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Equitable Statement No. 1-R
Docket No. R-2008-2029325
Witness: John M. Quinn
Date: 11/19/08

RJS

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

John M. Quinn

(Prepared October 2008)

PUBLIC VERSION

PREPARED REBUTTAL TESTIMONY OF JOHN M. QUINN

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is John M. Quinn. My business address is 225 North Shore Drive, Pittsburgh, PA 15212-5352.

Q. ARE YOU THE SAME JOHN M. QUINN WHO SUBMITTED PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes I am. My direct testimony is contained in Equitable Statement No. 1 and was part of the information filed by Equitable Gas Company on June 30, 2008, pursuant to Title 52 of the Pennsylvania Code, Section 53.51, *et seq.*, in support of its general base rate filing.

II. Purpose of Rebuttal Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to the direct testimony of Office of Consumer Advocate ("OCA") witnesses Roger D. Colton, and Glen A. Watkins, Office of Trial Staff ("OTS") witness Amanda Gordon, Michael Gruber, and Jeremy Hubert, Independent Oil and Gas Association ("IOGA") witness Diane Meyer Burgraff and IOGA/HESS Corporation witness James L. Crist.

My testimony will address certain issues raised by the aforementioned witnesses while other issues raised by them will be addressed by the rebuttal testimony submitted by other Equitable witnesses in this proceeding.

Q: WHAT ISSUES WILL YOUR REBUTTAL TESTIMONY ADDRESS?

A: I will address the recovery of universal service costs, the OCA's revenue imputation related to negotiated delivery service agreements, the proposed wind down of Equitable's Agency Service Program, revenue allocation, and rate design.

III. OCA's Contentions Concerning Universal Service Cost Recovery

(A) Overview

Q. STARTING ON PAGE 3 OF HIS CORRECTED DIRECT TESTIMONY MR. COLTON ADDRESSES EQUITABLE'S PROPOSAL RELATED TO THE RECOVERY OF UNIVERSAL SERVICE COSTS THROUGH RIDER D. HAS MR. COLTON ACCURATELY DESCRIBED EQUITABLE'S PROPOSAL?

A. No. Mr. Colton's testimony is factually incorrect in several areas. I will correct several misstatements and inaccuracies throughout my rebuttal testimony.

Before addressing the matters about which I disagree with Mr. Colton let me state that Equitable has indeed proposed that Rider D – Universal Service and Energy Conservation be the rate design and tariff mechanism

selected for the recovery of costs associated with the Company's universal service programs. Equitable's proposed tariff was included in Exhibit IV Item 53.53 IV-B-6 Supplement No. 60, Eighth Revised Page No. 96. Equitable has proposed to recover costs associated with its Commission approved Customer Assistance Program ("CAP") design, the administration of its CAP, and its Low Income Usage Reduction Program costs through Rider D. [1] Mr. Colton is correct that Equitable has proposed that Rider D be *a reconcilable surcharge applicable to non-CAP residential customers.*

Q: FIRST, ON PAGE 3 OF HIS DIRECT TESTIMONY, MR. COLTON STATES THAT "ON AN ANNUAL BASIS, THE COMPANY ESTIMATES WHAT IT EXPECTS TO SPEND ON ITS UNIVERSAL SERVICE COSTS USING BOTH KNOWN AND PROJECTED INFORMATION." IS THIS AN ACCURATE EXPLANATION OF THE COMPANY'S RIDER D PROPOSAL?

A: No it is not. Equitable does not propose to calculate its annual universal service costs on an annual static basis as implied by Mr. Colton. Instead, as described in proposed Rider D, each quarter Equitable proposes to revise, or update, either up or down, its projection of annual universal service costs based on several variables. For example, Equitable proposes to modify its estimate to include changes in the average annual usage of

[1] Equitable's LIURP is an energy conservation program which is also included as a part of the Company's universal service programs previously approved by the Commission. Equitable witness Narkevic presents revised Rider D tariff language in his rebuttal testimony, Equitable Statement No. 3-R, proposing to clarify Rider D by adding LIURP as a cost to be recovered.

current CAP customers and projected CAP additions, changes to the quarterly residential sales rate (including gas costs), changes to the average monthly CAP payment and average LIHEAP grants.

Q: SECOND, ON PAGE 3 OF HIS DIRECT TESTIMONY MR. COLTON STATES THAT EQUITABLE PROPOSES A QUARTERLY RECONCILIATION OF ITS ACTUAL EXPENDITURES TO ITS EXPECTED EXPENDITURES. IS THIS AN ACCURATE RESTATEMENT OF EQUITABLE'S PROPOSAL?

A: No, it is not. As described in paragraph IV of the Company's proposed Rider D, Equitable proposed an annual reconciliation of actual total CAP costs with the actual total CAP recoveries each August. Again, as I stated previously, Equitable proposes to adjust its projected annual costs quarterly in order to reflect changes to several of the variables which impact or cause changes to the annual universal service cost.

Q: LASTLY, ON PAGE 3 OF HIS DIRECT TESTIMONY MR. COLTON STATES THAT EQUITABLE PROPOSES, THROUGH A QUARTERLY RECONCILIATION PROCESS, TO RETURN OVER-EXPENDITURES TO CUSTOMERS (WITH INTEREST) OR COLLECT ITS UNDER-EXPENDITURES (ALSO WITH INTEREST). IS THIS AN ACCURATE RESTATEMENT OF EQUITABLE'S PROPOSAL?

A: No, it is not. As I previously stated. Equitable has not proposed a quarterly reconciliation, nor has it proposed to include carrying charges (interest) on over or under recoveries of actual CAP expenditures. I will discuss carrying charges later in my testimony.

Q: MR. COLTON STATES THAT EQUITABLE'S PROJECTION OF CAP COSTS IS BASED ON METHODOLOGICAL FLAWS. DO YOU AGREE?

A: No. As I will demonstrate and discuss later, certain of the OCA's proposed recommendations are not consistent with other witnesses testimony, do not pass muster when compared to actual results, and will produce under-recoveries of CAP expenses resulting in substantial adverse working capital impacts to Equitable.

Q: WOULD YOU PLEASE ELABORATE ON THE INCONSISTENCIES IN OCA'S TESTIMONY RELATED TO RIDER D?

A: Yes. Mr. Colton provides several recommendations to Equitable's calculation of CAP billed revenue that reduce the Company's projected CAP throughput, yet no corresponding adjustment to reduce revenue at present rates is offered by any other OCA witness who has supported other future test year revenue adjustments. Mr. Colton also objects to the recovery of administrative expenses through Rider D, but no corresponding adjustment is made to the OCA's proposed SG&A labor expense. Lastly, Mr. Colton's offsets to CAP credits completely ignore the Company's future test year

experience related to bad debt expense and working capital. I will discuss these items in greater detail later in my rebuttal testimony.

Q: DOES ANY OTHER PENNSYLVANIA NGDC ESTIMATE UNIVERSAL SERVICE PROGRAM EXPENDITURES SIMILAR TO WHAT EQUITABLE HAS PROPOSED IN THIS PROCEEDING?

A: Yes. Based on my review, Columbia Gas of Pennsylvania's method of projecting its universal program expenditures is very similar to Equitable's proposed methodology.

(B) OCA Proposes to Eliminate CAP Administrative costs from Rider D

Q: WOULD YOU PLEASE EXPLAIN MR. COLTON'S ADJUSTMENT TO REMOVE CAP ADMINISTRATIVE COSTS FROM RIDER D?

A: Yes. Mr. Colton recommends that Equitable should only be permitted to recover incremental expenses through Rider D that are directly attributable to its universal service program. According to Mr. Colton, any expenses that are not incremental universal service program expenses should be recovered through "base rates", not through Rider D.

Q: DOES THE COMMISSION'S PROPOSED RULEMAKING ORDER ISSUED AT L-00070186 SUGGEST THAT ONLY INCREMENTAL CAP ADMINISTRATIVE COSTS ARE ELIGIBLE FOR RECOVERY?

A: No. The policy statement states that administrative costs, including costs related to collection activities are eligible for recovery.

Q: MR. COLTON RECOMMENDS THE REMOVAL OF $299,184 IN CAP ADMINISTRATIVE COSTS FROM RIDER D. WERE YOU ABLE TO LOCATE A CORRESPONDING ADJUSTMENT TO INCREASE BASE RATE ADMINISTRATIVE COSTS BY $299,184 IN EITHER OCA WITNESS MORGAN'S OR MR. COLTON'S TESTIMONY OR EXHIBITS?

A: No, I was not. The only discussion related to this issue that I found appears in Mr. Colton's testimony. I found no testimony from an OCA witness adding the adjusted administrative costs back into the Company's revenue requirement calculation as it should be if the Commission were to adopt Mr. Colton's testimony. Mr. Colton himself seems to acknowledge this at page 22 of his direct testimony.

Q. DO YOU AGREE WITH WITNESS COLTON'S CONCLUSION THAT THE COMPANY'S CAP ADMINISTRATIVE EXPENSES ARE NOT INCREMENTAL?

A. No, I do not. In the event the Company were not required to have a CAP universal service program, it would not incur these specific costs related to CAP.

Q. DO YOU AGREE WITH MR. COLTON'S STATEMENT THAT THE COMPANY COULD NOT IDENTIFY WHAT SALARIES AND BENEFITS SHOULD BE RECOVERED AS A UNIVERSAL SERVICE COST?

A. No, I do not. The Company has tracked its costs associated with its CAP for the 2007 historic test year. The Company incurred $168,794 of costs associated with labor and benefits directly related to CAP in 2007. In the event that the CAP universal service program would cease to exist, the Company would eliminate these costs from its cost of providing distribution service.

Q. WOULD YOU EXPLAIN THE DIFFERENCE BETWEEN THE CAP ADMINISTRATIVE COSTS INCLUDED IN THE RIDER D CALCULATION OF $299,184 AND THE $168,794 PROVIDED ABOVE?

A. Yes. As previously mentioned, the costs totaling $168,794 represent the actual 2007 costs incurred related to CAP administrative labor and benefits. The $130,390 difference represented expected future test year increases in the staff solely related to CAP administrative matters due to the increased participation in CAP.

Q. WERE THESE COSTS INCURRED IN THE FUTURE TEST YEAR?

A. The Company has not to date hired new employees to fill these positions in 2008 despite the significant growth in CAP participants.

Q. DO YOU PROPOSE AN ADJUSTMENT TO THE ADMINISTRATIVE COSTS INCLUDED BY THE COMPANY IN THE RIDER D CALCULATION AS WELL AS A CHANGE TO THE ADJUSTMENT PROPOSED BY WITNESS COLTON?

A. Yes. I am proposing that the administrative costs to be included in the Rider D surcharge calculation be changed to $168,794, a reduction of $130,390. Similarly, I am also rebutting Mr. Colton's adjustment to remove the entire $299,184 and am suggesting that his adjustment be revised to equal the Company's reduction of costs totaling $130,390.

(C) Number of CAP Bills – Adjustment #1

Q: MR. COLTON STATES THAT EQUITABLE'S ESTIMATE OF CAP COSTS TO BE RECOVERED THROUGH RIDER D IS BASED ON AN OVERSTATED NUMBER OF MONTHLY CAP BILLS THAT THE COMPANY CAN BE EXPECTED TO ISSUE TO CAP CUSTOMERS. IS MR. COLTON CORRECT?

A: No, I disagree with Mr. Colton. Mr. Colton's opinion as to the appropriate methodology relied upon to project the 2008 number of monthly CAP bills is based on average historic 2007 data that, when compared to actual experience, substantially understates the number of monthly CAP bills which will be rendered in 2008, and, therefore, grossly understates the CAP credits needed to be recovered through Rider D which will result in an under-recovery of Rider D expenses.

Q: WOULD YOU PLEASE DESCRIBE MR. COLTON'S PROPOSED METHODOLOGY FOR PROJECTING CAP PARTICIPATION?

A: Yes. The OCA recommends using an average full-time equivalent of CAP participants from the prior year grossed-up by the growth rate experienced during the same prior year period for purposes of projecting CAP participants, which in turn would be used to calculate the amount of CAP credits used in the derivation of Equitable's proposed Rider D. For example, under the OCA's proposal, if one were attempting to calculate projected 2008 CAP participation, the average monthly number of full-time CAP participants for the entirety of 2007 must be calculated. Based on my calculations, included in Attachment JMQ-4, the average monthly CAP customers receiving a bill during 2007 was 15,410, and the average growth rate for 2007 was 14.7%. Mr. Colton arrived at slightly different numbers. He calculated the average number of monthly CAP participants to be 15,209[2], and the average growth rate to be 14%. Using Mr. Colton's numbers, the OCA recommends that the 2008 projected full-time equivalent participants would be 17,338 (15,209 x 1.14). The OCA then annualizes its 17,338 projected full-time CAP participants to arrive at the number of CAP bills to be rendered during 2008 of 208,059 (17,338 x 12).

[2] Page 9 of Mr. Colton's direct testimony states that the 2007 average number of CAP participants receiving bills was 15,209. However, there is no reference or workpaper supporting Mr. Colton's calculation and I am unable to replicate Mr. Colton's number using information provided by Equitable to the OCA.

Q: BASED ON NINE MONTHS OF ACTUAL CAP PARTICIPATION DURING 2008, CAN YOU COMPARE AND CONTRAST THE OCA'S RECOMMENDATION OF 208,059 PROJECTED BILLS TO THE COMPANY'S EXPECTED EXPERIENCE FOR 2008?

A: Yes. I have prepared Attachment JMQ-5. Attachment JMQ-5 details that actual CAP participation for the months of January through September 2008 has increased from 17,194 to 19,349 customers. Assuming a modest 1% per month growth for the months of October – December 2008[3], Equitable projects that CAP participation by December 2008 will be 20,335 which will produce total CAP bills for 2008 of 227,145. In contrast, the OCA's proposed methodology produced only 208,059 monthly CAP bills.

Q: HOW MANY PROJECTED CAP BILLS DID EQUITABLE'S ORIGINALLY FILED ATTACHEMENT JMQ-2 PROPOSE?

A: 227,712.

Q: WHAT IS THE DIFFERENCE BETWEEN THE OCA'S PROPOSAL AND EQUITABLE'S IN CAP COSTS TO BE RECOVERED?

A: The difference is $2,243,472. In other words, based on 9 months of actual CAP participation and 3 months of a conservative estimated participation, the OCA's recommended methodology would have generated a $2,243,472 under-recovery of CAP costs.

[3] The 1% growth rate was determined by summing the average monthly change in CAP participation for October of 2006 and 2007and the September 2008 CAP participation level.

Q: WHAT IS THE DIFFERENCE IN CAP COSTS TO BE RECOVERED BETWEEN THE EQUITABLE'S PROPOSED PROJECTION METHODOLOGY AND THE 9 MONTHS ACTUAL AND 3 MONTHS PROJECTED CAP PARTICIPATION?

A: It would be approximately $70,000.

Q: BASED ON YOUR ANALYSIS, SHOULD THE COMMISSION USE THE OCA'S PROPOSED METHODOLOGY TO ESTIMATE FUTURE CAP COSTS TO BE COLLECTED THROUGH RIDER D?

A: No. Equitable's proposal projected a more accurate annual participation rate for 2008 and therefore it should be accepted as the appropriate methodology.

(D) Number of CAP Bills – Adjustment #2

Q: ON PAGE 10 OF HIS TESTIMONY MR. COLTON PRESENTS A SECOND ADJUSTMENT TO THE NUMBER OF BILLS TO BE USED TO CALCULATE CAP EXPENSES. DO YOU HAVE ANY COMMENTS?

A: Yes. First, in point of clarification of a discrepancy/issue raised by the OCA, Equitable had 18,805 active CAP customers as of July 31, 2008. However, there were only 18,602 active CAP customers at the time July bills were generated, i.e. not all active CAP customers were issued a bill during the July billing cycle. I do not find this unusual given that Equitable

has 21 residential billing cycles and customers are admitted to the CAP throughout these 21 billing cycles. Clearly, if a customer is admitted to CAP after the customer's assigned billing cycle, the customer will not be issued a bill for that particular month. However, in an attempt to once again reduce the number of projected CAP bills relied upon to estimate Equitable's Rider D surcharge, Mr. Colton claims that his review of the Company's CAP data base indicates that only 98.5% of customers listed as CAP participants received a bill that had usage associated with it.

Q: WOULD YOU EXPECT ALL CAP BILLS TO HAVE USAGE ASSOCIATED WITH THE THEM?

A: Not necessarily. If a customer only uses natural gas for space heating it is possible that the customer would have no consumption during the summer months and, as a result, generate no CAP credit. However, in such cases the CAP customer is expected to pay his or her monthly budget payment. As such, Equitable has included these payments in the calculation of the average monthly CAP customer payment of $76.

Q: WERE YOU ABLE TO CONFIRM THAT ONLY 98.5% OF CAP PARTICIPANTS RECEIVED A BILL DURING 2007?

A: No. I was unable to confirm Mr. Colton's calculation. Based on our analysis during 2007 there were 182,907[4] CAP bills rendered in 2007 and 181,443 of the CAP bills contained billed usage. This equates to 99.1%.

Q: HAS THE OCA PROPOSED AN ADJUSTMENT TO THE NUMBER OF PROJECTED CAP BILLS WHICH RELIES ON THIS THEORY THAT 98.5% OF CAP BILLS HAVE NO USAGE?

A: Yes. The OCA recommends that the projected CAP bills should be reduced by 1.5% because there would be no CAP credit created by a zero consumption bill.

Q: DO YOU AGREE?

A: No. I previously demonstrated that Equitable's methodology for estimating CAP bills produced a more reasonable result when compared to the 2008 nine months actual and 3 months estimated CAP participation. This proposal, which can only result in a further under-recovery of CAP credits, should be rejected as well.

(E) CAP Credits – OCA Adjustment #3

Q: HAVE YOU REVIEWED THE OCA'S PROPOSED ADJUSTMENT FOR CAP CREDITS AND DO YOU HAVE ANY COMMENTS?

[4] On Page 9, line 7 Mr. Colton states that there were 185,510 actual bills rendered to CAP participants during 2007. No reference supporting this number was provided.

A: Yes. I have reviewed Mr. Colton analysis and have attempted to replicate his conclusions which are based on the results taken from the Company's response to OCA-V-12. For the most part, I have been able to replicate Mr. Colton's calculations. The OCA is correct that under Equitable's current effective, Commission-approved CAP design, CAP participants do not earn a CAP credit until they make their full required CAP payment. Further, I would agree that historical evidence supports the premise that CAP customers do not make 100% of their required CAP payments under Equitable's CAP design described above. However, I find inconsistencies with Mr. Colton's reliance on the number of CAP credits granted by Equitable. For example, Mr. Colton's summary of potential CAP credits versus actual CAP credits granted reveals that on average Equitable's CAP customers only pay their bill and earn a CAP credit 74% of the time. However, Equitable's bad debt rate for confirmed low-income customers, as reported to the PUC's Bureau of Consumer Services ("BCS"), was 15.83%. Clearly there is a problem. Perhaps customers on CAP have poorer payment habits than our overall average confirmed low-income customers who may not be on CAP.

Q: WHAT IS YOUR SOLUTION?

A: Equitable has advocated in previous CAP proceedings that our current design attempts to provide an incentive for CAP customers to pay their monthly budget payment, i.e. CAP credits are earned once a

customer's percentage income payment is made. Equitable is willing to abandon this program design and provide CAP credits when a CAP customer's bill is rendered. Based on Equitable's review of other CAP programs, this design and accounting methodology has been approved by the Commission most recently in Columbia Gas of Pennsylvania's base rate case.

Q: IF EQUITABLE'S CAP DESIGN IS MODIFIED CONSISTENT WITH YOUR PROPOSAL IS MR. COLTON'S PROPOSED ADJUSTMENT NECESSARY?

A: No. Mr. Colton's adjustment is based upon a number of CAP credits. Under my proposed revision to the Company's CAP design, the number of CAP credits Equitable has historically provided would be irrelevant. On a going forward basis, Equitable would recognize CAP credits when a CAP bill is issued. Therefore, each CAP bill rendered would generate a CAP credit.

Q: WHAT DO YOU RECOMMEND IF THE COMMISSION DOES NOT ACCEPT YOUR CAP PROGRAM DESIGN MODIFICATION?

A: I recommend that Equitable be permitted to apply carrying charges of 8% per annum on over-recovered and 6% per annum on under- recovered CAP expenses determined in August of each year as proposed by Equitable.

Q: WHY ARE YOU RECOMMENDING THE APPLICATION OF INTEREST ON OVER OR UNDER-RECOVERED CAP EXPENSES?

A: First, the concept was suggested by the OCA, and Equitable finds the concept to be reasonable. Second, given the large variation in projected CAP expenses to be recovered through Rider D between the Company's proposal and the OCA's proposal, I think it is a reasonable compromise and would provide Equitable assurance that it will not incur incremental working capital requirements due to the underfunding of expenses associated with its CAP.

(F) Universal Service Cost Offsets – OCA Adjustment #4

Q: WOULD YOU EXPLAIN THE OCA'S PROPOSED UNIVERSAL SERVICE PROGRAM OFFSETS TO THE COMPANY'S DETERMINATION OF COSTS TO BE RECOVERED THROUGH RIDER D?

A: Yes. The OCA has proposed two offsets: a bad debt expense offset, and a cash working capital savings offset.

The OCA's bad debt expense offset is premised on the assumption that low-income customers who are behind in their payments to Equitable and eligible to participate in the Company's CAP, but choose not to, will ultimately result in a bad debt expense which is currently reflected in base delivery service rates. As CAP participation increases, low-income customers are asked to pay a portion of their total bill based on a

percentage of their income. The difference between the total bill and the CAP customer's payment (CAP Credit) is paid by non-CAP customers through Rider D. Under this theory, Equitable would realize a lower annual bad debt expense level in base rates than it would in the absence of CAP. Based on this assumption, the OCA concludes that the incremental CAP funding should be reduced to reflect bad debt savings. The OCA recommends that the offset should be equal to the incremental revenues collected through CAP Rider D multiplied by the bad debt rate for confirmed low-income customers. The OCA uses the 2007 bad debt rate for confirmed low-income customers as reported by the Company in a report to the Commission's Bureau of Consumer Services. Mr. Colton calculates this offset to be $1,221,370, which is based on the entire recommended increase in Rider D funding proposed by the OCA ($7,715,537 x 15.83%).

Q. DO YOU AGREE WITH WITNESS COLTON'S PROPOSED BAD DEBT EXPENSE OFFSET AMOUNT?

A. No, I do not. Mr. Colton completely ignores the adjustment for bad debt expense already made and reflected by Equitable witness Mitchell in the Company's future test year expense claims.

Q. DID THE COMPANY INCLUDE A BAD DEBT OFFSET IN ITS HISTORIC TEST YEAR?

A. Yes. The Company calculated a reduction in bad debt expense of $1,162,312 as reflected in Exhibit III, Item: §53.53 III.A.17 Historic Test Year, sheet 9 of 11. This adjustment was made as the average net write-off percentage declined in 2007 compared to 2006, in part due to the expansion of the CAP program. The adjustment approximates the amount proposed by witness Colton. Note also that the historic test year claim was then used as a basis for the future test year claim. Thus, this bad debt offset is already embedded and reflected in the future test year cost of service.

Q. DO YOU PROPOSE A CHANGE TO THE ADJUSTMENT PROPOSED BY WITNESS COLTON?

A. Yes. I propose that witness Colton's adjustment to offset CAP related recoverable costs be excluded as it amounts to a duplicate adjustment. The inclusion of the OCA's offset of bad debts in Rider D would overstate the expected bad debt offset and artificially lower the costs to be included in the Rider D calculation for CAP below the level of what will be incurred.

Q: DO YOU THINK MR. COLTON'S BAD DEBT OFFSET ADJUSTMENT IS ACCURATE?

A: No. I think the basis relied upon by Mr. Colton is flawed. Mr. Colton's adjustment focuses on an incremental funding requirement and

assumes this provides a bad debt savings. This is incorrect. As the OCA knows, Equitable has been operating under a CAP funding settlement whereby the Company has been at risk for all CAP credits over $.58/Mcf. As a result, Equitable's incremental CAP funding level and resulting request in this proceeding is quite large and should be deemed irrelevant in the determination of a bad debt savings calculation. As stated previously, Mr. Mitchell's proposed bad debt adjustment already includes the bad debt savings impacts of 18,976 CAP customers. The OCA's proposal should be rejected.

Q: WOULD YOU PLEASE EXPLAIN THE OCA'S SECOND PROPOSED OFFSET TO CAP CREDITS?

A: Yes. Mr. Colton's second proposed offset is related to working capital savings generated by the reduction in customer payments that are in arrears once a customer joins the CAP.

Q: DO YOU AGREE WITH WITNESS COLTON'S PROPOSED WORKING CAPITAL SAVINGS OFFSET AMOUNT?

A. No, I do not. Again, the OCA completely ignores the analysis of Equitable witness Ross who prepared a test year lead lag study which already included the working capital savings resulting from Equitable's CAP program in his future test year cash working capital claim. To accept Mr. Colton's working capital offset amounts to double counting the savings.

Q: DO YOU THINK MR. COLTON'S WORKING CAPITAL OFFSET ADJUSTMENT IS ACCURATE?

A: No. I think the basis relied upon by Mr. Colton is flawed. Similar to his bad debt savings offset, Mr. Colton's adjustment focuses on an incremental funding requirement and assumes this provides working capital savings. This is incorrect. Again, as the OCA knows, Equitable has been operating under a CAP funding settlement whereby the Company has been at risk for all CAP credits over and above $.58/Mcf. As a result, Equitable's incremental CAP funding level and resulting request in this proceeding is quite large, and should be deemed irrelevant in the determination of a working capital savings calculation. As stated previously, Mr. Ross' proposed cash working capital requirement is based on sound and accepted rate making principles and already includes the working capital savings impacts of 18,976 CAP customers. The OCA's proposal should be rejected.

Q: WOULD YOU PLEASE SUMMARIZE EQUITABLE'S REBUTTAL POSITION RELATED TO THE OCA'S RECOMMENDATIONS FOR THE CALCULATION OF RIDER D?

A: Yes. Mr. Colton's recommendations should be rejected and my original Attachment JMQ-2 and Supplement No. 60 Eighth Revised Page No 96 should be accepted as filed.

IV. OTS Universal Service Cost Recovery

(A) CAP Credit Limit

Q: HAVE YOU REVIEWED OTS WITNESS GORDON'S TESTIMONY RELATED TO EQUITABLE'S UNIVERSAL SERVICE AND ENERGY CONSERVATION PROGRAMS?

A: Yes. The OTS recommends that Equitable should follow the Commission's policy statement and impose a CAP maximum credit of $1,000 for each enrolled CAP Customer. The OTS estimates that the annual cost to Rider D customers from CAP customers exceeding the $1,000 maximum CAP credit is in excess of $8 million. I have reviewed Ms. Gordon's calculations and find them to be accurate. However, I do not agree with her recommendation. Specifically, Ms. Gordon did not address the Commission's proposed exemptions contained in Section 69.265(4)(vi) of the Commission's CAP Regulations. Equitable witness Gagorik will discuss this in more detail in her rebuttal testimony.

Q: IS EQUITABLE CURRENTLY OPERATING ITS UNIVERSAL SERVICE AND ENERGY CONSERVATION PROGRAMS PURSUANT TO A COMMISSION ORDER?

A: Yes. Equitable, OTS, OCA and other parties submitted a joint settlement in Docket Nos P-00062240 and M-00061959. The Commission

approved the settlement in an Order entered September 27, 2007. I have included the settlement as Attachment JMQ-6 to my rebuttal testimony.

Per its terms, the settlement would continue in effect until the effective date of rates approved by the Commission in Equitable's next base rate case. The settlement approved Equitable's 2007-2009 Universal Service and Energy Conservation Plan and a funding mechanism, Rider D. Paragraph V of the settlement also included a provision related to CAP consumption whereby Equitable would monitor consumption by CAP participants to ensure that the participant is maintaining annual usage at or below 110% of historical average usage, adjusted for weather. Provisions were included on page 6 of the settlement describing exactly how this would be accomplished.

Given that the settlement has only been in effect for barely over a year, one reasonable option would be to afford Equitable the opportunity to evaluate its progress pursuant to the terms of the settlement, and to report on the impacts of CAP customer consumption in the Company's next tri-annual Universal Service and Energy Conservation Plan. If, on the other hand, the Commission were to adopt the OTS recommendation and require Equitable to implement a $1,000 CAP credit limit, it is my opinion that CAP customers who exceed the credit limit would be unable to remain on the CAP. This would result in numerous defaults on their obligations to remain current on their Equitable accounts which ultimately would lead to termination of service and the write-off of these accounts as uncollectible.

Q: WHY DO YOU BELIEVE THAT THE IMPLEMENTATION OF THE OTS RECOMMENDATION WILL LEAD TO A HIGHER BAD DEBT EXPENSE?

A: As previously discussed, an average CAP customer payment is $76 per month, or $912 per year. The Company's historical experience under the current payment terms reveals that only 74% of CAP customers are able to remain current on their percentage of income monthly payment in order to generate a CAP credit, and according to information provided to the BCS, Equitable's confirmed low-income customer's bad debt rate was 15.83%. Therefore, I believe it is reasonable to conclude that a modification of current payment terms as proposed by the OTS will exacerbate the Company's CAP default rate and increase our future test year bad debt write-offs.

Q: WHO WILL BE ASKED TO PAY FOR THE INCREASE IN BAD DEBT EXPENSE?

A: It will become the responsibility of non-CAP residential customers the very same class of customers that the OTS asserts is being burdened by not enforcing the $1,000 CAP credit limit.

Q: IF THE OTS RECOMMENDATION IS ADOPTED, SHOULD THERE BE A CORRESPONDING ADJUSTMENT TO EQUITABLE'S BAD DEBT

EXPENSE , CREDIT AND COLLECTION EXPENSES, AND WORKING CAPITAL ALLOWANCE?

A: Yes. I believe an adjustment would be appropriate to reflect that CAP customers will be unable to remain current on their payment obligations, and thus, will fall into the collections process once they have exceeded the $1,000 limit.

(B) Rider D Recovery

Q: ON PAGE 11 OF HER DIRECT TESTIMONY MS. GORDON STATES THAT EQUITABLE'S CURRENT RIDER D IS NON-RECONCILABLE AND IS ADJUSTED QUARTERLY ON A PROSPECTIVE BASIS. IS THIS ACCURATE?

A: It is partially accurate. Equitable's current Rider D rate is a fixed $.58/Mcf. The rate is not adjusted quarterly, and Equitable is at risk for under-recoveries of its universal service expenses, *i.e.* currently the mechanism is non-reconcilable. Equitable's proposal relative to Rider D in this proceeding is to update the Rider D rate, up or down, on a quarterly basis to reflect changes related to quarterly gas cost changes and CAP participation changes. In addition, on an annual basis, Equitable proposes to reconcile actual universal service costs with estimates in order to fully recover actual universal service costs. It is my intent to utilize quarterly updates of known information to assist in minimizing over or under recoveries of the Company's universal service costs.

Q: DOES THE OTS SUPPORT THE COMPANY'S PROPOSED RIDER D?

A: No. The OTS recommends that Rider D only be adjusted prospectively on a quarterly basis to track changes in costs with no annual reconciliation. The OTS concludes that Equitable's proposal seeks to use a form of both recovery mechanisms as discussed in guidance offered by the Commission at Docket No. M-00051923, and, in the OTS' opinion, an annual reconciliation mechanism does not provide an incentive for the Company to control costs or create more cost effective measures.

Q: DO YOU AGREE WITH THE OTS' RECOMMENDATION?

A: No. As I stated earlier, Equitable's proposal is designed to fully recover its actual universal service program costs, as provided by statute, while attempting to limit large over or under recoveries during the program year due to changes in projected variables. In my opinion, Equitable is attempting to replicate a methodology similar to that currently followed under the Commission's 1307(f) regulations related to gas costs.

If however, the Commission were to decide that Equitable's Rider D mechanism must utilize either a periodically reconcilable surcharge, or prospective quarterly adjustments, as provided at Docket No. M-00051923, Equitable requests that Rider D be reconciled periodically to recover the actual level of costs.

V. Negotiated Rate Revenue

Q: AT PAGES 25 THROUGH 35 OF HIS TESTIMONY OCA WITNESS WATKINS PRESENTS A NEGOTIATED RATE REVENUE ADJUSTMENT. HAVE YOU REVIEWED MR. WATKINS TESTIMONY?

A: Yes, I have. Mr. Watkins proposes a revenue adjustment of $22.8 million for what he refers to in Schedule GAW-7 as "Foregone Revenues" from negotiated rate customers.

Q: IS MR. WATKINS' NEGOTIATED RATE REVENUE ADJUSTMENT A SIGNIFICANT ADJUSTMENT?

A: Yes. This adjustment is obviously a significant adjustment. It is more than one-third and almost one-half of the Company's requested additional revenue increase from its filing.

Q: HOW DID MR. WATKINS CALCULATE HIS NEGOTIATED RATE REVENUE ADJUSTMENT?

A: Mr. Watkins' adjustment is calculated in his Schedule GAW-7. As shown there, Mr. Watkins calculated an average negotiated rate per Mcf for the negotiated deliveries under Rate GDS and Rate DDS. He then compared the average negotiated rate to a calculated maximum tariff rate. He then multiplied the dollar difference by the negotiated deliveries to produce "Foregone Revenues" totaling $22,790,905. He proposes the

adjustment stating, at page 3 of his direct testimony, that, in his view, the Company failed to verify or support the recovery of the revenue.

Q: CAN THE COMPANY VERIFY AND SUPPORT ITS NEGOTIATED RATE REVENUE?

A: Absolutely. The Company can verify and support its negotiated rate revenue levels in every instance. I will address this further later in my testimony. In my view, Mr. Watkins' adjustment is arbitrary and discriminatory towards Equitable Gas Company and, if adopted by the Commission, it would be confiscatory. I will also address in more detail later but want to point out here that several of the negotiated rate customers are large users of natural gas. Equitable's largest customer, United States Steel Corporation ("U.S. Steel"), was the subject of discussion in Equitable's recently concluded 2008 Section 1307(f) proceeding. U.S. Steel is Equitable's largest delivery service customer with annual requirements in excess of 6.9 Bcf. The total negotiated deliveries in Mr. Watkins' Schedule GAW-7 are 15.5 Bcf. U.S. Steel is, thus, approximately 45% of the negotiated deliveries. The U.S. Steel testimony in the 1307(f) proceeding is attached to my testimony here as Attachment JMQ-7. It emphasizes the importance of a negotiated rate level to U.S. Steel and the Western Pennsylvania economy. In response to discovery in this proceeding, U.S. Steel has advised that it would not pay a full margin rate of $2.36 per Mcf. (See JMQ-Attachment 8). The OCA participated in the 1307(f) proceeding

and is well aware of the circumstances involving U.S. Steel and its claim for a negotiated rate.

Q: WOULD YOU BRIEFLY EXPLAIN EQUITABLE'S CURRENT TARIFF AUTHORITY FOR NEGOTIATED RATES?

A: Yes. Equitable's current tariff provides the Company discretion to negotiate with customers, or their designated agents, to establish rates at or below the current maximum stated tariff rate. The purpose of the negotiation procedure is to enable the company to retain customer load and maximize revenue. The tariff provisions are not new and have been in existence for many years. In fact, I believe the tariffs of all western Pennsylvania NGDCs have almost identical provisions related to negotiated rates and terms.

Q: MR. WATKINS STATES THAT EQUITABLE HAS PROPOSED TO CONTINUE ITS PRACTICE OF "DEVIATING" DOWNWARD FROM APPROVED MAXIMUM RATES FOR SELECTED CUSTOMERS. DO YOU AGREE WITH HIS CHARACTERIZATION?

A: No, not at all. Rate negotiation is part of Equitable's approved tariff in the same way and with the same force and effect as are the maximum rate levels that appear in the tariff. Negotiation is not a deviation. As I stated previously, in order for Equitable to retain load and maximize revenue, negotiated rates are absolutely essential. The fact of the matter is that

certain customers in western Pennsylvania have alternate fuel options. Many are geographically located in NGDC overlapping service territories, and/or in close proximity to natural gas pipelines, and/or natural gas wells. These specially situated customers have the opportunity to shop for both natural gas commodity service and natural gas delivery service. If all other western Pennsylvania NGDCs continue the practice of negotiating with these specially situated customers and/or their agents, Equitable has no option but to continue the same practice or risk losing customers and delivery service revenue.

Q: ON PAGE 27 OF HIS DIRECT TESTIMONY MR. WATKINS STATES THAT EQUITABLE IS SEEKING AUTHORIZATION TO INSULATE ITS SHARHOLDERS FROM THE EFFECTS OF COMPETITION RESULTING FROM THE ESTABLISHMENT OF NEGOTIATED, OR MARKET BASED RATES. DO YOU HAVE ANY COMMENT?

A: Yes. I disagree with the OCA's contention. First, as I have said, this is the first base rate case filed by Equitable since 1997. During the intervening twelve year period since Equitable filed its last base rate case it has been Equitable's shareholders who have insulated its customers from the effects of competition. However, during this intervening period Equitable proactively and aggressively negotiated with competitive customers in an attempt to maximize its delivery service revenue.

Secondly, as the Commission is aware, beginning in 2006 Equitable Resources, Inc. and its shareholders, attempted to acquire the distribution assets of Dominion Peoples and Dominion Hope. After nearly two years of effort and over $25 million invested by the shareholders of Equitable Resources it became apparent that we would be unsuccessful in gaining the support of the Pennsylvania Attorney General ("PA AG") and the Federal Trade Commission ("FTC"). The primary issue in opposition to the acquisition identified by the PA AG and the FTC related to gas-on-gas competition. In their view, competition, including gas-on-gas competition would be adversely impacted (reduced) if the transaction were to be granted. After considerable investment in time and resources the board of directors of both companies mutually agreed to terminate the acquisition.

Q: IS EQUITABLE REQUESTING THAT ITS CUSTOMERS SHARE IN THE EXPENSES OF THE ABANDONED TRANSACTION IN THIS PROCEEDING?

A: No, we are not. All costs associated with the transaction have been removed from the historic and future test year, and thus, Equitable has insulated customers from its economic impact. In Equitable's opinion, and as demonstrated by the Commission's approval of the transaction, the proposed acquisition would have provided affirmative public benefits both through reductions in gas cost and eventually through a combined utility cost of service delivery rates. This would have been accomplished through

a variety of synergies including a reduction in over-lapping NGDC service territories in western Pennsylvania, and thus, a reduction in gas-on-gas competition. In my opinion, Equitable demonstrated, at substantial cost to its shareholders, a desire to share with its customers the benefits of a combined utility.

Q: ON PAGE 27 OF HIS DIRECT TESTIMONY MR. WATKINS STATES THAT EQUITABLE PROVIDED NO INFORMATION IN ITS APPLICATION, TESTIMONY, OR WORKPAPERS CONCERNING ITS REQUEST TO EXEMPT SHAREHOLDERS FROM RESPONSIBILITY FOR WHAT HE TERMS ARE "DISCOUNTED RATE REVENUES". DO YOU HAVE ANY COMMENT?

A: Yes. I think Mr. Watkins' testimony is extremely misleading and contrary to the facts. As I discuss at some length later in my testimony, Equitable provided information to the OCA that was sufficient for the OCA to withdraw a series of interrogatories that asked for information about negotiated rate revenue for Equitable customers. Additionally, as discussed in my direct testimony, Equitable's last general base rate increase was filed in 1997. Since this last rate case Equitable's shareholders have invested over $200 million in gross plant additions to maintain the safe and reliable distribution of gas and substantially improve customer service. To suggest that Equitable's shareholders should bear responsibility for rates that have been negotiated to levels below maximum tariff rates to maintain customer

load and revenue is contrary to past Commission precedent established in previous base rate proceedings and thus wholly unsupported.

Q: DID EQUITABLE PARTICIPATE IN THE RECENT COLUMBIA GAS RATE PROCEEDING?

A: Yes, it did. Columbia Gas of Pennsylvania's ("Columbia") filed its base rate case with the Commission in January of 2008 and Equitable intervened to monitor the proceeding and evaluate, among other things, the issue of negotiated rates for competitive customers. Equitable's 2008 base rate case submitted in this proceeding is absolutely consistent with the information submitted in its last base rate case in 1997, and more significantly in regard to this issue of negotiated rate revenue, consistent with the testimony and exhibits submitted by Columbia at Docket No. R-2008-2011621.

Q: DID THE OCA RAISE AN ISSUE OF NEGOTIATED RATE REVENUE IN THE COLUMBIA PROCEEDING AT DOCKET NO. R-2008-2011621 AND PROPOSE AN ADJUSTMENT FOR "FOREGONE REVENUES" IN THAT PROCEEDING?

A: No, it did not even though Columbia has 13.8 Bcf of negotiated throughput.

Q: WHAT WAS THE OCA'S POSITION IN COLUMBIA'S RATE CASE RELATED TO COLUBMIA'S 13.8 BCF OF NEGOTIATED THROUGHPUT?

A: Basically, the OCA took no position. Equitable was a party to the Columbia proceeding and the issue was never raised by any party including the OCA. To clarify the OCA's position, Equitable has served a request for admissions. However, the OCA has not yet responded to the request. Equitable asked the OCA to explain the differing positions taken by it here in this proceeding and in the Columbia proceeding. I have attached the OCA's response to OCA-II-1 as Attachment JMQ-9.

Q: WHY IS EQUITABLE INTERESTED IN THE OCA'S POSITION ON THE ISSUE OF NEGOTIATED RATE REVENUE IN THE COLUMBIA BASE RATE FILING?

A: We are interested for two reasons. First, Equitable believes that it would be reasonable to assume that it should be afforded the same treatment from the OCA related to negotiated rate support that Columbia received, a precedent if you will. To my thinking, it is not a matter of what an OCA witness does from case to case but what the OCA itself does from case to case. Second, Columbia is a competitor of Equitable and an intervenor in this proceeding. As stated in my direct testimony, even though Columbia's delivery rates are lower than Equitable's, Columbia still must negotiate delivery rates for competitive customers. Obviously, the information related to negotiated agreements is highly confidential. This

was imparted to the OCA. The release of this type of information could expose Equitable and its customers to further loss of load.

Q: DID EQUITABLE PROVIDE THE SAME DEMONSTRATION AND PRESENTATION IN THIS PROCEEDING AS COLUMBIA DID IN THEIR BASE RATE CASE?

A: Yes. I believe that Equitable has made the very same demonstration here that Columbia made in its recently concluded proceeding. Yet, in this proceeding, the OCA has proposed a $23 million dollar adjustment for "Foregone Revenues." In the Columbia proceeding with the same witness, the OCA was silent and no adjustment was proposed.

Q: ON PAGE 28 OF HIS DIRECT TESTIMONY MR. WATKINS ASSERTS THAT EQUITABLE DID NOT MEET A COMMISSION FILING REQUIREMENT AT 52 PA. CODE §53.53 III E.11. DO YOU HAVE ANY COMMENT?

A: Yes. Again, it appears that the OCA would arbitrarily hold Equitable to a different standard than its direct competitors. Equitable provided the information asked for in the filing requirement regulation. Pursuant to 52 Pa. Code § 53.51(c)(2) the OCA was obligated to raise this issue with the Commission's Secretary within 30 days of the submission of the Company's base rate filing or the filing is deemed perfected. It is my understanding that the OCA did not raise this issue within the prescribed time period.

Therefore, Equitable's filing was deemed to have complied with the Commission's filing requirements.

Q: ON PAGE 29 OF HIS DIRECT TESTIMONY MR. WATKINS INFORMS THE COMMISSION THAT THEY SHOULD BE CONCERNED ABOUT NEGOTIATED RATES DUE TO COMPETITIVE FORCES. DO YOU HAVE ANY COMMENT?

A: Yes. This issue was raised during Equitable's attempt to acquire Dominion Peoples. Clearly the FTC and the PA AG do not share the OCA's concern on the issue of gas-on-gas competition. In fact, based on their positions articulated to the 6th Circuit Federal Court of Appeals, they both deem such competition appropriate and reasonable for those select few customers who happen to be physically located in over-lapping service territories.

