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Exhibit No.: ____________
Issues: Cost of Service Study
Witness: Ronald J. Amen
Type of Exhibit: Direct Testimony
Sponsoring Party: Missouri Gas Energy
Case No.: GR-2006-
Date Testimony Prepared: May 1, 2006

MISSOURI PUBLIC SERVICE COMMISSION

MISSOURI GAS ENERGY

CASE NO. GR-2006-

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Missouri Public Service Commission

DIRECT TESTIMONY OF

RONALD J. AMEN

Jefferson City, Missouri

May 1, 2006

MGE Exhibit No. 15
Case No(s). GR-2006-0422
Date 1-9-06 Rptr PF

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DIRECT TESTIMONY OF RONALD J. AMEN

I. BACKGROUND AND TESTIMONY HISTORY OF WITNESS

Q. Please state your name and business address.

A. My name is Ronald J. Amen. My business address is 1201 Third Avenue, Suite 3320, Seattle, WA 98101.

Q. By whom are you employed and in what capacity?

A. I am a Director with Navigant Consulting, Inc. ("NCI") and a member of the Litigation, Regulatory and Markets Practice Area of the Firm. NCI is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q. Please describe NCI's business activities.

A. NCI is a global management consulting firm that provides strategic, financial, management, and expert services to energy-based, network and other regulated industries. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas and electric industries. Included in NCI's relevant experience are the areas of utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at transmission and distribution, gas pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous utility companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over twenty-seven (27) years of experience in the utility industry, the last eight (8) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management and energy marketers in matters pertaining to costing and pricing, regulatory planning and policy development, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Appendix A to my testimony.

II. EXECUTIVE SUMMARY

Q. For what purpose has NCI been retained by Missouri Gas Energy ("MGE" or the "Company")?

A. NCI has been retained by MGE as a consultant in the area of utility costing and rate design and related regulatory matters. Specifically, MGE has requested that we assist the Company in conducting a cost of service study to determine the embedded costs of serving its natural gas retail customers, in addition to various costing and pricing studies related to the provision of gas distribution service.

Q. What is the purpose of your testimony in this proceeding?

A. I will present the results of the retail natural gas cost of service study filed by the Company in this proceeding. I will discuss the underlying methodology and basis used in the Company's gas cost of service study.

I will then describe the full-cost level of revenue responsibility between customer classes as a result of the revenue requirement proposed by MGE in this proceeding and as supported by the cost of service study. I will discuss the use of cost of service results as a guide to be incorporated into the rate design process. Because the results of the cost of service study suggest shifts in revenue responsibility between customer classes, witness Mr. Russell Feingold will be proposing changes in the rates of MGE's rate schedules that reflect the cost of service study results and the Company's alternative rate design proposals.

Q. Please summarize your conclusions with regard to the selection and use of the Company's cost allocation methodology?

A. The Company's design day coincident peak allocation methodology, along with the identification of a customer component of distribution mains, best reflects cost causation on the Company's system. It has a sound conceptual and theoretical basis and reflects the principles deemed appropriate by the Commission in establishing an allocation methodology because it is related to the actual system as built to serve all classes of customers. Therefore, it is superior to other cost allocation methodologies that give recognition to system utilization characteristics.

Q. What conclusions did you reach with regard to the class-by-class results of the cost of service study?

A. The residential service class ("Rate RS") exhibits the lowest rate of return of all the classes and is well below the current system average of 4.54%. While the rate of return exhibited by the small general service class ("Rate SGS") is above the current system average, it is still below the Company's proposed 8.936% rate of return. Both the large general service class ("Rate LGS") and the large volume service class ("Rate LV") exhibit rates of return that are highest among the classes at 11.935% and 12.655%, respectively.

III. LIST OF SCHEDULES SPONSORED IN TESTIMONY

Q. What Schedules are you sponsoring in this proceeding?

A. I am sponsoring the following Schedules:

- Schedule RJA – 1 Embedded Class Cost of Service Study Summary
- Schedule RJA – 2 Functionalized Rate Base, Revenue Requirement and Unit Costs
- Schedule RJA – 3 Detailed Cost of Service Study Results
- Schedule RJA – 4 Allocation Factors
- Schedule RJA – 5 Class Load and Service Characteristics of the Company's Customers
- Schedule RJA - 6 Graph of Relationship between Footage of Mains and Number of Customers

IV. INTRODUCTION OF THE COMPANY'S COST OF SERVICE STUDY PRESENTATION

Q. Please describe Schedule Nos. RJA – 1, RJA – 2, RJA – 3 and RJA – 4 in more detail.

A. Schedule **RJA – 1** presents the following revenue requirement and rate of return summary results of the Company's embedded cost of service study:

- Earned Return Summary at Present Rates

- Revenue Requirement at Equalized Rates of Return, and
- Proposed Revenue Requirement and Rate of Return by Service Classification

Schedule **RJA – 2**, presents the following summary information:

- Functionalized Rate Base at Equalized Rates of Return
- Functionalized Revenue Requirement at Equalized Rates of Return
- Unit Costs at Equalized Rates of Return

Schedule **RJA – 3** presents all details of the Company's proposed cost of service study by Federal Energy Regulatory Commission ("FERC") primary account by rate schedule.

Finally, Schedule **RJA – 4** summarizes the following:

- External Classification and Allocation Factors
- Internal Allocation Factors

The external classification and allocation factors were derived from MGE's pro forma level of customers, volumes and revenues, as well as the results of subsidiary analyses conducted by NCI, with the assistance of Company personnel, related to cost causation indicators for certain plant and expense elements. The internal allocation factors are derived within the cost of service study model, consisting of subtotals and other combinations of related plant and O&M

accounts, which are then used to allocate certain related accounts and miscellaneous, general and administrative overhead accounts.

Q. **What was the source of the cost data analyzed in the Company's cost of service study?**

A. All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

Q. **Did you make any changes to the classes of service included in the Company's cost of service study compared to the cost study submitted in its last gas rate proceeding?**

A. No.

V. FACTORS INFLUENCING THE COST ALLOCATION FRAMEWORK

Q. **Please discuss the factors that you believe can influence the overall cost allocation framework utilized by a gas Local Distribution Company ("LDC").**

A. The overall framework within which an LDC performs a cost of service cost study, that is, the three standard steps or phases followed by a utility when performing a cost study – cost functionalization, cost classification and cost allocation, can be influenced by various factors. These factors can include: (1) the physical configuration of the LDC's gas system; (2) the availability of data within the LDC; and (3) the state regulatory policies and requirements applicable to the LDC. The physical configuration of the transmission and distribution system provides certain considerations. For example, is the distribution system a centralized grid/single city-gate or a dispersed/multiple city-gate configuration? Does the LDC have an integrated transmission and distribution system or a distribution-only operation? Does the system operate under a multiple-pressure based or a single-pressure based configuration?

The structure of the LDC's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available.

State regulatory policies and requirements refer to the particular approaches historically used to establish utility rates in the state. Specific methodological preferences or guidelines for performing cost studies or designing rates, which have been previously established by the state regulatory agency, can influence the particular cost allocation method utilized by the LDC.

Q. **How do these factors relate to the specific circumstances applicable to the Company?**

A. The physical configuration of the Company's gas system is a dispersed/multiple service area transmission and distribution system in central and western Missouri (including Kansas City, St. Joseph, Joplin and Monett). The multi pressure-based local distribution system consists of approximately 8,074 miles of mains, 5,022 miles of service lines and 47 miles of transmission lines. The Company has detailed plant accounting records for many of its distribution-related facilities including mains, services and meters.

In the Company's most recent prior rate case, the Commission expressed a preference for utilizing a costing methodology that allocates some distribution mains costs on the basis of the number of customers served in order to recognize the fact that the distribution system is built to provide customers with access to the system as well as to accommodate peak demand.

Q. Why are these considerations relevant to conducting the Company's cost of service study?

A. It is important to understand these considerations because they influence the overall context within which the Company's cost studies were conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the Company's gas system design and operations and understanding the regulatory environment in the State of Missouri as it pertains to cost of service studies and gas ratemaking issues.

VI. GUIDING PRINCIPLES OF COST ALLOCATION

Q. Please state the purpose of a cost of service study.

A. A cost of service study is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and to help determine the individual class revenue requirements.

Q. What are the guiding principles that should be followed when performing a cost of service study?

A. The concept of *cost causation* is the fundamental and underlying philosophy applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the utility in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than providing service off-peak.

The distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers, either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer billing and accounting expenses.

Demand or *capacity* related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the LDC for its sales service customers. However, when a gas utility company's cost of gas is not recovered through its base rates, very little of its remaining delivery service cost structure is commodity related.

Q. What are the steps to performing cost of service studies?

A. The three broad steps used to perform cost of service studies are 1) functionalization; (2) classification; and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service are Distribution and Customer Accounts. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer; (2) demand or capacity; and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, and commodity or revenue allocation factors.

Q. How does the cost analyst establish the cost and utility service relationships?

A. To establish these relationships, the cost analyst must analyze a company's gas system design and operations, its accounting records and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" relates to a specific identification of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods although for many costs, those associated with meters and services as an example, allocation methods supported by special studies, discussed below, can be a good proxy for direct assignment.

Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. **Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?**

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. **Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform a cost of service study.**

A. As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q. Please describe the key issues related to the allocation of demand-related costs within a cost of service study.

A. A complex part of the allocation process is the allocation of demand-related costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. In fact, it is not unusual for more than one demand cost allocation methodology to be used in a cost of service study. Despite the use of different methods to allocate demand costs, it is fair to say that three basic methodologies form the foundation for the allocation process. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the company. Under this methodology, demand related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group. The Peak Demand Allocation process might focus on a single peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days or the expected contribution to the system peak on a design day.

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand).

A simplified version of this methodology is the Average and Peak methodology. This cost methodology often gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's or rate class' maximum demand, irrespective of the time of the system peak.

