BEFORE THE
TENNESSEE REGULATORY AUTHORITY

In The Matter of ATMOS ENERGY CORPORATION	)
For approval of Adjustments to its Rates and Revised	) Docket No.07-00105
Tariff.	)

DIRECT TESTIMONY OF
CHARLES W. KING

CONCERNING
DEPRECIATION AND COST OF REMOVAL

On behalf of
Office of the Attorney General
Consumer Affairs and Protection Division

July 21, 2007

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DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 37-year history, members of the firm have participated in over a thousand proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Office of the Attorney General.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to recommend depreciation rates for the Tennessee gas properties and the shared services plant of Atmos Energy ("Atmos" or "the Company"). In the process, I will review and critique the depreciation study submitted by Donald S. Roff on behalf of Atmos.

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I began by requesting the Company to provide me with the same data that it had provided its consultant, Mr. Roff. Having reviewed the data, I then input it into our Company's depreciation analysis software to test the validity of Mr. Roff's results. I also prepared a number of data requests and carefully read the Company's responses. Independently, I evaluated the approach used by Mr. Roff to the treatment of salvage and retirement costs, and I developed the alternatives that I shall discuss in my testimony. I then prepared the schedules found in my Exhibits CWK-1 and CWK-2. The calculations underlying these schedules are found in my workpapers. The workpapers were prepared and the calculations performed either by me or under my direction.

SUMMARY OF RECOMMENDATIONS

Q. WHAT DEPRECIATION RATES DO YOU RECOMMEND?

A. My recommended depreciation rates are set forth in Schedules 1 of my two exhibits, CWK-1 which pertains to Tennessee plant, and CWK-2 which covers shared services plant. A comparison of my accruals with the existing accruals and the Company's proposed accruals is a follows

Table 1
Category Depreciation Accruals based on 9/30/06 Plant

	At Existing Rates	At Company Proposed Rates	At AG Recommended Rates
TN Transmission	$ 408,068	$ 391,526	$ 292,767
TN Distribution	10,007,392	7,795,985	5,084,420
TN General	212,878	439,074	428,978
Tennessee Plant	$ 10,628,338	$ 8,626,585	$ 5,806,165
Shared Services	$ 19,615,241	$ 22,277,742	$ 21,414,931

Q. HOW DO YOUR RECOMMENDED DEPRECIATION RATES DIFFER FROM THOSE PROPOSED BY MR. ROFF?

A. My recommended depreciation rates differ from those proposed by Mr. Roff in the following respects:

- I recommend separate rates, accruals and reserves for depreciation and for future cost of removal.

- I recommend Average Life Group depreciation, while Mr. Roff recommends Equal Life Group depreciation.

- I recommend accrual for net removal costs based on the present value of those costs, while Mr. Roff proposes to charge ratepayers for future removal costs at their undiscounted nominal value.

- Finally, I recommend a change in Atmos's accounting treatment of third party reimbursements. Such reimbursements should be credited to the depreciation reserve rather than subtracted from plant in service. They would then be treated as positive salvage, thereby reducing the Company's requirement for removal cost allowances.

DEPRECIATION- GENERAL

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.
[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for salvage, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. **CAN DEPRECIATION BE CALCULATED WITH PRECISION?**

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q. HOW DOES THIS JUDGEMENTAL CHARACTERISTIC OF DEPRECIATION INFLUENCE THE AUTHORITY'S APPROACH TO THE SUBJECT?

A. The Authority must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Authority must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. This is why, in this proceeding, the Authority must choose among depreciation rates that yield widely differing annual depreciation accruals.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. As traditionally applied, it is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered. With a few exceptions (e.g. vehicles, work equipment) most gas utility plant has a higher removal cost than its salvage value, so that recognition of net salvage in adds to the amount to be recovered. I must emphasize at this point that I recommend separating the accrual of net salvage from "pure" depreciation, i.e. capital recovery. This topic will be discussed in some detail later in my testimony.

Finally, virtually all major utilities, including Atmos, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1 -.05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700{,}000}{10 \text{ years}} = \$70{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70{,}000}{\$1{,}000{,}000} = 7.0\%$$

The foregoing illustrates the traditional formulation of depreciation rates. As I shall discuss later in this testimony, I am recommending that depreciation be separated from negative net salvage recovery.

SERVICE LIFE ESTIMATION

Q. WHAT INFORMATION DID YOU RECEIVE FROM ATMOS TO ASSIST YOU IN YOUR STUDY OF PLANT ACCOUNT SERVICE LIVES?

A. I received the record of plant additions, retirements, transfers, adjustments, and balances for each account each year as far back as 1950. This information I refer to as “vintage data.” For most of the major shared services accounts, I also received a record of plant retirements by year of placement. I refer to this information as “actuarial data.”

Q. WERE THERE ANY PROBLEMS WITH THESE DATA?

Yes. For many of the smaller accounts there was insufficient plant activity, that is, additions and retirements, to perform reliable statistical studies.

Q. WHAT LIFE STUDIES DID YOU PERFORM?

A. I performed three types of life studies for each account for which there were sufficient data, Simulated Plant Record ("SPR") studies, actuarial studies and Geometric Mean Turnover ("GMT") analyses.

Q. PLEASE DESCRIBE THE SPR STUDIES.

The SPR study procedure is a trial and error mechanism whereby a computer program fits alternative Iowa Curves and average service life combinations to the record of plant additions, retirements and balances.

The SPR – Balances program measures the degree to which various combinations of Iowa curves and service lives applied to the plant additions each year yield the plant balances in subsequent years. The degree of fit is measured by sum of the squared differences between the predicted plant balances and the actual balances. When the square root of those differences is divided into the average of the actual balances, the result is a "conformance index." The reciprocal of the conformance index is called the "index of variation." The lower that index, the better the fit.

Another test of SPR results is the "retirements experience index," which measures the maturity of the account under each curve-life combination. A retirements experience index of 100 indicates that the account has experienced a full life cycle, that is, all of the plant placed in the oldest vintage is now retired. An index of 50 suggests that the account is only half way through its life cycle. In general, SPR results with retirements experience indexes less than 50 are considered to have little value, while those over 75 are considered of significant value.

Q. PLEASE DESCRIBE THE ACTUARIAL STUDIES.

A. Actuarial studies are far more precise than SPRs, but they require considerably more data and, to be effective, the data must be fairly "thick," that is, they must reflect a fairly large number of retirements. Actuarial studies use the record of retirements by date of placement, which means that the age of each retirement must be known. With this knowledge, it is possible to compute the history of retirements at each age, and from that record, to fit Iowa curve and service life combinations that reproduce that history.

Unfortunately, the actuarial data are quite thin for Atmos's Tennessee plant. I was able to perform actuarial studies for only two accounts, and even there, the results are not particularly satisfactory. The shared services data are much thicker, and I was able to perform actuarial analyses for all but three of the accounts.

Q. PLEASE DESCRIBE THE GEOMETRIC MEAN TURNOVER METHOD.

A. The Geometric Mean Turnover Method ("GMT") is one of several turnover methods of life analyses. "Turnover" means the period of time that it takes for the plant in an account to retire fully. The advantage of turnover methods is that they study retirements in relation to plant balances irrespective of the age of the property retired.[3] The GMT method is based on ratios of annual additions and retirements to plant balances. The life estimate is the reciprocal of the geometric mean of the additions and retirements ratios averaged over a period of years.[4] The GMT method is very useful in detecting service lives and service life trends. Turnover methods assume a uniform retirement dispersion, in other words the results of turnover analyses focus on the fundamental life statistic, unencumbered by 31 possible Iowa curve retirement dispersion estimates.

Q. IS THERE A SOURCE WHERE THE AUTHORITY COULD FIND DETAILED EXPLANATIONS OF THESE STUDY METHODOLOGIES?

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[3] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Depreciation Manual"), p. 81.

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") has published a manual titled, "Public Utility Depreciation Practices," the latest edition of which is dated August 1996. This manual provides a full description of the theories behind depreciation, the procedures for studying it, the application of depreciation, and its effect on a utility's financial performance.

Q. DID THESE STUDIES YIELD PRECISE INDICATIONS OF SERVICE LIFE?

A. No. In many cases, the best fits were associated with curve and life combinations that had inadequate retirement experience indices.

Q. WHAT WERE THE RESULTS OF YOUR SERVICE LIFE ANALYSES OF ATMOS'S TENNESSEE PLANT?

A. The results of my service life analyses of Atmos's Tennessee plant are set forth on Schedule 2 of Exhibit CWK-1. In this schedule, I have presented the Atmos study life and curve shape parameters which can be compared with my results.

Schedule 2 shows that there are insufficient data to conduct meaningful analyses of the transmission accounts. My SPR life indication for the largest distribution account, Mains, is 58 years, as compared with 55 years recommended by Mr. Roff. My SPR and GMT indications for the second largest account, Services, bracket Mr. Roff's 48 years. The life indications for the meters and meter installation accounts suggest that meter installations have a much longer life than meters, a counter-intuitive conclusion.

With the exception of the Structures account, all of my general plant life indications are longer than Mr. Roff's selected life parameters. However, general

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[4] Id., p. 91.

plant data are often misleading owing to the difficulty in maintaining accurate records for accounts that consist of many small pieces of equipment.

Q. WHAT LIFE ESTIMATES DO YOU RECOMMEND FOR ATMOS'S TENNESSEE PLANT?

A. Given the limitations of Atmos's data and my desire to limit the areas of controversy, I recommend accepting Mr. Roff's life and curve shape parameters for Atmos's Tennessee properties.

Q. WHAT WERE THE RESULTS OF YOUR STUDIES OF SHARED SERVICES PLANT?

A. The shared services data are much thicker and therefore more suitable for analysis than the Tennessee data. As a consequence, I was able to perform actuarial studies for all but three of the accounts. With one exception, my analyses confirm the life parameters proposed by Mr. Roff. That exception is Account 399.03, Network Hardware, where my study indicates a totally counter-intuitive 73 years. This result stems from the thinness of the retirements data for this account.

Q. WHAT LIFE ESTIMATES DO YOU RECOMMEND FOR ATMOS'S SHARED SERVICES PLANT?

A. I recommend accepting Mr. Roff's parameters for the shared services accounts.

EQUAL LIFE GROUP DEPRECIATION

Q. WHY ARE YOU DISCUSSING EQUAL LIFE GROUP DEPRECIATION?

A. I am discussing Equal Life Group depreciation because that is the procedure that Mr. Roff has used in developing his proposed depreciation rates for Atmos's plant, both the Tennessee property and the shared services plant.