Q: BEGINNING ON PAGE 33 OF HIS DIRECT TESTIMONY, MR. WATKINS STATES THAT HE ASKED A SERIES OF DATA REQUESTS SEEKING INFORMATION ABOUT EQUITABLE'S NEGOTIATED RATES IN JULY. HE STATES THAT BY THE MIDDLE OF SEPTEMBER HE HAD NOT RECEIVED ANY RESPONSES TO HIS INQUIRIES. DO YOU HAVE ANY COMMENT?

A: Yes. I am very surprised by Mr. Watkins' testimony. I can only describe it as misleading and incomplete. The series of data requests Mr. Watkins refers to are OCA Set II Interrogatories Nos. 19, 20, 22, and 23 which were served by the OCA on the Company on August 1, 2008. I will explain the circumstances of these OCA interrogatories and the events that followed the service of them in the following question and answer but what must be recognized about the interrogatories at the outset is that, ultimately, they were withdrawn by the OCA after Equitable provided information to the OCA that Counsel for the OCA acknowledged to be satisfactory. That information was sent to the OCA on September 18, 2008. The next day, September 19, 2008, the OCA advised by email that OCA Set II Interrogatories Nos. 19, 20, 22, and 23 were withdrawn. I have attached a copy of the e-mail as Attachment JMQ-10.

Q: WOULD YOU EXPLAIN IN MORE DETAIL WHAT OCCURRED IN REGARD TO OCA SET II INTERROGATORIES NOS. 19, 20, 22 AND 23?

A: Yes. When the Interrogatories were served on August 1, 2008, Equitable was negotiating a confidentiality agreement with the OCA and the rest of the intervenors who were seeking access to confidential information. On September 8, 2008 the OCA sent a letter to the Company's outside counsel along with executed confidentiality agreement documents signed by both the OCA and its consultants.

OCA Set II Interrogatories Nos. 19, 20, 22, and 23 requested highly confidential information which was quite detailed and voluminous. After receiving the executed confidentiality agreement documents Equitable's attorneys contacted the OCA in an attempt to arrive at a solution that would satisfy the OCA's inquiries. A conference call was held on or about September 11, 2008 with Equitable personnel including myself, the Company' outside Counsel, Counsel for the OCA, Mr. Watkins, the OTS and its technical support staff. During the call Equitable did express concern that the requested information was highly confidential and could expose sensitive information to several competitors who had also intervened in this proceeding. The focus of the discussions led to a concern expressed by the OCA that Equitable was attempting in the rate filing to shift revenue responsibility associated with negotiated delivery service agreements to residential customers.

During the call Equitable attempted to demonstrate, by reference to the cost allocation studies submitted in this proceeding, that our proposal was not to shift revenue responsibility to the residential class. Equitable also suggested that the highly confidential information requested could best be viewed at the Company's offices in Pittsburgh where our data base of contracts and supporting documents are housed. This proposal was rejected by the OCA. We then offered to make the information available for inspection at our attorney's offices in Harrisburg. Again, this offer was rejected.

Shortly after the call further communication occurred between our Counsel and Counsel for the OCA. It was agreed that Equitable would informally provide a summary of highly confidential negotiated rate revenue information which would demonstrate that Equitable was not proposing a shift of revenue responsibility to residential customers. This information was sent to the OCA on September 18, 2008. On September 19, 2008 Equitable's attorney received the previously mentioned email from the OCA withdrawing OCA-II-19, 20, 22, and 23. Again, that email is attached as Attachment JMQ-10. After reviewing the e-mail Equitable was under the impression that the matter had been resolved.

Having participated in the foregoing and believing the matter had been resolved to the OCA's satisfaction and with the "series of interrogtories" having been withdrawn, Equitable was very surprised to read in Mr. Watkins's testimony that he was proposing to impute $22.8 million in incremental revenue attributed to the delta between maximum tariff rates and Equitable's average negotiated rate. The Company was also surprised to read that Mr. Watkins was basing this adjustment on a failure to respond to Interrogatories that the OCA had withdrawn. In my opinion, Mr. Watkins proposed revenue adjustment is unprecedented, inconsistent with prior Commission rate making decisions, unsupported by any fact, and at odds with the withdrawal of the subject interrogatories and the provision of the information to OCA Counsel. Equitable believes it responded to such requests. The adjustment should be disregarded.

Q: DID EQUITABLE RESPOND TO THE OCA DATA REQUEST MENTIONED BY MR. WATKINS AT PAGE 35 OF HIS DIRECT TESTIMONY?

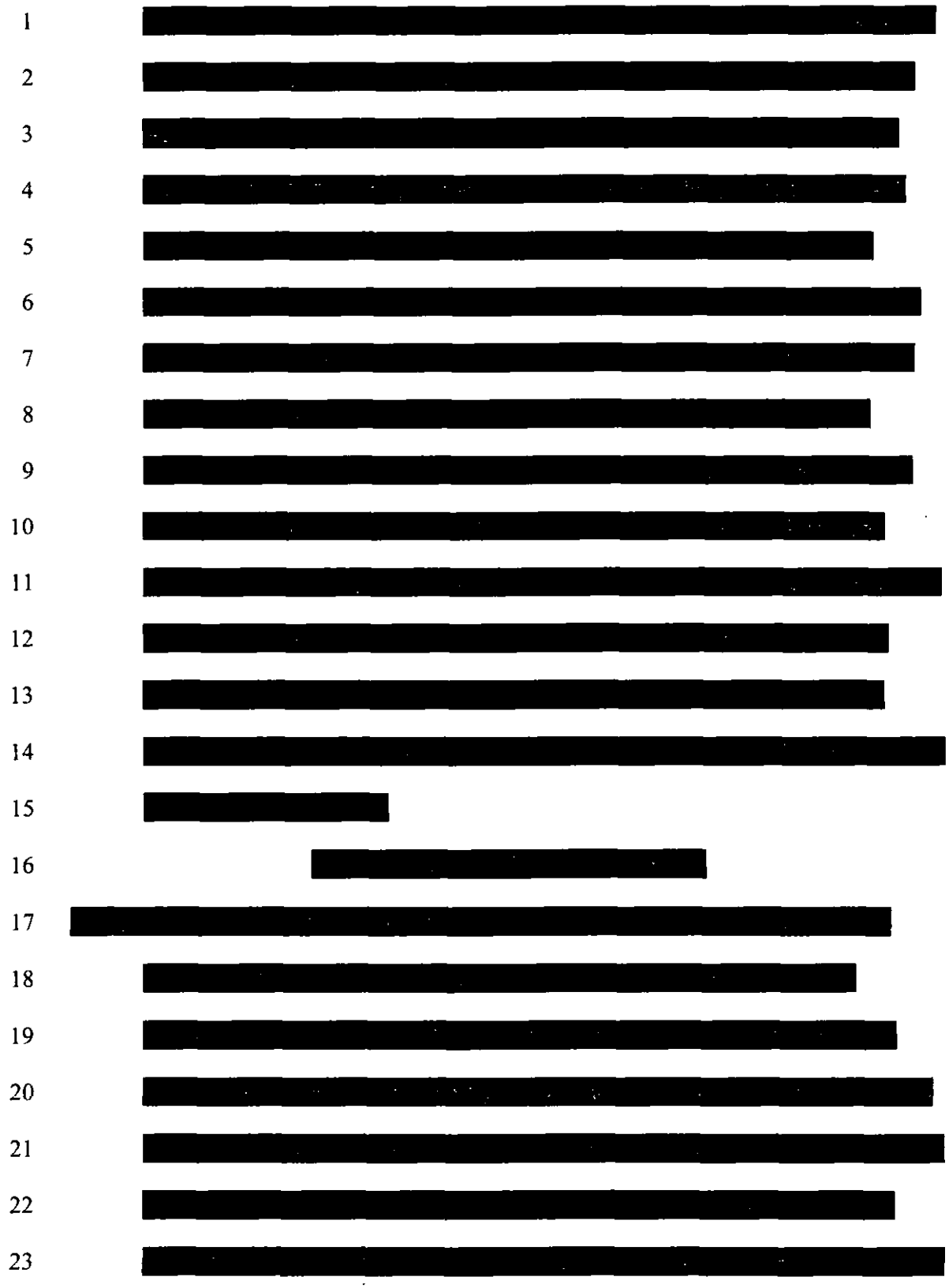
A: Yes. The OCA did not submit this data request until shortly before the due date for its direct testimony and the response was not due from Equitable until after the due date for the OCA's direct testimony. Equitable filed a timely response to the data request.

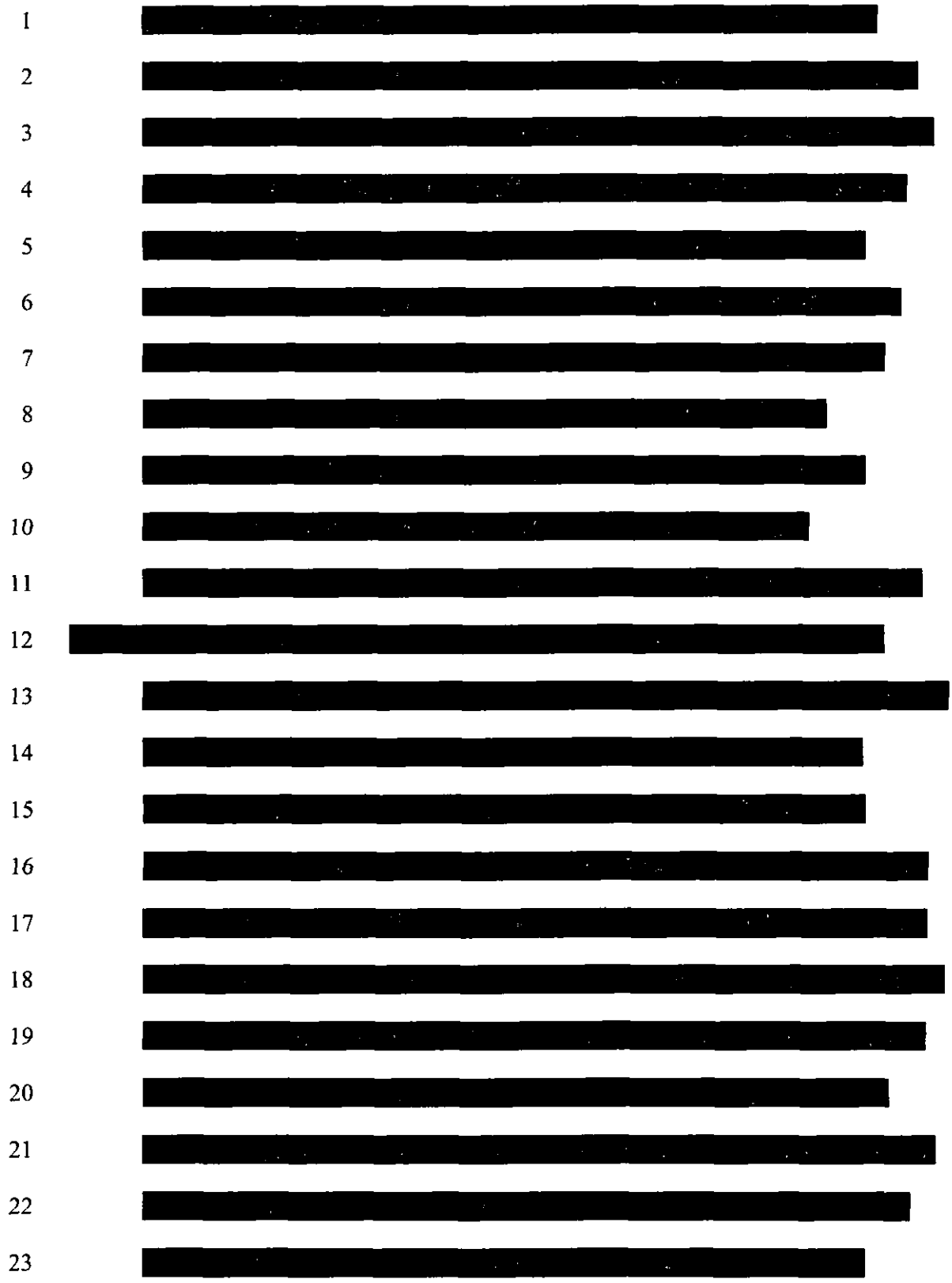
************BEGIN HIGHLY CONFIDENTIAL TESTIMONY ADDRESSING NEGOTIATED RATE REVENUE***********

[redacted]

[redacted]

[redacted]





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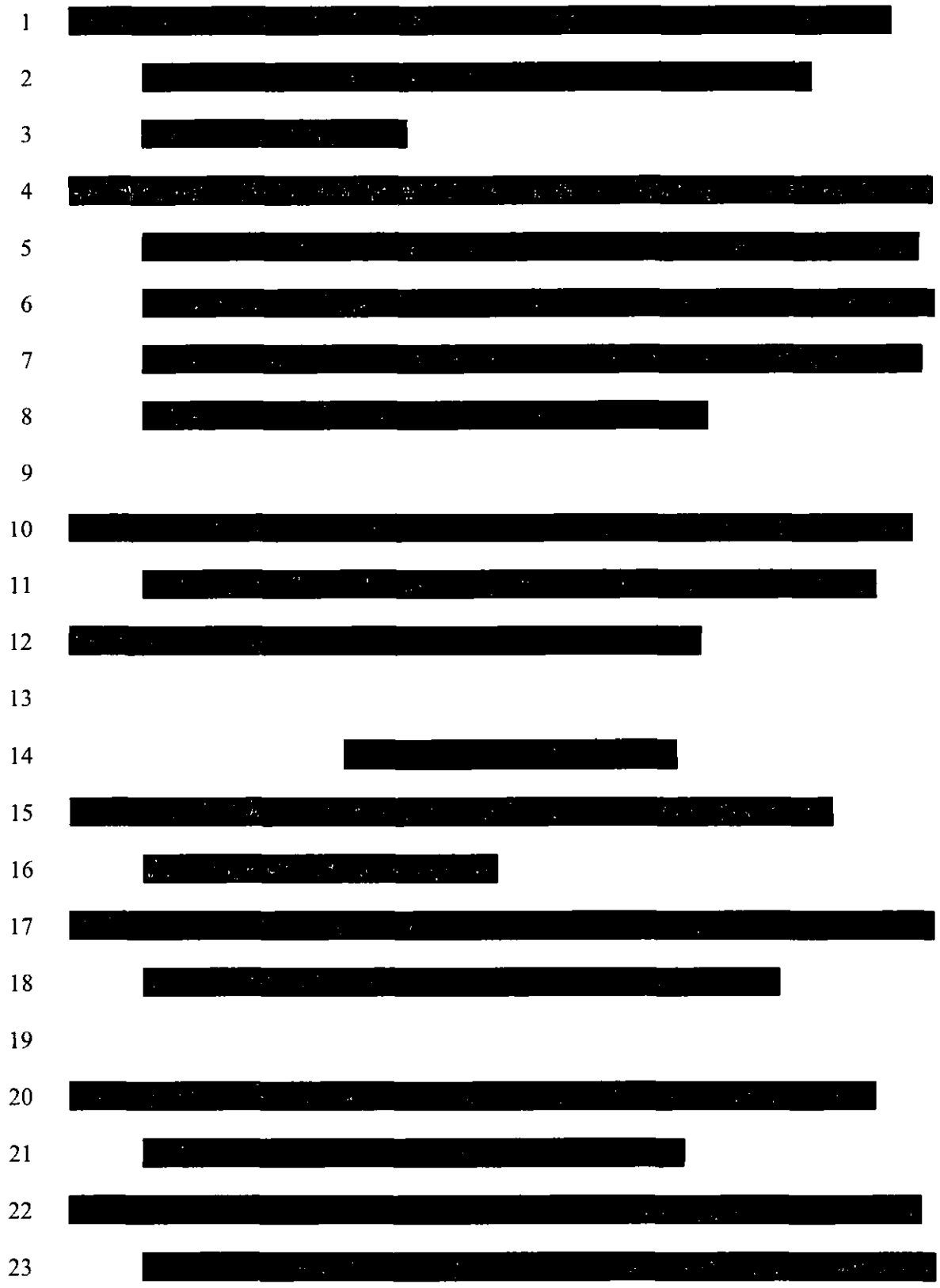

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**********END OF HIGHLY CONFIDENTIAL TESTIMONY*********

VI. Retail Market Issues

Q. BEGINNING AT PAGE 21 OF HIS TESTIMONY, MR. CRIST DISCUSSES THE RETAIL NATURAL GAS MARKET STATING AT PAGE 22, LINES 20 THROUGH 22 THAT EQUITABLE'S CONTRACT SERVICE RATES AND AGENCY PROGRAM ARE NOT APPROPRIATE. IS EQUITABLE PROPOSING TO TERMINATE ITS CONTRACT SERVICE RATES?

A. Yes. Equitable's Contract Service Rates are its Rate CSF – Contract Service Firm and Rate CSI – Contract Service Interruptible. Supplement No. 60 proposes that Rate CSF and CSI be removed from Equitable's Tariff. Equitable presently serves no customers under either Rate CSF or Rate CSI. In point of fact, Equitable has not had Rate CSF or Rate CSI customers for many years. Equitable, of course, has the tariff authority to negotiate rates under tariff language that it is retaining in its tariff.

Q. IS EQUITABLE PROPOSING TO MODIFY ITS AGENCY SERVICE PROGRAM?

A. Yes, it is. Equitable's agency service is described at Rule 11.7 of the Company's tariff rules and regulations. Rule 11.7 provides as follows:

> 11.7 Company Agency
> If requested by the customer, and agreed to by the Company, the Company will act as agent for the customer in securing storage services and transportation capacity on transmission pipelines to transport customer's gas to the pipeline delivery points on the Company's system. This service shall be administered by the Company subject to the same terms, conditions and rates placed upon other pool operators operating under Equitable's tariff. The Company shall not be responsible for storage and transportation charges incurred on behalf of the customer, nor for the performance, non-performance or continued availability of any pipeline

transportation service. The charges for this service shall be determined by negotiation between the Company and the customer.

As explained in the tariff, agency is a transportation service. It is provided to customers for several reasons, not the least of which is to preserve the Company's ability to retain customers who might be seeking to move their delivery service to a competing NGDC. Agency service has been available almost twenty years. Equitable did not propose any changes to its agency service Program tariff language as part of Supplement No. 60. Equitable, however, is planning to modify the use of its program as of December 31, 2008.

Q. DO SUPPLIERS OTHER THAN EQUITABLE ENERGY PROVIDE THE GAS FOR THE AGENCY SERVICE PROGRAM?

A. Not at this time, although they have in the past.

Q. WOULD YOU DISCUSS HOW EQUITABLE INTENDS TO HANDE ITS AGENCY PROGRAM IN THE FUTURE?

A: Yes. Equitable currently offers an agency program that has been part of Equitable's mix of service offerings for well over twenty years, most recently being reapproved by the Commission in Equitable's 1997 base rate case despite marketer opposition. In the 2006 acquisition proceedings wherein Equitable Resources was seeking to acquire Dominion Peoples and Dominion Hope, the provision of agency service was a contentious

issue. Ultimately, that issue was resolved by a settlement between Equitable and Hess that was approved by the Commission on April 13, 2007. I have attached a copy of the settlement as Attachment JMQ-11. This settlement would have, except in limited instances, removed Equitable from offering agency service by transferring the existing agency customers to our affiliated marketing entity. Eventually, in January, 2008 Equitable Resources and Dominion Resources became frustrated with the delay in receiving Federal approvals and mutually agreed to terminate the acquisition. At the time, Equitable filed this base rate case it was unsure whether it desired to continue to provide agency service in the future or would simply allow agency service to wind down.

Q: WHAT DO YOU MEAN BY THE TERM "WIND DOWN"

A: By that term, I mean that Equitable was considering simply allowing existing contracts to expire at the end of their term without agreeing to further extensions.

Q: HAS EQUITABLE BEEN AN ACTIVE AGENCY PROVIDER?

A: Equitable has not been aggressively utilizing its agency service for some time. In fact, Equitable has added only one new agency account since November, 2006, and the customer was only added to eliminate the risk of bypass to another NGDC. Our standard agency agreement does provide for rolling the contract over, usually on an annual basis, by the

Company providing the customer with a re-determined rate some 60 days prior to the end of the agreement. If the Company and customer can not agree on a new re-determined rate at least 45 days prior to expiration of the contract, then the re-determined rate is set by the Company based on market prices. As a rule, prior to making the re-determined rate offer, Equitable has contacted the customer to see what their gas supply needs are and to determine the price the customer would want to extend the agreement.

Q: HAS EQUITABLE CONTNUED TO EXTEND ITS AGENCY CUSTOMER CONTRACTS?

A: We have. There is significant customer demand for this service. However, Equitable is no longer interested in remaining as the agent to procure gas supplies for its customers. Initially, we believed that if we were to follow the procedure already agreed to with Hess in the acquisition case that it would be acceptable to all parties and particularly with Hess.

Q: WHEN DID YOU BECOME AWARE THAT HESS WAS NO LONGER INTERESTED IN SUCH AN AGREEMENT?

A: During the discovery phase of this proceeding it became apparent that Hess no longer liked the terms of the deal that the Commission had tentatively approved in 2007. Accordingly, Equitable began to reassess how it would handle the wind down of agency.

Q: HOW IS EQUITABLE PLANNING TO WIND DOWN THE AGENCY SERVICE?

A: Equitable plans to ask the Commission to address Judge Corbett's recently issued Interim Order or ask Judge Corbett to clarify the Order. Obviously, Hess has objected to any transfer of these agency customers to Equitable's marketing affiliate. Nevertheless, that marketing affiliate is the gas supplier for these customers and has procured both a gas supply and if necessary, arranged for any hedges or other financial instruments associated with that supply. Our customers have expressed to us that they are very concerned that if agency ends they could lose the benefit of the gas supply arrangements already in place. Our first concern is ensuring that customers get the benefit of the bargains they have struck. Therefore, our proposal would be to continue to renew contracts that expire between now and the end of January, 2009. Contracts falling within the period would be renewed for no longer than twelve (12) months. In the mean time, and consistent with the terms of our agency agreements, we would notify all customers with contracts set to be renewed on or after February 1, 2009 that Equitable has decided not to offer agency service, except in limited circumstances, and that their agency service agreement will expire a the end of its then current term. Customer will be advised that they can return to tariff service or they can contact any of the gas marketers listed on Equitable's web-site. We will also provide, with that letter, a list of the

marketers currently active on the Equitable system. This notice will be prepared with marketers and the Commission's Bureau of Fixed Utility Services input and we would propose to send it to all agency customers by December 1, 2008, to advise them of changes coming with agency service.

Q: WHAT HAPPENS TO THE AGENCY PROGRAM AFTER THE NOTICE IS SENT?

A: Agency service would continue consistent with the contracts entered into with the agency customers. For example, a customer who accepted a re-determined rate contract on June 1, 2008 for a one-year period will continue to have agency service from Equitable until June 30, 2009. Prior to the expiration of the agency contract, other customers will be again advised in a letter similar to the one previously sent of the need to find a gas marketer or return to tariff sales service. In other words, each month a number of contracts will end as Equitable will not offer a re-determined rate or, in the absence of agreement, establish a market price. Equitable's agency contracts expire at different time throughout the year, and a number of the customers have elected a 24 month red-determined price. Therefore, the vast majority of the agency customer will be gone from agency by the end of either 2009 or 2010. There are a few longer term agreements that Equitable will continue to honor until they expire on their own terms.

Q. IS EQUITABLE PROPOSING TO REMOVE THE PROVISION FROM ITS TARIFF?

A. No. As stated previously, Equitable will agree to not act as an agent on behalf of customers to secure supply services, pursuant to Section 11.7 except in the limited circumstance of a customer attempting to bypass or otherwise leave the Equitable distribution system.

Q. MR. CRIST CLAIMS THAT EQUITABLE REALIZES $9,146,179 OF MARGIN FROM THE AGENCY SERVICE PROGRAM. HAS MR. CRIST CORRECTLY ANALYZED THIS MARGIN?

A. No, he has not. Mr. Crist claims that the margin Equitable realizes from operation of the Agency Program is $9,146,179, suggesting that Equitable is at risk for the margin and would lose it if Hess or another supplier aside from Equitable Energy would provide the gas for the Agency Program. Mr. Crist completely misunderstands what this amount represents. Equitable does not make profit from the provision of agency service. The $9,146,179 is the revenue received by Equitable for providing the delivery service associated with the Agency Program, which is often referred to as non-gas margin and only a portion of which would represent return. Equitable would continue to receive this delivery service revenue regardless of who supplies the gas – whether the supplier is an Equitable affiliate, Hess or another natural gas supplier. Equitable would lose the revenue ***if and only if*** the customer were to leave the Equitable system for

the system of another local distribution company, and Hess has stated and argued vigorously that it has never, does not now, and does not intend to engage in or facilitate *gas on gas* competition.

VII. Revenue Allocation

Q: HAS MR. FEINGOLD PREPARED AND SUBMITTED REVISIONS TO HIS PREVIOUSLY FILED CLASS COST OF SERVICE STUDIES?

A: Yes. Mr. Feingold's rebuttal testimony discusses his findings and recommendations. I have relied upon Mr. Feingold's studies to provide a perspective as to the rate of return earned by the Company for each customer class. A summary of the results of the class cost of service studies at current rates under Mr. Feingold's two allocation bases is as follows:

	Comparison of Cost of Service Study Results Class Rates of Return on Rate Base (at Current Rates)	
Customer Class	**Design Day**	**Peak & Average**
RS	2.42%	3.19%
GSS	12.51%	11.83%
GSL	8.81%	5.09%
AGS	(2.15%)	(2.15%)
Total Company	3.80%	3.80%

Q: HAVE THE RESULTS OF MR. FEINGOLD'S REVISED STUDIES SUBSTANTIALLY MODIFIED THE OBSERVATIONS YOU SUMMARIZED ON PAGE 11 OF YOUR DIRECT TESTIMONY?

A: No. Under either the Design Day or Peak & Average cost of service study methodologies the RS and AGS customer classes produce class rates of return below the system average while the GSS and GSL customer classes produce class rates of return in excess of the system average.

Q: BASED ON MR. FEINGOLD'S REVISED STUDIES AS WELL AS YOUR PREVIOUS DISCUSSION RELATED TO THE YOUR PROPOSED REVENUE ALLOCATION CONTAINED IN YOUR DIRECT TESTIMONY, ARE YOU PROPOSING ANY CHANGES TO YOUR RECOMMENDED REVENUE ALLOCATION?

A: No I am not.

Q: HAS YOUR PROPOSED ALLOCATION OF THE REVENUE INCREASE BEEN ACCEPTED BY OTHER PARTIES IN THIS PROCEEDING?

A: No. The OCA, OTS, OSBA, and IOGA all have submitted alternative revenue allocation proposals.

Q: CAN YOU PLEASE SUMMARIZE THE ALTERNATIVE REVENUE ALLOCATION PROPOSALS?

A: I have summarized the OCA, OTS and IOGA alternative proposals in Attachment JMQ-12. I will address the OSBA's proposal later in my rebuttal testimony.

Q: DO YOU HAVE ANY COMMENT ON THE OCA'S PROPOSED REVENUE ALLOCATION?

A: Yes. Mr. Watkins has agreed with the Company's proposal to allocate 100% of the proposed revenue increase related to universal service costs to the residential class, and also agreed to set the AGS customer class to full cost of service rates. Next, Mr. Watkins proposes to allocate 50% of the remaining system average increase or $1.320 million to the GSS class. This was done in recognition that under current rates the GSS class produces a higher than system average rate of return. Mr. Watkin's then opines that since the GSL class is below the system average rate of return under his preferred allocation study basis, the GSL class should be assessed a higher than system average increase, or 110% of the system average resulting in a recommended increase of $5.865 million. Mr. Watkins recommends allocating the remaining $20.378 million to the RS class.

Mr. Watkin's proposal as compared to the Company shifts $2.8 million in annual revenue responsibility from the RS class to the GSL class. I disagree. Mr. Watkin's basis for his revenue allocation proposal is his reliance on his cost allocation study which suggests that the GSL class is earning below the system average rate of return. Mr. Feingold disagrees, and addresses Mr. Watkin's cost allocation study in his rebuttal testimony.

Q: HAS MR. WATKIN'S PROPOSED A SCALE BACK METHOD IN CASE THE COMMISSION DOES NOT APPROVE 100% OF EQUITABLE'S FILED FOR REVENUE INCREASE?

A: Yes. Mr. Watkin's proposes that any reduction in universal service costs should be reflected in Rider D. He recommends that the AGS class revenue allocation should be maintained at full cost of service rates, and the remaining classes be reduced proportionally downward. With the exception of the revenue allocation to the GSL class, Equitable does not oppose this proposal.

Q: DO YOU HAVE ANY COMMENT ON THE OSBA'S PROPOSED REVENUE ALLOCATION?

A: Yes. Mr. Kalcic's proposed revenue allocation is based upon his reliance on his proposed cost allocation methodology. Mr. Feingold's rebuttal testimony discusses his disagreement with Mr. Kalcic's cost allocation methodology, and thus, I cannot support Mr. Kalcic's premise related to his calculated revenue subsidies, nor his proposed revenue allocation.

Q DO YOU HAVE ANY COMMENT ON THE OTS PROPOSED REVENUE ALLOCATION?

A: Yes. It appears that Mr. Gruber does not oppose Equitable's proposed revenue allocation to the RS and AGS class. However, he

proposes no revenue increase to the GSS class and a $4.382 million increase to the GSL class. I disagree. I do not think it is reasonable to exempt the GSS class from any revenue increase

Mr. Gruber has recommended a scale back method. Mr. Gruber recommends that the first $3.011 million should first reduce the RS class revenue allocation with proportional reductions thereafter to all classes. I disagree. Unless there are approved reductions to Rider D, each class should proportionally share in revenue reductions except for the AGS class.

Q DO YOU HAVE ANY COMMENT ON THE IOGA PROPOSED REVENUE ALLOCATION?

A: Yes. My only comments are that for the various reasons detailed in the rebuttal testimony of various Equitable witnesses, I have relied upon Mr. Feingold's analysis and reject IOGA's revenue allocation proposals.

VIII. Rate Design

Q; HAVE ANY INTERVENORS PROPOSED ALTERNATIVES TO YOUR RATE DESIGN RECOMMENDATIONS?

A: Yes. Both the OCA and OTS have submitted testimony which opposes Mr. Feingold's proposed average monthly customer cost studies. Mr. Feingold has submitted rebuttal testimony supporting his cost studies while discussing errors and inconsistencies contained in the OTS and OCA

analysis. I stand by the rate design recommendations presented in my direct testimony.

IX. Rider C Surcharge

Q: THE OCA DISAGREES WITH YOUR PROPOSAL TO CREATE A SURCHARGE TO RECOVER COSTS ASSOCIATED WITH A NEGOTIATED RETAINAGE RATE. DO YOU HAVE ANY COMMENT?

A: Yes. The retainage discount is essentially a gas cost. Therefore, the value of the discount will change with gas supply cost changes. Given the variability of the actual cost of the discount it makes little sense to attempt to quantify the cost based on some estimate in 2008 and include the cost in base rates. Due to the variability of costs, this particular item best lends itself to process whereby actual costs incurred over a calendar year are determined and reconciled or compared to actual recoveries.

X. Other Matters

Q: MS. BURGRAFF BELIEVES THAT PRODUCERS OUTSIDE OF THE CROOKED CREEK AREA CHARGED RATE AGS SHOULD BE GIVEN REFUNDS. DO YOU AGREE?

A: I do not. Mr. Rafferty has discussed the benefits provided to all producers and the fact that the Rate AGS tariff was initially applicable to the entire Apollo district and later both the Apollo and Equitable districts. He has also mentioned that producers willingly signed agreements to pay these

charges and only later tried t use IOGA to overturn these fees after receiving the full benefit of gathering service. As Mr. Rafferty shows all facilities in the Apollo district, whether gathering field lines, compression or lower pressure transmission lines are absolutely necessary to provide this gathering service. Equitable acted prudently in obtaining producer commitments to fund the gathering system projects and to increase their ability to market more production and charges assessed for the use of these facilities are appropriate and should not be refunded.

Q: WAS THERE A RATE MORATORIUM IN EFFECT THAT WOULD LIMIT THE USE OF RATE AGS?

A: There was a base rate moratorium in effect for a period ending with January 1, 2006. It prohibited the filing of a new distribution base rate case. There was nothing in effect that would limit the ability of Equitable to collect gathering rate unrelated to distribution service, not was there any discussion of a gathering rate moratorium at any time in the negotiating process. As I participated in the negotiations, I can unequivocally state that Ms. Burgraff is wrong if she believes that Equitable would have agreed to a small increase in CAP funding at the expense of even higher revenues received from gathering services.

A: Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

Attachment JMQ-4

Equitable Gas Company
Number of CAP Customers Receiving Bills
Docket No. R-2008-229325

Line No.		2007 Actual (1)	2007 Actual CAP Payments(1)
1	Jan-08	14,383	$ 966,705
2	Feb	14,798	1,226,890
3	Mar	15,575	1,270,209
4	Apr	15,757	1,275,988
5	May	15,720	1,210,965
6	Jun	15,482	1,105,084
7	Jul	15,280	1,053,192
8	Aug	15,222	1,072,293
9	Sep	15,044	1,049,800
10	Oct	15,264	1,051,719
11	Nov	15,899	1,083,546
12	Dec	16,492	1,052,473
13	# of CAP Customers Receiving a CAP Bill	**184,916**	$ 13,418,863
14	Ave. # of CAP Customers	**15,410**	
15	2007 Growth Rate: (Line 12-Line 8)/Line 8	**14.7%**	

Source: (1) OCA-V-1, and OCA-V-12

Attachment JMQ-5

Equitable Gas Company
Number of CAP Customers Receiving Bills
Docket No. R-2008-229325

Line No.		9x12 2008 CAP Participation
1	Jan-08	17,194
2	Mar-08	17,966
3	Apr-08	18,516
4	Apr-08	18,673
5	May-08	18,783
6	Jun-08	18,729
7	Jul-08	18,805
8	Aug-08	19,241
9	Sep-08	19,349
10	October-08	19,547
11	November-08	20,008
12	December-08	20,335
13	# of CAP Customers Receiving a CAP Bill	227,145

Source: Lines 1-9: 10-13-08 email from S. Gagorik
Lines 10-12: J. Mitchell growth projections

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-6

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held September 27, 2007

Commissioners Present:

Wendell F. Holland, Chairman
James H. Cawley, Vice Chairman
Tyrone J. Christy
Kim Pizzingrilli

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	P-00062240
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa. Code §62.4	:	M-00061959

ORDER

BY THE COMMISSION:

We adopt as our action the Recommended Decision of Administrative Law Judge Mark A. Hoyer dated August 15, 2007;

THEREFORE,

IT IS ORDERED:

1. That the Joint Settlement Agreement that Equitable Gas Company, the Office of Trial Staff, the Office of Consumer Advocate, the Office of Small Business Advocate and Allegheny County ACORN/Mon Valley Unemployed Committee have submitted at Docket No. P-00062240 and Docket No. M-00061959 is hereby approved.

2. That Equitable Gas Company shall file a tariff supplement consistent with the Joint Settlement Agreement to become effective on one day's notice to the Commission, for service rendered on or after the entry date of the Commission's Final Order.

3. That Equitable Gas Company, the Office of Trial Staff, the Office of Consumer Advocate, the Office of Small Business Advocate and Allegheny County ACORN/Mon Valley Unemployed Committee shall comply with the terms and conditions of the Joint Settlement Agreement as though each term and condition stated therein had been the subject of an individual ordering paragraph.

4. That upon acceptance and approval by the Commission of the tariff supplement as being consistent with this Order and the Joint Settlement Agreement, the proceedings at Docket Nos. P-00062240 and M-00061959 shall be terminated and the dockets marked closed.

BY THE COMMISSION

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: September 27, 2007

ORDER ENTERED: SEP 27 2007

THOMAS, THOMAS,
ARMSTRONG & NIESEN
Attorneys and Counsellors at Law

THOMAS T. NIESEN
Direct Dial: 717.255.7641
tniesen@ttanlaw.com

July 13, 2007

James J. McNulty
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
P. O. Box 3265
Harrisburg, PA 17105-3265

In re: Docket Nos. P-00062240 and M-00061959
Equitable Gas Company

Dear Secretary McNulty:

Enclosed for filing in the above matter are an original and three (3) copies of the Joint Settlement Agreement of the Office of Trial Staff, Office of Consumer Advocate, Office of Small Business Advocate, Allegheny County ACORN/Mon Valley Unemployed Committee and the Equitable Gas Company Division of Equitable Resources, Inc. (the "Settling Parties"). The Joint Settlement Agreement resolves all contested issues in the matter. The Settling Parties represent all of the active parties to the proceeding with the exception of the Peoples/Equitable Merger Intervenors which do not oppose the Joint Settlement Agreement. Appended to the Joint Settlement Agreement are Statements by the OTS, OCA, OSBA and Equitable in support of the settlement. Copies of the Joint Settlement Agreement are being served upon Judge Hoyer and upon the persons and in the manner set forth on the Certificate of Service attached thereto.

Please note that the Settling Parties, in Section G of the Joint Settlement Agreement, respectfully request that the Public Utility Commission act as expeditiously as reasonably possible in this matter so that the settlement supplement and other settlement terms and conditions become effective as soon as possible, preferably by October 1, 2007. In its Statement in Support, Equitable Gas Company explains that Commission action on this matter by October 1, 2007, before the 2007-2008 winter heating season, will benefit CAP participants through open and continuing CAP enrollment and suspension of CAP customer deposits while allowing the Company to begin to recover the cost of these CAP program commitments. To facilitate expeditious review and final Commission approval by October 1, 2007, Equitable has attached a proposed Recommended Decision to its Statement in Support.

Very truly yours,

THOMAS, THOMAS, ARMSTRONG & NIESEN

By

Thomas T. Niesen

cc: Certificate of Service
Honorable Mark A. Hoyer (w/encl.)
Daniel L. Frutchey, Esq. (w/encl.)
070713-McNulty (Settlement).wpd

Before The
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Administrative Law Judge
Mark A. Hoyer, Presiding

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	Docket No. P-00062240
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa.Code §62.4	:	Docket No. M-00061959

JOINT SETTLEMENT AGREEMENT

The Office of Trial Staff ("OTS") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), Allegheny County ACORN/Mon Valley Unemployed Committee ("ACORN/MVUC"), the Office of Small Business Advocate ("OSBA") and the Equitable Gas Company Division ("Equitable" or "Company") of Equitable Resources, Inc., parties to the above-captioned consolidated proceedings (hereinafter sometimes referred to collectively as "Settling Parties"), respectfully present this Joint Settlement Agreement for consideration and approval by Administrative Law Judge Mark A. Hoyer and, upon his recommendation, by the Commission.

I. The Company

The Company is the regulated utility division of Equitable Resources, Inc. Equitable is engaged in the purchase, distribution, sale and transportation of natural gas and serves over 257,000 residential, commercial and industrial customers in the City of Pittsburgh and adjacent territories in Allegheny, Armstrong, Butler, Clarion, Fayette, Greene, Indiana, Jefferson, Washington and Westmoreland Counties in Southwestern Pennsylvania.

II. Universal Service and Energy Conservation Plan 2007-2009

On May 31, 2006, Equitable submitted its Universal Service and Energy Conservation Plan 2007-2009 ("Plan 2007-2009") to the Commission pursuant to 52 Pa. Code §62.4. Plan 2007-2009 proposed several modifications to Equitable's existing Universal Service programs.

In a Tentative Order entered August 22, 2006, at Docket No. M-00061959, the Commission approved Plan 2007-2009 with certain modifications and provided interested parties the opportunity to submit comments on the proposed revisions discussed in the Tentative Order.

Comments to the Tentative Order were filed by Equitable, Pennsylvania Utility Law Project ("PULP"), the Pittsburgh American Indian Center, Mary E. Flagg and Dave Price. PULP and Equitable filed reply comments.

By Final Order entered December 26, 2006, the Commission noted that the comments and reply comments raised factual issues regarding the design and operation of Plan 2007-2009 consistent with Section 1501 and Chapters 14 and 22 of the Public Utility Code and that the matter would be referred to the Office of Administrative Law Judge for hearing. Concluding that the issues involved in Plan 2007-2009 are intertwined with the issues in the Petition filed by Equitable and docketed

at P-00062240, the Commission consolidated the proceedings at M-00061959 and P-00062240.

III. Equitable's Petition Re CAP Funding

On October 6, 2006, Equitable filed a petition to adjust its Rider D –Universal Service and Energy Conservation Rider ("USECR Rider" or "Rider D") to fund Universal Service and Energy Conservation Programs on an ongoing basis. The Company's proposed USECR Rider of $0.72 per Mcf represented an increase of $0.42 per Mcf to the existing rate of $0.30 per Mcf. The proposed Rider also would have established a quarterly adjustment filing and an annual reconciliation feature for reconciling actual CAP costs and actual CAP recoveries.[1]

The petition was docketed at P-00062240 and answers to the petition were filed by the OTS, the OCA and the OSBA. A petition to intervene was filed by the Peoples/Equitable Merger Intervenors ("PEMI"), an ad hoc group presently consisting of eight commercial and industrial customers of Equitable and The Peoples Natural Gas Company, d/b/a Dominion Peoples.

By Order entered December 26, 2006, the Commission concluded that the petition and responsive pleadings revealed contested issues of fact and that the matter would be referred to the Office of Administrative Law Judge for hearing. Concluding that the issues involved in the petition are intertwined with the issues in the proceeding concerning Plan 2007-2009 at M-00061959, the Commission consolidated the proceedings at P-00062240 and M-00061959.

---

[1] CAP refers to Equitable's Customer Assistance Program. The program is presently known as the Energy Assistance Program or "EAP." The name change to CAP, which would be consistent with the Commission's Policy Statement on Customer Assistance Programs and reduce confusion with the Low Income Home Energy Assistance Program, has been postponed due to programming and time constraints associated with Equitable Resources' pending acquisition of Dominion Peoples and Dominion Hope.

IV. The Consolidated Proceedings at P-00062240 and M-00061959

The Commission assigned the consolidated proceedings to Administrative Law Judge Mark A. Hoyer. An initial prehearing conference was held on February 16, 2007, at which a schedule of various hearing, testimony submission, briefing and other dates was agreed to by the parties and later memorialized in a Revised Prehearing Order dated February 23, 2007. On February 23, 2007, ACORN/MVUC filed a petition to intervene in the consolidated proceedings.

In accordance with the procedural schedule, Equitable served direct testimony on March 16, 2007. OTS, OCA and ACORN/MVUC served direct testimony on April 27, 2007. Equitable and ACORN/MVUC served rebuttal testimony on May 16, 2007, and OTS, OCA, ACORN/MVUC and Equitable served surrebuttal testimony on May 30, 2007. The OTS, OCA and ACORN/MVUC, in addition, propounded a substantial number of interrogatories, which were answered by Equitable.

Following the circulation of testimony and the completion of discovery, the Settling Parties were able to achieve a proposed resolution of all issues addressed in the testimony of their respective witnesses. As a consequence, a large portion of the remainder of the litigation schedule was cancelled including the first evidentiary hearing scheduled for June 14, 2007.

V. Terms and Conditions of Settlement

Settling Parties agree that these proceedings can be settled without further litigation. The Terms and Conditions set forth in the following paragraphs of this Joint Settlement Agreement present a comprehensive resolution of all issues.

Effective Period of Settlement Terms and Conditions

This Joint Settlement Agreement and the Terms and Conditions of Settlement contained herein will be effective for the period commencing with the entry of a

final Commission order approving this Joint Settlement Agreement and continue in effect until the effective date of rates approved by the Commission in Equitable's next base rate case.

Modification of Proposed Rider D

Equitable will modify Rider D to eliminate the annual reconciliation of CAP revenues and expenses and establish a fixed Rider D rate of $0.58/Mcf. Equitable will be at risk to manage its CAP with a fixed Rider D rate of $0.58/Mcf (inclusive of the currently effective $0.30/Mcf Rider D rate) during the effective period of these Settlement Terms and Conditions. The form of the tariff supplement to implement the settlement modifications to proposed Rider D is attached hereto as Attachment A. Equitable may file the settlement tariff supplement to become effective on one day's notice for service rendered on and after the entry date of the Commission's approval of the Joint Settlement Agreement.