VII. REVIEW OF THE LOAD AND SERVICE CHARACTERISTICS OF THE COMPANY'S CUSTOMERS

Q. **As stated earlier, the load characteristics of an LDC's customers are an important element in determining the costs incurred by the LDC in serving its customers. Have the load characteristics of the Company's customers been summarized?**

A. Yes. The relevant load characteristics of the Company's various customer groups are shown in Schedule **RJA – 5**. In reviewing this information, it is important to point out that for each class of service, the absolute and relative level of certain of these load characteristics have a direct influence on the type and level of costs incurred by the Company in serving its customers.

Q. **What are the implications of class load characteristics for purposes of determining the costs to serve an LDC's customers?**

A. Annual load factor is an important indicator of how a customer utilizes an LDC's pipeline capacity. As a customer's annual load factor increases, it indicates that the customer is using the LDC's system capacity more efficiently than a lower load factor customer. In addition, peak day demand is a key element in the sizing of an LDC's facilities and in determining the level of costs incurred in serving its customers. The day-to-day utilization of an LDC's facilities by its customers is measured by their annual gas consumption characteristics.

VIII. THE METHODOLOGICAL AND CONCEPTUAL BASIS USED IN THE COMPANY'S COST OF SERVICE STUDY

Q. How have the demand-related costs been allocated in the Company's Cost of Service Study?

A. The Company's cost of service study methodology uses a coincident peak demand allocation factor, derived on a design day basis, for allocating various portions of its capacity related costs. Capacity costs for the Company consist of the costs associated with city-gate facilities and the capacity portion of the Company's transmission and distribution system.

Q. Please explain why the Company has chosen to utilize a Coincident Peak methodology in developing its Cost of Service Study?

A. The Company has based its proposed rates on the study results using the coincident peak allocation methodology because this demand allocation approach, along with an additional cost causative principle – that being a customer related element to the distribution system, best reflects cost causation on the Company's system. From a gas engineering perspective, it is clear that a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system, whether the investment is driven by the need to replace aging and deteriorating pipelines or for the purpose of expanding distribution capacity to serve growing demand on the system. An LDC's gas system sized to accommodate average gas demands would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the

LDC is assured of being able to satisfy its service obligation throughout the year. As such, cost causation with respect to demand related costs are unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the LDC's gas system by customers with low load factors. Clearly, under-utilization of an LDC's gas system is a result that an LDC can hardly encourage, recognizing that higher system utilization will result in lower unit costs to all customers served by the LDC.

For the above-stated reasons, it is inappropriate to rely upon a commodity-based allocation factor, as derived from annual gas throughput volume, for purposes of allocating demand related costs to an LDC.

Q. Why did you choose to utilize the Company's design day demand rather than its actual peak day demand as a demand allocation factor?

A. Use of an LDC's design day demand is superior to using its actual peak day demand or an historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These include:

1. An LDC's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.

2. Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.

3. Design day demand provides more stable cost allocation results over time.

Q. **Please explain why the Company's design day demand best reflects the factors that actually cause costs to be incurred.**

A. The Company must consistently rely upon design day demand in the acquisition of its upstream gas supply-related resources and in the design of its own distribution facilities required to service its firm service customers. And perhaps more importantly, design day demand directly measures the gas demand requirements of the Company's firm service customers which create the need for the Company to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis.

In my opinion, there is no better way to capture the true cost of the Company's operations than to utilize its design peak day requirements within its cost of service studies.

Q. **Please explain why use of design day demand provides more stable cost allocation results over time.**

A. By definition, an LDC's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of an LDC's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

Q. Please discuss the rationale and evidentiary basis for the classification of a portion of the investment in distribution mains as customer related.

A. It is an accepted principle throughout the gas industry that distribution mains (Account No. 376) are installed to meet both system peak load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes, it is. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach, and; 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, which is the method utilized in the Company's cost study, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of his peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, (1) Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners (NARUC), and (2) Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment. Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. **With respect to the Company's specific operating conditions, is there demonstrable evidence to support the use of a customer component of distribution mains?**

A. Yes. As an example, the results of the zero intercept analysis based on the Company's investment in plastic distribution mains can be expressed formulaically as follows:

$$y = mx + b$$

Where: y = average cost per installed foot of MGE's distribution mains

m = $1.33 per installed foot per inch of pipe diameter

x = diameter of distribution mains

b = $3.89 per installed foot

This equation reveals that regardless of the main's diameter, the average cost of a plastic distribution main on MGE's gas system will be at least equal to $3.89 per installed foot. Stated differently, $3.89 of the total cost of each foot of installed main is <u>unrelated</u> to the main's diameter. The $3.89 per foot cost component is exclusively related to the simple fact that MGE incurs this cost to install a plastic main, regardless of its size. That is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these disaggregated costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of MGE's plastic distribution mains as distinguished from the per foot demand cost component, which is equal to $1.33 per foot times the diameter of the plastic distribution main.

Q. **Please summarize the results of the zero intercept study for MGE's distribution mains?**

A. Similarly to the analysis described above for plastic distribution mains, statistical regressions were performed for the Company's steel and cast iron mains, the results of which were applied to the current system footage of the respective pipe types to derive the total cost of a zero inch distribution system. The results of the study indicate that 32.6% of the distribution mains investment should be considered customer-related. The remaining 67.4% of the investment in distribution mains is demand-related. The total mains investment costs are classified accordingly for allocation purposes in the cost study.

Q. **Have you analyzed the relationship between the number of customers served by MGE and level of investment in distribution mains?**

A. Yes. I have provided a graphical representation of the relationship between total installed footage of distribution mains and the number of residential customers, the class of customers that represent most of the growth in recent years on the Company's system. This graph is shown on Schedule **RJA – 6**. As would be expected, as the number of customers served by MGE <u>increases</u>, the level of investment in distribution mains, as measured by installed footage, also <u>increases</u>.

Q. Why would one expect there to be a strong correlation between the number of customers served by MGE and the length of its system of distribution mains?

A. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's more remote or "off-system" location. Recognizing that the goal is to more reasonably classify and allocate the total cost of MGE's distribution mains facilities, it is appropriate to analyze the cost causative factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system or "zero capacity" approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by MGE represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

Q. **Has the Commission previously endorsed the development of a customer component of distribution mains for MGE?**

A. Yes. The development of a customer component of distribution mains is consistent with the Commission's 2004 Order in MGE's prior rate case (Docket No. GR-2004-0209), wherein the Commission stated:

> " The zero-intercept method used by MGE recognizes that when a main is built to reach a customer, a certain portion of the cost of the main will be incurred no matter how much gas the customer uses. Thus the cost of a zero inch main would be the customer-related portion of the cost of the main. The extra cost derived from installing larger mains, mains that are large enough to meet peak demand, would be the demand-related portion of the cost of the main. ... MGE's zero-intercept method recognizes the different nature of these costs and is a preferable method. " [1]

Q. **Please describe the special studies conducted for purposes of allocating other distribution plant investment.**

A. Regarding the Company's major plant accounts, customer weighting factors were developed to allocate the following plant accounts: Services – Account No. 380,

[1] Missouri Public Service Commission, Case No. GR-2004-0209, Report and Order dated September 21, 2004, pages 40-42.

Meters – Account 381, Meter Installations – Account No. 382 and House Regulators – Account No. 383. These weighting factors reflect any differences in the current unit costs that particular customer groups cause the Company to incur. For example, the cost of a 3/4-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger commercial or industrial customer. The use of weighting factors takes these unit cost differences into account when assigning costs to the various customer classes. For Industrial Measuring & Regulating Station Equipment – Account No. 385, a direct assignment of this plant to the Large Volume Service ("LVS") service class was facilitated by the identification in the property records of specific electronic gas measurement equipment with the customers in this class. Similarly, the Company's Automated Meter Reading ("AMR") Communication Equipment, Account 397.1, were assigned to the services classes other than LVS on the basis of number of customers, as these AMR devices are installed on the meters of all but the LVS customers.

Q. **How were the particular type and size of facilities for each plant account that should be attributed to each of the Company's customer groups determined?**

A. Based on its historical installation and operating experience, the Company has established engineering and operational standards which enable the direct identification of the typical size, length and material type of service line by customer group. This information is contained in the Company's customer information system and property records. Similarly, with regard to meters, the Company was able to conduct a detailed analysis of data also contained in its customer information system and property records that identified the type and size of meter for each customer it serves. This analysis also was used to determine the type and size of equipment, by customer class, for house regulators and to assign the installation costs of meters and house regulators to specific customer classes.

Q. **Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.**

A. These items were allocated by function in proportion to their associated plant accounts.

Q. **How did the study allocate distribution-related operation and maintenance expenses?**

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's operation and maintenance expenses generally are thought to support the utility's corresponding plant in service accounts. That is, the existence of particular plant facilities necessitates the incurrence of cost (i.e., expenses) by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Maintenance of Meters and House Regulator Expense, is allocated on the same basis as its corresponding plant accounts, Account No. 381 – Meters and Account No. 383 – House Regulators. With the Company's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. How did the study allocate Customer Accounting Expenses (Accounts 902 – 904)?

A. Meter Reading Expense, Account 902, was allocated on the basis of the number of customers by class. A special study of the cost types and activities performed related to charges to Account 903, Customer Records and Collection Expense, resulted in the construction of a composite allocation, which was derived from a weighting of the number of payment arrangements, bills and service orders by class. An analysis of uncollectible expenses by class was conducted for the purpose of allocating Account 904, Uncollectible Accounts Expense.

Q. How did the study allocate Customer Service and Information Expenses (Accounts 908 – 910) and Sales Expenses (Accounts 912 and 916)?

A. Customer Assistance Expense, Account 908, was directly assignable to the Residential class. An analysis of the charges to this account revealed that the labor costs and other expenditures were entirely related to MGE's administration of and funds expended under its low-income weatherization program. The remaining customer service and information accounts, Account 909, Informational & Instructional Advertising, and Account 910, Miscellaneous Expenses, were allocated on the basis of number of customers.

