Exhibit No.:
Witness: Charles D. Laderoute
Type of Exhibit: Direct Testimony
Issue: Cost of Service Study, Rate Design and Tariff Issues
Sponsoring Party: Midwest Gas Users' Association
Case No.: GR-2001-292

MISSOURI PUBLIC SERVICE COMMISSION

FILED[2]

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Missouri Public Service Commission

MISSOURI GAS ENERGY

CASE NO. GR-2001-292

PREPARED DIRECT TESTIMONY OF

CHARLES D. LADEROUTE

April 26, 2001

47849.1

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.	)	GR-2001-292

AFFIDAVIT OF CHARLES D. LADEROUTE

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Charles D. Laderoute, of lawful age, on his oath states: That he has reviewed the attached written testimony in question and answer form, all to be presented in the above case, that the answers in the attached written testimony were given by him; that he has knowledge of the matters set forth in such answers; that such matters are true to the best of his knowledge, information and belief.

Charles D. Laderoute

Subscribed and sworn to before me this 25th day of April, 2001.

Carolyn R. Belden
Notary Public

[SEAL]

My Commission expires: Nov. 3, 2003

NOTARY SEAL STATE OF MISSOURI
CAROLYN R. BELDEN
Jackson County
My Commission Expires
November 3, 2003

47849.1

PREPARED DIRECT TESTIMONY OF
CHARLES D. LADEROUTE

Q. **Please state your name, occupation and address.**

A. My name is Charles D. Laderoute. I am an energy consultant and President of Charles D. Laderoute, Ltd., 5114 Amazonia Road, St. Joseph, Missouri 64505.

Q. **By whom have you been retained?**

A. My testimony is on behalf of the Midwest Gas Users' Association ("MGUA")

Q. **What are your qualifications?**

A. I have nearly twenty-nine years of rate, regulatory and economic experience; twenty-two years as a consultant. My full qualifications are included as Appendix A to this testimony.

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

A. I am testifying on the establishment of class revenue requirements via a cost of service allocation study ("COSS"), cost support levels for establishing monthly service, customer or minimum charges and portions of rate design. I will also address certain conceptual matters in support of these specific items. Finally, I will make several policy suggestions.

Q. Please identify the Schedules which you are sponsoring.

A. I am sponsoring the following Schedules, all of which are part of this exhibit:

Schedule	Description
CDL-1	Comparison of Calendar 2000 Data versus 12 Months end September 1997
CDL-2	Comparison of Calendar 2000 Data versus 12 Months end September 1997
CDL-3	Residential Rate Class AMR related & Meter Reading Costs
CDL-4	Comparison of Cost Allocation Results - Case Nos. GR-98-140 vs GR-96-285
CDL-5 p. 1	Spread of Revenue Deficiency in this Case Assuming Cost Relationships from Case GR-98-240 Using MGE COSS
CDL-5 p. 2	Spread of Revenue Deficiency in this Case Assuming Cost Relationships from Case GR-98-240 Using Noack COSS Adjusted for Demand Allocator
CDL-6 p. 1	Cost Allocation Study Results - Top Down
CDL-6 p. 2	Cost Allocation Study Results - Revenue Neutral Result
CDL-6 p. 3	Cost Allocation Study Results - Including Requested Rate of Return
CDL-7	Complete Cost Allocation Study
CDL-8 p. 1	Monthly and Annual Ccf, Annual Ccf and Peak Month Allocators and Load Factor
CDL-8 p. 2	Monthly Billing Equivalents and Average Annual Customers
CDL-8 p. 3	Determination of Excess Gas Usage Factors
CDL-9	Analysis of Mains PIS
CDL-10	Spread of Revenue Requirements Based on COSS

In addition to my Schedules, I have included a Technical Discussion as Appendix B to my Testimony. All of this material was prepared by me or under my direct supervision.

Q. Have you previously testified before the Missouri Public Service Commission ("MPSC" or "the Commission") or other Commissions or Boards?

A. I have not previously testified before the MPSC. I have testified on several occasions before the following: Michigan Public Service Commission, the Rhode Island Public Utilities Commission, Alberta Public Utilities Board, Massachusetts Department of Public Utilities, and Wisconsin Public Service Commission. I have also testified before: Washington Utilities and Transportation Commission, U.S. Department of Energy Economic Regulatory Administration and the South Carolina Public Service Authority. I have submitted testimony in cases that were settled before: Federal Energy Regulatory Commission and the Vermont Public Service Board.

Regulatory Framework, Revenue Requirements and Costs

Q. Mr. Laderoute, within the regulatory framework, what are the general steps in establishing rates?

A. There are typically four steps: establishing the revenue requirements (also known as the total cost of service), assigning and allocating costs to rate classes, setting the rate class revenue requirements and designing rates. My testimony is focusing on the latter three items.

Q. Why are cost and the setting of rate levels (class revenue requirements) such paramount issues?

A. Regardless of how much unbundling may take place, a person or business who wishes to use gas in the Missouri Gas Energy ("MGE") service territory is generally limited to having the delivery of the gas provided essentially by only one firm - the local distribution company ("LDC"); in this case MGE. As such, all gas users, whether a sales customer who relies on MGE to provide commodity gas or a transportation customer who procures their own commodity gas, rely on MGE to provide delivery service. With the exception of a user who is close to an interstate pipeline and may have the opportunity to "bypass" the LDC, a gas user is generally dependant upon MGE and this Commission for the prices (in this case the base rates or distribution charges) that they face for delivery.

Q. The Commission and MGE?

A. Certainly. MGE by its actions, business strategy and manner of operations controls the costs that it brings to the Commission. The Commission itself has oversight of the overall level of costs that are allowed (the total revenue requirement) and decides the rate level (class revenue requirements). In this particular case, MGE itself did not file a COSS, so the Commission has less input to use in reaching its decision.

Q. But MGE did propose a method to allocate the revenue deficiency.

A. That is true and I understand why they proposed their case as filed. Unfortunately, the method that they proposed is problematical for several reasons: it does not comport with standard ratemaking practice, it is not necessarily sound, and it could be a contributing factor to MGE returning in another couple of years with yet another request for an increase to base rates. In this case, they spread the total revenue deficiency to rate classes based upon each rate class's portion of existing revenues. While this method is occasionally used for specific limited purposes, such as spreading an interim increase subject to refund, it is not an acknowledged generally accepted approach to determining class revenue requirements.

Q. On what basis do you reach that conclusion?

A. My training in economics, nearly 29 years experience in gas and electric rate regulation, reading and reviewing hundreds of state, provincial and FERC Orders and Decisions, reviewing hundreds of cost allocation studies filed in state regulatory cases and before the FERC and reading scores of authoritative works.

Q. Why is spreading a revenue deficiency to rate classes not necessarily a sound approach to establishing rate class revenue requirements?

A. For several reasons. Two related aspects of utility prices are paramount issues: undue price discrimination and cross subsidization. If one class of customers is not bearing its cost to serve, in order to keep the utility whole, then by definition another class or classes must cover those costs in their respective rates. When this happens, the latter is subsidizing the former.

Moreover, if rate class revenue requirements are not set fairly close to costs, it is only fortuitous if existing revenues bear a close relationship to costs. If an objective party is asked to determine if price discrimination or cross subsidization is taking place, they can only make their determination based on comparing revenues to costs.

Q. If the revenue deficiency is spread to rate classes based on existing revenue relationships, how could that be a contributing factor to MGE returning in another couple of years with yet another request for an increase to base rates?

A. Existing revenue relationships do not necessarily have anything to do with cost relationships. Embedded within rates are various components of costs - return on investment, depreciation, O & M expenses, et cetera. In general, as a utility grows in customers and consumption (sales plus transport), its revenues grow proportionally to cover the costs embedded in the existing rate levels. If the rate level is not sufficient to cover the actual costs to serve the class, then as that class grows, by definition, the utility will face a revenue deficiency. Assume three rate classes with Class A and C covering some portion of the revenue requirements (caused by cost) of Class B. Assume over time that Class A and C stay essentially the same in terms of customers and consumption, but that there is growth in Class B. The problem is that Class B, by not covering its costs, is responsible for the revenue deficiency that the utility faces. Assume that when rates were set, Class B is charged $1.00 per Mcf, yet the costs attributable to it are actually $1.10, with the difference being primarily driven by costs associated with Mains. Now, at some later time due to inflation, additional investments, and other factors the cost is actually $1.20. What happens if Class A and C are not growing? By definition, the utility will be losing not $0.10, but $0.20 per Mcf. And the existing revenue relationships are **meaningless** in determining required revenue levels by class. The utility will simply never catch up. The best that it can do is to file yet another rate case.

Q. Can you give another example of how cross subsidies could occur and why existing revenue by class can be problematical as a method to determine class revenue responsibility?

A. Continue with the same assumptions in the last response. Add some new assumptions. First, assume substantial amounts of Mains are being added to reach customers who are virtually all in Class B. Also assume that the utility's facilities policy is set in such a manner that approximately 90% of the costs of Mains extensions for new customers are recovered in rates set for all customers. Finally assume that the amount of Mains in rate base are as follows for Class B: historical amount of Mains per historical customer for Class B is $400 per customer, the incremental cost per new customer is $2,000 and the new average is $500 per customer. The next time that rates are set there will now be several cross subsidies. First, existing Class B customers will be subsidizing new Class B customers. Class A and C customers will be subsidizing existing Class B customers once and new Class B customers twice. Again, existing revenues don't necessarily have any relationship to costs.

Overview and General

Q. Mr. Laderoute are you generally familiar with the background of regulation for this company?

A. Generally, yes. As part of my research, I reviewed the Commission's Orders in Case No. GR-98-140 and Case No. GR-96-285 including the Remand Order. I also read all the Direct, Supplemental Direct, Rebuttal and Surrebuttal pertaining to COSS and rate design in Case No. GR-98-140. Finally, I reviewed the Direct testimony and portions of Rebuttal and Surrebuttal regarding COSS and rate design in Case No. GR-96-285.

Q. Do you have any reservations, caveats or qualifications with respect to your testimony?

A. At the time that this was prepared, there were many Data Requests outstanding that I assisted in preparing. Numerous other responses, though provided in a reasonable time after the request from MGE, have not been reviewed adequately to serve as input to my COSS. In several cases regarding important pieces of data, there are outstanding follow-up questions. The Responses to these could change certain of the results, and at least regarding two items the impact could be non-trivial. I would therefore like to reserve the right to update my findings to the extent that data becomes available for input into my model.

Q. Prior to turning to specifics of your cost allocation studies, are there general matters that you would like to address?

A. Yes. In reviewing some of the data, there are a number of items that raised concern or indicated to me that some general elaboration was necessary. First, comparing data from Case No. GR-98-140 (Test Year 12 Months ending September 1997 Normalized and adjusted) to data from the instant case there are some interesting results. See Schedule CDL-1. While the Company has indicated that it has used a different weather normalization method, it is not clear what portion of the reduction of Mcf consumption is due to that.

My concern is not that they changed the method. I just want to point out that this can complicate comparisons between these two cases. While overall number of customers has increased by 4.6%, annual consumption has decreased by 5.0%. Moreover, Peak Month use (January in both cases) has decreased by 10.3%.

Second, in reviewing this data, note that the number of customers are averages over the year. While the LVS class shows 441 customers, there were 431 at the beginning of 2000 and 451 at the end of 2000. Based on data available to me at this time, all customer additions to the LVS class over the course of the year were customers switching from SGS or LGS. Certainly over the past several years there may have been some customer additions to LVS who were new to MGE and customer deletions. But the bottom line is that this class has essentially been static since the last case. Virtually all of the customer growth has been in the SGS and Residential rate classes.

Third, and most troubling is the data shown on Schedule CDL-2. Since the last rate case, MGE has added over $49,000,000 of Mains Plant in Service ("PIS") (A/C 376). This represents a 21.6% change while the number of customers changed by 4.6%. At the time of the last rate case, the amount of Mains per customer was $489 and this is now $567. Looking at this data from the incremental view, the Change in Mains per Change in Customers is $2,262. Certainly the Company has some general Mains that are replaced (for general purposes or as part of the safety program). However, clearly the incremental cost of newer customers far exceeds that of existing customers. In fact, as the Commission indicated in its Order in Case No. GR-98-140 at page 49, "96 percent of the total cost of facilities extensions to serve new customers will be recovered through the rates to be set in this proceeding". In that Case, MGE had proposed changes to its Facilities Extension Policy so that new customers would bear a higher portion of the costs associated with facilities to serve them. That proposal was rejected by the Commission. Since the Extension Policy has not changed, that percentage value is likely still about the same. Further, note that Mains Depreciation Expense has increased by 35.6%. I am not trying to make Extension Policy a part of this case. However, in reviewing my COSS results, the Return and Federal Income Taxes associated with only the increase in Mains PIS since the last case amounts to $7,245,260 of additional revenue requirements. See Schedule CDL-2. That in combination with $1,536,606 of incremental Depreciation Expense adds up to nearly $9 million (7,245,250+1,536,606) of additional revenue requirements since the last case. This is also a substantial portion of the revenue requirements in this case. These costs are allocated to all rate classes. As a result of this policy, existing customers, be they Residential or LVS, are **subsidizing new customers**.

Fourth, again looking at the data on Schedule CDL-2, Meter Installations have increased dramatically. My presumption, while I await data request responses from MGE, is that a large portion of the significant increase since the rate case is attributable to the installation of the AMR equipment. I have not specifically taken this into consideration in performing my COSS, but should. Cost attributable to installing AMR equipment should only be borne by the classes Residential, SGS and LGS. The LVS class is already metered using EGM equipment. They have paid for the Metering portion of that equipment. This has been so since the Stipulation in Case No. GR-93-240.

Finally, a comment about AMR metering communications equipment. In the process, I will introduce certain results from my COSS. Please refer to Schedule CDL-3. At this time, I do not know how much AMR equipment was included in revenue requirements in the last rate case. And it is impossible for me to determine how it may have been included in the various COSS studies. However, this schedule shows that costs allocated to the Residential rate class for Meter Reading have been reduced by $1,269,476 comparing my values to those derived from Mr. Cumming's COSS in Case No. GR-98-140. In my COSS, AMR costs are allocated to Sales customers only since the LVS class already has the EGM equipment in place. Within my study, $5,176,487 of AMR related costs are included for return, FIT and Depreciation Expense for only the Residential class. My reason for pointing this out is that this is a very large amount of dollars. Second, within my COSS discussion, I do not detail every single nuance of every dollar allocated. This, though, illustrates that there are significant dollars involved - likely much larger than included in the last case. This represents a substantial portion of the revenue requirements in this case. Moreover, none of these costs should be allocated to the LVS class because, as noted above, they already have EGM equipment. In the prior case, most parties allocated these costs to all rate classes which was incorrect.

Cost of Service Comparisons

Q. Please describe Schedules CDL-4 and CDL-5.

A. Schedule CDL-4 compares the results of cost of service studies over time by the same party. It shows that when using relatively similar methods, the cost allocation results, in terms of the portions of allocated costs, will stay approximately the same. This is important because in terms of the fractions showing cost responsibility by rate class, this schedule shows that the cost responsibility does not change substantially. One of the reasons I prepared this schedule was to impute the class revenue requirements from the current case using the results of MGE's last COSS. That is, I wanted to see what the results would be for the current case had MGE performed a COSS using the methodology from the last case.

The results of such an analysis are shown on Schedule CDL-5 page 1. Using the COSS results from MGE's unadjusted COSS based on 12 months ending September 30, 1997, Line 1 shows the rate class allocated costs. Line 3 shows the fractions of totals, which I applied against the Revenue Requirements of the current case at Line 5. Line 7 shows the values MGE determined for current adjusted revenue in the current case. At Line 9, I am showing the allocated revenue requirements less current adjusted revenue; i.e. Line 5 - Line 7. I show at Line 11 the MGE proposed revenues and at Line 13 MGE's proposed numbers less Line 9.

There are though, two factors that I wanted to address. First, there was substantial concern with the approach used by MGE in determining its Demand allocator to allocate Demand related Mains in Case No. GR-98-140. They used peak month consumption, but "discounted" the values for the LVS rate class by 50%. Some parties disagreed with that, as do I. So, I wanted to see the results were the LVS class volumes not reduced. Second, I did not have access to the MGE model, but I did have the model used by Mr. Noack. At this point Mr. Noack is employed by MGE. Had MGE filed a COSS in this case, I have to presume that it would have embraced some of the thinking that he used in the last case. Whether or not that is actually the case, the model was available so I used it as the starting point.

After modifying the Demand allocation factors for demand related Mains, the results are shown on Schedule CDL-5 page 2. The structure and description of this schedule is the same as that discussed above for CDL-5 page 1. In terms of the revenue requirements for the instant case, this modification adds $1,737,578 of costs to the LVS class (based on

Schedule CDL-5 p. 2 Line 5, col. e: 9,735,762 - 7,998,184 from p.1 Line 5, col.e of this schedule). The important conclusions are shown at Lines 9 - 13. Had a cost based determination been used rather than spreading the revenue requirement increase on current revenues, the Residential class would receive $7,064,874 more revenue requirements and the LVS class $4,350,352 less compared to the MGE proposal. In terms of a cost based approach, the revenue increase (decrease) for Residential and LVS would be, respectively, $34,838,701 and ($1,079,750).

