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State of Minnesota
Department of Revenue

In the Matter of the Proposed Rules of the Department of Revenue Governing the Valuation and Assessment of Electric, Gas Distribution and Pipeline Companies (Utility Companies)

Statement of Need and Reasonableness

The above-captioned rules are being proposed in order to update and revise the current Rules and Regulations of the Department of Revenue Relating to Ad Valorem (Property) Taxes. The current rules have been in effect since 1975. They have been revised five times. Once in 1976, 1979, 1982, 1983 and again in 1984; however, it is the announced intention of the Department of Revenue to revise the rules whenever conditions, economic or otherwise, dictate a need for revision. This intention is clearly expressed in Minn. Rule 8100.0200, Introduction, of the current rules, "The methods, procedures, indicators of value, capitalization rates, weighing percents, and allocation factors will be used as described in Minn. Rules Parts 8100.0300 to 8100.0600 for 1982 and subsequent years, or until, in the opinion of the Commissioner of Revenue, <u>different conditions justify a change</u>." (emphasis supplied) It is now the opinion of the Commissioner of Revenue that the rules should be revised.

This document has been prepared as a verbatim affirmative presentation of the facts necessary to establish the statutory authority, need for, and reasonableness of the proposed new rules. It is submitted pursuant to Minn. Rule 1400.0500 requiring a Statement of Need and Reasonableness.

In order to solicit outside information and opinion in the preparation of these proposed rules an open forum type discussion meeting was held on January 17, 1985. This meeting was attended by members of the Department of Revenue together with city and county assessors and representatives of various utility companies. A list of those in attendance, the agenda, meeting notes, and correspondence received relative to this meeting is available in the Department of Revenue. Various suggestions and comments made at these meetings were received and duly considered by the agency.

Authority to Adopt Rules

Minn. Stat. § 270.06 (14) states that the ..."Commissioner of Revenue may promulgate rules and regulations for the administration and enforcement of the property tax. Such rules and regulations shall have the force and effect of law..." The above captioned rules are encompassed within this authority.

Further, Minn. Stat. § 270.11, Subd. 1 and 6 gives the Commissioner of Revenue the authority to review, modify, revise, raise or lower the assessed valuation of any real or personal property of any individual, co-partnership, company, association or corporation. The Commissioner of Revenue is also charged with the responsibility under Minn. Stat. §§ 273.33, Subd. 2; 273.37, Subd. 2; and 273.38 of assessing the... "personal property, consisting of the pipeline system of mains, pipes and equipment attached thereto, of pipeline companies and others engaged in the operations or business of transporting natural gas, gasoline or other petroleum products by pipelines... transmission lines of less than 69kv, transmission lines of 69kv and above located in an unorganized township and distribution lines, (of electric companies) and equipment attached thereto, having a fixed situs outside the corporate limits of cities... the distribution lines, and the attachments and appurtenances thereto, (of electric companies) used primarily for supplying electricity to farmers at retail...". Such assessments are best discharged through the promulgation of such rules as are being proposed here.

Adoption of Proposed Rules
Need and Reasonableness

The agency is currently proposing revisions to the existing body of the ad valorem rules for utility property. These revisions concern Minn. Rules 8100.0300, Subd. 3, Cost approach.

This approach utilizes the capitalization of income in a mathematical process in an attempt to derive a value which represents the present worth of the future earnings of the property. The capitalization process has two major factors: 1) the income to be capitalized and 2) the capitalization rate. We propose to change one of these factors to more accurately reflect current economic conditions.

We currently use three years of net utility operating income as the income to be capitalized. This is the income after expenses, depreciation and taxes, but before interest expense. This level of income is usually referred to as the income developed by the regulatory agency. It excludes all income from operations and investments that are not directly related to the operation of the company. This particular income stream is preferred by most utility appraisers, and has the most acceptance throughout the country.

The agency uses three years of these net utility operating earnings in order to level out the peaks and valleys inherent in income determination. This leveling out provides for a relatively stable value, rather than a value which would vary widely from year to year. At present the three years are weighted 40% for the first year's income, 35% for the second and 25% for the third. This weighing of income provides for the most attention to be paid to the most recent performance of the company and attempts to strike a balance between stable income and the recognition of current economic conditions effecting a company.

