracy of the DCF method is dependent upon the degree with which the future cash flow estimates of dividends and estimated selling price of the stock used in the DCF analysis are representative of what the average investor is expecting for the future.

When an analyst's best estimate for the future is that earnings, dividends, stock price and book value will all grow at the same rate, implementing the DCF method may be simplified by expressing the cost of equity, as:

$$k = D/P + g$$

where:

k = cost of equity

D = dividend rate

P = market price

g = future expected growth rate

My "b x r" approach, or the simplified version of the DCF method, and my approach to the complex version of the DCF are consistent with how securities analysts implement these methods, and is consistent with the principles explained in this testimony.

Q. TO WHAT DOES THE GROWTH COMPONENT OF THE DCF FORMULA REFER?

A. It refers to the expected growth in cash flows. Cash flows include dividends plus the eventual proceeds from the sale of the stock. Some analysts incorrectly oversimplify the DCF model by saying that only dividends are being discounted. However, since earnings are either reinvested or used for dividends, earnings are more important than dividends in determining the total future cash flow growth that is expected. Therefore, if the DCF model were to examine only one factor, earnings would be preferable to dividends as the indicator of total future cash flow.

Q. IS IT POSSIBLE TO APPLY THE DCF METHOD WHEN NON-CONSTANT GROWTH RATES ARE FORECAST?

A. Yes. Conceptually, it is possible to make a separate year-by-year estimate of what the dividend for any given company will be. Thus, each year's dividend could be separately discounted back to arrive at its net present value. Through a series of repeated computations one can determine a discount rate that is sufficient for the stream of future cash flows to have the same net present value as the current market price. This procedure is moderately cumbersome. When certain specific conditions exist, it is possible to greatly simplify the process. **If and only if** there is no basis to forecast different rates of future expected growth for earnings, dividends, book value, and stock price, it is mathematically acceptable to use the simplified version of the DCF formula.[10] Earnings per share is equal to the book value per share times return on book equity. Therefore, anything that causes the book value per share of a utility company to decrease will tend to cause the earnings per share to decrease and anything that causes the book value per share to increase will tend to cause the earnings per share to increase.

10 Earnings, book value, dividends, and stock price virtually never actually grow at the same rate. However, what is important to recognize in using the simplified version of the DCF model is that the analyst has no basis to forecast different future rates of growth for each of these items.

Q. DOES THE DCF METHOD TAKE INTO CONSIDERATION REGULATORY INFLUENCES ON FUTURE CASH FLOW PROSPECTS FOR A UTILITY COMPANY?

A. Yes. Rate levels influence a company's likely future earnings. Future expected earnings influence stock prices. Earnings are the source of dividends. Therefore, the level of rates allowed by a commission influences the amount of dividends a company will be able to pay in the future. Also, total earnings prospects have a strong influence on a company's stock price. Therefore, the level of rates also influences the future market price that a company's stock is likely to attain.

Q. HOW DOES STOCK PRICE COMMUNICATE THE COST OF EQUITY BEING DEMANDED BY INVESTORS?

A. The relationship between the market price of a common stock and the future cash flows (dividends and stock sale proceeds) which an investor obtains as a result of the ownership of that stock determines the cost of equity. For a going concern such as the typical regulated public utility, future earnings determine future cash flow. The only way to measure whether or not investors believe a utility company is being provided a reasonable opportunity to earn a fair level of earnings on the book value of its assets is by examining the stock price. If the stock price is high in relation to the book value of the assets, this means that investors are optimistic about a company's cash flow prospects. If a stock price is low in relation to the book value of the assets, then investors are pessimistic about the Company's cash flow prospects.

Q. CAN THE STOCK PRICE CHANGE WITHOUT AN INCREASE OR DECREASE IN AUTHORIZED RATES?

A. Yes. Factors outside rate cases, such as the general state of the economy, and interest rate changes, can influence the level of earnings expected by investors. Also, changes in the cost of equity demanded by investors can, and often do, cause stock prices to change. For example, several years ago when equity costs were in the 14% range, future cash flows expected by investors had to be higher than in the current environment to support any given stock price. Stock prices will change if the relative valuation placed on future earnings by investors changes. Note that the value of $1.00 of cash flow expected by investors in one year is worth only $0.877 at a time when the cost of equity demanded by investors was 14% ($0.877 X 1.14 = $1.00), whereas the same $1.00 of earnings expected in one year is worth $0.909 when the cost of equity demanded by investors is 10% ($0.909 X 1.10 = $1.00).

The current stock price is equal to the sum of the net present value of all future expected cash flows. As a result, stock prices change if the cost of equity changes.

Q. CAN YOU GIVE A SIMPLE EXAMPLE THAT ILLUSTRATES THE UNDERLYING PRINCIPLE BEHIND THE DCF METHOD?

A. Yes. DCF stands for Discounted Cash Flow. What is being discounted is the value of cash flow received in the future. This makes it possible to properly equate the future receipts of cash to the value of current cash. One thousand dollars received next year is worth less than the same amount received today. This is true, if for no other reason, because a person could take the $1,000 received today and put it in a bank account guaranteed by the federal government. Assuming a 3% interest rate, at the time of withdrawal the person would receive $1,030 from the bank. In this way, $1,000 today is worth the same as $1,030 received in one year. Because of this time value of money, the difference in value of $1,000 received next year versus $1,000 today is dependent upon the interest rate, or cost of capital.

The valuation explained above is directly applicable to a decision to purchase co. mon stock. The essential differences between an investment in common stock and a deposit in a bank account are that the exact yield for common stock is unspecified and there is no federal guarantee on the funds. Because of these uncertainties, a stock investment is more risky. Nevertheless, the basic principle of the time value of money that exists for the bank account investment still applies for the common stock investment.

Whether an investor buys stock in a company or puts money in a bank account, he or she gives up cash today in exchange for the right to potential future gains. The investor in the bank account receives specified interest income, whereas the investor in common stock receives any dividends the company may pay plus the right to sell the stock at prevailing market prices. Today's stock price is the present value of the expected dividends and the proceeds from eventual sale of the stock. It is the interest rate, or "discount rate," or "cost of equity," that makes the future anticipated dividends and future anticipated selling price equal to the present market price.

The simplified DCF formula is k = D/P + g where "k" equals the cost of equity, "D" equals the dividend, "P" equals market price and "g" equals the future anticipated rate of growth in dividends, earnings, book value, and stock price. This version of the DCF method is quantified by computing "D/P" (dividend yield), determining "g" and then adding these two results together.

Q. IS IT ALWAYS ACCEPTABLE TO APPLY THE SIMPLIFIED VERSION OF THE DCF METHOD?

A. No. Making a decision to use this simplified version of the DCF formula requires that the retention rate times return on book equity, or "b x r" approach be used to compute growth. This is because the "b x r" approach arrives at a future sustainable constant growth rate. Other techniques to compute growth rates, such as the historic rate of change in dividend or earnings, are from environments in which earnings, dividends, book value, and stock price all grew at varying rates. This excludes them from use in the simplified, or D/P + g version of the DCF formula.

Q. IS IT GENERALLY PROPER TO USE THE D/P + G SIMPLIFIED VERSION OF THE DCF METHOD FOR PUBLIC UTILITIES?

A. Yes. For most regulated utilities, future expected business conditions are relatively stable. Earnings fluctuate to a certain degree based upon local weather and economic cycles, certain extraordinary events and the timing of rate cases. However, results generally tend to cycle back to a normal profit allowance as a result of commission orders to either increase or decrease rates. This is in contrast to some non-utility companies that might have a fad product with a profit expectation for only a few years or a developing company with several early years of projected poor earnings.

Q. IS A FIVE-YEAR FORECASTED GROWTH RATE APPROPRIATE TO USE DIRECTLY IN THE SIMPLIFIED VERSION OF THE DCF MODEL?

A. No. Computing a compound annual growth rate starting from an historic period to a time such as five years in the future can result in erroneous results. Using the resultant 5 year growth rate as "g" in the simplified D/P + g formulation is a common mistake. Analysts' published growth rates are not constant growth rates. They include the impact of growth from a base year that may have abnormally depressed or abnormally high earnings. This is why analysts' projected growth rates are generally only usable in the complex version of the DCF method. It is incorrect to rely upon growth from an historic period for use in the DCF method. This is true because such growth is rarely sustainable. Because it is not sustainable, it is not reflected in stock prices. To be sustainable, the historic base period would have to contain a return on book equity and payout ratio that is exactly equal to the future anticipated return on book equity and payout ratio.

Q. IS THE EXPECTED RETURN ON BOOK EQUITY, OR "r," A KEY TO THE ACCURATE IMPLEMENTATION OF THE DCF MODEL?

A. Yes. Other things being equal, earnings per share are proportional to the earned return on book equity. Earnings per share directly impact the future cash flow expected by investors both because earnings provide the source of dividends, and because the future stock price is dependent upon future earnings and dividend prospects. Focusing on return on book equity is more reliable than other means of estimating sustainable growth rates as long as the value chosen for "r" is reflective of the return on book equity investors expect in the current financial environment, and under normal weather and economic conditions.

B. Determination of Future Expected Return on Book Equity, "r"

Q. WHAT EVIDENCE IS AVAILABLE TO INVESTORS TO ESTIMATE THE FUTURE EXPECTED LEVEL OF RETURN ON BOOK EQUITY?

A. The following key factors are available to evaluate "r":

- Returns on book equity forecasted by securities analysts
- Historic levels and trends in allowed returns on equity
- Historic earned returns on equity.

My preference is to give the most weight to the returns on book equity forecast by securities analysts, especially when evaluating the aggregate data for a group of companies. However, examinations of historic earned returns on equity and allowed returns on equity are important checks to detect reporting errors or other problems with analysts' reports for any one company. Also, it is sometimes necessary to evaluate companies for which analysts' reports are not available.

Q. IS THE "r," OR RETURN ON BOOK EQUITY IN THE "b X r" DETERMINATION OF GROWTH, THE SAME AS THE COST OF EQUITY, OR "k"?

A. No. It is possible for the future expected return on book equity, "r," and the cost of equity, "k," to be substantially different. Some people mistakenly confuse the value of "r" in the "b x r" approach with the cost of equity.

The factor "r" helps quantify the growth rate that investors expect because the rate of earnings actually earned on equity has a great influence on the attained level of future cash flows. This differs from the cost of equity, "k," which reflects the return investors expect to receive on their market price investment. The return the investor will receive on the market price investment takes into consideration the future cash flows consistent with the achieved return on book equity, "r." If the market price is above book value, "k" will be less than "r," and if the market price is below book value, "k" will be higher than "r."

An analogy with bonds shows how different the cost of equity, "k," and the future expected return on book equity, "r", can be. Assume that a utility company issued a non-callable long-term bond when long-term interest rates were 12% for $1,000 with a coupon interest rate of 12%. Further, assume that the bond is to reach maturity in 30 years, and that, due to a decline in interest rates, the company could now issue a similar 30 year bond at an interest rate of 9%. If the current cost of interest being demanded by investors is only 9%, the bond with a 12% coupon would have a market price substantially in excess of its original face value, about $1,300. This is because the discounted cash flow, or DCF, of the future expected payments (of $120 per year on a 12% bond plus $1,000 in 30 years) has a net present value of about $1,300 when using a discount rate of 9%. In the hypothetical example, investors are willing to settle for an interest rate yield of 9%. In this example, "r" on the 12% bond (the bond equivalent of earned return on book equity) would be 12%, but "k" (the total return on the market price of the bond equivalent of cost of equity) would be only 9%. In the case of this hypothetical bond, regulators could readily tell that investors were more than willing to accept the 12% yield because the price of the bond would be above its original issue price.[11]

As explained in the above example, when a bond has a market price in excess of its face value, the total return received by an investor who purchases the bond at market will be less than the coupon rate of interest. The same concept applies to an investment in common stock, except the appropriate comparison is to book value instead of face value. Also, instead of a specific coupon rate, no contract specifies the earnings return received by investors. Instead, estimated levels of future cash flow determine the effective rate investors perceive. The return on book equity, or "r," that investors expect for the future is the critical indicator of the estimate of future cash flow.

11 Given the downtrend in interest rates over the last several years, there are many examples of bonds selling above the original issue price. In evaluating such bonds, it must be recognized that those which are subject to being "called" by the issuing company may have a lower market price than similar bonds which are not subject to call provisions.

Further, it should be noted that there are many differences between bonds and stock. In the 12 percent bond hypothetical, for example, the interest cost to the company remains at 12 percent over the life of the bond. As a result, the 12 percent rate must be passed on to ratepayers. Common stock returns, however, are not fixed.

C. Use of Short-term five-year Analysts Growth Rate Forecasts to Estimate Future Growth

Q. SOME PEOPLE ATTEMPT TO USE RAW, UNADJUSTED ANALYSTS' SHORT-TERM, FIVE-YEAR GROWTH RATES AS A PROXY FOR THE FUTURE SUSTAINABLE GROWTH RATE IN A DCF FORMULA. IS THIS APPROPRIATE?

A. No. Consider, for instance, the following example where weather conditions in 1990 were unfavorable, and as a result, a utility company only earned 10.0% on its book equity in that year, but investors believed the company was capable of earning an average of 12.0% on book equity in a normal year. In this case, the growth in earnings per share necessary to bring the 10.0% earned return on book equity up to 12.0% would unsustainably inflate analysts' estimates for growth over the next few years. Note that an increase from 10% to 12% return on book equity is a one-time growth in earnings per share of 20%. A non-recurring source of growth such as this, even spread out over five years, would still overstate the future sustainable growth rate by approximately 4%. If used in the DCF model this could overstate the cost of equity by up to 400 basis points. Once the return on book equity made its increase from 10% to 12%, this growth rate would not be sustainable because analysts would be aware that the cause of growth was a recovery of earnings from a time of abnormally depressed earnings to a time of more normal earnings. In this example, the analyst's growth forecast may be consistent with investor expectations, but it is still inappropriate to use that type of growth in the D/P +g simplified formulation of the DCF model because analysts never intended it to be a future sustainable growth rate.