Demonstration and Selling Expense, Account 912, was apportioned to the classes based on an evaluation of the underlying cost types, cost centers and activities performed. Charges to this account consisted primarily of labor costs related to the functions performed by the Company's "Key Account" representatives and activities associated with residential builders and developers. Miscellaneous Sales Expense, Account 916, was allocated on the same basis as Account 912.

Q. How did the study allocate administrative and general expenses?

A. Administrative and general ("A&G") expenses, Account 920, were allocated on the basis of the Company's total O&M, exclusive of A&G.

Q. How did the study allocate amortization expenses and taxes other than income taxes?

A. The study allocated Amortization Expense – SLRP, Accounts 404 – 405 in a manner to reflect the specific cost factor associated with this particular amortization expense category, that is, the Service Line Replacement Program. Therefore, the expenses were allocated on the same basis as services. Amortization Expense – Other was allocated on the basis of intangible plant, as this amortization expense is related to intangible plant items, including various computer and technology systems and the associated capitalized software. Taxes other than income taxes were allocated on the basis of total plant.

Q. How were income taxes allocated to each customer class?

A. Deferred income taxes were allocated on a total plant basis. Current income taxes were directly calculated for each rate class based on its income before federal and state income taxes. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues, previously allocated expenses and any adjustments made by the Company for tax computation purposes.

IX. RESULTS OF THE COMPANY'S COST OF SERVICE STUDY

Q. Please discuss the results of the cost of service study filed by the Company.

A. Referring to Schedule **RJA – 1**, the following results at present rates from the Company's cost of service study are indicated on Line No. 15:

1. The residential service class ("Rate RS") exhibits the lowest rate of return at 2.878%, well below the current system average of 4.54%.

2. The small general service class ("Rate SGS") currently provides a rate of return of 7.503%, which is above the current system average of 4.54%, with a revenue-to-cost ratio of .927 at the Company's proposed 8.936% rate of return.

4. The large general service class ("Rate LGS") currently provides the second highest return among all classes at 11.935% and exhibits a revenue-to-cost ratio of 1.175.

5. The large volume service class ("Rate LV") exhibits the highest return among all of the classes at 12.655%, with a revenue-to-cost ratio of 1.231.

It should also be noted here that the foregoing cost of service study results reflect the Company's proposed revenue requirement for base rates that excludes the Company's cost of purchased gas.

Q. Please explain how the full-cost revenue requirement by class and unit cost analysis presented in Schedule RJA – 2 were determined.

A. The NCI computer model extracts the functionalized, classified and allocated expenses and rate base data for each class of service and applies the system average rate of return to the allocated rate base to determine the required net income. This amount is then grossed up to account for the income and general tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yield the total revenue requirement by function for each component of cost (i.e., the customer, demand and commodity portions of the distribution and customer accounts functional categories) at the system average rate of return. The summary total of these calculations is shown in Schedule **RJA – 2**, page 1 of 2. The computer model then unitizes each of the various cost components by dividing the associated revenue full-cost requirement by the corresponding customer usage characteristics or billing determinants. The results of the unit cost calculations are presented on page 2 of the schedule. A monthly customer cost is calculated for each customer class, as well as unit commodity and demand costs.

X. COST OF SERVICE STUDY GUIDELINES FOR REVENUE ALLOCATION AND RATE DESIGN

Q. How can the Cost of Service Study results provide guidelines for rate design?

A. Cost of service study results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results and resulting revenue-to-cost ratios show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service (or "parity"), resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q. **Do the Cost of Service Study results provide guidance in establishing rates within each rate class as well?**

A. Yes. The classified costs, as allocated to each class of service within the cost study, provide useful cost information in determining the level of customer, demand and commodity charges.

Q. **Please explain how the classified costs can be used for rate design.**

A. If the classified costs presented in Schedule **RJA - 2**, the Unit Cost Summary by Function, were used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its pro forma revenue requirement would be recovered.

Q. **Have the results of the cost of service study been used in establishing the Company's proposed class-by-class revenue responsibility levels?**

A. Yes. As discussed by witness Russell A. Feingold, the results of the cost of service study have been used to move the classes toward a more cost based distribution of the overall revenue responsibility.

XI. CONCLUDING REMARKS

Q. Please summarize the reasons why the design day coincident peak methodology was chosen by the Company as its allocation methodology.

A. The Company's allocation methodology was chosen for the following reasons:

1. As a capacity allocation approach, the design day coincident peak method best reflects cost causation on the Company's system,
2. Along with the identification of a customer component of distribution mains, it reflects the principles deemed appropriate by the Commission in establishing an allocation methodology, that is, it is related to the actual system as built to serve all classes of customers,
3. It has a sound conceptual and theoretical basis, and
4. It is superior to the other commonly used, primary cost allocation methodologies that give recognition to system utilization characteristics.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2006-____

AFFIDAVIT OF RONALD J. AMEN

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Ronald J. Amen, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form, to be presented in the above case; that the answers in the foregoing Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Ronald J. Amen
RONALD J. AMEN

Subscribed and sworn to before me this 26th day of APRIL 2006.

Kim W. Henzi
Notary Public

My Commission Expires: Feb. 3, 2007

Kim W. Henzi
Notary Public - Notary Seal
State of Missouri
Jackson County
My Commission Expires Feb. 3, 2007

Appendix A

to Accompany the

Direct Testimony

of

Ronald J. Amen
Director
Navigant Consulting, Inc.

NAVIGANT
CONSULTING

NAVIGANT
CONSULTING

Ronald J. Amen

Ronald J. Amen
Director

Navigant Consulting
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Seattle, WA 98101
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ramen@navigantconsulting.com

Professional History

- Director, Navigant Consulting
- Manager, Federal Regulatory Affairs, Puget Sound Energy, Inc.
- Director, Rates and Tariffs, Washington Natural Gas Company
- Regional Director; Director of Rates, Indiana Energy (now Vectren)
- Data Processing Manager, Asst. District Manager, Ohio Valley Gas Corporation

Education

- B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska

Professional Associations

- Associate Member, American Gas Association
- Past Member, Marketing & Regulatory Committees of the Pacific Coast Gas Association
- Past Member, Rate Committee of the American Gas Association
- Past Member, Statistics and Load Forecasting Methods Committee of the American Gas Association
- Past Chairman, Rate Committee of the Indiana Gas Association

Mr. Amen is a Director with the Energy practice group of Navigant Consulting, Inc. He has over twenty-seven years of combined experience in utility management and consulting in the areas of regulatory affairs, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: cost allocation and pricing issues; regulatory strategy; resource strategy, planning and financial analysis; and expert witness testimony.

Professional Experience

Resource Planning, Strategy and Financial Analysis

» As part of a review of a *Pacific Northwest electric/gas utility's* gas procurement strategy and hedging analytics, provided gas LDC case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.

» For a *Pacific Northwest electric/gas utility*, Mr. Amen provided resource planning strategy and analysis for the company's 2003 Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.

» Engaged by a *Pacific Northwest electric/gas utility* as a member of an NCI team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multi-track solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

» Provided an evaluation of the functions provided by a *Midwestern gas/electric utility*'s underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.

» Engaged by a *Midwestern municipal electric utility* as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.

» For a *Southern gas/electric utility*, conducted an evaluation of two operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

» For a *European electric utility*, provided strategy and analysis support, including a review of the natural gas value chain in the U.S., as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

Cost Allocation, Pricing Issues and Rate Design

» For a *Midwestern energy company*, assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of Revenue Decoupling and Weather Normalization Adjustment ("WNA") mechanisms for its two regulated gas utility subsidiaries. Regulatory filings are currently pending.

» For a *Midwestern gas/electric utility*, assisted the Company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.

» Served as engagement manager for cost of service and rate design support for a *Canadian gas utility* client. Work included expert witness testimony, for the client's capital investment recovery proceeding for a major pipeline project, a cross-provincial transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's PBR and unbundling initiatives and an upcoming global rate design proceeding. Cost of service support included the licensing of a Navigant Consulting Cost of Service computer model.

» Representing a *Pacific Northwest electric/gas utility*, he provided Cost of Service and Rate Design support, including expert witness testimony and conducted research on Electric Power Cost Adjustment Mechanisms and Gas Supply Pricing Options of utilities in North America.

» For a *Northeastern gas utility*, served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a state-wide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

» Engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case for a *Midwest gas transmission/distribution utility*. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.

» Provided rate design support for reconfiguration of a *Pacific Northwest gas utility*'s Commercial / Industrial sales and transportation service offerings. Included collaborative work with an industrial customer stakeholder group.

» Engagement manager for Cost of Service and Rate Design support for two of a *Northeastern gas utility* client's general rate proceedings.

» For a *South American gas utility*, affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.

» For a *Canadian energy marketer*, provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.

» For a *Northwestern gas utility*, negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of 48.5MM therms of annual throughput, and maintained contribution to system costs.

» For a *Northwestern gas utility*, obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and re-designed rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.

Regulatory Policy, Strategy and Analysis

» Provided management of an *Eastern electric/gas utility* with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using NCI's proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures and construction cost control areas.

» Provided management of an *Eastern gas utility* with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on NOI, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

» Provided expert witness testimony for an *Eastern gas utility* on the subject of new area expansion programs in the U.S. for the client's general rate case proceeding. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.

» For a *Pacific Northwest electric/gas utility*, redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client's residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

» Assisted a *Pacific Northwest gas utility* in the restructuring of its commercial / industrial service offerings, including collaborative work with an industrial customer group.

» Provided case strategy and cost of service support for the biennial cost allocation proceedings of *two utility subsidiaries of a Western U.S. energy company.*

» Represented *a Western Canadian gas utility* in the client's capital investment recovery proceeding for a major pipeline project, a cross-provincial transmission pipeline. The project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's PBR and unbundling initiatives and a global rate design proceeding.