Q. Could this schedule be used to establish the rate class revenue requirements in this case?

A. Yes. At the time that I prepared that analysis, I was unsure that I could finish an independent COSS in time for filing. I have been able to finish a study, subject to the caveats that I indicated earlier. I would make modifications to my COSS based on responses to data requests to MGE. The information on Schedule CDL-5 is of use to serve as a surrogate for an MGE COSS since they didn't file a study.

Cost of Service Allocation Study

Q. Could you give an example of how your COSS might change dependant on Responses to Data Requests of MGE?

A. Certainly. Apparently MGE tariffs allow LVS customers to transport or take Sales gas. Aside from this being a complicating matter, it affects how I allocate costs. In general, because LVS customers are transporters, they should bear **none** of the costs associated with Gas Inventory that are included in Working Capital. I have requested data that identifies the amounts of Sales gas that LVS customers are taking in the adjusted Test Year. When this data becomes available, I will modify my COSS and likely make a recommendation for a tariff change. In the meantime, my COSS allocates no Gas Inventory in Working Capital to the LVS class since they are Transporters, not Sales customers.

Q. Do you have a position or opinion with respect to the cost component numbers that you have used?

A. I do not necessarily agree that they are right are wrong. I used them because they are the values that MGE filed.

Q. Please illustrate the summary of your COSS.

A. Page 1 of Schedule CDL-6 shows the summary of the Top Down analysis. At Line 29 the Rate of Return by rate class is shown. This indicates that while the overall ROR is 5.88%, the class RORs range from a low of 4.18% for Residential to a high of 13.59% for LGS. In considering these results, bear in mind that they are based on all of the rate base and income statement numbers that MGE filed in this case.

Q. Have you prepared a schedule to identify the costs associated with a "revenue or ROR neutral" COSS?

A. Yes, page 2 of Schedule CDL-6. A revenue neutral COSS simply takes the Top Down COSS results, identifies the resulting Rate of Return ("ROR") for the system and builds a Bottom Up COSS assuming that each rate class is set to earn the overall realized ROR. All adjusted values as filed by MGE are included. However, no changes are included that are a function of revenue deficiency driven by ROR and associated Federal Income Taxes. This would simply keep the Company whole at the current ROR, but reallocate the class revenue requirements so that each class' revenue would bring about the same ROR as the system. The net result is shown at Lines 18-19. Residential rate levels would have to be increased by $10,384,565. All other classes would have rate level decreases with the largest decrease accruing to the SGS class. The largest percentage decrease based on distribution margin only is shown at Line 29 for the LGS class. Since a customer faces a total bill including PGA costs, Line 39 shows the percentage changes including PGA. This is a more reasonable illustration of the impact. In sum, this schedule is based on all the costs that MGE filed in its case, but does not change the level of Return plus Income Taxes to the Requested level of ROR of 10.562%.

Q. You have excluded the Unmetered Gas Light rate class from the COSS?

A. Yes. For such a small class their inclusion in a COSS is meaningless. I therefore treated them as a Revenue Offset and included their revenues in Other Revenues.

Q. Mr. Laderoute, are the values used in your COSS consistent with those filed by MGE?

A. Yes. My values for Rate Base, Total Operating Expenses and all other values agree with the Company filed values.

Q. Please continue with Schedule CDL-6 page 3.

A. The difference between this schedule and the prior schedule is a change to the Requested ROR at Line 2 to the Company requested value of 10.562%. There is a substantial difference. The net result is shown at Lines 18-19. Residential rate levels would have to be increased by $38,962,707. SGS would also be increased and LGS and LVS would both still be decreased. The largest percentage decrease shown at Line 29 would be for the LGS class. Since a customer faces a total bill including PGA costs, Line 39 is a better representation and shows the percentage changes including PGA. At either extreme, the Residential class requires a 12.83% increase while the LVS class requires a 10.52% decrease.

Q. Mr. Laderoute, looking at the COSS summary pages shown on Schedule CDL-6, are you surprised at the results?

A. No. In the three rate cases prior to Case No. GR-96-285, rate levels were not set on a cost of service basis, but were arrived at via a settlement. While there may have been some movement in the direction of setting rate levels closer to costs, they were not set at costs. (See Testimony of Dennis Kies in Case No. GR-96-285 at page 5.) In the original Order in Case No. GR-96-285 (January 22, 1997), the Commission rejected a Stipulation and Agreement that apparently would have set class revenue requirements closer to costs. The Commission then spread the revenue deficiency to classes based on existing class revenues. They did not address class cost of service. In its Order in Case No. GR-98-140 (August 21, 1998) at page 44, the Commission seems to be confusing class cost of service and revenues when it states:

> The Commission finds that the current division of cost by class remains just and reasonable. The Commission finds that there is not sufficient

> evidence presented in the record to support the findings proposed by the parties to change the current class cost of service percentage. There has not been any evidence of a significant change or development that would have supported any of the changes proposed. Therefore, there should be no change in the class cost of service as allocated among the rate classes and found to be just and reasonable under the prior case, Case No. GR-96-285, issued on October 31, 1996 [sic].

The Commission then went on to spread the revenue deficiency on the proportions of existing revenues. In its Remand Order in Case No. GR-96-285 (February 1, 2001) the Commission accepted the MPSC Staff COSS but then went on and did not use that study to determine rate class revenue responsibility. Instead, the Commission spread the revenue deficiency on existing revenues (while mistakenly referring to it as an equal percentage increase).

In sum, costs have had little if any relationship to class revenues set for MGE. Moreover, costs have not been used to set revenues. Comparing Lines 28 and 26 on Schedule CDL-6 page 3, the relationship of costs and existing revenues is quite different. For Residential their existing revenues are 69.64% of total revenues while their costs are 76.16% of total costs. Note also rate SGS. While their portion of cost responsibility is 16.80%, even though their portion of existing revenues is 19.94%, they require an increase of approximately $2.5 million.

Q. Please describe the fully allocated cost of service study filed in this case.

A. The complete cost allocation study has been included as Schedule CDL-7. The first five schedules of the cost allocation, Pages 1-5 of this schedule, depict the summary ("topsheets") of this study. These pages contain numerous summaries of the detailed information determined in the cost allocation study. My cost of service allocation study embraces all of the principles covered in the COSS Technical Discussion, Appendix B to this testimony, which covers the allocation factor conceptually, customer cost methods and other fundamental aspects of cost allocation.

Each of the COSS schedules may be thought of as a vertical page. For cost allocation purposes, we have considered four classes: Residential, Small General Service, Large General Service and Large Volume Service. Due to the number of classes utilized, only one page is required for each of the twenty-five COSS schedules. The COSS shows clearly what is being allocated, what allocation method is being used, the amount to be allocated, the values for allocators and their source, and depicts a summary of classified costs by demand, commodity and customer classification. The most important aspects of the cost allocation are addressed in this testimony. General principles are described in the COSS Technical Discussion.

Q. What general steps did you perform in your fully allocated cost of service study?

A. The Company's 2000 test year adjusted revenue requirements and other data supported by MGE Witness Noack is utilized. All costs were functionalized which in this case was limited to Distribution, as the Company has no Production, Transmission or Storage. Next, all cost items were classified. I first considered whether the cost items were of a fixed or variable nature. Then, I classified the costs between Demand, Commodity and Customer related. Demand, Commodity and Customer Allocation factors were developed at Schedule CDL-8 based upon the 2000 test year billing determinants and other data for the rate classes. In terms of the mechanics, rate base items are allocated first since many expenses are a function of a rate base item. Expenses are next allocated followed by other taxes. Income taxes are the final item.

Q. Can an individual easily identify the cost classifications within your cost allocation study?

A. Yes. Within my study, Schedule CDL-7, I show a column labeled "CR" which stands for Cost Responsibility. While many costs are strictly Demand ("D"), Commodity ("C") or Customer ("CU") related, some are functions of more than one of these. For example, if a cost item is a function of all three classifications, it is labeled as DCC. If it is a function of Demand and Customer, it is shown as DCU, etc. Composite allocators are shown at the bottom of each of my schedules so that one can clearly see how an allocation was performed. Turning to Page 7 of this schedule, one can see at Lines 5-7 that Mains have D in the CR column - they are demand related. At Line 10 Services is shown. They are a customer related cost, so a CU is shown in the cost responsibility, CR, column.

Q. In general, what allocation factors were used?

A. Approximately 50 major direct allocators are used. Many of these were developed externally and some were developed internally to the study. In addition, numerous minor internal allocators are used where costs are based on more than one classification or where previously allocated items are used as an allocator. The major allocators are shown on Pages 20-25.

Q. Please describe how one can identify what allocation methods are used in your study?

A. Please turn to Page 12 of Schedule CDL-7 which shows the allocation of Distribution Operation Expenses. Account 871, Distribution Load Dispatching, Line 4, is allocated on the basis of Peak Month. This is indicated in the area identified as Allocation Basis. The values being used as the allocator are shown at Line 26. This is Allocation Factor 1 on this schedule (schedule here referring to my COSS schedules) and it is the Sys 1 factor. The "Sys" means that this is an external factor or one that can be found on the AFACTOR schedules starting at Page 20. There are five AFACTOR schedules and they include other externally developed factors or major allocation factors and certain internally generated allocation factors. The peak Month allocation factors come from Line 2 of Page 20.

Looking back at Page 12 of Schedule CDL-7, at Line 6 you see that Account 874, Mains & Services Expense, is allocated on the basis of Tot(al) Mains & Services (PIS) which is Sys Factor 20 and Allocation Factor 2 of this schedule. Account

870, Operation Supervision & Engineering, is allocated on the subtotal of the above allocated costs on this schedule at Line 15. The allocation factor is a minor composite allocation factor and is not included in the AFACTOR schedules. It is simply shown at Line 34 and is determined from the data shown at Line 15. It is Allocation Factor 9 for this Schedule and it is identified as DEXP1-9. This identifier is developed in the following manner. The DEXP1 comes from the Name (Schedule Name) shown in the upper left of the page. The 9 means that it is the ninth allocation factor on the DEXP1 schedule. This labeling method can be used to quickly identify where an allocator was developed.

Note line 35 where Allocation Factor 10 for this schedule is shown. The allocation factor here is Demand Related Mains & Services PIS. Mains & Services Expense, Account 874, is allocated on the basis of Tot(al) Mains & Services at Line 6. Since Mains and Services PIS have both demand and customer related costs, Mains & Services Expense must also be split into a demand component and a customer related component. Allocation Factor 10 is labeled as DPT-13. Turning to Page 7 of this exhibit, Line 43 depicts the development of this allocator. Returning to Page 12, Allocation Factor 10 on this schedule is used to determine the demand related portion of Account 874 to be included in the Demand related costs for this schedule. Demand related costs for this schedule are summarized at Line 21. All internal allocation factors can be traced by using the above method.

Q. **What allocation method did you use to allocate demand related costs?**

A. The primary Demand allocator used is the Peak Month consumption. The primary cost item this is used for is Demand related Mains PIS. In this study, I have broken Mains PIS into two components: an amount assignable to Residential and SGS and allocated to them on the basis of their respective Peak Month's values excluding all other classes and a Demand related portion. In conjunction with this disaggregation of Mains PIS, I believe that Peak Month is a reasonable method. The development of the Peak Month allocators is shown on Schedule CDL-8 page 1. Each of the steps in its determination is shown clearly on that schedule. The Peak Month allocator is a reasonable method of allocating certain demand related costs. The system is designed and sized to meet peak loads.

Q. Mr. Laderoute, why did you assign certain of the demand related Mains PIS costs to only the Residential and SGS rate classes?

A. I do so based on a review of material filed by parties in previous MGE rate case. In Mr. Hall's studies in GR-96-285 and GR-98-140 he indicated that "it can be said that mains which are less than 4" provide little, if any, benefit to the larger customer classes". (Respectively, Hall Direct at page 23 and page 30, GR-96-285 and GR-98-140) Within his approach in both cases, he assigned Mains less than 4" to the Residential and SGS rate classes. In his Supplemental Direct testimony in GR-96-285, Mr. Beck determines at Schedule 3 Revised various service sizes. He shows LVS services at 4" and LGS services at 3" and 4". The associated Mains would not be smaller. Further, at Revised Schedule 5 he indicates the stand alone Mains pipe diameters of 3.345 " for LGS and 5.1119" for LVS. While he did not file detailed schedules with his Direct Testimony in GR-98-140, he does indicate at pages 3 and 4 that the studies he performed were "essentially an update of Staff's C-O-S study in MGE's prior rate filing, Case No. GR-96-285". In order to be on the conservative side, I only assigned Mains of less than 3 " to the Residential and SGS classes. The determination is shown on Schedule CDL-9.

Q. Did you include a Customer related portion of Mains PIS?

A. No, although I did consider doing so for several reasons. Historically, MGE in its COSS has supported a minimum system approach. See for example, Case Nos. GR-98-140, Cummings Surrebuttal Testimony at pages 5 - 8 and Gillmore Direct Testimony at Schedule DSG 1A Page 2 in Case No. GR-96-285. Second, in the COSS that he sponsored in Case No. GR-98-140, Mr. Noack supported a minimum system. See his Schedule MRN-1 page 2 which was an update to the MGE study filed in the case. See also his Rebuttal Testimony in that case at pages 12, 15 - 16, and 19. Third, in its COSS for both Case No. GR-96-285 and GR-98-140, the Staff, via witness Beck, included a portion of Mains that he refers to as 'Stand Alone'. See pages 2 - 7 of his Direct Testimony in Case No. GR-96-285 and Schedule 6 which was updated via Revised Schedule 1 attached to his Supplemental Direct Testimony in that case. In his Direct Testimony in Case No. GR-98-140, Mr. Beck indicates at page 3 that the COSS in that case was an update to the study he performed in the prior case. In his Rebuttal in that case he indicates at page 5 that:

> Staff's "Underlying Cost" mains allocator determined the percentage of the cost of mains that could be considered to be stand-alone costs (which are similar to customer related costs) versus integrated system costs (which are similar to capacity related costs) to be 28% and 72% respectively.

In his Schedule 1 attached to his Supplemental Testimony in Case No. GR-96-285, Mr. Beck shows 28.16% of Mains cost as Stand Alone. Now these non-demand related costs are very similar to the customer related costs that would be generated via a minimum system study. In fact their impact is exactly the same.

Finally, as I indicated earlier in this testimony, I have concerns about the additions to Mains in conjunction with the Facilities Extension policy. There appears to be a significant amount of investment that was not caused by customers in the LVS class and to a lesser extent in the LGS class. Since these customers would otherwise be allocated a significant portion of these costs based on the demand allocator, some approach might be needed to prevent allocating costs to classes who likely did not cause them. A reasonable method is that of classifying a portion of the costs as customer related and allocating them on a non-demand basis.

Q. Had you included a Customer component of Mains, what portion would that be?

A. As can be seen near the bottom lower portion of Schedule CDL-9, approximately 24% of Mains would have been classified as Customer related. This is a bit less than the 28% of stand alone costs in Mr. Beck's last two COSS for MGE.

Q. Turning back specifically to your COSS, please discuss in detail the more important items included on the summary pages of your COSS, Schedule CDL-7, Pages 1-5.

A. Page 1 of Schedule CDL-7 depicts the results of the "Top-Down" study. Here, the test year pro forma adjusted values are summarized to determine the realized rate of return ("ROR") at Line 29. The realized rate of return for the Company in toto, System Total column, and each of the rate classes is determined.

Based upon the 2000 information, the Company would earn a 5.88% overall rate of return on an annual basis (Page 1, Line 29, System Total column). Line 30 of Page 1 of this schedule shows an Index of Return for each rate and the System Total with the System Total annual as the base at 100. For example, note the Residential rate of return of 4.18%. Compared to the overall Company annual rate of return of 5.88%, this class earns only 71% of (.71 times) the overall company annual rate of return. This is determined by dividing 4.18 by 5.88 and expressing the result as a percentage.

Q. Which rate classes show the highest and lowest Index of Return?

A. Large General Service is highest at 231 and Residential is lowest at 71.

Q. What conclusions can be drawn from the information on Rates of Return and Index of Return.

A. Any class with an Index over 100 is subsidizing other classes, that is contributing more to cost recovery than customers with an Index less than 100. In comparison only with the realized rate of return of 5.88% in toto, the Company is not earning an adequate return on its investment for customers in the Residential class. Stated a different way, all classes earning less than the overall Company ROR are being subsidized by customers earning more than the overall Company ROR.

Q. Please discuss the second summary page of your COSS, Page 2 of Schedule CDL-7.

A. COSS Schedule 1-B shows the analysis to determine required revenues by rate class based on 2000 costs and the Company's requested rate of return. I took the Net Income results of the Top-Down study and added to it the changed Net Income and changed Income Related Taxes to determine the Revenues associated with the Company's requested rate of return. At the COSS stage, it is my belief that the class revenue requirements should utilize equalized rates of return for all rate classes, in this case 10.562%.

Page 2 has been set up to match the required revenues for 2000 as determined by data attached to the Testimony of Company Witness Noack. This schedule is typically called a "Bottom-Up" analysis; that is, we start at the bottom, Return Required at Target ROR Line 5, and work up towards the revenue requirement. In the process, the only cost elements which change from the Top Down analysis are Return and Income Taxes. All other cost items stay the same and have been reflected in the Top-Down analysis shown on COSS Schedule 1-A, Page 1 of this exhibit.