A capitalization rate is then applied to this weighted income. The capitalization rate is an anticipated rate of return from an investment; a rate at which income is processed (capitalized) to indicate the probable capital value. Usually this rate is commensurate with the risk of the business venture.

In developing a capitalization rate three basic methods are available. They are:

1. The Summation Method - which uses the "safe rate" (usually that of government bonds) and adds to it an allowance for management, non-liquidity, and risk. This method is usually considered to be the least reliable and is not in common use by appraisers of utility property.

2. The Comparative Method - which computes a capitalization rate by measuring the actions of purchasers in the market place. However, since utilities very seldom sell as a unit there are few market transactions from which a rate can be developed. For this reason this method is rarely used in the field of utility valuation.

3. The Band of Investment Method - which is the combination of the rate applicable to the portion of the capital structure represented by debt with the rate applicable to the portion of the capital structure represented by equity. The rate developed is a weighted average, the weighing representing percentages of the mortgage and equity position or bands of investment. This method, which is currently used by the agency, is the most generally accepted method of developing a capitalization rate for use in the appraisal of utilities.

The computation of the capitalization rate using the band of investment method is done on the basis of an average utility within an industry; that is, all companies within one industry (i.e. electric, gas distribution, pipeline) share the same rate. This is done as a matter of convenience due to the agency's lack of time and personnel. It is common practice for utility appraisers all across the country to apply a single capitalization rate to companies within the same industry.

The information used in the computation of the cap rate is taken from the latest edition of Moody's Public Utility Manual and includes the following techniques:

1. A determination of what percent of the capital structure of the average utility is made up of long term debt, preferred stock and common equity.
2. A determination of the average interest rate for contracted indebtedness, commonly referred to as the embedded cost of debt. This average interest rate will make up the debt portion of the capitalization rate.
3. A determination of the average dividend rate of the outstanding preferred stock. This dividend rate will make up the preferred stock portion of the capitalization rate.
4. A determination of the rate of return for common equity; which will make up the equity portion of the cap rate.
5. The application of the determined rate to the various bands of investment to develop the capitalization rate for the average utility.
6. The final step is to assign a risk factor to each type of utility to establish a cap rate for that particular industry.

Attached to this document is an example of the application of these techniques. You will note that the average utility cap rate as computed is 11.5%. We have adjusted this rate to allow for risk as follows:

1. Electric utilities - adjusted to 11.25% because they have lower than average interest rates and better than average earnings stability.
2. Gas distribution utilities - no adjustment made. This group represents the average utility.
3. Pipeline companies - adjusted to 11.75% because they have a higher risk factor than the average utility. Pipelines usually pay a slightly higher rate of interest, and because they do not have a monopoly, as do electric and gas companies, their earnings are less stable.

The revision proposed by the agency is occasioned by the fact that the last calculation of the capitalization rate in 1984 - using the same sources and methodology as shown in our Exhibit - resulted in a 11% average utility capitalization rate. As is evidenced by the Exhibit the data now results in the calculation of a 11.5% average utility capitalization rate.

The agency believes that the amending of the present rules to incorporate these revisions to the current capitalization rates is both reasonable and logical. The major factor causing the proposed changes in the capitalization rates, over those currently in use, is the increase in the interest rates. It is a matter of record that these rates have risen steadily over the past few years.

Interest rates may be advertised which would tend to indicate that our proposed capitalization rates are too low and should be adjusted to even higher levels; however, it must be kept in mind that the interest rates in question are those currently in effect. The income which comprises the income stream is an average of three year's historical income. The capitalization rate proposed by the agency is also based on historical information. It is paramount in appraisal practice to match the correct income stream to the corresponding capitalization rate. In the agency's judgment the rates as now proposed accurately reflect the proper capitalization rate to be applied to the weighted income stream. The combination of these two elements into the income indicator of value will produce an equitable estimate of the worth of a utility. The agency is committed to a policy of review and change, as it witnessed by our introductory statement on page 1 of this document. As economic conditions change, the computation of both the capitalization rate and the income stream may well change. At this time, however, the agency believes the rates as proposed should be adopted.