Q. ARE ABNORMAL WEATHER CONDITIONS THE ONLY POTENTIAL SOURCE OF UNSUSTAINABLE GROWTH RATES?

A. No. Economic conditions, abnormal expenses, or an overall change in cost of capital rates also could have caused a modification to the earnings ability of utility companies.

Q. WILL THE USE OF A LARGE GROUP OF COMPARATIVE COMPANIES HELP TO SMOOTH THE UPS AND DOWNS CAUSED BY YEARS OF ABNORMAL EARNINGS?

A. No. This is because weather patterns, economic conditions, and the overall levels of allowed returns on equity can and often do affect many of the companies in a similar way.

Q. CAN YOU PROVIDE TEXTBOOK SUPPORT FOR YOUR OBSERVATIONS THAT ANALYSTS' GROWTH RATES ARE NOT CONSTANT GROWTH RATE FORECASTS?

A. Yes. The textbook Intermediate Financial Management, by Brigham and Gapenski, The Dryden Press, 1990, at page 147 states that analysts' forecasts, such as the ones compiled by I/B/E/S "often assume non constant growth".

D. Proper Method to Determine Sustainable Growth for Use in The DCF Formula

Q. HOW SHOULD THE GROWTH RATES FOR USE IN THE SIMPLIFIED VERSION OF THE DCF MODEL BE ESTIMATED?

A. The future growth rate is dependent upon the future earnings a utility will achieve. The proper determination of the future growth rate, or "g" portion of the D/P + g formula, is to multiply the future expected earned return on book equity by the portion of these future expected earnings retained in the business rather than paid out as a dividend (retention rate). This results in the sustainable growth rate that is appropriate for use in the simplified version of the DCF method. Earnings retained in the business are what is available for reinvestment in utility assets.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW RETAINED EARNINGS AND EARNED RETURN ON BOOK EQUITY COMBINE TO PRODUCE GROWTH?

A. Yes. Assume a company with a book value of $20.00 per share at the beginning of a year earns 10% on equity and pays a dividend of $1.50 per share. Its earnings in that year would be $2.00 (the $20.00 book value multiplied by 10%). Retained earnings would be $2.00 less $1.50 of dividends, or $0.50. Since the $0.50 represents a permanent increase in equity capital, the book value of the company at the end of the year would be $20.50 per share. In this way, by foregoing the additional potential $.50 dividend, the common equity holder has invested an additional $.50 in the business.

If the company anticipates continuing to earn 10% on its book equity, anticipated earnings in the next year would be $2.05 ($20.50 multiplied by 10%). In this example the growth in earnings is $2.05/$2.00 =1.025 or 2.5% growth. Mathematically, it is possible to express the growth caused by retained earnings as "b" times "r" where "b" equals the retention rate and "r" equals the future anticipated return on book equity. In this example, the retention rate "b" is $.50/$2.00, or 0.25, and "r" has been assumed to be 10%. The "b x r" result is therefore 0.25 x 10%, or 2.5% growth.

Note that it is proper to compare the cause of growth in earnings per share for a utility to the cause of growth of earnings in a savings account. If an investor has $1,000 in a savings account paying 3% interest, in the first year earnings will be $30. At the end of one year the account will contain $1,030. If the investor decides to leave the $30 in the account (or retain all earnings), then earnings in the next year will grow from $30 to $30.90 ($1,030 x 3%). Conversely, if the investor decides to withdraw the $30 of first-year earnings, earnings in the second year will not grow to $30.90 but will remain at $30. Exactly the same principle holds for determining the sustainable growth rate of a common stock investment. Earnings that are retained are reinvested in the business. The earnings produced from the assets purchased with the reinvested earnings cause future earnings growth. Alternatively, the payment of earnings as a dividend makes them unavailable for reinvestment in assets that would create future earnings growth to occur. Therefore, the future sustainable growth rate, whether it be earnings per share for a company or the balance in a savings account, directly relates to "b" and "r."

E. Additional Factor Affecting Sustainable, Long-term Growth

Q. IS THERE ANYTHING OTHER THAN EARNINGS AND DIVIDENDS THAT CAN INFLUENCE THE BOOK VALUE GROWTH OF A COMPANY?

A. Yes. As noted earlier, if a company sells new common stock equity, the amount received per share will be the market price, not book value. The total common stock equity accounts include the proceeds from the sale of new stock. Selling new stock increases the number of shares outstanding. Book value per share is equal to total common equity divided by total shares outstanding. Therefore, a new common equity sale at a price above the book value increases the existing book value per share. A new common equity sale at a price below book value decreases the existing book value per share.

F. Market Price Relationship to Investors' Expectations of Return on Book Equity.

Q. DOES THE ORIGINAL COST OF THE ASSETS OWNED BY A COMPANY DETERMINE THE MARKET PRICE OF A COMPANY'S COMMON STOCK?

A. Only indirectly. Future cash flows, which are the direct determinant of stock price, are created by the earning ability of the assets owned by the company. Company management decides what to produce with the funds available to a company. Therefore, it is the perceived future success of management in earning profits on assets, not merely the cost of the assets, that determines the market price for essentially any stock.

Before considering the impact of items such as unregulated activities, investment tax credits, financing costs, disallowed rate base or operating expenses, regulators should strive to set authorized earnings at the level required to result in a market-to-book ratio averaging approximately 1.0 in the long run. If regulators were to set earnings at a level that would cause investors to lower the market price below book value, the perceived earnings power of the assets would be less than their net original cost. Conversely, if regulators were to set earnings at a level that would cause investors to raise the market price above book value, this would mean investors would be perceiving that the profits on the assets would be high enough to be worth more than the original cost of the assets.

If the net present value of the future expected cash flows is equal in value to the original cost of the assets, then the market price will equal book value of the company's stocks and bonds. Conversely, if investors believe the net present value of the future cash flows is more (or less) than the book value of the assets owned by a company, then the market price of the company's stocks and bonds will be correspondingly more (or less) than the book value of the company's assets.

Q. ARE THERE ANY UNDESIRABLE RESULTS ASSOCIATED WITH SETTING A RETURN AT SOME LEVEL OTHER THAN THAT WHICH WOULD RESULT IN A MARKET PRICE EQUAL TO THE BOOK VALUE OF USED AND USEFUL UTILITY INVESTMENT?

A. Yes. If the market-to-book ratio target from regulated activities were less than 1.0, management might resist making new capital investments in order to minimize dilution. Conversely, a market-to-book ratio above 1.0 derived from the authorized return would also be an undesirable target for a regulated company. Not only would it result in higher profits than appropriate, it also would give management an incentive to invest in unneeded new assets. Equity raised to finance the new assets would cause the book value to inflate. Therefore, if regulation permits a utility to increase its book value per share merely by purchasing new assets, a potential risk exists that a utility may purchase more assets than needed to provide safe and adequate service.

The DCF method measures the rate of return investors expect to earn on their market price investment. Market price will equal book value once investors believe that regulators will allow a utility company the opportunity to earn the same return on book value that the investors are demanding on market value.

G. Summary of Proper Implementation of DCF Method

Q. PLEASE SUMMARIZE WHAT NEEDS TO BE DETERMINED IN ORDER TO BE ABLE TO CORRECTLY APPLY THE D/P + g VERSION OF THE DCF METHOD TO ARRIVE AT AN INDICATED COST OF EQUITY?

A. Four determinations are part of the proper application of the D/P + g formulation of the DCF Method:

1. Dividend Yield (D/P);[12]

2. The return on book equity rate which investors anticipate a company will earn in the future;

3. The future expected retention rate; and

4. The impact of any sales of new equity at other than book value, a factor which needs to be reflected as an increment to the growth rate computed from the "b x r" computation.

Whether using the D/P +g simplified version of the DCF method, or the complex DCF method, it is essential that the above determinations be internally consistent.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Assume the following:

Market Price	=	$14.00/share
Book Value	=	$10.00/share
Dividend Rate	=	$ 1.00/share

The dividend yield is 7.14% ($1.00/$14.00).

Q. IN THIS EXAMPLE, HOW WOULD THE RETENTION RATE BE COMPUTED?

A. The retention rate is dependent upon both the dividend rate used to compute the dividend yield and the future expected return on book equity. For example, if an analyst felt that investors anticipated this hypothetical company to be able to earn 12.0% on its equity in the future, the determination of the only correct retention rate to use with the above assumptions is as follows:

12D represents the dividend rate, and P represents the market price of common stock.

Anticipated Return On Book Equity of 12.0% x Book Value of $10.00 = $1.20 EPS

$$\frac{\text{Dividends of \$1.00}}{\text{Earnings per Share of \$1.20}} = 0.833 \text{ Payout Ratio}$$

Retention rate = 1 - 0.833 payout ratio, or 0.167.

Q. IS IT PROPER TO SEPARATELY ESTIMATE THE DIVIDEND RATE, THE FUTURE EXPECTED RETURN ON BOOK EQUITY, AND THE RETENTION RATE?

A. No. The point of the above example is to show that the dividend yield computation and the growth rate computation are interdependent, not independent, determinations. This is because the allocation of each dollar of earnings available to a company may be either for dividends or for reinvestment in the business. Dividends provide a current benefit to investors. Reinvested earnings provide a future benefit in the form of growth in earnings.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW AVOIDABLE ERRORS WOULD BE CREATED BY AN INCONSISTENCY BETWEEN THE RETENTION RATE, DIVIDEND RATE, AND FUTURE EXPECTED RETURN ON BOOK EQUITY?

A. Yes. Consider the following hypothetical facts:

1) dividend yield had been computed based upon a $0.75 per share dividend rate,
2) the future expected return on book equity was 13.0%,
3) book value was $10.00 per share.

On the basis of the above, the earnings per share determined to be typical of the future would be the 13% future expected return on book equity times the $10.00 book, or $1.30. This means that the sum of earnings available to pay dividends or for reinvestment in the business is $1.30. If, as has been assumed, we already counted $.75 of the available $1.30 in earnings to pay the dividend, then the only retention rate consistent with the other assumptions is ($1.30 - $ 0.75) / ($1.30), or 42.3%. In this hypothetical example, the only correct retention rate to use is 42.3%. A retention rate of anything but this 42.3% would result in an impossible inconsistency. For example, if someone was to conclude that the retention rate should be 25%, and had used the $.75 dividend in its dividend yield computation, earnings would have to be $1.00, because a $.75 dividend requires $1.00 in earnings in order for the retention rate to be equal to 25%. However, it was already assumed that investors expect the future return on book equity to be 13%. Therefore the earnings per share derived from this expectation is $1.30. Earnings for a company cannot be both $1.00 and $1.30 at the same time.

Q. IS IT POSSIBLE TO PRECISELY DETERMINE THE COST OF EQUITY?

A. Used properly, the DCF model is the most accurate available means to quantify the cost of equity. Even this method contains a certain degree of imprecision because it depends upon the determination of investors' expectations of future cash flow. Future cash flow is highly dependent upon future expected earnings, or return on book equity levels. Earnings levels are not guaranteed, and are not specified by contract.

The greatest source of imprecision in arriving at the cost of equity in utility rate proceedings comes from the improper selection of techniques, or the misapplication of the selected techniques, rather than a difficulty in quantifying investors' expectations. For example, in the DCF method, if one approaches the quantification of investor growth expectations by merely observing historic growth rates or even short-term projections of growth rates, a misapplication of the DCF method likely would result. It is very helpful to properly quantify growth. Recognition that growth occurs because of earnings retained in the business and re-invested in used and useful assets, and the use of a realistic estimate of the future return on book equity are likely to produce relatively accurate estimates of growth.

APPENDIX B

TESTIFYING EXPERIENCE OF JAMES A. ROTHSCHILD THROUGH DECEMBER 31, 1995

ALABAMA

Continental Telephone of the South; Docket No. 17968, Rate of Return, January, 1981

ARIZONA

Southwest Gas Corporation; Rate of Return, Docket No. U-1551-92-253, March, 1993

Sun City West Utilities; Accounting, January, 1985

CONNECTICUT

Connecticut American Water Company; Docket No. 800614, Rate of Return, September, 1980

Connecticut Light & Power Company; Docket No. 85-10-22, Accounting and Rate of Return, February, 1986

Connecticut Light & Power Company; Docket No. 88-04-28, Gas Divestiture, August, 1988

Connecticut Natural Gas; Docket No. 780812, Accounting and Rate of Return, March, 1979

Connecticut Natural Gas; Docket No. 830101, Rate of Return, March, 1983

Connecticut Natural Gas; Docket No. 87-01-03, Rate of Return, March, 1987

Connecticut Natural Gas, Docket No. 95-02-07, Rate of Return, June, 1995

United Illuminating Company; Docket No. 89-08-11:ES:BBM, Financial Integrity and Financial Projections, November, 1989.

DELAWARE

Artesian Water Company, Inc.; Rate of Return, December, 1986

Artesian Water Company, Inc.; Docket No. 87-3, Rate of Return, August, 1987

Diamond State Telephone Company; Docket No. 82-32, Rate of Return, November, 1982

Diamond State Telephone Company; Docket No. 83-12, Rate of Return, October, 1983

Wilmington Suburban Water Company; Rate of Return Report, September, 1986

Wilmington Suburban Water Company; Docket No. 86-25, Rate of Return, February, 1987

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

Maine Yankee Atomic Power Company, Docket No. EL93-22-000, Cost of Capital, July, 1993

New England Power Company; CWIP, February, 1984. Rate of return.

New England Power Company; Docket No.ER88-630-000 & Docket No. ER88-631-000, Rate of Return, April, 1989

New England Power Company; Docket Nos. ER89-582-000 and ER89-596-000, Rate of Return, January, 1990

New England Power Company: Docket Nos. ER91-565-000, ER91-566-000 , FASB 106, March, 1992. Rate of Return.