The Total Revenue Change is depicted on Line 16. At Lines 18 and 19 I have applied the Company's Gross Up and Gross Down factors for Uncollectibles and Late Fees, respectively. At Line 22, I show the total Required Gas Operating Revenue excluding PGA revenue; PGA revenues are not an issue in this case. This includes Other Operating Revenue items. Other Operating Revenue, an offset to total revenue requirements, are as requested by MGE in this case. At Line 27, I have shown Required Sales of Gas Revenue plus Transportation revenue, again excluding PGA revenue. All of these values would generate an equalized rate of return of 10.562% for each rate class.

As can be seen at Line 16 - 19, in order for each class to generate the same rate of return, the rate levels need to be increase for Residential and SGS. In view of the realized rates of return and the Company requested ROR, the rate levels for LGS and LVS should be decreased.

Utilizing only Base rates (i.e. excluding PGA revenues), the percentage increase by class are shown at Line 29. While on their face, certain of the values may be considered to be rather large percentage wise, I believe that the impact on customers should be viewed including the associated PGA revenues. These values are shown at Line 39.

Q. Please describe Page 3 of Schedule CDL-7?

A. Page 3 of Schedule CDL-7, shows the determination of the Company's required Sales of Gas and Transportation revenue with major items shown by cost class component: Demand, Commodity and Customer. The important aggregates are shown here. Within my COSS, I have classified all costs as being

Demand, Commodity or Customer related. This schedule summarizes all the key cost components. Near the bottom, Lines 29-31, I summarize Demand, Commodity and Customer Related costs. These costs added together comprise the Total Required Sales of Gas and Transportation Revenue. At Lines 37-39 the classified costs are shown unitized in terms of $/Mcf.

Q. **What is portrayed on Exhibit CDL-7 Page 4?**

A. The primary purpose of this schedule is to determine the Company's Required Sales of Gas and Transportation Revenue excluding PGA on a unitized basis. At the top of this page, I show the costs in the form of Demand, Commodity and Customer related costs. This is the same data as shown on the prior page. I also show some statistical information to facilitate the analysis. At Lines 15-17, I show the current, required and increased values per Mcf by class. At the lower portion, I indicate the unitized values. Customer related costs are shown in terms of per Mcf and per customer. The total cost per Mcf is shown at Line 31. In reviewing this data, the costs are simply unitized COSS costs and are not necessarily those that would correspond with rate design.

Q. Mr. Laderoute, what method did you use to classify costs as customer related in the COSS?

A. As covered more fully in the COSS Technical Discussion (Appendix B to this Testimony), I used the Basic Customer Approach. I have also shown on Schedule CDL-7 page 5 the values for the Simple Customer method. As I indicate in the COSS Technical Discussion, the Simple Customer method that I determine can be considered above an absolute floor in considering what costs are a function of having a customer attached to the system. In this study these costs are quite inclusive and should provide guidance in establishing customer or service charges, with some caveats as discussed later.

Q. Please describe the general flow of your cost allocation study.

A. First, rate base items are allocated since they will be used later to allocate certain expense items. Then, operation and maintenance expenses are allocated, followed by depreciation and other taxes. Next, operating revenues are assigned and allocated. At this point, income taxes may be determined. Finally, the summary pages are generated.

Q. Let's move to the details of the cost allocation study. Starting with revenue, please discuss schedule by schedule the rationale for the most important items in your cost allocation study as shown on Schedule CDL-7.

A. On COSS Schedule 2, Page 6 of this exhibit, Sales rate Distribution Charge revenues are displayed as well as the same values for Transportation customers - labeled as Base Rate Margin Revenue. The values are taken from MGE Schedule FJC-1, they are specifically assigned to rate classes, and reflect the 2000 adjusted revenues as determined by MGE.

Q. How did you determine the appropriate method to allocate the various items of Other Operating Revenue shown on this page?

A. I used a composite allocator giving a weight of 50 % to customers and 50% Mcf.

Q. How was Distribution Plant in Service costs allocated at Page 7 of this exhibit?

A. Peak Month was used to allocate Distribution Plant in Service Accounts 374 - 379. These facilities are sized for capacity purposes and are Demand related.

I disaggregated the costs associated with Mains A/C 376 on Schedule CDL-9. The values at the top and the footage in the center bottom of this schedule was taken from the Response by MGE to MGUA DR 212. Since the values included did not add up to the amount $278,969,931 included at Schedule C page 1 attached to Mr. Noack's testimony, I spread that total back to the various sizes at the bottom left of Schedule CDL-9. From this, I took the value of $79,003,720 for Mains less than 3" which I assigned to Residential and SGS. Those values were in turn allocated to the two rate classes based on their Peak Month values excluding the values for the other two rate classes.

Next, I performed the calculations necessary to determine a Customer component. As noted earlier, I have not included a Customer component of mains in the COSS. I took the footage in the lower center portion and removed the footage assigned to Residential and SGS. The balance of 18,479,847 feet was priced out at the average price of $3.64 per foot for 2" Mains that I calculated at the lower right. This gave me the value of $67,189,638 that could be used for Customer related Mains PIS which represents 24% of Total Mains PIS (67,189,638/278,969,931).

Q. If you were to include a Customer component, how would you allocate that value?

A. I would not use a simple customer count allocator that some analysts might use. I would weight customers using the same weighted factor used to weight Services. This is described further below, but the factor weights each LVS customer, for example, at 23.26 times the weight given to a Residential. Further, the weighted customer factors that I use for Services are not based on customer numbers for LVS, but includes an additional 30 to account for the customers who have multiple meter/service combos.

Q. Please continue describing how you allocated Distribution Plant items on page 7 of Schedule CDL-7.

A. The balance of $199,966,211 of Mains was allocated to all rate classes based on Peak Month.

I have requested data from MGE in order to attempt to perform Special studies to determine the costs by class for the accounts: 380-384. These studies should be based on the **actual embedded costs** for each item for each class. For classes with small number of customers, a 100% sample should be used. For Residential and SGS samples can be used. Barring the availability of this data, I used the data shown in OPC Witness Hu's Case No. GR-98-140 Rebuttal Testimony at page 6 as follows:

Item	Account	Res	SGS	LGS	LVS
Services	380	624.42	624.42	5,341.81	14,524.80
Meters	381	55	243	2,275	5,617.25
Meter Instal.	382	162.84	162.84	2,104.89	6,472.08
H.Reg/Inst.	383-4	23.40	290	817.37	2,009.53

I do not consider that data optimal, but it is available at this point. One reason that it is problematical is that it is based on a replacement cost analysis that determines the costs for a typical new customer. This does not give recognition to the actual historical costs. Further, for example it may not be representative of the actual historical costs that serve as the basis for rate setting. Many LVS customers were former SGS or LGS customers. A Meter for them doesn't cost $5,617.25 but is some far lesser value. In the instant case, all of the additions to the LVS class but one were former LGS customers with one being an SGS customer. Even based on this replacement cost data, the LGS customer Meters cost is $2,275 - not $5,617.25.

As noted above, in determining the weighted customer costs for each of Accounts 380 - 384, I used the number of customers for each rate class and for LVS added 30 (based on MGE data) to account for those customers who have multiple services and meters. Electronic Gas Measurement A/C 385 serves only LVS customers, so that cost was assigned to that class.

Q. Based on the COSS results, can you give an illustration of the impact of using these replacement values for Meters and Services?

A. Yes. And in the process I will also illustrate the impact based on two customers who have multiple Services and Meters since this has been an area of concern in the past. At Page 25 of Schedule CDL-7, I have summarized at Lines 12 - 14 data taken from Page 7. At Lines 19 - 22 I have unitized these costs per customer. For the LVS class, I have added the 30 extra units for Transportation customers with multiple Meters and Services. The allocated values are for Services and Meters, respectively: $11,397 and $3,765 per customer.

In MGUA Data Request 221 we asked for a disk including the data that we requested in DR 149. Included in DR 149, inter alia, was historical costs for Meters and Services for LVS customers. Based on that data, the following are the average gross PIS values for UMKC and CMSU compared to the COSS values:

	Services	Meters
CMSU	$896	$1,894
UMKC	$557	$2,300
COSS	$11,397	$3,765

At this point we have outstanding clarification requests to MGE regarding this data. When we get that clarification, I intend to specifically assign actual costs for at least Meters and Services for all LVS customers. In the meantime, the above shows clearly that the COSS costs borne by CMSU and UMKC related to Services and Mains is considerably more than their actual costs. With 14 and 5 Meter/Service combos, respectively, CMSU and UMKC have the highest number per "actual" customer of the LVS customers with multiple combinations.

Q. Please continue with the allocation of General Plant in Service.

A. General Plant, Schedule CDL-7 Page 8 was allocated in a two step process. First, AMR PIS Account 397.1 was allocated to Sales only customers on a straight number of customers basis. This equipment was installed for Sales customers and is not used by LVS customers who use EGM equipment. As I indicated earlier in my testimony, this is a very substantial cost item. I allocated the balance of General PIS on the basis of an equal 50/50 weighting of customers and Mcf. I used that same approach to allocate the non-AMR related Intangible PIS. I determined the amount of AMR Intangible plant from DR MGUA 178.

Q. Please discuss the allocation of Accumulated Depreciation, shown on Page 9 of Schedule CDL-7.

A. Accumulated Depreciation was available in detail in MGE Workpaper D-1. For each of the individual accounts, I used the corresponding PIS values to allocate the respective values. The balance is all due to General PIS.

Q. Working Capital is shown on Schedule CDL-7 Page 10. Please discuss the more important of these allocations.

A. Materials and Supplies and Prepayments are mostly related to the plant - in this case MGE only has Distribution plant, so I used that as the allocator. Gas Inventory is held to meet the needs of Sales customers. It serves the purpose of assisting in meeting the usage requirements of Sales customers during the winter or peak months. I allocated these costs to Sales rates only based on the Excess Gas Use approach. See Schedule CDL-8 Page 3. I determined the average use per month by rate class for the off-peak months of April-October. These values were then multiplied by 12 to determine a base use value by class. The resulting values were then subtracted from annual Mcf by class and the result is considered Excess Use. Each Sales rate class' Excess Use is divided by the total Excess Use to determine the Excess Use allocation factor.

I analyzed the MGE Schedule E-4 attached to Mr. Noack's Testimony to determine various components of Cash Working Capital. Working Cash - O&M - Purchased Gas is a function of Sales, so this was allocated to Sales classes on the basis of Ccf for the Sales rate classes. Other O&M Working Cash is a function of the Company's operations so I allocated this on the basis of Total O & M Expenses excluding Gas Cost. Working Cash - Taxes - Property is a function of Total plant in service which was used as the allocator. Total PIS was also used to allocate Offsets. Prepaid pension is a function of labor and barring the availability of a detailed special study, O & M excluding gas is a good surrogate and was used to allocate this.

Q. **Describe Page 11 of Schedule CDL-7, your Rate Base summary exhibit.**

A. This schedule merely summarizes the previously allocated information from other schedules. In addition, several additional items are included. SLRP Deferrals and Deferred Income Taxes-SLRP are a function of Services PIS which was used as the allocator. Barring more detailed data, Customer Advances are a function of Mains. I broke Customer Deposits (based on MGE Schedule B-2) into two components and assigned the Residential value. For the C & I value, I allocated it to non-Residential classes based on Revenues. Deferred Income Taxes are mainly a function of excess of tax over book depreciation and is therefore a function of Total PIS.

Q. Moving to the Operation and Maintenance Expenses portion of your COSS, Mr. Laderoute, please discuss the allocation of Distribution expenses, Schedule CDL-7 Page 12.

A. Accounts 871-2, and 875-877 are essentially related to the capacity of the system. Therefore, I allocated these costs on Peak Month. Accounts 874 and 878 are directly related to the corresponding plant in service account items, which were used to allocate them. Since Account 874 includes costs associated with both Mains and services, a composite allocator of the PIS values was calculated and used. Similarly Account 878 was allocated on aggregated Meters and House Regulators PIS, Accounts 381 and 382 respectively. Customer Installation Expenses is a function of the number of customers and was allocated on Average Monthly Customers.

Account 880 is a miscellaneous catch-all account. Since it is essentially a function of all the other expenses shown on this schedule up to this point, I have used the Subtotal which would reflect a composite weighting of the various other allocation factors. A/Cs 870 and 881 have been allocated on the same basis.

With respect to the Distribution Maintenance Expenses on Page 13, they are all a function of the respective PIS accounts, with a couple of exceptions. A/Cs 885 and 894 are essentially a function of the other costs and I thus used the Subtotal to allocate these costs.

Q. Please describe the allocation of Customer Accounts and Customer Service & Info Expenses on Page 14 of Schedule CDL-7.

A. Based on the response to MGUA DR 171, I assigned $30,928 to Transports for A/C 901 & 903. Account 902 was allocated on a weighted customer basis using the following weights: 10, 20, 30, and 45 for Res, SGS, LGS and LVS respectively. Account 903 is essentially a function of customers - therefore I allocated these costs on the basis of Average Customers. Uncollectibles are a function and cost of doing business and are a function of revenues. I made a calculation to include PGA revenues so as to split Uncollectibles between PGA related and Margin related. Using data from MGE Schedule H-3, I divided the value 307,289,585 by 438,139,565 from MGE Schedule H-1. This is an approximation of the PGA related revenue of total revenue and the result is .70135. I then multiplied the Uncollectible value filed by MGE, 3,455,836 by .70135 to derive an estimate of PGA related Uncollectibles. This was allocated to the Sales classes on the basis of Sales Revenue including PGA Revenue (determined at Page 6 of CDL-7). The balance of Uncollectibles was allocated to all classes on the basis of Sales of Gas and Transportation revenue. I considered that all customers should share equally in the costs associated with Customer Service & Info so these costs were allocated to all classes on the basis of Average Customers.

Q. How did you treat Sales Expenses and Administrative and General Expenses?

A. Please see Page 15 of this exhibit. Sales Expenses are neither a function simply of Mcf sales, nor of customers. It may take as much time, expense and effort to gain a sale of 75 Mcf as a sale of 7,500 Mcf. Sales Expenses are directed toward Sales customers. Therefore, I allocated all Sales Expenses on the basis of a composite allocator weighted evenly on a customer and Mcf basis to Sales customers only.

I broke Administrative and General Expenses into four components. I assigned $35,208 based on the response to MGUA DR 171. Property Insurance is a function of property, so I allocated Account 924 on the basis on Total PIS. Account 926, Employee Pensions and Benefits are a function of labor. Total O & M excluding gas costs is a good proxy for a detailed payroll study, so I used it to allocate these costs. The balance of A & G was allocated on a composite allocator evenly weighing PIS and O&M expenses.

Q. **Mr. Laderoute, please discuss the Summary of O & M Expenses on Page 16 of Schedule CDL-7.**

A. This schedule simply summarizes the Operation & Maintenance Expenses that were allocated on prior schedules. It also portrays a number of totals and subtotals and depicts the calculation of Total O & M Expenses including Gas Costs which is used as an allocator elsewhere in the COSS.

Q. **How were Depreciation and Amortization Expenses treated?**

A. Page 17 of Schedule CDL-7 shows the allocation of Depreciation and Amortization Expenses. I used the detailed information from the Company's filing at MGE Schedule H-12. I used the corresponding Plant in Service values to allocate most of the Depreciation Expense, since the expense is a direct function of the underlying plant. With respect to the two AMR related items, those costs were allocated to the Sales rate classes on the basis of Sales customers. EGM Depreciation was assigned to LVS. Amortization of SLRP was on the basis of Services PIS. The Customer Service System was allocated equally to each customer on the basis of average customers.

Q. Please discuss Taxes Other Than Income portrayed on Schedule CDL-7, Page 18.

A. Property Taxes were allocated on the basis of Total Plant in Service values since property taxes are directly a function of PIS. As a proxy for a more direct labor allocator, I used O & M excluding Gas Cost, to allocate Payroll Taxes which is comprised of FUTA, FICA and SUTA.

Q. How were Income Taxes determined?

A. This determination is shown on Page 19 of Schedule CDL-7. All calculations of Income taxes are determined on a by-class calculated method. Starting with revenues and working down an income-type statement, Taxable Income was calculated for each class by subtracting expense items from revenue and including the Additions and Deductions to arrive at Income Before Taxes.

Q. Why was Total PIS used to allocate Interest on Long Term Debt?

A. Interest charges are a function of capitalization. Capitalization is used to pay for Plant in Service.

Q. Mr. Laderoute, please turn to Pages 20-25 of Schedule CDL-7 and describe these schedules.

A. This area of the COSS summarizes some of the various allocators used in my study. Many of these allocators were determined externally while some, e.g. Total PIS, Page 22 Line 23 of this exhibit, are developed internally.