CAP Consumption

Equitable will monitor CAP participants' consumption to ensure that the participant is maintaining annual usage at or below 110 percent of historical average usage, adjusted for weather. To accomplish this objective, the Company will institute the following procedures:

1. During the CAP enrollment process, Equitable will advise the CAP customer of the importance of energy conservation, explain that usage will be reviewed on an ongoing basis and that unjustified excess usage may be billed to the CAP customer. Educational material in the form of conservation tips and a plain language statement of the rules included in the "CAP Consumption" section of this Joint Settlement Agreement will be provided in the CAP brochure and sent to all CAP customers.

2. High usage CAP customers will be referred to the Company's Low Income Usage Reduction Program (LIURP) and receive the

highest priority for weatherization or other energy conservation help. High usage is defined as annual normalized usage in excess of 200 Mcf.

3. Equitable will review and compare the most recent annual usage of CAP participants, adjusted for weather, with historical normalized usage for these customers.

   a. When usage exceeds 110 percent of historical average usage, adjusted for weather, Equitable will contact the customer to discuss energy conservation techniques. The customer will be advised that, if consumption is not reduced by the next review, the customer may be removed from CAP unless one of the conditions under (b) exists.

   b. CAP participants will be exempted from (a) above if the participant meets one or more of the exceptions identified in the CAP Policy Statement which presently are as follows:

      i. The household experienced the addition of a family member.

      ii. A member of the household experienced a serious illness.

      iii. Energy consumption was beyond the household's ability to control.

      iv. The household is located in housing that is or has been condemned or has housing code violations that negatively affect energy consumption.

      v. Energy consumption estimates have been based on consumption of a previous occupant.

   c. Customers removed from CAP under (a) above will need to reduce consumption to historical usage levels, adjusted for weather, or pay the amount of the excess usage to be reinstated in CAP. High usage customers under 2 above must agree to receive weatherization services for reinstatement in CAP.

   d. Customers removed from CAP for these reasons will be sent a removal letter including information describing the steps required for CAP reinstatement.

CAP Customer Deposits

Equitable will suspend the right to request customer deposits from CAP customers and, in the case of applicants for CAP, will provisionally suspend the necessity for a deposit pending a decision on their application. For those not accepted for CAP participation, customer deposits will be required.

CAP Enrollment

Consistent with its Universal Service and Energy Conservation Plan 2007-2009, Equitable's CAP will offer open and continuing enrollment for eligible customers without limitation on the number of participants.

CAP Arrearage Forgiveness

Equitable will continue to offer CAP arrearage forgiveness through its funding sources already in place including the following:[2]

- Arrearage forgiveness will be provided on a monthly basis for CAP customers who remain current.
- The monthly CAP budget amount will continue to include an embedded $5 co-payment that is then matched on a 3 to 1 basis, for a $20 per month reduction in pre-program arrears until the initial program balance has been reduced to zero.
- For customers who default or become delinquent with their monthly CAP payments, arrearage forgiveness will be suspended until they make up their missed payments and the account becomes current again. At this time, the pending arrearage forgiveness credits will be applied reducing the pre-program arrears balance.

Minimum CAP Payments

Consistent with its Universal Service and Energy Conservation Plan 2007-2009, as modified by the Commission in its Tentative Order entered August 22, 2006 and as agreed upon in the Company's Reply Comments of September 21, 2006,

[2] Equitable's CAP arrearage forgiveness generally eliminates CAP pre-program arrearages in four years.

Equitable will not increase minimum CAP payments from $25 and will not request initial CAP enrollment payments.

Notice Pursuant to Dispute Procedures

Consistent with CAP Policy Guidelines, Equitable will provide notice to CAP applicants and CAP customers pursuant to the dispute procedures outlined in Chapter 56 and referred to in the CAP Policy Statement at 52 Pa. Code §69.265(5).

Preservation of Issues

All issues concerning CAP cost recovery (and related universal service issues) may be addressed in the Company's next general base rate filing and the Settling Parties are free to propose similar or alternative cost recovery mechanisms at that time.

E. Evidentiary Basis

The Settling Parties believe that the testimony and exhibits sponsored by the Company, OTS, OCA and ACORN/MVUC fully support the fairness and reasonableness of the proposed settlement and demonstrate that it is in the public interest. Accordingly, at the hearing held June 15, the Settling Parties proposed, with Administrative Law Judge Hoyer's approval, that the statements of testimony and associated exhibits of the Settling Parties, as set forth below, be admitted into the record by stipulation without the necessity of calling witnesses to the stand for the purpose of authenticating their respective statements and exhibits and being available for cross examination made unnecessary by virtue of the settlement. The parties confirm, however, as addressed at the June 15 hearing, that, to the extent that any testimony and accompanying exhibits are inconsistent with this settlement, they are deemed withdrawn. If for some reason the Commission should act to reject all or any

part of this settlement, a hearing will be held on the subject issues prior to Commission disposition:

Testimony and Exhibits Admitted by Stipulation

Party	Witness	Statements	Attachments/Exhibits/ Schedules
Equitable	Jeffery Mitchell	Equitable St. No. 1 Equitable St. No. 1-R Equitable St. No. 1-SR	Attachments A and B
Equitable	John M. Quinn	Equitable St. No. 2 Equitable St. No. 2-R	Attachments A, B and C Attachments A through H
OTS	Amanda Gordon	OTS St. No. 1 OTS St. No. 1-SR	OTS Exhibit No. 1 OTS Exhibit No. 1-SR
OCA	Roger D. Colton	OCA St. No. 1 OCA St. No. 1-S	Schedules RDC-1 through RDC-9 and Attachment A Schedules RDC-1SR through RDC-6SR
ACORN/ MVUC	John Howatt	ACORN/MVUC St. No. 1 ACORN/MVUC St. No. 2 ACORN/MVUC St. No. 3	Exhibit JH-1 Exhibit JH-2 Exhibits JH-3 and JH-4

The Settling Parties request that this Joint Settlement Agreement be designated ALJ Exhibit 1 and admitted into the record as a late-filed exhibit.

F. Settlement Perspective

The Settling Parties agree that, based upon the evidence of record in this proceeding, the resolution of the issues herein proposed is in the public interest. Although the Settling Parties may not be in total agreement with respect to the issues resolved by this Joint Settlement Agreement, they believe the proposed Settlement

provides an appropriate basis for settlement of their differences as to all issues. Statements in support of this Joint Settlement Agreement on behalf of Equitable, OTS, OCA, ACORN/MVUC and OSBA are attached hereto.[3]

This Joint Settlement Agreement is being presented only in the context of the proceedings at Dockets Nos. P-00062240 and M-00061959 in an effort to resolve outstanding issues in a manner which is fair and reasonable and in the public interest. This Joint Settlement Agreement reflects compromises on all sides and is presented without prejudice to any position any of the Settling Parties may have advanced or may advance in the future, and without prejudice to the positions initially advanced by the Settling Parties on the merits of the issues. Those positions are preserved should the Commission reject this settlement in whole or in part and in such event all parties retain the right to litigate their respective issues. Regardless of whether this Joint Settlement Agreement is approved or not, no adverse inference shall be drawn, nor shall prejudice result, to any party hereto in this or any future proceeding as a consequence of this Joint Settlement Agreement.

This Settlement is proposed by the Parties to resolve litigation of this proceeding. This Settlement is conditioned upon, and subject to, acceptance and adoption by the Commission. If this Settlement, or any part thereof, is for any reason modified in any respect by the Commission, any Party may withdraw from this Settlement in which case the Settlement shall be of no force and effect. If any Party withdraws from this Settlement, it must do so in a written document, filed with the Commission and served upon the Parties within five (5) business days after the entry of the Order modifying the proposed Settlement. If the Settlement is disapproved, or if any Party withdraws from

[3] PEMI, an intervenor in this proceeding, has authorized the Settling Parties to represent that PEMI does not oppose the Joint Settlement Agreement. PEMI will submit a letter to the Commission confirming its position regarding the Joint Settlement Agreement.

the Settlement following modification thereof by the Commission, the above-captioned proceeding will continue with litigation on the originally proposed Petition.

G. Request for Expedited Treatment

The Settling Parties respectfully request that the Commission act as expeditiously as reasonably possible in this matter so that the settlement supplement and other settlement terms and conditions become effective as soon as possible, preferably by October 1, 2007.

WHEREFORE, the Office of Trial Staff, the Office of Consumer Advocate, Allegheny County ACORN/Mon Valley Unemployed Committee, the Equitable Gas Company Division of Equitable Resources, Inc. and the Office of Small Business Advocate, by their respective attorneys, respectfully request that Administrative Law Judge Mark A. Hoyer and the Pennsylvania Public Utility Commission approve the settlement proposed in this Joint Settlement Agreement.

Respectfully submitted,

OFFICE OF TRIAL STAFF

By _____
Allison Curtin Kaster, Prosecutor
Johnnie E. Simms, Chief Prosecutor

OFFICE OF CONSUMER ADVOCATE

By _____
Christy M. Appleby
Assistant Consumer Advocate
Darryl Lawrence
Assistant Consumer Advocate
Tanya J. McCloskey
Senior Assistant Consumer Advocate

ALLEGHENY COUNTY ACORN MON VALLEY UNEMPLOYED COMMITTEE

By _____
Harry S. Geller, Esquire
John C. Gerhard, Esquire

EQUITABLE GAS COMPANY

By _____
Charles E. Thomas, Jr., Esquire
Thomas T. Niesen, Esquire
Daniel L. Frutchey, Esquire

OFFICE OF SMALL BUSINESS ADVOCATE

By _____
Lauren M. Lepkoski
Assistant Small Business Advocate

Joint Settlement Agreement (Final Executed Version).wpd

SUPPLEMENT NO.

TO

GAS - PA. P.U.C. NO. 22

EQUITABLE GAS COMPANY

A DIVISION OF EQUITABLE RESOURCES, INC.

SCHEDULE OF RATES, RULES AND REGULATIONS

FOR

GAS SERVICE IN

CITY OF PITTSBURGH

AND TERRITORY ADJACENT THERETO

(For Lists of Communities Served, see Page No. 4)

ISSUED: EFFECTIVE:

Tariff Supplement Filed to Reflect
The Joint Settlement Agreement
In Docket Nos. P-00062240 and M-00061959

Issued

By

D. L. FRUTCHEY
SENIOR VICE PRESIDENT
EQUITABLE GAS COMPANY
225 NORTH SHORE DRIVE
PITTSBURGH, PA 15212-5861

CHANGE IN RATES AND TARIFF MODIFICATION

Rider D - Universal Service and Energy Conservation, page 96

RIDER D

UNIVERSAL SERVICE AND ENERGY CONSERVATION

I. This rider provides a method of recovery of costs associated with the Company's Universal Service and Energy Conservation programs.

II. This Rider shall be applicable to Rate RS, and residential customers receiving service under rate FDS except customers enrolled in the EAP.

III. Rate: $0.580 per Mcf (I)

(I) Indicates Increase.

ISSUED: EFFECTIVE:

D. L. FRUTCHEY
SENIOR VICE PRESIDENT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	**Docket No. P-00062240**
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa.Code §62.4	:	**Docket No. M-00061959**

OFFICE OF TRIAL STAFF
STATEMENT IN SUPPORT OF
JOINT SETTLEMENT AGREEMENT

TO ADMINISTRATIVE LAW JUDGE MARK A. HOYER:

INTRODUCTION

The Office of Trial Staff ("OTS") of the Pennsylvania Public Utility Commission ("Commission"), by and through its Prosecutor, Allison C. Kaster, hereby respectfully submits that the terms and conditions of the foregoing Joint Settlement Agreement ("Settlement") are in the public interest and represent a fair and just balance of the interests of Equitable Gas Company ("Equitable" or "Company") and its customers.

SETTLEMENT

1. OTS was established under the provisions of Section 306 of the Public Utility Code, 66 Pa.C.S. § 306, in 1986 and is charged with the representation of the public

interest in proceedings relating to rates, rate-related services and application proceedings affecting the public interest held before the Commission. Consequently, in negotiated settlements, it is incumbent upon OTS to ensure that the public interest is served and to quantify to what extent amicable resolution of any such proceeding will benefit the public interest. Based upon OTS' analysis of the filing, acceptance of this proposed Settlement is in the public interest and OTS recommends that Administrative Law Judge ("ALJ") Mark Hoyer and the Commission approve the Settlement in its entirety.

2. On May 31, 2006, Equitable filed its Universal Service and Energy Conservation Plan 2007-2009 ("Plan 2007-2009"), Docket No. M-00061959. In a Tentative Order entered August 22, 2006, the Commission modified and approved Plan 2007-2009.

3. On October 6, 2006, Equitable filed a Petition to increase its customer assistance program funding and to implement an adjustable rate mechanism to recover universal service and energy conservation plan costs, Docket No. P-00062240.

4. On October 26, 2006, OTS filed an Answer to Equitable's Petition. In the Answer, OTS requested that the Commission deny the relief requested by the Company and refer the matter to the Office of Administrative Law Judge ("OALJ").

5. The Commission consolidated the two docket numbers, Docket Nos. M-00061959, P-00062240, and referred the proceeding to OALJ for the prompt scheduling of hearings to result in the issuance of a Recommended Decision. The OALJ assigned ALJ Hoyer as presiding officer of this proceeding.

6. A Prehearing Conference was held February 16, 2007, at which time a procedural schedule was developed.

7. OTS filed Direct Testimony on April 27, 2007, Revised Direct Testimony on April 30, 2007, and Surrebuttal Testimony on May 30, 2007.

8. A hearing was convened on June 15, 2007 for the purpose of entering the testimony of the Settling Parties into the record by stipulation. At the hearing, OTS entered OTS St. No. 1 (Revised Direct Testimony of Amanda Gordon and accompanying exhibit) and OTS St. No. 1-SR (Surrebuttal Testimony of Amanda Gordon and accompanying exhibit) into the evidentiary record.

9. In accordance with Commission's policy favoring settlements, 52 Pa. Code § 5.231, the parties to the instant proceeding achieved a full and complete settlement of all issues utilizing the mediation process.

10. The OTS submits that the Settlement represents a balance of the interests of the Company and its customers. Accordingly, for the reasons articulated below, OTS maintains that the proposed Settlement is in the public interest and should be approved by the ALJ and the Commission:

a. Equitable's Rider D rate will be fixed at $0.58/Mcf. This represents a $0.28 increase over the existing Rider D rate of $0.30, and a $0.14 decrease to the $0.72 rate proposed by the Company in its Petition. OTS analyzed the Company's filing and engaged in formal and informal discovery with the Company. Through these efforts, OTS maintains that the Rider D rate of $0.58/Mcf is in the public interest. The agreed upon Rider D rate allows Equitable to recover its universal service costs, but

moderates the impact of the increase to Equitable's ratepayers. Pursuant to the Settlement, the $0.58/Mcf Rider D rate will be non-reconcilable. In testimony, OTS opposed the Company's request for annual reconciliation and recommended that Rider D be adjusted prospectively on a quarterly basis. OTS asserted that annual reconciliation fails to provide an incentive to prudently incur costs or create cost effective measures if the Company is guaranteed dollar for dollar recovery. Accordingly, this term is in the public interest because the non-reconcilable Rider D enables enrolled CAP customers to obtain benefits available through the CAP program while ensuring that recovery of those costs from non-CAP customers result in just and reasonable rates.

b. The Company agreed to monitor the consumption of CAP participants by instituting multiple procedures to ensure that CAP participation usage is at or below 110% of historical average usage, adjusted for weather. The procedures include educating CAP customers of the importance of energy conservation, distributing educational materials about conservation, referring high usage CAP customers to the Low Income Usage Reduction Program, and giving high usage customers highest priority for weatherization. If the CAP customer exceeds 110% of historical average usage, adjusted for weather, Equitable will contact that customer about conservation techniques and advise that the customer may be removed from CAP if consumption is not reduced unless the customer meets one of the express exemptions outlined in the Settlement. Customers will be permitted to be reinstated in CAP by reducing consumption to historical levels or paying the amount of the excess usage and agreeing to receive weatherization services. Customers will be sent a removal letter that includes the information describing how the

customer can be reinstated in CAP. This multi-step plan is in the public interest because energy conservation and personal responsibility are a vital component of universal service programs. CAP customers must be held responsible for excessive gas usage as the burden for paying that expense falls on non-CAP customers. As discussed above, the procedures outlined in the Settlement ensure that CAP customers are given notice of this responsibility and gives CAP customers an opportunity to reduce consumption before removal from the CAP program. Accordingly, the agreed upon procedures allow CAP customers to benefit from Equitable's CAP program, while ensuring that gas consumption remains at an acceptable level.

c. The Settlement provides that Equitable will suspend deposits for CAP customers. This settlement term serves the public interest because it alleviates the financial burden imposed on low income customers for entry into the CAP program.

d. Equitable will not limit the enrollment number of CAP participants. Allowing all eligible customers to enroll in CAP is in the public interest as it ensures that eligible customers will have access to the benefits provided through Equitable's CAP program.

e. CAP arrearage forgiveness will continue through its current funding sources. Through the write-down of accumulated arrearages, arrearage forgiveness eliminates the pre-program balances of CAP customers. Accordingly, OTS maintains that arrearage forgiveness benefits CAP customers and is in the public interest.

12. Based upon OTS' analysis of the filing, acceptance of this proposed Settlement is in the public interest. Resolution of this case by settlement rather than

litigation will avoid the substantial time and effort involved in continuing to formally pursue all issues in this proceeding at the risk of accumulating excessive expense.

13. OTS further submits that the acceptance of the foregoing settlement will negate the need for an evidentiary hearing, the preparation of Main and Reply Briefs, the preparation of Exceptions and Reply Exceptions, and the filing of possible appeals.

14. The Settlement is conditioned upon the Commission's approval of all terms and conditions contained therein and should the Commission fail to grant such approval or otherwise modify the terms and conditions of the Settlement, it may be withdrawn by the Company or OTS as provided therein.

15. OTS' agreement to settle this case is made without any admission or prejudice to any position that OTS might adopt during subsequent litigation in the event that the Settlement is rejected by the Commission or otherwise properly withdrawn by any other parties to the instant proceeding.

16. If the ALJ recommends that the Commission adopt the Settlement as proposed, OTS agrees to waive the filing of Exceptions. However, OTS has not waived its right to file Reply Exceptions with respect to any modifications to the terms and conditions of the Settlement, or any additional matters, that may be proposed by the ALJ in the Recommended Decision. OTS also reserves the right to file Reply Exceptions to any Exceptions that may be filed by the Company.

WHEREFORE, the Commission's Office of Trial Staff represents that it supports the Settlement as being in the public interest and respectfully requests that Administrative Law Judge Mark A. Hoyer recommend, and the Commission subsequently approve, the foregoing Joint Settlement Agreement, including all terms and conditions contained therein.

Respectfully submitted,

Allison C. Kaster

Allison C. Kaster
Prosecutor

Pennsylvania Public Utility Commission
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Dated: July 13, 2007

OFFICE OF CONSUMER ADVOCATE
STATEMENT IN SUPPORT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	Docket No. P-00062240
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 51 Pa. Code §62.4	:	Docket No. M-00061959

STATEMENT OF THE
OFFICE OF CONSUMER ADVOCATE
IN SUPPORT OF SETTLEMENT

The Office of Consumer Advocate (OCA) finds the terms and conditions of the Joint Settlement Agreement (Settlement) to be in the public interest for the following reasons:

I. Introduction

On October 6, 2006, Equitable Gas Company (Equitable or Company) filed the above-captioned Petition. Through the Petition, Equitable sought approval of an increase to the level of funding for its Customer Assistance Program (CAP) and implementation of an adjustable funding mechanism to recover associated expenses for Universal Service and Energy Conservation Plan costs. Equitable currently has in place a Universal Service and

Energy Conservation Rider D (Rider D) which is set at 30¢/Mcf. Equitable proposed in its Petition to increase Rider D to 72¢/Mcf and to make the mechanism adjustable on a quarterly basis and reconcilable annually.

Prior to filing the Petition, Equitable submitted a Universal Service and Energy Conservation Plan 2007-2009 (Plan 2007-2009 or Plan) at Docket No. M-00061959. The Commission issued a Tentative Order, directing Equitable to modify its Plan and provided interested parties the opportunity to comment on the revisions. The Commission then consolidated the Tentative Order for the Plan 2007-2009 into the instant case on December 22, 2006.

On October 27, 2006, the OCA filed its Notice of Intervention, Notice of Appearance, and Answer to Equitable's Petition. The Office of Small Business Advocate (OSBA), Allegheny County ACORN/Mon Valley Unemployed Committee (ACORN/MVUC), and the Peoples/Equitable Merger Intervenors (PEMI) also intervened in the case. The Office of Trial Staff (OTS) filed its Notice of Appearance. The matter was assigned to the Office of Administrative Law Judge and was further assigned to Administrative Law Judge Mark A. Hoyer for investigation and scheduling of hearings to determine whether the Commission's Tentative Order on the Plan 2007-2009 should be made final and whether Equitable's proposed modifications to its Rider D should be adopted.

An initial prehearing conference was held on February 16, 2007 in order to develop a procedural schedule. Equitable submitted Direct Testimony on March 16, 2007. The OCA, OTS, and ACORN/MVUC submitted Direct Testimony on April 27, 2007. Equitable and ACORN/MVUC served Rebuttal Testimony on May 16, 2007. On May 30, 2007,

Equitable, OCA, OTS and ACORN/MVUC submitted Surrebuttal Testimony. Settlement meetings were held, and as a result, those negotiations led to the instant Settlement. A hearing was held on June 15, 2007, for the purpose of submitting the stipulated testimony into the record. The remainder of the evidentiary hearings were cancelled.

For the reasons set forth below, the OCA submits that the proposed Settlement is in the public interest.

II. Discussion

The proposed Settlement provides that Equitable will modify Rider D to eliminate the annual reconciliation of CAP revenues and expenses and establish a fixed Rider D rate of 58¢/Mcf, inclusive of the currently effective 30¢/Mcf Rider D rate. The Company had originally proposed a 72¢/Mcf reconcilable surcharge, a 42¢/Mcf increase. The OCA submits that the fixed 58¢/Mcf Rider D, or a 28¢/Mcf increase, is reasonable in the instant case. By utilizing the fixed 58¢/Mcf charge until the Company's next base rate proceeding, the Company will retain the incentive to manage the costs of the programs and maximize the savings and benefits from the programs.

Equitable will also continue to offer open and continuing enrollment for eligible customers without limitation on the number of participants, under its fixed Rider. Under the terms of the Settlement all eligible customers will continue to be enrolled in the program. This will ensure that the program remains available as required under the Natural Gas Choice Act. 66 Pa.C.S. § 2203(7), (8).

Equitable has also agreed to implement a program to monitor CAP participants' consumption to ensure that the participant is maintaining annual usage at or below 110 percent of historical average usage, adjusted for weather. The Settlement provides that

Equitable will provide a multi-step plan regarding CAP consumption that will balance the interests of high-usage CAP customers with the interests of the ratepayers paying the Rider D surcharge. Equitable will provide the following in order to address this issue: (1) conservation education materials to CAP customers in advance of their enrollment; (2) referrals for high usage CAP customers to the Low Income Usage Reduction Program (LIURP); (3) continued monitoring and review of the CAP customer's most recent annual usage, adjusted for weather, with their historical normalized usage; (4) contact to CAP customers who have higher usage to discuss conservation techniques; (5) notice to CAP customers with high usage that they may be billed at the higher rate for this usage; (6) application of exemptions from the requirement to pay for higher than average usage for those customers exempted under the CAP Policy Statement; (7) notification by letter of removal from the program if removal becomes necessary, and (8) reinstatement process for those customers removed from CAP due to high usage. The OCA submits that monitoring high usage customers, and providing those customers with the ability to reduce any excess usage, will assist the customer in affording service and will help to control the costs of the program.

The Settlement also proposes several additional modifications to Equitable's 2007-2009 Plan. Equitable will suspend the practice of requesting customer deposits from CAP customers, and for CAP applicants, Equitable will provisionally suspend the requirement of a customer deposit until a final decision is reached on the CAP application. Equitable will not increase the minimum CAP payments of $25 and will not request initial CAP enrollment payments. The OCA supports these proposals as beneficial to CAP customers. These

proposals make access to essential utility service more affordable and will allow CAP customers to more easily enroll in the program and to maintain service.

Equitable will also continue to offer CAP arrearage forgiveness through its current funding sources. The Settlement maintains the current process for arrearage forgiveness, which provides for arrearage forgiveness on a monthly basis to reward CAP customers for their on-time payments. With an on-time CAP payment, including a $5 arrearage co-payment, Equitable will match on a 3 to 1 basis the arrearage portion of the payment through its existing funding mechanism. These provisions ensure that Equitable's CAP customers continue to make progress towards retiring their arrears without further increasing costs to other customers.

The OCA submits that the proposed modifications to Rider D and the 2007-2009 Plan will benefit both CAP customers and other ratepayers. The OCA submits, therefore, that these modifications should be adopted and are in the public interest.

III. Conclusion

WHEREFORE, for the foregoing reasons, the Office of Consumer Advocate submits that the proposed Settlement is in the public interest and in the best interest of Equitable Gas ratepayers.

Respectfully submitted,

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Date: **July 12, 2007**

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ALLEGHENY COUNTY ACORN
MON VALLEY UNEMPLOYED COMMITTEE
STATEMENT IN SUPPORT

Before The
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Administrative Law Judge
Mark A. Hoyer, Presiding

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	**Docket No. P-00062240**
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa. Code §62.4	:	**Docket No. M-00061959**

STATEMENT OF MON VALLEY UNEMPLOYED COMMITTEE AND ALLEGHENY ACORN IN SUPPORT OF THE JOINT SETTLEMENT AGREEMENT

Mon Valley Unemployed Committee ("MVUC") and Allegheny ACORN ("ACORN"), signatory parties to the Joint Petition for Settlement in Dockets P-00062240 and M-00061959, through counsel Pennsylvania Utility Law Project, find the terms and conditions of the Settlement to be in the public interest and, in support, state as follows:

I. Background

On May 31, 2006, Equitable Gas Company ("Equitable") submitted its Universal Service and Energy Conservation Plan 2007-2009 ("Plan 2007-2009") to the Commission pursuant to 52 Pa. Code §62.4. The Plan included several changes to Equitable's existing Universal Service and Energy Conservation programs.

A Tentative Order was entered on August 22, 2006, at Docket No. M-00061959, wherein the Commission approved Plan 2007-2009 with some modifications. Also in the Tentative Order, the Commission invited interested parties to submit comments. Equitable, the Pennsylvania Utility Law Project ("PULP"), the Pittsburgh American Indian Center, Mary E. Flagg, and Dave Price all filed comments. PULP and Equitable also filed reply comments.

In a Final Order entered December 26, 2006, the Commission found that the comments and reply comments regarding Plan 2007-2009 raised factual issues and referred the matter to the Office of Administrative Law Judge for hearing. Also in the December 26, 2006 Final Order, the Commission found that issues involved in Plan 2007-2009 were related to issues in another matter docketed at P-00062240 involving Equitable's request to increase its Rider D –Universal Service and Energy Conservation Rider to provide additional funding for its Universal Service and Energy Conservation programs. The Commission consolidated the two proceedings at M-00061959 and P-00062240.

The consolidated proceedings were assigned to Administrative Law Judge Mark A. Hoyer. An initial pre-hearing conference was held on February 16, 2007. On February 23, 2007, PULP filed a petition to intervene in the consolidated proceedings on behalf of MVUC and ACORN. Equitable served direct testimony on March 16, 2007. The Office of Trial Staff ("OTS"), the Office of the Consumer Advocate ("OCA"), MVUC and ACORN served direct testimony on April 27, 2007. Equitable and MVUC and ACORN served rebuttal testimony on May 16, 2007. OTS, OCA, MVUC and ACORN, and Equitable served surrebuttal testimony on May 30, 2007. After the exchange of testimony and the completion of discovery, but before the evidentiary hearings, the Settling Parties achieved this proposed Joint Settlement Agreement.

II. Terms and Conditions of Settlement

The Settlement, which is a compromise of positions arrived at through negotiation with the various parties, improves upon Equitable's 2007-2009 Universal Service and Energy Conservation Programs in several ways, each of which serve the public interest. The result of these improvements is that low-income customers may be expected to more easily and

successfully participate in Equitable's CAP program. These program modifications, combined with increased CAP participation, should enhance the ability of low-income residential customers to maintain service and reconnect to service should a service termination occur.

Equitable agrees to suspend its right to collect security deposits from CAP customers and from CAP eligible customers who apply for entry and who are subsequently accepted into the CAP program. Forbearing from the collection of these security deposits will remove an unnecessary barrier that hampers low-income customers' entry and reentry into the CAP program. It is expected that the removal of the strain of a security deposit from the fragile budget of a low-income household will facilitate that household's ability to make consistent and regular ongoing CAP payments and avoid termination of service.

Equitable agrees to offer open and continuing enrollment for eligible customers into the CAP program, without limitation on the number of participants in the CAP program. Open enrollment is a sound way to ensure a robust and growing CAP program that is available to all eligible customers who need its assistance. It is expected that such a robust program, with no enrollment ceilings or program closures, will assist additional low-income customers achieve more manageable monthly natural gas payments and help Equitable reduce the number of low-income residential customers who suffer from service termination.

Equitable will not increase its minimum CAP payment or collect an initial CAP enrollment payment. It is expected that through these steps, Equitable will maintain a more readily accessible CAP program. Higher minimum payments or any kind of entrance fee are unaffordable to low-income customers. By agreeing not to impose such fees, Equitable will be removing barriers to entry and ultimate program success.

Equitable agrees to provide notice of the dispute procedures outlined in Chapter 56 and referred to in the CAP Policy Statement at 52 Pa. Code §69.265(5). It is expected that this practice will inform CAP customers and CAP eligible customers of their rights to dispute certain actions of the company and enable these customers to protect themselves from potential mistakes or errors made by the company.

III. Conclusion

For each of the forgoing reasons, Mon Valley Unemployed Committee and Allegheny ACORN submit that the terms and conditions of the Joint Petition for Settlement are in the public interest and should be approved by the Commission.

Respectfully submitted,

Harry S. Geller, Esquire
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July 12, 2007

OFFICE OF SMALL BUSINESS ADVOCATE
STATEMENT IN SUPPORT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Funding Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	**Docket No. P-00062240**
And	:	
Equitable Gas Company's Universal Service and Energy Conversation Plan Submission Pursuant to 52 Pa. Code §62.4:	:	**Docket No. M-00061959**

STATEMENT OF THE OFFICE OF SMALL BUSINESS ADVOCATE IN SUPPORT OF THE SETTLEMENT

I. Introduction

The Office of Small Business Advocate ("OSBA") is an agency of the Commonwealth of Pennsylvania authorized by the Small Business Advocate Act (Act 181 of 1988, 73 P.S. §§ 399.41 – 399.50) to represent the interests of small business consumers as a party in proceedings before the Pennsylvania Public Utility Commission ("Commission").

On October 6, 2006, Equitable Gas Company ("Equitable" or "Company") filed with the Commission a Petition for Approval to Increase the Level of Funding for its Customer Assistance Program and to Implement an Adjustable Funding Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs ("Petition").

On October 18, 2006, the OSBA filed a Notice of Intervention and an Answer to Equitable's Petition.

On December 21, 2006, the Commission ordered that Equitable's Petition and Equitable's Universal Service and Energy Conservation Plan Submission at Docket No. M-00061959 be consolidated and be assigned to the Office of Administrative Law Judge ("OALJ") for hearings and a recommended decision.

Equitable served direct testimony on March 16, 2007. The Office of Trial Staff ("OTS"), the Office of Consumer Advocate ("OCA"), and the Allegheny County ACORN/Mon Valley Unemployed Committee ("ACORN/MVUC") served direct testimony on April 27, 2007. Equitable and ACORN/MVUC served rebuttal testimony on May 16, 2007. OTS, OCA, ACORN/MVUC and Equitable served surrebuttal testimony on May 30, 2007.

The OSBA did not file testimony.

II. Summary of the OSBA's Principal Concerns

On October 18, 2006, the OSBA filed an Answer in this proceeding. In its Answer, the OSBA acknowledged that Equitable's proposed Universal Service and Energy Conservation Rider ("USECR Rider") did not allocate universal service costs to small business customers. The OSBA also stated in its Answer that the OSBA was entering this proceeding to ensure that the Company's proposed USECR Rider was not modified in order to require Equitable's small business customers to help finance low-income energy programs.

To this point in the proceeding, the OSBA has participated in negotiations which have led to the Joint Petition for Settlement ("Settlement").

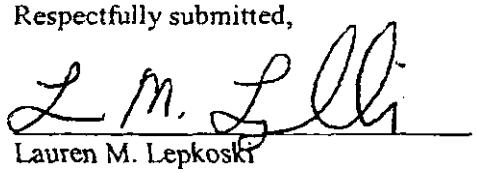
III. Settlement

The Settlement sets forth a comprehensive list of issues which were resolved through the negotiation process. The OSBA does not object to the resolution of any of those issues. Of particular interest to the OSBA is the fact that the Settlement will not impose universal service costs on small business customers. As the OSBA's principal concern has been resolved, signing this Settlement enables the OSBA to conserve its resources and avoid the uncertainties inherent in fully litigating the case.

IV. Conclusion

WHEREFORE, the OSBA respectfully requests that the Administrative Law Judge and the Commission approve the Settlement without modification.

Respectfully submitted,



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Dated: July 13, 2007

EQUITABLE GAS COMPANY
STATEMENT IN SUPPORT

Before The
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Administrative Law Judge
Mark A. Hoyer, Presiding

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	**Docket No. P-00062240**
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa.Code §62.4	:	**Docket No. M-00061959**

EQUITABLE GAS COMPANY'S STATEMENT IN SUPPORT OF JOINT SETTLEMENT AGREEMENT

AND NOW comes the Equitable Gas Company Division of Equitable Resources, Inc. ("Equitable" or "Company"), by its attorneys, and respectfully submits this statement in support of the Joint Settlement Agreement presented in the above-captioned consolidated proceedings:

I. Background

1. These consolidated proceedings concern Equitable's Universal Service and Energy Conservation Plan 2007-2009 ("Plan 2007-2009") and its proposed Rider D - Universal Service and Energy Conservation Rider ("USECR Rider"). In separate Opinions and Orders at M-00061959 and P-00062240, the Commission consolidated the proceedings.

2. The Settling Parties, *viz.* Equitable, the Office of Consumer Advocate ("OCA"), the Office of Trial Staff ("OTS"), Allegheny County ACORN/Mon Valley Unemployed Committee ("ACORN/MVUC") and the Office of Small Business Advocate ("OSBA"), and the Peoples/Equitable Merger Intervenors ("PEMI"), which has expressed no opposition to the Joint Settlement Agreement, represent all active parties to the consolidated proceedings.

3. The Settling Parties have agreed that the consolidated proceedings can be settled without further litigation under the terms set forth in the Joint Settlement Agreement.

II. The Joint Settlement Agreement Is Consistent With the Requirements of the Public Utility Code and in the Public Interest

Policy Considerations

4. It is the policy of the Commission to encourage parties in contested proceedings to enter into settlements. 52 Pa. Code §5.231(a). A settlement mitigates the time and expense of litigating the matter to its ultimate conclusion. This directly benefits all parties concerned.

5. The Joint Settlement Agreement proposes the resolution of all issues in these consolidated proceedings. Where the active parties in a proceeding have reached a settlement, the principal issue for Commission consideration is whether the agreement reached is in the public interest. Pa. P.U.C. v. CS Water and Sewer Associates, 74 Pa. P.U.C. 767, 771 (1991). Equitable submits that the resolution of the issues proposed in the Joint Settlement Agreement is in the public interest and consistent with statutory and regulatory requirements.

Specific Settlement Terms and Conditions

6. Several specific settlement terms and conditions are presented in the Joint Settlement Agreement. They are in the public interest as follows:

Effective Period of Settlement Terms and Conditions

This Joint Settlement Agreement and the Terms and Conditions of Settlement will be effective for the period commencing with the entry of a final Commission order approving the Joint Settlement Agreement and will continue in effect until the effective date of rates approved by the Commission in Equitable's next base rate case. The Settlement, thus, provides a measure of beneficial program and rate stability for both Equitable and its CAP and other customers that would not exist absent the settlement.

Modification of Proposed Rider D

The modification of Rider D to eliminate the proposed annual reconciliation feature produces a fixed Rider D rate for the effective period of the settlement terms. Although the Commission's Order at M-00051923 allows for a reconcilable surcharge, Equitable has agreed to eliminate the reconciliation feature in settlement of this proceeding (while preserving its right to reintroduce a reconciliation feature in a later proceeding) in return for the fixed Rider D settlement rate of $0.58/Mcf (inclusive of the currently effective $0.30/Mcf Rider D rate). In settlement of this proceeding, Equitable has accepted the risk of managing its CAP, with open enrollment and other features of potentially significant additional cost, with a fixed Rider D rate of $0.58/Mcf during the effective period of the settlement terms.

CAP Consumption

Equitable has agreed in settlement to monitor CAP participants' consumption to ensure that the participant is maintaining annual usage at or below 110 percent of historical average usage, adjusted for weather. To accomplish this objective, the Company will institute the several procedures identified in the body of the Joint Settlement Agreement. These procedures encourage CAP customers to adopt conservation methods and to maintain usage profiles consistent with weather adjusted norms.

CAP Customer Deposits

Chapter 14 of the Public Utility Code allows Equitable to collect a customer deposit from applicants and customers, including CAP applicants and customers. In settlement of this proceeding and during the effective period of the settlement terms, Equitable will suspend the right to request customer deposits from CAP customers and, in the case of applicants for CAP, will provisionally suspend the necessity for a deposit pending a decision on their application. For those not accepted for CAP participation, customer deposits will be required.

CAP Enrollment

Consistent with its Universal Service and Energy Conservation Plan 2007-2009, Equitable will offer open and continuing CAP enrollment for eligible customers without limitation on the number of participants. With a fixed Rider D rate for the effective period of the settlement terms, Equitable will be at risk for the cost associated with increases in customer enrollment for the effective period of the settlement terms.

CAP Arrearage Forgiveness

The Joint Settlement Agreement makes no changes in arrearage forgiveness available to CAP customers. Equitable will continue to offer CAP arrearage forgiveness through its funding sources already in place. Equitable's CAP arrearage forgiveness generally eliminates CAP pre-program arrearages in four years.

Minimum CAP Payments

Consistent with its Universal Service and Energy Conservation Plan 2007-2009, as modified by the Commission in its Tentative Order entered August 22, 2006 and as agreed upon in the Company's Reply Comments of September 21, 2006, Equitable will not increase minimum CAP payments from $25 and will not request initial CAP enrollment payments. Equitable had initially proposed to increase minimum CAP payments to $35 and to request an initial payment for those CAP applicants who had received a termination notice or who had not made a payment in the most recent sixty days.

Notice Pursuant to Dispute Procedures

Consistent with CAP Policy Guidelines, Equitable will provide notice to CAP applicants and CAP customers pursuant to the dispute procedures outlined in Chapter 56 and referred to in the CAP Policy Statement at 52 Pa. Code §69.265(5).

Preservation of Issues

While the parties have successfully resolved all issues in this proceeding to their respective satisfaction, the Joint Settlement Agreement expressly recognizes that the resolution is limited to this case. All issues concerning CAP cost recovery (and related universal service issues) may be addressed in the

Company's next general base rate filing and the Settling Parties are free to propose similar or alternative cost recovery mechanisms at that time.

III. Request for Expedited Treatment

7. These consolidated proceedings were initiated many months ago by the filing of Equitable's Universal Service and Energy Conservation Plan 2007-2009 on May 31, 2006, and by the filing of Equitable's CAP Funding Petition on October 6, 2006. Equitable believes that the terms and conditions accepted by the parties in resolution of all issues in these consolidated proceedings are clearly in the public interest and asks that the Commission approve the Joint Settlement Agreement in its entirety as soon as reasonably possible and well before the 2007-2008 winter heating season for the benefit of CAP participants and so that funding can begin to cover Equitable's CAP program commitments including open and continuing CAP enrollment and suspension of CAP customer deposits. To facilitate expedited treatment and final Commission approval by October 1, 2007, Equitable has attached a proposed Recommended Decision to this Statement in Support.

WHEREFORE, the Equitable Gas Company Division of Equitable Resources, Inc. respectfully requests that Administrative Law Judge Mark A. Hoyer recommend approval of and the Pennsylvania Public Utility Commission approve the Joint Settlement Agreement in full settlement of all issues in these consolidated proceedings.

Respectfully submitted,

By _____

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EGC Statement in Support (Final).wpd

Proposed Recommended Decision
Submitted with
Equitable Gas Company's
Statement in Support

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	P-00062240
and	:	
Equitable Gas Company's Universal Service and Energy Conversation Plan Submission Pursuant to 52 Pa. Code §62.4	:	M-00061959

RECOMMENDED DECISION

Before
Mark A. Hoyer
Administrative Law Judge

HISTORY OF THE PROCEEDING

On May 31, 2006, the Equitable Gas Company ("Equitable") submitted its Universal Service and Energy Conservation Plan 2007-2009 ("Plan 2007-2009") to the Public Utility Commission ("Commission") pursuant to 52 Pa. Code § 62.4. Plan 2007-2009 proposed several modifications to Equitable's existing Universal Service programs. In a Tentative Order entered August 22, 2006 at Docket No. M-00061959, the Commission approved Plan 2007-2009 with certain modifications and provided interested parties the opportunity to submit comments on the proposed revisions discussed in the Tentative Order.

On October 6, 2006, Equitable filed a Petition for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs. This Petition, docketed at P-00062240, proposed an adjustment to Equitable's Rider D – Universal Service and Energy Conservation Rider ("USECR Rider" or "Rider D") that would fund Universal Service and Energy Conservation Programs on an ongoing basis and would establish a quarterly adjustment filing and an annual reconciliation feature for reconciling actual Customer Assistance Program ("CAP") costs and actual CAP recoveries.

By orders entered on December 26, 2006 at each of the foregoing docket numbers (i.e., M-00061959 and P-00062240), the Commission consolidated these matters and referred the consolidated proceeding to the Commission's Office of Administrative Law Judge for hearing and the issuance of a recommended decision.

A telephonic prehearing conference was held on February 16, 2007. Participating parties included Equitable, the Commission's Office of Trial Staff ("OTS"), the Office of Small Business Advocate ("OSBA"), the Office of Consumer Advocate ("OCA"), and the Peoples/Equitable Merger Intervenors ("PEMI"). The parties present for the prehearing conference agreed to a litigation schedule that was set forth in a Revised Prehearing Order dated February 23, 2007. Also on February 23, 2007, the Allegheny County ACORN/Mon Valley Unemployed Committee ("ACORN/MVUC") filed a petition to intervene in the consolidated proceedings.

Equitable served its direct testimony on March 16, 2007. OTS, OCA, and ACORN/MVUC served their respective direct testimony on April 27, 2007. Equitable and ACORN/MVUC served rebuttal testimony on May 16, 2007, and OTS, OCA, ACORN/MVUC,

and Equitable served surrebuttal testimony on May 30, 2007. No testimony was presented by either OSBA or PEMI. In addition, the OTS, OCA, and ACORN/MVUC propounded a substantial number of interrogatories, which were answered by Equitable.

Following the circulation of testimony and completion of discovery, the parties were able to reach a proposed resolution of all issues addressed in the testimony. As a result, the first evidentiary hearing scheduled for June 14, 2007, was cancelled. The parties have filed as of July 13, 2007, a Joint Settlement Agreement ("Settlement") that is attached to this Recommended Decision. Statements in support of the Joint Settlement Agreement from Equitable, OTS, OCA, ACORN/MVUC and OSBA are attached to the Joint Settlement Agreement. PEMI filed a letter expressing no opposition to the Joint Settlement Agreement. The Joint Settlement Agreement is summarized and reviewed in the discussion section that follows.

DISCUSSION

The Joint Settlement Agreement was filed with the Secretary and submitted to me by the parties on July 13, 2007. The Settlement Agreement itself is 12 pages in length and addresses issues related to Equitable's Plan 2007-2009 and Rider D. It is executed by Equitable, OTS, OCA, ACORN/MVUC and OSBA and not opposed by PEMI, being all of the parties that participated in the case. Also attached and incorporated by reference are the supporting statements of Equitable, OTS, OCA, ACORN/MVUC and OSBA and the no-opposition letter of PEMI.