Utility Distribution System Operations

» Provided research and consulting support for a *Midwestern gas/electric utility* to establish performance metrics and benchmarks from peer group companies for the client's performance management system.

» For a *Midwestern energy company*, Mr. Amen was responsible for marketing, customer service, distribution system construction, operation and maintenance, for one of six operating service territories of the company's gas utility. Mr. Amen managed a field sales force responsible for sales plan development, including market analysis, program design, regulatory considerations, and cost-effectiveness evaluations for the following customer segments and/or trade alley groups: residential home builders and commercial developers; HVAC contractors; large commercial and industrial key accounts; public institutions; and governmental facilities.

Expert Witness Testimony Presentation

» Arkansas Public Service Commission

» British Columbia Utility Commission (Canada)

» Connecticut Department of Public Utility Control

» Delaware Public Service Commission

» Illinois Commerce Commission (pending)

» Indiana Utility Regulatory Commission

» Oklahoma Corporation Commission

» Pennsylvania Public Utility Commission

» Washington Utilities and Transportation Commission

» Federal Energy Regulatory Commission

Recent Industry Presentations

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4-7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17-18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18-20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18-20, 2005

MISSOURI GAS ENERGY
Embedded Class Cost of Service Study

Line No.	Description	Total Company	Residential	Small General	Large General	Large Volume
	(a)	(b)	(c)	(d)	(e)	(f)
	Rate Base					
1	Plant in Service	842,607,781	634,200,387	152,203,108	8,419,846	47,784,440
2	Accumulated Reserve	(285,295,099)	(220,164,716)	(47,831,526)	(2,516,091)	(14,782,766)
3	Other Rate Base Items	23,890,682	8,319,784	8,619,301	1,338,460	5,613,137
4	TOTAL RATE BASE	$ 581,203,364	$ 422,355,455	$ 112,990,884	$ 7,242,215	$ 38,614,810
	Revenue at Existing Rates					
5	Base Rate Revenues	$ 155,143,130	$ 108,390,514	$ 32,347,330	$ 2,305,234	$ 12,100,052
6	Other Revenues	$ 4,858,264	$ 3,397,840	$ 1,026,916	$ 70,153	$ 363,355
7	TOTAL REVENUE	$ 160,001,395	$ 111,788,355	$ 33,374,246	$ 2,375,387	$ 12,463,408
	Expenses					
8	Other Operation and Maintenance	$ 87,143,447	$ 68,329,997	$ 14,697,725	$ 762,903	$ 3,352,821
9	Depreciation Expense	$ 24,918,174	$ 19,267,642	$ 4,307,985	$ 209,188	$ 1,133,359
10	Amortization Expense	$ 8,230,816	$ 6,512,010	$ 1,327,974	$ 59,984	$ 330,847
11	Other Expenses	$ 9,293,960	$ 7,015,638	$ 1,669,661	$ 91,260	$ 517,401
12	Income Taxes	$ 4,030,509	$ (1,492,677)	$ 2,893,232	$ 387,687	$ 2,242,267
13	TOTAL EXPENSES	$ 133,616,905	$ 99,632,610	$ 24,896,578	$ 1,511,022	$ 7,576,695
14	Operating Income	$ 26,384,490	$ 12,155,744	$ 8,477,667	$ 864,366	$ 4,886,713
15	Present Rate of Return	4.5396%	2.8781%	7.5030%	11.9351%	12.6550%
16	Relative Rate of Return	1.00	0.63	1.65	2.63	2.79
17	Revenue/Cost Ratio	0.7935	0.7283	0.9267	1.1752	1.2313
	Cost of Service Requirement Given Equal Rates of Return					
18	Required Return	8.9360%	8.9360%	8.9360%	8.9360%	8.9360%
19	Required Operating Income	$ 51,936,333	$ 37,741,683	$ 10,096,865	$ 647,164	$ 3,450,619
20	Operating Income (Deficiency)/Surplus	$ (25,551,843)	$ (25,585,939)	$ (1,619,198)	$ 217,201	$ 1,436,093
	Expenses					
21	Other Operation and Maintenance	$ 87,143,447	$ 68,329,997	$ 14,697,725	$ 762,903	$ 3,352,821
22	Depreciation Expense	$ 24,918,174	$ 19,267,642	$ 4,307,985	$ 209,188	$ 1,133,359
23	Amortization Expense	$ 8,230,816	$ 6,512,010	$ 1,327,974	$ 59,984	$ 330,847
24	Other Expenses	$ 9,293,960	$ 7,015,638	$ 1,669,661	$ 91,260	$ 517,401
25	Income Taxes	$ 20,129,998	$ 14,628,295	$ 3,913,443	$ 250,834	$ 1,337,425
26	TOTAL EXPENSES	$ 149,716,395	$ 115,753,583	$ 25,916,789	$ 1,374,169	$ 6,671,853
27	REVENUE REQUIREMENT	$ 201,652,727	$ 153,495,267	$ 36,013,654	$ 2,021,334	$ 10,122,473
28	Other Revenues	$ 4,858,264	$ 3,397,840	$ 1,026,916	$ 70,153	$ 363,355
29	RATE SCHEDULE REVENUE REQUIREMENT	$ 196,794,463	$ 150,097,426	$ 34,986,738	$ 1,951,180	$ 9,759,118
30	Revenue (Deficiency)/Surplus	$ (41,651,332)	$ (41,706,912)	$ (2,639,408)	$ 354,053	$ 2,340,935
	Proposed Revenue Requirement					
31	Proposed Return	8.9360%	7.9482%	11.1651%	11.9351%	12.6550%
32	Relative Rate of Return	1.00	0.89	1.25	1.34	1.42
33	Proposed Operating Income	$ 51,936,332	$ 33,569,699	$ 12,615,555	$ 864,366	$ 4,886,713
34	Income Taxes	$ 20,129,998	$ 11,999,647	$ 5,500,398	$ 387,687	$ 2,242,267
35	Expenses Other Than Income Taxes	$ 129,586,397	$ 101,125,288	$ 22,003,346	$ 1,123,335	$ 5,334,428
36	RATE SCHEDULE REVENUE REQUIREMENT	$ 196,794,462	$ 143,296,794	$ 39,092,382	$ 2,305,234	$ 12,100,052
37	Other Revenues	$ 4,858,264	$ 3,397,840	$ 1,026,916	$ 70,153	$ 363,355
38	REVENUE REQUIREMENT	$ 201,652,727	$ 146,694,634	$ 40,119,298	$ 2,375,387	$ 12,463,408
39	Revenue/Cost Ratio	1.0000	0.9557	1.1140	1.1752	1.2313

MISSOURI GAS ENERGY
Functional Rate Base

	System Total	Residential	Small General	Large General	Large Volume
Distribution					
Demand	$ 231,603,665	$ 138,085,741	$ 53,660,864	$ 5,757,263	$ 34,099,797
Commodity	$ 10,167	$ 4,655	$ 1,923	$ 227	$ 3,361
Customer	$ 330,743,392	$ 267,713,637	$ 57,124,129	$ 1,470,556	$ 4,435,071
Sub-total	$ 562,357,224	$ 405,804,033	$ 110,786,916	$ 7,228,047	$ 38,538,229
Customer Accounting					
Demand	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -
Customer	$ 18,846,140	$ 16,551,423	$ 2,203,968	$ 14,168	$ 76,581
Sub-total	$ 18,846,140	$ 16,551,423	$ 2,203,968	$ 14,168	$ 76,581
TOTAL					
Demand	$ 231,603,665	$ 138,085,741	$ 53,660,864	$ 5,757,263	$ 34,099,797
Commodity	$ 10,167	$ 4,655	$ 1,923	$ 227	$ 3,361
Customer	$ 349,589,532	$ 284,265,059	$ 59,328,096	$ 1,484,724	$ 4,511,652
TOTAL RATE BASE	$ 581,203,364	$ 422,355,455	$ 112,990,884	$ 7,242,215	$ 38,614,810

MISSOURI GAS ENERGY
Functional Revenue Requirement

	System Total	Residential	Small General	Large General	Large Volume
Distribution					
Demand	$ 54,442,941	$ 32,148,054	$ 12,546,312	$ 1,356,792	$ 8,391,783
Commodity	$ 21,050	$ 9,639	$ 3,982	$ 470	$ 6,959
Customer	$ 102,106,750	$ 81,625,852	$ 18,288,691	$ 631,303	$ 1,560,904
Sub-total	$ 156,570,741	$ 113,783,545	$ 30,838,985	$ 1,988,566	$ 9,959,646
Customer Accounting					
Demand	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -
Customer	$ 45,081,986	$ 39,711,722	$ 5,174,669	$ 32,768	$ 162,827
Sub-total	$ 45,081,986	$ 39,711,722	$ 5,174,669	$ 32,768	$ 162,827
TOTAL					
Demand	$ 54,442,941	$ 32,148,054	$ 12,546,312	$ 1,356,792	$ 8,391,783
Commodity	$ 21,050	$ 9,639	$ 3,982	$ 470	$ 6,959
Customer	$ 147,188,737	$ 121,337,574	$ 23,463,360	$ 664,071	$ 1,723,731
TOTAL REVENUE REQUIREMENT	$ 201,652,727	$ 153,495,267	$ 36,013,654	$ 2,021,334	$ 10,122,473
TOTAL FIXED COSTS	$ 201,631,677	$ 153,485,628	$ 36,009,672	$ 2,020,863	$ 10,115,514