Q. WHAT IS EQUAL LIFE GROUP DEPRECIATION?

A. Equal Life Group ("ELG") depreciation is based on the concept that the units of plant within a "mass property" account do not retire at once, but rather in a dispersed manner over a period of many years. ELG attempts to depreciate the short-lived units within each vintage of plant over their expected life span and the long-lived units over their much longer life. This is done by applying an assumed retirement dispersion pattern and average service life onto the plant balance of each vintage. These retirement dispersions are described by a series of "Iowa Curves."

Equal life groups are not maintained as sub-accounts, nor are they even identified as discrete quantities. Rather, ELG is applied by weighting the accrual rate of each vintage by the hypothetical dispersion of units among equal life groups. No record is kept of the actual retirements from each of these hypothetical ELGs.

Q. WHAT IS THE ALTERNATIVE TREATMENT TO ELG?

A. The alternative treatment is the Average Life Group ("ALG") procedure, also called the Vintage Group procedure. This method of computing depreciation rates is currently employed by Atmos,[5] as well as almost all other major gas or electric utilities. The ALG procedure assumes that all units of plant in a given vintage have a common retirement date and therefore a common remaining life.

Q. WHAT IS THE EFFECT OF IMPLEMENTING ELG DEPRECIATION IN

LIEU OF ALG DEPRECIATION?

A. ELG has the effect of charging higher depreciation rates in the early years of a vintage's life than ALG and lower depreciation rates in the later years. If every vintage of plant throughout history contained the same amount of investment as every other vintage, there would be no difference between ELG and ALG accruals. That is because the accelerated depreciation on short-lived ELGs would be offset by the decelerated depreciation on long-lived ELGs.

But vintages of plant are not the same size. Generally, each new vintage is larger than its predecessor. This is because the system is growing, but even if there were no system growth, inflation would cause the recent vintages to contain more dollars than the older vintages. As a consequence, the average dollar in any plant category is typically somewhat newer than the midpoint of the life span of the overall plant. As a result, ELG virtually always increases depreciation rates and accruals.

Q. **WHAT IS YOUR ASSESSMENT OF ELG DEPRECIATION?**

A. In theory, ELG more precisely reflects the pattern of retirements from "mass property" accounts in which many units retire according to a predictable pattern that can be described by an Iowa curve. For most of Atmos' plant accounts, however, this procedure represents "specious precision" because the units of plant within each vintage do not retire in a continuous flow consistent with an Iowa curve. Certainly, this is the case with the Structures and Improvements account, but it also applies to accounts that appear to reflect "mass property" characteristics.

[5] Atmos's current depreciation rates are based on a study of plant date December 31, 1990 and approved by the TRA in 1992. That study made no mention of ELG. In Docket No. 05-000258 Atmos submitted an SSU study that used ELG, but the TRA adopted Staff's calculation, which used ALG.

To illustrate, let us consider the Distribution Mains account (A/C 376), which is Atmos' largest single account and the one that should show the most even retirements pattern over time. In 2003, there were $59,997 in retirements from this account. In the next year, 2004, there were $939,083 in retirements, 15 times the 2003 number. Then, in 2005 retirements were $39,288, less than a twentieth the previous year. In 2006, retirements jumped again, this time to $311,798. To treat this account with the ELG procedure is improper because retirements clearly do not follow the predicted pattern of the Iowa curves. Most of the other accounts, being much smaller, show even greater variability to the pattern of retirements.

Q. IS ELG TYPICALLY USED TO DEPRECIATE GAS PLANT?

A. No. ELG is generally not used by gas distribution companies in depreciating their plant.

Q. HAS ELG BEEN USED BY ANY OTHER UTILITY INDUSTRY?

A. Yes. It has been used by the telephone industry since 1981.

Q. HOW WAS ELG IMPLEMENTED BY THE TELEPHONE INDUSTRY?

A. The Federal Communications Commission ("FCC") authorized telephone companies to employ ELG in its Order of December 5, 1980 strictly on a going-forward basis beginning with 1981 vintages of plant.[6] All existing vintages would continue to be depreciated throughout their remaining lives on an ALG basis. This going-forward approach was necessitated by the absence of depreciation reserve records on an account and vintage basis and on the impropriety of introducing a new depreciation procedure "mid-stream" during the life of a vintage. The FCC also required that all depreciation rates be re-prescribed every

[6] Report and Order, FCC Docket No. 20188, December 5, 1980.

three years to reflect changed parameters and the fact that the ELG depreciation rate for each vintage of plant declines each year throughout its life. The FCC also allowed telephone companies to submit "technical updates" to these ELG rates between the triennial re-prescriptions so long as they did not change the basic life, salvage and survivor curve parameters.

Q. IF THE TRA WERE TO AUTHORIZE THE USE OF ELG FOR ATMOS, WOULD THE SAME IMPLEMENTATION PROCEDURES BE APPROPRIATE?

A. Yes, although I do not recommend ELG. Like AT&T (which in 1981 included all Bell local telephone companies), Atmos has no record of book depreciation accruals by vintage of plant. It is no more appropriate now to change depreciation procedures in mid-stream than it was in 1980. Depreciation is a process of allocating the recovery of original investment rationally over the life of the plant. It is altogether inappropriate to use one method, ALG, for the first part of a vintage's life and then change to a more accelerated procedure, ELG, for the latter portion of its life. This practice would not be a "rational" allocation of recovery over the plant's life, and it would result in a severe intergenerational inequity. Through the application of the remaining life technique, it would require the generation of ratepayers immediately following the implementation of ELG to recover the shortfall in depreciation reserve that ELG creates when superimposed on a pre-existing ALG depreciation program.

Q. WOULD THERE BE ANY FURTHER PROBLEMS ASSOCIATED WITH IMPLEMENTING ELG?

A. Yes. Under ELG, the depreciation rate for each vintage declines each year as the short-lived life groups retire. This means that the each year's depreciation rate is no longer appropriate for the next year. The FCC solved this problem by conducting full-scale reviews of depreciation rates every three years and by allowing the companies to file for annual technical updates. The TRA would have to do the same thing. If the TRA were to allow ELG, it could spend considerably more time on depreciation matters than it does now.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO ELG DEPRECIATION?

A. I recommend that the TRA reject Atmos' application for ELG depreciation and retain the existing ALG procedure.

<u>SEPARATION OF DEPRECIATION FROM REMOVAL COST ACCRUAL</u>

Q. WHY ARE YOU RECOMMENDING THAT ATMOS'S DEPRECIATION RATES AND ACCRUALS BE SEPARATED BETWEEN PLANT-ONLY DEPRECIATION AND REMOVAL COSTS?

A. This separation is a necessary first step towards rationalizing the processes for recovering capital investment, i.e. depreciation, and for accruing the cost of removing plant. As I shall discuss, Atmos has already adopted this separation for financial reporting purposes. I propose that this separation be adopted for regulatory purposes as well. Depreciation serves a totally different function than removal cost allowances. Depreciation recovers past investment, while removal cost allowances seek to build a reserve against future costs.

Q. WHAT HAS BEEN THE RELATIONSHIP BETWEEN DEPRECIATION AND REMOVAL COSTS IN THE PAST?

A. All Tennessee utilities, including Atmos, have employed a procedure that combines depreciation, salvage and removal costs. This procedure adjusts depreciation rates to capture an estimate of future "net salvage" costs. Net salvage is the difference between positive salvage and removal costs. In a gas utility, there is very little positive salvage, so most "net salvage" is negative, which means that the depreciation rate is increased to capture future removal costs.

The procedure begins with a "net salvage ratio," which is the ratio of net salvage to plant in service. This ratio is used to inflate (or deflate in the case of positive salvage) the amount to be recovered through depreciation. The "whole life" depreciation rate is calculated as follows:

$$\frac{\text{Plant investment x (1-net salvage ratio)}}{\text{Average service life}} = \text{Depreciation rate}$$

Most utilities use the remaining life technique, but the effect of the net salvage ratio is the same:

$$\frac{\text{(Plant investment x (1-net salvage ratio)) – Depreciation reserve}}{\text{Remaining life}} = \text{Annual accrual}$$

$$\frac{\text{Annual accrual}}{\text{Plant investment}} = \text{Depreciation rate}$$

Q. WHY IS IT APPROPRIATE TO CHANGE THIS PROCEDURE NOW?

A. Recent pronouncements from the Financial Accounting Standards Board ("FASB"), the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC") cast considerable doubt on the traditional practice of capturing net removal costs through adjustments in the depreciation rates. Furthermore, there are serious problems with the traditional method of calculating net salvage allowances, which I will discuss later in this testimony.

1. <u>FINANCIAL ACCOUNTING STANDARDS BOARD</u>

Q. WHAT PRONOUNCEMENTS FROM FASB CAST DOUBT ON THE TRADITIONAL PRACTICE OF CAPTURING NET REMOVAL COSTS THROUGH ADJUSTMENTS IN DEPRECIATION?

A. In June 2001, FASB promulgated Statement of Financial Accounting Standards No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations*. In March 2005, it issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143.*

Q PLEASE DESCRIBE SFAS 143.

A. SFAS 143 addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."[7] A good example of such an obligation is the requirement to dismantle, entomb or decontaminate a nuclear generating plant.

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the "fair value" of that cost, defined as the cost of a contract with an independent party to retire the asset, negotiated when the asset is installed. In effect, this fair value is the present value of the future cost, using as the discount factor the risk-adjusted interest rate when the liability was recognized. The company also adds a value corresponding to that liability to the asset being booked. The initial fair value estimate is considered to be part of the original cost of the asset, which in turn is depreciated over the asset's life.

[7] SFAS 143, ¶2

The annual expense associated with this liability consists of two parts. One is the depreciation of the liability, which is the present value of the liability divided by the life of the asset. The second expense is the annual accretion in the present value of the liability, similar to interest expense.

Q. CAN YOU DESCRIBE HOW THIS PROCESS WORKS?

A. Assume that Atmos installs a section of main that it expects to last for 40 years. Assume further that Atmos is legally obligated to remove that main when it retires. The estimated removal cost at the time of removal is $1 million. Atmos would record an asset and book a liability for this retirement cost, not at $1 million, but at $1 million discounted at the risk-adjusted interest rate. If the risk-adjusted interest rate over 40 years is 5 percent, then the asset and the liability would be booked as $142,046 ($1 mil/1.05^{40})

Each year, Atmos would show two items of expense. The first would be the depreciation of the asset, $142,046/ 40 years = $3,551. The second expense would be the annual accretion in the present value of the liability. In this instance, it would be $1 million times $1/1.05^{39} – 1/1.05^{40}$. This is $1 million x (0.149148 - 0.142046 =.00710) or $7,100. Total expense in the first year of operation would be $3,551 + $7,100 = $10,651**.**

The first expense item, the depreciation of the initial Asset Retirement Obligation ("ARO"), stays the same each year throughout the asset's life. The second item, the annual accretion in the liability, increases as the present value factors increase.