In accordance with the provisions of the Settlement, a fixed Rider D rate of $0.58 per Mcf would be established, which would represent a $0.28 per Mcf increase over the currently effective Rider D rate of $0.30 per Mcf. The proposed fixed Rider D rate, and all other terms

and conditions of the Joint Settlement Agreement, would become effective upon the entry of a final Commission order approving the Settlement and would continue in effect until the effective date of rates approved by the Commission in Equitable's next base rate case.

The parties have stipulated to the evidentiary basis of the Settlement in detail. Joint Settlement Agreement, pp. 8-9. In addition, the parties have requested that the Joint Settlement Agreement be designated ALJ Exhibit 1 and admitted as a late filed exhibit. The request is granted in the first ordering paragraph of this Recommended Decision.

The Commission encourages parties in contested proceedings to try to settle issues among themselves. 52 Pa. Code §5.231(a). A settlement mitigates the time and expense of litigating a matter to its ultimate conclusion. In this case, the parties have resolved a number of issues in a comprehensive manner which achieves a net savings of resources for all of the parties and this Commission.

Where the active parties in a proceeding have reached a settlement, the principal issue for Commission consideration is whether the agreement reached is in the public interest. Pa. P.U.C. v. CS Water and Sewer Associates, 74 Pa. P.U.C. 767, 771 (1991). I conclude that the Joint Settlement Agreement here is in the public interest and recommend that this Commission so find.

Settlement Terms and Conditions

Preliminarily and as a threshold matter, the Joint Settlement Agreement provides that the Terms and Conditions of Settlement will be effective for the period commencing with the entry of a final Commission order approving the Joint Settlement Agreement and will continue in effect until the effective date of rates approved by the Commission in Equitable's next base rate case.

The second settlement term deals with proposed modifications to Equitable's Rider D. In its Petition filed at Docket No. P-00062240, Equitable proposed a USECR Rider of $0.72 per Mcf, which represented an increase of $0.42 per Mcf to the existing rate of $0.30 per Mcf. Under the terms of the Joint Settlement Agreement, Equitable agrees to modify Rider D to eliminate the annual reconciliation of CAP revenues and expenses and establish a fixed Rider D rate of $0.58/Mcf and to manage its CAP with a fixed Rider D rate of $0.58/Mcf (inclusive of the currently effective $0.30/Mcf Rider D rate) during the effective period of the Settlement's terms and conditions. The form of the tariff supplement to implement the settlement modifications to proposed Rider D is attached to the Joint Settlement Agreement as Attachment A. The Settling Parties agree that Equitable may file the settlement tariff supplement to become effective on one day's notice for service rendered on and after the entry date of the Commission's approval of the Joint Settlement Agreement.

The third settlement term pertains to CAP consumption. Equitable agrees to monitor CAP participants' consumption to ensure that the participant is maintaining annual usage at or below 110 percent of historical average usage, adjusted for weather. To accomplish this objective, the Company will institute the following procedures:

1. During the CAP enrollment process, Equitable will advise the CAP customer of the importance of energy conservation, explain that usage will be reviewed on an ongoing basis and that unjustified excess usage may be billed to the CAP customer. Educational material in the form of conservation tips and a plain language statement of the rules included in the "CAP Consumption" section of this Joint Settlement Agreement will be provided in the CAP brochure and sent to all CAP customers.

2. High usage CAP customers will be referred to the Company's Low Income Usage Reduction Program (LIURP) and receive the highest priority for weatherization or other energy conservation help. High usage is defined as annual normalized usage in excess of 200 Mcf.

3. Equitable will review and compare the most recent annual usage of CAP participants, adjusted for weather, with historical normalized usage for these customers.

a. When usage exceeds 110 percent of historical average usage, adjusted for weather, Equitable will contact the customer to discuss energy conservation techniques. The customer will be advised that, if consumption is not reduced by the next review, the customer may be removed from CAP unless one of the conditions under (b) exists.

b. CAP participants will be exempted from (a) above if the participant meets one or more of the exceptions identified in the CAP Policy Statement which presently are as follows:

   i. The household experienced the addition of a family member.

   ii. A member of the household experienced a serious illness.

   iii. Energy consumption was beyond the household's ability to control.

   iv. The household is located in housing that is or has been condemned or has housing code violations that negatively affect energy consumption.

   v. Energy consumption estimates have been based on consumption of a previous occupant.

c. Customers removed from CAP under (a) above will need to reduce consumption to historical usage levels, adjusted for weather, or pay the amount of the excess usage to be reinstated in CAP. High usage customers under 2 above must agree to receive weatherization services for reinstatement in CAP.

d. Customers removed from CAP for these reasons will be sent a removal letter including information describing the steps required for CAP reinstatement.

The fourth settlement term results in the suspension of Equitable's right to request customer deposits from CAP customers and, in the case of applicants for CAP, results in the provisional suspension of the necessity for a deposit pending a decision on their application. The parties agree that customer deposits be required for those not accepted for CAP participation.

The fifth settlement term concerns CAP enrollment. In accordance with Plan 2007-2009, the parties agree that Equitable's CAP shall offer open and continuing enrollment for eligible customers without limitation on the number of participants.

The sixth settlement term addresses CAP arrearage forgiveness, and Equitable agrees to continue to offer CAP arrearage forgiveness through the funding source it already has in place.

The seventh settlement term deals with minimum CAP payments. Consistent with its Plan 2007-2009, as modified by the Commission in its Tentative Order entered August 22, 2006 and as agreed upon in the Company's Reply Comments of September 21, 2006, Equitable agrees not to increase minimum CAP payments from $25 and not to request initial CAP enrollment payments.

The eighth settlement term pertains to the notice to be given to applicants and customers in CAP disputes. In accordance with CAP Policy Guidelines, Equitable agrees to provide notice to CAP applicants and CAP customers pursuant to the dispute procedures outlined in Chapter 56 and referred to in the CAP Policy Statement at 52 Pa. Code §69.265(5).

Finally, the Settlement allows the Settling Parties to address all issues concerning CAP cost recovery (and related universal service issues) in Equitable's next general base rate filing. The parties agree that they are free to propose similar or alternative cost recovery mechanisms at that time.

As the foregoing discussion makes clear, the parties here have resolved a number of contentious issues in a comprehensive, yet fair matter. The Settlement reflects compromises on all sides and achieves a net saving of resources for all of the parties and this Commission. I conclude that the Settlement is in the public interest and recommend that this Commission find the same.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the parties to and the subject matter of this proceeding.

2. The Joint Settlement Agreement submitted by Equitable Gas Company, the Office of Trial Staff, the Office of Consumer Advocate, Allegheny County ACORN/Mon Valley Unemployed Committee and the Office of Small Business Advocate and not opposed by the Peoples/Equitable Merger Intervenors achieves a comprehensive resolution of all matters at issue in these consolidated proceedings.

3. Where the active parties in a proceeding have reached a settlement, the principal issue for Commission consideration is whether the agreement reached is in the public interest. Pa. P.U.C. v. CS Water and Sewer Associates, 74 Pa. P.U.C. 767, 771 (1991). The resolution of issues as proposed in the Joint Settlement Agreement is in the public interest and should be approved.

ORDER

THEREFORE,

IT IS RECOMMENDED:

1. That the Joint Settlement Agreement, including late filed ALJ Exhibit 1 and the statements in support, are admitted into the record of this proceeding.

2. That the Joint Settlement Agreement as identified and admitted above, submitted by Equitable Gas Company, the Office of Trial Staff, the Office of Consumer Advocate, Allegheny County ACORN/Mon Valley Unemployed Committee and the Office of Small Business Advocate and not opposed by the Peoples/Equitable Merger Intervenors at Docket Nos. P-00062240 and M-00061959 is adopted and approved.

3. That Equitable Gas Company shall be permitted to file a tariff supplement identical to the one attached to the Joint Settlement Agreement, to become effective on one day's notice, for service rendered on and after the entry date of the Commission's approval of the Joint Settlement Agreement;

4. That Equitable Gas Company and all parties to the Joint Settlement Agreement in this matter shall comply with all of the terms and conditions of said Settlement as though each term and condition had been the subject of an individual ordering paragraph.

5. That upon the acceptance and approval by the Commission of the Joint Settlement Agreement the proceedings at Docket Nos. P-00062240 and M-00061959 shall be terminated and marked closed.

Dated:_____

_____
Mark A. Hoyer
Administrative Law Judge

Before The
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Administrative Law Judge
Mark A. Hoyer, Presiding

Petition of Equitable Gas Company for Approval to Increase the Level of Funding for Its Customer Assistance Program and to Implement an Adjustable Rate Mechanism to Recover Associated Expenses Concerning Universal Service and Energy Conservation Plan Costs	:	Docket No. P-00062240
Equitable Gas Company's Universal Service and Energy Conservation Plan Submission Pursuant to 52 Pa. Code §62.4	:	Docket No. M-00061959

CERTIFICATE OF SERVICE

I hereby certify that I have this 13th day of July, 2007, served a true and correct copy of the foregoing Joint Settlement Agreement in the above matter, upon the persons and in the manner set forth below:

BY EMAIL AND FIRST CLASS MAIL

Christy M. Appleby
Darryl A. Lawrence
Assistant Consumer Advocates
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
Email: cappleby@paoca.org

Allison Curtin Kaster, Prosecutor
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
P. O. Box 3265
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Lauren M. Lepkoski
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jgerhardpulp@palegalaid.net

Thomas T. Niesen
PA Attorney ID No. 31379

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-7

McNees Wallace & Nurick LLC
attorneys at law

BARRY A. NAUM
DIRECT DIAL: (717) 237-5378
E-MAIL ADDRESS: BNAUM@MWN.COM

May 23, 2008

VIA E-MAIL AND FEDERAL EXPRESS

Honorable John H. Corbett, Jr.
Administrative Law Judge
Pennsylvania Public Utility Commission
1103 Pittsburgh State Office Building
300 Liberty Avenue
Pittsburgh, PA 15222

Re: United States Steel Corporation v. Equitable Gas Company;
Docket No. C-2008-2036023

Dear Judge Corbett:

Enclosed please find two (2) copies of the Direct Testimony of Ronald D. Cerminaro, Statement No.1, on behalf of United States Steel Corporation ("U. S. Steel"), in the above-referenced proceeding.

As evidenced by the attached Certificate of Service, all parties in this proceeding are being duly served with a copy of this testimony. If you have any questions, please contact us.

Very truly yours,

MCNEES WALLACE & NURICK LLC

By
Pamela C. Polacek
Vasiliki Karandrikas
Barry A. Naum

Counsel to United States Steel Corporation

BN/km
Enclosures
c: James J. McNulty, Secretary (Transmittal Letter and Certificate of Service only - via Hand Delivery)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA E-MAIL AND FIRST CLASS MAIL

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Thomas, Long, Niesen & Kennard
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John F. Povilaitis, Esq.
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Harrisburg, PA 17102-202

Todd S. Stewart, Esq.
Hawke McKeon & Sniscak LLP
PO Box 1778
100 N. Tenth Street
Harrisburg, PA 17105

Barry A. Naum

Dated this 23rd day of May, 2008, at Harrisburg, Pennsylvania.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	R-2008-2021160
v.	:	C-2008-2034000
	:	C-2008-2034099
Equitable Gas Company	:	
United States Steel Corporation	:	
	:	
v.	:	C-2008-2036023
	:	
Equitable Gas Company	:	

DIRECT TESTIMONY

OF

RONALD D. CERMINARO

ON BEHALF OF

UNITED STATES STEEL CORPORATION

May 2008

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	R-2008-2021160
v.	:	C-2008-2034000
	:	C-2008-2034099
Equitable Gas Company	:	
United States Steel Corporation	:	
	:	
v.	:	C-2008-2036023
	:	
Equitable Gas Company	:	

DIRECT TESTIMONY BY RONALD D. CERMINARO
UNITED STATES STEEL CORPORATION

Q. Please state your name and business address.

A. My name is Ronald D. Cerminaro. My business address is:

United States Steel Corporation
600 Grant Street
Pittsburgh, PA 15219-2800

Q. By what company are you employed?

A. I'm employed by United States Steel Corporation ("U. S. Steel").

Q. How long have you worked for U. S. Steel?

A. I've worked for U. S. Steel for 20 years.

Q. What is your current position with U. S. Steel?

A. My current position is the Manager, Regional Procurement.

Q. What are your duties in your current position?

A. I am responsible for the supervision of the procurement function for U. S. Steel in the areas of energy and other various commodities. One of my main functions is to acquire the necessary electricity and natural gas for the corporation at an economical price.

Q. What is your educational and employment background prior to joining U. S. Steel?

A. The following is a brief summary of my professional background and qualifications.

BS, (Civil Engineering), University of Pittsburgh, 1975
MBA, University of Pittsburgh, 1980
Registered Professional Engineer (P.E.) 1980
Lifetime Certification as Purchasing Manager (C.P.M.) 2001

Prior to U. S. Steel, I was the Director of Purchasing for Presbyterian University Hospital of Pittsburgh for approximately 6 years. Prior to that, I was an engineer in different levels at LTV Steel for about 7 years.

Q. Does U. S. Steel have any facilities located in the service territory of Equitable Gas Company ("Equitable")?

A. Yes. The main ones are the Clairton, Edgar Thompson and Irvin Plants. Along with our Fairless Hills Plant near Philadelphia, we collectively refer to these facilities as the "Mon Valley Works." Our headquarters and several additional facilities are also in the territory. As Mr. Quinn of Equitable noted in his direct

testimony, U. S. Steel is Equitable's largest delivery service customer, with annual requirements of approximately 6 Bcf.

Q. What do the U. S. Steel facilities manufacture?

A. Our plants in the area manufacture coke and flat rolled steel products.

Q. Please provide some information regarding the contribution and impact of U. S. Steel in Southwestern Pennsylvania.

A. U. S. Steel is a major employer in Southwestern Pennsylvania and has a significant impact on the community.

- In the Pittsburgh region, U. S. Steel employs close to 5,000 with an annual payroll of approximately $433.8 million. Of those 5,000 employees, approximately 3,000 work at the Clairton, Edgar Thompson and Irvin Plants.
- In the Southwestern Pennsylvania region, we contribute annually well over $1.24 billion to the area's economy through purchases with over 1,000 vendors.
- U. S. Steel paid approximately $6.7 million in local taxes for 2007 in Southwestern Pennsylvania.
- Company-insured employees and retirees supported the Pittsburgh region medical facilities and professionals by spending $80 million on healthcare.
- U. S. Steel's support of 15,000 Pittsburgh-region pensioners and surviving spouses totaled $127 million in 2007.

All of these figures were compiled as of December 31, 2007.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to respond to the testimony of Mr. Quinn regarding the delivery service agreement between U. S. Steel and Equitable for the Clairton, Edgar Thompson and Irvin Plants.

Q. Please provide the background of U. S. Steel's negotiation of a delivery service agreement with Equitable.

A. U. S. Steel signed a delivery service agreement with Equitable on January 1, 2005, that contained a negotiated retainage rate of 1.5%. As noted in Mr. Quinn's testimony, that agreement expired as of December 31, 2007.

Approximately 7 months prior to the expiration of the agreement, we initiated negotiations with Equitable for a new contract. Unfortunately, the parties could not reach an agreement prior to December 31, 2007.

As a result, U. S. Steel and Equitable entered into a three-month temporary agreement with a temporary delivery rate and temporary retainage rate of 4%. U. S. Steel entered into this temporary agreement in anticipation that good faith negotiations would continue towards finalizing a long-term permanent agreement that continued our 1.5% retainage rate. The parties again could not reach an agreement prior to the expiration of that three-month agreement by its end date (i.e., March 31, 2008) and it is rolling over on a month-to-month basis.

Q. In agreeing to the three-month temporary contract, did U. S. Steel anticipate that the retainage rate for the permanent agreement would be based solely on a pipeline integrity study performed by Equitable?

A. No. We were very clear to Equitable throughout this process that we expect the 1.5% rate to continue based on multiple factors. Although the pipeline integrity study was one factor, we believe that the 1.5% also is justified based on economic development concerns.

Q. Please explain the economic development impact of U. S. Steel in Southwestern Pennsylvania.

A. As I detailed earlier in my testimony, U. S. Steel's operations at the Clairton, Edgar Thompson and Irvin Plants and other locations in the Pittsburgh region have a large impact on our employees and others in the service territory. We are one of the most significant employers in Southwestern Pennsylvania. A study by the American Iron and Steel Institute concluded that each steel industry job generates seven jobs in other economic sectors.

Q. In addition to this general impact, has U. S. Steel announced any new initiatives for the Mon Valley Works that will enhance the economic development benefits of the facility?

A. Yes. Earlier this year, we announced a proposal to construct new coke batteries at the Clairton Plant. This proposed project will not only help to retain existing jobs in Western Pennsylvania, but will also create hundreds of new construction jobs

in the Mon Valley. The combination of a 1.5% retainage rate and an appropriate delivery service rate will aid U. S. Steel in pursuing this project.

Q. Please explain the competitive environment for U. S. Steel's products.

A. Mon Valley's products compete with those of domestic and foreign producers. Limiting the cost of inputs for the manufacture of steel to reasonable levels contributes favorably to that competitiveness.

Q. Do the Clairton, Edgar Thompson and Irvin Plants also face internal competition from other U. S. Steel facilities that produce similar products?

A. Yes. The Mon Valley Works competes internally with all U. S. Steel facilities, including our Gary Works in Indiana. The tariffed loss factor for natural gas service to the Gary Works is 0.85%.

Q. Have you calculated the economic impact on U. S. Steel from using a 1.5% retainage rate rather than the 3.4% maximum rate requested by Equitable?

A. Yes. Using the same approximate usage of 6 Bcf that was stated in Equitable's testimony, we calculated the economic impact on U. S. Steel from using a 1.5% retainage rate rather than a 3.4% retainage rate is $1.25 million per year. This is based on an assumed natural gas price of $11.00. We think this is a conservative estimate because the current strip price for gas is higher than $11.00.

Q. How does this compare to Equitable's total cost of gas?

A. According to Item 53.64(a), Section I, Part A, Sheet 1 of 6 in Equitable's April 1, 2008, filing, Equitable projects that its total cost of gas for the 12 months ending September 30, 2009, will be $280,696,286. Assuming that Equitable has already reflected recovery of the impact of the 3.4% maximum retainage in this amount, the incremental impact of U. S. Steel's 1.5% negotiated retainage rate would increase the total projected cost of gas to $282,262,938 (assuming a natural gas price of $13.74), an increase of approximately 0.5%.

Q. Did U. S. Steel request in discovery for Equitable to confirm that the 1.5% retainage rate meets the marginal cost test set forth in Mr. Quinn's testimony?

A. Yes. Equitable, however, has not responded to this discovery request as of the date this testimony is being provided to the parties.

Q. Is U. S. Steel requesting a rate lower than 1.5%?

A. No. We have told Equitable the retainage rate (i.e., 1.5%) and the confidential delivery rate that we need from an economic standpoint. The Commission should understand, however, that both elements of the contract impact our economic evaluation. As a result, if we do not obtain the transportation rate that we have indicated to Equitable, then our requested retainage rate will decrease accordingly.

Q. Has Equitable agreed to a retainage rate lower than 1.5% for another customer?

A. Yes. Equitable's Exhibit JMQ-1 indicates that it agreed to a rate of 0.5% for a customer.

Q. U. S. Steel is requesting a 1.9% reduction to the retainage rate due to economic development reasons (from 3.4% to 1.5%). Has Equitable agreed to a negotiated retainage rate that is 1.9% lower than the tariffed retainage rate based on economic development/job retention purposes?

A. Yes. Equitable's Exhibit JMQ-1 indicates that Equitable agreed to a retainage reduction of 2.5% for a customer for this specific reason in comparison to the currently-tariffed rate of 6.0%. Even if the contract was negotiated when the tariffed rate was 5.0%, it still represents a negotiated reduction of 1.5%, which is comparable to U. S. Steel's request.

Q. Do you have any further comments regarding the 1.5% retainage rate?

A. Yes. When U. S. Steel agreed to the 4% temporary retainage rate, we did so out of the belief that a more appropriate rate would be negotiated to take effect at the end of the three-month period. Any retainage rate that results from this proceeding should apply from April 1, 2008, which is the date we anticipated having the new permanent agreement in place, or, at a minimum, from the date that we filed our Complaint.

Q. Finally, Equitable's testimony indicates that it may desire to transfer the facilities serving U. S. Steel to Equitrans. Do you have any comments?

A. I am informed by counsel that this would require our consent and/or PUC approval. We are willing to discuss this option with Equitable, but will not commit to it.

Q. Does this conclude your testimony?

A. Yes

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-8

Pennsylvania Public Utility Commission, *et al.* v. Equitable Gas Company
Docket Nos. R-2008-2029325, *et al.*

RESPONSES OF EQUITABLE INDUSTRIAL INTERVENORS TO INTERROGATORIES OF EQUITABLE GAS COMPANY – SET II

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3. The direct testimony of Glenn A. Watkins, OCA Statement No. 3, page 3, lines 5 through 7, claims that Equitable has provided no support for its "revenue deficiency" resulting from "discounted negotiated distribution rates" and proposes the imputation of additional revenue reflecting service to negotiated rate customers at rates approximating $2.36 per Mcf. Please state whether U. S. Steel would be willing to negotiate a delivery service rate of $2.36 per Mcf.

Response:

No.

Response Provided By: Ronald D. Cerminaro, U. S. Steel
10/24/2008

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-9

Responsible Witness: Glenn A. Watkins
October 20, 2008

Pa. P.U.C., et al. v. Equitable Gas Company
Docket Nos. R-2008-2029325, et al. and C-20066800

Responses of the Office of Consumer Advocate to Equitable Gas Company
Interrogatories (Set II)

1. Please refer to the direct testimony of Glenn A. Watkins, OCA Statement NO. 3, page 3, lines 5 through 7, which claims that Equitable has provided no support for its "revenue deficiency" resulting from "discounted negotiated distribution rates" and also refer to Exhibit No. 103, Schedule No. 1 sponsored by Columbia Gas Company in its Base Rate Case (Docket No. R-2008-2011621) in regard to the approximate 14 Bcf of "flexed" Columbia volumes.

   a. State the OCA's position in the Columbia Gas proceeding relating to the Columbia "flexed" volumes.

   b. Identify the OCA witness in the Columbia proceeding responsible for reviewing the Columbia "flex" volumes and provide a copy of all testimony provided by that witness in the Columbia proceeding.

   c. Describe and provide a copy of the support provided by Columbia Gas Company in its BASE Rate Case (Docket No. R-2008-2011621) and reviewed by the OCA and/or its witness in regard to the approximate 14Bcf of "flexed" volumes identified in Columbia's Exhibit No. 103, Schedule No. 1.

   d. State whether the OCA agrees that its position in this proceeding concerning Equitable Gas Company and what it refers to as "discounted negotiated distribution rates" differs from its position in the Columbia proceeding concerning Columbia "flexed" volumes. If the OCA believes that its position is the same in both proceedings, state fully and completely the basis or bases for such belief.

   e. If the OCA believes that its position is not the same, state fully and completely the basis or bases for the differing positions in the two proceedings.

Response:

   a. Columbia's "flexed volumes" were not addressed by Mr. Watkins.

   b. Unknown by Mr. Watkins. See (a) above.

   c. Mr. Watkins reviewed the entire Columbia rate filing as well as all Columbia responses to OCA data requests in that case. Mr. Watkins does not recall if any information related to "flex volumes". Columbia's base rate filing materials are publicly available at the Pennsylvania Public Utility Commission or available on Columbia's website at:

Response to No. 1 continued:

http://www.columbiagaspamd.com/tariff/CPA_rate%20case%20index.htm

d. See (a) above.

e. See (a) above.

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-10

Quinn, John

From: Thomas Niesen [tniesen@thomaslonglaw.com]
Sent: Friday, September 19, 2008 2:45 PM
To: Frutchey, Dan; Quinn, John; Narkevic, Robert
Subject: Highly Confidential Information Addressing Matters Re Telephone Discussion

Dan/John/Bob - See Darryl's email below.

Tom

From: Lawrence, Darryl A. [mailto:DLawrence@paoca.org]
Sent: Friday, September 19, 2008 2:19 PM
To: Thomas T. Niesen
Cc: Horner, Jessica; Tunilo, Candis
Subject: RE: Highly Confidential Information Addressing Matters Re Telephone Discussion

Tom,

Per our phone conversation, the OCA will withdraw OCA Set II-19, 20, 22 and 23 based on the additional information and analysis of these issues that you and the Company have supplied.

Darryl

From: Thomas T. Niesen [mailto:tniesen@thomaslonglaw.com]
Sent: Thursday, September 18, 2008 11:30 AM
To: Lawrence, Darryl A.
Cc: Frutchey, Daniel; Quinn, John; Narkevic, Bob; Thomas, Jr, Charles
Subject: Highly Confidential Information Addressing Matters Re Telephone Discussion

Darryl - During our telephone conversation on Thursday of last week you offered to withdraw the OCA's Set II Interrogatories 19, 20, 22 and 23 if we could show you that the negotiated rate "discounts" are being made up by customers in the same rate class. The Interrogatories (and we recognize and appreciate your willingness to withdraw/modify the Interrogatories if we are ultimately unconvincing to you) request a voluminous level of detail related to Equitable's negotiated rate agreements. Initially, addressing what we believe is the substance of your Interrogatories, we presume that the OCA is attempting to evaluate whether or not Equitable is maximizing the level of negotiated delivery service revenue from competitive customers. In order to demonstrate that the Company is indeed maximizing its negotiated agreements, the Company has prepared Highly Confidential Attachment 1 for your review (we are providing this Highly Confidential information to you for your review only and not at this time as a response to any Interrogatory). Highly Confidential Attachment 1 is a list of Equitable's top 14 accounts by volume. These accounts make up 77% of the negotiated volume appearing on Exhibit III-E-20 and nearly 40% of the revenue.

All of the customers listed in Highly Confidential Attachment 1 could elect service from another NGDC. Many of the customers under negotiated agreements appearing in Highly Confidential Attachment 1 are large industrial customers with installed alternative fuel who compete in global markets. These customers employ thousands of individuals and contribute millions of dollars to the western PA economy through taxes, and the procurement of goods and services. Two of the customers on this list are represented in this case, and are currently negotiating with Equitable for new delivery service contracts. One of the two customers has provided Equitable with a bona fide written offer from another NGDC to provide delivery service. The negotiated rates paid by the Highly Confidential Attachment 1 customers are the maximum that they will pay based on the service alternatives available to them.

Turning to the question of whether "discounts" remain within the same rate class, we believe it is clear from the cost of service studies presented in Exhibit IV that the level of negotiated rates and negotiated rate "discounts" are recorded and maintained within the same rate class and, to the extent they are made up at all, made up by customers in the same rate class. For your ease of reference we have summarized the studies in Attachment 2.

Specifically, the cost of service analysis breaks the Company's customers into four classes: Residential, General Service Small, General Service Large and Appalachian Gathering. Focusing on the residential class, cost of service is allocated to the residential class. Residential cost of service is subtracted from residential service revenue to produce a dollar and rate of return at both present and proposed residential rates. There is no carry over of expenses or revenue from the General Service Small or Large or Gathering Service classes to the Residential class cost of service analysis. There is no line item for negotiated rate "discount" recovery included at any point in the Residential class cost of service analysis.

It is perhaps more clearly shown by focusing on the General Service Small and General Service Large classes were the rate negotiating occurs. Customers within both of the GSS and GSL classes negotiate rates but the negotiated rate levels remain within the respective classes. Exhibit III, Item III-E-20, for both Rate GDS and Rate DDS show a line item entry for "negotiated deliveries" both volumes and dollars. These negotiated levels are then reflected in the cost of service analysis for the GSS and GSL classes and used to produce a dollar and rate of return at both present and proposed GSS and GSL class rates.

As you can see from the cost of service study results, the returns from both the GSS and GSL classes are above the system average ROR of 3.8%. In fact, under both studies the GSS class is considerably above the system average ROR which supports the premise that Equitable is attempting to contain the negotiated rates within the GSS and GSL class, not the RS class.

Based on the cost of service results and other considerations, John Quinn then proposes to allocate $1.4 MM in additional revenue responsibility to the GSS class and an additional $3 MM to the GSL class. While we believe our revenue allocation proposal is reasonable, we recognize that it may be a matter in dispute. Regardless, however, counter positions to our proposal would not seem to require discovery of specific customer rate negotiated "discounts."

Please consider the foregoing and let us know if you wish to discuss it further.

Tom

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-11

Equitable Gas Company

Docket No. A-122250F5000

Settlement Agreement with Hess Corporation and Constellation New Energy - Gas Division, LLC

Agency Program

The entire issue of exiting the Agency Service is dependent on (1) receiving a final Commission order acceptable to Equitable and (2) closing of the stock purchase transaction. Equitable agrees that it will not enter into any settlement with another party to this proceeding that is inconsistent with this settlement although Equitable may extend the existing delivery service agreements for PEMI member customers just as it may extend delivery service agreements for any customer.

Proposed Conditions of Settlement

1. Equitable Gas Company ("Equitable") shall agree to not act as an agent on behalf of customers to secure supply services, pursuant to Section 11.7, Supplement No. 35 to Equitable's Gas Tariff – PA. P.U.C. No. 22, except in the limited circumstance of a customer attempting to bypass or otherwise leave the Equitable distribution system. Similar treatment would exist on the Peoples' system until merger of the companies.

2. Equitable shall file tariff sheets amending Section 11.7, above, no later than thirty (30) days after closing of the stock acquisition. The revised Section 11.7 shall read as follows: "The Company may act as an agent for securing supply services only under the following limited circumstances:
    1. The customer requests such a service of the Company.
    2. The customer is an existing customer of the Company
    3. The customer represents that it has received a bona fide offer from another company to bypass or otherwise leave the Equitable distribution system.
    4. Equitable must attempt to obtain offers for supply services from at least three different natural gas suppliers.
    5. Equitable shall provide documentation to the Commission, upon request, that the four conditions above have been met."

Equitable Gas Company

Docket No. A-122250F5000

Settlement Agreement with Hess Corporation and Constellation New Energy - Gas Division, LLC

3. Equitable commits to not sign up any customers under Dominion Rate CER in the current tariff, Supplement No. 37 to Gas PA-PUC No. 43, or any other agency program or agency provision in the current tariff, notably the agency programs contained in Rates GS-T and T, and to file with the PA PUC to remove these tariff provisions from Dominion's current and future tariffs and that such filing to be made no later than thirty (30) days after closing on the stock acquisition. Equitable may seek to replace these provisions with the proposed language contained in paragraph 2 above.

4. All existing agency service contracts executed pursuant to Section 11.7 shall be grandfathered and assigned to Equitable's marketing affiliate within thirty days of the Commission's final order approving the stock acquisition on terms acceptable to Equitable. All services provided in conjunction with the assigned contracts will be subject to Natural Gas Supplier Standards of Conduct, 52 Pa. Code § 62.142. The assignment shall be accompanied by written notice from Equitable to its customers that the contract will terminate at the expiration of the present term. At the time of the assignment, Equitable will also send all customers then receiving agency service a written notice, in form and substance mutually agreeable to Hess, Constellation and Equitable, that upon the expiration of the assigned contracts the customers will be required to receive their natural gas supply from an NGS of their choice. The notice shall list all current NGSs, including Equitable Energy, that are licensed to supply gas in Equitable's service territory.

5. Equitable is not aware, at this time, of the method used by Dominion Peoples with regard to its agency service. Accordingly, Equitable may elect to handle agency service on Peoples consistent with paragraph 4, above, or as follows:

Equitable Gas Company

Docket No. A-122250F5000

Settlement Agreement with Hess Corporation and Constellation New Energy - Gas Division, LLC

All existing agency service contracts executed by Dominion People shall be non-renewed by Peoples upon the expiration of their present terms. Equitable shall cause Dominion Peoples to send its customers written notice of termination or non-renewal within thirty days of closing on the stock purchase transaction. Such notice shall be accompanied by a notice, in form and substance mutually agreeable to Hess, Constellation and Equitable and similar to that referenced in paragraph 4, above, advising agency customers of Dominion Peoples that they will be required to receive their natural gas supply from an NGS of their choice upon the expiration of their agency contract and containing a list of all current NGSs that are licensed to supply gas in Dominion People's service territory.

6. In the event there are any existing agency contracts executed under Section 11.7 which have terms expiring during the consideration of this Application, Equitable shall be permitted to renew such contracts, but shall limit such contract renewals to no longer than a twelve (12) month term. Equitable agrees that, except in circumstances satisfying the conditions set forth in paragraph 2 above, it will not enter into any new agency contracts during the consideration of the Application.

7. Subject to 1 and 2, above, for all existing non-agency customers or for agency customers whose contracts have expired, natural gas commodity in the Equitable service territories shall only be available from Equitable Gas Company at PGC rates or from a PA PUC licensed natural gas supplier.

8. To the extent that marketers provide us with accurate information, Equitable shall ensure the information on its website regarding available NGSs is up to date, accurate, and does not list "Equitable Gas Company – Marketing Department" as a competitive supplier.

Non-agency Settlement needs:

1. As part of the proceeding combining the tariffs of Equitable and Dominion, Equitable commits to filing tariff provisions that promote the development of

Equitable Gas Company

Docket No. A-122250F5000

Settlement Agreement with Hess Corporation and Constellation New Energy - Gas Division, LLC

the competitive market in the combined service territory. Prior to commencing any proceeding to combine the tariffs of Equitable and Dominion, Equitable agrees to form a users group of marketers to make recommendations concerning the proposed merged tariff.

2. Prior to implementing the proposed changes to the Equitable ALTRA system intended to replace Dominion Peoples' ESCRIPT system, Equitable shall convene a users group of marketers who serve on the Equitable and Dominion Peoples' systems for the purposes of testing the new ALTRA system before it is implemented.

3. Attached to this settlement term sheet is a chart listing the functions that Equitable intends its ALTRA system to have. Equitable agrees that the users group may recommend and Equitable will consider changes to Equitable's operational rules and practices that are necessary to achieve the functionality set forth on the chart.

AGREED TO BY:

Christopher A. Lewis
Counsel to Hess Corporation and
Constellation New Energy - Gas Division, LLC

Randall L. Crawford
President - Equitable Utilities

Comparative Summary
Equitable Gas-PA Division and Dominion Peoples
Transportation Pool Management Functionality

A. Transportation Pool Type Overview

	Dominion Peoples		Equitable		Equitable
	Present		**Present**		**Close**
1	Rate NP1 (Non-Priority One Pooling Service)	1	Rate GPS (General Pooling Service)	1	Rate NP1 (Non-Priority One Pooling Service)
2	Rate P1 (Priority One Pooling Service)	2	Rate FPS (Firm Pooling Service)	2	Rate P1 (Priority One Pooling Service)
3	Rate LGA (Local Gas Aggregation Service)	3	N/A	3	Rate LGA (Local Gas Aggregation Service)
4	Rate GS-T (General Service-Transport) [Standalone Pool] Rate T (Industrial Service-Transport) [Standalone Pool]	4	Rate GDS (General Delivery Service) [Standalone Pool] Rate DDS (Daily Delivery Service) [Standalone Pool]	4	Rate GS-T (General Service-Transport) [Standalone Pool] Rate T (Industrial Service-Transport) [Standalone Pool]
				5	Rate GPS (General Pooling Service)
				6	Rate FPS (Firm Pooling Service)
				7	Rate GDS (General Delivery Service) [Standalone Pool] Rate DDS (Daily Delivery Service) [Standalone Pool]

B. Storage Service Type Overview

	Dominion Peoples		Equitable		Equitable
	Present		**Present**		**Close**
1	Rate ST (Storage Service) [No Notice]	1	N/A		Rate ST (Storage Service) [No Notice]
2	Rate ST-SW (Storage Service Scheduled Withdrawal)	2	N/A		Rate ST-SW (Storage Service Scheduled Withdrawal)

Comparative Summary
Equitable Gas-PA Division and Dominion Peoples
Transportation Pool Management Functionality

C. IT Systems Functionality Overview

	Dominion Peoples ESCRIPT System		Equitable ALTRA System
	A. Online Scheduling		
1	Interstate Pipeline Nominations	1	Interstate Pipeline Nominations
2	Storage Nominations	2	Storage Nominations
3	Local Gas Nominations	3	Local Gas Nominations
4	Pool to Pool Trading	4	Pool to Pool Trading
5	Imbalance Trading	5	Imbalance Trading
	B. Online Reports		
1	Daily Storage Balances	1	Daily Storage Balances
2	Direct Pooling Report	2	Direct Pooling Report
3	NP1 Pooling Report	3	NP1 Pooling Report
4	P1 Pooling Report	4	P1 Pooling Report
5	Pool to pool transfers	5	Pool to pool transfers
6	Storage Nominations	6	Storage Nominations
7	Transportation Nominations	7	Transportation Nominations
	C. Online Downloads		
1	Telemetered Customer Usage - Daily	1	Telemetered Customer Usage - (Daily VIA EQT.COM)
2	Producer Metered Volumes - Monthly	2	Producer Metered Volumes - Monthly

Comparative Summary
Equitable Gas-PA Division and Dominion Peoples
Transportation Pool Management Functionality

D. Website Functionality Overview

	DOM.COM (Outside ESCRIPT)		EQT.COM (Outside ALTRA)
A. Online Uploads			
1	Customer Enrollment	1	Customer Enrollment
2	Billing Rates	2	Billing Rates
3	*Supply Source (PA versus Interstate)*	3	*Supply Source (PA versus Interstate)*
B. Online Downloads			
1	Pooling Invoice	1	Pooling Invoice (VIA ALTRA)
2	Pool Metered Usage	2	Pool Metered Usage
3	Enrollment Response File	3	Enrollment Response File
4	Monthly Customer Confirmation File	4	Monthly Customer Confirmation File
5	Activity File	5	Activity File
6	Billing File	6	Billing File
7	Payment File	7	Payment File
8	Transfer File	8	Transfer File
C. Customer Enrollment Mailings			
1	Confirmation Letter	1	Confirmation Letter

Rebuttal Testimony of John M. Quinn
Equitable Gas Company
Docket No. R-2008-2029325
Attachment JMQ-12

Equitable Gas Company, LLC
Summary Revenue Allocation Proposals
Docket No. R-2008-2029325

Litigation Positions:

Party	Total Non-gas Revenue Increase	Proposed Revenue Increase RS	Proposed Revenue Increase GSS	Proposed Revenue Increase GSL	Proposed Revenue Increase AGS
EGC	$ 51,950	$ 40,050	$ 1,432	$ 2,950	$ 7,518
OCA (1)	51,950	37,243	1,320	5,865	7,522
OSBA (2)	51,950				
OTS (3)	51,950	40,050	-	4,382	7,518
IOGA (4)	57,391	47,000	10,391	-	-
Average of Recommendations		$ 41,086	$ 3,286	$ 3,299	$ 5,640

Summary of Percentage Increase by Class

		RS	GSS	GSL	AGS
Current Operating Revenue	$ 157,692	$ 108,301	$ 14,590	$ 29,475	$ 5,326
EGC		37%	10%	10%	141%
OCA (1)		34%	9%	20%	141%
OSBA (2)					
OTS (3)		37%	0%	15%	141%
IOGA (4)		43%	71%	0%	0%

Notes:

(1)

(2) Mr. Kalcic's revenue allocation combines a first-dollar relief, and residual scaleback to classes tied to the Equitable's approved revneue increase.

(3) The first $3.011 MM in revenue reduction should reduce the RS class. Any additional revenue reduction shoud be used to proportionally reduce all rate classes.

(4)

OUTLINE

ORAL REJOINDER OF EQUITABLE WITNESS DAVID W. ROSS

I. Rejoinder to OTS witness Debra Backer:

A. Adjustment to billing lag days

1. Use of AMR as a timely and accurate meter reading system

2. Improvements in customer service, collection, and billing processes and related savings

3. Cost of estimated/erroneous meter readings – bill process

4. Use of gathering meters

5. Meter reading dates, audit exceptions and the CIS billing system

II. Rejoinder to OCA witness Lafayette Morgan

A. Short Term Incentive Compensation Payment (STIP) Expense Day Lag

1. Factors considered in incurring the STIP expense

B. Corporate Shared Services Expense Lag

1. Substantiation of the development of the expense amount

a. Actual data
b. Impact of quarterly reconciliations

2. Development of payment date

a. Use of accounting journal entries versus wire transfer dates

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Equitable Statement No. 2-R
Docket No. R-2008-2029325
Witness: Jeffery C. Mitchell
Date: 11/19/08

EQUITABLE GAS COMPANY

Rebuttal Testimony of

Jeffery C. Mitchell

PREPARED REBUTTAL TESTIMONY OF JEFFERY C. MITCHELL

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffery C. Mitchell. My business address is 225 North Shore Drive, Pittsburgh, PA 15212-5861.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company as Vice President and Controller.

Q. ARE YOU THE SAME JEFFERY C. MITCHELL WHO SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am. My direct testimony accompanied the Company's general base rate filing and was pre-marked for identification as Equitable Statement No. 2.

II. Purpose and Scope of Testimony

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to respond to the various adjustments proposed by witnesses for the Office of Consumer Advocate ("OCA") and Office of Trial Staff ("OTS"). The table below identifies the witness and each adjustment by witness:

Witness	Adjustments
Lafayette K. Morgan, Jr.- OCA	Collections Costs, Anode Expenses (including Cathodic Protection Costs), Customer Experience Survey Costs, PA One Call Expenses, Lobbying Expenses, Payroll Expenses, Pension and Post-retirement Expenses, Regulatory Commission Expenses, Fuel Expenses, Injuries and Damages Expenses, Right-of-Way Mowing Expenses, Universal Service Costs and Interest Synchronization

Debra Backer- OTS	Rate Case Expenses, Pension Expenses, and Advertising Expenses

III. Organization of Rebuttal Testimony

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony is organized by issues identified and addresses the adjustments of each witness within each topic. The primary issues addressed in my rebuttal testimony are related to expense adjustments proposed by the OCA and OTS witnesses. These expense items will be addressed in my rebuttal testimony based on the following order:

1) Expenses

A) Collections Costs

B) Anode Expenses

Cathodic Protection

C) Customer Experience Survey Costs

D) PA One Call Expenses

E) Lobbying Expenses

F) Payroll Expenses

G) Pension and Post-retirement Expenses

H) Regulatory Commission Expenses

I) Fuel Expenses

J) Injuries and Damages Expenses (includes Legal Settlements)

K) Right-of-Way Mowing Expenses

L) Universal Service Costs

M) Interest Synchronization

N) Advertising Expenses

IV. Expense Adjustments

A) Collections Costs

Q. DO YOU AGREE WITH WITNESS MORGAN'S COMMENTS REGARDING THE INAPPROPRIATENESS OF THE COMPANY'S COLLECTIONS COST ADJUSTMENT?

A. No, I do not.

Q. PLEASE DESCRIBE THE NATURE OF THESE COLLECTIONS COSTS.

A. The collections costs are paid to third party collection agencies based on a percentage of the amount of previously written off accounts receivable balances collected from the former customer by the third party agency.

Q. DO YOU AGREE WITH WITNESS MORGAN'S STATEMENT THAT THE COMPANY IS ATTEMPTING TO RECOVER COSTS ACCUMULATED BEFORE THE TEST YEAR?

A. No, I do not. The third party collections costs totaling $612,202 were the actual costs incurred in the historic test year of 2007.

Q. DO YOU AGREE WITH MR. MORGAN'S STATEMENT THAT THE COMPANY DOES NOT INCUR SUCH ANNUAL RECURRING COSTS FOR COLLECTIONS?

A. No, I do not. These costs are incurred every year, only the amount differs. Again, the costs incurred for 2007 were $612,202.

Q. PLEASE PROVIDE THE HISTORIC THIRD PARTY COLLECTIONS COSTS INCURRED BY THE COMPANY.

A. Total third party collections costs incurred for 2005-2007 were as follows:

2005- $639,072

2006- $759,750

2007- $612,202

The three year average of these costs is $670,341.

Q. DO YOU AGREE WITH WITNESS MORGAN'S COMMENT THAT THE COMPANY'S ACCOUNTING FOR THESE COLLECTIONS COSTS IS ESSENTIALLY AN UNAUTHORIZED DEFERRED ACCOUNTING FOR THESE COSTS?