MISSOURI GAS ENERGY
Unit Costs

	System Total	Residential	Small General	Large General	Large Volume
Distribution					
Demand (per Peak Day therm per month)	$ 0.49640	$ 0.50180	$ 0.49940	$ 0.49500	$ 0.47280
Commodity (per therm)	$ 0.00003	$ 0.00003	$ 0.00003	$ 0.00003	$ 0.00003
Customer (per customer per month)	17.13	15.72	24.11	151.14	262.34
Demand and Commodity (per therm)	$ 0.07100	$ 0.09230	$ 0.08730	$ 0.07990	$ 0.03250
Customer Accounting					
Demand (per Peak Day therm per month)	-	-	-	-	-
Commodity (per therm)	-	-	-	-	-
Customer (per customer per month)	7.56	7.65	6.82	7.84	27.37
Demand and Commodity (per therm)	-	-	-	-	-
TOTAL					
Demand (per Peak Day therm per month)	$ 0.49640	$ 0.50180	$ 0.49940	$ 0.49500	$ 0.47280
Commodity (per therm)	$ 0.00003	$ 0.00003	$ 0.00003	$ 0.00003	$ 0.00003
Customer (per customer per month)	24.70	23.37	30.93	158.98	289.70
Demand and Commodity (per therm)	$ 0.07100	$ 0.09230	$ 0.08730	$ 0.07990	$ 0.03250
PDAY	109,675,761	64,061,601	25,122,367	2,740,994	17,750,799
ANVOL	767,444,317	348,537,342	143,785,145	16,976,604	258,145,226
CUST	5,960,169	5,191,476	758,566	4,177	5,950

MISSOURI GAS ENERGY
Detailed Cost of Service Study Results

Account Allocation
Test Year TME 12/31/05 Pro Forma

				Residential				Small General			
Acct. No.	Account Description	Allocator	Total	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL
	RATE BASE										
	Plant-in-Service										
	Intangible Plant										
301	Organization	DISTPLNT	15,600	2,911	-	8,729	11,640	1,142	-	1,720	2,862
302	Franchises	DISTPLNT	32,096	5,969	-	17,960	23,949	2,349	-	3,539	5,888
303	Misc. Intangible	DISTPLNT	27,564,993	5,143,501	-	15,424,194	20,567,696	2,017,073	-	3,039,796	5,056,869
-	*Sub-total*		*27,612,689*	*5,152,401*	-	*15,450,883*	*20,603,284*	*2,020,563*	-	*3,045,056*	*5,065,619*
	Distribution Plant										
374	Land & Land Rights	ACT376_385	1,831,620	341,772	-	1,024,896	1,366,668	134,029	-	201,986	336,015
375	Structures & Improvements	ACT376_385	5,556,273	1,036,775	-	3,109,053	4,145,828	406,581	-	612,731	1,019,313
376	Mains	PDAY	331,433,389	130,489,364	-	94,027,620	224,516,983	51,172,647	-	13,820,336	64,992,984
378	Meas. & Reg. Sta. Equip.-General	PDAY	11,579,565	6,783,623	-	-	6,783,623	2,652,419	-	-	2,652,419
379	Meas. & Reg. Sta. Equip.-City Gate	PDAY	3,034,196	1,772,274	-	-	1,772,274	695,014	-	-	695,014
380	Services	SRV	289,906,474	-	-	249,835,702	249,835,702	-	-	36,721,270	36,721,270
381	Meters	MTRS	30,425,241	-	-	17,824,493	17,824,493	-	-	9,988,610	9,988,610
382	Meter Installations	MTRS_INST	67,025,981	-	-	45,906,834	45,906,834	-	-	20,264,865	20,264,865
383	House Regulators	REG	11,295,323	-	-	9,310,604	9,310,604	-	-	1,368,488	1,368,488
385	Electronic Gas Measurement	ACCT385	362,437	-	-	-	-	-	-	-	-
387	Other Equipment		-	-	-	-	-	-	-	-	-
-	*Sub-total*		*752,450,499*	*140,403,807*	-	*421,039,202*	*561,443,009*	*55,060,691*	-	*82,978,287*	*138,038,978*
	General Plant										
389	Land & Land Rights	OPEREXP	773,880	80,940	79	525,787	606,807	31,741	33	98,749	130,524
390	Structures & Improvements	OPEREXP	4,199,112	439,186	429	2,852,949	3,292,563	172,231	177	535,820	708,228
391	Office Furniture & Equipment	OPEREXP	7,288,716	760,236	742	4,938,491	5,699,468	298,134	307	927,511	1,225,951
392	Transportation Equipment	OPEREXP	5,044,280	527,582	515	3,427,170	3,955,267	206,896	213	643,666	850,775
393	Stores Equipment	OPEREXP	513,584	53,716	52	348,938	402,706	21,065	22	65,535	86,622
394	Tools, Shop & Garage	OPEREXP	5,070,504	530,324	518	3,444,988	3,975,830	207,972	214	647,012	855,198
396	Power Operated Equipment	OPEREXP	243,807	25,500	25	165,647	191,171	10,000	10	31,111	41,121
397	Communication Equipment -AMR	CUST_XLV	35,718,650	-	-	31,119,619	31,119,619	-	-	4,574,014	4,574,014
397	Communication Equipment	OPEREXP	3,268,403	343,934	336	2,234,198	2,578,468	134,877	139	419,610	554,626
398	Miscellaneous General Plant	OPEREXP	423,657	44,310	43	287,840	332,193	17,377	18	54,060	71,455
-	*Sub-total*		*62,544,593*	*2,805,728*	*2,739*	*49,345,626*	*52,154,093*	*1,100,293*	*1,132*	*7,997,087*	*9,098,511*
	TOTAL PLANT-IN-SERVICE		842,607,781	148,361,936	2,739	486,835,712	634,200,387 -	58,181,547	1,132	94,020,430	152,203,108 -

		Large General				Large Volume			
Acct. No.	Account Description	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL
	RATE BASE								
	Plant-in-Service								
	Intangible Plant								
301	Organization	125	-	39	163	807	-	128	935
302	Franchises	256	-	79	336	1,659	-	264	1,924
303	Misc. Intangible	220,074	-	68,274	288,348	1,425,210	-	226,870	1,652,081
-	*Sub-total*	*220,455*	-	*68,392*	*288,847*	*1,427,676*	-	*227,263*	*1,654,939*
	Distribution Plant								
374	Land & Land Rights	14,623	-	4,537	19,160	94,701	-	15,075	109,776
375	Structures & Improvements	44,360	-	13,762	58,122	287,280	-	45,730	333,010
376	Mains	5,583,229	-	75,589	5,658,818	36,157,237	-	107,367	36,264,604
378	Meas. & Reg. Sta. Equip.-General	289,394	-	-	289,394	1,874,129	-	-	1,874,129
379	Meas. & Reg. Sta. Equip.-City Gate	75,830	-	-	75,830	491,078	-	-	491,078
380	Services	-	-	670,224	670,224	-	-	2,679,278	2,679,278
381	Meters	-	-	746,666	746,666	-	-	1,865,472	1,865,472
382	Meter Installations	-	-	158,190	158,190	-	-	696,092	696,092
383	House Regulators	-	-	194,727	194,727	-	-	421,503	421,503
385	Electronic Gas Measurement	-	-	-	-	-	-	362,437	362,437
387	Other Equipment	-	-	-	-	-	-	-	-
-	*Sub-total*	*6,007,437*	-	*1,863,696*	*7,871,133*	*38,904,426*	-	*6,192,954*	*45,097,379*
	General Plant								
389	Land & Land Rights	3,463	4	3,308	6,775	22,428	57	7,290	29,775
390	Structures & Improvements	18,791	21	17,949	36,761	121,694	310	39,556	161,560
391	Office Furniture & Equipment	32,528	36	31,070	63,634	210,653	536	68,473	279,662
392	Transportation Equipment	22,574	25	21,562	44,160	146,187	372	47,518	194,077
393	Stores Equipment	2,298	3	2,195	4,496	14,884	38	4,838	19,760
394	Tools, Shop & Garage	22,691	25	21,674	44,390	146,947	374	47,765	195,086
396	Power Operated Equipment	1,091	1	1,042	2,134	7,066	18	2,297	9,380
397	Communication Equipment -AMR	-	-	25,017	25,017	-	-	-	-
397	Communication Equipment	14,716	16	14,056	28,789	95,301	242	30,977	126,520
398	Miscellaneous General Plant	1,696	2	1,811	3,709	12,278	31	3,991	16,300
-	*Sub-total*	*120,048*	*134*	*139,685*	*259,867*	*777,438*	*1,978*	*262,705*	*1,032,121*
	TOTAL PLANT-IN-SERVICE	6,347,940	134	2,071,773	8,419,846 -	41,109,539	1,978	6,672,923	47,784,440