Q. WHAT IS FASB INTERPRETATION NO. 47?

A. FASB Interpretation 47 was issued in March 2005 to clarify "that the term *conditional asset retirement obligation* as used in FASB Statement 143…refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity." The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can reasonably be estimated.

Q. DOES FASB INTERPRETATION NO. 47 SIGNIFICANTLY CHANGE THE UTILITIES' INTERPRETATION OF SFAS 143?

A. It should cause the utilities to reconsider their evident dismissal of what appear to be legal obligations whose specific date of retirement is indeterminate. The Interpretation emphasizes that if there is any doubt about the date of the retirement, that doubt should be reflected in the discount factor. It should not become an excuse for disregarding the obligation for purposes of SFAS 143.

Q. DOES SFAS 143 DEAL ONLY WITH LEGAL RETIREMENT OBLIGATIONS?

A. Most of SFAS 143 deals with legal retirement obligations. However, in the "Background Information and Basis for Conclusions" section of the document is found a paragraph that address non-legal obligations, and specifically non-legal obligations of rate-regulated entities. Paragraph B73 of that section states as follows:

> Many rate-regulated entities currently provide for the costs related to asset retirement obligations in their financial statements and recover those amounts in rates charged to their customers. Some of those costs related to asset retirement obligations are within the scope of this Statement; others are not with in the scope of this Statement and, therefore, cannot be recognized as liabilities under its provisions. The objective of including those amounts in rates currently charged to customers is to allocate costs to customers over the lives of those assets. The amount charged to customers is adjusted periodically to reflect the excess or deficiency of the amounts charged over the amounts incurred for the retirement of long-lived assets. <u>The Board concluded that if asset retirement costs</u>

> <u>are charged to customers of rate-regulated entities but no liability is recognized, a regulatory liability should be recognized if the requirements of Statement 71 are met.</u> (emphasis added)

Thus, the FASB states quite clearly that a separate regulatory liability should be recognized for non-legal asset retirement obligations if the costs of those obligations are being recovered in rates.

Q. WHAT IS THE RELEVANCE OF SFAS 143 TO THE ISSUES IN THIS PROCEEDING?

A. There are three ways in which SFAS 143 is relevant to this proceeding. First, with respect to legal AROs, SFAS 143 establishes a clear-cut procedure for recording these obligations on Atmos's balance sheet and a procedure for recognizing them in income statements. This Authority does not necessarily have to adopt these procedures for ratemaking purposes. However, I believe there should be a clear and demonstrable reason for overriding SFAS 143 if the Authority decides not to use these accounting practices for regulation. I will discuss this issue in more detail later in this testimony.

The second way in which SFAS 143 is relevant relates to paragraph B73, quoted above. It is clear that the accounting community has determined that even non-legal retirement obligations should be separately identified as regulatory liabilities.

Finally, SFAS 143 sets forth the principles that might govern the recognition and accrual of reserves for future retirement obligations, that is, future removal and dismantlement costs. Specifically, SFAS 143 establishes that future costs should <u>not</u> be recognized in the current period at their future value, but rather at their present value.

2. <u>FEDERAL ENERGY REGULATORY COMMISSION</u>

Q. WHAT PRONOUNCEMENTS OF THE FERC CAST DOUBT ON THE CONTINUED RECOVERY OF REMOVAL COSTS THROUGH DEPRECIATION CHARGES?

A. On April 9, 2003, FERC issued Order No. 631. It relates to accounting, financial reporting, and rate filing requirements for asset retirement obligations.

Q. PLEASE DESCRIBE FERC ORDER 631.

A. Most of FERC Order 631 deals with the effects of SFAS 143, which prescribes the treatment of future costs associated with legal obligations to retire assets. As noted, that standard requires entities to declare those future obligations as liabilities on their balance sheets, and it establishes procedures for recognizing those obligations on income statements.

FERC declined to apply the SFAS 143 standards to removal costs that were not legal obligations. It did, however, require all jurisdictional entities to maintain separate records of costs of removal for non-legal retirement obligations when allowances for these costs could be identified. Accordingly, the FERC added a new paragraph 2C to its instructions with regard to Account 108 – "Accumulated Provision for Depreciation of Electric Utility Plant:"

> Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 108, Accumulated provision for depreciation of electric utility plant.

This new provision necessarily requires utilities to identify separately annual additions and deletions from this account. Each utility must show the annual accrual for removal costs and the annual amount of removal costs incurred.

This requirement is a major change from the previous treatment of removal costs. In the past, removal costs have usually been incorporated into depreciation. Removal cost allowances were recorded as part of depreciation expense, and plant removal expenditures were charged to depreciation reserves. Only through careful analysis has it been possible to identify how many dollars of annual depreciation went to recover past capital expenditures – true depreciation – and how many dollars were accrued to offset future removal costs.

Q. WHAT IS THE RELEVANCE OF FERC ORDER 631 TO THE ISSUES IN THIS PROCEEDING?

A. FERC Order 631 builds into the regulatory accounting system the requirements of SFAS 143, setting the stage for regulators to apply SFAS 143 for ratemaking purposes. Additionally, FERC Order 631 establishes a requirement to account separately for non-legal retirement obligations, specifically to separate depreciation reserves between capital recovery and reserves for future removal costs.

Several qualifiers are appropriate, however. First, FERC's accounting pronouncements are not binding on the TRA. The TRA can prescribe its own accounting standards. Additionally, it must be acknowledged that FERC has not yet decoupled removal costs accounting from depreciation. While it requires utilities to maintain subsidiary records of removal cost accruals, those accruals are still captured in the depreciation reserve.

3. SECURITIES AND EXCHANGE COMMISSION

Q. WHAT DIRECTIVES FROM THE SEC ARE RELEVANT TO THE ISSUES IN THIS PROCEEDING?

A. The accounting profession was apparently uncertain as to the interpretation of paragraph B73 of SFAS 143, and the firm of Deloitte and Touche took the lead in soliciting an interpretation from the SEC. The SEC then issued directives that all rate-regulated utilities must report as "regulatory liabilities" the accrual of reserves against future removal costs.

Q. PLEASE DEFINE THE TERM "LIABILITIES."

A. Liabilities are defined by FASB as "probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events."[8]

Q. PLEASE DEFINE "REGULATORY LIABILITIES."

A. Paragraph 11 of Statement of Financial Accounting Standards No. 71 describes regulatory liabilities as follows:

> Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:
>
> a. A regulator may require refunds to customers. Refunds that meet the criteria of paragraph 8 (accrual of loss contingencies) of FASB Statement No. 5, *Accounting for contingencies,* shall be recorded as liabilities and as reductions of revenue or as expenses of the regulated enterprise.
>
> b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates.

[8] FASB Concepts Statement No. 6, *Elements of Financial Statements.*

> Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred.
>
> c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. That would be accomplished, for rate-making purposes, by amortizing the gain or other reduction of net allowable costs over those future periods and reducing rates to reduce revenues in approximately the amount of the amortization. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated enterprise shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

Q. HOW WOULD YOU DEFINE THE REGULATORY LIABILITY FOR REMOVAL COSTS?

A. This liability represents funds collected from ratepayers that the utility is expected to spend in the future to remove or dismantle plant. If it appears that the utility will not spend these funds for their intended purpose, then it should refund them to ratepayers by means of amortization that is recognized in rates.

Q. DOES ATMOS RECOGNIZE ITS REMOVAL COST RESERVE AS A REGULATORY OBLIGATION IN ITS FINANCIAL REPORTS?

A. Yes. Atmos's reports that as of September 30, 2006, it recognized $291.6 million on a company-wide basis as a regulatory liability for removal costs. [9]

Q. WHAT DO YOU CONCLUDE FROM THE FOREGOING SURVEY OF ACCOUNTING PRONOUNCEMENTS?

A. I conclude that the utilities in general, and Atmos in particular, are now being required to separate their accounting for removal costs from their accounting for

[9] Response to AG Data Request 2-57.

depreciation, and that they must record the outstanding removal cost reserve as a regulatory liability on their financial books.

Q. WHAT RECOMMENDATION DO YOU DRAW FROM THIS CONCLUSION?

A. I recommend that the TRA require Atmos to separate the accounting for removal costs from the accounting for depreciation and to recognize accrued removal cost reserves as regulatory liabilities for ratemaking purposes.

<u>First,</u> Atmos is already performing this separate accounting by reason of SFAS 143, FERC Order 631 and the SEC directives.

<u>Second,</u> the separation of removal cost accounting from depreciation will provide a much needed improvement in the transparency of Atmos's accounting reports. Heretofore, the incorporation of net salvage into depreciation rates has obscured its impact on accrual rates. Except through careful and detailed analysis it has been difficult to determine how much of the annual depreciation charge was related to recovery of capital – pure depreciation – and how much was accrued against future removal cost. It was virtually impossible to determine how much of the depreciation reserve related to removal costs and how much was recovered capital. With the total separation of removal cost accounting from depreciation, the Authority will have a very clear idea of the relative impact of these two very different functions.

<u>Third</u>, the greater transparency of the regulatory liability treatment of removal cost accrual will enhance the ability of the Authority to monitor these accruals so that if the money collected from ratepayers is not spent, it can be refunded, or alternatively, if the costs exceed the funds collected, adjustments can be made in the accruals to compensate the utility.

Fourth, the function of depreciation is very different from the function of removal cost accrual. Depreciation recovers costs that have already been incurred. Removal cost accrual is intended to build reserves for costs that have yet to be incurred. More importantly, depreciation deals with historical costs that are known and certain, while removal cost accrual deals with future costs that are unknown and estimated. Given these very disparate characteristics, it is altogether appropriate that these two accounting activities be separated entirely.