A. No, I do not. These costs were not recorded as a deferred or regulatory asset by the Company but rather were recorded in the A/R reserve.

Q. WHY IS THE CLASSIFICATION OF THESE COSTS IN THE A/R RESERVE DIFFERENT THAN A DEFERRED OR REGULATORY ASSET?

A. Deferred or regulatory assets include costs that are incurred but not recognized in the income statement until a later period. Such costs are then typically amortized and recognized as expense over a period of time. Costs charged to the A/R reserve are recognized in the income statement as a result of the Company's quarterly analysis of the adequacy of the A/R reserve. If these costs had been accounted for as a deferred or regulatory asset, the Company would be claiming costs incurred over several years and seeking recovery through amortization.

Q. PLEASE EXPLAIN THE QUARTERLY A/R RESERVE ANALYSIS PROCESS AND THE ADJUSTMENTS TO THE INCOME STATEMENT.

A. The Company records an estimated amount of bad debt expense each month and a corresponding increase to the A/R reserve. At quarter-end, the Company evaluates the adequacy of the A/R reserve through the A/R reserve analysis process. The process entails comparing the aged A/R balances to the A/R reserve balance, as well as recent and historic collection and write-off trends. Based on this analysis, the Company determines whether or not to record additional bad debt expense to increase the A/R reserve or to reduce bad debt expense to decrease the A/R reserve.

Q. HOW ARE THE COLLECTIONS COSTS RECOGNIZED AND NOT DEFERRED?

A. Since the A/R reserve is evaluated for adequacy and adjusted quarterly via an applicable income statement adjustment, all reserve activity is recognized in the income statement either directly, such as bad debt expense recorded monthly, or indirectly, such as the collections costs.

Q. PROVIDE A THEORETICAL EXAMPLE OF HOW COLLECTIONS COSTS ARE RECOGNIZED.

A. In the month of September, the Company pays $50,000 in collections costs which are charged to the A/R reserve, thus reducing the reserve balance. At quarter-end, the Company completes the A/R reserve analysis which results in an A/R reserve shortage of $500,000. The Company then records bad debt expense in the amount of $500,000 and an increase in the A/R reserve. Had the collections costs of $50,000 not been incurred, the A/R reserve would not have been reduced by this amount, and the total increase in bad debt expense to fund the shortage in the A/R reserve would only have been $450,000. Thus, the collections costs are indirectly recognized in the income statement.

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADJUSTMENT FOR COLLECTIONS COSTS?

A. No, I do not. I recommend that the adjustment of $612,202 actually be increased to reflect the three-year average collections costs activity as calculated in my rebuttal testimony to be $670,341. See Schedule JCM-2 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON COLLECTIONS COSTS?

A. Yes, it does.

B) Anode Expenses

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADJUSTMENT TO REMOVE $269,658 FOR ANODE EXPENSES FROM THE COST OF SERVICE?

A. No, I do not.

Q. PLEASE DESCRIBE WHAT THE $269,658 BALANCE RESPRESENTS IN THE FUTURE TEST YEAR.

A. The $269,658 balance represents the expected and estimated costs to be incurred in the future test year for routine inspection and maintenance.

Q. WHY DO YOU DISAGREE WITH THE ADJUSTMENT?

A. I disagree with the adjustment because these inspection and maintenance costs cannot be capitalized per generally accepted accounting principles.

Q. PLEASE EXPLAIN THE COMPANY'S ACCOUNTING POLICY CHANGE THAT OCCURRED BEGINNING IN 2008.

A. Please see Schedule JCM-3 that includes the Company's response to interrogatory OCA-I-19 and OCAVIII-20 which describes the change in the accounting policy and explains the difference between capital and expense related items.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE CHANGE IN ACCOUNTING POLICY.

A. Through evaluations made by operations personnel and the accounting group, it was determined that large scale anode replacement will extend the useful life of the steel pipe that is cathodically protected from corrosion via the anodes. Thus, the Company changed the accounting policy for large scale replacement of anodes from being recorded as an operations and maintenance (O&M) expense to being capitalized. It is important to note that the routine inspection and maintenance of anodes as well as replacement of anodes within a limited pipeline segment ("small scale anodes") are not capitalizable and are recorded as an O&M expense.

Q. DO YOU HAVE AN UPDATE ON THE ESTIMATED FUTURE TEST YEAR OPERATIONS AND MAINTENANCE EXPENSE FOR THE ROUTINE INSPECTION AND SMALL SCALE ANODE REPLACEMENTS IN 2008?

A. Yes, I do. The actual O&M expense related to maintenance and small scale replacements of anodes through September 30, 2008 is $385,126. The projected total costs for 2008 is $513,502.

Q. PLEASE SUMMARIZE YOUR COMMENTS ON WITNESS MORGAN'S ANODE EXPENSE ADJUSTMENT AND PROVIDE ANY UPDATES TO THE FUTURE TEST YEAR O&M EXPENSE.

A. There is no change in accounting for routine maintenance and small scale anode replacement. Accepting the adjustment as proposed by witness Morgan will

understate the O&M expense related to anode inspection and maintenance. Based on the updated 2008 future test year anode O&M expense to be incurred, the Company is increasing its future test year claim by $243,844, resulting in estimated costs for 2008 of $513,502 as compared to the amount included in the Company's filing of $269,658.

Q. ARE THERE ANY OTHER ANODE RELATED MATTERS ADDRESSED BY WITNESS MORGAN?

A. Yes. Witness Morgan has also proposed an adjustment to reduce the future test year O&M related to DOT compliance costs of $133,524.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No, I do not. Similar to my comments regarding routine inspection and maintenance of anodes, these estimated costs of $133,524 are related to the routine inspection, maintenance and small scale replacement of anodes on the Company's gathering system. Thus, these costs are recorded as O&M and must be included in the future test year cost of service. Furthermore, these costs are exclusive of the previously mentioned updated 2008 future test year amount of $513,502 for routine inspection and maintenance. See Schedule JCM-4 for the calculation of these adjustments.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON ANODE COSTS AND DOT COMPLIANCE COSTS?

A. Yes, it does.

C) Customer Experience Study Costs

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADJUSTMENT TO NORMALIZE CUSTOMER EXPERIENCE STUDY COSTS?

A. I do agree with the normalization of the customer experience study costs. However, I do not agree with witness Morgan's normalization adjustment to reduce future test year O&M expenses by $636,686. I believe the 5-year period proposed by witness Morgan is excessive and is not representative of the Company's plans for evaluating its customer experience on an on-going basis.

Q. PLEASE EXPLAIN THE COMPANY'S POSITION ON NORMALIZING THE CUSTOMER EXPERIENCE STUDY COSTS.

A. The Company proposes that the total customer experience study costs be normalized over a 3-year period. The Company continues to focus on means to improve customer service. The Company plans to study customer needs and the benefit of proposed service enhancements, and to determine if past operational improvements have had the desired effect. The Company plans to confirm the impact to customers of such improvements by conducting smaller, focused surveys on an annual basis, as well as a larger scale survey every three years for comparative changes to the 2007 baseline. Such surveys will provide valuable feedback that the Company can evaluate and utilize to further enhance the experience of its customer base.

Q. PLEASE PROVIDE THE COMPANY'S PROPOSED ADJUSTMENT FOR CUSTOMER EXPERIENCE STUDY COSTS.

A. Based on the current customer survey plan, the Company will include $265,286 ($795,858 divided by 3 years) in the O&M cost of service, thus reducing the original cost of service amount by $530,572 ($795,858 less $265,286).

Q. HOW DOES THE COMPANY'S POSITION VARY FROM WITNESS MORGAN'S ADJUSTMENT?

A. The Company proposes that witness Morgan's reduction of the cost of service be decreased by $106,114, which is equal to witness Morgan's adjustment of $636,686 less the Company's adjustment of $530,572. See Schedule JCM-5 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON CUSTOMER EXPERIENCE STUDY COSTS?

A. Yes, it does.

D) PA One Call Expenses

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADJUSTMENT TO REMOVE $83,197 FOR PA ONE CALL EXPENSES FROM THE COST OF SERVICE?

A. No, I do not.

Q. DO YOU AGREE WITH THE REVISED COST PER UNIT AND CORRESPONDING ADJUSTMENT PROPOSED BY WITNESS MORGAN?

A. I agree that the unit cost for the line locates to be completed by an external contractor in the future test year should be at a rate of $16.05 per unit compared to the estimate that was included in the base rate filing for the future test year of $17.50. Accordingly, I also agree with the corresponding reduction in O&M

expense of $45,742, which is equal to 31,546 line locates x $1.45 per unit (or $17.50 less $16.05).

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADUSTMENT FOR PUBLIC AWARENESS COSTS?

A. I agree with the adjustment to exclude the public awareness costs of $10,000 as these costs are not incremental per further review of these PA One Call related costs.

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADUSTMENT FOR WORK MANAGEMENT SUPPORT COSTS?

A. No. I disagree with the exclusion of work management support costs. Witness Morgan comments that these costs are not incremental costs, and that only costs of the new contract should be reflected. I do not agree with this position because the costs are indeed incremental as they are related to the expanded volume of work that is not included in the historic test year. The work management support costs include the expanded use of the contractor's Translore system to manage the PA One Call tickets as well as management support for the project. Thus, the contractor management support costs of $27,455 are incremental to the historic level of costs and should not be omitted from the cost of service.

Q DO YOU HAVE UPDATED INFORMATION FOR THE 2008 FUTURE TEST YEAR?

A. Yes, I do. The projected incremental volume for the future test year is 32,420 locates, or 874 line locates higher than the 31,546 that was used to determine the adjustment for the future test year. This increased volume will increase the future test year PA One Call costs by $14,028. Furthermore, the Company annually incurs

PA One Call System Charges that are payable to the state based on the total PA One Call requests. If the PA One Call ticket is within the buffer zone of the Company's facilities, it is then dispatched for location within 72 hours. The unit cost for this PA One Call System Charge is $.85 per call. The future test year currently assumes 83,000 calls at $.85 per call, or $70,550. As a result of the continued public awareness initiatives and the increased volume of construction work in the Company's service region, the updated future test year volume of PA One Call requests is expected to be 107,675 based on actual volume of 80,855 through September 2008. This increased volume results in an increase in PA One Call System Charges of $20,974, or 24,675 more calls x $.85 per call. The Company expects the on-going volume of calls subject to the PA One Call System Charges to continue at this level.

Q. PLEASE SUMMARIZE YOUR FUTURE TEST YEAR ADJUSTMENTS.

A. See schedule JCM-6 for the summary of the future test year adjustments which decreases the Company's original total future test year cost adjustment of $572,000 by $20,741, for a revised adjustment total of $551,259.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON PA ONE CALL EXPENSES?

A. Yes, it does.

E) Lobbying Expenses

Q. DO YOU AGREE WITH WITNESS MORGAN'S REMOVAL OF LOBBYING EXPENSES FROM THE COST OF SERVICE?

A. I agree that lobbying expenses should not be part of the cost of service for ratemaking purposes.

Q. DO YOU AGREE WITH THE ADJUSTMENT PROPOSED BY WITNESS MORGAN?

A. No, I do not. Upon reviewing witness Morgan's direct testimony and proposed lobbying expense adjustment, an error was identified in the Company's response to data request OTS-RE-78-D, item D.

Q. PLEASE DESCRIBE THE NATURE OF THE ERROR IN THE RESPONSE TO OTS-RE-78-D.

A. The response to data request OTS-RE-78-D was incorrect as it assumed that the entire corporate allocation for Equitable Resources' governmental affairs activities was deemed to be related to lobbying. Upon further review, the costs included in the future test year totaling $122,009 represent employee labor and fringe benefits for the corporate allocation of governmental affairs and already excluded lobbying costs of $88,378. The Company made an adjustment to exclude the $88,378 from the Per Books columns on Exhibit III, Item: §53.53 III.A.17 for the historic test year, as the Company agrees that lobbying costs should be removed from the cost of service (see Schedule JCM-7 for further details). Based on the Company's updated review of the nature of the $122,009 of allocated costs, the Company does not agree with the adjustment proposed by witness Morgan which would improperly reduce the cost of service for costs that are properly recoverable in the future test year.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING THE LOBBYING EXPENSE ADJUSTMENT PROPOSED BY WITNESS MORGAN?

A. Yes, I do. I agree with excluding $1,584 from the cost of service for the portion of the AGA dues attributed to lobbying. As such, the revised response to the data request OTS-RE-78-D, item D. should read, "the Company's lobbying fee expenses for the FTY are $1,584."

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON LOBBYING EXPENSES?

A. Yes, it does.

F) Payroll Expenses

Q. DO YOU AGREE WITH WITNESS MORGAN'S ADJUSTMENT TO REMOVE $342,428 FOR PAYROLL AND BENEFITS EXPENSES FROM THE COST OF SERVICE?

A. No, I do not.

Q. EXPLAIN YOUR DISAGREEMENT WITH WITNESS MORGAN'S ADJUSTMENT RELATED TO UNFILLED POSITIONS.

A. I disagree with a component of the adjustment related to unfilled positions as listed on witness Morgan's schedule LKM-13. Two of the Compressor Operator positions were filled on June 16, 2008 by hiring new employees (employee numbers #99909909 and #99909986) at a total annual salary cost of $100,464. The other remaining vacant positions identified in Schedule LKM-13 remain unfilled and will not be filled by December 31, 2008. As such, I agree with witness Morgan's adjustment for the Producer Services Analyst and Engineer.

Q DO YOU DISAGREE WITH WITNESS MORGAN'S COMMENTS THAT A POSITION WAS INCLUDED TWICE IN THE FUTURE TEST YEAR.

A. Yes, I do. Please note that there is an outstanding data request to clarify this adjustment amount. I assume that the position questioned by witness Morgan is actually employee #99908558, whose position was vacated on December 31, 2007. This position was then filled by hiring new employee # 99909678 on January 28, 2008 with an annual salary amount of $65,532 (per the attachment in Company response to OCA-IX-8). With this underlying assumption, I do not agree with the adjustment proposed by witness Morgan related to the perceived double-counting of labor and fringe costs.

Q. WHY DO YOU NOT AGREE WITH THIS ADJUSTMENT?

A. I do not agree with the adjustment since employee #99908558 was promoted into a new role in the Customer Operations department effective January 1, 2008, and as such, these employee costs remain in the cost of service. The new employee #99909678 was then hired into the role vacated by employee #99908558. As a result, the costs for both employees were properly included in the cost of service, and removing the cost for employee #99908558 would improperly reduce the Company's cost of service.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING THE PAYROLL AND BENEFITS EXPENSE ADJUSTMENTS?

A. Yes, please see schedule JCM-8 for the calculation of the proposed adjustment to the future test year which reduces the original future test year O&M by $124,206 to $218,222. Please also note that upon receipt of the outstanding data request, the Company will update this response as deemed necessary.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON PAYROLL AND BENEFITS EXPENSES?

A. Yes, it does.

G) Pension and Post-retirement Expenses

Q. DESCRIBE THE BASIS FOR INCLUDING PENSION AND POST-RETIREMENT EXPENSE IN THE COST OF SERVICE.

A. The Company based its historic and future test year pension and post-retirement benefit expense on the related actuarially determined expenses in accordance with generally accepted accounting principles. The Company also assumed the 2008 future test year expense would equal the 2007 historic test year actual expense.

Q. DOES WITNESS BACKER AGREE WITH THIS APPROACH?

A. No, she does not.

Q. DOES WITNESS MORGAN AGREE WITH THIS APPROACH?

A. Yes, he does.

Q. WHY DID THE COMPANY UTILIZE THIS APPROACH RATHER THAN INCLUDE CASH–BASED FUNDING IN THE COST OF SERVICE?

A. The expense-based approach for determining pension and post-retirement benefit expense in the cost of service was used for the following reasons: the expenses are recognized over the life of the plan based on assumptions that are subject to annual audits and independent actuarially determined calculations; expenses are less volatile in amount than cash payments as cash payments might only be made periodically based on the ERISA minimum funding obligations; expenses are not subjective as they are based on the actuarial calculations, whereas cash payments are subjective in nature as the Company may make more payments than the required

minimum if it so chooses; and the expenses are recorded in accordance with generally accepted accounting principles.

Q. DO YOU AGREE WITH THE POSITION OF WITNESS BACKER TO EXCLUDE THE ENTIRE FUTURE TEST YEAR PENSION AND POST-RETIREMENT BENEFIT EXPENSE?

A. No, I do not. Although I agree that the Company did not make cash payments to the pension plan in 2007 and has not to date made cash payments in 2008 due to the plan being funded at more than the minimum requirement in these years, it is unreasonable to include zero costs in the cost of service for 2007 and 2008 due to the funding status circumstances that did not require a cash payment. As an example of the volatility of cash payments, the Company is expected to make cash payments to the pension plan of $10.5 million for Equitable Gas Company obligations in early 2009 based on recent changes in the funding status of the plan. Due to this payment occurring in 2009 outside of the future test year, witness Backer's approach would suggest that these costs would not be included in the future test year cost of service. In the event that this payment were to be made in the fourth quarter of 2008, witness Backer's approach would suggest that this payment be included. This would result in an increase in the cost of service by approximately $8.0 million ($10,500,000 in 2009 funding payment less $2,457,296 future test year expense) due to this payment. Even if witness Backer would propose to normalize this payment over three years, the Company's pension and post-retirement benefit costs would still exceed $3.0 million and be slightly higher than the amount included by the Company in the cost of service.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO WITNESS BACKER'S POSITION IN HER DIRECT TESTIMONY.

A. For the reasons previously mentioned, I disagree with the cash-based approach to determining the pension and post-retirement benefit cost of service. As a result, witness Backer's adjustment to reduce the cost of service by $2,457,296 should not be accepted.

Q. DOES WITNESS MORGAN AGREE WITH THIS CASH-BASED ADJUSTMENT FOR PENSION AND POST-RETIREMENT BENEFITS?

A. No, he does not. Witness Morgan is suggesting that the Company update the future test year costs based on the updated 2008 actuarial study provided in the Company response to data request OTS-RE-68-D.

Q. DO YOU AGREE WITH UPDATING THE 2008 FUTURE TEST YEAR COSTS?

A. Yes, I do. However, rather than utilizing the updated 2008 actuarial study included in the Company response to data request OTS-RE-68-D, the future test year costs should be adjusted based on a more recent update the Company received from its actuaries.

Q. WHAT ARE THE UPDATED PENSION AND POST-RETIREMENT BENEFIT COSTS FOR THE 2008 FUTURE TEST YEAR?

A. The updated actuarially determined information has resulted in updated 2008 future test year costs of $2,992,738 for Equitable Gas.

Q. DOES THE COMPANY PROPOSE AN ADJUSTMENT TO THE FUTURE TEST YEAR PENSION AND POST-RETIREMENT BENEFIT EXPENSE?

A. Yes, based on the updated 2008 actuarially determined information, and after reducing the total expense by 1.64% for West Virginia and by multiplying the total Pennsylvania costs by the O&M percentage consistent with witness Morgan's calculation, the total updated pension and post-retirement benefit expense for the future test year is $2,484,447, an increase of $27,151 from the amount included in the future test year of $2,457,296. See schedule JCM-9 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON PENSION AND POST-RETIREMENT EXPENSES?

A. Yes, it does.

H) Regulatory Commission Expense

Q DO YOU AGREE WITH THE TOTAL ADJUSTMENT PROPOSED BY WITNESS MORGAN RELATED TO THE NORMALIZATION OF REGULATORY COMMISSION EXPENSES?

A. No, I do not agree with the total adjustment amount.

Q. DESCRIBE THE AREAS IN WHICH YOU DISAGREE AND ANY PROPOSED CHANGES TO THE ADJUSTMENTS OF WITNESS MORGAN.

A. First, I disagree with witness Morgan's complete exclusion of the management audit costs. As stated in the Company response to OCA-IV-15 and OTS-RE-138, the Company expects the management audit to commence in the fourth quarter of 2008 and expects the costs to be incurred during the course of the audit. Furthermore, it is common to recover costs associated with these mandated audits. Based on the expected recoverability of these costs, the ability to reasonably estimate the costs,

and the expectation of the audit commencing during the future test year, it is reasonable to include an annual normalized expense amount in the future test year. As such, I am recommending that witness Morgan's adjustment to reduce O&M be decreased by $150,000 for the normalization of the management audit fees. Second, I continue to disagree with the normalization period of five years proposed by witness Morgan. Although the Company's prior history of filing rate cases has been sporadic, the Company is forecasting that another rate case will be filed in three years based on the current economic environment and its focus on ensuring adequate returns on its rate base. As such, I am proposing that witness Morgan's adjustment to reduce O&M be decreased by $140,155.

Q. DO YOU AGREE WITH ANY COMPONENT OF THE ADJUSTMENT PROPOSED BY WITNESS MORGAN?

A. Yes. I agree with the component of witness Morgan's calculation that excludes costs related to West Virginia matters.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TO THE ADJUSTMENT PROPOSED BY WITNESS MORGAN CONCERNING REGULATORY COMMISSION EXPENSE.

A. The adjustment proposed by witness Morgan to reduce O&M by $298,781 should be reduced by $290,155, resulting in a decrease in O&M of $8,626 to remove costs related to West Virginia. See schedule JCM-10 for the calculation of this adjustment.

Q DO YOU AGREE WITH THE ADJUSTMENT PROPOSED BY WITNESS BACKER RELATED TO THE NORMALIZATION OF REGULATORY COMMISSION EXPENSES?

A. No, I do not agree with the total adjustment amount. I also disagree with the normalization period of five years as proposed by witness Backer for the same reasons identified in my response to witness Morgan.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TO THE ADJUSTMENT PROPOSED BY WITNESS BACKER.

A. The adjustment proposed by witness Backer to reduce O&M by $140,155 should be reduced to zero. However, per my response to witness Morgan, I agree to reduce the O&M adjustment by $8,626 for the costs related to West Virginia matters. See schedule JCM-10 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON REGULATORY *COMMISSION EXPENSES?*

A. Yes, it does.

D) Fuel Expenses

Q. DO YOU AGREE WITH THE METHODOLOGY USED BY WITNESS MORGAN IN HIS ADJUSTMENT FOR FUEL EXPENSES?

A. Yes, in part. I agree with witness Morgan's assumptions for the estimated fuel usage which reflects a reduction in consumption over the entire future test year. I reviewed witness Morgan's calculation on schedule LKM-16 and agree with the forecasted diesel and gasoline consumption. However, I disagree with the price assumption for diesel fuel of $4. I have estimated the cost per gallon of diesel fuel at $4.24 per gallon in the Company response to OCA VIII-19. I believe a rate of $4.24 per gallon is more likely over the period of time the rates being set in this proceeding will be in effect. Using witness Morgan's estimated diesel consumption

and the $4.24 per gallon rate, the adjustment proposed by witness Morgan that reduced O&M by $69,623 will be reduced by $20,609. This results in a revised adjustment to O&M of $49,014. See schedule JCM-11 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON FUEL EXPENSES?

A. Yes, it does.

J) Injuries and Damages Expense

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION FOR INJURIES AND DAMAGES EXPENSE INCLUDED IN THE COST OF SERVICE.

A. The Company determined its cost of service for injuries and damages matters based on the expenses recorded on the books of record. The 2007 historic test year account activity was then reviewed and the adjustments to expense and the corresponding reserve were normalized by backing these adjustments out of the cost of service. This resulted in an increase to the cost of service for injuries and damages expenses of $3,145,292. Note that the future test year was assumed to equal the historic test year for injuries and damages.

Q. PLEASE SUMMARIZE WITNESS MORGAN'S APPROACH TO THE COST OF SERVICE ADJUSTMENTS FOR INJURIES AND DAMAGES.

A. Witness Morgan proposed a normalization adjustment for injuries and damages expense using the actual claims paid over a three-year period from 2005-2007.

Q. DO YOU AGREE WITH NORMALIZING THIS ACTIVITY USING A THREE-YEAR AVERAGE OF THE ACTUAL CLAIMS PAID FOR INJURIES AND DAMAGES?

A. Although the Company's adjustments to the historic test year were calculated differently, I agree with normalizing the activity for the historic test year over a three year average of claims paid. As proposed by witness Morgan, using years 2005, 2006 and 2007 to determine the average would reduce injuries and damages expense by $2,755,953. However, I believe 2008 should be included in the three year average.

Q. ARE THERE ANY UPDATES TO THE FUTURE TEST YEAR FOR INJURIES AND DAMAGES?

A. Yes. The 2008 total estimated payments for injuries and damages are $383,149, which consists of $300,841 actually incurred through September 2008 and $82,308 estimated for the fourth quarter 2008.

Q. WHAT IMPACT DOES THE 2008 UPDATE HAVE ON THE ADJUSTMENTS FOR THE FUTURE TEST YEAR?

A. Using a rolling-three year average for 2006-2008, the updated three-year average for injuries and damages is $334,175, which is $49,126 higher than the $285,049 proposed by witness Morgan. Thus, the adjustment to reduce O&M expenses would decrease to $2,755,953 is now a reduction in O&M of $2,706,827 based on the updated information. See Schedule JCM-12 for calculations supporting the amounts discussed in this section of my rebuttal testimony.

Q. PLEASE SUMMARIZE THE COMPANY'S FILING WITH RESPECT TO LEGAL SETTLEMENT EXPENSES.

A. The Company also determined its cost of service for legal settlements based on the expenses on the books of record for 2007. The 2007 historic test year account activity was then reviewed and adjustments to expense and the corresponding

reserve were normalized by backing these adjustments out of the cost of service. This resulted in a decrease to the cost of service for legal settlement expenses of $2,135,243. Note that the future test year was assumed to equal the historic test year for legal settlements.

Q. PLEASE SUMMARIZE WITNESS MORGAN'S APPROACH TO THE COST OF SERVICE ADJUSTMENTS FOR LEGAL SETTLEMENTS.

A. Witness Morgan accepted the Company's expense-based normalization adjustment and did not propose any adjustments to the cost of service for legal settlement expenses.

Q. ARE THERE INCONSISTENCIES IN WITNESS MORGAN'S APPROACHES TO THE LEGAL SETTLEMENT COSTS AND THE INJURIES AND DAMAGES COSTS?

A. Yes, there are.

Q. DO YOU AGREE WITH WITNESS MORGAN'S APPROACH?

A. No, I do not. The nature and accounting for the legal settlements is very similar to the injuries and damages and should be treated in the same manner for the cost of service.

Q. DO YOU AGREE WITH NORMALIZING THE LEGAL SETTLEMENTS PAID OVER A THREE YEAR PERIOD RATHER THAN USING THE EXPENSE ON THE BOOKS FOR THE PUROSE OF DETERMINING THE RATEMAKING COST OF SERVICE?

A. For consistency, I do agree with normalizing the expense using the legal settlements paid over a three-year period.

Q. WHAT WERE THE LEGAL SETTLEMENTS PAID FOR 2005-2007 AND WHAT WAS THE THREE-YEAR AVERAGE?

As provided in the Company response to data request OCA VIII-27, the legal settlement payments and three-year average for 2005-2007 were as follows:

2005- $108,750

2006- $311,680

2007- $3,960,828

Three year average- $1,460,419

Q. DOES THE COMPANY HAVE A REVISED ADJUSTMENT FOR LEGAL SETTLEMENT EXPENSES USING THE THREE-YEAR AVERAGE CASH PAYMENTS FOR LEGAL SETTLEMENTS.

A. Yes. As a result of using witness Morgan's three-year average cash payment approach and years 2005-2007 for the normalization adjustment, O&M would increase by $1,460,419 related to legal settlements. However, we now have more current data available. The 2008 total estimated payments for legal settlements are $1,767,422, which consists of $1,627,422 actually incurred through September 2008 and $140,000 estimated for the fourth quarter 2008. Consistently applying the rolling three-year average methodology, the average payments for legal settlements would be $2,013,310.

Q. WHAT IMPACT DOES THE 2008 UPDATE HAVE ON THE ADJUSTMENTS FOR THE FUTURE TEST YEAR?

A. Using a rolling-three year average for 2006-2008, the updated three-year average for legal settlements is $2,013,310 which is $552,891 higher than the $1,460,419

adjustment based upon years 2005-2007. See Schedule JCM-13 for calculations supporting the amounts discussed in this section of my rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON INJURIES AND DAMAGES AND LEGAL SETTLEMENTS?

A. Yes, it does.

K) Right-of-Way Mowing Expenses

A. DO YOU AGREE WITH THE ADJUSTMENT PROPOSED BY WITNESS MORGAN TO REDUCE THE RIGHT-OF-WAY MOWING EXPENSES BY $384,431?

A. No, I do not.

Q. DO YOU PROPOSE AN ADUSTMENT TO THE AMOUNT INCLUDED IN THE COST OF SERVICE PROVIDED BY THE COMPANY IN ITS FILING?

A. Yes, I do.

Q. EXPLAIN THE REVISED ADJUSTMENT TO THE COST OF SERVICE FOR RIGHT-OF-WAY MOWING.

A. In the rate case filing, the Company adjusted the actual historic and future test year costs for right-of-way mowing due to the expected mowing of over 800 miles of rights-of-way in 2008. This was a significant increase from prior years, but was commensurate with the Company's focus to evaluate lost and accounted for gas in 2008. Subsequently, the Company revised its estimate and expects to mow 345 miles of rights-of-way in 2008 at a cost of $580 per mile. This is also approximately the number of miles the Company expects to mow on an annual basis going forward. This will enable the Company to mow its rights-of-way on a two to

three year cycle, which is more frequent than the historical level of right-of-way mowing. Since the Company's enhanced focus on lost and unaccounted for gas is expected to continue for many years, the Company believes the total cost of service should reflect mowing 345 miles per year, rather than being normalized using the levels from 2007 and prior years. As such, the Company has revised its estimate of the future test year right-of-way mowing costs to be $200,100 instead of the original estimated future test year mowing costs of $539,910 (2007 actual of $55,479 plus historic test year adjustment of $384,431 plus future test year adjustment of $100,000). This results in the Company reducing its future test year O&M by $339,810. Thus, I recommend that the adjustment proposed by witness Morgan be reduced by $44,621 to be consistent with the Company's revised future test year right-of-way mowing costs. See schedule JCM-14 for the calculation of this adjustment.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON RIGHT-OF-WAY MOWING EXPENSES?

A. Yes, it does.

L) Universal Service Costs

Q. DOES THE COMPANY AGREE WITH THE ADJUSTMENTS PROPOSED BY OCA WITNESS COLTON IN HIS DIRECT TESTIMONY AND INLCUDED ON SCHEDULE LKM-20 IN WITNESS MORGAN'S DIRECT TESTIMONY?

A. No, it does not. Company witness Quinn will address these proposed adjustments in his rebuttal testimony.

M) Interest Synchronization

Q. DO YOU AGREE WITH THE INTEREST SYNCHRONIZATION CALCULATION PROPOSED BY WITNESS MORGAN?

A. I agree with the calculation methodology proposed by witness Morgan, but not the assumptions utilized and the adjustment proposed on schedule LKM-21. The Company's rebuttal adjustment will be incorporated in the quarterly update to the future test year financial statements to be submitted on or before November 7, 2008.

N) Advertising Expenses

Q. DO YOU DISPUTE THE ADVERTISING ADJUSTMENT PROPOSED BY WITNESS BACKER?

A. No, I do not.

Q. DO YOU HAVE A SUMMARY COMPARING WITNESS MORGAN'S ADJUSTMENTS TO THE FUTURE TEST YEAR AND THE COMPANY'S RESPONSE TO THESE ADJUSTMENTS?

A. Yes, I do. Please see schedule JCM-1 for the summary.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

Equitable Gas Company
Summary of Adjustments to Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-1

The following schedule summarizes the adjustments proposed by OCA Witness Morgan and OTS Witness Baker, as well as the Company's revised adjustments per the rebuttal testimony and updates to the amounts included in the future test year.

Item	Adjustment Description	Amount Included in filed FTY	O&M Expense Increase (Decrease) FTY Adjustment per Morgan	O&M Expense Increase (Decrease) FTY Adjustment per Backer	O&M Expense Increase (Decrease) Rebuttal Adjustment per Equitable	O&M Expense Increase (Decrease) Update to FTY per Equitable	*Updated* Amount Included in Equitable's Revised FTY	Reference
A	Third party Collections Costs	$ 612,202	$ (612,202)		$ 612,202	$ 58,139	$ 670,341	JCM-2
B	Anode Expense	$ 269,658	$ (269,658)		$ 269,658	$ 243,844	$ 513,502	JCM-4
B	DOT Compliance/ Cathodic Protection Costs	$ 133,524	$ (133,524)		$ 133,524	$ -	$ 133,524	JCM-4
C	Normalization of Customer Experience Expense	$ 795,858	$ (636,686)		$ 106,114	$ -	$ 265,286	JCM-5
D	PA One Call Expense	$ 572,000	$ (83,197)		$ 27,455	$ 35,001	$ 551,259	JCM-6
E	Governmental Affairs (including Lobbying expenses)	$ 123,593	$ (123,593)		$ 122,009		$ 122,009	JCM-7
F	Payroll Expense	$ 342,428	$ (342,428)		$ 218,222		$ 218,222	JCM-8
G	Pension and Post-Retirement Benefits Expense	$ 2,457,296	$ (463,473)	$ (2,457,296)	$ 2,457,296	$ 27,151	$ 2,484,447	JCM-9
H	Regulatory Commission Expense	$ 516,861	$ (298,781)	$ (140,155)	$ 290,155		$ 508,235	JCM-10
I	Fuel Expense	$ 1,380,814	$ (69,623)		$ 20,609		$ 1,331,800	JCM-11
J	Injuries and Damages Expense	$ 3,041,002	$ (2,755,953)			$ 49,126	$ 334,175	JCM-12
J	Legal Settlements	$ -	$ -		$ 1,460,419	$ 552,891	$ 2,013,310	JCM-13
K	Right-of-way Mowing Expense	$ 539,910	$ (384,431)			$ 44,621	$ 200,100	JCM-14
N	Advertising Expense	$ 12,640		$ (12,640)	$ -	$ -	$ -	
	Subtotal	$ 10,797,786	$ (6,173,549)	$ (2,610,091)	$ 5,717,663	$ 1,010,773	$ 9,346,210	
L	Universal Service Costs (see Witness Quinn's rebuttal testimony for Company's rebuttal position)		$ (10,380,693)		*	*		
M	Interest Synchronization		$ (315,889)		**	**		
	Totals	$ 10,797,786	$ (16,870,131)	$ (2,610,091)	$ 5,717,663	$ 1,010,773	$ 9,346,210	

NOTE: A revised future test year summary of Operating Income inclusive of these adjustments and all other Company adjustments will be provided with the quarterly update to the future test year financial statements on or before November 7, 2008.

* *See Witness Quinn's rebuttal testimony for the Company's rebuttal position.*

** Equitable's rebuttal adjustment to the Interest Synchronization adjustment will be provided with the quarterly future test year update.

Rebuttal to Adjustment to Remove Collections Costs from the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-2

Items	Amount	
Third Party Collections Costs Included in Future Test Year	$ 612,202	1)
Updates to Collections Cost Adjustment for Future Test Year	$ 58,139	1)
Third Party Collections Costs Included in Future Test Year	$ 670,341	1)
Adjustment Proposed by OCA Witness Morgan	$ (612,202)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, A) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-8.

Item: OCA-I-19
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-I-19

With reference to Exhibit III-A-17 (FTY), Sheet 9, please provide an explanation of the adjustment for anodes costs previously capitalized. In your response, please address the following:

a. Explain what anodes are;

b. When the costs were expensed and the amount expensed;

c. The amount of expenses related to anodes that were included in the 2007 O&M expenses; and

d. Explain the cause of the $1,000,000 adjustment and provide the supporting documentation.

Response:

Per the interrogatory above, please note the adjustment is related to "anode costs previously expensed, to be capitalized in 2008" per Exhibit III-A-17 (FTY), Sheet 9, rather than an "adjustment for anodes costs previously capitalized" as stated above in the interrogatory. As such, an normalization adjustment was reflected in Exhibit III-A-17 (FTY), Sheet 9 to reduce expenses in the future test year.

a. An anode is an electrode through which electric current flows into a polarized electrical device. Anode groundbed systems are utilized to distribute cathodic protection current to protect pipelines.

b. The installation costs of the original anodes are capitalized with the installation of the steel pipe. Historically, costs related to the periodic inspection and replacement of individual anodes are generally treated as a period cost when incurred.

c. The amount of expenses related to anodes that was included in the 2007 O&M expenses was $1,269,658.

d. The $1,000,000 adjustment to reduce O&M expenses is related to a change in the Company's operational procedure and accounting treatment in 2008 as it was confirmed that the replacement of anodes will extend the useful life of the steel pipe beyond its depreciable life, thus can be capitalized. This change in procedure resulted in a reduction in the estimated 2008 expenses and thus was adjusted in the future test year. Note that the total adjustment approximates the amount of dollars that will be capitalized in 2008 that The revised anode replacement policy is summarized as follows:

Installation of new anodes with original pipeline- all costs associated with the installation shall be capitalized.

Routine inspection of anodes- all costs (labor, fringe, outside service, material) associated with inspecting and maintaining cathodic protection within a limited pipeline segment shall be recorded as operations and maintenance costs when incurred.

Replacement of anodes- all costs related to planned replacement of anodes on a large scale across a significant pipeline segment shall be capitalized.

Item: OCA-VIII-20
Respondent: Jeffery C. Mitchell
Position: Vice President and Controller

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-VIII-20

With reference to the response to OCA-I-19, given that the 2007 O&M expenses were the basis upon which adjustments were made to derive the future test year O&M expense, why would it not be appropriate to remove the entire $1,269,568 in O&M expenses rather than removing only $1,000,000?

Response:

In the response to OCA-I-19 (d), the Company outlined the change in its operational procedure and accounting for the cost of replacing anodes. This change resulted in the estimated adjustment to reduce costs by $1,000,000 in the future test year. The difference between the 2007 total actual costs of $1,269,568 and the $1,000,000 adjustment represents the on-going operations and maintenance costs related to the routine inspection of anodes and the replacement of anodes on a smaller scale per the Company's operational procedure. Based on the nature of Company's operational procedure, it is not appropriate to remove the entire $1,269,568.

Rebuttal to Adjustment to Remove Anode Expense and Cathodic Protection Costs from the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-4

Items	Amount	
Anode Expenses Included in the Future Test Year	$ 269,658	1)
Updates to Anode Expense for Future Test Year	$ 243,844	1)
Updated Anode Expense Included in Future Test Year	$ 513,502	
Adjustment Proposed by OCA Witness Morgan	$ (269,658)	2)
DOT Compliance Cathodic Protection Costs Included in the Future Test Year	$ 133,524	1)
Adjustment Proposed by OCA Witness Morgan	$ (133,524)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, B) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-9.

Rebuttal to Adjustment of Customer Experience Study Costs In the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-5

Items		Amount	
Customer Experience Study Costs Included in the Future Test Year	$	795,858	1)
Adjustment to Customer Experience Study Costs Included in the Future Test Year	$	(530,572)	1)
Updated Normalized Customer Experience Study Costs Included in the Future Test Year	$	265,286	1)
Adjustment Proposed by OCA Witness Morgan	$	(636,686)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, C) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-10.

Rebuttal to Adjustment of PA One Call Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-6

Items		Amount	
Annualized PA One Call Expense for Future Test Year	$	572,000	1)
Revisions to Annualized PA One Call Expense			
Annual Contract Rate Variance ($16.05 vs. $17.50 per locate)	$	(45,742)	1)
Public Awareness Costs	$	(10,000)	1)
Revised Annualized PA One Call Expense for Future Test Year	$	516,258	
Updates to Annualized PA One Call Expense for the Future Test Year:			
Increased Line Locate Volume	$	14,028	1)
Increased PA One Call System Charge Volume	$	20,974	1)
Updated Annualized PA One Call Expense for the Future Test Year	$	551,260	1)
Adjustment Proposed by OCA Witness Morgan	$	(83,197)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, D) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-11.

Rebuttal to Adjustment to Remove Lobbying Expenses for Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-7

Items		Amount	
Total Governmental Affairs Expense Allocated to Equitable Gas	$	210,387	1)
Excluded Lobbying Expenses	$	(88,378)	1)
Governmental Expenses per Books (excludes lobbying costs)	$	122,009	2)
Portion of AGA Dues Related to Lobbying	$	1,584	3)
Total Governmental and AGA Lobbying Related Costs in Future Test Year	$	123,593	1)
Lobbying Cost Adjustment for Future Test Year per Equitable:			
Portion of AGA Dues Related to Lobbying	$	(1,584)	3)
Total Governmental Expenses per Books (excluding lobbying expense)	$	122,009	
Adjustment Proposed by OCA Witness Morgan	$	(123,593)	4)

1) See Witness Mitchell Rebuttal Testimony Section IV, E) for further discussion.

2) The Governmental Affairs costs net of lobbying primarily consists of employee costs for the Government Affairs group.

3) Exhibit VI, Standard Data Request, Volume 1, Item No.33.

4) Amount per OCA Witness Morgan schedule LKM-12.

Rebuttal to Adjustment of Payroll Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-8

Items		Amount	
Unfilled Positions Addressed by Witness Morgan in Future Test Year			
Compression Operator	$	45,531	2)
Compression Operator	$	45,531	2)
Producer Services Analyst	$	39,967	2)
Producer Services Engineer	$	65,000	2)
Total	$	196,029	
Future Test Year Update- Filled Positions			
Compression Operator	$	50,232	1)
Compression Operator	$	50,232	1)
Vacated Position Addressed by Witness Morgan in Future Test Year			
New Position Created, Vacated Position Filled in January 2008	$	67,438	2)
Updated Payroll Expense for Positions Addressed by Witness Morgan	$	167,902	
Total Fringe Benefits Percentage		29.97%	2)
Updated Fringe Benefits Expense	$	50,320	
Total Updated Payroll and Fringe Benefits Expense for Positions Addressed by Witness Morgan for Future Test Year	$	218,222	2)
Adjustment Proposed by OCA Witness Morgan	$	(342,428)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, F) for further discussion.

2) Amount per Witness OCA Morgan schedule LKM-13.

Rebuttal to Adjustment of Pension and Post-Retirement Benefit Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-9

Items		Amount	
Pension and Post-Retirement Benefit Expense for Future Test Year			
2008 Pension Expense	$	594,491	2)
2008 Post-Retirement Benefit Expense	$	1,807,247	2)
Total	$	2,401,738	
Updated Pension and Post-Retirement Benefit Expense for Future Test Year			
Updated 2008 Pension Expense	$	1,185,491	
Updated 2008 Post-Retirement Benefit Expense	$	1,807,247	
Total	$	2,992,738	1)
Pennsylvania Percentage		98.36%	2)
Pennsylvania Pension and Post-Retirement Benefit Expense	$	2,943,657	
O&M Percentage		84.40%	2)
Updated Pennsylvania Pension and Post-Retirement Benefit O&M Expense for Future Test Year	$	2,484,447	1)
Adjustment Proposed by OCA Witness Morgan	$	(463,473)	2)
Adjustment Proposed by OTS Witness Backer	$	(2,457,296)	3)

1) See Witness Mitchell Rebuttal Testimony Section IV, G) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-14.

3) Amount per OTS Witness Backer Direct Testimony.

Rebuttal to Adjustment of Regulatory Commission Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-10

Items		Amount	
Regulatory Commission Costs Included for Future Test Year			
Rate Case	$	1,051,160	2)
Service Life Study	$	15,000	2)
PUC Management Audit	$	750,000	2)
Total	$	1,816,160	
Normalization Period per Company for Rate Case (years)	$	3	1)
Normalized Rate Case Expense for Future Test Year	$	350,387	2)
Normalization Period per Company for Service Life Study and Management Audit (years)	$	5	1)
Normalized Service Life Study and Management Audit Expense for Future Test Year	$	153,000	2)
Historical Test Year Regulatory Expense	$	13,474	2)
Total Regulatory Commission Expense Included in the Future Test Year	$	516,861	1)
Update to Regulatory Commission Expense for Future Test Year	$	(8,626)	1)
Updated Normalized Regulatory Commission Expense for Future Test Year	$	508,235	1)
Adjustment Proposed by OCA Witness Morgan	$	(298,781)	2)
Adjustment Proposed by OTS Witness Backer	$	(140,155)	3)

1) See Witness Mitchell Rebuttal Testimony Section IV, H) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-15.