MISSOURI GAS ENERGY
Detailed Cost of Service Study Results

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Acct. No.	Account Description	Allocator	Total	Residential DEM	Residential COM	Residential CUS	Residential TOTAL	Small General DEM	Small General COM	Small General CUS	Small General TOTAL	Large General DEM	Large General COM	Large General CUS	Large General TOTAL	Large Volume DEM	Large Volume COM	Large Volume CUS	Large Volume TOTAL
Accumulated Reserve																			
-	**Intangible Plant**																		
301	Organization	DISTPLNT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
302	Franchises	DISTPLNT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
303	Misc. Intangible	DISTPLNT	(14,885,985)	(2,777,657)	-	(8,329,562)	(11,107,219)	(1,089,284)	-	(1,641,588)	(2,730,872)	(118,847)	-	(36,870)	(155,717)	(769,660)	-	(122,517)	(892,177)
-	*Sub-total*		*(14,885,985)*	*(2,777,657)*	-	*(8,329,562)*	*(11,107,219)*	*(1,089,284)*	-	*(1,641,588)*	*(2,730,872)*	*(118,847)*	-	*(36,870)*	*(155,717)*	*(769,660)*	-	*(122,517)*	*(892,177)*
-	**Distribution Plant**																		
374	Land & Land Rights	ACT376_385	(375,460)	(70,059)	-	(210,091)	(280,151)	(27,474)	-	(41,405)	(68,879)	(2,998)	-	(930)	(3,928)	(19,413)	-	(3,090)	(22,503)
375	Structures & Improvements	ACT376_385	(395,184)	(73,739)	-	(221,128)	(294,867)	(28,918)	-	(43,580)	(72,497)	(3,155)	-	(979)	(4,134)	(20,432)	-	(3,253)	(23,685)
376	Mains	PDAY	(103,736,748)	(40,842,422)	-	(29,430,105)	(70,272,527)	(16,016,745)	-	(4,325,686)	(20,342,431)	(1,747,519)	-	(23,659)	(1,771,178)	(11,317,008)	-	(33,605)	(11,350,613)
378	Meas. & Reg. Sta. Equip.-General	PDAY	(3,431,604)	(2,004,399)	-	-	(2,004,399)	(786,044)	-	-	(786,044)	(85,762)	-	-	(85,762)	(555,398)	-	-	(555,398)
379	Meas. & Reg. Sta. Equip.-City Gate	PDAY	(784,243)	(458,076)	-	-	(458,076)	(179,639)	-	-	(179,639)	(19,600)	-	-	(19,600)	(126,928)	-	-	(126,928)
380	Services	SRV	(126,843,419)	-	-	(109,311,166)	(109,311,166)	-	-	(16,066,738)	(16,066,738)	-	-	(293,245)	(293,245)	-	-	(1,172,270)	(1,172,270)
381	Meters	MTRS	(3,063,347)	-	-	(1,794,648)	(1,794,648)	-	-	(1,005,697)	(1,005,697)	-	-	(75,178)	(75,178)	-	-	(187,824)	(187,824)
382	Meter Installations	MTRS_INST	(13,742,841)	-	-	(9,412,624)	(9,412,624)	-	-	(4,155,058)	(4,155,058)	-	-	(32,435)	(32,435)	-	-	(142,725)	(142,725)
383	House Regulators	REG	(2,080,655)	-	-	(1,715,060)	(1,715,060)	-	-	(252,082)	(252,082)	-	-	(35,870)	(35,870)	-	-	(77,643)	(77,643)
385	Electronic Gas Measurement	ACCT385	(97,535)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(97,535)	(97,535)
-	*Sub-total*		*(254,551,036)*	*(43,448,696)*	-	*(152,094,822)*	*(195,543,518)*	*(17,038,820)*	-	*(25,890,246)*	*(42,929,066)*	*(1,859,033)*	-	*(462,295)*	*(2,321,328)*	*(12,039,179)*	-	*(1,717,945)*	*(13,757,124)*
-	**General Plant**																		
389	Land & Land Rights	OPEREXP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
390	Structures & Improvements	OPEREXP	(862,331)	(90,191)	(88)	(585,882)	(676,161)	(35,369)	(36)	(110,036)	(145,442)	(3,859)	(4)	(3,686)	(7,549)	(24,991)	(64)	(8,123)	(33,178)
391	Office Furniture & Equipment	OPEREXP	(932,720)	(97,553)	(95)	(633,706)	(731,354)	(38,256)	(39)	(119,018)	(157,314)	(4,174)	(5)	(3,987)	(8,166)	(27,031)	(69)	(8,786)	(35,886)
392	Transportation Equipment	OPEREXP	(2,412,064)	(252,278)	(246)	(1,638,798)	(1,891,322)	(98,933)	(102)	(307,787)	(406,822)	(10,794)	(12)	(10,310)	(21,117)	(69,904)	(178)	(22,722)	(92,804)
393	Stores Equipment	OPEREXP	(162,879)	(17,035)	(17)	(110,662)	(127,715)	(6,681)	(7)	(20,784)	(27,471)	(729)	(1)	(696)	(1,426)	(4,720)	(12)	(1,534)	(6,267)
394	Tools, Shop & Garage	OPEREXP	(896,375)	(93,752)	(92)	(609,012)	(702,856)	(36,766)	(38)	(114,380)	(151,184)	(4,011)	(4)	(3,832)	(7,847)	(25,978)	(66)	(8,444)	(34,488)
396	Power Operated Equipment	OPEREXP	431,708	45,152	44	293,310	338,506	17,707	18	55,087	72,812	1,932	2	1,845	3,779	12,511	32	4,067	16,610
397	Communication Equipment -AMR	CUST_XLV	(12,389,162)	-	-	(10,793,969)	(10,793,969)	-	-	(1,586,516)	(1,586,516)	-	-	(8,677)	(8,677)	-	-	-	-
397	Communication Equipment	OPEREXP	1,644,560	172,007	168	1,117,356	1,289,531	67,454	69	209,853	277,377	7,360	8	7,030	14,398	47,661	121	15,492	63,275
398	Miscellaneous General Plant	OPEREXP	(278,836)	(29,163)	(28)	(189,446)	(218,638)	(11,437)	(12)	(35,580)	(47,029)	(1,248)	(1)	(1,192)	(2,441)	(8,081)	(21)	(2,627)	(10,728)
-	*Sub-total*		*(15,858,077)*	*(362,814)*	*(354)*	*(13,150,810)*	*(13,513,978)*	*(142,281)*	*(146)*	*(2,029,160)*	*(2,171,587)*	*(15,524)*	*(17)*	*(23,505)*	*(39,046)*	*(100,532)*	*(256)*	*(32,678)*	*(133,466)*
-	TOTAL ACCUMULATED RESERVE		(286,295,099)	(46,589,167)	(354)	(173,576,194)	(220,164,716)	(18,270,386)	(146)	(29,560,994)	(47,831,526)	(1,993,404)	(17)	(522,670)	(2,516,091)	(12,909,370)	(256)	(1,873,140)	(14,782,766)

MISSOURI GAS ENERGY
Detailed Cost of Service Study Results

Test Year TME 12/31/05 Pro Forma

				Residential				Small General				Large General				Large Volume			
Acct. No.	Account Description	Allocator	Total	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL
	Rate Base Adjustments and Working Capital																		
	Other Rate Base																		
n/a	SLRP Deferrals & Deferred Taxes	SRV	7,893,579	-	-	6,802,532	6,802,532	-	-	999,847	999,847	-	-	18,249	18,249	-	-	72,951	72,951
n/a	Customer Deposits	CUST	(3,934,258)	-	-	(3,424,288)	(3,424,288)	-	-	(503,308)	(503,308)	-	-	(2,753)	(2,753)	-	-	(3,910)	(3,910)
n/a	Customer Advances	MAINSVCS	(13,665,727)	(2,869,978)	-	(7,562,918)	(10,432,896)	(1,125,489)	-	(1,111,610)	(2,237,100)	(122,797)	-	(16,403)	(139,201)	(795,241)	-	(61,289)	(856,530)
n/a	Deferred Income Taxes	TOTPLNT	(65,431,243)	(11,520,788)	(213)	(37,726,728)	(49,247,729)	(4,517,987)	(88)	(7,300,993)	(11,819,068)	(492,938)	(10)	(160,880)	(653,829)	(3,192,290)	(154)	(518,174)	(3,710,618)
n/a	Materials and Supplies/Prepayments	TOTPLNT	1,836,345	323,334	6	1,058,811	1,382,151	126,799	2	204,904	331,705	13,834	0	4,515	18,350	89,592	4	14,543	104,139
n/a	Prepaid Pension	LABOR	5,076,328	756,921	1,113	3,784,405	4,542,440	296,834	460	875,847	1,173,141	32,386	54	35,813	68,254	209,735	804	81,955	292,494
n/a	Gas Inventory	GASINV	77,761,966	48,226,820	-	-	48,226,820	18,421,832	-	-	18,421,832	1,912,483	-	-	1,912,483	9,200,831	-	-	9,200,831
n/a	Cash Working Capital	OPEREXP	13,353,691	1,396,664	1,364	9,072,727	10,470,755	547,715	563	1,703,972	2,252,251	59,759	87	57,080	116,906	387,001	985	125,794	513,780
n/a	Alternative Minimum Tax Credit	TOTPLNT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
n/a	ECWR Deferrals	ECWR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	*Total Other Rate Base*		*23,890,682*	*36,312,972*	*2,270*	*(27,995,458)*	*8,319,784*	*13,749,703*	*938*	*(5,131,339)*	*8,619,301*	*1,402,727*	*111*	*(64,378)*	*1,338,460*	*5,899,628*	*1,639*	*(288,130)*	*5,613,137*
-	TOTAL RATE BASE		581,203,364	138,086,741	4,655	284,265,059	422,355,456	53,660,854	1,923	59,328,096	112,990,884	5,757,263	227	1,484,724	7,242,216	34,099,797	3,361	4,611,652	38,614,810