Q. HAVE YOU CALCULATED SEPARATE DEPRECIATION AND REMOVAL COST RATES?

A. Yes. Those rates are presented in Schedule 1 of Exhibit CWK-1. In order to calculate those rates, it is necessary to separate the removal cost reserves from the true depreciation reserves. I show this separation on Schedule 3 of Exhibit CWK-1. In response to a data request, Atmos provided the calculation of the removal cost reserve that it presents in its financial reports. That calculation showed the proportion of each Tennessee account's depreciation reserve that should be allocated to the removal cost reserve. Those proportions are presented on column C of Schedule 3. When applied to all of the relevant accounts, the Tennessee removal cost reserve comes to $18,773,453.

CALCULATION OF REMOVAL COST ALLOWANCES

Q. WHAT DO YOU MEAN BY "REMOVAL COSTS?"

A. Removal costs are any costs that are required to retire a unit of plant. They include dismantlement, physical removal and restoration of the site to a permanent, stable condition.

Q. DOES ATMOS INCUR REMOVAL COSTS?

A. Yes. On a company-wide basis, it incurs removal costs for most of its transmission and distribution plant accounts other than land and rights of way. It has reported Tennessee-specific removal costs for four of its distribution plant accounts.

Q. HOW DOES ATMOS'S DEPRECIATION WITNESS, MR. ROFF, TREAT REMOVAL COSTS?

A. Mr. Roff produces a ratio of future removal costs to the plant balance for each account that incurs these costs. He then inflates the amount to be recovered by that ratio. If the removal cost ratio is, for example, 50 percent, Mr. Roff increases the amount to be recovered by 50 percent. In this manner, he produces depreciation rates that recover both the original investment and the expected cost to remove that investment.

Q. DO YOU AGREE WITH THIS TREATMENT?

A. No. As I have discussed, recent accounting changes have mandated that the accrual of reserves for removal costs be separated from the recovery of original investment. This calls for separate depreciation and removal cost rates. The appropriate accrual for removal costs is through expense items separate from depreciation. The appropriate treatment of accrued removal cost reserves is to recognize them as regulatory liabilities on the Company's books for purposes of regulation.

Q. HOW LARGE ARE THE REMOVAL COST RATIOS RECOMMENDED BY MR. ROFF?

A. They are very large. Mr. Roff's removal cost ratios are presented in column 9 of his Schedule 2 in his Exhibit DSR-3. These ratios are characterized as "net salvage." When the removal cost is higher than the expected salvage value, the net of the two is negative, which is why all these ratios are presented as negative values. As can be seen, these ratios range as high as negative 55 percent for the meters and meter installation accounts. A negative 55 percent net salvage ratio means that for every dollar of depreciation recovered, another 55 cents is accrued against future removal costs.

Q. WHAT IS THE AGGREGATE AMOUNT OF ANNUAL REMOVAL COST ACCRUALS THAT WOULD RESULT FROM MR. ROFF'S PROPOSED DEPRECIATION RATES?

A. Schedule 4 in Exhibit CWK-1 shows the accruals that Mr. Roff proposes based on September 30, 2006 plant in service. The accrual rates in column D are taken from Schedule 2 in Mr. Roff's Exhibit DSR-3. The accruals are presented in column E. In total, they come to an annual expense to ratepayers of $1,786,097.

Q. HOW LARGE ARE THE ACTUAL REMOVAL COSTS THAT ATMOS HAS EXPERIENCED?

A. The actual annual removal cost expenditures, net of salvage, for the years 2002 through 2006 are shown in Schedule 5 of Exhibit CWK-1. The average removal cost expenditure for these five years has been $250,647.

Q. HOW DO MR. ROFF'S PROPOSED REMOVAL COST ACCRUALS COMPARE WITH THE ACTUAL REMOVAL COST EXPERIENCE?

A. In the last column of Schedule 4, I show that the excess of Mr. Roff's proposed removal cost accruals over average removal cost expenditures is $1,535,450. Mr. Roff would collect removal cost accruals that are seven times actual removal cost expenditures.

Q. HOW DOES MR. ROFF DERIVE SUCH LARGE REMOVAL COST ACCRUALS WHEN THE ACTUAL EXPERIENCED REMOVAL COSTS ARE SO MUCH LESS?

A. Mr. Roff uses a procedure that I call the Traditional Inflated Future Cost Approach ("TIFCA"). For each major category of plant, he compares the original cost of retirements during recent years with the experienced costs of removal during those same years. The ratio of the removal costs to plant retirements becomes the removal cost ratio. As Mr. Roff's report indicates, this ratio can be as high as 55 percent. These ratios are used to develop annual removal cost rates. When those rates are applied to all plant in service as of the September 30, 2006, the result is an annual accrual of almost $1.89 million.

The reason for these very high removal cost ratios is that Mr. Roff is comparing dollars of very different value. The numerator of the removal cost ratio is recently incurred removal costs covering the years since about 2001. The denominator of the removal cost ratio is the original cost of the plant retired. Those costs can be quite old. The average service life of a main, for example, is 55 years. If a 55 year-old main is retired, its original cost is expressed in 1951 dollars. In 1951, the dollar was worth many times its present value.

With many low-valued dollars in the numerator and a few high-valued dollars in the denominator, the removal cost ratio is very high. Overall, these high ratios result in proposed removal cost accruals seven times actual removal cost expenditures.

Q. WHAT IS THE RATIONALE BEHIND TIFCA?

A. The rationale underlying TIFCA is set forth on page 157 of Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners in August 1996:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. <u>The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.</u> (emphasis supplied.)

The TIFCA procedure purports to forecast the future cost of removal associated with plant currently in service, and it charges that cost to the ratepayers that use that plant.

Q. IS THIS RATIONALE VALID?

A. The rationale is arguably valid for large, single units of plant, such as power plants, and then only when the future costs are discounted to the present. It is highly questionable for "mass property" accounts, such as ATMOS's electric and gas distribution accounts, for two reasons:

- The procedure charges present ratepayers with the undiscounted cost of future removal activities, and
- When applied to mass property accounts, the TIFCA procedure results in a permanent and growing advance of funds from ratepayers to the utility.

Q. WHY DO YOU SAY THAT TIFCA FAILS TO RECOGNIZE THE PRESENT VALUE OF FUTURE COSTS?

A. The TIFCA procedure charges ratepayers now for the projected cost of removal that presumably will be incurred at the time of plant's retirement. Under Mr. Roff's proposal, when Atmos installs a meter in 2007, it would add a removal cost allowance of 55 cents to each dollar of construction cost recovered. Yet that 55 cents will not be spent, on average, for another 36 years, or until the year 2043. A dollar spent in 2043 is worth far less than a dollar collected in 2007. Not only will inflation erode the value of the 2043 dollar, but the holder of the dollar has the benefit of its earning (or spending) value in the intervening 35 years.

The TIFCA procedure simply ignores this relationship between present and future dollars. It assumes that a dollar collected now has exactly the same value as a dollar spent 36 years from now. Through the mechanism of composite depreciation rates, Mr. Roff would have Atmos collect these 2043 dollars from ratepayers starting next year.

Q. WHY DO YOU SAY THAT TIFCA RESULTS IN A PERMANENT AND GROWING ADVANCE OF FUNDS FROM RATEPAYERS TO THE UTILITY?

A. Two arguments are advanced in defense of TIFCA. The first and most conventional argument focuses on the individual assets. When an individual asset is placed in service, it carries with it an obligation to remove it, and with it an expected future cost. According to this argument, the "matching principle" requires that the future removal cost be recovered over the life of the asset.

The second argument in support of TIFCA is that removal cost allowances build up the reserve, which in turn reduces the net investment rate base. The reduced rate base lowers the requirement for return and income taxes. The argument holds that over time, this reduction cancels out the increase in revenue requirement represented by the excessive depreciation expenses and thereby conveys to ratepayers the present value effect of their contributions to the removal cost reserve.

Neither of these arguments recognizes that removal cost accruals are <u>flows</u> of money generated by the installation and retirement of large numbers of individual items in mass property accounts. The flows do not – and never will -- match. The inflow of newly installed plant always exceeds the outflow of retired plant, and there is always more new plant than old plant. The dollar value of Atmos's plant is always expanding. Atmos's plant is growing, but even if it were not, inflation will cause the dollars added each year to exceed the dollars retired. As a result, there is always more new plant generating higher removal cost charges than old plant that has accumulated removal cost reserve. Ratepayers never catch up.

The result is an ever-expanding advance from ratepayers to the utility for "future costs" that, when incurred, will by then be overwhelmed by further accruals for yet greater costs farther into the future. The effect is a permanent and ever-growing loan from ratepayers to the utility. As of the September 30, 2006, that loan was $18.77 million, but this amount is certain to grow as long as the TIFCA approach to accruing removal cost reserves is retained.

Q. BUT ISN'T THE ACCRUAL OF REMOVAL COST RESERVE ANALOGOUS TO THE ACCRUAL OF DEPRECIATION RESERVES?

A. No. Depreciation is the process of restoring capital that investors effectively loaned to ratepayers for costs that have already been incurred. Removal cost accruals are advances from ratepayers to the company and its investors for costs that have not been incurred.

Q. WHAT IS THE SOLUTION TO THE FIRST WEAKNESS OF TIFCA, ITS FAILURE TO RECOGNIZE THE PRESENT VALUE OF FUTURE COSTS?

A. The solution to the failure of TIFCA to recognize the present value of future costs is to apply the SFAS 143 procedures to the Company's estimates of future removal costs. This requires forecasting the value of future removal costs, then discounting those costs back to the time the plant was installed, depreciating those discounted values, and incorporating a factor for the annual increment in the current present value of the discounted removal costs.

Q. HAVE YOU APPLIED THIS APPROACH TO ATMOS'S TENNESSEE PLANT?

A. Yes. Schedule 6 in Exhibit CWK-1 develops annual SFAS 143 expenses based on the simplifying assumption that each account is treated as though it were a single asset. Column B duplicates Mr. Roff's proposed net salvage factors, and column C shows the total amount of future net salvage that must be recovered. Column D presents Mr. Roff's average service lives for each account, which then become the basis for discounting the total removal cost values back to the average date of placement of the plant. That discounted value is presented in column E using 7.96 percent, the capital cost approved for Atmos Docket No. 05-0258, as the discount factor.

Columns F and I present the expense elements under the SFAS 143 methodology. Column F is a straight-line depreciation of the discounted removal cost in column E using Mr. Roff's average service lives. Column I is the current year's increment in the discount factor times the total undiscounted value of the removal cost to be recovered. Column J presents the sum of the two SFAS 143 expense elements. Finally, column K shows the accrual rates that result from this procedure.