The second proposed change in the rules concerns the amount of depreciation which will be allowed as a reduction of the cost of the utility's property. There are several types of cost which are used in the appraisal of utilities:

1. Original Cost - Original cost is the actual cost of a property when it was first acquired or constructed.
2. Book Cost - Book cost is the original cost of a property less accrued depreciation.
3. Reproduction Cost - Reproduction cost is the present dollar cost to reproduce a replica of the existing property, i.e. what the property would cost today. Reproduction cost is obtained by trending known costs up or down, depending on whether current construction costs are greater or less than when the property was first constructed.
4. Replacement Cost - Replacement cost is the present dollar cost to replace a property with one having similar or equal usefulness.

The estimation of value by use of the cost approach requires the use of the proper type of cost, and then computing the loss in value due to depreciation.

Depreciation is made up of three factors:

1. Physical deterioration which is the loss in value from original cost caused by normal use and wearing out of the property.
2. Functional obsolescence which is a loss in value because of functional deficiencies or inadequacies within the property itself. Normally, functional obsolescence would result from technological changes which result in better, more efficient techniques.
3. Economic obsolescence which is a loss in value caused by factors outside the property itself.

In the case of electric utilities the various elements of depreciation are considered by the Federal Energy Regulatory Commission which then specifies what rates of depreciation are to be used by the various utilities for different classes of assets.

The four major electric utilities operating within Minnesota are currently at the following depreciation level:

Original Cost of Plant in Service	$5,264,012,804
Accrued Depreciation	1,383,366,422
Book Cost of Plant in Service	3,880,646,384
Ratio of Depr. to Original Cost	(Approx.) 26%

The rules propose to allow the electric companies a maximum of 20% depreciation. The difference between 26% and 20% is the agency's method of calculating replacement cost for the utility's property and acts as a hedge against inflation.

Minn. Stat. § 273.11, Subd. 1 requires that ..."all property shall be valued at its market value." With most types of property the concept of market value equates to replacement cost. The owner of a 20 year old three bedroom, 1000 square foot rambler does not have his property valued by the local assessor at the original cost of $20,000; neither does the assessor use book cost. The assessor would use some form of either reproduction or replacement cost. When the house was built in 1965 construction costs must have been approximately $20 per square foot; hence, the selling price, (market value, original cost) of $20,000. Today, inflation has pushed these same construction costs to $70 per square foot, so the market value or replacement cost of the property is $70,000.

The agency recognizes that a multimillion dollar utility does not sell in the same way a three bedroom rambler might. It also recognizes that in most instances the utility is limited in its earnings by its rate base; (rate base is normally original cost less depreciation). However, it is readily apparent that because of inflation the cost of replacing the facilities at today's prices would be more than the original cost at the time of installation. Our holding of the depreciation at a specified maximum attempts to recognize both the wearing out and obsolescence of the facilities together with the fact that to replace or reproduce the facility would produce more value. The agency believes that the proposed maximum depreciation allowance is a reasonable and viable method of accomplishing both these objectives.

The major pipeline and gas distribution companies have the following depreciation levels.

Original Cost of Plant in Service	$4,684,656,977
Accrued Depreciation	2,017,277,418
Book Cost of Plant in Service	2,667,379,559
Ratio of Depr. to Original Cost	(Approx.) 43%

The proposed values would allow pipeline and gas distribution companies a maximum of 50% depreciation. The overall industry average depreciation rate of 43% does not exceed the maximum allowable depreciation as in the case of electric utilities. The agency is aware of this difference. We believe that because of the dissimilarity between the industries that the depreciation rates are proper. The electric industry is constantly updating and replacing its property so that overall depreciation rate is fairly low. In the pipeline industry, on the other hand, it is common practice to build a line and leave it in place for years. Since the pipes are normally buried they are not easily accessible as are electric wires. In addition, the state of the art in the pipeline industry changes much more slowly than in the electric industry. There are only so many ways you can design a pipe, while new and different ways for transmitting electricity are regularly being discovered. (Witness the change from transporting electricity in A.C. form to the D.C. mode.) There is very little replacement and updating in the pipeline field. Minnesota has operating pipelines which were built in the 1940's. Because of this longer life span of pipeline property, a larger depreciation allowance is necessary to adequately reflect the loss in value of the property. The same rationale holds true in most instances for gas distribution companies.