Setting the Rate Levels - Rate Class Revenue Requirements

Q. What recommendation do you have in setting the rate class revenue responsibility?

A. They should be based on the costs that my COSS has identified. If the Commission decides that it wishes other classes to continue to subsidize the Residential class, then I would suggest that the Commission keep the level of revenues for the LGS and LVS class at the current levels. The reductions that would otherwise be applicable for these classes, approximately $1,646,726, could be used to offset the increase to the Residential class. However, should the Commission choose to do this, I would recommend that this case either be continued on an open basis or reopened one year from now. The revenues for Residential would increase by a like amount and the LGS and LVS class revenue levels would be reduced by $509,236 and $1,137,490 respectively.

Whether or not the revenue requirements amount changes from that requested by MGE, I believe that the Commission in this case for MGE should set rate levels on the basis of costs. I am sympathetic with all users who are facing gas costs much higher than in the past. The LVS customers like LGS, SGS and Residential are paying the higher costs for gas commodity. That is not an issue in this case. It is time that rate levels be set at least close to costs. In the past, decisions have been made indicating that costs were used as a starting point, yet the final resolution had **nothing** to do with costs. To wit, establishing class revenue requirements by spreading a revenue increase on the basis of existing revenues. Definitionally, that is not using costs as a starting point.

Q. What is your recommendation should the revenue requirements change in this case?

A. Having reviewed the revenue requirements information supplied by the Staff, it would appear likely that the level may be lower than that filed by MGE. Of course, there is always the opportunity for a Settlement as well. In such cases, the best approach is to plug the various values into the model and see what the result is. An alternative, though less accurate approach is to spread the total revenue requirement to rate classes based on the proportionate shares of my allocated COSS (Schedule CDL-7 Page 2 Line 28 - i.e. for Res, SGS, LGS and LVS respectively: .761553159, .168044905, .014057144, and .056344791.

Q. Have you prepared an exhibit to illustrate this?

A. Yes. Schedule CDL-10 shows various levels of total revenue requirements and the spread to the rate classes based on the total cost of service fractions by rate class. Comparing the values shown at Line 21 with a zero increase to the values shown on Schedule CDL-6 Page 2 illustrates that this approach is less accurate than a more detailed analysis.

Rate Design

Q. What comments do you have regarding rate design?

A. My only comments are directed at rate LVS, though the Simple Cost calculations shown at Page 5 of Schedule CDL-7 can provide guidance for the other classes. Given that there is no cost support behind the MGE proposal, I do not believe that it should be accepted. Based upon my cost analysis, the LVS costs show no more than $318.01 per customer or $297.77 per customer including the 30 extra units for multiple service/meter combinations. These values are far below the $614 proposed and $409.30 currently in effect. However, I have stated several concerns in this Testimony and illustrated specific costs that indicate even the $297.77 is too high. First, none of the "new" to LVS customers are new to the Company. They all switched from SGS or LGS. As such, their existing Meters and Services costs are far overstated by the weighted replacement costs that were used.

Second, the investigation of UMKC and CMSU costs of actual Meters and Services (who between the two account for 19 units - 4%) shows far less costs than those imputed due to the allocation based on weighted customers using replacement costs. The average costs for the Services actually in place to serve CMSU is $896 and for UMKC $557, yet the COSS value is $11,397. For Meters, the actual average cost for CMSU is

$1,894 and $2,300 for UMKC compared to the COSS imputed value based on replacement costs of $3,765.

Within a COSS for a class with a small number of customers such as LVS, it is customary to specifically determine the actual costs based on the actual facilities in place to serve them. I have requested such data and been supplied some of it, but barring further clarification I cannot complete a study for LVS Services and Meters. Considering my recommendations above in class revenue requirements, the best I can recommend at this point is to simply keep the current compromise method used in place until such time as a thorough and complete analysis may be performed. That is, after paying up to 2 full Customer Charges each additional metering point is billed at 50% of the indicated Customer Charge.

If the Commission chooses to leave the current class revenue requirements set at current revenue levels, then there should be no change to the structure of the LVS rate, its components or levels. Should the Commission choose to reduce the revenue requirements for LVS, I recommend that the Customer Charge level revenue be reduced by 25% of the total percentage reduction for the class. For example, if it were determined that the LVS class revenues should go down by 10%, the Customer Charge level of revenue would go down by 2.5%. I arrived at this purely based on judgement.

General Recommendations

Q. Mr. Laderoute, do you have any general recommendations for the Commission?

A. Yes - several. First, I believe that the Commission should encourage filing utilities to perform a cost allocation study in order to facilitate and assist with the necessary determinations. Some Commissions have done this in the form of standardized filing requirements that require filing a cost of service study. Second, the Commission should encourage filing utilities to perform special studies to determine, to the maximum extent practicable, the actual embedded average cost of Meters, Services, Regulators and Meter Installations by rate class. Third, I recommend that the Commission should encourage filing utilities to file detailed workpapers at the time of filing a case in order to reduce the amount of Data Requests. Finally, I would encourage the Commission to consider opening a generic docket to address Facilities Line Extensions policies. Given changes in the industry, it may be appropriate to do this for both gas and electric utilities.

Q. Does this conclude your testimony?

A. Yes at this time. However, as I noted earlier, I would reserve the ability to supplement this testimony and certain schedules as additional data becomes available from MGE.

Appendix A - Qualifications

Q. Please state your name, occupation and address.

A. My name is Charles David Laderoute. I am a consultant and President of Charles D. Laderoute, Ltd., 5114 Amazonia Road, St. Joseph, Missouri 64505.

Q. What is your educational background?

A. I graduated with a Bachelor of Science degree in Engineering Management, minoring in Mechanical Engineering, from the University of Missouri - Rolla in 1971. In 1972 I received a Bachelor of Science degree in Economics, also from the University of Missouri - Rolla. I completed a Master of Arts degree in Economics from Eastern Michigan University - Ypsilanti, Michigan in 1980. I have taken further graduate courses at Harvard University (Certificate of Advanced Studies - ABD), Boston College (PhD) and Eastern Michigan University (MBA).

Q. What other professional training have you completed?

A. I completed the P.U.R. Guide sponsored by Public Utilities Reports in 1975, the AGA Gas Rate Fundamentals Course sponsored by the American Gas Association and conducted by the University of Wisconsin Graduate School of Business in 1976, and the American Gas Association Seminar on Gas Rates at the

University of Maryland in 1977. While employed at Consumers Power Company, I attended many company-sponsored courses including Introduction to Public Utility Accounting sponsored by the AGA and EEI General Accounting Committees.

Q. What is your business experience?

A. During the past 29 years my work in the fields of energy economics and public utility regulation has included rate, financial, economic and regulatory matters associated with 53 utilities and 12 commercial and industrial customers in 29 states, 2 Canadian provinces, and 3 foreign countries.

My firm's consulting services embrace the areas of cost of service, rate design, revenue requirements, financial analysis, and rate of return for both retail and wholesale operations. I have served clients regarding policy analysis, technical studies and compliance assistance dealing with federal and retail regulatory requirements including FPA, NGA, PURPA, NGPA, NECPA, and FUA. I have performed gas, electric, and steam cost of service and rate design studies as well as prepared rate filings, exhibits, and testimony presented to State and Federal regulatory agencies.

I have performed or supervised studies in the associated areas of: cogeneration, gas underground storage rates, electric transmission and wheeling rates, gas transportation rate design and policy, unit power and short?term power studies, profitability and separations studies, load dispatching, antitrust analysis including price squeeze, load research, integrated resource planning, load management, conservation, power purchases from non?utility sources, load and customer forecasting, degree day normals analysis and development of weather normalization adjustment clauses.

Prior to forming Laderoute, Ltd., I was Principal Consultant and Project Manager for rate and regulatory assignments in the Energy Planning and Economic Services Group of Chas. T. Main, Inc., Boston, Massachusetts. Earlier, I served as Senior Rate Analyst responsible for the supervision of all wholesale electric rates and associated regulatory activities for Consumers Power Company in Jackson, Michigan.

Q. Please identify your regulatory appearances.

A. I testified for Southeastern Michigan Gas Enterprises (now known as SEMCO Energy) of behalf of its LDC subsidiaries Michigan Gas Co. ("Mi-Gas") and Southeastern Michigan Gas Co. ("SEMGas"). My testimony addressed: rate reclassification including billing determinants and revenues on new rate classes, the cost of service allocation study ("COSS") filed in the case, proposed rate design and portions of the Company's analysis in support of Daily Balancing. In 1993 and 1994, I testified in Northwestern Utilities Limited ("NUL") (Alberta, Canada) General Rate Application. I addressed the cost of service study ("COSS"), the cost causation study ("CCS" - essentially a hybrid incremental/marginal cost of service study), pricing and certain rate design issues in Phase II of the proceeding in 1994. The 1993 testimony in Phase I of the case covered a number of components of NUL's forecasted revenue requirements including: personal computers, software amortization, Operation & Maintenance expenses, plant acquisition adjustment, and intercompany transactions. I testified on behalf of Providence Gas Company in 1993 in two cases; a rate increase filing, Docket No. 2082, and Docket No. 2076B. My work in Docket No. 2076B included preparation of an allocated cost of service, revenue reallocation and rate design based on declining block rates. My testimony in Docket No. 2082 (Direct and Rebuttal) supported the Company's proposal to move from 15 year to 10 year weather normals. I also prepared and sponsored the cost allocation study submitted in that case. In November 1992, I prepared testimony for

Providence Gas Company in Docket No. 2076A in support of its proposal to implement declining block rates for firm base rates. As part of Settlement of consolidated Dockets 2076 & 2082, I assisted the company to reclassify all of its rates from end-use based to size based and developed seasonal declining block rate structures.

I submitted testimony on behalf of Wisconsin Gas Company in 1992 in Docket No. 6650-GR-110. My testimony supported the company's proposal to utilize 10 year weather normals rather than 20 year normals. The weather normalization issue was taken out of that case and the Wisconsin commission opened a generic docket to address the issue of weather normalization by all gas and electric utilities. My testimony was resubmitted in Docket No. 05-UI-105 and I presented Rebuttal testimony in that case as well. In 1991, rebuttal testimony was prepared on behalf of Vermont Gas Systems in Docket No. 5516. I supported the company's proposal to use 10 year weather normals. As part of settlement, the testimony did not become part of the record, but 10 year normals were settled on. I testified on behalf of Providence Gas Company in Docket No. 2001 in 1991. That testimony covered dual fuel and interruptible sales and transportation fully allocated and marginal cost of service. In Providence Gas

Company's 1991 Docket No. 1673, I developed a weather normalization clause to adjust the base rates for normal weather. The adjustment would take place on a deferred basis comparing current month degree days with 15 year normal degree days. During 1991 and 1992 I testified in Northwestern Utilities Limited ("NUL") (Alberta, Canada) General Rate Application, Phases I and II. My testimony in Phase I covered certain components of NUL's revenue requirements as well as the weather normalization methodology. In Phase II, I performed a fully allocated cost of service study and prepared testimony on that study and rate design. I served as a witness in Docket No. 1971, Providence Gas Company's 1990 base rate case. My testimony included the Company's customer and load forecast, fully allocated cost of service study and firm sales rate design.

I submitted testimony to the Federal Energy Regulatory Commission ("FERC") on behalf of K N Energy, Inc. in 1990 Docket Nos. RP87-86-005, et al. This testimony supported the seasonal rate design filed by K N to meet the FERC's Policy Statement on rate design. That case was settled. I have testified on several occasions for Michigan Gas Company. In its 1989 base rate Case U-9323, I presented Direct and Rebuttal testimony on cost allocation, seasonal rate design, load and customer forecast, weather normalization, treatment of holding company cost allocation and assignment, and treatment of plant acquisition adjustment. I presented Direct testimony in Michigan Gas Company's 1988 base rate Case No. U-9112 on cost allocation and seasonal rate design. That case was settled. In Case No. U-8897, I presented Rebuttal testimony for Michigan Gas Company in its 1988 Gas Cost Recovery Plan. This testimony pertained to the development of quarterly gas cost recovery factors. In 1987, I presented Direct and Rebuttal (two appearances) testimony before the Massachusetts Department of Public Utilities on behalf of Commonwealth Gas Company, Case No. DPU 87-122. This testimony embraced fully allocated cost of service and marginal cost of service. I testified in 1980 on the use of fully allocated cost of service studies before the Washington Utilities and Transportation Commission in the Matter of The Washington Water Power Company Cause No. U-80-13 on behalf of Inland Empire Paper Company. During 1980, I testified before the Economic Regulatory Administration regarding its Proposed Voluntary Guideline on the PURPA Cost of Service Standard. I served as the expert witness in the South Carolina Public Service Authority's generic hearings regarding PURPA Sections 111 and 114 in 1980.

Q. **Aside from general speeches, have you any experience lecturing in the area of public utility rates and regulation?**

A. In 1989, my firm presented to the World Bank a one day "Seminar on Regulation of Power and Gas Utilities." During 1984 and 1985 my firm presented a two day seminar on three occasions for the Electric Council of New England on "Fundamentals of Cost of Service and Rate Design." Since 1981, I have been associated with the Center for Professional Advancement as a Course Director, Organizer and Instructor. The Center is the world's largest private organization offering post-collegiate short courses for engineers, scientists and technical managers. I have been Course Director for Principles of Electric Utility Rate Regulation since 1981. I organized Principles of Gas Utility Rate Regulation and served as Course Director. This course was first offered in 1982. Both of these courses have been sponsored by the Center and offered in various cities around the country. I served as Course Organizer and Director of Advanced Methods in Electric Utility Rate Regulation, Course Co-Organizer and Instructor for Electric Utility Load Research and Course Organizer and Director of Electric Rate Case Participation by Power Consumers. These courses were also sponsored by the Center. In addition, I have taught over 1,000 professionals, engineers and managers to use personal computers in numerous short courses.

Q. Have you served in any other capacity as a lecturer?

A. As an Adjunct Instructor I taught courses in Microeconomics, Macroeconomics, Consumer Economics, Business Mathematics, Algebra and Current Economic Issues at Jackson Community College, Jackson, Michigan.

Q. What articles or speeches have you prepared related to public utility rates and regulation?

A. I have written numerous papers and presented speeches pertaining to the areas of gas and electric rate making including the use of microcomputers:

"Weather Normalization Analytics", presented to the Gas Supply Planning, Management, Control, & Deliverability Under Order 636 Conference, sponsored by the Institute of Gas Technology, Houston, TX March 7-9, 1994.

"Determination of Weather Normals", presented before the Energy Modeling: Optimizing Information and Resources Conference, sponsored by the Institute of Gas Technology, Chicago, IL June 7-8, 1993.

"Weather, Weather Normalization and Weather Normalization Adjustment Clauses", unpublished paper, 1992.

"The Weather Problem for the Gas Industry", presented at the 13th Annual North American Conference of the International Association for Energy Economics, Chicago, IL, Nov. 18-20, 1991.

"Is There a Trend? Analysis with an Application on Weather for the Gas Industry", presented before the International Association of Business Forecasting Sixth Annual Conference, Atlanta, GA Oct. 6-8, 1991.

"Overview of Gas Forecasting: Some Pragmatic Considerations", presented to the New England Gas Forecasting Association, Westborough, MA Sep. 10, 1991.

"Gas LDC Weather Normalization: What People Are Doing About the Weather", presented at the Seventh NARUC Biennial Regulatory Information Conference - Columbus, OH Sept. 13, 1990.

"Weather Normalization for Gas Local Distribution Companies: An Analysis of 15 Year versus 30 Year Average Degree Days", a paper presented before the International Association of Business Forecasting Fourth Annual Conference, Philadelphia, PA Sep. 27, 1989.

"Current Rate and Regulatory Issues Facing LDCs", speech presented to the Michigan Electric and Gas Association 1989 Spring Seminar, Lansing, MI April 24, 1989.

"Time Differentiated Natural Gas Utility Rates, Demand Cost Allocation Methods and the Relative System Utilization Method", paper presented to the State Regulatory Affairs Committee, Michigan Electric and Gas Association, Lansing, MI Jan. 19, 1989.

"Gas Transportation Rate Design - A Treatise" unpublished paper, Dec. 1988.

"The Relative System Utilization Method (RSUM) for Time Differentiated Natural Gas Utility Cost Allocation Studies", paper presented at Sixth NARUC Biennial Regulatory Information Conference - Columbus, OH Sept. 14, 1988.

"Gas Local Distribution Company Rate Design," speech presented to the New England Gas Association 1988 Ratemaking Concepts Seminar, Sutton, MA, April 27, 1988.

"The Game of Gas Rate Design: Issues and Strategies," speech presented to the New England Gas Association Planning and Rates Group Workshop, Sturbridge, MA, June 3, 1987.

"Marginal Cost Pricing for Natural Gas Local Distribution Utilities," speech presented before the Eighth Annual North

American Conference of the International Association of Energy Economists, Massachusetts Institute of Technology, Cambridge, MA, November 19, 1986.

"Utilization of Marginal Costs in the Natural Gas Industry," speech presented before the American Gas Association Advanced Regulatory Seminar, University of Maryland, College Park, MD, October 6, 1986.

"Performing Statistics in a DBASE III Application: Bill Frequency Distribution & Load Research Customer Sample Selection." Feature article for PEGBoard, the journal of the Planning Engineers Desktop Computer Users Group, Vol. 5 #3, May-June 1986.

"Managers Use of Microcomputers in the Electric Utility," before the Annual Meeting New York Power Authority, Harrison Conference Center, Glen Cove, Long Island, New York, March 27, 1986.