Q. WHAT IS THE SOLUTION TO THIS PROBLEM OF AN EVER-GROWING LOAN FROM RATEPAYERS TO THE UTILITY?

A. The solution is to this problem is to use a rolling average of the last five years' actual removal costs as the basis for quantifying annual removal cost allowances. This average, computed for each account, is ratioed to the account balance to derive the annual removal cost rates for each account.

This procedure preserves the practice of accruing removal cost reserves by means of rates applied to plant balances, but it effectively halts any further increase in the reserves already accumulated.

Q. HAVE YOU CALCULATED THE ACCRUAL RATES THAT WOULD BE APPROPRIATE UNDER THIS APPROACH?

A. Yes. Schedule 5 in Exhibit CWK-1 shows the rates and accruals using the five year average approach for the four Atmos distribution plant accounts for which I have removal cost data. Columns B through F present the net removal costs for each account each year during the five years 2002 through 2006. Column G sums these annual removal costs, and column H converts these totals to average annual amounts, and the final column presents the ratios of these amounts to the plant balances.

Schedule 5 in Exhibit CWK-1 shows that total accruals under this procedure come to approximately $250,647 annually, based on September 30, 2006 plant balances.

Q. ARE THERE ANY OTHER JURISDICTIONS THAT USE THE TWO APPROACHES YOU HAVE PROPOSED FOR TREATING REMOVAL COSTS?

A. Yes. Within the last month, the Maryland Public Service Commission adopted the present value approach in two decisions involving the Potomac Electric Power Company[10] and the Delmarva Light & Power Company.[11]

The five year average approach was adopted last year by the Delaware Public Service Commission for the Delmarva Light & Power Company.[12] This

[10] Maryland P.S.C. Order No. 81517, Case No. 9092, July 19, 2007.
[11] Maryland P.S.C. Order No. 81518, Case No. 9093, July 19, 2007.

approach is used for all utilities in Pennsylvania. It has been adopted by the New Jersey Board of Public Utilities for Rockland Electric Company,[13] Atlantic City Electric Company,[14] Jersey Central Power & Light Company[15] and Public Service Electric & Gas Company.[16] A slight modification of it has been approved for the past 16 years by the Georgia Public Service Commission for the Georgia Power Company.[17]

Q. WHAT ARE THE RELATIVE MERITS OF THESE TWO APPROACHES?

A. The present value approach is conceptually more appropriate because it conforms with generally accepted account principles and because it allocates the cost of removal to the plant over its life in "real" rather than "nominal" dollars. It suffers from the continued requirement to forecast future removal costs and, because plant is always growing, it perpetuates the buildup of a permanent and growing loan from ratepayers to the utility.

The five-year-average approach accrues removal cost reserves only at the rate that removal costs are experienced, and it has the advantage of being rooted in real cost data, not somewhat conjectural estimates of future costs. Its weakness is conceptual. It charges current ratepayers only for the cost of current removal activities and builds no reserve for the future.

Q. WHICH APPROACH DO YOU RECOMMEND?

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[12] Delaware P.S.C. Order No. 6930, Case No. 05-304, signed June 6, 2006, ¶ 174.
[13] I/M/O Rockland Electric Company, BPU Docket Nos. ER02080614 and ER02100724, Initial Decision, June 10, 2003 and Summary Order, July 31, 2003.
[14] I/M/O Atlantic City Electric Company, BPU Docket Nos. ER03020110, ER04060423, EO03020091 and EM02090633, Decision and Order Adopting Initial Decision and Stipulation of Settlement, May 26, 2005.
[15] I/M/O Jersey Central Power & Light Company, BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173, Summary Order, August 1, 2003.
[16] I/M/O Public Service Electric and Gas Company, BPU Docket No. GR05100845, Decision and Order Adopting Initial Decision and Stipulation of Settlement, November 11, 2006, p. 4.
[17] Georgia PSC Docket No. 4007-U, 1991

A. Normally, I would recommend the five-year average approach because I believe it is fairer to ratepayers. In this case, however, I cannot make that recommendation because of the inadequacies of Atmos's removal cost data. The Company has reported no removal costs for transmission plant even though such costs presumably will be incurred when the plant is retired. It reports removal costs for only four of the distribution plant accounts even though the Company apparently expects to incur removal costs for seven accounts.

For these reasons, I recommend the present value approach to removal costs accrual. I have replicated the removal cost allowances developed in Schedule 6 of Exhibit CWK-1 in Schedule 1, which shows my recommended rates and accruals.

THIRD PARTY REIMBURSEMENTS

Q. WHAT ARE THIRD PARTY REIMBURSEMENTS?

A. Third party reimbursements are moneys paid to Atmos, usually by government agencies such as the highway department, for the cost of moving facilities for purposes of public convenience and necessity. A prime example is a highway relocation, where Atmos must move a main from one location to another. When that happens, Atmos bills the highway department for the cost of moving the main and for the cost of installing the new main.

Q. ARE THIRD PARTY REIMBURSEMENTS A SIGNIFICANT AMOUNT OF MONEY?

A. Yes. In fiscal year 2006, Atmos received $892,265 in third party reimbursements for its Tennessee operations. In fiscal year 2005, these reimbursements came to $916,651.[18]

[18] Response to AG Data Request 2-5, Part E.

Q. CAN YOU PROVIDE A HYPOTHETICAL EXAMPLE OF A THIRD PARTY REIMBURSEMENT?

A. Yes. A Highway Department requires Atmos to move a section of main. The original of the old section of main was $2,000, the cost to cap off the old section of main is $1,000, and the cost to install the new section of main is $5,000. Atmos would probably not bill the Highway Department for the old section because it would assume that it is fully depreciated, but it would bill for the cost to retire the old main and the cost of the new main. The bill to the Highway Department would be $1,000 for retirement costs and $5,000 for the installation of the new main, a total of $6,000.

Q. HOW WOULD ATMOS BOOK THESE COSTS?

A. The $2,000 original cost of the old main plus the $1,000 removal cost of that main would be deducted from plant in service and from the depreciation reserve. The $5,000 for the new main would be added to plant in service.

Q. HOW WOULD ATMOS BOOK THE REIMBURSEMENT FROM THE HIGHWAY DEPARTMENT?

A. The entire $6,000 reimbursement from the Highway Department would be credited to plant in service.[19] That is, plant in service would be reduced by $6,000.

Q. IS THIS TREATMENT OF THE HIGHWAY DEPARTMENT'S REIMBURSEMENT APPROPRIATE?

[19] Response to AG Data Request 2-22.

A. No. The treatment of the removal cost is inconsistent with the treatment of the reimbursement. The cost is deducted from the depreciation reserve, while the reimbursement is credited to plant in service.

Q. WHAT IS THE EFFECT OF THIS ASYMMETRICAL TREATMENT OF REMOVAL COSTS?

A. The effect on net plant – the rate base – is a wash. Reducing plant in service by $6,000 has the same effect on net plant as increasing the depreciation reserve by $6,000. However, since the $1,000 in removal costs were deducted from the depreciation reserve but the $1,000 in removal cost reimbursement was not credited to that reserve, the effect is to overstate removal costs by $1,000.

Q. WHAT IS THE SOLUTION TO THIS PROBLEM?

A. The solution is to credit third party reimbursements to the depreciation reserve. As noted, this procedure would not affect net plant. In our example, net plant would be reduced by $6,000 in both cases. But this treatment would result in reimbursements for removal costs being treated as positive salvage. That treatment would prevent the overstatement of removal costs that is now embedded in the current accounting system. That overstatement shows up in depreciation studies when the Company's analyst – Mr. Roff in this case – computes his removal cost ratios.

Q. DO YOU HAVE ANY SUPPORT FOR THIS CHANGE IN ATMOS'S ACCOUNTING PRACTICES?

A. Yes. The National Association of Regulatory Commissioners ("NARUC") occasionally issues interpretations of the FERC's Uniform System of Accounts. Such an interpretation was issued in 1988. Question and Answer No. 65 are as follows:

Question:

> Under arrangements with another party, sometimes the United States Government, a utility company agrees, or is obligated, to remove, relocate, rearrange, reroute, or otherwise make changes in utility property, other than for the purposes of rendering utility service to the other party, for which the utility is reimbursed for all or a portion of the costs incurred. What is the proper accounting for such property changes and the reimbursements received from the other parties?

Answer:

> The cost of plant retirements should be accounted for in accordance with the rules applicable thereto. The cost of new plant should be included in the appropriate plant accounts at actual cost of construction. The reimbursement received shall be accounted for (a) by crediting operation and maintenance expenses to the extent of the actual expenses occasioned by the plant changes and (b) **crediting the remainder to the reserve for depreciation,** unless contractual terms definitely characterize residual or specific amounts as applicable to the cost of replacement. In the latter event, appropriate credits should be entered in the plant accounts. (emphasis supplied)[20]

As noted, Atmos does <u>not</u> credit any of the reimbursements to the reserve for depreciation.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that Atmos be directed to credit all future third party reimbursements to the depreciation reserve.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

[20] Question and Answer No. 65 in the NARUC publication "interpretations of Uniform System of Accounts for Electric and Gas Utilities," dated September 1988; Question and Answer No. 67 in the NARUC "Interpretations of Uniform System of Accounts for Electric Gas and Water Utilities as Revised February 27, 1981."

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. and Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, costs earnings and depreciation.