There is a further consideration to be looked at as well. It is an acknowledged fact that the need for electricity will go on for the foreseeable future. The demand for electric power can be met in a number of ways; by hydro power, nuclear energy or coal fired generating plants. In short, the electric industry is here to stay. Gas and oil in the other hand are not quite as stable or certain. It may well be that a pipeline may not have nearly as long a life as the builder intended either because the source of supply is exhausted, or is cut off for political or economic reasons. This of course, has a decided effect on the market value of the property. A prospective buyer would be much more willing to pay a higher price for a long term monopoly utility, than for a relatively short term speculative utility. The larger depreciation allowance given to pipelines and gas distribution companies is one of the agency's methods of recognizing this fact. We believe the proposal to be reasonable in its concept, and necessary if we are to find a realistic estimate of market value for these types of utilities.

The third change in Minn. Rules 8100 concerns adjusting electric utility property to take into account the effect of inflation on property values. This change is aimed at a specific type of electric utility asset, the major generating plants. The adjustment is accomplished through the use of a special study called the "Average Cost per Kilowatt of Installed Capacity."

The "Average Cost per Kilowatt of Installed Capacity" is a method of replacement cost which computes the national average cost of building a major generating plant. This average is then applied to all major plants operated by a utility. If the national average is higher than the original cost of the plant the original cost is increased to that of the average; if the national average is lower no adjustment is made.

The reason this average is computed and used can best be explained by again using the homeowner as a comparison. The appraiser can best estimate the value of the three bedroom rambler by using two methods; 1) comparable sales, and 2) cost per square foot of construction. It is apparent that major utility generating plants do not sell frequently on the open market. Therefore the comparable sales avenue of appraisal is not generally available to us. Major generating plants are not built on a square foot basis, but rather on a capacity basis. They are measured and classed as to how many kilowatts they can produce operating at maximum capacity. Therefore, instead of using the square foot construction costs of generating plants to estimate current worth, as we would in the case of a house, we utilize cost per kilowatt.

We feel that this is a fair and workable technique of calculating an accurate measure of replacement cost for a number of reasons.

1. It follows accepted appraisal techniques of comparing construction costs for like properties.
2. It makes no adjustment on smaller standby units which are often kept in working condition by a utility for emergency use only.
3. By using the national average, the utility in Minnesota receives the benefit of warm weather building methods which are usually less costly.
4. The method gives the utility the advantage of the most advanced technology used in building power plants, and refutes the argument "We wouldn't build a plant like that today."
5. It typically produces an additional value only for older plants and does not produce an across the board increase for the newer plants.

The proposed revision would broaden the study for computing the national average for hydro-electric, steam and gas turbine plants. The agency believes that this revision is both necessary and reasonable because of a drastic change in the reporting of information used in the computation of this study.

In prior years the U.S. Department of Energy compiled information submitted to it by the various electric utilities operating within the United States into a series of publications. Three of these annual publications dealt with the construction costs and annual production expenses of the various types of plants. These publications were entitled: Hydroelectric Plant Construction Cost and Annual Production Expenses; Thermal - Electric Plant Construction Cost and Annual Production Expenses and Gas Turbine Electric Plant Construction Cost and Annual Production Expenses. The last edition of these publications listed 378 hydro, 647 steam and 435 gas turbine plants.

The three publications have now been condensed by the Energy Information Administration into one publication entitled Historical Plant Cost and Annual Production Expenses for Selected Electric Plants. This report lists only 286 hydro, 375 steam and 64 gas turbine plants. It becomes readily apparent that more than 50% of the plants have been deleted from the data which forms the basis of the study. In order to preserve the statistical integrity of the study the agency believes it is both reasonable and necessary to revise the rules to provide for a broad study base and eliminate drastic yearly fluctuations which are inherent in a small sample base.

Commensurate with this revision the agency also proposes to change the period used for the computation of the obsolescence factors. These factors; plant use and thermal efficiency, are presently calculated by using only plants constructed during the last 15 years. The proposal is to broaden the study to include all plants of a specific type included in the Historical Plant Cost and Annual Production Expenses for Selected Electric Plants publication. These obsolescence allowances are applied only to hydro and steam type generating plants.