"Natural Gas Utility Cost of Service Demand Allocation Methods," speech presented to the Spring meeting of the New England Utility Rate Forum, Worcester, MA, April 11, 1985. Unpublished.

"Microcomputers in the Electric Power Industry", Feature article in Nov-Dec 1984 issue of PEGBoard, the journal of the Planning Engineers Desktop Computer Users Group, p. 1.

"Microcomputer Utilization in the Electric Utility Industry", article in Public Utilities Fortnightly, Sept. 27, 1984 p.31.

"Microcomputers in the Electric Utility Industry" paper presented at Fourth NARUC Biennial Regulatory Information Conference - Columbus, OH Sept. 7, 1984.

"Gas Transmission Pipeline Cost Allocation and Rate Design - The Need for Change", paper presented at the Second Annual Energy Conference sponsored by the New England chapter of the International Association of Energy Economists, Boston, MA June 28, 1984.

"An Introduction to Lotus 1-2-3: Typical Bill and Graphing Application for Electric Utilities" speech presented to the Spring 1984 Meeting of the New England Utility Rate Forum, Andover, MA March 9, 1984. Unpublished.

"Selective Marketing by Electric Utilities," speech presented to the 1983 Northeast Regional Public Power Annual Conference, Chatham, MA Sept. 1983.

"Allocated Cost of Service Studies on Microcomputers," speech presented to the Summer 1983 Meeting of the New England Utility Rate Forum, Sturbridge, MA July 21, 1983.

"A Tool Kit for the Rate Analyst Pertaining to Public Utility Expert Testimony," speech presented to Fall 1982 Meeting of the New England Utility Rate Forum.

"The Public Utility Regulatory Policies Act - PURPA - Purposeful Policy or Federal Boondoggle", speech presented to Electric Council of New England - Financial and General Accounting Committee, April 24, 1981.

"Electric Utility Transmission and Wheeling Service: An Analysis of Private Class A and B Electric Utilities" - Masters Thesis - Eastern Michigan University, Ypsilanti, Michigan, December 1980.

"The Federal Energy Regulatory Commission's PURPA Cogeneration Rules: Economic, Rate Design, and Policy Aspects," presented at the Seventh Annual University of Missouri, Rolla-Department of Natural Resources (UMR-DNR) Conference on Energy, 1980.

"Rate of Return Regulatory Policy - The Bane of Electric Utilities?," presented at the Seventh Annual University of Missouri, Rolla-Department of Natural Resources (UMR-DNR) Conference on Energy, 1980.

"Time-Differentiated Accounting Costs for Electric Utility Rate Design," paper presented at Second NARUC Biennial Regulatory Information Conference, Columbus, OH, 1980.

"Utility Rate Structures: What We Can and Should Do and What We Can't and Should Not Do," paper presented at the Fifth Annual UMR-DNR Conference on Energy, University of Missouri, Rolla, 1978.

"Utilization of Load Studies and Load Data for Rate Determination in Electric Utilities" unpublished paper, Dec. 1976.

Q. **Please identify your professional affiliations.**

A. I am currently or have previously held the following memberships and offices: American Bar Association Industrial Organization Economist Associate member, firm Associate member of the American Gas Association with memberships as Analytical Associate and Financial Associate, Charter Member of the International Association for Energy Economics and Past President of the New England Chapter, Charter member and President of the Planning Engineers Desktop Computer Users Group, a microcomputer users group, American Economics Association, American Meteorological Society, American Society for Engineering Management (Charter and Lifetime Member), Association of Demand-Side Management Professionals (Charter), Association of Energy Engineers and its Demand-Side Management Society (Charter), Association for Evolutionary Economics, National Association of Business Economists, and the National Society of Rate of Return Analysts.

Q. Are you a member of any honorary organizations?

A. I am a member of Omicron Delta Epsilon International Honorary Economics Society. I am listed in: the International Biographical Centre's 1985 edition of the International Businessmen's Who's Who, the 13th and forward editions of Marquis Who's Who in the World, the 23rd and forward editions of Marquis Who's Who in the East, the 27th and forward editions of Marquis Who's Who in Finance and Industry, the ninth edition of the International Who's Who of Intellectuals, the inaugural and forward editions of Marquis Who's Who in Science and Engineering, the 52nd and forward editions of Marquis Who's Who in America and the fourth edition of Marquis Who's Who of Emerging Leaders in America.

Appendix B - COSS Technical Discussion

I. FULLY ALLOCATED COST OF SERVICE STUDY PRINCIPLES.

A. General Principles

Fully allocated cost of service studies, sometimes referred to as fully distributed or embedded cost of service studies, are necessary because of the nature of gas utility service. Many of the costs incurred to serve customers are of a joint or common nature. Any business, utility or other, that sells more than one product or service incurs costs, whether an out of pocket expense or costs related to capital investments, that are joint or common costs. Distribution Mains, an investment, are used to distribute gas to all rate classes served from the distribution system. The Demand portion of purchased gas, an expense, is incurred to sell gas to all system sales rate classes. There is no exact method to determine a product's or service's share of a joint or common cost. Thus, these costs are allocated using a method that is reasonable based upon judgement.

In some cases, costs are specifically identifiable as to their cost causation. These costs can be directly assigned to a rate class or classes to reflect proper cost causation. Some analysts refer to cost allocation as assigning costs. This is improper. Occasionally it is possible to assign a portion of the cost associated with a specific account and allocate the balance for individual accounts. In most cases, because a cost is common, it is necessary to identify a reasonable method to allocate that cost item to rate classes. That is, we seek to determine what caused the utility to incur the cost. This concept is referred to as proper cost causation.

Fully allocated cost studies pertain to the analysis of accounting costs. The results of such studies determine average costs. Since the utility's revenue requirements are determined based upon accounting costs, the results of a cost allocation study may be used to determine the revenue requirements by rate class.

B. Top-Down and Bottom-Up Cost Allocation Studies

The process of performing a fully allocated cost of service study may be approached in two ways: top-down and bottom-up. Some analysts do not do a top-down study, but merely perform a study to determine revenue requirements by rate class (bottom-up). These are discussed in detail in Sections I. E. and F below.

C. Fundamental Steps in Cost Allocation

The cost allocation is comprised of five primary steps. All cost items, whether income or rate base related, are:

- functionalized
- classified
- allocated
- aggregated
- summarized

Functionalization assigns costs to the function performed. For a gas utility the following broad functions are often used:

- Production
- Storage
- Transmission
- Distribution

After all costs have been Functionalized, they are next Classified. This analysis is actually comprised of two parts. First, each cost is analyzed and a determination is made as to whether the cost is of a fixed or variable nature. An example of a fixed cost is Distribution Mains, Uniform System Accounts ("USA") Number 376. The investment is sunk and is the same whether customers take any gas or not. Mains investment is a Plant in Service item and is included in Rate Base. The cost we are interested in is the return associated with this investment; it is a fixed cost. An example of a variable cost is the Commodity portion of purchased gas. These costs vary directly with, and are a function of, consumption whether measured on a volumetric basis, Mcf, or a thermal basis, i.e. MBTU or DT.

The second step, Classification, is to classify the costs to three categories: Demand, Commodity and Customer. Demand (also referred to as Capacity) costs are those costs that are considered a function of the capacity of the system. Demand costs are by their very nature considered fixed types of costs. Again, Distribution Mains are a good example because they are sized, for the most part, to meet peak capacity requirements. Commodity costs are by their nature variable since they vary with, and are a function of the amount of consumption, whether volumetric or thermal. Customer costs include both fixed and variable costs. They arise simply because a customer is hooked to the system. An example of a fixed customer cost is the investment in Services, USA Number 380. This is a sunk cost and is, therefore, fixed. It is incurred whether the customer takes any gas or not. A variable customer cost is meter reading. It is not absolutely necessary to read meters. Additionally, meter reading cost is a function of the frequency of meter reads; i.e. monthly, bimonthly, etc. Therefore, this cost is variable. In general, the analyst usually considers costs that are of a fixed nature, excluding customer related costs, to be capacity or demand related and those that are variable, again excluding customer related costs, to be commodity related.

The third primary step is to allocate costs or allocation. An important part of any cost allocation study pertains to the determination of appropriate allocators. Variable costs, other than customer related, are virtually always allocated on the basis of consumption. This may be thermal, DT, or volumetrically based, Mcf.

In all cost allocation studies the allocator that is most problematical is the demand allocator. In the natural gas industry, this is especially a problem because most gas utilities do not measure demands of their customers and very few perform load research studies that can be used to determine the customers' demand characteristics. Even if larger customers do have demand meters, smaller customers such as residential and small C&I seldom do.

Aggregation pertains to the collecting the individual allocated cost items together into the three groups: demand, commodity and customer related costs.

Finally, since there is a significant amount of detail in a typical COSS, the results are summarized for ease of analysis and review.

D. Aggregation Problems, Simple Cost Studies and Catch-All Cost Categories

It is our belief that Cost of Service Studies are more accurate if an analyst attempts to allocate most costs on an account basis. In a cost allocation study, the following steps are usually performed: functionalization, classification, allocation and finally collection or aggregation of the allocated/classified costs. Some analysts collect costs together as Customer, Commodity and Demand related and then allocate the "aggregated" costs. This approach can lead to aggregation problems which can result in less accurate results or results that are simply wrong.

One reason why analysts do this is that allocating aggregated costs can make for a much simpler study, which can be done in less time. It also does not take as much thought and consideration as a detailed account-by-account study. Based upon our review of numerous studies throughout North America, especially where we have independently performed studies against the same raw data, we have found consistently that the simpler studies often end up allocating costs improperly and in a less fair manner.

Here is a simple example from a real life case. An analyst classified demand recording meters as a Demand related cost. For the utility involved, the amounts were substantial. They then aggregated together the Demand related Distribution costs. Next, they allocated the aggregated costs on the basis of Non Coincident Demand ("NCD") by rate class. However, the analyst made no attempt to modify the NCD factors for rate classes who were not Demand metered - including Residential and all smaller general service rate classes. In this case, the NCD for the Residential class was 38.6% and they were allocated $317,000 of Demand related costs associated with the Demand related meters. Aside from the issue of classifying the costs in question as Demand related (in our mind they should have been classified as Customer related), the fact was that demand related costs were being allocated costs to rate classes who could not possibly have caused the costs to be incurred. Since the costs were aggregated together and then allocated on a demand basis to all classes, they became a small cost item in the simple total. This problem is referred to as an aggregation problem and is particularly an issue in studies where a simple approach is used and cost are aggregated prior to allocation rather than after allocation.

Generally, a COSS is easier to follow and likely more accurate if costs are aggregated to cost class (demand, commodity and customer) after they are allocated, not before. The result is admittedly a more complex study with more pieces of paper. It is our view that this is not a bad thing. Additionally, we believe results are more accurate with a lesser chance of aggregation problems if more costs are allocated by account rather than in toto.

A final issue of concern is that some analysts will not take the time to try to determine an appropriate allocator. As a result, there may be many cost items that they simply throw into the category of Customer or Demand related and then use a general customer or demand allocator to allocate the cost. While expedient, the result may be wrong at worst or simply unfair in terms of the result.

E. Top-Down Analyses

In a Top-Down study, the goal is to ascertain realized rates of return in toto and by rate class for a test year. Financial and operational results for a test year are analyzed starting at revenues (the top) and progressing down through Net Income. Net Income is the bottom line from which we determine rate of return. The test year can be a full historical period, a historical period adjusted for "known and measurable" changes or a forecasted period. If a forecasted approach is used, a base year is often shown to provide real data.

Regardless of whether historical data with known and measurable changes or a fully projected test year is used, each revenue and expense item is allocated or assigned to rate classes. This is often referred to as the Income Statement side of a cost allocation study. Elsewhere in a cost allocation study, all Rate Base items (the Balance Sheet side of a study) are assigned or allocated to classes. In general, Rate Base is determined by adding all Plant in Service ("PIS"), less Accumulated Depreciation, plus Working Capital. Often there will be deductions to Rate Base, sometimes referred to as "offsets". These may include such items as Customer Deposits, Accumulated Deferred Income Taxes or Contributions. Once the allocations are complete, Net Income can be divided by the Rate Base for the System Total and for each rate class to ascertain the Rate of Return for the company and each rate class used in the study.

Allocation of costs completes the analysis in a "Top-Down" study. The analyst can determine the actual results of operations and ascertain the rate of return by rate class and for the system by dividing net income by rate base for the system in toto and for each rate class.

Before proceeding, two words of caution regarding areas of potential confusion. First, while an analyst may use some customer basis to allocate a particular cost item, he or she may classify the costs to commodity. Thus, while a customer basis, e.g. average or weighted customers, may be viewed as the fairest allocator, the analyst believes that the cost should in fact be recovered in the commodity portion of the rate. Second, Customer related costs includes costs of both a fixed and variable nature - they are not all fixed.

F. Bottom-Up Analyses

When performing a "Bottom-Up" study, the analyst must add an additional step to a cost analysis. The purpose of a Bottom-Up study is to determine the required revenue, by rate class and in total, based upon the desired rates of return. As noted above, it is certainly possible to perform a cost allocation study without doing the top-down portion. In a Bottom-Up study, allocated rate base is multiplied by the required rate of return to determine required Net Income. This is the bottom line. All other cost items, including required Income Taxes brought about by the required Net Income, are added to the required Net Income to arrive at the required revenue by rate class and for the total company. Thus, we are working from the bottom up to the top.

In the determination of the total company revenue requirements and in a cost allocation study, a key determinant of revenue is the rate of return. This is especially true since required income taxes ("IT") are essentially a direct function of return. In a Bottom Up study, rate of return defines Net Income. Because IT is a function of Net Income there is a multiplier effect to get to required revenue. Aside from all other cost items, if net income changes by one dollar, revenue must change by some multiple to cover the change in IT. A simple form of the multiplier is determined by taking 1/(1-t) where "t" is the tax rate. Some analysts refer to this as a revenue expansion factor.

It is our belief that a goal of utility regulation should be generally to establish revenue requirements on the basis of equalized rates of return for all rate classes; i.e. the rate of return for all rate classes should be the same as that required by the company overall. This may not be appropriate in certain cases; e.g. for Interruptible customers.

The transition from the Top-Down study to the Bottom-Up study is straightforward. In terms of costs, the only items which change are the Net Income, Income Taxes and any other items affected by the income change. Other items might include, for example, gross receipts taxes. All other costs are unaffected by a change in rate of return. As a result, the Bottom-Up study starts with the Net Income from the Top-Down study and adds (or subtracts) the additional (or decremental) costs for increased (decreased) Net Income and increased (decreased) federal level income taxes. Once these are determined, the Bottom-Up study is completed and the result is the overall required revenues by rate class.

In summary, a Top-Down cost allocation study seeks to determine the realized rate of return by rate class starting with revenue at the top and working down to the bottom line, Net Income. The Bottom-Up study starts at the required Net Income, the bottom, and works up to determine required revenue by rate class.

II. DETERMINATION OF ALLOCATION FACTORS.

A. Customers

There are two types of Customer allocation factors: unweighted and weighted. When the customers in all rate classes should bear the same weight, the unweighted factors are used. The average number of customers by rate class or equivalently number of bills are then used in the COSS.

Weighted Customer allocation factors are used when a different weight should be applied, but the number of customers has to be worked into the calculus. For example, based on MGE data that I used, the cost of a Residential Meter is $55 and that for a typical LGS customer is $2,275. To determine the weights, the cost (from a special study) for items are divided by the costs for the lowest cost class, usually Residential. In this case, the weight is 41.3636 (2,275/55) for LGS and 1.0 for Residential (55/55). The weights are multiplied by the number of customers in a class. This is summed across all classes and each class' amount is divided by the Total. The result is the weighted allocation factor.

In some case, the appropriate number of customers is not based on the number of "customers" or bills rendered. In this case, MGE has 30 extra meter/service combos for its 441 LVS customers. Therefore, in determining weighted factors for Accounts 380-383, 471 was used for the LVS class rather than 441 "customers".

B. Commodity

Monthly Mcf (or Dt or Ccf) sales data by rate class are summed and each rate class' amount is divided by the Total

C. Demand

There are many types of demand allocation factors that can be used. For purposes of this study, we chose to use the Peak Month method.

III. CUSTOMER COST METHODS

The determinations discussed in this section pertain to studies that include a Bottom-Up as well as Top-Down analysis. Some of the material included here is germane only to a Bottom-Up study. This material identifies some of the logic as to why we classify certain costs as Customer related. It can assist in understanding of how we come up with the Customer related costs, which backup a proposed monthly Customer Charge.

There are four generally accepted methods categorized as approaches to determine customer related costs in a cost allocation study, though two of these, zero intercept and minimum system, actually are approaches to identify a portion of Mains PIS as customer related. The methods are: minimum system, zero intercept, simple customer and a method that we refer to as the basic customer method. In a COSS, we usually determine customer related costs using the simple customer and the basic customer methods. The costs that we include in the Simple Customer Approach are fairly comprehensive as follows.