Philadelphia Electric Company - Conowingo; Docket No. EL-80-557/588, July, 1983. Rate of Return.

Ocean States Power Company, Ocean States II Power Company, Docket No. ER94-998-000 and ER94-999-000, Rate of Return, July, 1994.

Ocean States Power Company, Ocean States II Power Company, Docket No ER 95-533-001 and Docket No. ER-530-001, Rate of Return, June, 1995 and again in October, 1995.

Southern Natural Gas, Docket No. RP93-15-000. Rate of Return, August, 1993, and revised testimony December, 1994.

Transco, Docket No. RP95-197-000, Phase I, August, 1995. Rate of Return.

FLORIDA

Alltel of Florida; Docket No. 850064-TL, Accounting, September, 1985

Florida Power & Light Company; Docket No. 810002-EU, Rate of Return, July, 1981

Florida Power & Light Company; Docket No. 82007-EU, Rate of Return, June, 1982

Florida Power & Light Company; Docket No. 830465-EI, Rate of Return and CWIP, March, 1984

Florida Power Corporation; Docket No. 830470-EI, Rate Phase-In, June, 1984

Florida Power Corp.; Rate of Return, August, 1986

Florida Power Corp.; Docket No. 870220-EI, Rate of Return, October, 1987

GTE Florida, Inc.; Docket No. 890216-TL, Rate of Return, July, 1989

Gulf Power Company; Docket No. 810136-EU, Rate of Return, October, 1981

Gulf Power Company; Docket No. 840086-EI, Rate of Return, August, 1984

Gulf Power Company; Docket No. 881167-EI, Rate of Return, 1989

Gulf Power Company; Docket No. 891345-EI, Rate of Return, 1990

Rolling Oaks Utilities, Inc.; Docket No. 850941-WS, Accounting, October, 1986

Southern Bell Telephone Company; Docket No. 880069-TL, Rate of Return, January, 1992

Southern Bell Telephone Company, Docket No. 920260-TL, Rate of Return, November, 1992

Southern Bell Telephone Company, Docket No. 90260-TL, Rate of Return, November, 1993

Tampa Electric Company; Docket No. 820007-EU, Rate of Return, June, 1982

Tampa Electric Company; Docket No. 830012-EU, Rate of Return, June, 1983

United Telephone of Florida; Docket No. 891239-TL, Rate of Return, November, 1989

United Telephone of Florida; Docket No. 891239-TL, Rate of Return, August, 1990

Water and Sewer Utilities, Docket No 880006-WS, Rate of Return, February, 1988.

GEORGIA

Georgia Power Company; Docket No. 3397-U, Accounting, July, 1983

ILLINOIS

Central Illinois Public Service Company; ICC Docket No. 86-0256, Financial and Rate of Return, October, 1986.

Central Telephone Company of Illinois, ICC Docket No. 93-0252, Rate of Return, October, 1993.

Commonwealth Edison Company; Docket No. 85CH10970, Financial Testimony, May, 1986.

Commonwealth Edison Company; Docket No. 86-0249, Financial Testimony, October, 1986.

Commonwealth Edison Company; ICC Docket No. 87-0057, Rate of Return and Income Taxes, April 3, 1987.

Commonwealth Edison Company; ICC Docket No. 87-0043, Financial Testimony, April 27, 1987.

Commonwealth Edison Company; ICC Docket Nos. 87-0169, 87-0427,88-0189,880219,88-0253 on Remand, Financial Planning Testimony, August, 1990.

Commonwealth Edison Company; ICC Docket Nos. 91-747 and 91-748; Financial Affidavit, March, 1991.

Commonwealth Edison Company; Financial Affidavit, December, 1991.

Commonwealth Edison Company, ICC Docket No. 87-0427, Et. Al., 90-0169 (on Second Remand), Financial Testimony, August, 1992.

GTE North, ICC Docket 93-0301/94-0041, Cost of Capital, April, 1994

Illinois Power Company, Docket No. 92-0404, Creation of Subsidiary, April, 1993

Illinois Bell Telephone Company, Dockets No. ICC 92-0448 and ICC ______, Rate of Return, July, 1993

Northern Illinois Gas Company; Financial Affidavit, February, 1987.

Northern Illinois Gas Company; Docket No. 87-0032, Cost of Capital and Accounting Issues, June, 1987.

Peoples Gas Light and Coke Company; Docket No. 90-0007, Accounting Issues, May, 1990.

KENTUCKY

Kentucky Power Company; Case No. 8429, Rate of Return, April, 1982.

Kentucky Power Company; Case No. 8734, Rate of Return and CWIP, June, 1983.

Kentucky Power Company; Case No. 9061, Rate of Return and Rate Base Issues, September, 1984.

West Kentucky Gas Company, Case No. 8227, Rate of Return, August, 1981.

MAINE

Bangor Hydro-Electric Company; Docket No. 81-136, Rate of Return, January, 1982.

Bangor Hydro-Electric Company; Docket No. 93-62, Rate of Return, August, 1993

Maine Public Service Company; Docket No. 90-281, Accounting and Rate of Return, April, 1991.

MARYLAND

C & P Telephone Company; Case No. 7591, Fair Value, December, 1981

MASSACHUSETTS

Boston Edison Com., any; Docket No. DPU 906, Rate of Return, December, 1981

Fitchburg Gas & Electric; Accounting and Finance, October, 1984

Southbridge Water Company; M.D.P.U., Rate of Return, September, 1982

MINNESOTA

Minnesota Power & Light Company; Docket No. EO15/GR-80-76, Rate of Return, July, 1980

NEW JERSEY

Atlantic City Sewage; Docket No. 774-315, Rate of Return, May, 1977

Atlantic City Electric Company, Docket Nos. ER 8809 1053 and ER 8809 1054, Rate of Return, April, 1990

Elizabethtown Gas Company. BRC Docket No. GM93090390. Evaluation of proposed merger with Pennsylvania & Southern Gas Co. April, 1994

Elizabethtown Water Company; Docket No. 781-6,Accounting, April, 1978

Elizabethtown Water Company; Docket No. 802-76, Rate of Return, January, 1979

Elizabethtown Water Company; Docket No. PUC 04416-90, BPU Docket No. WR90050497J, Rate of Return and Financial Integrity, November, 1990.

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Essex County Transfer Stations; OAL Docket PUC 03173-88, BPU Docket Nos. SE 87070552 and SE 87070566, Rate of Return, October, 1989.

Hackensack Water Company; Docket No. 776-455, October, 1977 and Accounting, February, 1979

Hackensack Water Company; Docket No. 787-847, Accounting and Interim Rate Relief, September, 1978

Hackensack Water Company; AFUDC & CWIP, June, 1979

Hackensack Water Company; Docket No. 804-275, Rate of Return, September, 1980

Hackensack Water Company; Docket No. 8011-870, CWIP, January, 1981

Middlesex Water Company; Docket No. 793-254, Tariff Design, September, 1978

Middlesex Water Company; Docket No. 793-269, Rate of Return, June, 1979

Middlesex Water Company; Docket No. WR890302266-J, Accounting and Revenue Forecasting, July, 1989

Middlesex Water Company; Docket No. WR90080884-J, Accounting, Revenue Foresasting, and Rate of Return, February, 1991

Middlesex Water Company, Docket No. WR92070774-J, Rate of Return, January, 1993

Mount Holly Water Company; Docket No. 805-314, Rate of Return, August, 1980

National Association of Water Companies; Tariff Design, 1977

New Jsersy American Water Compay, BPU Docket No. WR9504, Rate of Return, September, 1995

New Jersey Bell Telephone; Docket No. 7711-1047, Tariff Design, September, 1978

New Jersey Land Title Insurance Companies, Rate of Return and Accounting, August and November, 1985

New Jersey Natural Gas; Docket No. 7812-1681, Rate of Return, April, 1979

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United Artists Cablevision; Docket No. CTV-9924- 83, Rate of Return, April, 1984

West Keansburg Water Company; Docket No. 838-737, Rate of Return, December, 1983

NEW YORK

Consolidated Edison Company; Case No.27353, Accounting and Rate of Return, October, 1978

Consolidated Edison Company; Case No. 27744, Accounting and Rate of Return, August 1980

Generic Financing Case for Electric & Gas Companies; Case No. 27679, May, 1981

Long Island Lighting Company; Case No. 27136, Accounting and Rate of Return, June, 1977

Long Island Lighting Company; Case No. 27774, Rate of Return, November, 1980

Long Island Lighting Company; Case No. 28176 and 28177, Rate of Return and Revenue Forecasting, June, 1982

Long Island Lighting Company, Case No. 28553, Rate of Return and Finance, March, 1984

Long Island Lighting Company, Case No. 93-E-1123, Rate of Return and Finance, May, 1994

New York Telephone, Case No. 27469, April, 1979

New York Telephone, Case No. 27710, Accounting, September, 1981

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OCOE

Overall Summary of Cost of Equity Recommendation

	Cost of Equity Recommendation	Source
Water Companies	9.85%	Sch. JAR 2, P. 1
Gas Distribution Companies	10.35%	Sch. JAR 2, P. 2
Average of Gas and Water	**10.10%**	

Water Utilities
COST OF EQUITY SUMMARY

	Based Upon Average for Year nded12/31//95Stock Prices		Based Upon Stock Prices on 12/31/95	
Simplified DCF, or D/P + g Results	9.52%	[A]	9.25%	[A]
Complex DCF, or two-stage DCF results	10.59%	[B]	10.21%	[C]
Risk Premium			9.76%	[D]
CAPM			8.12%	[E]

Recommended Equity Cost Rate	9.75%
Capital Structure Risk Adjustment [F]	0.10%
Cost of equity net of tax effect	9.85%

Source:

[A] Sch. JAR 4,P. 1
[B] Sch. JAR 5, P 1
[C] Sch. JAR 5, P 2
[D] Sch. JAR 8, P. 1
[E] Sch. JAR 9, P. 1
[F] Based upon difference between company requiested capital structure and industry average capital strucutre as shown on Sch. JAR 11, P. 1.
Cost difference due to capital structure change is based upon results of analysis as shown on Sch. JAR 12, which indicates a cost of equity change of about 0.035% for each 1% change in the level of

Sch. JAR 2, P. 2

NATURAL GAS COMPANIES
COST OF EQUITY SUMMARY

	Based Upon Average for Year Ended 12/31/95 Stock Prices		Based Upon Stock Prices on 12/31/95	
Simplified DCF, or D/P + g Results	9.95%	[A]	9.77%	[A]
Complex DCF, or two-stage DCF results	10.72%	[B]	10.29%	[C]
Risk Premium Result			10.17%	[D]
CAPM Result			7.67%	[E]

Equity Cost rate Using Average of Comparative Group Capital Structure	10.00%
Estimated Adjustment for Capital Structure Risk Change [F]	0.35%
Recommended Equity Cost Rate	10.35%

Source:

[A] Sch. JAR 4, P 2
[B] Sch. JAR 5, P. 3
[C] Sch. JAR 5, P. 4
[D] Sch. JAR 8, P. 2
[F] Based upon difference between company requiested capital structure and industry average capital strucutre as shown on Sch. JAR 11, P. 2.
Cost difference due to capital structure change is based upon results of analysis as shown on Sch. JAR 12, which indicates a cost of equity change of about 0.035% for each 1% change in the level of common equity in the capital structure.

Sch. JAR 3

FINANCIAL DATA ON
MINNESOTA POWER & LIGHT CO.

	1988	1989	1990	1991	1992	1993	1994	YTD Oct-95	AT Oct-95	
Market Price- High	$26.50	$27.60	$27.40	$32.50	$35.00	$36.50	$33.00	$28.60		
Market Price- Low	$21.00	$22.90	$22.30	$26.00	$29.60	$30.00	$24.80	$24.30		
Average			$24.85	$29.25	$32.30	$33.25	$28.90	$26.45	$29.00	
Book Value , Y/E	$16.86	$17.46	$16.36	$16.02	$16.58	$18.03	$17.98			
Book Value, Avg.		$17.16	$16.91	$16.19	$16.30	$17.31	$18.01	$18.35	$18.35	[A]
Earnings Per Share	$2.35	$2.01	$2.00	$2.19	$2.31	$2.20	$1.64			
Dividends Per Share	$1.72	$1.78	$1.86	$1.90	$1.94	$1.98	$2.02	$2.04	$2.04	
Dividend Yield			7.48%	6.50%	6.01%	5.95%	6.99%	7.71%	7.03%	
Return on Equity		11.71%	11.83%	13.53%	14.17%	12.71%	9.11%			
Market-to-Book			1.47	1.81	1.98	1.92	1.61	1.44	1.58	

Source: Value Line.
Value Line future expected return on book equity = 14.50%

[A] Value Line Est. for 12/95

DCF

Value Line Water Companies **Sch. JAR 4,P. 1**
DISCOUNTED CASH FLOW (DCF) INDICATED COST OF EQUITY

		BASED ON AVERAGE MARKET PRICE FOR Year Ending 12/31/95	BASED UPON MARKET PRICE AS OF 12/31/95
1 Dividend Yield On Market Price	[B]	6.21%	5.95%
2 Retention Ratio:			
a) Market-to-book	[B]	1.38	1.46
b) Div. Yld on Book	[C]	8.56%	8.68%
c) Return on Equity	[A]	11.25%	11.25%
d) Retention Rate	[D]	23.88%	22.82%
3 Reinvestment Growth	[E]	2.69%	2.57%
4 New Financing Growth	[F]	0.52%	0.63%
5 Total Estimate of Investor Anticipated Growth	[G]	3.21%	3.20%
6 Increment to Dividend Yield for Growth to Next Year	[H]	0.10%	0.10%
7 Indicated Cost of Equity	**[I]**	**9.52%**	**9.25%**

Some of the Considerations for determining Future Expected Return on Equity:

				Source:
[A]	Value Line Expectation		11.75%	Sch. JAR 6, P. 1
	Expectation Derived from Zack's Consensus Growth Rate		11.39%	Sch. JAR 6, P. 2
	Earned Return on Equity in	1995	10.15%	Sch. JAR 6, P. 1
	Earned Return on Equity in	1994	10.47%	Sch. JAR 6, P. 2

For recommended expectation, see text.