3) Amount per OTS Witness Backer Direct Testimony.

Rebuttal to Adjustment of Fuel Expense for Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-11

Items	Diesel Amount	Gasoline Amount	Totals
Total Annual Fuel Expense Included in Future Test Year	$ 392,391 2)	$ 988,423 2)	$ 1,380,814 2)
Update to Annual Fuel Expense for Future Test Year			
January 2008 - August 2008 Fuel Usage	57,247 2)	178,709 2)	
Period Number of Months	8	8	
Annual Number of Months	12	12	
Annualized 2008 Fuel Usage	85,871 2)	268,064 2)	
2008 Price per Gallon	$ 4.24 1)	$ 3.61 2)	
Updated Annual Fuel Expense for Future Test Year	$ 364,091	$ 967,709	$ 1,331,800 1)
Adjustment Proposed by OCA Witness Morgan	$ (69,623) 2)		

1) See Witness Mitchell Rebuttal Testimony Section IV, I) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-16.

Rebuttal to Adjustment of Injuries and Damages Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-12

Items		Amount	
Injuries and Damages Expense Included in the Future Test Year	$	3,041,002	2)
Normalization of Injuries and Damages Expense Included in the Future Test Year:			
Charges Against the Injuries and Damages Reserve for Amounts Paid:			
2006 Amounts Paid	$	256,243	2)
2007 Amounts Paid	$	363,135	2)
2008 Amounts Paid (9 month actual, 3 month estimate)	$	383,148	1)
2006-2008 Average	$	334,175	1)
Updated Injuries and Damages Expense Included in Future Test Year	$	334,175	1)
Adjustment Proposed by OCA Witness Morgan	$	(2,755,953)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, J) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-17.

Rebuttal to Adjustment of Legal Settlement Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-13

Items		Amount	
Legal Settlement Expense Included in the Future Test Year as Filed	$	-	1)
Normalization of Legal Settlement Expense Included in the Future Test Year Based on Amounts Paid:			
Legal Settlements Paid:			
2006 Amounts Paid	$	311,680	3)
2007 Amounts Paid	$	3,960,828	3)
2008 Amounts Paid (9 month actual, 3 month estimate)	$	1,767,422	1)
2006-2008 Average	$	2,013,310	1)
Updated Normalization of Legal Settlement Expense Included in the Future Test Year Based on Amounts Paid:	$	2,013,310	1)
Adjustment Proposed by OCA Witness Morgan	$	-	

1) See Witness Mitchell Rebuttal Testimony Section IV, J) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-17.

3) Amounts per Company response to OCA VIII-27.

Rebuttal to Adjustment of Right-of-Way Mowing Expense in the Future Test Year Ended December 31, 2008

Docket No. R-2008-2029325
Schedule JCM-14

Items		Amount	
Right-of-Way Mowing Expense Included in the Future Test Year:			
2007 Right-of-Way Mowing Expense	$	55,479	1)
2007 Historic Test Year Adjustment	$	384,431	1)
2008 Future Test Year Adjustment	$	100,000	1)
Total Right-of-Way Mowing Expense Included in the Future Test Year	$	539,910	2)
Normalization of Right-of-Way Mowing Expense Included in the Future Test Year:			
Annual Miles of Right-of-Way Mowing		345	1)
Cost per Mile	$	580	1)
2006-2008 Average	$	200,100	1)
Updated Normalized Right-of-Way Mowing Expense Included in the Future Test Year	$	200,100	1)
Adjustment Proposed by OCA Witness Morgan	$	(384,431)	2)

1) See Witness Mitchell Rebuttal Testimony Section IV, K) for further discussion.

2) Amount per OCA Witness Morgan schedule LKM-18.

Equitable Statement No. 3-R
Docket No. R-2008-2029325
Witness: Robert M. Narkevic
Date: 11/19/08 215

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Robert M. Narkevic

PREPARED REBUTTAL TESTIMONY OF ROBERT M. NARKEVIC

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Robert M. Narkevic. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company ("Equitable" or the "Company") as Manager of Rates.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted direct testimony that has been marked as Equitable Statement No. 3.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony I will address the issues raised in the direct testimony of Mr. Jeremy B. Hubert on behalf of the Office of Trial Staff (OTS)

relating to throughput, revenue and gas cost levels. Secondly, I will discuss issues raised by Mr. Brian Kalcic on behalf of the Office of Small Business Advocate (OSBA) regarding miscellaneous service revenue and forfeited discount revenue, which are also topics discussed by Mr. Hubert. Lastly, I will discuss the concern of Amanda Gordon, also representing the OTS, related to the application of STAS to the Company's Rider D Universal Service and Conservation Charge.

III. Weather Normalization

Q. WHAT IS THE PURPOSE OF A WEATHER NORMALIZATION ADJUSTMENT?

A. The weather normalization adjustment is used in the ratemaking process to adjust test year throughput and revenues to a level that would be expected under "normal" weather conditions as measured by annual heating degree days.

Q. WHAT IS THE NUMBER OF HEATING DEGREE DAYS USED BY THE COMPANY TO NORMALIZE FUTURE TEST YEAR THROUGHPUT AND WHAT IS IT BASED ON?

A. The Company used 5,541 Heating Degree Days which is the 20-year average number of degree days obtained from the National Oceanographic Atmospheric Association (NOAA).

Q. WHAT IS THE NUMBER OF HEATING DEGREE DAYS MR. HUBERT IS RECOMMENDING?

A. Mr. Hubert states that the NOAA 30-year average for the Pittsburgh International Airport (PIT) is 5,829 heating degree days for 1971 - 2000. However, since the Company provided OTS with the data to calculate the rolling NOAA 30-year average for 1978 – 2007, Mr. Hubert is recommending using a 30-year rolling average of 5,678 heating degree days.

Q. WHY DOES MR. HUBERT RECOMMEND A 30-YEAR AVERAGE?

A. According to Mr. Hubert, the methodology utilized by NOAA to determine "normal" is to use three consecutive decades. He does, however, state on page 22, lines 9 through 11, of his testimony, that the average of values over a 30 year period may or may not be what one would expect to occur on an annual basis.

Q. DO YOU AGREE THAT A 30 YEAR PERIOD IS A PROPER PERIOD TO DETERMINE "NORMAL"?

A. No, I do not, especially over these last 30 years. I have prepared the attached Exhibit RMN Rebuttal-1 which demonstrates that 30 years of data is not a good representation of "normal". The exhibit lists the last 30 years of annual heating degree days, recorded by NOAA at PIT, in column "b". Column "c" is the last 30 year rolling average number of heating degree days of 5,678, which is recommended by Mr. Hubert. The difference of the actual heating degree days, column "b", and the 30 year rolling average, column "c", is listed in column "d". The results demonstrate that a non proportional level of the total heating degree days occurs in the first ten years of the 30 year period and when the actual heating

degree days are compared to the average, eight of the first 10 years exceed the average for a total of 2,748 (column "e") total heating degree days above the average. In comparison, the last ten years of the period, 1998 through 2007, have only 3 years that the heating degree days exceed the average, for a total of (2,480) (column "e") total heating degree days below the average.

Q. DOES YOUR EXHIBIT PRESENT ANY OTHER COMPARISON?

A. Yes. Mr. Hubert mentions in his testimony on page 25, that the officially calculated NOAA 30 year average for PIT is 5,829 heating degree days for 1971-2000. My exhibit also does a comparison of the actual degree days over the last 30 years to this average of 5,829 (column "f") and indicates the difference in column "g". This comparison shows that only one year over the last 10 years, 1998 through 2007, exceeds the average, and that year is only by 11 heating degree days. The total difference over this last 10 year period is (3,990) (column "h") total heating degree days below the average.

Q. WHAT DO YOU CONCLUDE FROM THE RESULTS OF YOUR EXHIBIT?

A. The results of Exhibit RMN Rebuttal-1 support the conclusion that a 30 year average is not a reasonable indicator of what should be deemed "normal". As discussed previously, Mr. Hubert states that a 30 year period may or may not be what one would expect to occur on an annual basis. In this case, the analysis demonstrates that a 30 year period is not what one would expect to occur on an annual basis. Regardless of differing opinions about "Global Warming," the data

and analysis presented on Exhibit RMN Rebuttal-1 demonstrate that the use of a 20 year period to determine "normal" heating degree days as the Company has done in this filing is much more reasonable than using a 30 year average of degree days. The 20 year average data is more likely to be reflective of what will actually occur.

Q. DOES MR. HUBERT HAVE ANY OTHER ISSUES WITH THE COMPANY'S CALCULATION OF NORMALIZED THROUGHPUT?

A. Yes. As discussed in my direct testimony, the calculation of future test year throughput included a conservation adjustment of 1%. Mr. Hubert believes that the adjustment is speculative and should be rejected. Mr. Hubert states that the price of gas has fallen since the beginning of July and that customers are just as likely to increase natural gas usage by replacing electric stoves and water heaters.

Q. DO YOU AGREE WITH MR. HUBERT'S ASSESSMENT?

A. No. Included with the filing in Exhibit VI, Volume 1 of 3, Standard Data Requests, Revenue Requirement No. 11 is an in depth study by the American Gas Association discussing the steady decline in use per residential gas customer of 1% annually since 1980 and the acceleration of this decline since 2000. The key findings of the study are:

1. Weather-adjusted use per residential customer fell by 13.1% from 2000 through 2006.
2. The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2% annually.
3. Further acceleration was witnessed in 2004 to 2006 period, as evidenced by a 4.9 % annual rate of decline.
4. The decline in use per customer has accelerated since 2000 in all 9 geographic regions analyzed.

Mr. Hubert's belief that conservation and the Company's associated adjustment is speculative because gas prices have recently declined and conversions to natural gas may occur from electric stoves and water heaters is inconsistent with the demonstrated decline in residential usage. Additionally, I think it is common knowledge that the Commission and Pennsylvania government are encouraging Pennsylvania citizens to conserve energy of all types. I also find it inconsistent for Mr. Hubert to propose reliance on a 30 year average of heating degree days for weather normalization purposes but then disregard over 20 years of historical documented decline in residential usage for purposes of conservation analysis while suggesting that conservation is speculative. Finally, Mr. Hubert's assertion that conversions may occur from electric stoves and water heaters does not constitute a significant load. Stoves and water heaters are actually primary sources of baseload for customers. Mr. Hubert's Exhibit No. 5, Schedule 14, indicates that baseload is only 21% of normalized load (4,023,965 / 19,175,701). It would take a significant number of these conversions to offset the effects of continuing conservation.

Q. DOES MR. HUBERT RECOMMEND AN ADDITIONAL BAD DEDT EXPENSE ADJUSTMENT RELATED TO HIS RECOMMENDATION OF A WEATHER NORMALIZATION ADJUSTMENT?

A. No, he does not.

Q. DO YOU BELIEVE THERE SHOULD BE A BAD DEBT ADJUSTMENT TO INCREASE BAD DEBT EXPENSE?

A. In my opinion, the Commission should reject Mr. Hubert's weather normalization adjustment as I explained above. If the adjustment is rejected, no adjustment increasing bad debt expense would be necessary. However, if the Commission were to adopt Mr. Hubert's weather normalization adjustment, then a corresponding increase in bad debt expense would be necessary based on the additional revenue and the corresponding uncollectible rate.

IV. Forfeited Discount Revenue

Q. WHAT ARE FORFEITED DISCOUNTS?

A. Forfeited discounts are actually late payment charges assessed to a customer when the customer does not pay their bill on time. Residential customers have 20 days to pay their bill and non-residential customers have 15 days.

Q. ARE REVENUES FROM THESE FORFEITED DISCOUNTS (LATE PAYMENT CHARGES) INCLUDED IN THE FILING?

A. Yes, approximately $1.56 million is reflected as future test year revenue.

Q. HAS ANY PARTY DISAGREED WITH THE LEVEL OF REVENUE INCLUDED IN THE FILING FOR FORFEITED DISCOUNTS?

A. Yes. Mr. Hubert of the OTS and Mr. Kalcic of the OSBA have both submitted testimony explaining that the $1.56 million of future test year revenue is the same as the historic test year revenue. Both Mr. Hubert and Mr. Kalcic state

that additional revenue related to forfeited discounts should be reflected due to the requested rate increase. Mr. Hubert has calculated an average percentage of forfeited discount revenue to sales revenue over a 3 year period, 2005 through 2007, and applied that percentage to the sales revenue proposed by Equitable in this filing. The result of Mr. Hubert's calculation is an additional $374,546 of revenue to be reflected in the future test year. Mr. Kalcic takes a different approach and calculates that the rate increase requested by Equitable ($51.9 million) is approximately 33.5% of present revenue ($155 million). Mr. Kalcic then states that since revenues are *proposed to increase by 33.5%, then forfeited discount revenue will increase* proportionally and generate an additional $520,000 ($1.56 million times 33.5%).

Q. DO YOU AGREE WITH EITHER MR. HUBERT OR MR. KALCIC IN THEIR ASSESSMENT OF WHAT SHOULD BE REFLECTED AS FORFEITED DISCOUNT REVENUE?

A. No, I do not. First of all Mr. Hubert uses a 3 year average to determine the percentage to apply to proposed revenues. OTS Exhibit No. 5, Schedule 1, of Mr. Hubert's testimony lists the percentage of forfeited discounts to sales revenue over the last 5 years as follows:

2003 - .701%
2004 - .694%
2005 - .431%
2006 - .417%
2007 - .407%

It is quite clear that the Company has been able to reduce the level of customers paying late and generating forfeited discount revenue. Mr. Hubert

acknowledges that the actions taken by the Company have had a positive effect on collections. The percentage of forfeited discounts to sales revenue has consistently decreased over the last 5 years. The Company is continuing its efforts to collect outstanding balances. Recent changes in Chapter 14 related to customer deposits, payment plans, and terminations support collection efforts. Furthermore, in excess of 3,000 additional customers are projected to be enrolled in CAP since December 2007. Once the customers are in CAP, late payment charges cease. Lastly, Mr. Rettger, in Equitable Statement No. 11, discusses overall enhancements in several areas of customer services which enable better relationships to develop with customers. For Mr. Hubert to believe that our delinquency percentage would actually increase after 5 straight years of decreases is not reasonable.

Mr. Kalcic goes one step further in attempting to apply an unreasonable rate of delinquency to AGS revenues also. His calculation of a 33.5% increase includes the revenues and proposed increases related to rate AGS. Forfeited discounts are not applied by the Company to AGS billings because normally the AGS revenue is netted against the cost of gas being delivered through the gathering system. For this reason and the reasons discussed above in the context of Mr. Hubert's proposed adjustment, the level of adjustment to forfeited discounts proposed by Mr. Kalcic is also unreasonable.

Q. DO YOU BELIEVE ANY ADJUSTMENT SHOULD BE MADE TO FORFEITED DISCOUNTS IN THE COMPANY'S FILING?

A. No. The Company believes that it would be unreasonable to assume a level of revenue from forfeited discounts in excess of the historic level.

V. Miscellaneous Service Revenues

Q. WHAT ARE MISCELLANEOUS SERVICE REVENUES?

A. Miscellaneous service revenues are revenues generated from services that are not directly related to the actual delivery of gas to customers. These services include, but are not limited to such items as connecting a customer (turning on the gas), performing a "high bill" investigation, and providing a temporary service line.

Q. ARE REVENUES FROM THESE MISCELLANEOUS SERVICES INCLUDED IN THE FILING?

A. Yes, approximately $1.2 million is reflected as future test year revenue.

Q. HAS ANY PARTY DISAGREED WITH THE LEVEL OF REVENUE INCLUDED IN THE FILING FOR THESE MISCELLANEOUS SERVICES?

A. Yes. Mr. Kalcic of the OSBA has submitted testimony explaining that the $1.2 million of future test year revenue is the same as the historic revenue indicated in this filing. Mr. Kalcic has argued that additional revenue of $1.2 million related to miscellaneous services should be reflected due to proposed rate increases in the charges related to several of the services. His assertion is based on a calculation

that assumes the same level of services performed in the historic test year at the proposed rates.

Q. IS MR. KALCIC'S ADJUSTMENT TO MISCELLANEOUS SERVICE REVENUE APPROPRIATE?

A. No. Mr. Kalcic's adjustment to miscellaneous service revenue unreasonably assumes the same level of miscellaneous services at the increased rate levels proposed in the filing. His assumption that the level of requests for the different miscellaneous services offered by the Company will remain the same after the rates for these services have increased is unreasonable. Mr. Kalcic has offered no analysis in support of his conclusion that customers, in fact, will act in this way. As with any type of charge, a reasonable person may weigh the cost of a particular service and decide to do something different.

Q. DO YOU BELIEVE ANY ADJUSTMENT SHOULD BE MADE TO MISCELLANEOUS SERVICE REVENUES IN THE COMPANY'S FILING?

A. No. The Company believes that there is no basis to determine the actual level of services that will be provided going forward and that the level of historic revenue is a reasonable basis to determine the future test year revenue.

VI. Application of STAS and Rider C to the Company's Rider D

Q. PLEASE DESCRIBE THE RECOMMENDATION OF OTS WITNESS GORDON REGARDING THE APPLICATION OF STAS AND THE COMPANY'S RIDER C RATE TO THE COMPANY'S RIDER D - UNIVERSAL SERVICE AND CONSERVATION CHARGE.

A. Ms. Gordon believes that the calculation of the Company's Rider D rate included in Mr. Quinn's testimony as Exhibit JMQ-2 is incorrect. She believes that the calculation should not include the current rates charged for STAS (State Tax Adjustment Surcharge) and the Company's Rider C – Transition Charge. Her recommendation is to use the new proposed rate for Rider C of $.01 and deny the inclusion of STAS.

Q. WHY DOES MS. GORDON BELIEVE STAS SHOULD BE ELIMINATED FROM THE CALCUALTION OF RIDER D?

A. Ms. Gordon believes that STAS is not a legitimate Universal Service Cost because it is not a policy, practice, or service that helps residential low-income retail gas customers to maintain natural gas supply and distribution.

Q. DO YOU AGREE WITH MS. GORDON THAT STAS IS NOT A LEGITIMATE UNIVERSAL SERVICE COST AND SHOULD BE ELIMINATED FROM THE CALCULATION?

A. No. Ms. Gordon has provided no basis for excluding STAS from being charged to a residential CAP customer prior to determining the customer's shortfall. STAS is a mechanism for utility companies to recover or refund any differences in

state taxes collected through its base rate and the actual amounts that will be assessed due to tax rate changes instituted by the State after a company's base rate is set. In other words, a company's base rate is set to collect appropriate State taxes that will be assessed at the state tax rates in effect at the time of the company's base rate case. Subsequent to the rate case the State may change the tax rate for a particular type of tax and in that case the company would either undercollect or overcollect funds to pay the taxes. Without the state tax adjustment surcharge the company then would need to file a base rate case to incorporate the correct state tax rate. Instead, the Company has the option to institute a STAS to reconcile the difference, rather than filing a rate case. In essence then, the STAS is a secondary but important method to recover or refund changes in state taxes otherwise included in base rates. Base rates are included in the calculation of Rider D, so STAS should be also, since there is no difference.

Q. DO YOU AGREE WITH MS. GORDON THAT THE RIDER D RATE CALCULATED IN EXHIBIT JMQ-2 SHOULD INCLUDE THE NEW PROPOSED RIDER C RATE OF $0.01 RATHER THAN THE CURRENT RIDER C RATE OF $0.227?

A. No. Mr. Quinn's exhibit JMQ-2 calculates the Rider D rate necessary to recover CAP related costs for the future test year at *current* rates and normalized throughput. The current Rider C rate of $0.227 is the correct and appropriate rate to use for a calculation at *current* (present) rates. When Ms. Gordon presents her OTS Adjusted Rider D Determination in OTS Exhibit No. 3, Schedule 2, she incorrectly

mixes the *proposed* Rider C with other *current* (present) rate components. I do not endorse Ms. Gordon's calculation but, for her calculation to be consistent, she would need to use the new proposed base rates throughout her Schedule 2 including the higher proposed customer charge and delivery service rates. To suggest that using the proposed Rider C rate of $.01 per Mcf but not any other new higher proposed rate is incorrect. Ultimately, of course, under the Company's proposal, the current Rider C rate of $0.227 per Mcf will be eliminated and rolled into the new base rate at the end of this proceeding.

Q. DO YOU HAVE ANY FURTHER COMMENT ABOUT PROPOSED RIDER D?

A. Yes. In the course of reviewing Ms. Gordon's calculation of Rider D and the component line items presented in OTS Exhibit No. 3, Schedule 2, I looked back at the Company's proposed Rider D tariff language. The proposed Rider D tariff language should mention LIURP costs as a Rider D component. It was an oversight in the drafting of the tariff language to not include a reference to LIURP costs. Both Mr. Quinn's Exhibit JMQ-2 and Ms. Gordon's OTS Exhibit No. 3, Schedule 2 include LIURP costs in the calculation of the Rider. Attached to my testimony as Exhibit RMN Rebuttal-2 is Rider D tariff language revised to include LIURP costs in the Rider D calculation.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes, it does.

Rebuttal Testimony of Robert M. Narkevic
Equitable Gas Company
Docket No. R-2008-2029325
Exhibit RNR-1

Year	Annual Actual Heat Deg Days	30 year Normal	Difference	10 year Difference	Mr. Hubert's 30 year Normal	Difference	10 year Difference
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1978	6,276	5,678	598		5,829	447	
1979	6,175	5,678	497		5,829	346	
1980	6,434	5,678	756		5,829	605	
1981	6,325	5,678	647		5,829	496	
1982	5,794	5,678	116		5,829	(35)	
1983	5,954	5,678	276		5,829	125	
1984	5,838	5,678	160		5,829	9	
1985	5,742	5,678	64		5,829	(87)	
1986	5,525	5,678	(153)		5,829	(304)	
1987	5,465	5,678	(213)	2,748	5,829	(364)	1,238
1988	5,985	5,678	307		5,829	156	
1989	6,112	5,678	434		5,829	283	
1990	4,865	5,678	(813)		5,829	(964)	
1991	5,030	5,678	(648)		5,829	(799)	
1992	5,629	5,678	(49)		5,829	(200)	
1993	5,628	5,678	(50)		5,829	(201)	
1994	5,606	5,678	(72)		5,829	(223)	
1995	5,748	5,678	70		5,829	(81)	
1996	5,988	5,678	310		5,829	159	
1997	5,919	5,678	241	(270)	5,829	90	(1,780)
1998	4,752	5,678	(926)		5,829	(1,077)	
1999	5,390	5,678	(288)		5,829	(439)	
2000	5,760	5,678	82		5,829	(69)	
2001	5,260	5,678	(418)		5,829	(569)	
2002	5,456	5,678	(222)		5,829	(373)	
2003	5,840	5,678	162		5,829	11	
2004	5,474	5,678	(204)		5,829	(355)	
2005	5,746	5,678	68		5,829	(83)	
2006	5,161	5,678	(517)		5,829	(668)	
2007	5,461	5,678	(217)	(2,480)	5,829	(368)	(3,990)
Total	170,338						
30 year avg.	5,678						
Total	110,810						
20 year avg.	5,541						
Total	54,300						
10 year avg.	5,430						

RIDER D

UNIVERSAL SERVICE AND ENERGY CONSERVATION

I. This rider provides a method of recovery of costs associated with the Company's Universal Service and Energy Conservation programs.

II. This Rider shall be applicable to Rate RS, and residential customers receiving service under rate FDS except customers enrolled in the CAP. The rate will be adjusted quarterly and filed with the Company's quarterly gas cost filings to be effective one (1) day after filing. (C)

III. Rate: $1.44 per Mcf (I)

Each PGC quarter, Rider D shall be calculated to recover projected Customer Assistance Program ("CAP") Credits plus the amortization of pre-CAP customer arrearages, administrative costs of providing the CAP program including reporting expenses and costs incurred for the retention of independent consultants to comply with the Commission's regulations. (C)

Net CAP costs will be calculated as follows: The average annual usage of current CAP customers and projected CAP additions will be multiplied by the projected quarterly residential sales rate plus applicable monthly meter charges for current and additional CAP customers, less projected average CAP customer payments and average LIHEAP grants, plus CAP administrative costs, plus LIURP costs, plus average pre-program arrearages not covered by the Company's settlement at Docket No. R-00994784 (DROP Settlement). Net program costs will be divided by projected non-CAP residential throughput. (C)

IV. Annual Reconciliation: Each August, actual total CAP costs will be reconciled with actual total CAP recoveries. Any over/under recoveries of CAP costs will be reflected in the determination of the new Rider D rate effective one (1) day after filing on October 1 of each year. (C)

(C) Indicates Change. (I) Indicates Increase.

Equitable Statement No. 4-R
Docket No. 2008-2029325
Witness: Carol B. Gras
Date: 11/19/08

25

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Carol B. Gras

PREPARED REBUTTAL TESTIMONY OF CAROL B. GRAS

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carol B. Gras. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. ARE YOU THE SAME CAROL GRAS WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony, which has been marked as Equitable Statement No. 4. In that testimony I addressed Equitable Gas Company's ("Equitable" or "Company") claims for utility plant in service, construction work in progress ("CWIP"), materials and supplies, and gas storage inventory. I also was the co-sponsor, with Mr. Wiedmayer, of the Company's measures of value claim.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony, I will respond to the testimonies of Office of Trial Staff ("OTS") Witness Jeremy Hubert and Office of Consumer Advocate ("OCA") Witness Lafayette Morgan to the extent that each of those witnesses testified to Equitable's claims for plant in service, construction work in progress, materials and supplies, gas storage inventory, and customer deposits.

Q. HAVE YOU REVIEWED MR. HUBERT'S AND MR. MORGAN'S DIRECT TESTIMONIES AND EXHIBITS?

A. Yes, I have reviewed each of those to the extent they address rate base, specifically utility plant in service and associated depreciation expense, construction work in progress (CWIP), materials and supplies, gas storage inventory and customer deposits. Other issues addressed by Mr. Hubert and Mr. Morgan will be addressed by other Equitable witnesses.

III. OCA Witness Morgan's Rate Base Adjustment

Q. WOULD YOU PLEASE SUMMARIZE THE SPECIFIC ADJUSTMENTS PROPOSED BY MR. MORGAN?

A. Yes. Mr. Morgan has proposed to eliminate $ 1,761,627 of post future test year additions.

Q. WHAT IS THE BASIS FOR MR. MORGAN'S PROPOSED ELIMINATION OF EQUITABLE'S CLAIM?

Mr. Morgan, generally, refuses to recognize CWIP. However, he recognizes that the Pennsylvania Commission does. Accordingly, he would allow in rate base the inclusion of non-revenue producing and non-expense reducing CWIP if placed into service within six months of the end of the future test year. Mr. Morgan disputes that Equitable's claim for $1,761,627 of post-future test year plant in service qualifies as CWIP, and has thus recommended disallowing its inclusion. Instead, Mr. Morgan characterizes Equitable's claim as being for "stand alone assets" that "are not projects that require construction to develop the final asset that is placed in service."

Q. DO YOU AGREE WITH MR. MORGAN'S CHARACTERIZATION?

A. Upon reviewing Mr. Morgan's testimony and related Schedule LKM-5, I accept Mr. Morgan's proposed elimination of $1,761,627 from Equitable's future test year rate base claim.

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT SHOULD BE REFLECTED IN THE FUTURE TEST YEAR AS A RESULT OF THE ABOVE PLANT IN SERVICE ADJUSTMENT?

A. Yes. Concurrent with this adjustment, future test year depreciation expense should be reduced by $74,118 or from $23,471,055 to $23,396,937.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON MR. MORGAN'S DIRECT TESTIMONY AND EXHIBITS?

A. Yes, it does. As I stated, however, other Equitable witnesses will address the remainder of Mr. Morgan's testimony.

IV. OTS Witness Hubert's Rate Base Adjustments

Q. WOULD YOU PLEASE SUMMARIZE THE SPECIFIC ADJUSTMENTS PROPOSED BY MR. HUBERT?

A. Yes. Mr. Hubert has proposed adjustments to the Company's claim in rate base for Gas Storage Inventory and Customer Deposits. In addition, Mr. Hubert has proposed to eliminate in its entirety Equitable's claim for post future test year additions of $13,151,140. I will address each of these adjustments individually.

Q. WHAT IS THE BASIS FOR MR. HUBERT'S PROPOSED ADJUSTMENT TO EQUITABLE'S CLAIM FOR GAS STORAGE INVENTORY?

A. Based upon updated actual cost information supplied by the Company in response to OTS-RB-15–D, Mr. Hubert recalculated a 13-month average of gas storage

inventory. The updated calculation, using a June 2007 – June 2008 time frame indicates that the average monthly balance for gas storage inventory of $75,175,769 should be reduced by $12,815,557 to $62,360,212. (OTS Exhibit No.5, Schedule 3, Line 15).

Q. DO YOU AGREE WTH MR. HUBERT'S PROPOSED ADJUSTMENT?

A. While I do not oppose, in theory, an adjustment to gas storage inventory that is based upon data that became available subsequent to Equitable's preparation of its filing, I do not agree with the period Mr. Hubert selected for his adjustment.

Q. PLEASE EXPLAIN.

As Mr. Hubert states in his testimony, "each item of the revenue requirement equation is synchronized to the test year period. By using a future test year, a company makes a projected, annualized and normalized estimate of future revenues and expenses and a corresponding measure of value at the end of the future test year. This is necessary so that rates set by the Commission reflect current and synchronized financial information." While I agree with updating the Company's claim for gas storage inventory based upon actual amounts, the time period Mr. Hubert selected (June 2007 – June 2008) does not coincide with the Company's future test year of December 31, 2008, and should be amended.

Q. WHAT DO YOU RECOMMEND CONCERNING THE COMPANY'S CLAIM FOR GAS STORAGE INVENTORY?

A. Based upon updated information, I recommend that the Company's claim of $75,175,769 for gas storage inventory be reduced by $5,352,159 to a level of $69,823,610. The updated 13-month average claim (December 2007 – December

2008) presented on Schedule CBG - 2 reflects the actual balance of gas storage inventory from December 2007 to September 2008, with projections for October, November and December 2008. The October – December 2008 projections were calculated based on volume activity as included in the Company's 2008 annual 1307(f) filing with the Pennsylvania Public Utility Commission and the actual per Mcf unit cost as of September 2008.

Q. WHAT IS THE BASIS FOR MR. HUBERT'S PROPOSED ADJUSTMENT TO EQUITABLE'S CLAIM FOR CUSTOMER DEPOSITS?

A. Based upon updated actual cost information supplied by the Company in response to OTS-RB-12-D and OTS-RB-25-D, Mr. Hubert recalculated a 13-month average of customer deposits. The updated calculation, using a June 2007 – June 2008 period indicates that the average monthly balance for customer deposits of $3,369,694 should be increased by $164,315 to $3,534,009 (OTS Exhibit No 5, Schedule 5, Line 15).

Q. DO YOU AGREE WTH MR. HUBERT'S PROPOSED ADJUSTMENT?

A. I agree with updates that are based upon data that became available subsequent to Equitable's preparation of its filing. However, as with the gas storage inventory adjustment, the period Mr. Hubert selected for the adjustment is incorrect and should be amended.

Q. WHAT DO YOU RECOMMEND CONCERNING THE COMPANY'S DEDUCTION FOR CUSTOMER DEPOSITS?

A. Based upon updated information through September 2008, I recommend that the Company's deduction of $3,369,694 for customer deposits be decreased by

$153,197 to $3,216,497. The updated 13 month average claim (December 2007 – December 2008) presented on Schedule CBG - 3 reflects the actual balance of customer deposits from December 2007 to September 2008, with projections for October, November, and December 2008 trended off of October – December 2007 activity.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON GAS STORAGE INVENTORY AND CUSTOMER DEPOSITS?

A. Yes, it does.

Q. UPON WHAT BASIS DOES MR. HUBERT RECOMMEND ELIMINATION OF EQUITABLE'S CLAIM FOR POST-FUTURE TEST YEAR PLANT ADDITIONS?

A. Mr. Hubert recommends elimination of Equitable's $13,151,140 claim for post future test year additions for a reason that ~~appears similar to that advanced by Mr. Morgan. That is, Mr. Hubert claims that~~ the plant that is reflected in this amount will not be used and useful at the end of the future test year, December 31, 2008. And while Mr. Hubert recognizes that the Pennsylvania Commission allows claims for CWIP, Mr. Hubert asserts that the Company's claim will be neither "in progress" during the future test year nor "'in service' shortly thereafter." Instead, Mr. Hubert characterizes this claim as comprising merely "budgeted amounts of plant additions the Company claims it will make."

Q. DO YOU AGREE WITH MR. HUBERT'S CHARACTERIZATION?

A. No. With the exception of the $ 1,761,627 adjustment proposed by Mr. Morgan and accepted by the Company, Mr. Hubert's recommendation should be rejected.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD REJECT MR. HUBERT'S RECOMMENDATION.

A. As stated more fully in my direct testimony, this claim is based upon the assumption that all 2008 non-revenue producing projects (with the exception of gathering and computer related projects which were individually assessed) that are not in service as of the future test year would be **completed within 6 months** of the end of the future test year. The underlying assumption was that these projects would be approved or authorized and in some stage of construction as of the end of the future test year (December 31 2008). As Mr. Hubert states in his testimony, the Commission has allowed claimed expenditures to complete Construction Work in Progress that will not be completed at the end of the future test year. However, in those circumstances, construction of the project has been required to be "in progress" during the future test year and "in service" shortly thereafter. These are precisely the type of projects that Equitable has included in its claim.

Q. WOULD YOU PLEASE DESCRIBE MR. HUBERT'S ASSERTION THAT EQUITABLE'S CLAIM FOR POST-FUTURE TEST YEAR PLANT ADDITIONS CREATES A MISMATCH BETWEEN THE CLAIMED RATE BASE AND THE OTHER ELEMENTS THAT DETERMINE THE COMPANY'S APPROPRIATE REVENUE LEVEL IN THIS PROCEEDING?

A. Yes. Mr. Hubert claims that a mismatch will occur because the post future test year plant additions are for plant installed after December 31, 2008, and the balance of the net plant, depreciation expense, revenues, other operating expenses, taxes and a reasonable rate of return are all based on data as of the future test year ending

December 31, 2008. He contends that these items change over time, using a different period creates a mismatch.

Q. DO YOU AGREE THAT THE COMPANY'S FILING HAS A MISMATCH?

A. No. The cost of the additions has been included in the filed rate base claim and the related depreciation expense has been included in the cost of service. As stated in my direct testimony (Equitable Statement No 4, page 6), these plant additions are all non-revenue generating and, as such, no incremental revenues will be generated from these investments. Taxes related to the additional deprecation expense are also reflected in the cost of service. Finally, as for the rate of return, there has been no evidence provided that would suggest that the rate of return for the post future test year additions will be in any way different than the rate of return established for the future test year. Thus, there is no mismatch for these factors.

Q. WHAT ABOUT REDUCTIONS TO OPERATING EXPENSES?

A. Mr. Hubert comments upon Equitable's potential to experience expense reductions related to these specific post future test year plant additions. He also advances several examples of how it would be "reasonable to believe" that the addition of new mains, services, and software would "tend" to reduce the Company's expenses. I disagree with Mr. Hubert's suppositions and conclusions. As described in my direct testimony on page 6 and in the response to OCA-IV-26 part b, these non – revenue generating (non-expense reducing) investments are being made by the Company to maintain existing customer service and system reliability, integrity and safety and are **not** intended to result in a reduction to expenses. For ease of

reference, I have attached a copy of my response to OCA-IV-26 as Schedule CBG-4.

Further, to the best of my knowledge, concurrent expense reductions are not the measure of whether or not new plant installed can be recognized as rate base. Contrary, to Mr. Hubert's inference that the Company would not be making these investments unless they were to reduce costs, various reasons support the replacement of plant in service. As addressed by Equitable witness Wesley A. Soyster (Equitable Statement No.12), Equitable has been proactively replacing its bare steel and cast iron pipeline over the last seven years and plans to continue that approach during the future test year and beyond. Were it not for the ongoing effects of this replacement program, designed to facilitate Equitable's system integrity and safety, it is not unreasonable to assume that the Company's operating costs associated with maintaining these older pipes would actually increase.

As for the software, new systems could benefit the Company by providing resources and information that the Company previously did not have, but it would not necessarily result in any reduction to expenses. For example, the Work Management System that is included in the Company's future test year rate base claim is designed to supplement and if viable eventually replace the manual processes of planning, scheduling and tracking of routine maintenance and compliance work across field operations. The near term expected benefits are better, more accurate information for regulatory compliance reporting and capital expenditure decision making and the ability to plan and schedule work more effectively. Expenses for training and deployment as well as maintenance of the

new system are expected to offset, in the near term, any efficiencies gained. In other cases, such as the future test year planned upgrade of Web Methods, the software is being replaced because the manufacturer no longer supports the old version. The replacement itself, however, does not generate any measurable cost savings.

Q. IN SUMMARY, HAS MR. HUBERT CORRECTLY CONCLUDED THAT EQUITABLE'S APPROXIMATE $11.4 MILLION CLAIM FOR POST-FUTURE TEST YEAR PLANT ADDITIONS SHOULD BE REJECTED?

A. No. Equitable's post-future test year plant additions clearly constitute CWIP and do not create a mismatch between the claimed rate base and the other elements that are included in a determination of the Company's appropriate revenue level in this proceeding.

Q. WITH WHAT OTHER ADJUSTMENTS PROPOSED BY MR. HUBERT DO YOU DISAGREE?

A. With the exception of the $74,118 future test year depreciation expense reduction related to my acceptance of Mr. Morgan's adjustment above, I disagree with Mr. Hubert's proposed reduction of annual deprecation expense related to post future test year plant additions of $639,933. To the extent that the Commission rejects Mr. Hubert's proposed elimination of post future test year plant additions, the Commission should also reject Mr. Hubert's adjustment to depreciation expense related to those investments, which, in this case, is $565,815.

Q. DOES THIS CONCLUDE YOUR DISCUSSION ON MR.HUBERT'S DIRECT TESTIMONY AND EXHIBITS?

A. Yes, it does. As I stated, however, other Equitable witnesses will address the remainder of Mr. Hubert's testimony.

V. Equitable's Revised Claim for Rate Base/Depreciation

Q. BASED UPON THOSE ADJUSTMENTS YOU DESCRIBE ABOVE, WOULD YOU PLEASE SUMMARIZE AND EXPLAIN EQUITABLE'S UPDATED CLAIM FOR RATE BASE AND DEPRECIATION?

A. Based upon the revisions proposed above to gas storage inventory and customer deposits as well as my acceptance of OCA witness Morgan's adjustment to post future test year plant additions, the Company's claimed measure of value for the future test year is reduced from $583,252,589 to $576,292,001. These adjustments and updated claim for rate base are presented on Schedule CBG -1.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING EQUITABLE'S CLAIM FOR RATE BASE AND DEPRECIATION EXPENSE?

A. Yes. The Company is in the process of preparing a quarterly update to its filing that it plans to file with the Commission on or before November 7, 2008. The update will include a revised measure of value (rate base) claim based upon actual results through September 2008 and projections for October 2008 – December 2008. The update will also reflect the results of the Company's Service Life Study, which is scheduled to be filed with the Commission by October 31, 2008.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony as necessary to the extent further information in response to discovery requests becomes available.

Equitable Statement No. 4-R
Docket No . R-2008 -2029325
Schedule CBG-1

Equitable Gas Company
Summary of Adjustments to FTY Measure of Value

Line No.	Description	Per Original Filing 12/31/2008	Adjustments	Balance At 12/31/2008
1	Original Cost of Plant in Service	$ 897,954,727	(1,761,627) (1)	$ 896,193,100
2	Less: Depreciation Reserve	289,353,072		289,353,072
3	Net Plant in Service	608,601,655	(1,761,627)	606,840,028
4	Additions			
5	Materials and Supplies	887,426		887,426
6	Current Gas Storage	75,175,769	(5,352,159) (2)	69,823,610
7	Cash Working Capital	11,335,335		11,335,335
8	Prepayments	234,270		234,270
9	Total Additions	87,632,800	(5,352,159)	82,280,641
10	Deductions			
11	Deferred Income Taxes	104,709,261		104,709,261
12	Deferred Income Taxes - Other			
13	Deferred ITC	4,902,910		4,902,910
14	Customer Advances			
15	Customer Deposits	3,369,694	(153,197) (3)	3,216,497
16	Total Deductions	112,981,865	(153,197)	112,828,668
17	Total	$ 583,252,590	$ (6,960,589)	$ 576,292,001

(1) OCA witness Morgan's adjustment to eliminate "stand alone" post future test year additions
(2) Equitable proposed adjustment to gas storage inventory based on updated actual information through Sept 2008
(3) Equitable proposed adjustment to customer deposits based on updated actual information through Sept 2008

NOTE: A revised future test year measure of value inclusive of these adjustments and any other rate base adjustments will be included with the quarterly update to the future test year financial statements scheduled to be filed with the Commission on or before November 7, 2008.

Equitable Statement No. 4-R
Docket No . R-2008 -2029325
Schedule CBG-2

Equitable Gas Company - PA Division
Summary of Gas in Storage
As of December 31, 2008 (Future Test Year)

		Balance	Volumes (Mcf)		$ Per Mcf
Dec-2007	$	92,072,208	12,005,930	$	7.67
Jan-2008		70,143,409	8,978,172	$	7.81
Feb-2008		44,712,754	5,638,044	$	7.93
Mar-2008		24,168,057	3,136,734	$	7.70
Apr-2008		23,807,941	2,998,298	$	7.94
May-2008		37,685,231	3,999,416	$	9.42
Jun-2008		48,553,013	4,801,215	$	10.11
Jul-2008		76,217,897	6,802,860	$	11.20
Aug-2008		90,335,452	8,172,105	$	11.05
Sep-2008		103,930,073	9,553,949	$	10.88
Oct-2008		119,619,511	11,104,949	$	10.77
Nov-2008		102,406,287	9,506,949	$	10.77
Dec-2008		74,055,094	6,874,949		10.77
13 Month Total	$	907,706,926			
		13			
13 Month Average Balance	$	69,823,610			
Per Original Filing	$	75,175,769	Equitable Exhibit I, Item I-A-2, Sheet 2 of 3		
Revised Adjustment	$	(5,352,159)			

Equitable Statement No. 4-R
Docket No . R-2008 -2029325
Schedule CBG-3

Equitable Gas Company - PA Division
Summary of Customer Deposits
As of December 31, 2008 (Future Test Year)

Month	$ Amount
Dec-2007	$ 3,484,804
Jan-2008	3,527,421
Feb-2008	3,595,878
Mar-2008	3,669,181
Apr-2008	3,563,416
May-2008	3,573,395
Jun-2008	3,627,300
Jul-2008	3,712,587
Aug-2008	2,663,195
Sep-2008	2,630,605
Oct-2008	2,578,923
Nov-2008	2,548,312
Dec-2008	2,639,446
13 Month Total	$ 41,814,464
	13
13 Month Average Balance	$ 3,216,497
Per Original Filing	$ 3,369,694 Equitable Exhibit I, Item I-A-2, Sheet 2 of 3
Revised Adjustment	$ (153,197)

Equitable Statement No.4 – R
Docket No. R-2008-2029325
Schedule CBG -4

Docket No. R-2008-2029325
Item: OCA-IV-26
Respondent: Carol B. Gras
Position: Manager, Planning and Analysis

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-IV-26

With reference to the post future test year plant additions of $13,151,140:

a) Please provide a listing of the projects that make up the total amount. Include a description of each project, the start date and completion date; and

b) Please identify each project that would result in a reduction to expenses and provide the annual expense reduction related to that project.

Response:

a) Refer to the direct testimony of Carol B. Gras, Equitable Statement No.4, page 6, for an explanation of the development of the post future test year claim. The attached schedule details the projects (by budget category) that have been included as post future test year additions. The expectation is that these projects will be completed within 6 months of the end of the future test year.

b) These projects represent expenditures to maintain existing customer service and system reliability, integrity and safety and are not intended to result in a reduction to expenses.