Mr. King has testified in electric, gas and water utility cases on virtually every aspect of regulation, including cost of capital, revenue requirements, depreciation, cost allocation and rate design. Mr. King is one of the nation's leading authorities on utility depreciation practices, having testified on this subject in several dozen cases before state regulatory bodies.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations. Mr. King directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES
Gas Plant
AG Recommended Depreciation and Cost of Removal Rates and Accruals
Based on December 21, 2005 Plant Balances

	Account Description	A	B	C	D	E	F	G	H	
		Plant Investment		Plant Only w/o Cost of Removal				Cost of Removal		
		30-Sep-06	Depreciation Reserve	Remaining to Be Recovered	ALG Remaining Life	Annual Accrual	Accrual Rate	Acrual Rate	Annual Accrual	Rec
		DSR-3, Sch1	Schedule 2	A-B	Roff Workpapers	C/D	E/A	Sch 6	A*G	
	TRANSMISSION PLANT									
365.2	Rights of Way	348,971	48,879	300,092	58.48	5,132	1.47%			
366.0	Structures and Improvements	2,679	1,255	1,424	21.50	66	2.47%			
367.0	Mains	11,671,967	2,171,669	9,500,298	41.64	228,153	1.95%	0.12%	14,499	
369.0	M&R Station Equipment	1,629,191	415,084	1,214,107	27.57	44,037	2.70%	0.05%	880	
	Total Transmission Plant	13,652,808	2,636,887	11,015,921		277,388	2.03%	0.11%	15,379	
	DISTRIBUTION PLANT									
374.2	Rights of Way	641,460	458,208	183,252	59.56	3,077	0.48%			
375.0	Structures and Improvements	614,964	254,553	360,411	37.86	9,520	1.55%			
376.0	Mains	151,083,809	59,541,024	91,542,785	39.81	2,299,492	1.52%	0.14%	213,767	
378.0	M&R Station Equipment	6,248,657	3,473,290	2,775,367	26.04	106,581	1.71%	0.06%	3,749	
379.0	City Gate Equipment	2,381,748	752,315	1,629,433	30.26	53,848	2.26%	0.05%	1,073	
380.0	Services	82,529,059	21,399,698	61,129,361	41.80	1,462,425	1.77%	0.08%	62,182	
381.0	Meters	11,069,083	6,343,604	4,725,479	20.91	225,991	2.04%	0.98%	108,425	
382.0	Meter Installations	21,126,176	8,081,388	13,044,788	33.91	384,689	1.82%	0.39%	82,460	
383.0	House Regulators	3,088,762	1,642,189	1,446,573	24.39	59,310	1.92%			
385.0	Industrial M&R Equipment	323,828	41,024	282,804	36.56	7,735	2.39%	0.03%	97	
	Total Distribution Plant	279,107,546	101,987,294	177,120,252		4,612,667	1.65%	0.17%	471,753	
	GENERAL PLANT									
390.0	Structures and Improvements	1,014,374	375,526	638,848	33.28	19,196	1.89%			
391.0	Office Furniture and Equipment	569,786	(27,715)	597,501	16.50	36,212	6.36%			
393.0	Stores Equipment	25,154	18,401	6,753	16.89	400	1.59%			
394.0	Tools, Shop and Garage Equipment	720,715	(214,340)	935,055	13.39	69,832	9.69%			
396.0	Power Operated Equipment	397,306	(273,990)	671,296	4.51	148,846	37.46%			
397.0	Communication Equipment	503,915	356,041	147,874	3.00	49,291	9.78%			
398.0	Miscellaneous Equipment	882,304	78,877	803,427	7.81	102,872	11.66%			
399.0	Other Tangible Property*	18,299	13,573	4,726	2.03	2,328	12.72%			
	Total General Plant	4,131,853	326,374	3,805,479		428,978	10.38%			
	Total Depreciable Plant	296,892,207	104,950,555	191,941,652		5,319,033	1.79%			

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES

Study Parameters

			Atmos Study		Snavely King					
					Actuarial					
Account Number	Description	9/30/06 Balance	ASL	Iowa Curve	ASL	Iowa Curve	Band	SPR	GMT Full Band	Commen
	TRANSMISSION PLANT									
365.2	Rights of Way	348,971	65.0	R5						No Retireme
366.0	Structures and Improvements	2,679	30.0	SQ						No Retireme
367.0	Mains	11,671,967	55.0	S4					321.74	One minor re
369.0	M&R Station Equipment	1,629,191	40.0	R2					127.22	One minor re
	Total Transmission Plant	13,652,808								
	DISTRIBUTION PLANT									
374.2	Rights of Way	641,460	65.0	R5						No Retireme
375.0	Structures and Improvements	614,964	45.0	R5						No Retireme
376.0	Mains	151,083,809	55.0	S4				58 S4	89.08	SPR Data
378.0	M&R Station Equipment	6,248,657	40.0	R2				50 L4	50.91	SPR Data
379.0	City Gate Equipment	2,381,748	40.0	R2	53	R5	1991-2006		216.3	2 Retirement
380.0	Services	82,529,059	48.0	R0.5				34 S6	50.91	SPR Data
381.0	Meters	11,069,083	36.0	R2.5				60 S4	127.33	SPR Data
382.0	Meter Installations	21,126,176	40.0	R1				33 L5	53.27	SPR Data
383.0	House Regulators	3,088,762	40.0	R3				60 S5	180.14	SPR Data
385.0	Industrial M&R Equipment	323,828	40.0	R2						No Retireme
	Total Distribution Plant	279,107,546								
	GENERAL PLANT									
390.0	Structures and Improvements	1,014,374	40.0	R3				34 SQ	39.7	SPR Data
391.0	Office Furniture and Equipment	569,786	20.0	S6				27 SQ	20.91	SPR Data
393.0	Stores Equipment	25,154	35.0	R1				50 R5	59.75	SPR Data
394.0	Tools, Shop and Garage Equipment	720,715	20.0	L1				43 SQ	46.01	SPR Data
396.0	Power Operated Equipment	397,306	10.0	S5				25 H3.5	45.66	SPR Data
397.0	Communication Equipment	503,915	15.0	S6				40 SQ	49.67	SPR Data
398.0	Miscellaneous Equipment	882,304	10.0	S3				9 R4	21.36	SPR Data
399.0	Other Tangible Property*	18,299	6.0	S6	84	L3	1998-2006			
	Total General Plant	4,131,853								
	Total Depreciable Plant	296,892,207								
	Fully Depreciated	1,852,336								
	Intangible Plant	241,284								
	Land	921,227								
	Total Gas Plant	299,907,054								

*** - Composite Existing Depreciation Rate.**

EWxhibit CWK-1
Schedule 3

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES
Depreciation and Cost of Removal Reserves as of September 30, 2006

Account Number	Description	A 9/30/06 Balance $
	TRANSMISSION PLANT	
365.2	Rights of Way	348,971
366.0	Structures and Improvements	2,679
367.0	Mains	11,671,967
369.0	M&R Station Equipment	1,629,191
	Total Transmission Plant	13,652,808
	DISTRIBUTION PLANT	
374.2	Rights of Way	641,460
375.0	Structures and Improvements	614,964
376.0	Mains	151,083,809
378.0	M&R Station Equipment	6,248,657
379.0	City Gate Equipment	2,381,748
380.0	Services	82,529,059
381.0	Meters	11,069,083
382.0	Meter Installations	21,126,176
383.0	House Regulators	3,088,762
385.0	Industrial M&R Equipment	323,828
	Total Distribution Plant	279,107,546
	GENERAL PLANT	
390.0	Structures and Improvements	1,014,374
391.0	Office Furniture and Equipment	569,786
393.0	Stores Equipment	25,154
394.0	Tools, Shop and Garage Equipment	720,715
396.0	Power Operated Equipment	397,306
397.0	Communication Equipment	503,915
398.0	Miscellaneous Equipment	882,304
399.0	Other Tangible Property*	18,299
	Total General Plant	4,131,853
	Total Depreciable Plant	296,892,207

Sources:

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES
Gas Distribution Plant
Comparison of Accruals for Cost of Removal with
Actual Average Experience For the Years 2002-2006

A	B	C	D	E	F	G
Account No.	Description	Original Cost 9/30/06	Net COR Accrual Rate	Net COR Accruals	Annual Net COR Expenditures	Differe
		Roff Sch 1	Roff Sch 2	C*J	Att DR 2-4	K-L
374.2	Rights of Way	641,460				
375.0	Structures and Improvements	614,964				
376.0	Mains	151,083,809	0.64%	966,936	111,090	855
378.0	M&R Station Equipment	6,248,657	0.13%	8,123	-	8
379.0	City Gate Equipment	2,381,748	0.13%	3,096	-	3
380.0	Services	82,529,059	0.42%	346,622	57,751	288
381.0	Meters	11,069,083	1.53%	169,357	42,741	126
382.0	Meter Installations	21,126,176	1.38%	291,541	39,065	252
383.0	House Regulators	3,088,762		-		
385.0	Industrial M&R Equipment	323,828	0.13%	421		
	Total Distribution Plant	279,107,546		1,786,097	250,647	1,535

Exhibit CWK-1
Schedule 5

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES
Net Gas Plant Removal Costs

Acct.	Description	A 9/30/06 Balance	B 2002	E 2003	D 2004	E 2005	F 2006	G Total Removal Cost 2002-2006	H Average Annual Cost	I Removal Cost Allowance
								Sum B - F	G/5	H/A
	DISTRIBUTION PLANT									
374.2	Rights of Way	641,460								
375.0	Structures and Improvements	614,964								
376.0	Mains	151,083,809	26,557	$56,581	$72,696	$18,289	$381,325	555,448	111,090	0.07%
378.0	M&R Station Equipment	6,248,657								
379.0	City Gate Equipment	2,381,748								
380.0	Services	82,529,059	85,954	77,128	42,696	19,179	63,798	288,755	57,751	0.07%
381.0	Meters	11,069,083	68,631	69,130	29,238	12,501	34,207	213,707	42,741	0.39%
382.0	Meter Installations	21,126,176	68,631	60,408	19,578	12,501	34,207	195,325	39,065	0.18%
383.0	House Regulators	3,088,762								
385.0	Industrial M&R Equipment	323,828								
	Total Distribution Plant	279,107,546							250,647	

Source: Attmt to DR 2-4

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES
Gas Plant
SFAS 143 Removal Cost Allowances Using Roff Proposed Cost of Removal Factors

Account No. (a)	Description (b)	A Original Cost Sept 30,06 (c)	B Proposed Net Salvage Ratio	C Removal Cost to Be Recovered	D Average Service Life	E Discounted Removal Cost @ 7.96%	F Depreciation of Removal Cost	G Average Remaining Life	H Increment Factor in 2005	Incre in Re Cost
		DSR-3, Sch 1	DSR-3, Sch 2	A x B	DSR-3, Sch 2	$C/1.0796^{D}$	E/D	Roff worpapers	PVG-1 -PVG	H
	TRANSMISSION PLANT									
367.0	Mains	11,671,967	-35%	4,085,188	55.0	60,500	1,100	41.64	0.003280	
369.0	M&R Station Equipment	1,629,191	-5%	81,460	40.0	3,806	95	27.57	0.009635	
	Total Transmission Plant	13,301,158								
	DISTRIBUTION PLANT									
376.0	Mains	151,083,809	-35%	52,879,333	55.0	783,119	14,239	39.81	0.003773	1
378.0	M&R Station Equipment	6,248,657	-5%	312,433	40.0	14,596	365	26.04	0.010833	
379.0	City Gate Equipment	2,381,748	-5%	119,087	40.0	5,564	139	30.26	0.007841	
380.0	Services	82,529,059	-20%	16,505,812	48.0	417,848	8,705	41.80	0.003240	
381.0	Meters	11,069,083	-55%	6,087,996	36.0	386,377	10,733	20.91	0.016047	
382.0	Meter Installations	21,126,176	-55%	11,619,397	40.0	542,836	13,571	33.91	0.005929	
385.0	Industrial M&R Equipment	323,828	-5%	16,191	40.0	756	19	36.56	0.004840	
	Total Distribution Plant	274,762,360								