Costs Included in the Simple Customer Approach

Expenses:

Services portion of Mains & Services (Acct. 874)
Meters & House Regulators (Acct. 878)
Customer Installation (Acct. 879)
Maintenance of Services (Acct. 892)
Maintenance of Meters & House Regulators (Acct. 893)
Meter Reading (Acct. 902)
Customer Records & Collections (Acct. 903)
Depreciation (associated with Accts. 380, 381 & 382)

Rate Base: (Return and FIT associated with)

Services (A/C 380) net of Accumulated Depreciation
Meters (A/C 381) " " " "
Meter Install. (A/C 382) " " "
House Reg. (A/C 383) " " "

Resulting revenue requirement grossed up for Gross Receipts Taxes if necessary.

The Basic Customer Method reflects all direct and indirect costs of having a customer attached to the LDC's system. Note that the basic customer approach does not assume that all costs classified as customer related are fixed - some are in fact variable; e.g. meter reading.

The Simple Customer approach may be viewed as limited in that it often does not cover all of the direct customer related costs, let alone appropriate indirect customer related costs, that an LDC incurs to serve a customer. However, there are several renditions of the simple customer approach. Those concerns are usually directed at the most elementary and minimal approaches, which include only the following:

Return on Meters PIS
Return on Services PIS
Meter Reading
Billing

More inclusive versions add some or all of the following:

Meters Operation	Meters Maintenance
Meters Depreciation	Meter related Income Taxes
Services Operation	Services Maintenance
Services Depreciation	Services related Income Taxes

The Basic Customer method includes the costs of return and associated income taxes associated with meters, meter installations, house regulators and services plant in service on the rate base side of the revenue requirements. It also includes, on the income statement side, the costs of meter reading and customer records and collection. Since other costs within a cost allocation study are in turn a function of these costs, whether directly or indirectly, they are included in the Basic Customer Method. Thus, this method seeks to include a greater array of costs, but costs that are considered to be a function of having the customer attached to the system.

In the determination of customer related costs, there may be cases where the actual method used is less important than how costs are classified and allocated. For example, it may be most appropriate to allocate a particular cost on the basis of number of customers, yet classify the cost to the commodity portion of the rate. This can be particularly true for some of the indirect costs that can get classified as customer related simply because they "tag along" with other costs in the cost allocation study. One of our concerns with many cost allocation studies is that vast groups of individual cost items are often collectively classified. This can create an aggregation problem in that once the costs have been aggregated it is simply impossible to ascertain what is or is not truly customer related.

The reader should not be mislead by the above discussion. In our cost allocation studies, we determine Customer related costs on both the simple customer basis and the basic customer method. The Simple customer approach that we calculate is comprehensive and is above what would likely be a lower limit for establishing monthly customer service charges while the Basic Customer Cost identifies a ceiling. For example, a COSS might show $20.71 per month on the Basic Customer method and $10.07 per month on the Simple Customer method for a Residential class. At what level should the customer service charge be set? If revenue requirements are set exactly equal to allocated costs, interclass considerations are generally not an issue. This is so because any customer related costs that are not recovered in the monthly Customer Service charge will be recovered in a rate class' Commodity charge. However, there may be intraclass considerations. If the Customer related costs are not recovered in the service charge, they must go into the commodity charge. The result is that larger customers would subsidize smaller customers within a rate. If revenue requirements are not set at equalized rates of return, there may be inter and intraclass considerations. Obviously there are many rate design goals and objectives, but costs are a paramount consideration.

Schedule CDL-1

File: Determinants.xls
Date: Apr. 6, 2001
Source: MGE WP
Prep: CDL

Missouri Gas Energy
2000 Cost of Service Study
Comparison of Calendar 2000 Data versus 12 Months end
September 1997

Line	12 Mos Sept '97	Residential	SGS	LGS	LVS	Total
	Ann Mcf	42,427,737	16,681,053	3,164,177	30,069,049	92,342,016
1						
2	Customers	413,073	56,523	465	430	470,491
3						
4	Peak Mo	9,161,011	3,485,095	543,241	3,313,434	16,502,781
5						
6	Avg Ann Use	102.7	295.1	6,804.7	69,928.0	196.3
7						
8	Avg Pk Mo Use per Cus	22.2	61.7	1,168.3	7,705.7	35.1
9						
10						
11	12 Mos Dec '00					
12	Ann Mcf	40,836,455	15,694,675	2,733,677	28,503,035	87,767,841
13						
14	Customers	431,374	59,903	472	441	492,190
15						
16	Peak Mo	8,231,268	3,040,642	530,580	3,001,113	14,803,603
17						
18	Avg Ann Use	94.7	262.0	5,794.9	64,583.9	178.3
19						
20	Avg Pk Mo Use per Cus	19.1	50.8	1,124.7	6,800.1	30.1
21						
22						
23	Change					
24	Ann Ccf	(1,591,282)	(986,378)	(430,500)	(1,566,014)	(4,574,175)
25						
26	Customers	18,301	3,380	7	11	21,699
27						
28	Peak Mo	(929,743)	(444,453)	(12,661)	(312,321)	(1,699,178)
29						
30	Avg Ann Use	(8.0)	(33.1)	(1,009.7)	(5,344.1)	(17.9)
31						
32	Avg Pk Mo Use per Cus	(3.1)	(10.9)	(43.5)	(905.6)	(5.0)
33						
34						
35	% Change					
36	Ann Ccf	(3.8)	(5.9)	(13.6)	(5.2)	(5.0)
37						
38	Customers	4.4	6.0	1.4	2.6	4.6
39						
40	Peak Mo	(10.1)	(12.8)	(2.3)	(9.4)	(10.3)
41						
42	Avg Ann Use	(7.8)	(11.2)	(14.8)	(7.6)	(9.1)
43						
44	Avg Pk Mo Use per Cus	(14.0)	(17.7)	(3.7)	(11.8)	(14.3)

File: MiscCalc.xls
Date: Apr. 12, 2001
Source: MGE WP
Prep: CDL

Missouri Gas Energy
2000 Cost of Service Study
Comparison of Calendar 2000 Data versus 12 Months end
September 1997

Line		Item (a)	12 Mos End Sept '97 (b)	2000 (c)	Change (d)	% Change (e)
1	Customers		470,491	492,190	21,699	4.6
2	Annual Mcf		92,342,016	87,767,841	(4,574,175)	(5.0)
3						
4	376	Mains	229,881,005	278,969,931	49,088,926	21.4
5	380	Services	212,781,120	248,048,065	35,266,945	16.6
6	381	Meters	26,333,410	28,150,505	1,817,095	6.9
7	382	Meter Install	38,911,272	49,974,693	11,063,421	28.4
8	383	House Reg	9,251,688	9,540,154	288,466	3.1
9	397.1	AMR	??	32,969,219		
10						
11	Mains per Customer		488.6	566.8	78.2	16.0
12	Services per Customer		452.3	504.0	51.7	11.4
13	Meter Install per Customer		82.7	101.5	18.8	22.8
14						
15	Change in Mains per Change in Customers				2,262	
16	Change in Meter Install per Change in Customers				510	
17						
18	Mains per Mcf		2.5	3.2	0.7	27.7
19	Services per Mcf		2.3	2.8	0.5	22.6
20						
21	Change in Mains per Change in Mcf				(10.7)	
22						
23						
24	Mains Depreciation Expense		4,321,763	5,858,369	1,536,606	35.6
25						
26	Mains Depr Exp per Customer		9.19	11.90	2.7	29.6
27						
28						
29						
30			Return & FIT factor		0.14759458	
31			Mains Incr Return & FIT		7,245,260	
32						
33			Ret, FIT & Depr		8,781,866	

File: MiscCalc.xls
Date: Apr. 12, 2001
Source: MGE WP
Prep: CDL

Missouri Gas Energy
2000 Cost of Service Study
Residential Rate Class AMR related &
Meter Reading Costs

Line		12 Mos End Sept '97	2000 (2)	Change
1	Total Meter Reading	2,312,724	617,852	(1,694,872)
2	Residential Meter Reading (1)	1,750,065	480,589	(1,269,476)
3				
4				
5	Total AMR PIS A/C 397.1	??	32,969,219	
6				
7	Residential AMR PIS		28,921,422	
8	Residential AMR Intangible PIS		364,255	
9			29,285,677	
10				
11	Less: Accum Depr		4,010,926	
12				
13	Net PIS		25,274,751	
14				
15				
16	Return & FIT @	0.14759458	3,730,416	
17				
18	Residential AMR Depr Exp		1,446,071	
19				
20	Res Return, FIT & Depr Exp - AMR		5,176,487	
21				
22				
23				
24	(1) Allocation factor from Schedule FJC-1 in Case GR-98-140 DR 51			
25	Residential=	0.75671169		
26	(2) Values from my COSS			

File: COSSComp.xls
Date: Apr. 10, 2001
Source: Various
Prep: CDL

Missouri Gas Energy
Case No. GR-2001-292
Comparison of Cost Allocation Results - Case Nos.
GR-98-140 vs GR-96-285

Line	Party (a)	Case (b)	Residential (c)	SGS (d)	LGS (e)	LVS (f)	Total (g)	Test. (h)	Witness (i)	Schedule (j)
1	MGE	GR-98-140	106,669,189	31,567,089	2,341,719	6,671,400	147,250,082	Direct	Cummings	FJC-1
2	MGE-2	GR-98-140	105,835,515	31,122,998	2,360,568	6,804,093	146,123,174	(1)	Cummings	FJC-1
3	MGE	GR-96-285	103,946,446	30,636,916	2,581,683	7,363,007	144,528,722	Direct	Gillmore	DSG 1B
4										
5	Fractions	GR-98-140	0.7244	0.2144	0.0159	0.0453	1.0000			
6	Fractions	GR-98-140-2	0.7243	0.2130	0.0162	0.0466	1.0000	(1)		
7	Fractions	GR-96-285	0.7192	0.2120	0.0179	0.0509	1.0000			
8										
9										
10	MPSC Staff	GR-98-140	93,717,770	24,182,917	2,072,548	10,546,286	130,520,213	Direct	Beck	1-1
11	MPSC Staff	GR-96-285	86,847,577	21,286,562	1,631,788	10,115,085	119,885,467	Direct	Ross	1
12										
13	Fractions	GR-98-140	0.7180	0.1853	0.0159	0.0808	1.0000			
14	Fractions	GR-96-285	0.7244	0.1776	0.0136	0.0844	1.0000			
15										
16										
17	OPC	GR-98-140	84,908,805	24,804,818	2,490,398	16,402,838	128,607,300	Direct	Kind	1
18	OPC	GR-96-285	77,447,835	19,084,865	1,218,442	13,555,376	111,309,059	Direct	Kind	1
19										
20	Fractions	GR-98-140	0.6602	0.1929	0.0194	0.1275	1.0000			
21	Fractions	GR-96-285	0.6958	0.1715	0.0109	0.1218	1.0000			
22										
23										
24	MGUA	GR-98-140	110,274,253	29,001,477	2,044,507	5,929,191	147,250,082			
25	Fractions	GR-98-140	0.7489	0.1970	0.0139	0.0403	1.0000			
26										
27	MGUA Adj	GR-98-140 (2)	108,601,418	28,357,047	1,944,891	8,346,127	147,250,082			
28	Fractions	GR-98-140 (2)	0.7375	0.1926	0.0132	0.0567	1.0000			
29										
30	(1) Based on 12 Months End Sept 1997									
31	(2) Adjusted to reflect full peak month use for LVS class - no 50% reduction									

File: Spread
Date: 4/6/01
Prep: CDL

MGE Case GR-2001-292

Spread of Revue Deficiency in this Case Assuming
Cost Relationships from Case GR-98-240
Using MGE COSS

Line		Total	Residential	Small GS	Lg GS	LVS	Unmetered
1	MGE Allocated costs - GR-98-140	146,123,260	105,835,515	31,122,998	2,360,568	6,804,093	86
2							
3	Fractions by class	1.000000000	0.724289309	0.212991402	0.016154635	0.046564065	0.000000589
4							
5	Rev Req GR-2001-292 spread	171,767,305	124,409,223	36,584,959	2,774,838	7,998,184	101
6							
7	Current Adj Rev	131,885,300	91,844,916	26,298,088	2,923,751	10,815,512	3,033
8							
9	Rev Incr (Decr) - COSS based	39,882,005	32,564,307	10,286,871	(148,913)	(2,817,328)	(2,932)
10							
11	Rev Incr - MGE Proposal	39,882,006	27,773,827	7,952,520	884,140	3,270,602	917
12							
13	Diff - Mge proposal less COSS based	1	(4,790,480)	(2,334,351)	1,033,053	6,087,930	3,849

File: Spread
Date: 4/6/01
Prep: CDL

MGE Case GR-2001-292

Spread of Revue Deficiency in this Case Assuming
Cost Relationships from Case GR-98-240
Using Noack COSS Adj for Demand Allocator (1)

Line		Total	Residential	Small GS	Lg GS	LVS	Unmetered
		(a)	(b)	(c)	(d)	(e)	(f)
1	Adj. Noack Allocated costs - GR-98-140	147,250,082	108,601,418	28,357,047	1,944,891	8,346,127	599
2							
3	Fractions by class	1.000000000	0.737530444	0.192577461	0.013208080	0.056679950	0.000004065
4							
5	Rev Req GR-2001-292 spread	171,767,305	126,683,617	33,078,512	2,268,716	9,735,762	698
6							
7	Current Adj Rev	131,885,300	91,844,916	26,298,088	2,923,751	10,815,512	3,033
8							
9	Rev Incr (Decr) - COSS based	39,882,005	34,838,701	6,780,424	(655,035)	(1,079,750)	(2,335)
10							
11	Rev Incr - MGE Proposal	39,882,006	27,773,827	7,952,520	884,140	3,270,602	917
12							
13	Diff - Mge proposal less COSS based	1	(7,064,874)	1,172,096	1,539,175	4,350,352	3,252
14							
15	(1) Reflects full peak month use - no 50% reduction						

FILE: MGE_COS
DATE: 24-Apr-01
NAME: SUMPAGE1
NR: SCH1A

Missouri Gas Energy
Gas Cost of Service Allocation Study
Test Year: 12 Months Ended December 31, 2000
Normalized - Peak Month

Laderoute, Ltd.
COSt Analyst I v. 6 (tm)
(c) 1986-2001

SCHED. # SCH1A
PAGE # 1

TITLE: **SUMMARY - PAGE 1 - REALIZED or TOP DOWN**

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1									
2	480-489	Sales of Gas & Transport Revenue	Schedule 2		131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
3									
4	488-495	Tot Other Operating Revenue	Schedule 2		4,858,301	3,259,231	730,025	77,988	791,057
5									
6		Total Gas Operating Revenue Excl GCR	Schedule 2		136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
7									
8		Expenses							
9		Gas O&M Exp Excl Gas Costs	Schedule 14		62,907,928	46,248,665	11,393,178	1,034,156	4,231,929
10		Depr & Amort Expense	Schedule 15		26,966,363	20,859,379	4,188,741	344,762	1,573,481
11		Interest on Customer Deposits	Schedule 16		791,258	449,265	224,634	24,974	92,384
12		Taxes Other than Inc Taxes	Schedule 16		9,063,142	6,428,627	1,630,529	158,538	845,448
13					----------	----------	----------	----------	----------
14		Total Op Exp Before Inc Taxes	Sum (L.9-13)		99,728,691	73,985,936	17,437,082	1,562,431	6,743,242
15									
16		Net Income Before Inc Taxes	L. 6 - L. 14		37,011,877	21,118,211	9,591,031	1,439,308	4,863,327
17									
18		Total Income Taxes	Schedule 17-B		6,502,977	5,581,032	748,223	48,353	125,368
19					----------	----------	----------	----------	----------
20		Total Op Expenses Plus Inc Taxes Excl Gas	L. 14 + L. 17 + L. 18		106,231,668	79,566,969	18,185,305	1,610,784	6,868,610
21									
22		Net Utility Operating Income	L. 6 - L. 20		30,508,900	15,537,179	8,842,808	1,390,955	4,737,959
23									
24		Rate Base	Schedule 8		518,824,134	371,772,438	98,519,129	10,233,055	38,299,512
25									
26		Rate of Return Before Income Taxes	L. 16/L. 24		7.13%	5.68%	9.74%	14.07%	12.70%
27		Index of Return Before Income Taxes			100	80	136	197	178
28									
29		**Rate of Return - Realized**	L. 22/L. 24		**5.88%**	**4.18%**	**8.98%**	**13.59%**	**12.37%**
30		**Index of Return - Realized**			**100**	**71**	**153**	**231**	**210**

Schedule CDL-6
Page 1 of 3

FILE: MGE_COS
DATE: 24-Apr-01
NAME: SUMPAGE2-A
NR: SCH1B-A

Missouri Gas Energy
Gas Cost of Service Allocation Study
Test Year: 12 Months Ended December 31, 2000
Normalized - Peak Month