Gas turbine plants will not be eligible for this allowance because the design and operation of these units has not changed appreciably from their introduction to the present time. These units were first introduced in the mid-1960's and are normally purchased in a packaged form much as one would buy an auxiliary generator, the only difference being the size. The cost per kilowatt of installed capacity of these units has varied only slightly over the years and the operating characteristics of all the units is fairly uniform since most are based on a relatively standard aircraft type jet engine. The agency believes that at this time there is no need to apply an obsolescence allowance to the plants; however, this position may change in the future if technological discoveries advance the state of the art to a point where obsolescence is warranted.

The age and operating characteristics of hydro and steam plants varies a substantial amount. If the intent of the average cost per kilowatt of installed capacity concept is to bring the cost per kilowatt of older plants up to relatively present day levels then the agency believes that it is only proper and reasonable to recognize the fact that even though an older plant may generate, or be capable of generating, as much power as a newer plant it may well do so with much less efficiency. Since this lack of efficiency, or obsolescence, would have an effect on the plant's market value, the agency believes that an allowance should be made for this fact. The example of the residential home can again be used to illustrate this point. A home of 1,000 square feet with a very fuel efficient heating system would be worth more than a comparable size home with an outdated, inefficient furnace.

The agency presently measures this obsolescence by establishing a standard and comparing the specific plant to the standard. The amount the specific plant varies from the standard is the amount the plant is obsolete.

One of the standards used for this measurement of obsolescence is called the "plant factor." The plant factor compares how much electrical energy a generating plant actually produced in a year to the maximum amount of energy it could have produced. For example, if a plant could have produced 1,000,000 KWH but only produced 500,000 KWH it was operating at a plant factor of 50%.

The plant factor is a good indicator of a generating plant's obsolescence because it actually measures obsolescence in two ways, economic and functional. If there is a low demand for a generating plant's product, electricity, then the plant will be operated at less then full capacity; hence a low plant factor. This lack of demand, or economic obsolescence, impacts a property's market value in much the same manner as a hotel built on a secondary road would most likely have a lower market value than one built near a busy freeway.

The plant factor would also recognize the downtime a generating plant experiences for maintenance and repair. It is logical to assume that an older plant would experience more time out of service for repair than a new one; simply because the component parts of the older plant have been exposed to more wear and tear, or are of an outmoded design which is not as reliable as a newer design. Another term for this frequency of repair and maintenance would be functional obsolescence. Thus, the more a generating plant is down for maintenance, the lower its plant factor would be, and the more functional obsolescence would be applied to this plant.

In order to compute the standard factor, the agency proposes to look at those plants which were used to compute the national average cost per kilowatt of installed capacity. Since these are the plants which serve to make up the basis of the additional value, it is only reasonable to use the operating characteristics of these same plants to compute the standard plant factor. The proposed rules detail how this standard is to be computed, and it is a very simple mathematical formula. The formula multiplies the installed capacity of the various plants in kilowatt hours (KWH) times the number of hours in a year; the product of this computation is the maximum amount of power the plant could have generated in a year. The amount of KWH the plant actually produced is then divided by this optimum generation amount and a percentage developed. This computation is done for all generating plants within the study period. The ten plants with the highest or best plant factor are then selected out of the study and an average computed of their plant factors. The use of ten plants insures that a stable index will be used each year without abrupt fluctuations due to one or two plants operating under highly unusual circumstances. This then becomes the standard. Plant factors are then computed in the same manner for each hydro or steam generating plant which would have additional cost dollars added to it because of the application of the average cost per kilowatt of installed capacity computation. Plant factors are computed for the most recent three years, and then averaged. A three year time span is used in order to minimize the downtime effect a major overhaul or repair due to an accident might have on the net generation of a plant. This three year average plant factor is then compared to the standard plant factor. The amount or percent the three year average deviates from the standard is the amount of obsolescence measured by the application of this method. This percentage will then be used to reduce the gross additional value added to the hydro-electric plants. Steam-electric plants will have an additional obsolescence factor computed.