EQUITABLE GAS COMPANY PA DIVISION
Post Future Test Year Additions

CATEGORY / DESCRIPTION	Budget AMOUNT	2008 % In Svc	Future Test Year Additions	Post Future Test Year Additions
	(a)	(b)	(c) = (a) x (b)	(d) = (a) - (c)
Mainline Replacement	18,368,000	65.0%	11,942,240	$ 6,425,760
Measuring and Regulating Stations	923,000	33.1%	305,247	617,753
Purchase New Meters and Regulators	1,347,000	52.8%	710,606	636,394
Tools and Equipment	595,000	59.3%	352,549	242,451
PC & Laptop Replacement	470,000	70.0%	329,000	141,000
Automotive Replacements	2,301,700	67.8%	1,559,918	741,782
Individually Assessed Projects:				
Gathering - 50% of Corrsion Protection Program on Gathering Lines				1,656,000
IT Projects - Work Management - $920K, Job Scheduler and Web Methods Upgrade - $80 K				1,000,000
Service Lines Replacements (associated with remainder of Mainline Replacements above)				1,690,000
			Total Post Future Test Year Additions	$ 13,151,140

Equitable Exhibit 5A-R
R-2008-2029325
Witness: Frank J. Hanley
Date: October 31, 2008

11/19/08
RLS

EQUITABLE GAS COMPANY

R-2008-2029325

EXHIBIT

TO ACCOMPANY THE

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

FAIR RATE OF RETURN

FINAL PROXY GROUP OF NATURAL GAS DISTRIBUTION COMPANIES
FOR EQUITABLE GAS COMPANY CASE
AS OF MARCH 21, 2008

Proxy Group has been chosen from :
Companies included in Value Line Investment Survey's (Standard Edition) group of Natural Gas Distribution Companies - As of March 14, 2008.
The companies need to be domestic, publicly traded and not a subsidiary of another company.
The companies need to be included in either Value Line Investment Survey (Standard Edition) or have meaningful Reuters long-term growth rates.
Excluding companies, which have had dividend cuts, are currently not paying dividends or have suspended or omitted dividend payments within the last 5 years (2003-2007 & to-date).
Excluding Companies, which have less than 50% of their revenues, net operating income or total assets derived from natural gas distribution operations .
Excluding Companies without five-years of data in I-Metrix Database and/or PCPlus/Research Insight Database.
Excluding Companies, which have publicly announced that they are involved in any acquisition or merger activity.

Hanley's Nine Proxy Companies	Ticker Symbol	Value Line Gas Distribution Group	Public/Not Sub/Not Foreign	Value Line Standard Edition	*Meaningful Reuters* Long-Term Growth Rates	*Dividend Cuts/* Omissions/ Not Pay Div	SIC CODE	SIC Description
AGL RESOURCES INC	ATG	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
ATMOS ENERGY CORP	ATO	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
LACLEDE GROUP INC	LG	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
NICOR INC	GAS	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
NORTHWEST NATURAL GAS CO	NWN	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
PIEDMONT NATURAL GAS CO INC	PNY	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
SOUTH JERSEY INDUSTRIES INC	SJI	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
SOUTHWEST GAS CORP	SWX	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
WGL HOLDINGS INC	WGL	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
OTS Witness Pionski's Eight Proxy Companies								
NATIONAL FUEL GAS CO	NFG	No	Yes	Yes	Yes	No	4924	Natural Gas Distribution
NEW JERSEY RESOURCES, INC	NJR	Yes	Yes	Yes	Yes	No	4924	Natural Gas Distribution
NSTAR	NST	No	Yes	Yes	Yes	No	4911	Electric Services
Client's Parent Company								
EQUITABLE RESOURCES INC /PA/	EQT	Yes	Yes	Yes	Yes	No	4923	Natural Gas Transmission/ Distribution

		Revenues for Fiscal Year 2007			*Net Operating Income for Fiscal Year 2007*			*Total Assets for Fiscal Year 2007*		
Hanley's Nine Proxy Companies	Ticker Symbol	Total Revenue	Regulated Natural Gas Distribution Operations	% of Revenues Derived from Gas Distribution Operations (Calculated)	Total NOI	Regulated Natural Gas Distribution Operations	% of NOI Derived from Gas Distribution Operations (Calculated)	Total Assets	Regulated Natural Gas Distribution Assets	% of Assets Allocated to Gas Distribution Operations (Calculated)
AGL RESOURCES INC	ATG	2494.000	1665.000	66.76	489.000	335.000	68.51 (1)	6268.000	4831.000	77.07
ATMOS ENERGY CORP	ATO	5599.431	3358.765	59.94	304.544	185.964	61.06	5896.917	5652.481	95.85
LACLEDE GROUP INC	LG	2021.594	1131.554	55.97	80.231	61.232	76.32	1641.153	1429.415	87.10
NICOR INC	GAS	3176.300	2627.500	82.72	157.400	94.500	60.04	4611.700	4279.700	92.80 (2)
NORTHWEST NATURAL GAS CO	NWN	1033.193	1015.970	98.33	110.863	101.416	91.46	2014.183	1940.844	96.36
PIEDMONT NATURAL GAS CO INC	PNY	1711.292	1711.292	100.00	137.347	137.347	100.00	2751.018	2655.311	96.52
SOUTH JERSEY INDUSTRIES INC	SJI	956.371	630.547	65.93	129.623	83.989	64.79 (1)	1529.441	1227.162	80.24
SOUTHWEST GAS CORP	SWX	2152.098	1614.766	84.33	172.809	161.807	93.63	3670.188	3518.304	95.86
WGL HOLDINGS INC	WGL	2648.008	1497.724	56.56	154.710	133.751	86.45	2791.406	2574.186	92.22
Average		2454.586	1717.013	74.17	192.947	143.890	78.03	3463.778	3123.156	90.45
OTS Witness Pionski's Eight Proxy Companies										
NATIONAL FUEL GAS CO	NFG	2039.566	1106.453	54.25	201.675	50.89	25.230	3994.180	2376.550	59.50
NEW JERSEY RESOURCES, INC	NJR	3022.046	1005.588	33.26	127.250	88.53	69.570	2247.692	1565.568	69.65
NSTAR	NST	3281.784	560.478	17.18	221.515	18.84	8.510	7759.545	799.768	10.31
		2774.465	690.840	34.90	183.490	52.75	34.437	4667.139	1580.628	33.87
Client's Parent Company										
EQUITABLE RESOURCES INC	EQT	1381.406	455.506	33.46 (3)	311.673	24.071	7.72 (4)	3936.971	1412.804	35.89 (5)

Notes:

(1) *Net operating income for the distribution operations are not available. Therefore, operating income was used for AGL Resources Inc. and South Jersey Industries Inc.*
(2) Total assets for the gas distribution operations are not available. Therefore, gross property plant and equipment amounts were used for Nicor Inc.
(3) The percentage of gas distribution revenues for the natural gas distributions operations is 33.46% (33.46% = $455.506 / $1361.406), while the percentage of revenues for Equitable Utilities, which includes the regulated and unregulated revenues, is 67.34% (67.34% = $916.821 / $1361.406).

(4) Net operating income for the gas distribution operations is not available. Therefore, operating income was used for Equitable Resources Inc. The operating income for the gas distributions operations is 7.72% (7.72% = $24.071 / $311.673), while the operating income for Equitable Utilities, which includes the regulated and unregulated distributions operations of the division is 36.47% (36.47% = $113.447 / $311.673).

(5) The percentage of total assets allocated to the gas distribution operations for Equitable Resources is not available. The percentage allocated to Equitable Utilities is 35.89% (35.897% = $1412.804 / $3936.971).

Source of Information:
Company 10-Ks

Equitable Exhibit 5A-R
Schedule 1
Page 1 of 2

NSTAR/MA

FORM 10-K
(Annual Report)

Filed 02/11/08 for the Period Ending 12/31/07

Address	800 BOYLSTON ST BOSTON, MA 02199
Telephone	6174242000
CIK	0001035675
Symbol	NST
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Technology
Fiscal Year	12/31

Equitable Gas Company
Comparison of Bond Ratings, Business Risk and Financial Risk Profiles for
Hanley's Nine Proxy Companies and OTS Witness Pionski's Eight Proxy Companies

		Moody's Bond Rating October 2008		Standard & Poor's Bond Rating October 2008							
		Bond Rating	Numerical Weighting (1)	Bond Rating	Numerical Weighting (1)	Credit Rating	Numerical Weighting (1)	Business Risk Profile (2)	Numerical Weighting (1)	Financial Risk Profile (2)	Numerical Weighting (1)
	Hanley's Nine Proxy Companies										
ATG	Agl Resources Inc (1)	A3	7	A-	7	A-	7	Excellent	1	Intermediate	2
ATO	Atmos Energy Corporation	Baa3	10	BBB	9	BBB	9	Excellent	1	Aggressive	3
GAS	Nicor Inc (2)	A1	5	AA	3	AA	3	Excellent	1	Intermediate	2
LG	Laclede Group, Inc. (The)(3)	A3	7	A	6	A	6	Excellent	1	Intermediate	2
NWN	*Northwest Natural Gas Company*	*A2*	*6*	*AA-*	*4*	*AA-*	*4*	*Excellent*	*1*	*Intermediate*	*2*
PNY	Piedmont Natural Gas Company	A3	7	A	6	A	6	Excellent	1	Intermediate	2
SJI	South Jersey Industries (4)	Baa1	8	A	6	BBB+	8	Excellent	1	Aggressive	3
SWX	Southwest Gas Corp	Baa3	10	BBB-	10	BBB-	10	Strong	2	Aggressive	3
WGL	Wgl Holdings, Inc. (5)	A2	6	AA-	4	AA-	4	Excellent	1	Intermediate	2
	AVERAGE	A3	7.3	A	6.1	A	6.0	Excellent	1.0	Intermediate	2.0
	OTS Witness Pionski's Eight Proxy Companies										
ATG	Agl Resources Inc (1)	A3	7	A-	7	A-	7	Excellent	1	Intermediate	2
GAS	Nicor Inc (2)	A1	5	AA	3	AA	3	Excellent	1	Intermediate	2
NFG	National Fuel Gas Company	Baa1	8	BBB+	8	BBB+	8	Satisfactory	3	Intermediate	2
NJR	New Jersey Resources Corp.(6)	NR	- -	A+	5	A	6	Excellent	1	Intermediate	2
NST	NSTAR (7)	A1	5	AA-/A+	4.5	A+	5.0	Excellent	1	Intermediate	2
PNY	Piedmont Natural Gas Company	A3	7	A	6	A	6	Excellent	1	Intermediate	2
SJI	South Jersey Industries (4)	Baa1	8	A	6	BBB+	8	Excellent	1	Aggressive	3
WGL	Wgl Holdings, Inc. (5)	A2	6	AA-	4	AA-	4	Excellent	1	Intermediate	2
	AVERAGE	A3	6.6	A+	5.4	A	6.0	Excellent	1.0	Intermediate	2.0

Notes:
(1) Ratings, Financial and Business Risk Profiles are that of Atlanta Gas Light.
(2) Ratings, Financial and Business Risk Profiles are that of NICOR Gas.
(3) Ratings, Financial and Business Risk Profiles are that of Laclede Gas Company.
(4) Ratings, Financial and Business Risk Profiles are that of South Jersey Gas.
(5) Ratings, Financial and Business Risk Profiles are that of Washington Gas Light.
(6) Ratings, Financial and Business Risk Profiles are that of New Jersey Natural Gas Company.
(7) Ratings, Financial and Business Risk Profiles are that of NSTAR Gas Company and NSTAR Electric Company.

Source Information:
Moody's Investors Service
Standard & Poor's Global Utilities Rating Service
Standard & Poor's Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest 9/23/08
Standard & Poor's Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest 9/9/08

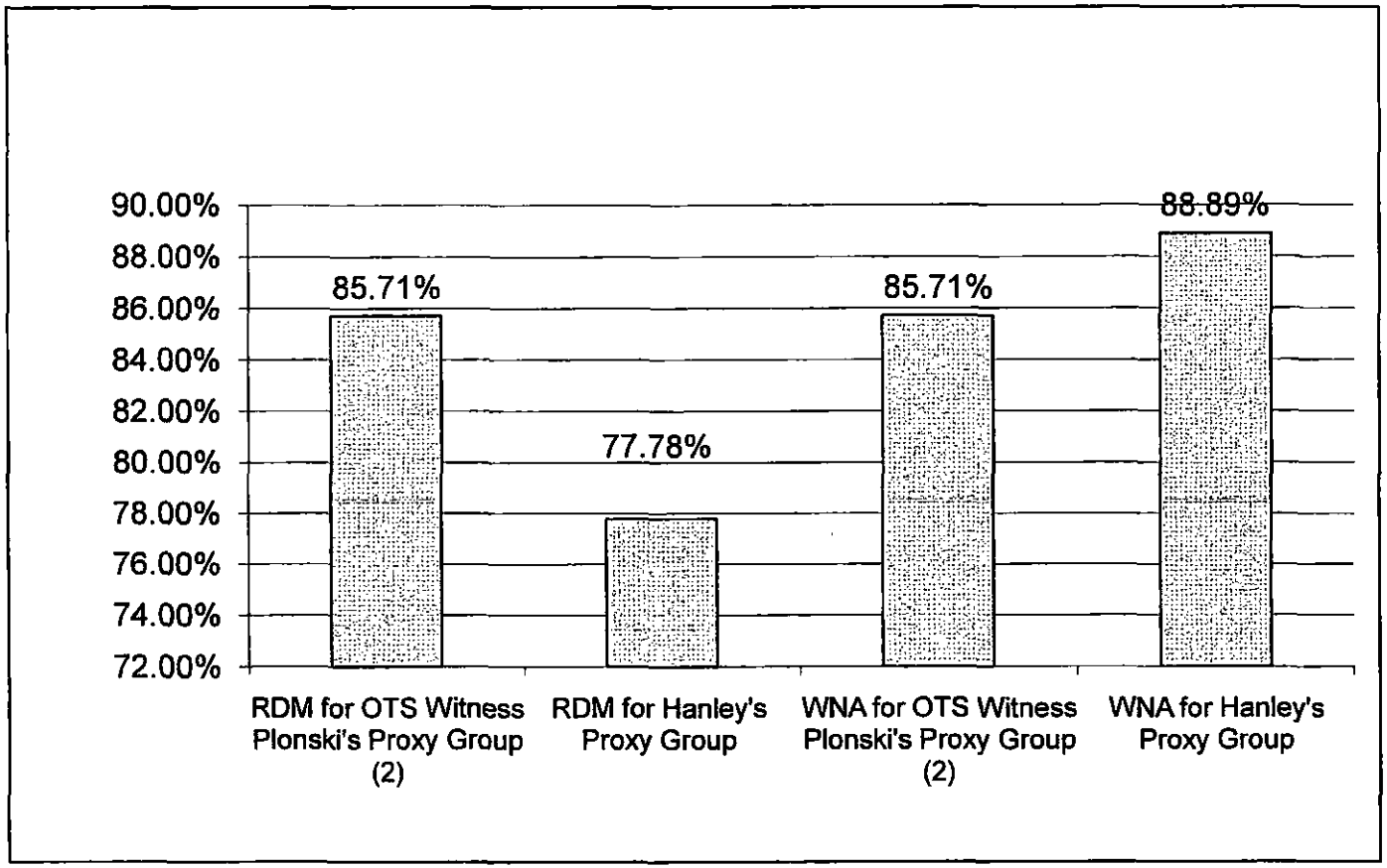
Equitable Gas Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		1 Market Capitalization on April 4, 2008 (1) (millions)	(times larger)	2 Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	3 Applicable Size Premium (3)	4 Spread from Applicable Size Premium (4)
1.	Equitable Gas Company					
	A. Based upon Hanley's Nine Proxy Companies	$ 484.456		9	2.56%	
	B. Based upon OTS Witness Pionski's Eight Proxy Companies	$ 532.953		8-9	2.38%	
2.	A. Hanley's Nine Proxy Companies	$ 1,582.002	3.3 x	6-7	1.55%	1.01%
	B. OTS Witness Pionski's Eight Proxy Companies	$ 2,115.199	4.0 x	5-6	1.54%	0.85%

Decile	Number of Companies	Recent Total Market Capitalization (10) (millions)	Recent Average Market Capitalization (millions)	Size Premium (Return in Excess of CAPM) (2)
1 - Largest	167	$ 10,357,817.750	$ 62,022.861	-0.34%
2	174	2,327,351.920	$ 13,375.586	0.68%
3	192	1,111,672.200	$ 5,789.959	0.76%
4	184	709,696.610	$ 3,857.047	0.93%
5	203	541,399.790	$ 2,666.994	1.47%
6	251	411,039.680	$ 1,637.608	1.60%
7	275	379,465.160	$ 1,379.673	1.50%
8	380	291,182.590	$ 766.270	2.20%
9	641	284,538.240	$ 443.897	2.56%
10 - Smallest	1775	201,705.150	$ 113.637	5.82%

Notes: (1) From Page 2 of this Schedule
(2) Gleaned from bottom of this page. Also referenced on Pages 11-23 of Equitable Exhibit 5A, Schedule 1.
(3) Corresponding risk premium to decile indicated in Column 2.
(4) Line 1A, Column 3 - Line 2A, Column 3, etc. For example the 1.01% in Line 2A, Column 4 is derived by: 2.56%-1.55%=1.01%

Revenue Decoupling Mechanisms (RDM) and Weather Normalization Adjustment Clauses (WNA)
OTS Witness Plonski's Seven Proxy Companies
and Mr. Hanley's Proxy Group of Nine Value Line Gas Distribution Companies (1)



Notes:

(1) Data from page 2 of this Schedule.
(2) Based on seven companies. NSTAR is not included because it is an electric services company.

Docket No. R-2008-2029325
Item: OTS-RR-20-D
Respondent: Frank J. Hanley, CRRA
Position: Principal and Director, AUS Consultants
Respondent: Robert M. Narkevic
Position: Manager, Rates

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RR-20-D

Reference Equitable Statement No. 5, direct testimony of F. J. Hanley, page 12, lines 3 - 10. Provide any and all studies and/or analyses done by the Company, or its witness, that details the extent of revenue loss and increased financial risk claimed by the Company's testimony.

Response:

Mr. Hanley's discussion of at page 12, lines 3 – 10, of Equitable Statement No. 5 concerns extraordinary business risk, not financial risk, as explained at the bottom of the preceding page 11, lines 19 – 22. The extent of revenue loss, estimated by the Company from gas-on-gas competition is attached.

Equitable Exhibit 5A-R
Schedule 4
Page 2 of 5

Equitable Gas Company
Marketing Department

Bypass Gains

Bypass Losses

ACCOUNT NAME	LOST TOO	START DATE	END DATE	ANNUAL MCF	LOST ANNUAL MCF	MARGIN MARGIN $/MON	METER MARGIN $/MCF	BALANCING MARGIN $/MCF	TRANSITION MARGIN $/MCF	DELIVERY MARGIN $
1	CPA	1/1/2001	BYPASS	431,000	431,000	800			0.20	$ 97,524
2	HOPE	2/1/2001	BYPASS	3,354	3,354	0	0.18		0.65	$ 2,784
3	DPNG	5/1/2001	BYPASS	7,137	7,137	195	0.18	0.227	2.36	$ 22,088
4	DPNG	9/1/2001	BYPASS	1,046	1,046	109	0.18	0.227	2.36	$ 4,202
5	DPNG	10/10/2001	BYPASS	7,741	7,741	75	0.18	0.227	1.00	$ 11,792
6	DPNG	10/10/2001	BYPASS	1,947	1,947	75	0.18	0.227	2.36	$ 6,287
7	DPNG	10/10/2001	BYPASS	3,339	3,339	75	0.18	0.227	0.50	$ 3,928
8	DPNG	10/15/2001	BYPASS	1,602	1,602	75	0.18	0.227	2.36	$ 5,333
9	DPNG	10/15/2001	BYPASS	2,977	2,977	167	0.18	0.227	2.36	$ 10,241
10	DPNG	10/31/2001	BYPASS	1,521	1,521	75	0.18	0.227	2.36	$ 5,109
11	DPNG	10/31/2001	BYPASS	299	299	17	0.18	0.227	2.56	$ 1,090
12	DPNG	11/1/2001	BYPASS	498	498	17	0.18	0.227	2.56	$ 1,679
13	DPNG	11/1/2001	BYPASS	2,277	2,277	75	0.18	0.227	2.36	$ 7,200
14	DPNG	11/1/2001	BYPASS	18,496	18,496	392	0.18	0.227	2.36	$ 55,882
15	DPNG	12/1/2001	BYPASS	4,243	4,243	75	0.18	0.227	2.36	$ 12,640
16	DPNG	12/1/2001	BYPASS	269	269	17	0.18	0.227	2.56	$ 1,001
17	DPNG	12/31/2001	BYPASS	11,632	11,632	28	0.18	0.000	0.50	$ 8,246
18	*DPNG*	*12/31/2001*	*BYPASS*	*651*	*651*	*28*	*0.18*	*0.227*	*2.56*	$ 2,266
19	DPNG	12/31/2001	BYPASS		636	85	0.18	0.227	2.56	$ 2,905
20	DPNG	1/28/2002	BYPASS		10,507	150	0.18	0.000	2.00	$ 24,705
21	DPNG	12/31/2001	BYPASS	461	461	17	0.18	0.227	2.56	$ 1,570
22	DPNG	12/31/2001	BYPASS		13,479	552	0.18	0.227	2.36	$ 43,920
23	DPNG	1/1/2002	BYPASS	1,981	1,981	75	0.18	0.227	2.36	$ 6,381
24		1/1/2002	BYPASS	1,210	1,210	28	0.18	0.227	2.36	$ 3,684
25	DPNG	1/1/2002	BYPASS		53	17	0.18	0.227	2.56	$ 360
26	DPNG	1/1/2002	BYPASS		118	17	0.18	0.227	2.56	$ 553
27	DPNG	1/23/2002	BYPASS	2,546	2,546	75	0.18	0.227	1.00	$ 4,482
28	DPNG	1/23/2002	BYPASS	1,008	1,008	75	0.18	0.227	2.36	$ 3,689
29		LOAD	LOSS	250,000	250,000				1.08	$ 270,000
30	DPNG	1/28/2002	3/1/2005	11,068	11,068	184	0.18	0.227	2.36	$ 32,833
31	DPNG	4/3/2001	BYPASS	2,116	2,116	75	0.18	0.227	2.36	$ 6,755
32	DPNG	10/16/2001	BYPASS	3,618	3,618	75	0.18	0.227	2.36	$ 10,911
33	DPNG	1/31/2002	BYPASS	199	199	28	0.18	0.227	2.56	$ 926
34	DPNG	1/31/2002	BYPASS	215	215	28	0.18	0.227	2.56	$ 973
35	DPNG	2/19/2002	BYPASS	1,462	1,283	75	0.18	0.227	2.36	$ 4,450
36	DPNG	2/19/2002	BYPASS	2,527	2,527	75	0.18	0.227	2.36	$ 7,892
37	DPNG	2/19/2002	BYPASS	1,477	1,477	75	0.18	0.227	2.36	$ 4,987
38	DPNG	2/19/2002	BYPASS	7,537	7,537	225	0.18	0.227	2.36	$ 23,555
39	TWP	3/25/2002	BYPASS	698	698	28	0.18	0.227	2.56	$ 2,405
40	DPNG	6/1/2002	BYPASS	4,472	4,472	75	0.18	0.227	2.36	$ 13,274
41		3/25/2002	BYPASS	2,803	2,803	75	0.18	0.227	2.36	$ 8,656
42		3/25/2002	BYPASS	2,140	2,140	75	0.18	0.227	2.36	$ 6,821
43		4/16/2002	BYPASS	0	0	17	0.18	0.227	2.56	$ 204
44	DPNG	7/1/2002	BYPASS	1,913	1,913	92	0.18	0.227	2.36	$ 6,397
45	DPNG	6/1/2002	BYPASS	2,713	2,713	75	0.18	0.227	0.50	$ 3,361
46	DPNG	8/1/2002	BYPASS	41,627	41,627	0	0.00	0.000	0.76	$ 31,637
47	DPNG	8/1/2002	BYPASS	1,147	1,147	0	0.00	0.000	0.76	$ 872
48	DPNG	10/1/2002	BYPASS	230	166	17	0.18	0.227	2.56	$ 696
49	DPNG	10/1/2002	BYPASS	1,335	1,335	75	0.18	0.227	2.36	$ 4,594
50	*DPNG*	*1/1/2003*	*PENDING*	*66,345*	*66,345*	*800*	*0.00*	*0.000*	*0.00*	$ 9,600
51		8/1/2002	BYPASS	16,906	16,906	0	0.00	0.000	0.15	$ 2,536
52	DPNG	10/1/2002	BYPASS	1,825	1,825	0	0.00	0.000	2.40	$ 4,380
53	DPNG	10/1/2002	PENDING	56	56	0	0.00	0.000	2.40	$ 133
54	DPNG	10/1/2002	BYPASS	621	621	0	0.00	0.000	2.40	$ 1,491
55	DPNG	10/1/2002	PENDING	878	878	0	0.00	0.000	2.40	$ 2,108
56	DPNG	10/1/2002	BYPASS	1,424	1,424	0	0.00	0.000	2.40	$ 3,416
57	DPNG	10/1/2002	BYPASS	1,660	1,660	0	0.00	0.000	2.40	$ 3,983

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Schedule 4
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Equitable Gas Company
Marketing Department

Bypass Gains

Bypass Losses

					LOST	MARGIN	METER	BALANCING	TRANSITION	DELIVERY
ACCOUNT	LOST	START	END	ANNUAL	ANNUAL	MARGIN	MARGIN	MARGIN	MARGIN	MARGIN
NAME	TOO	DATE	DATE	MCF	MCF	$/MON	$/MCF	$/MCF	$/MCF	$
58	DPNG	10/1/2002	BYPASS	5,518	5,518	28	0.18	0.000	1.79	$ 11,203
59	DPNG	10/1/2002	BYPASS	3,723	3,723	17	0.18	0.000	2.10	$ 8,693
60	DPNG	10/1/2002	BYPASS	1,381	1,381	17	0.18	0.000	2.10	$ 3,353
61	DPNG	10/1/2002	BYPASS	1,570	1,570	17	0.18	0.000	2.10	$ 3,784
62	DPNG	10/1/2002	BYPASS	1,085	1,085	17	0.18	0.000	2.10	$ 2,678
63	DPNG	10/1/2002	BYPASS	1,052	1,052	17	0.18	0.000	2.10	$ 2,603
64	DPNG	10/1/2002	BYPASS	1,872	1,872	17	0.18	0.000	2.10	$ 4,472
65	DPNG	10/1/2002	BYPASS	398	398	17	0.18	0.227	4.13	$ 2,009
66	DPNG	10/1/2002	BYPASS	391	391	17	0.18	0.227	4.13	$ 1,978
67	DPNG	1/1/2003	BYPASS	6,749	6,749	150	0.18	0.000	1.40	$ 12,463
68	DPNG	1/1/2003	BYPASS	6,776	6,776	150	0.18	0.000	1.40	$ 12,506
69	DPNG	1/1/2003	BYPASS	1,124	1,124	75	0.18	0.000	1.40	$ 2,676
70	DPNG	1/1/2003	BYPASS	1,883	1,883	150	0.18	0.000	1.40	$ 4,775
71	DPNG	1/1/2003	BYPASS	207	207	17	0.18	0.000	1.40	$ 531
72	DPNG	1/1/2003	BYPASS	4	4	17	0.18	0.000	1.40	$ 210
73	DPNG	1/1/2003	BYPASS	0	0	17	0.18	0.000	1.40	$ 204
74	DPNG	1/1/2003	BYPASS	348	348	17	0.18	0.000	1.40	$ 754
75	CPA	11/1/2002	BYPASS	1,253	1,253	75	0.18	0.227	2.36	$ 4,366
76		10/1/2002	BYPASS	315	315	17	0.18	0.227	2.56	$ 1,137
77		12/1/2002	BYPASS	5,044	5,044	150	0.28	0.227	2.36	$ 16,261
78		2/1/2003	BYPASS	940	940	17	0.00	0.000	0.47	$ 646
79	DPNG			900,000	900,000				0.35	$ 315,000
80	DPNG		12/31/2004	600,000	600,000				0.15	$ 90,000
81	TWP		10/31/2004	800,000	800,000				0.05	$ 42,400
82	TWP		10/31/2004	2,000,000	2,000,000				0.05	$ 106,000
83	CPA		9/30/2005	134,200	134,200	800	0.07		0.40	$ 72,674
84	DPNG		10/31/2005	155,000	155,000	800			0.30	$ 56,100
85	DPNG		5/1/2008	130,000	130,000	800	0.17		1.30	$ 200,700
86	DPNG			121,600	121,600	817	0.18		1.25	$ 183,692
87	DPNG			105,000	105,000				0.28	$ 29,400
88	DPNG			50,000	50,000					$ -
89	DPNG		5/1/2008	46,700	46,700	920	0.18	0.17	1.65	$ 104,440
90	DPNG		BYPASS	2,221	2,221	28	0.18		1.40	$ 3,845
91	DPNG	3/23/2000	BYPASS	3,889	3,889	28	0.18		1.40	$ 6,481
92	DPNG	3/6/2001	BYPASS	12,490	12,490	75	0.18		1.40	$ 20,634
93	DPNG			13,000	13,000					$ -
94	DPNG		9/30/2004	10,200	10,200	150			1.36	$ 15,672
95	DPNG			8,900	8,900					$ -
96	DPNG			5,600	5,600					$ -
97	DPNG			5,100	5,100					$ -
98	DPNG			4,500	4,500					$ -
99	DPNG			3,200	3,200					$ -
100	DPNG			1,800	1,800					$ -
101	DPNG			1,600	1,600					$ -
102	DPNG			1,200	1,200					$ -
103	DPNG			96,000	96,000	1674				$ 20,088
104	DPNG			50,500	50,500					$ -
105	DPNG		9/30/1997	130,000	130,000				0.45	$ 58,500
106	DPNG			70,000	70,000					$ -
107	DPNG									$ -
108	DPNG									

Equitable Gas Company
Pennsylvania and West Virginia
Discounted Contract Data

Equitable Exhibit 5A
Schedule 4
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	ACCOUNT NAME	CONTACT NAME	CONTACT PHONE	REASON FOR DISCOUNT: OIL	COAL	COKE OVEN	PROPANE	STEAM	ELECTRIC	NONJURIS FACILITY	PERC PIPELINE	GTA	TAP	OTHER	RETAINED OR NEW	ANNUAL DELIVERIES (MCF)	DISCOUNT FROM TARIFF (MMCF)	DISCOUNT END DATE	ANNUAL REVENUE
1												X			NEW	7,851	0.149	11/30/14	$1,945.43
2														X	RETAINED	1,782	0.130	09/30/08	$232.89
3								X						X	RETAINED	6	0.007	09/30/07	$0.05
4												X	X	X	RETAINED	3,343	1.000	10/31/09	$3,804.09
5												X			RETAINED	1,857	0.460	09/30/08	$308.73
6														X	RETAINED	33,180	0.460	04/30/09	$11,785.80
7																			
8														JV	RETAINED	7,180	0.307	12/31/09	$1,788.89
9													X		RETAINED	780	1.000	05/31/09	$1,476.14
10																			
11											X	X			RETAINED	48,489	1.879	07/31/08	$76,111.46
12														X	RETAINED	1,233	0.430	01/31/08	$332.80
13													X	X	RETAINED	1,718	0.170	09/31/08	$1,313.13
14												X			RETAINED	12,306	0.170	09/31/08	$2,340.40
15												X			RETAINED	6,864	0.710	09/30/08	$6,780.44
16												X			RETAINED	23,268	0.178	09/31/08	$5,497.92
17												X			RETAINED	8,613	0.178	09/31/08	$1,467.18
18												X			RETAINED	613	0.537	09/30/08	$278.53
19												X			NEW	3,883	0.860	09/31/15	$3,818.34
20												X			RETAINED	921	0.350	09/30/08	$264.36
21												X			RETAINED	3,888	0.178	09/31/08	$428.83
22												X			NEW	18,867	1.000	10/31/08	$18,695.48
23														A	RETAINED	3,424	1.360	10/31/08	$4,738.78
24												X			RETAINED	8,724	0.170	09/31/15	$972.11
25												X			RETAINED	2,301	0.170	09/31/08	$374.19
26													X	A	RETAINED	1,134	0.197	09/30/08	$221.61
27												X			RETAINED	8,117	0.348	04/30/15	$1,366.24
28												X			RETAINED	10,888	0.178	09/31/15	$2,338.91
29												X			RETAINED	3,772	0.178	09/31/08	$841.22
30									X			X			RETAINED	71,330	1.730	09/31/15	$18,347.98
31												X			NEW	41,228	1.727	09/30/11	$72,294.40
32														X	RETAINED	33,454	0.460	12/31/08	$18,311.79
33												X			RETAINED	18,624	0.120	02/28/10	$2,354.86
34														X	RETAINED	13,286	0.800	09/30/09	$8,719.35
35														X	RETAINED	89,918	0.800	01/31/09	$70,484.67
36														X	RETAINED	4,189	0.438	09/30/08	$1,787.21
37															RETAINED	5,218	0.836	12/31/10	$4,330.83
38								X				X			RETAINED	72,772	0.316	09/30/09	$15,353.16
39										X				X	RETAINED	47,709	0.210	MTM	$10,017.44
40														X	RETAINED	3,627	0.760	05/31/08	$1,788.11
41														X	RETAINED	6,738	0.310	09/30/08	$2,084.63
42														X	NEW	4,138	1.360	05/30/08	$5,707.98
43								X	X					X	RETAINED	460,272	3.140	09/30/10	$1,053,491.65
44														X	RETAINED	29,825	0.100	05/31/08	$2,982.50
45														X	NEW	9,842	0.917	09/31/15	$3,983.26
46														X	RETAINED	8,575	0.360	09/30/08	$3,384.47
47														X	NEW	2,247	2.000	09/30/10	$2,128.34
48														X	RETAINED	1,467	1.667	09/31/08	$1,617.49
49														X	RETAINED	5,577	0.310	09/30/09	$1,729.08
50																			
51														X	RETAINED	31,405	1.830	09/30/08	$46,049.68
52														X	RETAINED	7,183	0.170	09/31/10	$1,221.11
53												X			RETAINED	9,883	0.410	09/30/09	$3,884.12
54															NEW	19,188	0.154	09/31/20	$3,888.77
55								X						A	RETAINED	103,868	0.880	04/30/08	$83,884.68
56														A	RETAINED	845	0.710	09/30/08	$671.02
57														X	RETAINED	8,381	0.170	09/31/10	$1,113.37
58												X		X	RETAINED	211	0.727	09/31/20	$435.13
59				X							X	X			RETAINED	8,458	0.560	09/30/08	$3,748.22
60														X	RETAINED	8,982	0.510	11/30/09	$4,685.87
61												X			RETAINED	13,145	1.150	09/30/08	$15,117.21
62												X			RETAINED	46,370	1.000	09/30/08	$33,277.84
63								X						X	RETAINED	9,824	1.000	09/30/08	$9,436.33
64														X	RETAINED	16,792	0.402	09/30/08	$7,318.69
65												X		X	NEW	2,445	1.130	09/30/07	$2,762.45
66									X					X	RETAINED	33,825	1.650	09/30/08	$48,184.12
67													X		RETAINED	4,612	1.000	09/30/08	$4,777.84
68													X		RETAINED	8,868	1.000	09/30/08	$10,723.13
69													X		RETAINED	8,280	0.560	09/30/08	$4,482.33
70												X		A	RETAINED	2,388	1.360	12/31/08	$3,782.64
71														X	RETAINED	233	0.170	09/31/10	$42.36
72													X		RETAINED	8,833	0.850	09/30/08	$644.33
73														X	RETAINED	13,254	0.443	09/30/08	$5,711.67
74												X			RETAINED	9,888	0.170	09/31/10	$1,133.84
75												X			RETAINED	40,820	0.174	12/31/11	$2,831.84
76														X	RETAINED	1,818	0.200	09/30/08	$479.80
77												X			RETAINED	12,744	0.178	09/31/10	$2,534.48
78				X							X	X		X	RETAINED	53,180	0.910	03/31/09	$16,776.80
79																			
80												X		X	RETAINED	3,886	1.360	12/31/07	$3,881.88
81											X	X		X	RETAINED	38,980	0.170	07/31/08	$3,384.98
82												X			RETAINED	39,838	1.110	09/30/08	$34,339.10
83														X	RETAINED	19,168	0.100	09/30/09	$1,916.89
84														X	NEW	837	1.227	07/30/10	$781.35
85														A	RETAINED	1,865	0.830	09/30/09	$828.19
86												X			RETAINED	8,878	0.780	11/30/08	$6,789.31
87											X	X		X	RETAINED	78,838	1.340	03/31/10	$102,818.80
88												X		X	RETAINED	64,322	1.038	12/31/08	$69,184.88
89														X	RETAINED	1,284	0.438	09/30/09	$559.84
90														X	RETAINED	4,824	0.280	03/31/10	$1,254.64
91								X						X	RETAINED	49,848	2.230	10/31/08	$110,811.13
92														X	RETAINED	138,858	1.810	12/31/08	$247,714.51
93				X											NEW	2,825	0.388	09/30/09	$1,041.53
94												X		X	NEW	4,843	1.000	09/30/08	$4,384.53
95				X										X	RETAINED	66,888	1.388	09/31/10	$77,382.84
96												X			NEW	47,483	0.858	09/30/15	$38,343.89
97														X	RETAINED	3,830	0.788	12/31/08	$2,953.65
98												X			RETAINED	6,729	1.838	03/31/07	$14,722.87
99												X		X	RETAINED	57,881	1.570	09/30/10	$58,348.46
100														X	RETAINED	18,858	0.310	09/30/08	$3,162.84
101												X		X	RETAINED	32,431	0.178	09/31/10	$3,381.88
102													X		RETAINED	1,833	1.000	09/31/08	$1,162.54
103														X	RETAINED	2,838	1.838	09/30/08	$3,826.29
104												X			RETAINED	8,737	0.178	09/31/10	$973.34
105														X	RETAINED	8,077	0.178	09/31/10	$1,373.44
106														X	RETAINED	4,140	0.178	09/31/10	$703.77
107													X		RETAINED	1,258	0.918	11/30/08	$843.14
108				X				X						X	RETAINED	41,388	0.148	09/30/08	$6,388.78

Equitable Gas Company
Pennsylvania and West Virginia
Residential Customer Data

	Account Name	Contact Name	Contact Phone	Reason for Discount: Oil	Coal	Coke Gas	Propane	BTS/AH	Electric	Nonjuris Facility	FERC Pipeline	CTA	TWP	DPNG	Retained or New	Annual Deliveries (Mcf)	Discount from Tariff (Rate)	Discount End Date	Annual Revenue
110														X	RETAINED	7,666	0.430	11/2008	$3,296.48
111														X	NEW	430	0.147	03/2008	$63.18
112												X			NEW	3,302	1.230	07/2008	$3,631.66
113										X				X	NEW	48,312	0.170	06/2010	$8,021.19
114														X	NEW	21,000	0.300	06/2014	$6,180.00
115												X			RETAINED	12,139	1.230	06/2008	$15,121.84
116												X		X	RETAINED	391,101	0.300	10/2008	$105,058.29
117					X									X	RETAINED	133,344	1.510	12/2008	$201,183.44
118														X	RETAINED	30,020	0.700	06/2008	$22,917.16
119								X						X	RETAINED	14,845	0.300	06/2008	$12,306.70
120													X	X	RETAINED	66,434	1.000	06/2008	$126,288.84
121																			
122												X			RETAINED	36,091	0.700	10/2008	$13,676.91
123														X	NEW	8,020	0.700	10/2008	$7,020.31
124																			
125														X	RETAINED	1,467	1.300	01/2015	$2,536.97
126												X		X	RETAINED	14,000	0.170	06/2015	$3,227.63
127														X	RETAINED	2,877	0.510	06/2008	$1,333.03
128														X	RETAINED	8,544	0.172	07/2015	$1,647.66
129														X	RETAINED	6,856	0.170	06/2010	$1,548.25
130															NEW	2,272	1.153	11/2014	$2,567.35
131														X	RETAINED	433	1.300	07/2008	$324.88
132								X						X	RETAINED	30,237	0.500	06/2008	$14,436.25
133														X	RETAINED	1,863	0.170	06/2010	$397.88
134												X			RETAINED	4,167	1.140	04/2018	$4,738.75
135														X	RETAINED	1,732	1.000	01/2010	$1,734.00
136												X			RETAINED	22,255	0.170	09/2105	$3,783.83
137														X	RETAINED	8,000	0.100	06/2008	$804.00
138												X			RETAINED	4,703	0.300	06/2105	$1,322.89
139												X			RETAINED	4,000	0.170	06/2120	$783.48
140												X			NEW	1,204	1.140	01/2015	$1,362.76
141														X	NEW	885	1.227	12/2010	$1,221.36
142														X	RETAINED	17,183	0.170	06/2010	$3,822.76
143												X			RETAINED	3,402	0.170	06/2010	$538.47
144														X	RETAINED	8,340	0.530	06/2008	$4,864.97
145														X	RETAINED	676	0.100	06/2008	$168.76
146													X		NEW	1,854	1.300	12/2008	$1,328.29
147								X						X	RETAINED	3,726	1.000	06/2008	$3,230.70
148														X	NEW	8,711	0.570	04/2008	$3,908.83
149												X			RETAINED	4,862	1.230	08/2008	$5,109.66
150																			
151														X	RETAINED	438	0.360	06/2008	$168.23
152														X	RETAINED	4,144	1.140	05/2010	$4,722.26
153														X	RETAINED	84	0.100	10/2105	$8.69
154														X	RETAINED	1,256	0.310	06/2008	$389.35
155														X	RETAINED	36,204	0.230	12/2108	$8,326.89
156														X	RETAINED	7,884	0.110	08/2010	$775.81
157													X		RETAINED	33,439	1.300	05/2108	$32,676.88
158								X						X	RETAINED	222,804	1.350	08/2008	$300,404.89
159								X						X	RETAINED	874,138	1.913	10/2108	$1,583,830.88
160												X		X	RETAINED	4,884	0.170	08/2108	$830.30
161																			
162								X						X	RETAINED	381,389	0.500	08/2008	$148,719.39
163														X	RETAINED	33,133	0.800	08/2008	$27,031.95
164																			
165												X			NEW	33,784	0.800	06/2110	$11,672.31
166														X	RETAINED	44,861	0.170	06/2110	$7,662.24
167														X	RETAINED	14,908	0.230	11/2008	$3,488.13
168														X	NEW	8,865	1.132	08/2114	$7,628.13
169														X	RETAINED	4,881	0.140	08/2008	$638.47
170														X	RETAINED	8,537	0.130	08/2108	$1,111.22
171												X			RETAINED	3,317	1.000	08/2008	$3,582.47
172												X			RETAINED	12,610	1.230	08/2008	$15,792.30
																			$5,448,842.13

GAS ANNUAL REPORT
OF

EQUITABLE GAS COMPANY, A DIVISION OF EQUITABLE RESOURCES, INC.

Exact legal name of reporting gas company or corporation

(If name was changed during year, show also the previous name and date of change)

225 NORTH SHORE DRIVE, PITTSBURGH, PENNSYLVANIA 15212-5861

(Address of principal business office at end of year)

FOR THE

YEAR ENDED DECEMBER 31, 2007

TO THE

COMMONWEALTH OF PENNSYLVANIA

PUBLIC UTILITY COMMISSION

Name, title, address and telephone number (including the area code), E-Mail Address, and Web Site Address of the person to be contacted concerning this report:

Jeffery C. Mitchell

jmitchell@eqt.com

Vice President and Controller

225 North Shore Drive, Pittsburgh, Pennsylvania 15212-5861

412-395-3179

www.eqt.com

201. NOTES TO BALANCE SHEET (Continued)

ASSET RETIREMENT OBLIGATION: SFAS No. 143 requires that the Respondent accrue a liability for legal asset retirement obligations based on an estimate of the timing and amount of their settlement. For gas wells, the fair value of the Respondent's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are drilled. The Respondent is required to operate and maintain its natural gas pipelines and intends to do so as long as supply and demand for natural gas exists, which the Respondent expects for the foreseeable future. Therefore, the Respondent believes that the substantial majority of its natural gas pipelines have indeterminate lives.