Other Sources:

[B] Sch. JAR 6, P. 1 and
Sch. JAR 6, P. 2
[C] Line 1 x Line 2a
[D] 1- Line 2b/Line 2c
[E] Line 2c x Line 2d
[F] Estimated impact of dilution or premium due to sale of equity at other than book value. Computed based upon mathematically derived result based upon the historical external financing rate.
[M/B X (Ext. Fin Rate+1]/(M/B + Ext. Fin. Rate-1) Ext. Fin. rate used = 1.40% [J]
[G] Line 3 + Line 4
[H] Line 1 x one-half of line 5
[I] Line 1 + Line 5 + Line 6
[J] Sch. JAR 10, P. 1

Occgas

VALUE LINE GAS COMPANIES **Sch. JAR 4, P 2**
DISCOUNTED CASH FLOW (DCF) INDICATED COST OF EQUITY

		BASED ON AVERAGE MARKET PRICE FOR Dec. 1995 YTD	BASED UPON MARKET PRICE AS OF 12/31/95
1 Dividend Yield On Market Price	[B]	5.80%	5.30%
2 Retention Ratio:			
a) Market-to-book	[B]	1.58	1.72
b) Div. Yld on Book	[C]	9.15%	9.13%
c) Return on Equity	[A]	12.00%	12.00%
d) Retention Rate	[D]	23.71%	23.90%
3 Reinvestment Growth	[E]	2.85%	2.87%
4 New Financing Growth	[F]	1.19%	1.49%
5 Total Estimate of Investor Anticipated Growth	[G]	4.04%	4.35%
6 Increment to Dividend Yield for Growth to Next Year	[H]	0.12%	0.12%
7 Indicated Cost of Equity	[I]	**9.95%**	**9.77%**

Some of the Considerations for determining Future Expected Return on Equity:

				Source:
[A]	Value Line Expectation		12.23%	Sch. JAR 7, P. 1
	Expectation Derived from Zack's Consensus Growth Rate		12.39%	Sch. JAR 7, P. 2
	Earned Return on Equity in	1995	10.57%	Sch. JAR 7, P. 2
	Earned Return on Equity in	1994	11.01%	Sch. JAR 7, P. 2

For recommended expectation, see text.

Other Sources:

[B] Sch. JAR 7, P. 1 and
Sch. JAR 7, P. 2
[C] Line 1 x Line 2a
[D] 1- Line 2b/Line 2c
[E] Line 2c x Line 2d
[F] Estimated impact of dilution or premium due to sale of equity at other than book value. Computed based upon mathematically derived result based upon the historical external financing rate.
[M/B X (Ext. Fin Rate+1]/(M/B + Ext. Fin. Rate-1) Ext. Fin. rate used = 2.10% [J]
[G] Line 3 + Line 4
[H] Line 1 x one-half of line 5 2.10%
[I] Line 1 + Line 5 + Line 6
[J] Sch. JAR 10, P. 2

Sch. JAR 5, P 1

VALUE LINE WATER COMPANIES
FULL DCF METHOD
Based on Market Price for Year Ended 12/31/95

	Year	[1] Year End Book	[2] Retention Rate	[3] Dividend	[4] Earnings Per Share	[5] Retained Earnings Per Share	[6] External Financing Rate	[7] Increment to book from Ext. Fin.	[8] Total Increment to Book	[9] Market Price	[10] Mkt to Book	[11] Expect. Ret. on Equity	[12] Cash Fl. from Stock Trans.	[13] Cash Fl. from Div.	[14] Total Cash Flow
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
											M/B Chane				
											0.00				
	1994	$13.96		$0.00						$19.24	1.38				$0.00
First Stage	1995	$14.49	19.31%	$1.37	$1.69	$0.33			$0.33	$19.97	1.38	11.69%	($19.97)		($19.97)
	1996	$17.30	21.94%	$1.41	$1.80	$0.40			$0.40	$23.84	1.38	11.32%		$1.41	$1.41
	1997	$17.72	23.35%	$1.47	$1.92	$0.45			$0.45	$24.42	1.38	10.98%		$1.47	$1.47
	1998	$18.14	24.59%	$1.54	$2.04	$0.50			$0.50	$25.00	1.38	11.40%		$1.54	$1.54
	1999	$18.56	25.69%	$1.61	$2.17	$0.56			$0.56	$25.58	1.38	11.81%		$1.61	$1.61
Second Stage	2000	$19.22	25.69%	$1.58	$2.13	$0.55	1.10%	$0.08	$0.62	$26.50	1.38	11.25%		$1.58	$1.58
	2001	$19.91	25.69%	$1.64	$2.20	$0.57	1.10%	$0.08	$0.65	$27.45	1.38	11.25%		$1.64	$1.64
	2002	$20.63	25.69%	$1.69	$2.28	$0.59	1.10%	$0.08	$0.67	$28.43	1.38	11.25%		$1.69	$1.69
	2003	$21.37	25.69%	$1.76	$2.36	$0.61	1.10%	$0.09	$0.69	$29.45	1.38	11.25%		$1.76	$1.76
	2004	$22.14	25.69%	$1.82	$2.45	$0.63	1.10%	$0.09	$0.72	$30.51	1.38	11.25%		$1.82	$1.82
	2005	$22.93	25.69%	$1.88	$2.54	$0.65	1.10%	$0.09	$0.74	$31.61	1.38	11.25%		$1.88	$1.88
	2006	$23.76	25.69%	$1.95	$2.63	$0.67	1.10%	$0.10	$0.77	$32.74	1.38	11.25%		$1.95	$1.95
	2007	$24.61	25.69%	$2.02	$2.72	$0.70	1.10%	$0.10	$0.80	$33.92	1.38	11.25%		$2.02	$2.02
	2008	$25.49	25.69%	$2.09	$2.82	$0.72	1.10%	$0.10	$0.83	$35.13	1.38	11.25%		$2.09	$2.09
	2009	$26.41	25.69%	$2.17	$2.92	$0.75	1.10%	$0.11	$0.86	$36.40	1.38	11.25%		$2.17	$2.17
	2010	$27.36	25.69%	$2.25	$3.02	$0.78	1.10%	$0.11	$0.89	$37.70	1.38	11.25%		$2.25	$2.25
	2011	$28.34	25.69%	$2.33	$3.13	$0.80	1.10%	$0.11	$0.92	$39.06	1.38	11.25%		$2.33	$2.33
	2012	$29.35	25.69%	$2.41	$3.25	$0.83	1.10%	$0.12	$0.95	$40.46	1.38	11.25%		$2.41	$2.41
	2013	$30.41	25.69%	$2.50	$3.36	$0.86	1.10%	$0.12	$0.99	$41.91	1.38	11.25%		$2.50	$2.50
	2014	$31.50	25.69%	$2.59	$3.48	$0.89	1.10%	$0.13	$1.02	$43.41	1.38	11.25%		$2.59	$2.59
	2015	$32.63	25.69%	$2.68	$3.61	$0.93	1.10%	$0.13	$1.06	$44.97	1.38	11.25%		$2.68	$2.68
	2016	$33.80	25.69%	$2.78	$3.74	$0.96	1.10%	$0.14	$1.10	$46.59	1.38	11.25%		$2.78	$2.78
	2017	$35.02	25.69%	$2.88	$3.87	$0.99	1.10%	$0.14	$1.14	$48.26	1.38	11.25%		$2.88	$2.88
	2018	$36.27	25.69%	$2.98	$4.01	$1.03	1.10%	$0.15	$1.18	$49.99	1.38	11.25%		$2.98	$2.98
	2019	$37.58	25.69%	$3.09	$4.15	$1.07	1.10%	$0.15	$1.22	$51.79	1.38	11.25%		$3.09	$3.09
	2020	$38.92	25.69%	$3.20	$4.30	$1.11	1.10%	$0.16	$1.26	$53.65	1.38	11.25%		$3.20	$3.20
	2021	$40.32	25.69%	$3.31	$4.46	$1.15	1.10%	$0.16	$1.31	$55.57	1.38	11.25%		$3.31	$3.31
	2022	$41.77	25.69%	$3.43	$4.62	$1.19	1.10%	$0.17	$1.36	$57.57	1.38	11.25%		$3.43	$3.43
	2023	$43.27	25.69%	$3.55	$4.78	$1.23	1.10%	$0.18	$1.40	$59.64	1.38	11.25%		$3.55	$3.55
	2024	$44.82	25.69%	$3.68	$4.96	$1.27	1.10%	$0.18	$1.45	$61.78	1.38	11.25%		$3.68	$3.68
	2025	$46.43	25.69%	$3.81	$5.13	$1.32	1.10%	$0.19	$1.51	$63.99	1.38	11.25%		$3.81	$3.81
	2026	$48.10	25.69%	$3.95	$5.32	$1.37	1.10%	$0.20	$1.56	$66.29	1.38	11.25%		$3.95	$3.95
	2027	$49.83	25.69%	$4.09	$5.51	$1.42	1.10%	$0.20	$1.62	$68.67	1.38	11.25%		$4.09	$4.09
	2028	$51.61	25.69%	$4.24	$5.71	$1.47	1.10%	$0.21	$1.68	$71.14	1.38	11.25%		$4.24	$4.24
	2029	$53.47	25.69%	$4.39	$5.91	$1.52	1.10%	$0.22	$1.74	$73.69	1.38	11.25%		$4.39	$4.39
	2030	$55.39	25.69%	$4.55	$6.12	$1.57	1.10%	$0.22	$1.80	$76.34	1.38	11.25%		$4.55	$4.55
	2031	$57.38	25.69%	$4.71	$6.34	$1.63	1.10%	$0.23	$1.86	$79.08	1.38	11.25%		$4.71	$4.71
	2032	$59.44	25.69%	$4.88	$6.57	$1.69	1.10%	$0.24	$1.93	$81.92	1.38	11.25%		$4.88	$4.88
	2033	$61.57	25.69%	$5.06	$6.81	$1.75	1.10%	$0.25	$2.00	$84.86	1.38	11.25%		$5.06	$5.06
	2034	$63.78	25.69%	$5.24	$7.05	$1.81	1.10%	$0.26	$2.07	$87.90	1.38	11.25%	$87.90	$5.24	$93.14
												Internal Rate of Return			10.59%

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book plus value from Col.[8]
[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). Second stage is equal to final value of first stage.
[C] First Stage is from Value Line. Second stage is Col. [4] x (1-Col. [2])
[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [11]
[E] Col. [4] - Col. [3]
[F] Sch. JAR 9
[G]
[H] Col. [7] + Col. [8]
[I] Col. [1] x Col. [10]
[J] Sch. JAR 7, P. 1
[K] First stage is Col. [4]/Avg. of Current and prior year's Col. [1]. Second stage is from
[L] - Col. [9] for year of purchase, + Col. [9] for year of sale.
[M] Col. [3]
[N] Col. [12] + Col. [13]