MISSOURI GAS ENERGY
Detailed Cost of Service Study Results

Test Year TME 12/31/05 Pro Forma

Acct. No.	Account Description	Allocator	Total	Residential				Small General				Large General				Large Volume			
				DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL
EXPENSES																			
O & M Expenses																			
	Distribution																		
870	Operation Supervision & Engineering	ACT871_879	605,995	57,305	218	374,137	431,661	22,473	90	111,073	133,636	2,452	11	7,522	9,984	15,879	158	14,678	30,714
871	Load Dispatching	ANVOL	8,920	-	4,084	-	4,084	-	1,687	-	1,687	-	199	-	199	-	2,949	-	2,949
874	Mains and Services Expenses	MAINSVCS	3,060,109	642,662	-	1,693,532	2,336,195	252,026	-	248,918	500,944	27,497	-	3,673	31,171	178,075	-	13,724	191,799
875	Regulator Station Expenses	PDAY	730,599	426,743	-	-	426,743	167,351	-	-	167,351	18,259	-	-	18,259	118,246	-	-	118,246
876	Measuring & Regulating Station Exp-Ind.	NR_CUST	7,351	-	-	-	-	-	-	7,255	7,255	-	-	40	40	-	-	56	56
877	Measuring & Regulating Station Exp-City Gate	PDAY	5,176	3,023	-	-	3,023	1,186	-	-	1,186	129	-	-	129	838	-	-	838
878	Meter and House Regulator Expenses	MTRS_REG	4,586,129	-	-	3,233,528	3,233,528	-	-	1,110,183	1,110,183	-	-	83,488	83,488	-	-	158,930	158,930
879	Customer Installation Expenses	MTRS_REG	2,942,536	-	-	2,074,685	2,074,685	-	-	712,312	712,312	-	-	53,567	53,567	-	-	101,972	101,972
880	Other Expenses	ACT871_879	1,748,734	165,367	630	1,079,657	1,245,653	64,850	260	320,527	385,637	7,076	31	21,706	28,812	45,821	455	42,355	88,632
881	Rents	ACT871_879	96,433	9,119	35	59,537	68,691	3,576	14	17,675	21,266	390	2	1,197	1,589	2,527	25	2,336	4,888
885	Maintenance Supervision & Engineering	ACT887_893	1,115,108	369,449	-	379,859	749,308	144,883	-	96,894	241,777	15,808	-	1,927	17,734	102,370	-	3,918	106,289
886	Maintenance of Structures & Improvements	ACT887_893	56,405	18,688	-	19,214	37,902	7,329	-	4,901	12,230	800	-	97	897	5,178	-	198	5,376
887	Maintenance of Mains	PDAY	8,030,362	3,161,651	-	2,278,213	5,439,864	1,239,872	-	334,856	1,574,727	135,277	-	1,831	137,109	876,060	-	2,601	878,662
889	Maint. of Meas. & Reg. Sta. Equipment	PDAY	309,128	180,562	-	-	180,562	70,809	-	-	70,809	7,726	-	-	7,726	50,032	-	-	50,032
890	Maint. of Meas. & Reg. Sta. Equip.-Ind.	NR_CUST	282,926	-	-	-	-	-	-	279,230	279,230	-	-	1,527	1,527	-	-	2,169	2,169
891	Maint. of Meas. & Reg. Sta. Equip.-City Gate	PDAY	15,721	9,183	-	-	9,183	3,601	-	-	3,601	393	-	-	393	2,544	-	-	2,544
892	Maintenance of Services	SRV	803,753	-	-	692,659	692,659	-	-	101,808	101,808	-	-	1,858	1,858	-	-	7,428	7,428
893	Maintenance of Meters & House Regulators	MTRS_REG	673,633	-	-	474,956	474,956	-	-	163,069	163,069	-	-	12,263	12,263	-	-	23,344	23,344
894	Maintenance of Other Equipment	ACT887_893	132,320	43,839	-	45,074	88,914	17,192	-	11,498	28,690	1,876	-	229	2,104	12,147	-	465	12,612
-	*Sub-total*		*25,211,338*	*5,087,590*	*4,967*	*12,405,052*	*17,497,610*	*1,995,147*	*2,052*	*3,520,200*	*5,517,399*	*217,682*	*242*	*190,926*	*408,850*	*1,409,718*	*3,586*	*374,176*	*1,787,479*
	Customer Accounts Expense																		
901	Supervision	CUST	411,340	-	-	358,021	358,021	-	-	52,623	52,623	-	-	288	288	-	-	409	409
902	Meter Reading Expenses	CUST	822,320	-	-	715,728	715,728	-	-	105,199	105,199	-	-	575	575	-	-	817	817
903	Customer Records & Collection Expenses	ACCT903	12,352,335	-	-	10,490,460	10,490,460	-	-	1,840,225	1,840,225	-	-	10,557	10,557	-	-	11,092	11,092
904	Uncollectible Accounts	ACCT904	8,881,391	-	-	8,200,565	8,200,565	-	-	673,344	673,344	-	-	3,638	3,638	-	-	3,843	3,843
905	Miscellaneous Customer Accounts Expenses	CUST	58,048	-	-	50,524	50,524	-	-	7,426	7,426	-	-	41	41	-	-	58	58
-	*Sub-total*		*22,525,434*	-	-	*19,815,298*	*19,815,298*	-	-	*2,678,817*	*2,678,817*	-	-	*15,099*	*15,099*	-	-	*16,219*	*16,219*
	Customer Service & Information Expenses																		
908	Customer Assistance	ACCT908	744,378	-	-	744,378	744,378	-	-	-	-	-	-	-	-	-	-	-	-
909	Informational & Instructional Advertising	CUST	58,979	-	-	51,334	51,334	-	-	7,545	7,545	-	-	41	41	-	-	59	59
910	Misc. Customer Service and Informational Exp	CUST	3,543	-	-	3,084	3,084	-	-	453	453	-	-	2	2	-	-	4	4
-	*Sub-total*		*806,900*	-	-	*798,796*	*798,796*	-	-	*7,998*	*7,998*	-	-	*44*	*44*	-	-	*62*	*62*
	Sales Expense																		
912	Demonstration and Selling Expense	ACCT912	96,312	-	-	28,894	28,894	-	-	-	-	-	-	1,798	1,798	-	-	65,621	65,621
916	Miscellaneous Sales	ACCT912	3,156	-	-	947	947	-	-	-	-	-	-	59	59	-	-	2,150	2,150
-	*Sub-total*		*99,468*	-	-	*29,840*	*29,840*	-	-	-	-	-	-	*1,857*	*1,857*	-	-	*67,771*	*67,771*
-	**Administrative & General Expenses**																		
920-930's	Administrative & General Expenses	OPEXP_WOAG	38,500,307	4,026,751	3,932	26,157,771	30,188,453	1,579,129	1,624	4,912,758	6,493,511	172,292	192	164,570	337,053	1,115,770	2,838	362,680	1,481,289
-	*Sub-total*		*38,500,307*	*4,026,751*	*3,932*	*26,157,771*	*30,188,453*	*1,579,129*	*1,624*	*4,912,758*	*6,493,511*	*172,292*	*192*	*164,570*	*337,053*	*1,115,770*	*2,838*	*362,680*	*1,481,289*
-	TOTAL O & M EXPENSES		87,143,447	9,114,341	8,899	59,206,758	68,329,997	3,574,276	3,676	11,119,774	14,697,725	389,974	434	372,495	762,903	2,525,488	6,425	820,908	3,352,821

MISSOURI GAS ENERGY
Detailed Cost of Service Study Results

Test Year TME 12/31/05 Pro Forma

Acct. No.	Account Description	Allocator	Total	Residential				Small General				Large General				Large Volume			
				DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL	DEM	COM	CUS	TOTAL
Depreciation Expense																			
303	Miscellaneous Intangible	DISTPLNT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
374	Land Rights	ACT376_385	32,162	6,001	-	17,996	23,998	2,353	-	3,547	5,900	257	-	80	336	1,663	-	265	1,928
375	Structures	ACT376_385	138,907	25,919	-	77,726	103,646	10,165	-	15,318	25,483	1,109	-	344	1,453	7,182	-	1,143	8,325
376	Mains	PDAY	7,523,538	2,962,109	-	2,134,427	5,096,536	1,161,619	-	313,722	1,475,341	126,739	-	1,716	128,455	820,769	-	2,437	823,207
378	Meas. & Reg. Sta. Equip. - General	PDAY	331,176	193,440	-	-	193,440	75,859	-	-	75,859	8,277	-	-	8,277	53,600	-	-	53,600
379	Meas. & Reg. Sta. Equip. - City Gate	PDAY	75,855	44,307	-	-	44,307	17,375	-	-	17,375	1,896	-	-	1,896	12,277	-	-	12,277
380	Services	SRV	10,656,850	-	-	9,183,864	9,183,864	-	-	1,349,860	1,349,860	-	-	24,637	24,637	-	-	98,489	98,489
381	Meters	MTRS	870,162	-	-	509,781	509,781	-	-	285,674	285,674	-	-	21,355	21,355	-	-	53,353	53,353
382	Meter Installations	MTRS_INST	1,916,943	-	-	1,312,935	1,312,935	-	-	579,575	579,575	-	-	4,524	4,524	-	-	19,908	19,908
383	House Regulators	REG	323,046	-	-	266,283	266,283	-	-	39,139	39,139	-	-	5,569	5,569	-	-	12,055	12,055
385	Electronic Gas Measurement	NR_CUST	12,069	-	-	-	-	-	-	11,911	11,911	-	-	65	65	-	-	93	93
389-398	General Plant	GENPLNT	3,037,466	136,260	133	2,396,460	2,532,853	53,436	55	388,377	441,867	5,830	6	6,784	12,620	37,756	96	12,273	50,125
-	TOTAL DEPRECIATION EXPENSES		24,916,174	3,368,036	133	15,899,473	19,267,642	1,320,807	55	2,987,123	4,307,985	144,108	6	65,074	209,188	933,247	96	200,016	1,133,359
Amortization Expenses																			
404-405	Amortization Expense - SLRP	SRV	3,204,805	-	-	2,761,838	2,761,838	-	-	405,940	405,940	-	-	7,409	7,409	-	-	29,618	29,618
404-405	Amortization Expense - Other	ACT303	5,026,011	937,831	-	2,812,342	3,750,172	367,779	-	554,256	922,035	40,127	-	12,449	52,575	259,863	-	41,366	301,229
-	TOTAL AMORTIZATION		8,230,816	937,831	-	5,574,180	6,512,010	367,779	-	960,195	1,327,974	40,127	-	19,868	59,984	259,863	-	70,984	330,847
Other Expenses																			
408	Taxes other than Income Taxes	TOTPLNT	9,120,565	1,605,901	30	5,258,788	6,864,719	629,769	12	1,017,697	1,647,479	68,711	1	22,425	91,138	444,978	21	72,229	517,229
431	Interest on Customer Deposits	CUST	173,395	-	-	150,919	150,919	-	-	22,182	22,182	-	-	121	121	-	-	172	172
-	TOTAL OTHER EXPENSES		9,293,960	1,605,901	30	5,409,707	7,015,638	629,769	12	1,039,879	1,669,661	68,711	1	22,547	91,260	444,978	21	72,401	517,401
Income Taxes																			
	Income Taxes	RB	4,416,717	1,049,350	35	2,160,205	3,209,590	407,783	15	450,850	858,647	43,751	2	11,283	55,035	259,133	26	34,285	293,444
	TOTAL INCOME TAXES		4,416,717	1,049,350	35	2,160,205	3,209,590	407,783	15	450,850	858,647	43,751	2	11,283	55,035	259,133	26	34,286	293,444
TOTAL EXPENSES			134,003,114	16,075,458	9,097	88,250,323	104,334,878	6,300,414	3,758	16,557,821	22,861,993	686,671	444	491,256	1,178,371	4,422,711	6,568	1,198,594	5,627,872
REVENUE																			
-	RS - Residential Tariff Class	REV_RS	108,390,514	-	108,390,514	-	108,390,514	-	-	-	-	-	-	-	-	-	-	-	-
-	SGS - Small General Service Tariff Class	REV_SGS	32,347,330	-	-	-	-	-	32,347,330	-	32,347,330	-	-	-	-	-	-	-	-
-	LGS - Large General Service Tariff Class	REV_LGS	2,305,234	-	-	-	-	-	-	-	-	-	2,305,234	-	2,305,234	-	-	-	-
-	LV - Large Volume Tariff Class	REV_LV	12,100,052	-	-	-	-	-	-	-	-	-	-	-	-	-	12,100,052	-	12,100,052
487, 488, 4	Service Charges and Other Rev	OTHREV	4,858,264	-	3,397,840	-	3,397,840	-	1,026,916	-	1,026,916	-	70,153	-	70,153	-	363,355	-	363,355
	TOTAL REVENUE		160,001,395	-	111,788,355	-	111,788,355	-	33,374,246	-	33,374,246	-	2,375,387	-	2,375,387	-	12,463,408	-	12,463,408