Hydro-electric plants differ from steam plants in that hydro plants essentially use no fuel, they are powered by the movement of water. Steam electric plants on the other hand must burn a fuel to create heat to make steam; just as their name implies. Therefore, one of the measures of the efficiency of such a plant is the amount of fuel needed to produce a unit of electric power. This is called the "thermal efficiency factor." Since the fuels used in steam-electric plants vary; coal, oil, natural gas; the only common attribute of the various fuels is that they all contain British Thermal Units (BTU). The computation of the thermal efficiency factor measures the numbers of BTU's a plant would require to produce one KWH of electric power. This measure of a steam plants efficiency is a very viable measure of obsolescence, particularly in light of current costs of energy. A plant which requires a greater amount of fuel to produce a KWH would be less attractive to a buyer than one which could generate a KWH using a very small amount of fuel.

The thermal efficiency standard will be computed by again selecting the ten plants using the least amount of fuel or BTU's to produce a KWH from all those plants which comprise the study used to calculate the average cost per kilowatt of installed capacity. This standard will then be compared to the actual thermal efficiency of the subject steam electric plants.

There is no need to use a three year average thermal efficiency factor because the operating characteristics of a plant do not vary from year to year with respect to the utilization of fuel. The plants are much like an automobile in that a particular model of car may be rated at 20 MPG; one year it may actually get 18 MPG, another 22 but it would not suddenly jump up to 40 MPG. The amount or percentage that the subject plant deviates from the standard is the amount of obsolescence in the subject plant as measured by this thermal efficiency factor.

These two measures of obsolescences for steam electric plants; plant factor and thermal efficiency factor, are then averaged and this average obsolescence percentage is used to reduce the gross additional value added to the plant. Note that the agency is not proposing to adopt new indicators of obsolescence but merely to revise the period used to calculate these indicators.

EXHIBIT I

STATEMENT OF NEED AND REASONABLENESS

CAPITALIZATION RATE WORK-UP

A. The figures used in the study on the capitalization of the average utility were obtained from the Moodys Public Utility Manual Special Features Section and represent historic value figures. The results showed a make-up of 52% debt, 9% preferred stock and 39% common stock for the average utility.

B. The rates used in the Cost of Money Study represent the average of three different kinds of utility bonds. This study considered the imbedded debt of utilities and calculated a rate of 10.15%.

C. The indicated rates shown in the Common Stock Yield and Growth Study represent yields obtained by adding the dividend yield to the percent of earnings per share increase over a ten year moving average. This study not only considers dividend yield but appreciation in per share prices. The average indicated rate was calculated to be 13.78%.

D. The rate shown in Preferred Stock Study is the dividend yield only and does not reflect appreciation in the stock price. The average yield rate is shown as 11.13%.

E. The resulting capitalization rate calculation was obtained by adding a weighted debt cap rate percentage, a weighted preferred stock cap rate percentage, and a weighted common stock yield percentage.

CAPITALIZATION OF AVERAGE UTILITY WORKSHEET

ALL INFORMATION FROM 1983 MOODY'S PUBLIC UTILITY MANUAL SPECIAL FEATURES SECTION

10 YEAR STUDY - HOW THE AVERAGE UTILITY IS CAPITALIZED

	YEAR	PERCENT OF DEBT	PERCENT OF PREFERRED	PERCENT OF COMMON
Electric Companies	1974	55.0%	12.7%	32.3%
	1975	53.5%	12.8%	33.7%
	1976	52.5%	12.9%	34.6%
	1977	50.9%	13.1%	36.1%
	1978	50.5%	12.9%	36.6%
	1979	51.4%	12.7%	35.8%
	1980	51.3%	12.7%	36.2%
	1981	51.8%	11.9%	36.3%
	1982	50.3%	11.7%	38.0%
	1983	48.1%	11.5%	39.7%
	Average	51.5%	12.5%	35.9%
Transmission Companies	1974	59.6%	5.8%	34.6%
	1975	58.3%	5.3%	36.4%
	1976	55.5%	5.5%	39.1%
	1977	51.9%	4.9%	43.2%
	1978	52.4%	5.5%	42.1%
	1979	51.3%	5.3%	42.3%
	1980	51.5%	5.7%	42.8%
	1981	52.1%	4.9%	43.0%
	1982	51.2%	5.4%	43.4%
	1983	46.6%	6.4%	47.0%
	Average	53.0%	5.5%	41.4%
Distribution Companies	1974	56.0%	8.3%	35.8%
	1975	54.9%	8.8%	36.4%
	1976	53.0%	9.4%	37.6%
	1977	51.0%	9.9%	39.1%
	1978	48.3%	10.3%	41.3%
	1979	47.1%	9.8%	43.1%
	1980	47.5%	9.0%	43.5%
	1981	50.2%	7.9%	41.9%
	1982	50.3%	7.3%	42.4%
	1983	47.2%	7.3%	45.5%
	Average	50.5%	8.8%	40.7%
Rounded Average of Three Industry Averages		52 %	9 %	39 %