Sch. JAR 5, P 2

VALUE LINE WATER COMPANIES
FULL DCF METHOD
Based on Market Price on 12/31/95

	Year	[1] Year End Book	[2] Retention Rate	[3] Dividend	[4] Earnings Per Share	[5] Retained Earnings Per Share	[6] External Financl Rate	[7] Increment to book from Ext. Fin.	[8] Total Increment to Book	[9] Market Price	[10] Mkt to Book	[11] Expect. Ret. on Equity	[12] Cash Fl. from Stock Trans.	[13] Cash Fl. from Div.	[14] Total Cash Flow
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J] M/B Chane	[K]	[L]	[M]	[N]
											0.00				
	1994	$13.96								$20.37	1.46				
	1995	$14.49	19.31%	$1.37	$1.69	$0.33			$0.33	$21.14	1.46	11.89%	($21.14)		($21.14)
	1996	$17.30	21.94%	$1.41	$1.80	$0.40			$0.40	$25.24	1.46	11.32%		$1.41	$1.41
First Stage	1997	$17.72	23.35%	$1.47	$1.92	$0.45			$0.45	$25.85	1.46	10.98%		$1.47	$1.47
	1998	$18.14	24.59%	$1.54	$2.04	$0.50			$0.50	$26.46	1.46	11.40%		$1.54	$1.54
	1999	$18.56	25.69%	$1.61	$2.17	$0.56			$0.56	$27.08	1.46	11.81%		$1.61	$1.61
	2000	$19.22	25.69%	$1.58	$2.13	$0.55	1.40%	$0.12	$0.67	$28.05	1.46	11.25%		$1.58	$1.58
	2001	$19.91	25.69%	$1.64	$2.20	$0.57	1.40%	$0.12	$0.69	$29.05	1.46	11.25%		$1.64	$1.64
	2002	$20.63	25.69%	$1.69	$2.28	$0.59	1.40%	$0.13	$0.71	$30.10	1.46	11.25%		$1.69	$1.69
	2003	$21.37	25.69%	$1.76	$2.36	$0.61	1.40%	$0.13	$0.74	$31.18	1.46	11.25%		$1.76	$1.76
	2004	$22.14	25.69%	$1.82	$2.45	$0.63	1.40%	$0.14	$0.77	$32.30	1.46	11.25%		$1.82	$1.82
	2005	$22.93	25.69%	$1.88	$2.54	$0.65	1.40%	$0.14	$0.79	$33.46	1.46	11.25%		$1.88	$1.88
	2006	$23.76	25.69%	$1.95	$2.63	$0.67	1.40%	$0.15	$0.82	$34.66	1.46	11.25%		$1.95	$1.95
	2007	$24.61	25.69%	$2.02	$2.72	$0.70	1.40%	$0.15	$0.85	$35.90	1.46	11.25%		$2.02	$2.02
	2008	$25.49	25.69%	$2.09	$2.82	$0.72	1.40%	$0.16	$0.88	$37.19	1.46	[illegible]		$2.09	$2.09
	2009	$26.41	25.69%	$2.17	$2.92	$0.75	1.40%	$0.17	$0.92	$38.53	1.46	11.25%		$2.17	$2.17
	2010	$27.36	25.69%	$2.25	$3.02	$0.78	1.40%	$0.17	$0.95	$39.91	1.46	11.25%		$2.25	$2.25
	2011	$28.34	25.69%	$2.33	$3.13	$0.80	1.40%	$0.18	$0.98	$41.34	1.46	11.25%		$2.33	$2.33
	2012	$29.35	25.69%	$2.41	$3.25	$0.83	1.40%	$0.18	$1.02	$42.83	1.46	11.25%		$2.41	$2.41
	2013	$30.41	25.69%	$2.50	$3.36	$0.86	1.40%	$0.19	$1.05	$44.36	1.46	11.25%		$2.50	$2.50
	2014	$31.50	25.69%	$2.59	$3.48	$0.89	1.40%	$0.20	$1.09	$45.96	1.46	11.25%		$2.59	$2.59
	2015	$32.63	25.69%	$2.68	$3.61	$0.93	1.40%	$0.20	$1.13	$47.61	1.46	11.25%		$2.68	$2.68
Second Stage	2016	$33.80	25.69%	$2.78	$3.74	$0.96	1.40%	$0.21	$1.17	$49.32	1.46	11.25%		$2.78	$2.78
	2017	$35.02	25.69%	$2.88	$3.87	$0.99	1.40%	$0.22	$1.21	$51.09	1.46	11.25%		$2.88	$2.88
	2018	$36.27	25.69%	$2.98	$4.01	$1.03	1.40%	$0.23	$1.26	$52.92	1.46	11.25%		$2.98	$2.98
	2019	$37.58	25.69%	$3.09	$4.15	$1.07	1.40%	$0.23	$1.30	$54.82	1.46	11.25%		$3.09	$3.09
	2020	$38.92	25.69%	$3.20	$4.30	$1.11	1.40%	$0.24	$1.35	$56.79	1.46	11.25%		$3.20	$3.20
	2021	$40.32	25.69%	$3.31	$4.46	$1.15	1.40%	$0.25	$1.40	$58.83	1.46	11.25%		$3.31	$3.31
	2022	$41.77	25.69%	$3.43	$4.62	$1.19	1.40%	$0.26	$1.45	$60.94	1.46	11.25%		$3.43	$3.43
	2023	$43.27	25.69%	$3.55	$4.78	$1.23	1.40%	$0.27	$1.50	$63.13	1.46	11.25%		$3.55	$3.55
	2024	$44.82	25.69%	$3.68	$4.96	$1.27	1.40%	$0.28	$1.55	$65.39	1.46	11.25%		$3.68	$3.68
	2025	$46.43	25.69%	$3.81	$5.13	$1.32	1.40%	$0.29	$1.61	$67.74	1.46	11.25%		$3.81	$3.81
	2026	$48.10	25.69%	$3.95	$5.32	$1.37	1.40%	$0.30	$1.67	$70.17	1.46	11.25%		$3.95	$3.95
	2027	$49.83	25.69%	$4.09	$5.51	$1.42	1.40%	$0.31	$1.73	$72.69	1.46	11.25%		$4.09	$4.09
	2028	$51.61	25.69%	$4.24	$5.71	$1.47	1.40%	$0.32	$1.79	$75.30	1.46	11.25%		$4.24	$4.24
	2029	$53.47	25.69%	$4.39	$5.91	$1.52	1.40%	$0.33	$1.85	$78.01	1.46	11.25%		$4.39	$4.39
	2030	$55.39	25.69%	$4.55	$6.12	$1.57	1.40%	$0.35	$1.92	$80.81	1.46	11.25%		$4.55	$4.55
	2031	$57.38	25.69%	$4.71	$6.34	$1.63	1.40%	$0.36	$1.99	$83.71	1.46	11.25%		$4.71	$4.71
	2032	$59.44	25.69%	$4.88	$6.57	$1.69	1.40%	$0.37	$2.06	$86.71	1.46	11.25%		$4.88	$4.88
	2033	$61.57	25.69%	$5.06	$6.81	$1.75	1.40%	$0.39	$2.13	$89.83	1.46	11.25%		$5.06	$5.06
	2034	$63.78	25.69%	$5.24	$7.05	$1.81	1.40%	$0.40	$2.21	$93.05	1.46	11.25%	$93.05	$5.24	$98.29
												Internal Rate of Return			10.21%

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book plus value from Col.[8]
[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). Second stage is equal to final value of first stage.
[C] First Stage is from Value Line. Second stage is Col. [4] x (1-Col. [2])
[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [11]
[E] Col. [4] - Col. [3]
[F] Sch. JAR 9
[G]
[H] Col. [7] + Col. [8]
[I] Col. [1] x Col. [10]
[J] Sch. JAR 7, P. 1
[K] First stage is Col. [4]/Avg. of Current and prior year's Col. [1]. Second stage is fr Sch. JAR 4, P. 1
[L] - Col. [9] for year of purchase, + Col. [9] for year of sale.
[M] Col. [3]
[N] Col. [12] + Col. [13]

Sch. JAR 5, P. 3

VALUE LINE GAS COMPANIES

FULL DCF METHOD

Based on Market Price for Year Ended 12/31/95

	Year	[1] Year End Book	[2] Retention Rate	[3] Dividend	[4] Earnings Per Share	[5] Retained Earnings Per Share	[6] External Financing Rate	[7] Increment to book from Ext. Fin.	[8] Total Increme to Book	[9] Market Price	[10] Mkt to Book	[11] Expect. Ret. on Equity	[12] Cash Fl. from Stock Trans.	[13] Cash Fl. from Div.	[14] Total Cash Flow
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
											M/B Chane				
											0.00				
	1994	$13.77		$0.00						$21.74	1.58				$0.00
	1995	$14.08	16.87%	$1.22	$1.47	$0.25			$0.25	$22.23	1.58	10.58%	($22.23)		($22.23)
	1996	$14.64	26.39%	$1.25	$1.69	$0.45			$0.45	$23.11	1.58	11.80%		$1 25	$1 25
First Stage	1997	$15.36	29.30%	$1.29	$1 82	$0.53			$0.53	$24.25	1.58	12.12%		$1.29	$1.29
	1998	$16.08	31.84%	$1.32	$1.94	$0.62			$0.62	$25.38	1.58	12.36%		$1.32	$1.32
	1999	$16.79	34.08%	$1.36	$2.07	$0.70			$0.70	$26.51	1.58	12.58%		$1.36	$1.36
	2000	$17.76	34.08%	$1.37	$2.07	$0.71	2.10%	$0.21	$0.91	$28.04	1.58	12.00%		$1.37	$1.37
	2001	$18 78	34.08%	$1 45	$2 19	$0.75	2.10%	$0.22	$0.97	$29.65	1.58	12.00%		$1.45	$1.45
	2002	$19.86	34.08%	$1.53	$2.32	$0.79	2.10%	$0.23	$1.02	$31.35	1.58	12.00%		$1.53	$1.53
	2003	$21.00	34.08%	$1.62	$2.45	$0.84	2.10%	$0.25	$1.08	$33.16	1.58	12.00%		$1.62	$1.62
	2004	$22.21	34.08%	$1.71	$2.59	$0.88	2.10%	$0.26	$1.14	$35.06	1.58	12.00%		$1.71	$1.71
	2005	$23.48	34.08%	$1.81	$2.74	$0.93	2.10%	$0.27	$1.21	$37.08	1.58	12.00%		$1.81	$1.81
	2006	$24.84	34.08%	$1.91	$2.90	$0.99	2.10%	$0.29	$1.28	$39.21	1.58	12.00%		$1.91	$1.91
	2007	$26.26	34.08%	$2.02	$3.07	$1.04	2.10%	$0.31	$1.35	$41.47	1.58	12.00%		$2.02	$2.02
	2008	$27.77	34.08%	$2.14	$3.24	$1.10	2.10%	$0.32	$1.43	$43.85	1.58	12.00%		$2.14	$2.14
	2009	$29.37	34.08%	$2.26	$3.43	$1.17	2.10%	$0.34	$1.51	$46.37	1.58	12.00%		$2.26	$2.26
	2010	$31.06	34.08%	$2.39	$3.63	$1.24	2.10%	$0.36	$1.60	$49.04	1.58	12.00%		$2.39	$2.39
	2011	$32.84	34.08%	$2.53	$3.83	$1.31	2.10%	$0.38	$1.69	$51.86	1.58	12.00%		$2.53	$2.53
	2012	$34.73	34.08%	$2.67	$4.05	$1.38	2.10%	$0.41	$1.79	$54.84	1.58	12.00%		$2.67	$2.67
	2013	$36.73	34.08%	$2.83	$4.29	$1.46	2.10%	$0.43	$1.89	$57.99	1.58	12.00%		$2.83	$2.83
	2014	$38.84	34.08%	$2.99	$4.53	$1.55	2.10%	$0.45	$2.00	$61.33	1.58	12.00%		$2.99	$2.99
	2015	$41.06	34.08%	$3.16	$4.80	$1.63	2.10%	$0.48	$2.11	$64.85	1.58	12.00%		$3.16	$3.16
Second Stage	2016	$43.44	34.08%	$3.34	$5.07	$1.73	2.10%	$0.51	$2.23	$68.58	1.58	12.00%		$3.34	$3.34
	2017	$45.94	34.08%	$3.54	$5.36	$1.83	2.10%	$0.54	$2.36	$72.52	1.58	12.00%		$3.54	$3 54
	2018	$48.58	34.08%	$3.74	$5.67	$1.93	2.10%	$0.57	$2.50	$76.69	1.58	12.00%		$3.74	$3.74
	2019	$51.37	34.08%	$3.95	$6.00	$2.04	2.10%	$0.60	$2.64	$81.10	1.58	12.00%		$3.95	$3.95
	2020	$54.32	34.08%	$4.18	$6.34	$2.16	2.10%	$0.63	$2.79	$85.77	1.58	12.00%		$4.18	$4.18
	2021	$57.45	34.08%	$4.42	$6.71	$2.29	2.10%	$0.67	$2.96	$90.70	1.58	12.00%		$4.42	$4.42
	2022	$60.75	34.08%	$4.68	$7.09	$2.42	2.10%	$0.71	$3.13	$95.91	1.58	12.00%		$4.68	$4.68
	2023	$64.24	34.08%	$4.94	$7.50	$2.56	2.10%	$0.75	$3.31	$101.43	1.58	12.00%		$4.94	$4.94
	2024	$67.94	34.08%	$5.23	$7.93	$2.70	2.10%	$0.79	$3.50	$107.26	1.58	12.00%		$5.23	$5.23
	2025	$71.84	34.08%	$5.53	$8.39	$2.86	2.10%	$0.84	$3.70	$113.43	1.58	12.00%		$5.53	$5.53
	2026	$75.97	34.08%	$5.85	$8.87	$3.02	2.10%	$0.89	$3.91	$119.95	1.58	12.00%		$5.85	$5.85
	2027	$80.34	34.08%	$6.18	$9.38	$3.20	2.10%	$0.94	$4.13	$126.85	1.58	12.00%		$6.18	$6.18
	2028	$84.96	34.08%	$6.54	$9.92	$3.38	2.10%	$0.99	$4.37	$134.14	1.58	12.00%		$6.54	$6 54
	2029	$89.85	34.08%	$6.91	$10.49	$3.57	2.10%	$1.05	$4.62	$141.85	1.58	12.00%		$6.91	$6.91
	2030	$95.01	34.08%	$7.31	$11.09	$3.78	2.10%	$1.11	$4.89	$150.01	1.58	12.00%		$7.31	$7.31
	2031	$100.48	34.08%	$7.73	$11.73	$4.00	2.10%	$1.17	$5.17	$158.64	1.58	12.00%		$7.73	$7.73
	2032	$106.25	34.08%	$8.18	$12.40	$4.23	2.10%	$1.24	$5.47	$167.76	1.58	12.00%		$8.18	$8.18
	2033	$112.36	34.08%	$8.65	$13.12	$4.47	2.10%	$1.31	$5.78	$177 40	1.58	12.00%		$8.65	$8.65
	2034	$118.82	34.08%	$9.14	$13.87	$4.73	2.10%	$1.39	$6.11	$187.60	1.58	12.00%	$187.60	$9.14	$196.75
												Internal Rate of Return			10.72%

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book plus value from Col.[8]

[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). Second stage is equal to final value of first stage.

[C] First Stage is from Value Line. Second stage is Col. [4] x (1-Col. [2])

[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [11]

[E] Col. [4] - Col. [3]

[F] Sch. JAR 9

[G]

[H] Col. [7] + Col. [8]

[I] Col. [1] x Col. [10]

[J] Sch. JAR 7, P. 1

[K] First stage is Col. [4]/Avg. of Current and prior year's Col. [1]. Second stage is from

[L] - Col. [9] for year of purchase, + Col. [9] for year of sale.