Revenue Neutral

SCHED. # SCH1B-A
PAGE # 1

TITLE: **SUMMARY - PAGE 2-A - REQUIRED or BOTTOM UP**

LINE	A/C #	ITEM		ALLOCATION BASIS		CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		Rate Base		Schedule 8			518,824,134	371,772,438	98,519,129	10,233,055	38,299,512
2		Rate of Return - Ideal Target			Actual ROR %	5.880	5.880%	5.880%	5.880%	5.880%	5.880%
3		Index of Return - Ideal Target			Request ROR %	**10.562**	100	100	100	100	100
4											
5		Return Required at Target ROR		L. 1 * L. 2			30,508,900	21,861,682	5,793,312	601,744	2,252,162
6		Realized Net Utility Op Income		Schedule 17			30,508,900	15,537,179	8,842,808	1,390,955	4,737,959
7		Change in Net Income Required		L. 5 - L. 6			0	6,324,503	(3,049,495)	(789,211)	(2,485,797)
8											
9		Realized Tot Inc Taxes		Schedule 17			6,502,977	5,581,032	748,223	48,353	125,368
10		Change in FIT @	0.628855	* L. 7			0	3,977,196	(1,917,690)	(496,299)	(1,563,206)
11		Required Total FIT		L. 9 + L. 10			6,502,977	9,558,228	(1,169,467)	(447,946)	(1,437,838)
12											
13		Change in Net Income		L. 7			0	6,324,503	(3,049,495)	(789,211)	(2,485,797)
14		Change in FIT		L. 10			0	3,977,196	(1,917,690)	(496,299)	(1,563,206)
15							----------	----------	----------	----------	----------
16		Total Revenue Change		Sum (L.13-15)			0	10,301,699	(4,967,186)	(1,285,510)	(4,049,003)
17											
18		Revenue Change Grossed up for Uncollectibles			Factor	1.01030600	0	10,407,868	(5,018,378)	(1,298,759)	(4,090,732)
19		Revenue Change Grossed down for Late Pay Fee			Factor	0.997761	0	10,384,565	(5,007,141)	(1,295,851)	(4,081,573)
20											
21		Gas Operating Revenue Excl PGA		Schedule 2			136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
22		Required Gas Operating Rev Excl PGA		L. 19 + L. 21			136,740,568	105,488,712	22,020,971	1,705,888	7,524,996
23		Increased Operating Revenue - %		L. 19/L. 21			0.00%	10.92%	-18.53%	-43.17%	-35.17%
24											
25		Sales of Gas Rev & Trans Excl PGA		Schedule 2			131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
26		**Percent of Total Current Revenue**					**100.00**	**69.64**	**19.94**	**2.22**	**8.20**
27		Req Sales of Gas Rev & Trans Ex PGA		L. 19 + L. 25	Excludes Gas Lights		131,882,267	102,229,481	21,290,947	1,627,900	6,733,939
28		**Percent of Total Cost of Service**					**100.00**	**77.52**	**16.14**	**1.23**	**5.11**
29		Increased Revenue - %		L. 19/L. 25			0.00%	11.31%	-19.04%	-44.32%	-37.74%
30											
31		Ave Monthly Customers		Schedule 18-A			492,190	431,374	59,903	472	441
32		Realized Sales of Gas & Tran Rev Ex PGA		L. 25/L. 31	per Cust per year		268	213	439	6,198	24,506
33		Required Sales of Gas & Trans Rev Ex PGA		L. 27/L. 31	per Cust per year		268	237	355	3,451	15,258
34		Increased Sales of Gas & Tran Rev Ex PGA		L. 33 - L. 32	per Cust per year		0	24	(84)	(2,747)	(9,248)
35											
36		PGA Revenue		Schedule 2			307,289,585	211,738,095	81,377,305	14,174,185	0
37		Realized Sales of Gas & Tran Rev Incl PGA		L. 25 + L. 36			439,171,852	303,583,011	107,675,393	17,097,936	10,815,512
38		Required Sales of Gas & Trans Rev Incl PGA		L. 27 + L. 36			439,171,852	313,967,576	102,668,252	15,802,085	6,733,939
39		**Percent Increase**					**0.00**	**3.42**	**(4.65)**	**(7.58)**	**(37.74)**
40		Realized Sales of Gas & Tran Rev Incl PGA		L. 37/L. 31	per Cust per year		892	704	1,798	36,245	24,506
41		Required Sales of Gas & Trans Rev Incl PGA		L. 38/L. 31	per Cust per year		892	728	1,714	33,498	15,258

FILE: MGE_COS
DATE: 24-Apr-01
NAME: SUMPAGE2-A
NR: SCH1B-A

Missouri Gas Energy
Gas Cost of Service Allocation Study
Test Year: 12 Months Ended December 31, 2000
Normalized - Peak Month

Includes Requested ROR

SCHED. # SCH1B-A
PAGE # 1

TITLE: **SUMMARY - PAGE 2-A - REQUIRED or BOTTOM UP**

LINE	A/C #	ITEM		ALLOCATION BASIS	CR		SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		Rate Base		Schedule 8			518,824,134	371,772,438	98,519,129	10,233,055	38,299,512
2		Rate of Return - Ideal Target			Actual ROR %	5.880	10.562%	10.562%	10.562%	10.562%	10.562%
3		Index of Return - Ideal Target			Request ROR %	**10.562**	100	100	100	100	100
4											
5		Return Required at Target ROR		L. 1 * L. 2			54,798,205	39,266,605	10,405,590	1,080,815	4,045,194
6		Realized Net Utility Op Income		Schedule 17			30,508,900	15,537,179	8,842,808	1,390,955	4,737,959
7		Change in Net Income Required		L. 5 - L. 6			24,289,305	23,729,426	1,562,783	(310,140)	(692,765)
8											
9		Realized Tot Inc Taxes		Schedule 17			6,502,977	5,581,032	748,223	48,353	125,368
10		Change in FIT @	0.628855	* L. 7			15,274,451	14,922,368	982,764	(195,033)	(435,649)
11		Required Total FIT		L. 9 + L. 10			21,777,428	20,503,401	1,730,987	(146,679)	(310,281)
12											
13		Change in Net Income		L. 7			24,289,305	23,729,426	1,562,783	(310,140)	(692,765)
14		Change in FIT		L. 10			15,274,451	14,922,368	982,764	(195,033)	(435,649)
15							----------	----------	----------	----------	----------
16		Total Revenue Change		Sum (L.13-15)			39,563,756	38,651,795	2,545,546	(505,172)	(1,128,413)
17											
18		Revenue Change Grossed up for Uncollectibles			Factor	1.01030600	39,971,500	39,050,140	2,571,781	(510,379)	(1,140,043)
19		Revenue Change Grossed down for Late Pay Fee			Factor	0.997761	39,882,003	38,962,707	2,566,023	(509,236)	(1,137,490)
20											
21		Gas Operating Revenue Excl PGA		Schedule 2			136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
22		Required Gas Operating Rev Excl PGA		L. 19 + L. 21			176,622,571	134,066,854	29,594,136	2,492,503	10,469,079
23		Increased Operating Revenue - %		L. 19/L. 21			29.17%	40.97%	9.49%	-16.96%	-9.80%
24											
25		Sales of Gas Rev & Trans Excl PGA		Schedule 2			131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
26		**Percent of Total Current Revenue**					**100.00**	**69.64**	**19.94**	**2.22**	**8.20**
27		Req Sales of Gas Rev & Trans Ex PGA		L. 19 + L. 25	Excludes Gas Lights		171,764,270	130,807,623	28,864,111	2,414,515	9,678,022
28		**Percent of Total Cost of Service**					**100.00**	**76.16**	**16.80**	**1.41**	**5.63**
29		Increased Revenue - %		L. 19/L. 25			30.24%	42.42%	9.76%	-17.42%	-10.52%
30											
31		Ave Monthly Customers		Schedule 18-A			492,190	431,374	59,903	472	441
32		Realized Sales of Gas & Tran Rev Ex PGA		L. 25/L. 31	per Cust per year		268	213	439	6,198	24,506
33		Required Sales of Gas & Trans Rev Ex PGA		L. 27/L. 31	per Cust per year		349	303	482	5,118	21,929
34		Increased Sales of Gas & Tran Rev Ex PGA		L. 33 - L. 32	per Cust per year		81	90	43	(1,079)	(2,577)
35											
36		PGA Revenue		Schedule 2			307,289,585	211,738,095	81,377,305	14,174,185	0
37		Realized Sales of Gas & Tran Rev Incl PGA		L. 25 + L. 36			439,171,852	303,583,011	107,675,393	17,097,936	10,815,512
38		Required Sales of Gas & Trans Rev Incl PGA		L. 27 + L. 36			479,053,855	342,545,718	110,241,416	16,588,700	9,678,022
39		**Percent Increase**					**9.08**	**12.83**	**2.38**	**(2.98)**	**(10.52)**
40		Realized Sales of Gas & Tran Rev Incl PGA		L. 37/L. 31	per Cust per year		892	704	1,798	36,245	24,506
41		Required Sales of Gas & Trans Rev Incl PGA		L. 38/L. 31	per Cust per year		973	794	1,840	35,165	21,929

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Missouri Gas Energy
Gas Cost of Service Allocation Study
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SCHED. # SCH1A
PAGE # 1

TITLE: **SUMMARY - PAGE 1 - REALIZED or TOP DOWN**

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		-							
2	480-489	Sales of Gas & Transport Revenue	Schedule 2		131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
3									
4	488-495	Tot Other Operating Revenue	Schedule 2		4,858,301	3,259,231	730,025	77,988	791,057
5									
6		Total Gas Operating Revenue Excl GCR	Schedule 2		136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
7									
8		Expenses							
9		Gas O&M Exp Excl Gas Costs	Schedule 14		62,907,928	46,248,665	11,393,178	1,034,156	4,231,929
10		Depr & Amort Expense	Schedule 15		26,966,363	20,859,379	4,188,741	344,762	1,573,481
11		Interest on Customer Deposits	Schedule 16		791,258	449,265	224,634	24,974	92,384
12		Taxes Other than Inc Taxes	Schedule 16		9,063,142	6,428,627	1,630,529	158,538	845,448
13					----------	----------	----------	----------	----------
14		Total Op Exp Before Inc Taxes	Sum (L.9-13)		99,728,691	73,985,936	17,437,082	1,562,431	6,743,242
15									
16		Net Income Before Inc Taxes	L. 6 - L. 14		37,011,877	21,118,211	9,591,031	1,439,308	4,863,327
17									
18		Total Income Taxes	Schedule 17-B		6,502,977	5,581,032	748,223	48,353	125,368
19					----------	----------	----------	----------	----------
20		Total Op Expenses Plus Inc Taxes Excl Gas	L. 14 + L. 17 + L. 18		106,231,668	79,566,969	18,185,305	1,610,784	6,868,610
21									
22		Net Utility Operating Income	L. 6 - L. 20		30,508,900	15,537,179	8,842,808	1,390,955	4,737,959
23									
24		Rate Base	Schedule 8		518,824,134	371,772,438	98,519,129	10,233,055	38,299,512
25									
26		Rate of Return Before Income Taxes	L. 16/L. 24		7.13%	5.68%	9.74%	14.07%	12.70%
27		Index of Return Before Income Taxes			100	80	136	197	178
28									
29		**Rate of Return - Realized**	L. 22/L. 24		**5.88%**	**4.18%**	**8.98%**	**13.59%**	**12.37%**
30		**Index of Return - Realized**			**100**	**71**	**153**	**231**	**210**

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Missouri Gas Energy
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Includes Requested ROR

SCHED. # SCH1B-A
PAGE # 1

TITLE: **SUMMARY - PAGE 2-A - REQUIRED or BOTTOM UP**

LINE	A/C #	ITEM		ALLOCATION BASIS		CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		Rate Base		Schedule 8			518,824,134	371,772,438	98,519,129	10,233,055	38,299,512
2		Rate of Return - Ideal Target			Actual ROR %	5.880	10.562%	10.562%	10.562%	10.562%	10.562%
3		Index of Return - Ideal Target			Request ROR %	**10.562**	100	100	100	100	100
4											
5		Return Required at Target ROR		L. 1 * L. 2			54,798,205	39,266,605	10,405,590	1,080,815	4,045,194
6		Realized Net Utility Op Income		Schedule 17			30,508,900	15,537,179	8,842,808	1,390,955	4,737,959
7		Change in Net Income Required		L. 5 - L. 6			24,289,305	23,729,426	1,562,783	(310,140)	(692,765)
8											
9		Realized Tot Inc Taxes		Schedule 17			6,502,977	5,581,032	748,223	48,353	125,368
10		Change in FIT @	0.628855	* L. 7			15,274,451	14,922,368	982,764	(195,033)	(435,649)
11		Required Total FIT		L. 9 + L. 10			21,777,428	20,503,401	1,730,987	(146,679)	(310,281)
12											
13		Change in Net Income		L. 7			24,289,305	23,729,426	1,562,783	(310,140)	(692,765)
14		Change in FIT		L. 10			15,274,451	14,922,368	982,764	(195,033)	(435,649)
15							----------	----------	----------	----------	----------
16		Total Revenue Change		Sum (L.13-15)			39,563,756	38,651,795	2,545,546	(505,172)	(1,128,413)
17											
18		Revenue Change Grossed up for Uncollectibles		Factor	1.01030600		39,971,500	39,050,140	2,571,781	(510,379)	(1,140,043)
19		Revenue Change Grossed down for Late Pay Fee		Factor	0.997761		39,882,003	38,962,707	2,566,023	(509,236)	(1,137,490)
20											
21		Gas Operating Revenue Excl PGA		Schedule 2			136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
22		Required Gas Operating Rev Excl PGA		L. 19 + L. 21			176,622,571	134,066,854	29,594,136	2,492,503	10,469,079
23		Increased Operating Revenue - %		L. 19/L. 21			29.17%	40.97%	9.49%	-16.96%	-9.80%
24											
25		Sales of Gas Rev & Trans Excl PGA		Schedule 2			131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
26		**Percent of Total Current Revenue**					**100.00**	**69.64**	**19.94**	**2.22**	**8.20**
27		Req Sales of Gas Rev & Trans Ex PGA		L. 19 + L. 25	Excludes Gas Lights		171,764,270	130,807,623	28,864,111	2,414,515	9,678,022
28		**Percent of Total Cost of Service**					**100.00**	**76.16**	**16.80**	**1.41**	**5.63**
29		Increased Revenue - %		L. 19/L. 25			30.24%	42.42%	9.76%	-17.42%	-10.52%
30											
31		Ave Monthly Customers		Schedule 18-A			492,190	431,374	59,903	472	441
32		Realized Sales of Gas & Tran Rev Ex PGA		L. 25/L. 31	per Cust per year		268	213	439	6,198	24,506
33		Required Sales of Gas & Trans Rev Ex PGA		L. 27/L. 31	per Cust per year		349	303	482	5,118	21,929
34		Increased Sales of Gas & Tran Rev Ex PGA		L. 33 - L. 32	per Cust per year		81	90	43	(1,079)	(2,577)
35											
36		PGA Revenue		Schedule 2			307,289,585	211,738,095	81,377,305	14,174,185	0
37		Realized Sales of Gas & Tran Rev Incl PGA		L. 25 + L. 36			439,171,852	303,583,011	107,675,393	17,097,936	10,815,512
38		Required Sales of Gas & Trans Rev Incl PGA		L. 27 + L. 36			479,053,855	342,545,718	110,241,416	16,588,700	9,678,022
39		**Percent Increase**					**9.08**	**12.83**	**2.38**	**(2.98)**	**(10.52)**
40		Realized Sales of Gas & Tran Rev Incl PGA		L. 37/L. 31	per Cust per year		892	704	1,798	36,245	24,506
41		Required Sales of Gas & Trans Rev Incl PGA		L. 38/L. 31	per Cust per year		973	794	1,840	35,165	21,929

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Missouri Gas Energy
Gas Cost of Service Allocation Study
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TITLE: SUMMARY - PAGE 3: COST COMPONENTS BY COST CLASS