10 YEAR PREFERRED STOCK YIELD

YEAR	YIELD IN PERCENT
1974	9.95%
1975	10.63%
1976	9.12%
1977	8.43%
1978	9.03%
1979	9.76%
1980	12.82%
1981	15.11%
1982	14.42%
1983	12.06%
Average	11.13%

CAPITALIZATION OF AVERAGE UTILITY WORKSHEET

ALL INFORMATION FROM 1982 MOODY'S PUBLIC UTILITY MANUAL SPECIAL FEATURES SECTIONS

10 YEAR STUDY - COMMON STOCK YIELD AND GROWTH IN EARNINGS

YEAR	AVERAGE MARKET PRICE	DIVIDEND PER SHARE	DIVIDEND YIELD PER CENT	EARNINGS PER SHARE	5 YEAR MOVING AVERAGE EARNINGS PER SHARE	% EARNINGS PER SHARE INCREASE	INDICATED RATE
1974	$48.26	$4.83	10.01%	$ 7.63	$ 7.39	1.93%	11.94%
1975	$51.25	$4.97	9.70%	$ 7.77	$ 7.56	2.30%	12.00%
1976	$60.10	$5.18	8.62%	$ 7.86	$ 7.71	1.98%	10.60%
1977	$67.55	$5.54	8.20%	$ 8.83	$ 7.93	2.85%	11.05%
1978	$63.54	$5.81	9.14%	$ 8.59	$ 8.16	2.64%	11.78%
1979	$60.28	$6.22	10.32%	$ 8.95	$ 8.42	3.19%	13.51%
1980	$54.80	$6.58	12.01%	$ 8.98	$ 8.64	2.62%	14.63%
1981	$55.41	$6.99	12.62%	$10.46	$ 9.16	6.02%	18.64%
1982	$63.56	$7.43	11.69%	$10.90	$ 9.58	4.59%	16.28%
1983	$74.04	$7.87	10.63%	$11.88	$10.23	6.78%	17.41%
Average	$59.88	$6.14	10.29%	$ 9.19	$ 8.48	3.49%	13.78%

15 YEAR COST OF MONEY STUDY

YEAR	AVG. YIELD ALL UTILITY BONDS	AVG. YIELD NEWLY ISSUED BONDS	AVG. YIELD NEW GAS LIGHT & POWER
1969	7.99%	7.07%	7.98%
1970	8.85%	8.76%	8.79%
1971	7.71%	7.47%	7.70%
1972	7.46%	7.16%	7.50%
1973	7.88%	7.45%	7.91%
1974	9.21%	8.36%	9.59%
1975	9.76%	8.90%	9.97%
1976	8.80%	9.06%	8.92%
1977	8.38%	8.17%	8.43%
1978	9.22%	9.21%	9.30%
1979	10.64%	10.39%	10.85%
1980	13.09%	13.23%	13.46%
1981	16.30%	16.28%	16.31%
1982	14.56%	15.55%	14.93%
1983	12.53%	12.77%	12.70%
	10.16%	9.99%	10.29%
Average Cost of Three Money Indicators			10.15%

	COMPUTATION OF AVERAGE CAP. RATE	CAP. RATE
1.	Average Utility Debt Cost	10.15%
2.	Average Debt Percent of Capitalization	52%
3.	Weighted Debt Cap. Rate Factor	5.28%
4.	Avg. Utility Preferred Stock Yield	11.13%
5.	Avg. Preferred Stock Percent of Capitalization	9.00%
6.	Weighted Preferred Stock Cap. Rate Factor	1.00%
7.	Average Utility Equity Return	13.78%
8.	Avg. Equity Percent of Capitalization	39%
9.	Weighted Equity Capitalization Rate Factor	5.37%
	Avg. Utility Cap. Rate	11.65%
	Rounded to	11.50%

SP:N2