[M] Col. [3]

[N] Col. [12] + Col. [13]

Sch. JAR 5, P. 4

VALUE LINE GAS COMPANIES
FULL DCF METHOD
Based on Market Price on 12/31/95

	Year	[1] Year End *Book*	[2] Retenti *Rate*	[3] Dividend	[4] Earnings *Per Share*	[5] Retained *Earnings* Per Share	[6] External *Financing* Rate	[7] Increme *to book* from Ext. Fin.	[8] Total *Incremen* to Book	[9] Market *Price*	[10] Mkt to *Book*	[11] Expect. *Ret. on* Equity	[12] Cash Fl. *from* Stock Trans.	[13] Cash Fl. *from* Div.	[14] Total *Cash* Flow
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
											M/B Chane				
											0.00				
	1994	$13.77								$23.73	1.72				
	1995	$14.08	16.87%	$1.22	$1.47	$0.25			$0.25	$24.26	1.72	10.58%	($24.26)		($24.26)
	1996	$14.64	26.39%	$1.25	$1.69	$0.45			$0.45	$25.23	1.72	11.80%		$1.25	$1.25
First Stage	1997	$15.36	29.30%	$1.29	$1.82	$0.53			$0.53	$26.46	1.72	12.12%		$1.29	$1.29
	1998	$16.08	31.84%	$1.32	$1.94	$0.62			$0.62	$27.70	1.72	12.36%		$1.32	$1.32
	1999	$16.79	34.08%	$1.36	$2.07	$0.70			$0.70	$28.93	1.72	12.58%		$1.36	$1.36
	2000	$17.76	34.08%	$1.37	$2.07	$0.71	2.10%	$0.26	$0.97	$30.60	1.72	12.00%		$1.37	$1.37
	2001	$18.78	34.08%	$1.45	$2.19	$0.75	2.10%	$0.27	$1.02	$32.36	1.72	12.00%		$1.45	$1.45
	2002	$19.86	34.08%	$1.53	$2.32	$0.79	2.10%	$0.29	$1.08	$34.22	1.72	12.00%		$1.53	$1.53
	2003	$21.00	34.08%	$1.62	$2.45	$0.84	2.10%	$0.31	$1.14	$36.18	1.72	12.00%		$1.62	$1.62
	2004	$22.21	34.08%	$1.71	$2.59	$0.88	2.10%	$0.32	$1.21	$38.27	1.72	12.00%		$1.71	$1.71
	2005	$23.48	34.08%	$1.81	$2.74	$0.93	2.10%	$0.34	$1.28	$40.47	1.72	12.00%		$1.81	$1.81
	2006	$24.84	34.08%	$1.91	$2.90	$0.99	2.10%	$0.36	$1.35	$42.79	1.72	12.00%		$1.91	$1.91
	2007	$26.26	34.08%	$2.02	$3.07	$1.04	2.10%	$0.38	$1.43	$45.25	1.72	12.00%		$2.02	$2.02
	2008	$27.77	34.08%	$2.14	$3.24	$1.10	2.10%	$0.41	$1.51	$47.85	1.72	12.00%		$2.14	$2.14
	2009	$29.37	34.08%	$2.26	$3.43	$1.17	2.10%	$0.43	$1.60	$50.61	1.72	12.00%		$2.26	$2.26
	2010	$31.06	34.08%	$2.39	$3.63	$1.24	2.10%	$0.45	$1.69	$53.52	1.72	12.00%		$2.39	$2.39
	2011	$32.84	34.08%	$2.53	$3.83	$1.31	2.10%	$0.48	$1.79	$56.59	1.72	12.00%		$2.53	$2.53
	2012	$34.73	34.08%	$2.67	$4.05	$1.38	2.10%	$0.51	$1.89	$59.85	1.72	12.00%		$2.67	$2.67
	2013	$36.73	34.08%	$2.83	$4.29	$1.46	2.10%	$0.54	$2.00	$63.29	1.72	12.00%		$2.83	$2.83
	2014	$38.84	34.08%	$2.99	$4.53	$1.55	2.10%	$0.57	$2.11	$66.93	1.72	12.00%		$2.99	$2.99
	2015	$41.08	34.08%	$3.16	$4.80	$1.63	2.10%	$0.60	$2.23	$70.78	1.72	12.00%		$3.16	$3.16
Second Stage	2016	$43.44	34.08%	$3.34	$5.07	$1.73	2.10%	$0.63	$2.36	$74.85	1.72	12.00%		$3.34	$3.34
	2017	$45.94	34.08%	$3.54	$5.36	$1.83	2.10%	$0.67	$2.50	$79.15	1.72	12.00%		$3.54	$3.54
	2018	$48.58	34.08%	$3.74	$5.67	$1.93	2.10%	$0.71	$2.64	$83.70	1.72	12.00%		$3.74	$3.74
	2019	$51.37	34.08%	$3.95	$6.00	$2.04	2.10%	$0.75	$2.79	$88.51	1.72	12.00%		$3.95	$3.95
	2020	$54.32	34.08%	$4.18	$6.34	$2.16	2.10%	$0.79	$2.95	$93.60	1.72	12.00%		$4.18	$4.18
	2021	$57.45	34.08%	$4.42	$6.71	$2.29	2.10%	$0.84	$3.12	$98.98	1.72	12.00%		$4.42	$4.42
	2022	$60.75	34.08%	$4.68	$7.09	$2.42	2.10%	$0.89	$3.30	$104.68	1.72	12.00%		$4.68	$4.68
	2023	$64.24	34.08%	$4.94	$7.50	$2.56	2.10%	$0.94	$3.49	$110.69	1.72	12.00%		$4.94	$4.94
	2024	$67.94	34.08%	$5.23	$7.93	$2.70	2.10%	$0.99	$3.69	$117.06	1.72	12.00%		$5.23	$5.23
	2025	$71.84	34.08%	$5.53	$8.39	$2.86	2.10%	$1.05	$3.91	$123.79	1.72	12.00%		$5.53	$5.53
	2026	$75.97	34.08%	$5.85	$8.87	$3.02	2.10%	$1.11	$4.13	$130.91	1.72	12.00%		$5.85	$5.85
	2027	$80.34	34.08%	$6.18	$9.38	$3.20	2.10%	$1.17	$4.37	$138.43	1.72	12.00%		$6.18	$6.18
	2028	$84.96	34.08%	$6.54	$9.92	$3.38	2.10%	$1.24	$4.62	$146.39	1.72	12.00%		$6.54	$6.54
	2029	$89.85	34.08%	$6.91	$10.49	$3.57	2.10%	$1.31	$4.89	$154.81	1.72	12.00%		$6.91	$6.91
	2030	$95.01	34.08%	$7.31	$11.09	$3.78	2.10%	$1.39	$5.17	$163.71	1.72	12.00%		$7.31	$7.31
	2031	$100.48	34.08%	$7.73	$11.73	$4.00	2.10%	$1.47	$5.46	$173.13	1.72	12.00%		$7.73	$7.73
	2032	$106.25	34.08%	$8.18	$12.40	$4.23	2.10%	$1.55	$5.78	$183.08	1.72	12.00%		$8.18	$8.18
	2033	$112.36	34.08%	$8.65	$13.12	$4.47	2.10%	$1.64	$6.11	$193.61	1.72	12.00%		$8.65	$8.65
	2034	$118.82	34.08%	$9.14	$13.87	$4.73	2.10%	$1.73	$6.46	$204.74	1.72	12.00%	$204.74	$9.14	$213.88
												Internal Rate of Return			10.29%

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book plus value from Col.[8]
[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). Second stage is equal to final value of first stage.
[C] First Stage is from Value Line. Second stage is Col. [4] x (1-Col. [2])
[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [11]
[E] Col. [4] - Col. [3]
[F] Sch. JAR 9
[G]
[H] Col. [7] + Col. [8]
[I] Col. [1] x Col. [10]
[J] Sch. JAR 7, P. 1
[K] First stage is Col. [4]/Avg. of Current and prior year's Col. [1]. Second stage is f Sch. JAR 4, P. 1
[L] - Col. [9] for year of purchase, + Col. [9] for year of sale.
[M] Col. [3]
[N] Col. [12] + Col. [13]

COMPARATIVE WATER COMPANIES
SELECTED FINANCIAL DATA

WATER COMPANIES AND DIVERSIFIED WATER COMPANIES COVERED BY VALUE LINE:

	[1] Book Per Sh. Dec. 92 [A]	[2] Book Per Sh. Dec. 93 [A]	[3] Book Per Sh. Dec. 94 [A]	[4] Book Per Sh. Dec. 95 [A]		[5] Market Price At Dec-95 [C]	[6] Market Price High for Year [C]	[7] Market Price Low for Year [C]	[8] Market to Book At Dec-95 [D]	[9] Market to Book Avg. for Year [D]	[10] Div. Rate [C]	[11] Dividend Yield At Dec-95 [E]	[12] Dividend Yield Avg. for Year [E]
American Water Works	$19.64	$20.97	$22.46	$23.75	E	$38.88	$38.13	$26.75	1.64	1.40	$1.28	3.29%	3.95%
Aquarion Co.	$16.28	$16.83	$17.21	$17.25	E	$25.50	$26.00	$21.63	1.48	1.38	$1.62	6.35%	6.80%
California Water Service	$21.02	$21.80	$23.12	$23.35	E	$32.75	$35.25	$29.63	1.40	1.40	$2.04	6.23%	6.29%
Consumers Water	$11.82	$12.06	$12.22	$12.50	E	$18.25	$19.00	$14.50	1.46	1.36	$1.20	6.58%	7.16%
Philadelphia Suburban Corp.	$10.88	$11.92	$12.53	$12.35	E	$20.75	$21.50	$17.38	1.68	1.56	$1.16	5.59%	5.97%
United Water Resources	$9.55	$10.00	$11.17	$10.95	E	$12.00	$14.13	$11.75	1.10	1.17	$0.92	7.67%	7.11%
AVERAGE	$14.87	$15.60	$16.45	$16.69		$24.69	$25.67	$20.2[illegible]	1.46	1.38	$1.37	5.95%	6.21%

Sources:
[A] Most current Value Line at time of prep. of sch.
[B] Book value data for companies not in Value Line obtained from annual report to stockholders.
[C] New York Times
[D] Market price divided by book value
[E] Dividend rate divided by market price

COMPARATIVE WATER COMPANIES
EARNINGS PER SHARE AND RETURN ON EQUITY

Sch. JAR 6, P. 2

WATER COMPANIES AND DIVERSIFIED WATER COMPANIES COVERED BY VALUE LINE:

	[1] EPS 1994 [A]	[2] EPS 1995 [A]		[3] Return on Eq. 1995 [B]	[4] Value Line Future Exp. Return on Eq. 11/10/95 [A]	Return on Equity 1994
American Water Works	$2.34	$2.50	E	10.82%	10.50%	10.78%
Aquarion Co.	$1.87	$1.70	E	9.87%	14.50%	10.99%
California Water Service	$2.44	$2.30	E	9.90%	11.00%	10.86%
Consumers Water	$1.17	$1.30	E	10.52%	10.50%	9.64%
Philadelphia Suburban Corp.	$1.35	$1.45	E	11.66%	12.50%	11.04%
United Water Resources	$1.01	$0.90	E	8.14%	11.50%	9.54%
Average	$1.70	$1.69		10.15%	11.75%	10.47%

Source:

[A] Value Line
[B] Earnings Per Share divded by average book value. Book value shown on Sch. JAR 6, P. 1

RETURN ON EQUITY IMPLIED IN ZACK'S CONSENSUS GROWTH RATES

Sch. JAR 6, P. 3

	Dec. 94 Y/E Book [3]	Earnings 1994	Dividends	Zack's Consensus 5 Year Growth Rate 11/30/95	Y/E Book in 1998 at Zack's Growth	Y/E Book in 1999 at Zack's Growth	Earnings 1999 at Zack's Growth	Return on Equity to achieve Zack's Growth
American Water Works	$22.46	$2.34	$1.28	5.80%	$27.35	$28.76	$3.10	11.06%
Aquarion Co.	$17.21	$1.87	$1.62	4.00%	$18.31	$18.62	$2.28	12.32%
California Water Service	$23.12	$2.44	$2.04	3.00%	$24.84	$25.31	$2.83	11.28%
Consumers Water	$12.22	$1.17	$1.20	4.00%	$12.09	$12.05	$1.42	11.79%
Philadelphia Suburban Corp.	$12.53	$1.35	$1.16	3.60%	$13.36	$13.59	$1.61	11.96%
United Water Resources	$11.17	$1.01	$0.92	2.70%	$11.55	$11.66	$1.15	9.94%
				3.85%				11.39%

Projected return on equity is obtained by escalating both dividends and earnings per share by the stated growth rate, and adding earnings and subtracting dividends in each year to determine the book value.