LINE	A/C #	ITEM	ALLOCATION BASIS		CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		Demand Related Rate Base	Schedule 8	Totals		154,743,028	75,091,184	44,656,606	6,561,552	28,433,686
2		Commodity Related Rate Base	" "			10,664,499	7,499,221	2,515,558	385,951	263,769
3		Customer Related Rate Base	Schedule 8			353,416,607	289,182,033	51,346,965	3,285,552	9,602,057
4				518,824,134						
5		Demand Related Return	@ 10.562%			16,343,959	7,931,131	4,716,631	693,031	3,003,166
6		Commodity Related Return	@ 10.562%			1,126,384	792,068	265,693	40,764	27,859
7		Customer Related Return	@ 10.562%			37,327,862	30,543,406	5,423,266	347,020	1,014,169
8				54,798,205						
9		Demand Rel Tot Adj O&M	Schedule 14			10,691,462	6,310,038	2,307,035	284,432	1,789,958
10		Commod Rel Tot Adj Forma O&M	" "			31,385,431	22,756,649	5,948,534	607,944	2,072,305
11		Customer Rel Tot Adj Forma O&M	Schedule 14			20,831,035	17,181,978	3,137,610	141,780	369,666
12				62,907,928						
13		Demand Related Depr & Amort	Schedule 15			7,566,774	4,611,451	1,615,732	191,519	1,148,073
14		Commodity Related Depr & Amort	" "			0	0	0	0	0
15		Customer Related Depr & Amort	Schedule 15			19,399,589	16,247,928	2,573,009	153,243	425,409
16				26,966,363						
17		Dem Rel Other Taxes & Int on Cust Deposits	Schedule 16			4,327,449	2,597,144	985,090	114,948	630,268
18		Comm Rel Other Taxes & Int on Cust Deposits	" "			1,311,211	840,617	243,976	30,390	196,229
19		Cust Rel Other Taxes & Int on Cust Deposits	Schedule 16			4,215,740	3,440,131	626,097	38,176	111,336
20				9,854,400						
21		Demand Related FIT	Schedule 1-B			4,601,522	4,141,309	784,619	(94,053)	(230,354)
22		Commodity Related FIT	" "			450,115	413,585	44,199	(5,532)	(2,137)
23		Customer Related FIT	Schedule 1-B			16,725,791	15,948,507	902,169	(47,095)	(77,790)
24				21,777,428						
25		Subtotal Demand Related Cost	Includes Other Op Rev			43,531,167	25,591,073	10,409,106	1,189,877	6,341,111
26		Subtotal Commodity Related Cost	" " " "			34,273,141	24,802,918	6,502,402	673,565	2,294,256
27		Subtotal Customer Related Cost	Includes Other Op Rev			98,500,016	83,361,950	12,662,152	633,124	1,842,789
28				176,304,324						
29		Total Demand Related Cost	Excludes Other Op Rev			43,531,167	25,591,073	10,409,106	1,189,877	6,341,111
30		Total Commodity Related Cost Incl Gross Up & Dowr	" " " "			29,733,088	21,854,599	5,792,853	591,514	1,494,122
31		Total Customer Related Cost	Excludes Other Op Rev			98,500,016	83,361,950	12,662,152	633,124	1,842,789
32						----------	----------	----------	----------	----------
33		Total Required Sales of Gas & Trans Rev Ex PGA				171,764,270	130,807,623	28,864,111	2,414,515	9,678,022
34										
35		Total Mcf	Schedule 18-A			87,767,841	40,836,455	15,694,675	2,733,677	28,503,035
36										
37		Demand Related Cost per Mcf	L. 29/L. 35			0.4960	0.6267	0.6632	0.4353	0.2225
38		Commodity Related Cost per Mcf	L. 30/L. 35			0.3388	0.5352	0.3691	0.2164	0.0524
39		Customer Related Cost per Mcf	L. 31/L. 35			1.1223	2.0414	0.8068	0.2316	0.0647
40						----------	----------	----------	----------	----------
41		Total				1.9570	3.2032	1.8391	0.8832	0.3395

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TITLE: SUMMARY - PAGE 4: UNIT COST COMPONENT SUMMARY BY CLASS

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		Total Demand Related Cost	Schedule 1-C		43,531,167	25,591,073	10,409,106	1,189,877	6,341,111
2		Total Commodity Related Cost	" "		29,733,088	21,854,599	5,792,853	591,514	1,494,122
3		Total Customer Related Cost	Schedule 1-C		98,500,016	83,361,950	12,662,152	633,124	1,842,789
4					---------	---------	---------	---------	---------
5		Req Sales of Gas Rev & Trans Ex PGA			171,764,270	130,807,623	28,864,111	2,414,515	9,678,022
6									
7		Sales of Gas Rev & Trans Excl PGA			131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
8									
9		Adjusted Gas O&M Exp Excl Gas Costs			62,907,928	46,248,665	11,393,178	1,034,156	4,231,929
10									
11		Total Mcf	Schedule 18-A		87,767,841	40,836,455	15,694,675	2,733,677	28,503,035
12		Ave Monthly Customers	Schedule 18-A		492,190	431,374	59,903	472	441
13		Mcf per Customer per Month	L. 11/L. 12/12		14.9	7.9	21.8	482.9	5,382.0
14									
15	Per Mcf	Sales of Gas Rev & Trans Ex PGA			1.5026	2.2491	1.6756	1.0695	0.3795
16	Per Mcf	Req Sales of Gas Rev & Trans Ex PGA			1.9570	3.2032	1.8391	0.8832	0.3395
17	Per Mcf	Inc Sales of Gas Rev & Trans Ex PGA			0.4544	0.9541	0.1635	-0.1863	-0.0399
18									
19	Per Mcf	Adjusted Gas O&M Exp Excl Gas Costs			0.7168	1.1325	0.7259	0.3783	0.1485
20									
21		**Required Sales of Gas Rev & Trans Ex PGA**							
22									
23		Unit Demand Related Cost - $/Mcf	L. 1/L. 11		0.4960	0.6267	0.6632	0.4353	0.2225
24		Unit Commodity Related Cost - $/Mcf	L. 2/L. 11		0.3388	0.5352	0.3691	0.2164	0.0524
25					---------	---------	---------	---------	---------
26		Tot Dem & Comm Rel Unit Costs - $/Mcf			0.8348	1.1618	1.0323	0.6516	0.2749
27									
28		Unit Cust Related Cost - $/Cust/Mo	L. 3/L. 12/12		16.68	16.10	17.61	111.84	347.96
29		Unit Customer Related Cost - $/Mcf	L. 3/L. 11		1.1223	2.0414	0.8068	0.2316	0.0647
30									
31		TOTAL COST PER MCF - $/MCF	L. 26 + L. 29		1.9570	3.2032	1.8391	0.8832	0.3395

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Missouri Gas Energy
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PAGE # 1

TITLE: **Summary - Page 6: Unit Cost - Simple Customer Method**

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1	Rate Base:								
2	380	Services	Schedule 4		248,048,065	211,350,050	29,349,101	1,977,234	5,371,680
3	381	Meters	" "		28,150,505	15,901,035	9,755,768	719,264	1,774,438
4	382	Meter Installations	" "		49,974,693	41,769,942	5,800,378	590,441	1,813,932
5	383-4	House Regulators & Install	" "		9,540,154	3,343,895	5,754,761	127,732	313,766
6	385	Electronic Gas Measurement	Schedule 4		320,088	0	0	0	320,088
7	397.1	Comm Equip - AMR	Schedule 5		32,969,219	28,921,422	4,016,170	31,627	0
8					----------	----------	----------	----------	----------
9		Total PIS			369,002,724	301,286,344	54,676,178	3,446,297	9,593,904
10									
11	Less:	Accumulated Depreciation							
12		A/C 380-384 Related - $	Schedule 6		109,150,789	91,664,716	13,960,290	946,452	2,579,332
13	385	Electronic Gas Measurement	Schedule 6		40,948	0	0	0	40,948
14	397.1	Comm Eq - A/C 397.1 Related	Schedule 6		4,572,289	4,010,926	556,977	4,386	0
15					----------	----------	----------	----------	----------
16		Total Accumulated Depreciation			113,764,026	95,675,642	14,517,266	950,838	2,620,280
17									
18									
19		Net Rate Base	Sum(L.2-4)-L. 12		255,238,698	205,610,702	40,158,912	2,495,459	6,973,624
20		Return & FIT @ 0.147594585	* L. 19		37,671,850	30,347,026	5,927,238	368,316	1,029,269
21	Expenses:								
22	874	Mains & Services Exp-Total	Schedule 11-A		2,676,316	1,930,892	465,843	46,437	233,144
23									
24	874	Services Portion	Serv of Mains & Ser PIS		1,259,644	1,073,283	149,041	10,041	27,279
25	878	Meter & House Reg Exp	Schedule 11-A		4,535,372	3,347,951	903,075	76,032	208,314
26	879	Cust Install Exp	Schedule 11-A		2,515,229	2,204,443	306,120	2,411	2,255
27	892	Main of Services	Schedule 11-B		233,675	199,103	27,648	1,863	5,060
28	893	Main of Meters & House Reg	Schedule 11-B		986,187	727,990	196,368	16,533	45,297
29	902	Meter Reading Expenses	Schedule 12		617,852	480,589	133,474	1,577	2,213
30	903	Customer Records & Collection	Schedule 12		8,197,435	7,184,547	997,681	7,857	7,350
31		Depr Exp A/C 380 - Services	Schedule 15		11,360,601	9,679,832	1,344,189	90,557	246,023
32		Depr Exp A/C 381 - Meters	" "		692,502	391,165	239,992	17,694	43,651
33		Depr Exp A/C 382 - Meter Install	" "		1,234,375	1,031,718	143,269	14,584	44,804
34		Depr Exp A/C 383 - House Reg	" "		216,561	75,906	130,633	2,900	7,122
35		Depr Exp A/C 385 - Elec Gas Meter	" "		16,004	0	0	0	16,004
36		Depr Exp Gen Pt Comm Equip AMR	Schedule 15		1,648,461	1,446,071	200,809	1,581	0
37					----------	----------	----------	----------	----------
38		Total Expenses	Sum(L.24-37)		33,513,898	27,842,599	4,772,299	243,628	655,373
39									
40		Subtotal Costs	L. 20 + L. 38		71,185,748	58,189,625	10,699,537	611,944	1,684,642
41									
42		Ave Monthly Customers	Schedule 18-A		492,190	431,374	59,903	472	441
43		Tot LVS M & S Cust							471
44		Ave Annual Cost per Cust	L. 40/L. 42		144.63	134.89	178.62	1,297.22	3,817.16
45		Tot LVS M & S Cust							3,574.21
46		Ave Monthly Cost per Cust	L. 44/12		12.05	11.24	14.88	108.10	318.10
47		Tot LVS M & S Cust							297.85
48		Allocation Factor							
49		1 Sys 69	Ret&FIT of Rate Base		0.147594585				
50		2 Sys 21	Serv of Mains & Ser PIS		0.470663368	0.555848354	0.319938833	0.216226248	0.117003188

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NR: SCH2

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Gas Cost of Service Allocation Study
Test Year: 12 Months Ended December 31, 2000
Normalized - Peak Month

SCHED. # SCH2
PAGE # 1

TITLE: **GAS OPERATING REVENUES**

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		SALES OF GAS & TRANS REVENUE	132610133						
2									
3	480-489	Base Rate Margin Revenue	Specifically Assigned		131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
4									
5									
6									
7					---------	---------	---------	---------	---------
8		TOTAL SALES OF GAS & TRANS REVENUE		C/C	131,882,267	91,844,916	26,298,088	2,923,751	10,815,512
9									
10		Est. PGA Rev incl GRT		CO	307,289,585	211,738,095	81,377,305	14,174,185	0
11									
12		TOTAL SALES OF GAS & TRANS REVENUE + PGA		C/C	439,171,852	303,583,011	107,675,393	17,097,936	10,815,512
13									
14		OTHER OPER REVENUE	132610133						
15									
16	487	Late Payment Charges	50% Cust - 50% Mcf	CO	983,440	659,749	147,775	15,787	160,129
17	488	Misc Service Revenues	50% Cust - 50% Mcf	CO	3,073,529	2,061,902	461,839	49,338	500,450
18	483	Sales for Resale	50% Cust - 50% Mcf	CO		0	0	0	0
19	495	Other Gas Revenue	50% Cust - 50% Mcf	CO	68,552	45,989	10,301	1,100	11,162
20		Flex Rate Revenue	50% Cust - 50% Mcf		729,747	489,557	109,654	11,714	118,822
21	495.2	Unmetered Gas Lights	50% Cust - 50% Mcf	CO	3,033	2,035	456	49	494
22					---------	---------	---------	---------	---------
23		Total Other Operating Revenue		CO	4,858,301	3,259,231	730,025	77,988	791,057
24									
25		Total Operating Rev Excl PGA	L. 8 + L. 23	C/C	136,740,568	95,104,147	27,028,113	3,001,739	11,606,569
26									
27		TOTAL OPERATING REV Incl PGA	L. 12 + L. 25	C/C	444,030,153	306,842,242	108,405,418	17,175,924	11,606,569
28									
29		Allocation Factor							
30		1 Sys 7	50% Cust - 50% Mcf	CO	1.000000000	0.670858236	0.150263429	0.016052559	0.162825776
31		2 Sys 6	Ccf-Sales Rates	CO	1.000000000	0.689050672	0.264822855	0.046126473	0.000000000
32		3 Sys 1	Peak Month	D	1.000000000	0.556031376	0.205398762	0.035841295	0.202728567
33		4 OPREV-4	CustChgRel Sales&Tran Rev	CU	1.000000000	1.000000000	1.000000000	1.000000000	1.000000000
34		5 OPREV-5	ComChgRel Sales&Tran Rev	CO	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000

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NAME: DPT
NR: SCH4

Missouri Gas Energy
Gas Cost of Service Allocation Study
Test Year: 12 Months Ended December 31, 2000
Normalized - Peak Month

SCHED. # SCH4
PAGE # 1

TITLE: **DISTRIBUTION PLANT IN SERVICE**

LINE	A/C #	ITEM	ALLOCATION BASIS	CR	SYSTEM TOTAL	Residential Service	Small Gen Service	Large Gen Service	Large Vol Service
1		DISTRIBUTION PLANT							
2									
3	374	Land & Land Rights	Peak Month	D	1,233,940	686,109	253,450	44,226	250,155
4	375	Structures & Improvements	Peak Month	D	6,021,033	3,347,883	1,236,713	215,802	1,220,635
5	376	Mains - Assigned < 3 "	Res & SGS Peak Month	D	79,003,720	57,692,157	21,311,563	0	0
6	376	Mains - Customer	Mains Cust Factor	D	0	0	0	0	0
7	376	Mains - Capacity	Peak Month	D	199,966,211	111,187,487	41,072,812	7,167,048	40,538,863
8	378	Meas. & Reg. Equipment-Gen	Peak Month	D	10,422,024	5,794,972	2,140,671	373,539	2,112,842
9	379	Meas. & Reg. Equip-City Gate	Peak Month	D	3,074,013	1,709,248	631,398	110,177	623,190
10	380	Services	A/C 380 Services Factor	CU	248,048,065	211,350,050	29,349,101	1,977,234	5,371,680
11	381	Meters	A/C 381 Meters Factor	CU	28,150,505	15,901,035	9,755,768	719,264	1,774,438
12	381	Meters - Metretek				0	0	0	0
13	381	Meters - Itron				0	0	0	0
14	381	Meters - Other				0	0	0	0
15	382	Meter Installations	A/C 382 Meter Installs Factor	CU	49,974,693	41,769,942	5,800,378	590,441	1,813,932
16	383-4	House Regulators & Install	A/C 383 House Reg Factor	CU	9,540,154	3,343,895	5,754,761	127,732	313,766
17	385	Electronic Gas Measurement	Transport Customers	CU	320,088	0	0	0	320,088
18					---------	---------	---------	---------	---------
19		Subtotal Dist PIS		D/CU	635,754,446	452,782,780	117,306,615	11,325,461	54,339,590
20									
21	386	Other Prop. on Cust. Premises	Subtotal Dist PIS	D		0	0	0	0
22	387	Other Equipment	Subtotal Dist PIS	D		0	0	0	0
23					---------	---------	---------	---------	---------
24		TOTAL DIST PIS		D/CU	635,754,446	452,782,780	117,306,615	11,325,461	54,339,590
25									
26		Demand Related-DPIS		D	299,720,941	180,417,857	66,646,607	7,910,791	44,745,686
27		Commodity Related-DPIS		CO					
28		Customer Related-DPIS		CU	336,033,505	272,364,923	50,660,008	3,414,670	9,593,904
29				ck	635,754,446				
30		Allocation Factor							
31		1 Sys 1	Peak Month	D	1.000000000	0.556031376	0.205398762	0.035841295	0.202728567
32		2 Sys 65	Res & SGS Peak Month	D	1.000000000	0.730246083	0.269753917	0.000000000	0.000000000
33		3 Sys 5	Total Ccf	CO	1.000000000	0.465278105	0.178820341	0.031146676	0.324754878
34		4 Sys 56	A/C 380 Services Factor	CU	1.000000000	0.852052806	0.118320219	0.007971172	0.021655802
35		5 Sys 57	A/C 381 Meters Factor	CU	1.000000000	0.564857912	0.346557463	0.025550650	0.063033975
36		6 Sys 58	A/C 382 Meter Installs Factor	CU	1.000000000	0.835821878	0.116066313	0.011814792	0.036297017
37		7 Sys 59	A/C 383 House Reg Factor	CU	1.000000000	0.350507484	0.603214664	0.013388877	0.032888976
38		8 Sys 60	Mains Cust Factor	D	1.000000000	0.852052806	0.118320219	0.007971172	0.021655802
39		9 Sys 3	Average Cust	CU	1.000000000	0.876438368	0.121706518	0.000958441	0.000896674
40		10 Sys 8	Transport Customers	CU	1.000000000	0.000000000	0.000000000	0.000000000	1.000000000
41		11 Sys 9	Sales Customers	CU	1.000000000	0.877224952	0.121815747	0.000959301	0.000000000
42		12 DPT-12	Subtotal Dist PIS	D/CU	1.000000000	0.712197583	0.184515603	0.017814206	0.085472607
43		13 DPT-13	Dem Rel-Main&SerPIS	D	0.471441361	0.398464485	0.568140227	0.698496162	0.823445405
44		14 DPT-14	Cust Rel-Main&SerPIS	CU	0.528558639	0.601535515	0.431859773	0.301503838	0.176554595
45		15 DPT-15	Dem Rel-Dist PIS	D	0.471441361	0.398464485	0.568140227	0.698496162	0.823445405
46		16 DPT-16	Cust Rel-Dist PIS	CU	0.528558639	0.601535515	0.431859773	0.301503838	0.176554595