Exhibit CWK-2
Schedule 1

ATMOS ENERGY CORPORATION - SHARED SERVICES
Book Depreciation Study as of September 30, 2006
Comparison of Depreciation Rates and Annual Amounts

		A	B	C	D	E
			Present		Atmos Proposed	
Account Number	Description	9/30/06 Balance	Rates	Annual Amount	Rates	Annual Amount
		$	%	$	%	$
	GENERAL PLANT					
390.09	Improvements to Leased Premises	9,949,143	7.43	739,221	9.10	905,372
391.00	Office Furniture and Equipment	9,074,352	4.89	443,736	2.13	193,284
397.00	Communication Equipment	25,311,861	7.12	1,802,205	8.45	2,138,852
398.00	Miscellaneous Equipment	633,466	5.36	33,954	8.15	51,627
399.00	Other Tangible Property	224,866	15.75	35,416	4.66	10,479
399.01	Servers Hardware	14,567,322	14.29	2,081,670	6.95	1,012,429
399.02	Servers Software	8,647,580	14.29	1,235,739	4.00	345,903
399.03	Network Hardware	2,377,029	14.29	339,677	9.30	221,064
399.06	PC Hardware	6,691,156	16.83	1,126,122	14.86	994,306
399.07	PC Software	3,928,199	17.73	696,470	9.02	354,324
399.08	Application Software	111,323,312	8.22	9,150,776	11.11	12,368,020
399.24	General Startup Cost	23,172,326	8.33	1,930,255	15.89	3,682,083
	Total Depreciable General Plant	215,900,612	9.09	19,615,241	10.32	22,277,742
	Fully Depreciated	5,331,910				
	Late Retirements	4,363,383				
	Total Shared Services Facilities	225,595,905				

Exhibit CWK-2
Schedule 1

F	G
AG Recommended	
	Annual
Rates	Amount
%	$
8.82	877,514
1.98	179,672
8.28	2,095,822
7.78	49,284
4.51	10,141
6.95	1,012,429
4.00	345,903
9.30	221,064
13.00	869,850
8.88	348,824
10.53	11,722,345
15.89	3,682,083
9.92	21,414,931

ATMOS ENERGY CORPORATION - SSU

Account Number	Description	9/30/06 Balance $	Atmos Study ASL yrs.	Atmos Study Iowa Curve	Snavely King ASL	Snavely King Iowa Curve	Band	GMT	Comments
	GENERAL PLANT								
390.09	Improvements to Leased Premises	9,949,143	12.0	S4	12	L4	1987-2006	19.36	Actuarial
391.00	Office Furniture and Equipment	9,074,352	25.0	R4	19	S6	1987-2006	24.4	Actuarial
397.00	Communication Equipment	25,311,861	12.0	S5	12	S5	2002-2006	21.31	Actuarial
398.00	Miscellaneous Equipment	633,466	15.0	S3	15	R4	1987-2006	23.61	Actuarial
399.00	Other Tangible Property	224,866	7.0	R5	8	L3	1992-2006	8.53	Actuarial
399.01	Servers Hardware	14,567,322	10.0	SQ					No Retirements, No Curve Fit
399.02	Servers Software	8,647,580	10.0	SQ					No Retirements, No Curve Fit
399.03	Network Hardware	2,377,029	10.0	SQ	73	L3	1999-2006	23.19	Actuarial
399.06	PC Hardware	6,691,156	7.0	S1	7	L1	1987-2006	6.42	Actuarial
399.07	PC Software	3,928,199	8.5	R5	10	L3	1994-2006	9.92	Actuarial
399.08	Application Software	111,323,312	10.0	S3	10	S3	1986-2006	15.05	Actuarial
399.24	General Startup Cost	23,172,326	10.0	SQ					No Retirements, No Curve Fit
	Total Depreciable General Plant	215,900,612							
	Fully Depreciated	5,331,910							
	Late Retirements	4,363,383							
	Total Shared Services Facilities	225,595,905							

CHARLES W. KING
Snavely King Majoros O'Connor & Lee, Inc.
1220 L Street, N.W., Suite 410
Washington, D.C. 20005
(202) 371-1111
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission	U-1345-I	Arizona Public Service Co.	December 16, 1980
	Arizona Retailers Association	U-1345-II	Arizona Public Service Co.	January 15, 1981
CA	California Retailers Association	57666	Pacific Gas & Electric Co.	March 6, 1978
	California Retailers Association	57602	Southern California Edison	April 25, 1978
	California Retailers Association	59351	Pacific Gas & Electric Co.	June 12, 1981
	California Retailers & California Manufacturers	59351	Southern California Edison	May 20, 1982
	California Retailers Association	61138	Southern California Edison	May 28, 1982
CO	U. S. Department of Defense	I&S 1100	Colorado Springs (Elec)	June 14, 1977
	J.C. Penney Company	5693	All Electric Utilities	March 8, 1978
	U.S. Department of Defense	I&S 1339	Colorado Springs DPU (Gas)	October 18, 1979
	U. S. Department of Defense	I&S 1540	Colorado Springs DPU (Gas)	February 9, 1982
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Gas)	September 30, 1984
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 6, 1985
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	May 19, 1986
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 30, 1987
CT	Retailers Merchants Association	72-0204	Various Electric Utilities	July 22, 1976
	Division of Consumer Counsel	76-0604,5	CL&P and HELCO	November 10, 1977
	Public Utilities Control Auto	78-0303	Bridgeport Hydraulic Co.	(none)
	Division of Consumer Counsel	80-0403,4	CL&P and HELCO	August 11, 1980
	Division of Consumer Counsel	81-0413	United Illuminating Company	July 20, 1981
	Division of Consumer Counsel	81-0602,4	CL&P and HELCO	October 5, 1981
	Division of Consumer Counsel	82-0701	CL&P	September 28, 1982
	Coalition of Hotels, Alloys & Retailers	85-10-22	CL&P	(none)
	Coalition of Hotels, Alloys & Retailers	87-07-01	CL&P	April 25, 1988

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Exa
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
	D.C. People's Counsel	989	Washington Gas Light Company	May 22, 2002
	D.C. People's Counsel	1016	Washington Gas Light Company	September 23, 2003
DE	Delaware PSC Staff	94-164	Artesian Water Company	Filed March 10, 1995
	Delaware PSC Staff	94-149	Wilmington Suburban Water Company	March 10, 1995
	Delaware PSC Staff	04-152	Tidewater Utilities Company	Filed July 26, 2004
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
	Georgia Public Service Commission	14311-U	Atlanta Gas Light Company	April 8, 2002
	Georgia Public Service Commission	17066-U	Georgia Power Company	July 31, 2003
	Georgia Public Service Commission	18300-U	Georgia Power Company	October 26, 2004
	Georgia Public Service Commission	18638-U	Atlanta Gas Light Company	March 14, 2005
	Georgia Public Service Commission	19758-U	Savannah Electric & Power Company	March 29, 2005
	Georgia Public Service Commission	20298-U	Atmos Energy Corp.	October 11, 2005
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983
IL	Illinois Retail Merchants Association ("IRMA"/ Chicago Bldg. Mgrs. Association ("CBMA")	76-0698	Commonwealth Edison	June 22, 1977
	IRMA/CBMA	76-0568	All Electric Utilities	(none)
	IRMA/CBMA	80-0546	Commonwealth Edison	March 5, 1981
	IRMA/CBMA	82-0026	Commonwealth Edison	July 22, 1982
	IRMA/CBMA	83-0537	Commonwealth Edison	March 19, 1984
	IRMA/CBMA	87-0427	Commonwealth Edison	March/April 22, 1988
	IRMA/CBMA	90-0169	Commonwealth Edison	October 29, 1990
	City of O'Fallon, IL	02-0690	Illinois-American Water Company	Filed Feb.5, Apr.11,2003
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penney Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
	Attorney General of Kentucky	2002-145	Columbia Gas of Kentucky	Filed August 8, 2002
	Attorney General of Kentucky	2003-252	Union Heat Light & Power Co.	September 30, 2003
	Attorney General of Kentucky	2004-67	Delta Gas Company	August 18, 2004

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977
	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
	Giant Foods, Inc.	8855	Baltimore Gas & Electric Company	January 8, 2003
	Maryland People's Counsel	9036	Baltimore Gas & Electric Company	September 29, 2005
	Maryland People's Counsel	9092	Potomac Electric Power Company	April 16, 2007
	Maryland People's Counsel	9093	Delmarva Power & Light Company	April 9, 2007
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
	Michigan Attorney General	U-13380	Consumers Energy Company	September 9, 2002
	Michigan Attorney General	U-13715	Consumers Energy Company	April 24, 2003
	Michigan Attorney General	U-13808	Detroit Edison Company	Dec 12, 2003; Jan 30, Mar 5, 04