COMPARATIVE GAS COMPANIES
SELECTED FINANCIAL DATA

Sch. JAR 7, P. 1

GAS COMPANIES COVERED BY VALUE LINE:

[1]	[2]	[3]		[4]		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
	Book	Book	Book			Market Price			Market to Book			Dividend Yield	
	Per Sh. Y/E 1992	Per Sh. Y/E 1993	Per Sh. Y/E 1994	Book Y/E Y/E 1995		At Dec. 1995	High for 1995	Low for 1995	At Dec. 1995	Avg. for 1995 YTD	Div. Rate	At Dec. 1995	Avg. for YTD
	[A]	[A]	[A]	[A]		[B]	[B]	[B]	[C]	[C]	[B]	[D]	[D]
Atlanta Gas Light	$9.70	$9.90	$10.19	$10.13		$19.75	$20.00	$14.88	1.95	1.72	$1.06	5.37%	6.08%
Atmos Energy Corp.	$9.17	$9.64	$9.78	$10.95	E	$23.00	$23.00	$15.88	2.10	1.88	$0.96	4.17%	4.94%
Bay State Gas Co.	$14.90	$15.52	$16.20	$16.47		$27.75	$29.50	$22.25	1.68	1.58	$1.50	5.41%	5.80%
Brooklyn Union Gas	$14.55	$15.54	$16.27	$16.85	E	$29.25	$29.63	$22.00	1.74	1.56	$1.42	4.85%	5.50%
Cascade Natural Gas	$9.09	$9.96	$9.84	$9.85	E	$16.00	$17.50	$13.00	1.62	1.55	$0.96	6.00%	6.30%
Connecticut Energy	$12.80	$13.33	$14.45	$14.84		$22.25	$22.50	$18.50	1.50	1.40	$1.30	5.84%	6.34%
Connecticut Natural Gas	$13.26	$14.29	$14.62	$15.12		$23.38	$25.25	$21.25	1.55	1.56	$1.48	6.33%	6.37%
Energen Corp.	$12.75	$13.60	$15.30	$15.93		$24.13	$25.13	$20.13	1.51	1.45	$1.16	4.81%	5.13%
Indiana Energy, Inc.	$10.22	$11.52	$12.03	$12.44		$23.88	$24.13	$17.63	1.92	1.71	$1.10	4.61%	5.27%
Laclede Gas Company	$11.79	$12.19	$12.44	$13.00	E	$21.25	$23.13	$18.38	1.63	1.63	$1.26	5.93%	6.07%
MCN Corporation	$7.44	$7.97	$8.55	$9.85	E	$23.25	$23.50	$16.38	2.36	2.17	$0.93	4.00%	4.66%
NUI Corp.	$14.55	$14.92	$15.59	$15.90	E	$17.50	$17.75	$14.00	1.10	1.01	$0.90	5.14%	5.67%
New Jersey Resources	$14.16	$14.72	$14.46	$14.55		$30.13	$30.00	$21.50	2.07	1.78	$1.52	5.05%	5.90%
NICOR	$12.76	$13.05	$13.26	$13.65	E	$27.50	$28.50	$21.75	2.01	1.87	$1.28	4.65%	5.09%
Northwest Nat. Gas Co.	$18.62	$19.62	$20.44	$21.70	E	$33.00	$34.25	$27.50	1.52	1.47	$1.80	5.45%	5.83%
ONEOK, Inc.	$13.28	$13.63	$13.88	$14.38		$22.88	$24.81	$17.13	1.59	1.48	$1.16	5.07%	5.53%
Pacific Enterprises Corp.	$9.44	$12.19	$14.74	$15.20	E	$28.25	$28.63	$20.75	1.86	1.65	$1.36	4.81%	5.51%
Peoples Energy Corp.	$17.72	$18.02	$18.39	$18.40	E	$31.75	$32.00	$24.25	1.73	1.53	$1.80	5.67%	6.40%
Piedmont Natural Gas	$10.27	$10.90	$11.36	$12.30	E	$23.25	$24.88	$18.25	1.89	1.82	$1.10	4.73%	5.10%
Providence Energy Corp.	$12.02	$13.37	$13.82	$13.85	E	$17.00	$17.50	$14.63	1.23	1.16	$1.08	6.35%	6.72%
South Jersey Industries, Inc.	$13.90	$14.33	$14.46	$14.50	E	$23.13	$23.50	$17.88	1.59	1.43	$1.44	6.23%	6.96%
Southwest Gas Corp.	$15.99	$15.96	$15.31	$15.80	E	$17.63	$18.38	$13.63	1.12	1.03	$0.82	4.65%	5.13%
UGI	$12.97	$13.00	$13.13	$11.50	E	$20.75	$22.13	$18.88	1.80	1.66	$1.40	6.75%	6.83%
Washington Energy	$13.88	$13.85	$10.83	$8.15	E	$18.63	$19.13	$12.63	2.29	1.67	$1.00	5.37%	6.30%
Washington Gas	$10.67	$11.04	$11.51	$11.95	E	$20.50	$22.38	$16.13	1.72	1.64	$1.12	5.46%	5.82%
WICOR, Inc.	$15.91	$16.47	$17.23	$18.80	E	$32.25	$32.88	$26.63	1.72	1.65	$1.64	5.09%	5.51%
AVERAGE	$12.76	$13.41	$13.77	$14.08		$23.77	$24.61	$18.68	1.72	1.58	$1.25	5.30%	5.80%

Sources: [A] Most current Value Line at time of prep. of sch.
[B] Most current Value Line at time of prep. of sch.
[C] Market Price Divided by Book Value
[D] Dividend Rate Divided by Market Price

COMPARATIVE GAS COMPANIES **Sch. JAR 7, P. 2**
EARNINGS PER SHARE AND RETURN ON EQUITY

GAS COMPANIES COVERED BY VALUE LINE:

	[1] EPS 1994 [A]	[2] EPS 1995 [A]		[3] Return on Eq. 1995 [B]	[4] Value Line Future Exp. Return on Eq. 12/29/95 [A]	Return on Equity 1994
Atlanta Gas Light	$1.17	$1.33		13.09%	13.00%	11.65%
Atmos Energy Corp.	$0.97	$1.22		11.77%	11.00%	9.99%
Bay State Gas Co.	$1.85	$1.71		10.47%	12.00%	11.66%
Brooklyn Union Gas	$1.85	$1.90		11.47%	11.50%	11.63%
Cascade Natural Gas	$0.60	$0.85	E	8.63%	12.50%	6.06%
Connecticut Energy	$1.58	$1.60		10.93%	11.00%	11.38%
Connecticut Natural Gas	$1.85	$1.52		10.22%	12.50%	12.80%
Energen Corp.	$2.01	$1.77		11.34%	12.00%	13.91%
Indiana Energy, Inc.	$1.53	$1.46		11.93%	14.50%	12.99%
Laclede Gas Company	$1.42	$1.27		9.98%	11.50%	11.53%
MCN Corporation	$1.31	$1.40	E	15.22%	13.00%	15.86%
NUI Corp.	$1.25	$1.11		7.05%	9.00%	8.19%
New Jersey Resources	$1.89	$1.93		13.31%	14.00%	12.95%
NICOR	$2.07	$1.95		14.49%	15.50%	15.74%
Northwest Nat. Gas Co.	$2.44	$2.35		11.15%	12.00%	12.18%
ONEOK, Inc.	$1.34	$1.58		11.18%	11.50%	9.74%
Pacific Enterprises Corp.	$1.95	$2.10	E	14.03%	13.50%	14.48%
Peoples Energy Corp.	$2.13	$1.78		9.68%	13.00%	11.70%
Piedmont Natural Gas	$1.35	$1.45		12.26%	12.50%	12.13%
Providence Energy Corp.	$1.46	$1.09		7.88%	11.00%	10.74%
South Jersey Industries, Inc.	$1.21	$1.60	E	11.05%	12.00%	8.41%
Southwest Gas Corp.	$1.22	$0.75	E	4.82%	8.00%	7.80%
UGI	$1.17	$0.52		4.22%	12.00%	8.96%
Washington Energy	($0.16)	$0.35		3.69%	15.50%	-1.30%
Washington Gas	$1.42	$1.45		12.36%	11.50%	12.55%
WICOR, Inc.	$2.09	$2.25	E	12.49%	12.50%	12.40%
Average	$1.50	$1.47		10.57%	12.23%	11.01%

Source:

[A] Value Line

[B] Earnings Per Share divded by average book value. Book value shown on Sch. JAR 7, P. 1

RETURN ON EQUITY IMPLIED IN ZACK'S CONSENSUS GROWTH RATES

Sch. JAR 7, P. 3

	1994 Y/E Book [4]	Earnings 1994	Dividends	Zack's Consensus 5 Year Growth Rate 11/30/95	Y/E Book in 1997 at Zack's Growth	Y/E Book in 1998 at Zack's Growth	Earnings 1999 at Zack's Growth	Return on Equity to achieve Zack's Growth
Atlanta Gas Light	$10.19	$1.17	$1.06	4.80%	$10.69	$10.82	$1.48	13.75%
Atmos Energy Corp.	$9.78	$0.97	$0.96	6.00%	$9.83	$9.84	$1.30	13.20%
Bay State Gas Co.	$16.20	$1.85	$1.50	4.40%	$17.76	$18.20	$2.29	12.76%
Brooklyn Union Gas	$16.27	$1.85	$1.42	4.30%	$18.18	$18.71	$2.28	12.38%
Cascade Natural Gas	$9.84	$0.60	$0.96	5.80%	$8.18	$7.70	$0.80	10.02%
Connecticut Energy	$14.45	$1.58	$1.30	4.60%	$15.70	$16.06	$1.98	12.46%
Connecticut Natural Gas	$14.62	$1.85	$1.48	3.10%	$16.22	$16.65	$2.16	13.11%
Energen Corp.	$15.30	$2.01	$1.16	5.60%	$19.20	$20.32	$2.64	13.36%
Indiana Energy, Inc.	$12.03	$1.53	$1.10	5.10%	$13.98	$14.53	$1.96	13.76%
Laclede Gas Company	$12.44	$1.42	$1.26	3.50%	$13.14	$13.33	$1.69	12.74%
MCN Corporation	$8.55	$1.31	$0.93	8.70%	$10.43	$11.01	$1.99	18.55%
NUI Corp.	$15.59	$1.25	$0.90	4.10%	$17.14	$17.57	$1.53	8.81%
New Jersey Resources	$14.46	$1.89	$1.52	4.80%	$16.13	$16.59	$2.39	14.60%
NICOR	$13.26	$2.07	$1.28	4.20%	$16.77	$17.74	$2.54	14.74%
Northwest Nat. Gas Co.	$20.44	$2.44	$1.80	4.90%	$23.33	$24.14	$3.10	13.06%
ONEOK, Inc.	$13.88	$1.34	$1.16	6.50%	$14.72	$14.97	$1.84	12.36%
Pacific Enterprises Corp.	$14.74	$1.95	$1.36	4.60%	$17.38	$18.12	$2.44	13.75%
Peoples Energy Corp.	$18.39	$2.13	$1.80	3.10%	$19.82	$20.20	$2.48	12.40%
Piedmont Natural Gas	$11.36	$1.35	$1.10	5.90%	$12.52	$12.85	$1.80	14.18%
Providence Energy Corp.	$13.82	$1.46	$1.08	4.50%	$15.52	$15.99	$1.82	11.55%
South Jersey Industries, Inc.	$14.46	$1.21	$1.44	4.00%	$13.44	$13.16	$1.47	11.07%
Southwest Gas Corp.	$15.31	$1.22	$0.82	4.80%	$17.11	$17.62	$1.54	8.88%
UGI	$13.13	$1.17	$1.40	9.50%	$11.97	$11.61	$1.84	15.62%
Washington Energy	$10.83	($0.16)	$1.00	4.50%	$5.64	$4.20	($0.20)	-4.05%
Washington Gas	$11.51	$1.42	$1.12	3.70%	$12.80	$13.16	$1.70	13.07%
WICOR, Inc.	$17.23	$2.09	$1.64	8.70%	$19.46	$20.14	$3.17	16.02%
				5.14%				12.39%

Projected return on equity is obtained by escalating both dividends and earnings per share by the stated growth rate, and adding earnings and subtracting dividends in each year to determine the book value.

Summary of Risk Premium Equations
Electric Industry Analysis Applied to
Water. Companies
Interest Rates on 10/31/95

Indicated
Cost of Equity

Equation based on 30 Year Treasury Rate

Cost of Equity = 1.331 X Interest Rate + .589 X Ext. Fin.Rate - 0.24%

Interest Rate=	5.96%			
Interest Rate X	1.331		7.93%	
Ext. Fin. Rate =	1.40%			
Ext. Fin. Rate X	0.589	=	0.82%	
Constant			-0.24%	
				8.52%

Equation based on 5 Year Treasury Rate

Cost of Equity = 0.657 X Interest Rate + .5706 X Ext. Fin.Rate + 5.58%

Interest Rate=	5.39%			
Interest Rate X	0.657	=	3.54%	
Ext. Fin. Rate =	1.40%			
Ext. Fin. Rate X	0.5706	=	0.80%	
Constant			5.58%	
				9.92%

Equation based on 1 Year Treasury Rate

Cost of Equity = 0.3853 X Interest Rate + .5730 X Ext. Fin.Rate + 8.05%

Interest Rate=	5.20%			
Interest Rate X	0.3853	=	2.00%	
Ext. Fin. Rate =	1.40%			
Ext. Fin. Rate X	0.573	=	0.80%	
Constant			8.05%	
				10.86%

Average of 3 9.76%

Source: Yields from 12/30/95 New York Times
Regression analysis of cost of equity for all electric companies covered by Value Line vs interest rate and external financing rate.

All equations have an F that is significant to at least 99.99%

Occgas

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Summary of Risk Premium Equations
Electric Industry Analysis Applied to
Gas Dist. Companies
Interest Rates on 10/31/95

Indicated Cost of Equity

Equation based on 30-Year Treasury Rate

Cost of Equity = 1.331 X Interest Rate + .589 X Ext. Fin.Rate - 0.24%

	6.63%			
Interest Rate=	5.96%			
Interest Rate X	1.331	=	7.93%	
Ext. Fin. Rate =	2.10%			
Ext. Fin. Rate X	0.589	=	1.24%	
Constant			-0.24%	
				8.93%

Equation based on 5-Year Treasury Rate

Cost of Equity = 0.657 X Interest Rate + .5706 X Ext. Fin.Rate + 5.58%

Interest Rate=	5.39%			
Interest Rate X	0.657	=	3.54%	
Ext. Fin. Rate =	2.10%			
Ext. Fin. Rate X	0.5706	=	1.20%	
Constant			5.58%	
				10.32%

Equation based on 1-Year Treasury Rate

Cost of Equity = 0.3853 X Interest Rate + .5730 X Ext. Fin.Rate + 8.05%

Interest Rate=	5.20%			
Interest Rate X	0.3853	=	2.00%	
Ext. Fin. Rate =	2.10%			
Ext. Fin. Rate X	0.573	=	1.20%	
Constant			8.05%	
				11.26%
		Average of 3		10.17%

Source: Yields from 7/1/95 New York Times
Regression analysis of cost of equity for all electric companies covered by Value Line vs interest rate and external financing rate.