MISSOURI GAS ENERGY
Cost of Service - External Allocation Factors

Name	Description	Classifier	Total	Residential	Small General	Large General	Large Volume
	CUSTOMER EXTERNAL ALLOCATORS						
CUST	Proforma Number of Customers	CUS		87.04%	12.79%	0.07%	0.10%
	Test Year TME 12/31/05		496,681	432,623	63,214	348	496
	Test Year TME 12/31/05 Pro Forma		498,900	434,231	63,824	349	496
NR_CUST	Non-Residential Customer	CUS		0.00%	98.69%	0.54%	0.77%
	Test Year TME 12/31/05		64,058	-	63,214	348	496
	Test Year TME 12/31/05 Pro Forma		64,669	-	63,824	349	496
ACCT385	LVS Direct Assignment for Acct.385	CUS		0.00%	0.00%	0.00%	100.00%
	Test Year TME 12/31/05		1	-	-	-	1
	Test Year TME 12/31/05 Pro Forma		1	-	-	-	1
SRV	Weighted Services	CUS		86.18%	12.67%	0.23%	0.92%
	Test Year TME 12/31/05		503,877	434,231	63,824	1,165	4,657
	Test Year TME 12/31/05 Pro Forma		503,877	434,231	63,824	1,165	4,657
MTRS	Weighted Meters	CUS		58.58%	32.83%	2.45%	6.13%
	Test Year TME 12/31/05		30,056,926	17,608,717	9,867,692	737,627	1,842,889
	Test Year TME 12/31/05 Pro Forma		30,056,926	17,608,717	9,867,692	737,627	1,842,889
MTRS_INST	Weighted Meter Installation	CUS		68.49%	30.23%	0.24%	1.04%
	Test Year TME 12/31/05		216,667,549	148,397,995	65,508,009	511,365	2,250,181
	Test Year TME 12/31/05 Pro Forma		216,667,549	148,397,995	65,508,009	511,365	2,250,181
REG	Weighted Regulators	CUS		82.43%	12.12%	1.72%	3.73%
	Test Year TME 12/31/05		526,795	434,231	63,824	9,082	19,658
	Test Year TME 12/31/05 Pro Forma		526,795	434,231	63,824	9,082	19,658
MTRS_REG	Weighted Meters & Regulators	CUS		70.51%	24.21%	1.82%	3.47%
	Test Year TME 12/31/05		1	70.51%	22.47%	2.09%	4.93%
	Test Year TME 12/31/05 Pro Forma		1	70.51%	24.21%	1.82%	3.47%
ECWR	ECWR Deferrals Direct Assignment to Residential	CUS		100.00%	0.00%	0.00%	0.00%
	Test Year TME 12/31/05		1	1	-	-	-
	Test Year TME 12/31/05 Pro Forma		1	1	-	-	-
CUST_XLV	Proforma Number of Customers Excluding LV Tariff Class	CUS		87.12%	12.81%	0.07%	0.00%
	Test Year TME 12/31/05		498,404	434,231	63,824	349	-
	Test Year TME 12/31/05 Pro Forma		498,404	434,231	63,824	349	
OTHREV	Other Revenue Allocator	CUS		69.94%	21.14%	1.44%	7.48%
	Test Year TME 12/31/05		153,533,620	107,531,631	32,218,858	2,188,131	11,595,000
	Test Year TME 12/31/05 Pro Forma		156,534,483	109,479,251	33,087,480	2,260,355	11,707,397
ACCT903	Acct 903-Customer Accts & Collection Exp Allocator	CUS		84.93%	14.90%	0.09%	0.09%
	Test Year TME 12/31/05		11,293,811	9,591,488	1,682,529	9,653	10,142
	Test Year TME 12/31/05 Pro Forma		11,293,811	9,591,488	1,682,529	9,653	10,142
REV_RS	Residential Tariff Class Revenue Allocator			100.00%	0.00%	0.00%	0.00%
	Test Year TME 12/31/05		1	1			
	Test Year TME 12/31/05 Pro Forma		1	1			
REV_LV	Large Volume Tariff Class Revenue Allocator			0.00%	0.00%	0.00%	100.00%
	Test Year TME 12/31/05		1				1
	Test Year TME 12/31/05 Pro Forma		1				1
ACCT904	Acct 904 - Uncollectible Accounts Expense Allocator	CUS		92.33%	7.58%	0.04%	0.04%
	Test Year TME 12/31/05		8,877,958	8,197,396	673,084	3,637	3,842
	Test Year TME 12/31/05 Pro Forma		8,877,958	8,197,396	673,084	3,637	3,842
REV_SGS	SGS Tariff Class Revenue Allocator			0.00%	100.00%	0.00%	0.00%
	Test Year TME 12/31/05		1		1		
	Test Year TME 12/31/05 Pro Forma		1		1		
REV_LGS	LGS Tariff Class Revenue Allocator			0.00%	0.00%	100.00%	0.00%
	Test Year TME 12/31/05		1			1	
	Test Year TME 12/31/05 Pro Forma		1			1	
ACCT912	Acct 912 - Demonstration and Selling Expense Allocator	CUS		30.00%	0.00%	1.87%	68.13%
	Test Year TME 12/31/05		100	30		2	68
	Test Year TME 12/31/05 Pro Forma		100	30		2	68
ACCT908	Acct 908 - Customer Assistance Direct Assignment to RS	CUS		100.00%	0.00%	0.00%	0.00%
	Test Year TME 12/31/05		1	1			
	Test Year TME 12/31/05 Pro Forma		1	1			
	COMMODITY EXTERNAL ALLOCATORS						
ANVOL	Adjusted Proforma Annual Volume (Ccf)	COM		45.79%	18.92%	2.23%	33.06%
	Test Year TME 12/31/05		767,444,317	348,537,342	143,785,145	16,976,604	258,145,226
	Test Year TME 12/31/05 Pro Forma		789,690,779	361,601,935	149,378,333	17,646,827	261,063,683
	DEMAND EXTERNAL ALLOCATORS						
PDAY	Design Day Peak Volume	DEM		58.41%	22.91%	2.50%	16.18%
	Test Year TME 12/31/05		9,139,647	5,338,467	2,093,531	228,416	1,479,233
	Test Year TME 12/31/05 Pro Forma		9,139,647	5,338,467	2,093,531	228,416	1,479,233
GASINV	Incremental Winter Season Load Allocator for Gas Inv.	DEM		62.02%	23.69%	2.46%	11.83%
	Test Year TME 12/31/05		331,404,344	205,532,068	78,509,784	8,150,582	39,211,910
	Test Year TME 12/31/05 Pro Forma		331,404,344	205,532,068	78,509,784	8,150,582	39,211,910

MISSOURI GAS ENERGY
Cost of Service - Internal Allocation Factors

Name	Description	Total
ACT871_879	Accounts 871-879	11,340,820
ACT887_893	Accounts 887-893	10,115,523
ADMGEN	Administrative & General	38,500,307
RB	Rate Base	581,203,364
DISTPLNT	Distribution Plant	752,450,499
ACT376_385	Accounts 376-385	745,062,606
OPEREXP	Operating Expenses	87,143,447
MAINSVCS	Mains and Services	621,339,863
TOTPLNT	Total Plant	842,607,781
GENPLNT	General Plant	62,544,593
ACT303	Account 303	27,564,993
DISTGENPLNT	Distribution and General Plant	814,995,092
OPEXP_WOAG	Operating Expenses without A&G Expense	48,643,140

MISSOURI GAS ENERGY
Class Load and Service Characteristics

			Proforma Test Year Ended December 31, 2005			
Line No.	Tariff Class	Description	Annual Load (Ccf)	Seasonal Load Nov-Mar (Ccf)	Design Day Coincident Peak (Ccf)	Annual Load Factor (Ccf)
	(A)	(B)	(F)	(G)	(H)	(I)
1	RS	Residential	361,601,935	273,231,328	5,338,467	18.56%
2	SGS	Small General Service	149,378,333	109,487,573	2,093,531	19.55%
3	LGS	Large General Service	17,646,827	12,259,313	228,416	21.17%
4	LV	Large Volume	260,936,003	132,342,643	1,479,233	48.33%
5		Total	789,563,099	527,320,857	9,139,647	23.67%

MISSOURI GAS ENERGY