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MI (Cont'd)	Michigan Attorney General	U-12999	Consumers Energy Company	March 10, 2004
	Michigan Attorney General	U-13898,9	Michigan Consolidated Gas Co.	August 23, 2004
	Michigan Attorney General	U-14201	Detroit Edison Company	Filed December 5, 2004'
	Michigan Attorney General	U-14274	Consumers Energy Company	Filed February 15, 2005
	Michigan Attorney General	U-14148	Consumers Energy Company	Filed March 2, 25, 2005
	Michigan Attorney General	U-14399	Detroit Edison Company	July 29, 2005
	Michigan Attorney General	U-14428	Detroit Edison Company	September 7, 2005
	Michigan Attorney General	U-14292	All Michigan Utilities	September 27, 2005
	Michigan Attorney General	U-13808-R	Detroit Edison Company	November 7, 2005
	Michigan Attorney General	U-14547	Consumers Energy Company	Nov.7, 2005; Mar. 22, 2006
	Michigan Attorney General	U-14701	Consumers Energy Company	March 21, 2006
	Michigan Attorney General	U-14526	Consumers Energy Company	April 11.2006
	Michigan Attorney General	U-14561	All Gas Distribution Utilities	June 1, 2006
	Michigan Attorney General	U-15002	Detroit Edison Company	December 8, 2006
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
	Missouri Public Counsel	ER-2006-0315	Empire District Electric Company	September 14, 2006
	Missouri Public Counsel	GR-2007-0003	Ameren UE (Gas)	Filed December 15, 2006
	Missouri Public Counsel	ER-2007-0002	Ameren UE (Electric)	March 22, 2007
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-186	Montana-Dakota Utilities (Electric)	February 25, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas)	October 7, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas Depr.)	Filed April 7, 2003
	North Dakota Public Service Commission	PU-399-03-296	Montana-Dakota Utilities (Electric)	Filed October 15, 2003
	North Dakota Public Service Commission	PU-04-97	Montana-Dakota Utilities (Gas)	Filed July 6, 2004
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983
NJ	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
NY	N.Y. Council of Retail Merchants Metropolitan N.Y. Retail Council Metropolitan N.Y. Retail Council N.Y. Metro. Transit Authority	26806 27029 27136 27353	All Electric Utilities Consolidated Edison Company Long Island Lighting Company Consolidated Edison Company	February 3, 1976 (none) July 1, 1977 September 5, 1980
OH	Ohio Council of Retail Association Ohio Council of Retail Association	88-170-EL 83-1529-EL	Cleveland Elec. Illuminating Cincinnati Gas & Electric	(none) February 15, 1992
PA	Pennsylvania Retail Association Southeastern Pa. Transp. Authority Eastern Penn Energy Users Group Eastern Penn Energy Association Penn Business Utility User Group Pennsylvania Office of Consumer Advocate	76-PRMD-7 R-811626 R-822169 R-842651 R-850152 R-00016339	All Electric Utilities Philadelphia Electric Company Penn. Power & Light Company Penn. Power & Light Company Philadelphia Electric Company Pennsylvania-American Water Co.	September 7, 1977 December 11, 1981 March/April 1983 December 3, 1984 February 19, 1986 September 19, 2001
TX	Houston Retailers Association Houston Retailers Association Cities for Fair Utility Rates	5779 6765 8425/8431	Houston Lighting Company Houston Lighting Company Houston Lighting Company	October 19, 1984 September 25, 1986 April 25, 1989
UT	Div. Of Public Utilities Dept of Commerce Div. Of Public Utilities Dept of Commerce	98-2035-33 05-057-T01	Pacific Corp Questar Gas Company	Filed August 16, Sept 22, 1999 May 17, 2006
VA	Consumer Congress of Virginia Consumer Congress of Virginia Va. Business Committee on Energy Virginia Pipe Trades Council	19426 19960 PUE 7900012 PUE 8900051	Virginia Electric Power Company Virginia Electric Power Company Virginia Electric Power Company Old Dominion Electric Corp. &	July 1, 1975 September 19, 1978 February 25, 1981 October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases: Client	Case Number	Utility	Date of Cross-Examination
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
AK	GCI Communications, Inc.	U-97-82,U-97-143	Alaska Communications Systems	Filed Feb 25, April 5, 2004
	GCI Communications, Inc.	U-05-46	Matanuska Telephone Association	October 28, 2005
AZ	Arizona Burglar & Fire Alarm Association	9981-E-1051-80-64	Mountain State Telephone	(none)
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	U.S. Department of Defense	T-01051B-99-0105	US WEST Communications	Filed July 26, Sept 8, 2000
CA	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont.	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan. 18, Oct. 31, Nov 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985, October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac. Bell Tel. & GTE of CA.	January 23, 1989
	California Cellular Resellers	A.88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	1.87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	1.88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc.	1.88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U.S. Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U.S. Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U.S. Department of Defense	Appl.	Mountain Bell Telephone Company	September 18, 1986
	U.S. Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U.S. Department of Defense	I&S 891-O82T	U.S. West Communications	February 21, 1990
	U.S. Department of Defense	905-544T	U.S. West Communications	July 17, 1991
	U.S. Department of Defense	90A-665T	U.S. West Communications	October 23, 1991
	U.S. Department of Defense	92M-039T	U.S. West Communications	February 24-24, 1992
	U.S. Department of Defense	92S-229T	U.S. West Communications	July 30-31, 1992
	U.S. Department of Defense	90A-665T	U.S. West Communications	November 6, 1996
	AT&T	96S-331T	U.S. West Communications	April 17, 1997

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co.	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co.	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co.	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co.	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co.	December 5, 2000
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Exar
	Client	Case		
		Case Number	Utility	
ID	U.S. Department of Energy	U-1000-63	Mountain Bell Telephone Co.	May 16, 1983
	U.S. Department of Energy	U-1000-70	Mountain Bell Telephone Co.	March 6, 1984
IL	Illinois Alarm Companies	79-0143	Illinois Bell Telephone	September 26, 1979
	Attorney General of Illinois	81-0478	Illinois Bell Telephone	December 28, 1981
	GTE Sprint Communications Co.	83-0142	All Telephone Companies	August 4, 1983
	Federal Executive Agencies	89-0033	Illinois Bell Telephone	June 12, 1989
KS	State Corporation Commission	Depr. Repr.	Southwestern Bell	May 12-14, 1986
	Federal Executive Agencies	166.856-U	Southwestern Bell	November 7, 1989
	Federal Executive Agencies	190, 492	All Telephone Companies	November 4, 1994
KY	Kentucky Cable Telecommunications Assn.	2000-414	Blue Grass Energy Cooperative	January 11, 2001
	Kentucky Cable Telecommunications Assn.	2000-39	Cumberland Valley Electric, Inc.	January 11, 2001
MD	Maryland People's Counsel	6813	C&P Telephone Company	1975
	Maryland People's Counsel	6881	C&P Telephone Company	December 17, 1975
	Maryland People's Counsel	7025	C&P Telephone Company	March 15, 1975
	Maryland People's Counsel	7467	C&P Telephone Company	October 20, 1981
	Federal Executive Agencies	7851	C&P Telephone Company	March 20, 1985
	Federal Executive Agencies	8106	C&P Telephone Company	May 9, 1988
	Federal Executive Agencies	8274	C&P Telephone Company	August 2, 1990
MI	Michigan Attorney General	U-8911	Michigan Bell Telephone Co.	November 7, 1988
	Michigan Attorney General	U-9553	AT&T Communications/MCI	December 4, 1990
MN	GTE Sprint Communications Co.	83-102-HC	All Telephone Companies	August 5, 1983
	U.S. Department of Defense	87-021-BC	Northwest Bell Telephone Co.	(none)

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Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
MO	GTE Sprint Communications Co. Federal Executive Agencies Federal Executive Agencies	TR83-253 TC-89-14 TO-89-56	Southwestern Bell Tel. Co. Southwestern Bell Tel. Co. Southwestern Bell Tel. Co.	September 5, 1983 (none) November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990
NJ	Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate	Depr.Repr. 815-458 Depr.Repr. Depr.Repr. T092030358 TMO05080739	N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company United Telephone Co. of New Jersey	Mar-79 October 15, 1981 March 1, 1982 February 1, 1985 September 30, 1992 January 5,2006
NM	New Mexico Corporation Commission New Mexico Corporation Commission	1032 86-151-TC	Mountain Bell Telephone Co. General Telephone of Southwest	November 14, 1983 February 5, 1987
NV	Prime Cable of Las Vegas Prime Cable of Las Vegas	95-8034/8035 96-9035	Central Telephone - NV Sprint/Centel, Nevada Bell	Filed November 22, 1995 June 2, 1997
NY	Holmes Protection, Inc. Holmes Protection, Inc. 5 Alarm Companies GTE Sprint Communications Co.	27350 27469 27710 28425	New York Telephone Company New York Telephone Company New York Telephone Company All Telephone Companies	October 17, 1978 May 17, 1979 July 24, 1980 July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate	Depr.Repr. 86-511-C 86-541-C Depr.Repr. 89-180-C	Southern Bell Southern Bell General Telephone of South Southern Bell ALLTEL of South Carolina	July 1, 1986 December 11, 1986 April 8, 1987 July 10, 1989 September 26, 1989

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Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Exa
	Client	Case		
		Case Number	Utility	
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989
VI	V.I. Department of Commerce V.I. Public Service Commission	205 341	Virgin Islands Telephone Co. Virgin Islands Telephone Co.	April 29, 1980 March 20, 1991
WA	U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER WA Attorney General/TRACER U.S. Department of Defense WA Attorney General/WeBTEC/AARP WA Attorney General WA Attorney General	U-72-39 U-87-796-T U-88-20524 U-89-2698-F UT-940641 UT-941464 UT-951425 UT-961632 UT-021120 UT-040788 UT-040520 UT-050814	Pacific Northwest Bell Pacific Northwest Bell Pacific Northwest Bell US West Communications US West Communications US West Communications US West Communications US West Communications GTE Northwest, Inc Qwest Communications Verizon Northwest, Inc. Verizon Northwest, Inc. Verizon - MCI Merger	1973 December 20, 1983 November 8, 1988 November 28, 1989 Filed October 14, 1994 June 22, 1995 January 22, 1996 Filed June 23, 1997 July 29, 1997 May 22, 2003 August 12, 2004 February 2, 2005 November 2, 2005
WI	GTE Sprint Wisconsin Consumers Utility Board Wisconsin Consumers Utility Board	6720-TR-38 2055-TR-102 5846-TR-102	All Telephone Companies CenturyTel of Central Wisconsin Telephone USA, LCC	October 20, 1983 June 26, 2002 June 26, 2002

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Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeronautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date of Cross-Examination
U.S. Congress			
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	July 1979
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission - Surface Transportation Board			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Snavely King Majoros O'Connor & Lee, Inc.	Ex Parte 664	Cost of Capital	December 8, 2006
Civil Aeronautics Board			
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			
Surface Transportation Board			
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001

AFFIDAVIT

STATE OF TENNESSEE
BEFORE THE TENNESSEE REGULATORY AUTHORITY

In The Matter of ATMOS ENERGY CORPORATION	)
For approval of Adjustments to its Rates and Revised	) Docket No.07-00105
Tariff.	)

COUNTY OF HANCOCK)
STATE OF MAINE)

Before me this day appeared Charles W. King and stated:

1. My name is Charles W. King, I am the President of Snavely King Majoros O'Connor & Lee, Inc.

2. I have caused to be filed in the above-referenced case testimony on behalf of the Attorney General of Tennessee, Attachments A and B, and two exhibits.

3. The material was prepared entirely by me or under my direction.

4. The statements made and the data presented are true and correct to the best of my knowledge and belief.

Charles W. King

Donna L Sawyer
Notary Public
Donna L Sawyer
My Commission expires on
11-21-2007