All equations have an F that is significant to at least 99.99%

CAPITAL ASSET PRICING MODEL (CAPM) METHOD
Water Utilities

		Amount	Source
Risk Premium:			
1	Actual Earned Return on S&P Industrials 1926 through 1994	10.20%	Ibbotson Associates
2	Actual Earned Return on 30-Year Treas. Bonds from 1926 through 1994	4.80%	Ibbotson Associates
3	Difference	5.40%	Line 1 - Line 2
4	Current Interest Rate on 30-year Treasury Bonds	5.96%	
5	CAPM Indicated Cost of Equity on Industrual Companies	11.36%	Line 3 + Line 4
6	Indicated cost rate for water utilities		
a	Beta of Water Utilities	0.64	Value Line, average of water companies
b	Beta of 30-year treasuries	0.40	Computed
c	Beta of average company	1.00	Definition of beta
d	Change in capital cost rate with change in beta from average company to treasury beta	5.40%	Line 3
e	Change in capital cost rate per .01 change in beta	0.0900%	Line 6d/(Line c-Line b)/100
f	Capital cost reduction concurrent with change in beta from 1.00 to 0.64	3.24%	((Line 6c-Line 6a) x Line 6e) x 100
g	CAPM Risk Premium Indicated for Water Utilities	2.16%	Line 6d - Line 6f
h	Cost of equity indicated by CAPM Method applied to water utilities	8.12%	Line 6g + Line 4

CAPITAL ASSET PRICING MODEL (CAPM) METHOD
Gas Utilities

		Amount	Source
Risk Premium:			
1	Actual Earned Return on S&P Industrials 1926 through 1994	10.20%	Ibbotson Associates
2	Actual Earned Return on 30-Year Treas. Bonds from 1926 through 1994	4.80%	Ibbotson Associates
3	Difference	5.40%	Line 1 - Line 2
4	Current Interest Rate on 30-year Treasury Bonds	5.96%	
5	CAPM Indicated Cost of Equity on Industrual Companies	11.36%	Line 3 + Line 4
6	Indicated cost rate for water utilities		
a	Beta of Gas Utilities	0.59	Value Line, average of gas dist. companies
b	Beta of 30-year treasuries	0.40	Computed
c	Beta of average company	1.00	Definition of beta
d	Change in capital cost rate with change in beta from average company to treasury beta	5.40%	Line 3
e	Change in capital cost rate per .01 change in beta	0.0900%	Line 6d/(Line c-Line b)/100
f	Capital cost reduction concurrent with change in beta from 1.00 to 0.59	3.69%	((Line 6c-Line 6a) x Line 6e) x 100
g	CAPM Risk Premium Indicated for Gas Utilities	1.71%	Line 6d - Line 6f
h	Cost of equity indicated by CAPM Method applied to gas utilities	7.67%	Line 6g + Line 4

VALUE LINE WATER COMPANIES
EXTERNAL FINANCING RATE
(Millions of Shares)

Common Stock Outstanding	**1995**	**1998-2000**	**Compound Annual Growth**
American Water Works	33.50 E	35.50	1.46%
Aquarion Co.	6.50 E	6.50	0.00%
California Water Service	6.25 E	6.75	1.94%
Consumers Water	8.40 E	9.75	3.80%
Philadelphia Suburban Corp.	12.00 E	12.50	1.03%
United Water Resources	32.00 E	32.00	0.00%
	16.44	17.17	
	Average		1.37%
	Round to		1.40%

Source:
Value Line

VALUE LINE GAS COMPANIES
EXTERNAL FINANCING RATE
(Millions of Shares)

Common Stock Outstanding	1995	1998-00	Compound Annual Growth
Atlanta Gas Light	25.43	29.00	3.34%
Atmos Energy Corp.	15.75 E	17.50	2.67%
Bay State Gas Co.	13.53	14.00	0.86%
Brooklyn Union Gas	48.70 E	52.00	1.65%
Cascade Natural Gas	9.20 E	11.25	5.16%
Connecticut Energy	8.87	10.50	4.31%
Connecticut Natural Gas	9.93	11.00	2.59%
Energen Corp.	10.92	11.50	1.30%
Indiana Energy, Inc.	22.56	21.65	-1.02%
Laclede Gas Company	17.45 E	17.60	0.21%
MCN Corporation	66.30 E	76.00	3.47%
NUI Corp.	9.20 E	11.50	5.74%
New Jersey Resources	17.79	19.00	1.66%
NICOR	50.00 E	48.50	-0.76%
Northwest Nat. Gas Co.	14.80 E	15.75	1.57%
ONEOK, Inc.	27.02	27.50	0.44%
Pacific Enterprises Corp.	84.70 E	87.05	0.69%
Peoples Energy Corp.	34.90 E	35.15	0.18%
Piedmont Natural Gas	28.85 E	32.50	3.02%
Providence Energy Corp.	5.65 E	6.50	3.57%
South Jersey Industries, Inc.	10.75 E	12.25	3.32%
Southwest Gas Corp.	24.50 E	28.00	3.39%
UGI	33.00 E	37.00	2.90%
Washington Energy	24.20 E	25.25	1.07%
Washington Gas	43.00 E	46.00	1.70%
WICOR, Inc.	18.25 E	19.50	1.67%
	25.97	27.83	
	Average		2.10%
	Round to		2.10%

Source:
Value Line, Sept. 29, 1995

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Water Companies
Percentage of Common Equity in the Capital Structure
Excluding Short-term Debt

	1988	1989	1990	1991	1992	1993	1994	1995 Estimate		1996 Estimate
Value Line Water Companies										
American Water Works	38.30%	37.10%	38.10%	35.00%	36.60%	33.70%	34.20%	34.00%	E	34.00%
Aquarion Co.	55.50%	56.90%	47.50%	44.20%	48.00%	48.90%	50.80%	49.50%	E	51.00%
California Water Service	53.80%	55.10%	51.30%	52.40%	48.80%	48.20%	52.20%	50.00%	E	52.00%
Consumers Water Company	43.60%	41.40%	37.50%	43.90%	41.10%	43.70%	43.00%	42.00%	E	45.50%
Philadelphia Suburban Corp.	37.10%	34.50%	32.70%	32.50%	39.50%	46.70%	47.40%	46.50%	E	45.50%
United Water Resources	37.80%	34.60%	36.10%	33.80%	35.40%	39.50%	36.40%	34.50%	E	42.00%
AVERAGE	44.35%	43.27%	40.53%	40.30%	41.57%	43.45%	44.00%	42.75%		45.00%

Source: Value Line

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Gas Companies
Percentage of Common Equity in the Capital Structure
Excluding Short-term Debt

	1990	1991	1992	1993	1994	1995		Est. 1998-2000
Value Line Gas Companies								
Atlanta Gas Light	47.80%	48.80%	58.10%	53.10%	45.80%	47.60%		50.00%
Atmos Energy Corp.	48.30%	47.70%	50.30%	56.70%	51.90%	53.00%	E	56.00%
Bay State Gas Co.	53.70%	48.00%	57.00%	51.90%	52.30%	51.90%		54.00%
Brooklyn Union Gas	46.80%	45.40%	47.80%	50.80%	52.20%	53.00%	E	51.50%
Cascade Natural Gas	46.30%	46.70%	45.60%	47.30%	44.90%	45.50%	E	45.00%
Connecticut Energy	44.60%	50.10%	49.40%	45.20%	51.20%	54.20%		52.50%
Connecticut Natural Gas	48.70%	49.50%	48.70%	49.50%	47.30%	49.80%		50.50%
Energen Corp.	58.70%	60.60%	58.40%	62.00%	58.50%	56.90%		60.00%
Indiana Energy, Inc.	62.10%	53.20%	55.50%	61.10%	63.10%	61.40%		64.00%
Laclede Gas Company	58.10%	52.50%	55.30%	53.10%	55.50%	59.00%	E	55.50%
MCN Corporation	47.40%	50.60%	52.70%	48.40%	39.30%	39.00%	E	39.00%
NUI Corp.	44.00%	41.30%	44.60%	44.20%	45.20%	40.00%	E	47.00%
New Jersey Resources	42.70%	37.80%	44.80%	42.60%	42.00%	41.00%		42.00%
NICOR	60.30%	59.40%	62.10%	59.70%	56.90%	54.50%	E	57.00%
Northwest Nat. Gas Co.	47.00%	43.20%	43.90%	45.00%	45.10%	47.00%	E	48.00%
ONEOK, Inc.		51.00%		49.00%	50.00%	52.00%		
Pacific Enterprises Corp.	44.40%	36.70%	23.10%	35.70%	38.10%	41.50%	E	51.00%
Peoples Energy Corp.	51.00%	52.10%	55.10%	54.30%	50.60%	55.00%	E	52.00%
Piedmont Natural Gas	53.00%	52.00%	53.40%	50.60%	49.10%	49.50%	E	49.50%
Providence Energy Corp.	52.30%	50.70%	44.10%	51.10%	53.10%	48.00%	E	53.50%
South Jersey Industries, Inc.	51.70%	53.30%	52.10%	48.90%	49.90%	46.50%	E	49.50%
Southwest Gas Corp.	40.30%	38.10%	35.20%	35.00%	34.00%	33.00%	E	36.00%
UGI	32.20%	44.90%	50.70%	49.30%	51.60%	30.50%	E	40.50%
Washington Energy	46.10%	52.20%	47.50%	46.60%	40.30%	34.00%	E	34.50%
Washington Gas	56.40%	56.90%	57.30%	54.90%	56.70%	59.00%	E	57.50%
WICOR, Inc.	64.30%	58.30%	59.00%	62.10%	64.30%	65.00%	E	66.00%
AVERAGE	49.93%	49.27%	50.07%	50.31%	49.57%	48.76%		50.48%

Source: Value Line

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COMPARISON OF STOCK PRICE VOLATILITY OF WATER COMPANIES VS GAS DISTRIBUTION COMPANIES

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Water Companies High as Percent of Low	137.27%	162.26%	149.18%	159.44%	134.74%	122.82%	152.47%	145.96%	130.59%	125.14%	125.86%	126.12%
Gas Companies High as Percent of Low	139.42%	135.37%	140.01%	158.03%	130.71%	137.22%	130.13%	135.49%	131.59%	131.94%	137.05%	132.41%
Gas High/Low Percent/Water High/Low Percent	1.56%	-16.57%	-6.15%	-0.88%	-2.99%	11.73%	-14.65%	-7.17%	0.77%	5.43%	8.89%	4.99%

VALUE WATER UTILITY INDUSTRY HI/LOW STOCK PRICES
1984 TO 1995

HIGH STOCK PRICE FOR YEAR:

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
American Water Works	$10.30	$16.50	$22.30	$25.90	$18.80	$21.50	$19.60	$26.80	$28.40	$32.10	$32.30	$38.13
Aquarion Co.	$15.50	$24.70	$29.80	$34.90	$36.00	$29.60	$25.90	$27.30	$25.50	$29.30	$28.00	$26.00
California Water Svc.	$15.80	$24.60	$30.30	$32.00	$32.30	$28.80	$28.50	$31.30	$35.00	$41.30	$41.00	$35.25
Consumers Water	$12.30	$17.30	$22.50	$22.50	$21.30	$20.50	$18.30	$18.50	$19.80	$21.50	$18.80	$19.00
Philadelphia Suburban Corp.	$13.30	$15.50	$19.30	$19.00	$16.90	$14.50	$15.00	$16.40	$16.50	$20.80	$19.60	$21.50
United Water Resources	$9.10	$12.10	$18.10	$23.00	$20.50	$17.90	$16.50	$16.60	$16.60	$15.90	$14.80	$14.13

LOW STOCK PRICE FOR YEAR:

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
American Water Works	$6.80	$9.00	$13.90	$13.90	$14.90	$16.80	$12.50	$15.50	$20.60	$24.60	$25.30	$26.75
Aquarion Co.	$12.20	$14.80	$20.30	$22.00	$25.10	$24.40	$19.00	$19.90	$20.10	$24.60	$21.50	$21.63
California Water Svc.	$13.30	$15.30	$21.90	$22.80	$24.00	$23.50	$22.30	$22.30	$26.30	$32.30	$29.40	$29.63
Consumers Water	$8.00	$9.60	$15.90	$15.00	$15.80	$14.80	$10.00	$13.80	$14.30	$17.00	$15.30	$14.50
Philadelphia Suburban Corp.	$10.20	$11.50	$12.70	$12.10	$12.10	$12.80	$10.40	$11.80	$13.80	$15.60	$17.10	$17.38
United Water Resources	$6.40	$8.20	$11.60	$14.00	$15.80	$15.80	$9.90	$10.90	$13.00	$14.00	$12.30	$11.75

High as Percent of Low

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
American Water Works	151.47%	183.33%	160.43%	186.33%	126.17%	127.98%	156.80%	172.90%	137.86%	130.49%	127.67%	142.52%
Aquarion Co.	127.05%	166.89%	146.80%	158.64%	143.43%	121.31%	136.32%	137.19%	126.87%	119.11%	130.23%	120.23%
California Water Svc.	118.80%	160.78%	138.36%	140.35%	134.58%	122.55%	127.80%	140.36%	133.08%	127.86%	139.46%	118.99%
Consumers Water	153.75%	180.21%	141.51%	150.00%	134.81%	138.51%	183.00%	134.06%	138.46%	126.47%	122.88%	131.03%
Philadelphia Suburban Corp.	130.39%	134.78%	151.97%	157.02%	139.67%	113.28%	144.23%	138.98%	119.57%	133.33%	114.62%	123.74%
United Water Resources	142.19%	147.56%	156.03%	164.29%	129.75%	113.29%	166.67%	152.29%	127.69%	113.57%	120.33%	120.21%
Average	137.27%	162.26%	149.18%	159.44%	134.74%	122.82%	152.47%	145.96%	130.59%	125.14%	125.86%	126.12%