B. Income Taxes

The Respondent files a consolidated federal income tax return including its subsidiaries. Current federal tax balances of all subsidiary companies are settled with the Respondent which makes consolidated tax payments. The consolidated federal income tax provision is allocated among the group's members on a separate return basis with tax credits allocated to those members which generate the credits. The consolidated Federal income tax liability of the Respondent has been settled with the IRS through 1997. The IRS has completed its review of the Respondent's Federal income tax filings for the 1998 through 2000 years. The audit results for these periods generated a tax refund for the Respondent that is in excess of $2 million which requires review and approval by the Joint Committee on Taxation (JCT). During the review process, the JCT questioned an issue that the Respondent had previously agreed upon with the IRS through the Fast Track Appeals process. The Respondent is currently working with the Settlement Agent and the IRS Manager to try to resolve the questions raised by the JCT.

The IRS has surveyed the 2001 and 2002 Federal income tax filings and is currently reviewing the research and experimentation tax credits claim for such years. During the second quarter of 2007, the IRS began an examination of the Respondent's Federal income tax filings for 2003 through 2005. The Respondent also is the subject of various routine state income tax examinations. The Respondent believes that it is appropriately reserved for any uncertain tax positions claimed during these periods.

C. Short-Term Loans

On October 27, 2006, the Respondent entered into a $1.5 billion, five-year revolving credit agreement, which replaced the Respondent's previous $1 billion, five-year revolving credit agreement. On December 15, 2006, the maturity date was extended to October 26, 2011 pursuant to its terms. Additionally, the Respondent may request two one-year extensions of the stated maturity date. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of the Respondent's commercial paper program. Subject to certain terms and conditions, the Respondent may, on a one time basis; request that the lender's commitments be increased to an aggregate amount of up to $2.0 billion.

The Respondent is not required to maintain compensating bank balances. The Respondent's debt issuer credit ratings, as determined by either Standard & Poor's or Moody's on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its lines of credit in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

Due to the volatility in the short-term debt markets during the second half of 2007, the Respondent determined that its lowest cost of short term borrowings would be obtained by utilizing its revolving credit facility. As of December 31, 2007, the Respondent had outstanding short-term loans under the revolving credit facility of $450.0 million and no commercial paper balances. Commitment fees averaging one-seventeenth of one percent in 2007 were paid to maintain credit availability under the revolving credit facility.

The weighted average interest rate for short-term loans outstanding as of December 31, 2007 was 5.26%. The maximum amount of outstanding short-term loans at any time during the year was $450.0 million in 2007. The average daily balance of short-term loans outstanding over the course of the year was approximately $199.5 million at weighted average annual interest rates of 5.84% during 2007.

D. Long-Term Debt

Aggregate maturities of long-term debt $0 in 2008, $4.3 million in 2009, $0 in 2010, $6.0 million in 2011 and $200.0 million in 2012.

E. Pension and Other Postretirement Benefit Plans

During 2007, the Respondent recognized a settlement expense of $0.5 million due to a plan design change for a specific union.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan's funded status in its statement of financial position, measure a benefit plan's assets and obligations as of the end of the employer's fiscal year and recognize the changes in the benefit plan's funded status in other comprehensive income in the year in which the changes occur. The Respondent adopted SFAS No. 158 as of December 31, 2006.

Equitable Gas Company
Authorized Returns on Common Equity and Common Equity Ratios
for Gas Distribution Companies and the Gas Operations of Combination Electric & Gas Companies
from June 2007 to September 2008

1	2	3	4	5	6	7

Company	Date	Jurisdiction	Type	Authorized Return on Common Equity	Authorized Common Equity Ratio	Moody's A Rated Public Utility Bond Yields (10)	Spread between Authorized Return on Common Equity and Moody's A Rated Public Utility Bond Yields (11)
Cascade Natural Gas Corporation (A Sub of MDU Resources)	06/05/07	OR	Gas	10.10 % (2)	45.00 %	5.97 %	4.13 %
Northern States Power (A Sub of Xcel Energy)	06/13/07	ND	Gas	10.75 (2, 3)	51.59	5.99	4.76
Yankee Gas Services (A Sub of Northeast Utilities)	06/29/07	CT	Gas	10.10 (2)	50.30	5.99	4.11
Public Service Company of New Mexico (A Sub of PNM Resources)	06/29/07	NM	Gas	9.53	51.80	5.99	3.54
Public Service Company of Colorado (A Sub of Xcel Energy)	07/03/07	CO	Gas	10.25 (2)	60.17	5.99	4.26
Arkansas Western Gas Co. (A Sub of Southwestern Energy)	07/13/07	AR	Gas	9.50 (2)	34.29 (4)	6.30	3.20
Aquila Networks (Gas Division)	07/24/07	NE	Gas	10.40 (3)	50.73	6.30	4.10
Southern Indiana Gas & Electric Co. (A Sub of Vectren Corp.)	08/01/07	IN	Gas	10.15 (2)	47.05 (4)	6.30	3.85
Columbia Gas of Kentucky (A Sub of NiSource Inc.)	08/29/07	KY	Gas	10.50 (2)	-- (5)	6.25	4.25
Northern States Power-Minnesota (A Sub of Xcel Energy)	09/10/07	MN	Gas	9.71 (3)	51.98	6.24	3.47
Washington Gas Light Company	09/19/07	VA	Gas	10.00 (2, 3)	-- (5)	6.24	3.76
Consolidated Edison Company of New York	09/25/07	NY	Gas	9.70 (2, 6)	48.00	6.24	3.46
Atmos Energy Corporation	10/08/07	TN	Gas	10.48 (2)	44.20	6.24	4.24
Delta Natural Gas Company	10/19/07	KY	Gas	10.00 (2)	-- (5)	6.18	3.82
CenterPoint Energy Resources (Gas Division)	10/25/07	AR	Gas	9.65 (2)	33.73 (4)	6.18	3.47
Washington Gas Light Company	11/15/07	MD	Gas	10.00	53.02	6.11	3.89
Arkansas Oklahoma Gas	11/20/07	AR	Gas	9.90 (2)	41.46 (4)	6.11	3.79
UNS Gas (A Sub of UniSource Energy Corp.)	11/27/07	AZ	Gas	10.00	50.00	6.11	3.89
Cheyenne Light, Fuel & Power Co. (A Sub of Black Hills Corp.)	11/29/07	WY	Gas/Electric (1)	10.90 (2)	54.00 (7)	6.11	4.79
Madison Gas & Electric Company (A Sub of MG&E Energy)	12/14/07	WI	Gas/Electric (1)	10.80	57.36	5.97	4.83
NorthWestern Corporation (Gas Division)	12/18/07	NE	Gas	10.40 (2)	-- (5)	5.97	4.43
Avista Utilities (A Sub of Avista Corporation)	12/19/07	WA	Gas/Electric (1)	10.20 (2)	46.00	5.97	4.23
Brooklyn Union Gas Company (A Sub of National Grid)	12/21/07	NY	Gas	9.80	-- (8)	5.97	3.83
KeySpan Gas East Corporation (A Sub of National Grid)	12/21/07	NY	Gas	9.80	-- (8)	5.97	3.83
National Fuel Gas Distribution Corporation	12/21/07	NY	Gas	9.10 (9)	44.35	5.97	3.13
Pacific Gas & Electric Company (A Sub of PG&E Corp.)	12/21/07	CA	Gas/Electric (1)	11.35	52.00	5.97	5.38
San Diego Gas & Electric Company (A Sub of Sempra Energy)	12/21/07	CA	Gas/Electric (1)	11.10	48.00	5.97	5.13
Northern States Power-Wisconsin (A Sub of Excel Energy)	01/08/08	WI	Gas/Electric (1)	10.75	52.51	5.97	4.78
Wisconsin Electric Power (A Sub of Wisconsin Energy Corp.)	01/17/08	WI	Gas/Electric (1)	10.75	54.36	6.16	4.59
Wisconsin Gas (A Sub of Wisconsin Energy Corp.)	01/17/08	WI	Gas	10.75	48.64	6.16	4.59
North Shore Gas (A sub of Integrys Energy Group)	02/05/08	IL	Gas	9.99	56.00	6.16	3.83
Peoples Gas Light & Coke (A sub of Integrys Energy Group)	02/05/08	IL	Gas	10.19	56.00	6.16	4.03
Indiana Gas (A Sub of Vectren Corporation)	02/13/08	IN	Gas	10.20 (2)	48.99 (4)	6.02	4.18
Avista Corp.	03/31/08	OR	Gas	10.00	50.00	6.21	3.79
Duke Energy	05/28/08	OH	Gas	10.50	55.76	6.29	4.21
Atmos Energy Corporation	06/24/08	TX	Gas	10.00	48.27	6.27	3.73
Questar Gas	06/27/08	UT	Gas	10.00	51.38	6.27	3.73
SourceGas Distribution	08/27/08	CO	Gas	10.25	53.13	6.40	3.85
Chesapeake Utilities	09/02/08	DE	Gas	10.25	61.61	6.40	3.85
Atmos Energy Corporation	09/17/08	GA	Gas	10.70	45.00	6.37	4.33
Central Illinois Light	09/24/08	IL	Gas	10.68	46.50	6.37	4.31
Central Illinois Public Service	09/24/08	IL	Gas	10.68	47.91	6.37	4.31
Illinois Power	09/24/08	IL	Gas	10.68	51.76	6.37	4.31
Avista Corp.	09/30/08	ID	Gas	10.20	47.94	6.37	3.83
Average				10.24 %	49.74 %	6.16 %	4.09 %
Average of Litigated Cases				10.34 %	51.59 %	6.18 %	4.15 %
Prospective Yield on A Rated Public Utility Bonds (12)						6.59 %	
Current Yield on Moody's A Rated Public Utility Bonds (13)							7.80 %
Average Spread between Authorized Returns on Common Equity and Moody's A Rated Public Utility Bond Yields in Litigated Cases						4.15	4.15
Average Spread between A and A3 Rated Bonds (14)						0.21	0.21
Reasonableness Check Indicated Common Equity Cost Rate						10.95 %	12.16 %

Notes on Page 2 of this Exhibit.

Equitable Gas Company
Notes Accompanying Authorized Returns on Common Equity and Common Equity Ratios
for Gas Distribution Companies and the Gas Operations of Combination Electric & Gas Companies
from June 2007 to September 2008

Notes:

(1) Order issued by appropriate Public Service Commission applies to the gas and electric divisions.

(2) Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

(3) Interim rates implemented prior to issuance of final order (normally under bond and subject to refund).

(4) Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(5) Common equity ratio was not specified in settlement.

(6) Rate change implemented in multiple steps.

(7) Hypothetical.

(8) The decisions for Brooklyn Union Gas Company and KeySpan Gas East Corporation were not settlements, but the common equity ratios were not specified.

(9) As shown on pages 4 through 8 of this Schedule, on January 17, 2008, National Fuel Gas Distribution Corporation (NFGDC) was authorized a ROE of 9.10%, which Mr. Hanley has excluded from the average of litigated cases and as the lowest ROE awarded for the 12-month period ended March 31,2008 as fully explained in Mr. Hanley's accompanying direct testimony because Regulatory Research Associates noted that it is the lowest awarded ROE to an energy utility nationwide in at least 30 years. Consequently, he has assumed the 9.50% ROE authorized for Arkansas Western Gas Company on 7/13/07 as the lowest realistic ROE awarded for the 12-month period ended March 31,2008.

(10) From Mergent Bond Record and Moody's Public Utility Manuals, various issues. Actual A rated public utility bond yield represents the yield of the prior month if the order was issued on or after the 10th of the month, or the yield of the second month prior if the order was issued before the 10th of the month. For example, the yield for 8/5/07 is the A rated public utility bond yield for April 2007 and the yield for 8/13/07 is the A rated public utility bond yield for May 2007.

(11) Column 6 - Column 4.

(12) Derived on Page 3 of this Schedule

(13) Found on Schedule 1B, Page 3.

(14) Derived on Page 3 of this Schedule

Sources of information:

Major Rate Case Decisions - January 2006 - December 2007, Supplemental Study, January 8, 2008, Published by Regulatory Research Associates, Inc., An SNL Energy Company.

Major Rate Case Decisions - January 2008 - September 2008, Special Report, Regulatory Study, October 3, 2008, Published by Regulatory Research Associates, Inc., An SNL Energy Company.

Mergent Bond Record Monthly Update, October 2008, Vol. 75, No. 10.

Equitable Gas Company
Derivation of the Prospective Yield of
A Rated Public Utility Bonds and
Spreads Between A and A3 Rated Bonds

Finding the Prospective Yield on A Rated Public Utility Bonds:

1. Average forecast based upon six quarterly estimates of Aaa rated corporate bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated October 1, 2008 (see Schedule 19). The estimates are detailed below.

Second Quarter 2008	5.60 %
Third Quarter 2008	5.60
Fourth Quarter 2008	5.70
First Quarter 2009	5.80
Second Quarter 2009	6.00
Third Quarter 2009	6.10
Average	5.80 %

2. The projected Aaa rated bond now needs to be adjusted to reflect the yield of a A rated public utility bond, which is not projected by Blue Chip Financial Forecasts. This is done by adding the two month average spread (August and September 2008) between the yield of the Aaa corporate bond and the A rated public utility bond shown below:

Spread - Corporate v. Public Utility Bonds

	Corporate Bonds	Public Utility Bonds			Aa (Pub. Util.) over Aaa (Corp.)	A (Pub. Util.) over Aaa (Corp.)	Baa (Pub. Util.) over Aaa (Corp.)
Years	Aaa Rated	Aa Rated	A Rated	Baa Rated			
August-08	5.64 %	6.09 %	6.37 %	6.98 %	0.45 %	0.73 %	1.34 %
September-08	5.65 %	6.13 %	6.49 %	7.15 %	0.48 %	0.84 %	1.50 %
Average Spread (2)					0.47 %	0.79 %	1.42 %

3. Prospective Yield on Aaa Corporate Bond: 5.80%

Spread Between Aaa Corporate Bond and A Rated Public Utility Bond: 0.79%

Prospective Yield on A Rated Public Utility Bonds: 6.59%

Finding the Spread Between A and A3 Rated Public Utility Bond Yields:

4. The prospective A rated public utility bond yield then needs a further adjustment to reflect the risk of a A3 rating, which is the rating of both Mr. Hanley's and OTS Witness Pionski's Proxy Groups. To do this, Mr. Hanley took the two month average spread between A and Baa rated bond yields shown below and then divided that value by three to reflect the three different classes of debt (i.e. A1, A2, and A3) and added that number to the prospective yield on A rated public utility bonds to reflect the A3 rating of both proxy groups.

	Spread - Public Utility Bonds	
Years	A over Aa	Baa over A
August-08	0.28 %	0.61 %
September-08	0.36 %	0.66 %
Average Spread (2)	0.32 %	0.64 %

5. Prospective Yield on A Rated Public Utility Bonds: 6.59%
1/3 Spread Between A and Baa Rated Public Utility Bonds: 0.21%
Prospective Yield on A3 Rated Public Utility Bonds: *6.80%*

Notes: (1) All yields are distributed yields.
(2) Equal weight has been given to the August 2008 and September 2008 spread.

Source of Information: Mergent Bond Record Monthly Update, October 2008, Vol. 75, No. 10
Blue Chip Financial Forecasts October 1, 2008

Equitable Gas Company
Comparison of Fed Funds Rate
and Yields on A Rated Public Utility Bonds

DATE	FED FUNDS RATE	MOODY'S A RATED PU BONDS	
Feb-05	2.50	5.61	
Mar-05	2.75	5.83	
Apr-05	2.75	5.64	
May-05	3.00	5.53	
Jun-05	3.25	5.40	
Jul-05	3.25	5.51	
Aug-05	3.50	5.50	
Sep-05	3.75	5.52	
Oct-05	3.75	5.79	
Nov-05	4.00	5.88	
Dec-05	4.25	5.80	
Jan-06	4.50	5.75	
Feb-06	4.50	5.82	
Mar-06	4.75	5.98	
Apr-06	4.75	6.29	
May-06	5.00	6.42	
Jun-06	5.25	6.40	
Jul-06	5.25	6.37	
Aug-06	5.25	6.20	
Sep-06	5.25	6.00	
Oct-06	5.25	5.98	
Nov-06	5.25	5.80	
Dec-06	5.25	5.81	
Jan-07	5.25	5.96	
Feb-07	5.25	5.90	
Mar-07	5.25	5.85	
Apr-07	5.25	5.97	
May-07	5.25	5.99	
Jun-07	5.25	6.30	
Jul-07	5.25	6.25	
Aug-07	5.25	6.24	
Sep-07	4.75	6.18	
Oct-07	4.50	6.11	
Nov-07	4.50	5.97	
Dec-07	4.25	6.16	
Jan-08	3.50	6.02	
Feb-08	3.00	6.21	
Mar-08	2.25	6.21	
Apr-08	2.00	6.29	
May-08	2.00	6.27	
Jun-08	2.00	6.38	
Jul-08	2.00	6.40	
Aug-08	2.00	6.37	
Sep-08	2.00	6.49	
Oct-08	1.50	7.80	(1)

Notes:
(1) Spot yield of A rated utility bonds referred to in Schedule 18, Page 3 as of October 22, 2008

FEDERAL RESERVE BANK of NEW YORK

Historical Changes of the Target Federal Funds and Discount Rates

1971 to present

Printer version

DATE	DISCOUNT RATE			FEDERAL FUNDS RATE	
	CHANGE	NEW LEVEL* PRIMARY[1]	SECONDARY[2]	CHANGE	NEW LEVEL
2008					
Oct 8	-.50	1.75	2.25	-.50	1.50
Apr 30	-.25	2.25	2.75	-.25	2.00
Mar 18	-.75	2.50	3.00	-.75	2.25
Mar 16	-.25	3.25	3.75		
Jan 30	-.50	3.50	4.00	-.50	3.00
Jan 22	-.75	4.00	4.50	-.75	3.50
2007					
Dec 11	-.25	4.75	5.25	-.25	4.25
Oct 31	-.25	5.00	5.50	-.25	4.50
Sep 18	-.50	5.25	5.75	-.50	4.75
Aug 17	-.50	5.75	6.25		
2006					
Jun 29	+.25	6.25	6.75	+.25	5.25
May 10	+.25	6.00	6.50	+.25	5.00
Mar 28	+.25	5.75	6.25	+.25	4.75
Jan 31	+.25	5.50	6.00	+.25	4.50
2005					
Dec 13	+.25	5.25	5.75	+.25	4.25

Nov 1	+.25	5.00	5.50	+.25	4.00
Sep 20	+.25	4.75	5.25	+.25	3.75
Aug 9	+.25	4.50	5.00	+.25	3.50
Jun 30	+.25	4.25	4.75	+.25	3.25
May 3	+.25	4.00	4.50	+.25	3.00
Mar 22	+.25	3.75	4.25	+.25	2.75
Feb 2	+.25	3.50	4.00	+.25	2.50
2004					
Dec 14	+.25	3.25	3.75	+.25	2.25
Nov 10	+.25	3.00	3.50	+.25	2.00
Sep 21	+.25	2.75	3.25	+.25	1.75
Aug 10	+.25	2.50	3.00	+.25	1.50
Jun 30	+.25	2.25	2.75	+.25	1.25
2003					
Jun 25	-.25	2.00	2.50	-.25	1.00
Jan 09		2.25	2.75		

**On Jan 9, 2003, this file began to track the primary and secondary credit rate.*

DATE	DISCOUNT RATE		FEDERAL FUNDS RATE	
	CHANGE	NEW LEVEL	CHANGE	NEW LEVEL/ RANGE
2002				
Nov 6	-1/2	3/4	-1/2	1 1/4
2001				
Dec 11	-1/4	1 1/4	-1/4	1 3/4
Nov 6	-1/2	1 1/2	-1/2	2
Oct 2	-1/2	2	-1/2	2 1/2

Corporate Bond Yield Averages

	AV. CORP.	CORPORATE BY RATINGS Aaa	Aa	A	Baa	CORPORATE BY GROUPS P.U.	IND.	R.R.		PUBLIC UTILITY BONDS Aaa	Aa	A	Baa		INDUSTRIAL BONDS Aaa	Aa	A	Baa		RAILROAD BONDS Aaa	Aa	A	Baa
2003																							
Jan.	6.84	6.17	6.59	6.76	7.35	7.13	6.54	—	Jan.	—	6.87	7.06	7.47	Jan.	6.17	6.30	6.46	7.23	Jan.	—	—	—	—
Feb.	6.62	5.95	6.34	6.63	7.06	6.92	6.31	—	Feb.	—	6.66	6.93	7.17	Feb.	5.95	6.02	6.33	6.94	Feb.	—	—	—	—
Mar.	6.53	5.89	6.28	6.54	6.95	6.80	6.26	—	Mar.	—	6.56	6.79	7.05	Mar.	5.89	6.04	6.30	6.84	Mar.	—	—	—	—
Apr.	6.44	5.74	6.22	6.45	6.85	6.68	6.18	—	Apr.	—	6.47	6.64	6.94	Apr.	5.74	5.97	6.26	6.76	Apr.	—	—	—	—
May	6.02	5.22	5.85	6.08	6.38	6.35	5.70	—	May	—	6.20	6.36	6.47	May	5.22	5.48	5.79	6.29	May	—	—	—	—
June	5.85	4.97	5.72	5.92	6.19	6.21	5.49	—	June	—	6.12	6.21	6.30	June	4.97	5.31	5.62	6.07	June	—	—	—	—
July	6.26	5.49	6.07	6.34	6.62	6.54	5.98	—	July	—	6.37	6.57	6.67	July	5.49	5.77	6.11	6.56	July	—	—	—	—
Aug.	6.57	5.87	6.31	6.63	7.01	6.78	6.35	—	Aug.	—	6.48	6.78	7.08	Aug.	5.87	6.13	6.48	6.92	Aug.	—	—	—	—
Sep.	6.37	5.72	6.13	6.42	6.79	6.58	6.16	—	Sep.	—	6.30	6.56	6.87	Sep.	5.72	5.95	6.27	6.71	Sep.	—	—	—	—
Oct.	6.32	5.70	6.11	6.33	6.73	6.50	6.14	—	Oct.	—	6.28	6.43	6.79	Oct.	5.70	5.94	6.23	6.67	Oct.	—	—	—	—
Nov.	6.27	5.65	6.08	6.28	6.66	6.44	6.09	—	Nov.	—	6.26	6.37	6.69	Nov.	5.65	5.91	6.18	6.63	Nov.	—	—	—	—
Dec.	6.20	5.65	6.02	6.19	6.60	6.36	6.04	—	Dec.	—	6.18	6.27	6.61	Dec.	5.62	5.85	6.11	6.58	Dec.	—	—	—	—
2004																							
Jan.	6.08	5.54	5.91	6.08	6.44	6.23	5.92	—	Jan.	—	6.06	6.15	6.47	Jan.	5.54	5.74	6.02	6.40	Jan.	—	—	—	—
Feb.	6.00	5.50	5.87	6.04	6.27	6.17	5.83	—	Feb.	—	6.10	6.15	6.28	Feb.	5.50	5.65	5.93	6.24	Feb.	—	—	—	—
Mar.	5.84	5.33	5.70	5.86	6.11	6.01	5.67	—	Mar.	—	5.93	5.97	6.12	Mar.	5.33	5.48	5.75	6.10	Mar.	—	—	—	—
Apr.	6.22	5.73	6.10	6.25	6.46	6.38	6.05	—	Apr.	—	6.33	6.35	6.46	Apr.	5.73	5.85	6.15	6.45	Apr.	—	—	—	—
May.	6.51	6.04	6.40	6.54	6.75	6.68	6.34	—	May.	—	6.66	6.62	6.75	May.	6.04	6.13	6.45	6.73	May.	—	—	—	—
June	6.42	6.01	6.21	6.42	6.78	6.53	6.31	—	June	—	6.30	6.46	6.84	June	6.01	6.12	6.37	6.72	June	—	—	—	—
July	6.24	5.82	6.02	6.23	6.62	6.34	6.13	—	July	—	6.09	6.27	6.67	July	5.82	5.94	6.18	6.57	July	—	—	—	—
Aug.	6.08	5.65	5.87	6.08	6.48	6.18	5.98	—	Aug.	—	5.95	6.14	6.45	Aug.	5.65	5.79	6.02	6.47	Aug.	—	—	—	—
Sep.	5.91	5.46	5.73	5.91	6.27	6.01	5.81	—	Sep.	—	5.79	5.98	6.27	Sep.	5.46	5.67	5.84	6.27	Sep.	—	—	—	—
Oct.	5.87	5.47	5.69	5.86	6.21	5.95	5.78	—	Oct.	—	5.74	5.94	6.17	Oct.	5.47	5.63	5.78	6.24	Oct.	—	—	—	—
Nov.	5.89	5.52	5.72	5.88	6.21	5.97	5.80	—	Nov.	—	5.79	5.97	6.16	Nov.	5.52	5.65	5.78	6.25	Nov.	—	—	—	—
Dec.	5.84	5.47	5.69	5.82	6.15	5.93	5.75	—	Dec.	—	5.78	5.92	6.10	Dec.	5.47	5.60	5.72	6.20	Dec.	—	—	—	—
2005																							
Jan.	5.72	5.36	5.58	5.68	6.02	5.80	5.63	—	Jan.	—	5.68	5.78	5.95	Jan.	5.36	5.48	5.58	6.08	Jan.	—	—	—	—
Feb.	5.55	5.20	5.44	5.51	5.82	5.64	5.45	—	Feb.	—	5.55	5.61	5.76	Feb.	5.20	5.32	5.40	5.87	Feb.	—	—	—	—
Mar.	5.77	5.40	5.64	5.73	6.06	5.86	5.67	—	Mar.	—	5.76	5.83	6.01	Mar.	5.40	5.53	5.63	6.11	Mar.	—	—	—	—
Apr.	5.65	5.33	5.44	5.58	6.05	5.72	5.58	—	Apr.	—	5.56	5.64	5.95	Apr.	5.33	5.31	5.52	6.15	Apr.	—	—	—	—
May	5.54	5.15	5.29	5.49	6.01	5.60	5.48	—	May	—	5.39	5.53	5.88	May	5.15	5.18	5.45	6.13	May	—	—	—	—
June	5.35	4.96	5.02	5.33	5.86	5.39	5.31	—	June	—	5.05	5.40	5.70	June	4.96	4.99	5.26	6.01	June	—	—	—	—
July	5.46	5.06	5.14	5.44	5.95	5.50	5.41	—	July	—	5.18	5.51	5.81	July	5.06	5.10	5.37	6.10	July	—	—	—	—
Aug.	5.49	5.09	5.20	5.48	5.96	5.51	5.46	—	Aug.	—	5.23	5.50	5.80	Aug.	5.09	5.16	5.45	6.12	Aug.	—	—	—	—
Sept.	5.53	5.13	5.24	5.50	6.03	5.54	5.51	—	Sept.	—	5.27	5.52	5.83	Sept.	5.13	5.21	5.47	6.22	Sept.	—	—	—	—
Oct.	5.77	5.34	5.46	5.75	6.29	5.79	5.74	—	Oct.	—	5.50	5.79	6.08	Oct.	5.34	5.42	5.70	6.49	Oct.	—	—	—	—
Nov.	5.86	5.42	5.55	5.83	6.39	5.88	5.83	—	Nov.	—	5.59	5.88	6.19	Nov.	5.42	5.52	5.78	6.59	Nov.	—	—	—	—
Dec.	5.81	5.38	5.51	5.84	6.33	5.83	5.80	—	Dec.	—	5.55	5.80	6.14	Dec.	5.38	5.45	5.88	6.51	Dec.	—	—	—	—
2006																							
Jan.	5.75	5.29	5.45	5.79	6.24	5.77	5.73	—	Jan.	—	5.50	5.75	6.06	Jan.	5.29	5.39	5.83	6.41	Jan.	—	—	—	—
Feb.	5.80	5.35	5.51	5.85	6.27	5.83	5.78	—	Feb.	—	5.55	5.82	6.11	Feb.	5.35	5.46	5.87	6.43	Feb.	—	—	—	—
Mar.	5.95	5.52	5.67	5.98	6.41	5.98	5.92	—	Mar.	—	5.71	5.98	6.26	Mar.	5.52	5.64	5.96	6.55	Mar.	—	—	—	—
Apr.	6.26	5.84	6.00	6.27	6.68	6.28	6.23	—	Apr.	—	6.02	6.29	6.54	Apr.	5.84	5.98	6.26	6.82	Apr.	—	—	—	—
May	6.36	5.95	6.13	6.40	6.75	6.39	6.33	—	May	—	6.16	6.42	6.59	May	5.95	6.10	6.37	6.90	May	—	—	—	—
June	6.35	5.89	6.11	6.39	6.78	6.39	6.31	—	June	—	6.16	6.40	6.61	June	5.89	6.05	6.36	6.94	June	—	—	—	—
July	6.33	5.85	6.08	6.36	6.76	6.37	6.28	—	July	—	6.13	6.37	6.61	July	5.85	6.02	6.35	6.91	July	—	—	—	—
Aug.	6.16	5.68	5.91	6.19	6.59	6.20	6.11	—	Aug.	—	5.97	6.20	6.43	Aug.	5.68	5.85	6.18	6.74	Aug.	—	—	—	—
Sep.	5.98	5.51	5.75	5.98	6.43	6.03	5.94	—	Sep.	—	5.81	6.00	6.26	Sep.	5.51	5.68	5.95	6.59	Sep.	—	—	—	—
Oct.	5.97	5.51	5.74	5.94	6.42	6.01	5.93	—	Oct.	—	5.80	5.98	6.24	Oct.	5.51	5.68	5.90	6.60	Oct.	—	—	—	—
Nov.	5.78	5.33	5.57	5.76	6.20	5.82	5.73	—	Nov.	—	5.61	5.80	6.04	Nov.	5.33	5.52	5.72	6.36	Nov.	—	—	—	—
Dec.	5.79	5.29	5.58	5.78	6.22	5.83	5.74	—	Dec.	—	5.62	5.81	6.05	Dec.	5.29	5.53	5.75	6.38	Dec.	—	—	—	—
2007																							
Jan.	5.92	5.40	5.75	5.93	6.34	5.96	5.88	—	Jan.	—	5.78	5.96	6.16	Jan.	5.40	5.71	5.91	6.52	Jan.	—	—	—	—
Feb.	5.88	5.39	5.72	5.88	6.28	5.91	5.85	—	Feb.	—	5.73	5.90	6.10	Feb.	5.39	5.70	5.86	6.44	Feb.	—	—	—	—
Mar.	5.84	5.30	5.66	5.84	6.27	5.87	5.80	—	Mar.	—	5.66	5.85	6.10	Mar.	5.30	5.66	5.83	6.43	Mar.	—	—	—	—
Apr.	5.99	5.47	5.83	5.99	6.39	6.01	5.96	—	Apr.	—	5.83	5.97	6.24	Apr.	5.47	5.82	6.00	6.54	Apr.	—	—	—	—
May	6.00	5.47	5.85	6.01	6.39	6.03	5.97	—	May	—	5.86	5.99	6.23	May	5.47	5.84	6.04	6.54	May	—	—	—	—
June	6.32	5.79	6.17	6.33	6.70	6.34	6.29	—	June	—	6.18	6.30	6.54	June	5.79	6.15	6.36	6.84	June	—	—	—	—
July	6.26	5.73	6.09	6.30	6.65	6.28	6.24	—	July	—	6.11	6.25	6.49	July	5.73	6.07	6.34	6.81	July	—	—	—	—
Aug.	6.26	5.79	6.06	6.29	6.65	6.28	6.23	—	Aug.	—	6.11	6.24	6.51	Aug.	5.79	6.01	6.35	6.79	Aug.	—	—	—	—
Sept.	6.21	5.74	6.02	6.23	6.59	6.24	6.17	—	Sept.	—	6.10	6.18	6.45	Sept.	5.74	5.93	6.28	6.73	Sept.	—	—	—	—
Oct.	6.12	5.66	5.94	6.13	6.48	6.17	6.06	—	Oct.	—	6.04	6.11	6.36	Oct.	5.66	5.84	6.14	6.60	Oct.	—	—	—	—
Nov.	5.97	5.44	5.78	5.97	6.40	6.04	5.90	—	Nov.	—	5.87	5.97	6.27	Nov.	5.44	5.67	5.97	6.51	Nov.	—	—	—	—
Dec.	6.15	5.49	5.91	6.19	6.65	6.23	6.07	—	Dec.	—	6.03	6.16	6.51	Dec.	5.49	5.78	6.22	6.78	Dec.	—	—	—	—
2008																							
Jan.	6.02	5.33	5.78	6.06	6.54	6.08	5.96	—	Jan.	—	5.87	6.02	6.35	Jan.	5.33	5.68	6.10	6.73	Jan.	—	—	—	—
Feb.	6.24	5.53	5.97	6.26	6.82	6.28	6.19	—	Feb.	—	6.04	6.21	6.60	Feb.	5.53	5.90	6.30	7.04	Feb.	—	—	—	—
Mar.	6.24	5.51	5.90	6.24	6.89	6.29	6.17	—	Mar.	—	5.99	6.21	6.68	Mar.	5.51	5.80	6.27	7.10	Mar.	—	—	—	—
Apr.	6.29	5.55	5.93	6.30	6.97	6.36	6.21	—	Apr.	—	5.99	6.29	6.81	Apr.	5.55	5.86	6.31	7.12	Apr.	—	—	—	—
May	6.30	5.57	6.00	6.30	6.92	6.38	6.22	—	May	—	6.07	6.27	6.79	May	5.57	5.93	6.33	7.05	May	—	—	—	—
June	6.42	5.68	6.11	6.43	7.07	6.50	6.35	—	June	—	6.19	6.38	6.93	June	5.68	6.02	6.48	7.22	June	—	—	—	—
July	6.44	5.67	6.05	6.47	7.16	6.50	6.38	—	July	—	6.13	6.40	6.97	July	5.67	5.97	6.54	7.35	July	—	—	—	—
Aug.	6.42	5.64	6.01	6.46	7.15	6.48	6.35	—	Aug.	—	6.09	6.37	6.98	Aug.	5.64	5.92	6.55	7.31	Aug.	—	—	—	—
Sep.	6.50	5.65	6.03	6.55	7.31	6.59	6.41	—	Sep.	—	6.13	6.49	7.15	Sep.	5.65	5.93	6.60	7.47	Sep.	—	—	—	—

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of nearly 75 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of Aaa -rated railroad term bond issues, Moody's® Aaa railroad bond yield average was discontinued as of December 18, 1967. Moody's® Aaa public utility average suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.

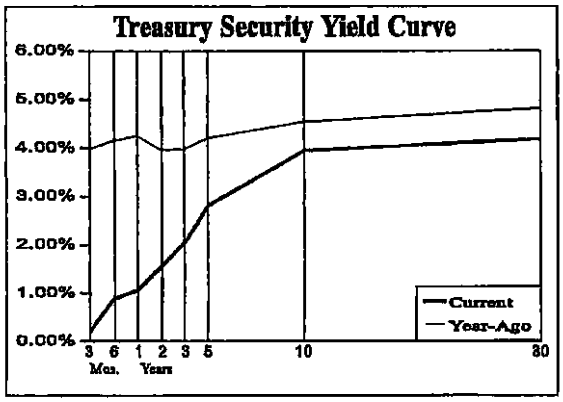
Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued as of December 10, 2001.

Note: October 2002 figures have been adjusted.

Note: January 2003 figures have been adjusted.

Selected Yields

	Recent (10/15/08)	3 Months Ago (7/16/08)	Year Ago (10/17/07)		Recent (10/15/08)	3 Months Ago (7/16/08)	Year Ago (10/17/07)
TAXABLE							
Market Rates				**Mortgage-Backed Securities**			
Discount Rate	1.75	2.25	5.25	GNMA 6.5%	6.06	5.60	5.70
Federal Funds	1.50	2.00	4.75	FHLMC 6.5% (Gold)	5.96	5.48	5.85
Prime Rate	4.50	5.00	7.75	FNMA 6.5%	5.91	5.43	5.80
30-day CP (A1/P1)	4.47	2.67	4.86	FNMA ARM	3.87	4.09	5.89
3-month LIBOR	4.55	2.79	5.20	**Corporate Bonds**			
Bank CDs				Financial (10-year) A	8.19	6.20	5.93
6-month	1.73	1.59	2.90	Industrial (25/30-year) A	7.03	6.27	6.01
1-year	2.27	2.11	3.61	Utility (25/30-year) A	6.67	6.35	6.21
5-year	3.48	3.94	3.91	Utility (25/30-year) Baa/BBB	7.03	6.56	6.27
U.S. Treasury Securities				**Foreign Bonds (10-Year)**			
3-month	0.21	1.35	3.99	Canada	3.76	3.74	4.43
6-month	0.88	1.87	4.16	Germany	4.12	4.39	4.39
1-year	1.07	2.14	4.26	Japan	1.59	1.58	1.66
5-year	2.82	3.19	4.21	United Kingdom	4.71	4.87	5.03
10-year	3.95	3.93	4.55	**Preferred Stocks**			
10-year (inflation-protected)	3.07	1.32	2.25	Utility A	6.57	6.41	6.23
30-year	4.19	4.59	4.83	Financial A	7.33	7.93	6.85
30-year Zero	4.04	4.62	4.82	Financial Adjustable A	5.49	5.49	5.49



TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.47	4.56	4.48
25-Bond Index (Revs)	5.97	5.04	4.78
General Obligation Bonds (GOs)			
1-year Aaa	2.15	1.50	3.36
1-year A	2.25	1.60	3.46
5-year Aaa	3.70	3.20	3.50
5-year A	3.75	3.30	3.60
10-year Aaa	4.86	3.80	3.80
10-year A	5.06	4.00	4.10
25/30-year Aaa	5.99	4.64	4.37
25/30-year A	6.37	4.99	4.55
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.17	4.75	4.50
Electric AA	6.12	4.65	4.60
Housing AA	6.60	5.00	4.75
Hospital AA	6.65	5.10	4.70
Toll Road Aaa	6.15	4.65	4.60

Federal Reserve Data

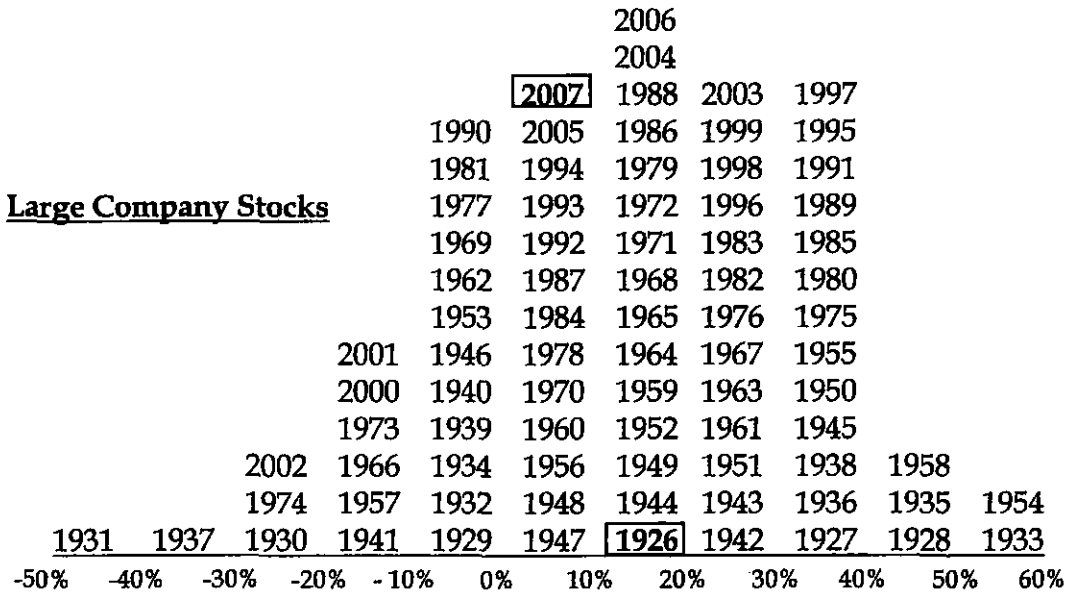
BANK RESERVES
(Two-Week Period; In Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/8/08	9/24/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	136035	68769	67266	30681	16422	9414
Borrowed Reserves	543050	267861	275189	235265	194609	116841
Net Free/Borrowed Reserves	-407015	-199092	-207923	-204584	-178186	-107428

MONEY SUPPLY
(One-Week Period; In Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	9/29/08	9/22/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1510.4	1479.0	31.4	35.7%	19.3%	11.1%
M2 (M1+savings+small time deposits)	7859.8	7863.8	-4.0	12.9%	6.3%	7.2%

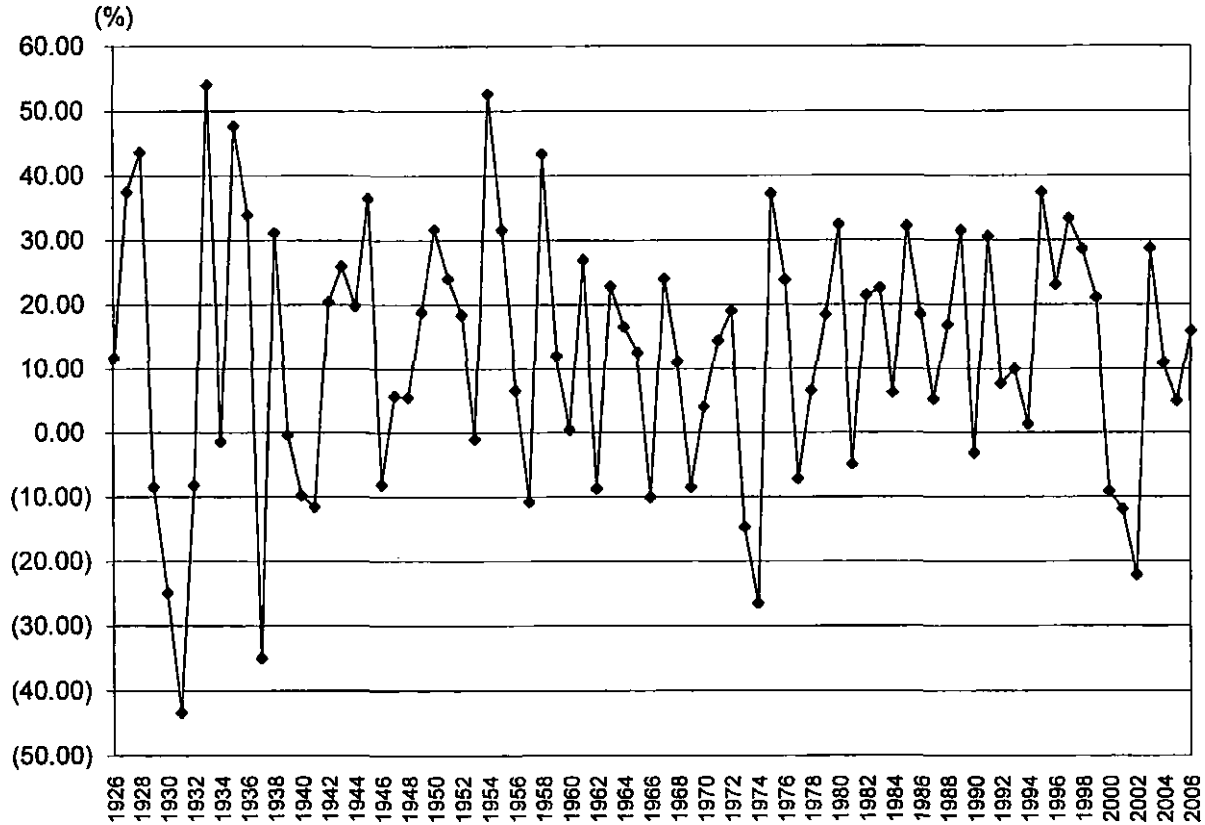
Equitable Gas Company
Total Returns on Large Company Stocks
1926 to 2007



Arithmetic Mean: $r_A = \sum_{t=1}^{n} r_t / n$

Source : Stocks, Bonds, Bills, and Inflation - Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, pp. 30-31, Morningstar, Inc., Chicago, IL

Equitable Gas Company
Large Company Stock Returns
From 1926 to 2007



Source of Information:

Stocks Bonds Bills and Inflation - Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., 2008 Chicago, IL.

Equitable Gas Company
Total Returns on Large Company Stocks
1926 to 2007

Large Company Stocks

2007

1926

-50% -40% -30% -20% -10% 0% 10% 20% 30% 40% 50% 60%

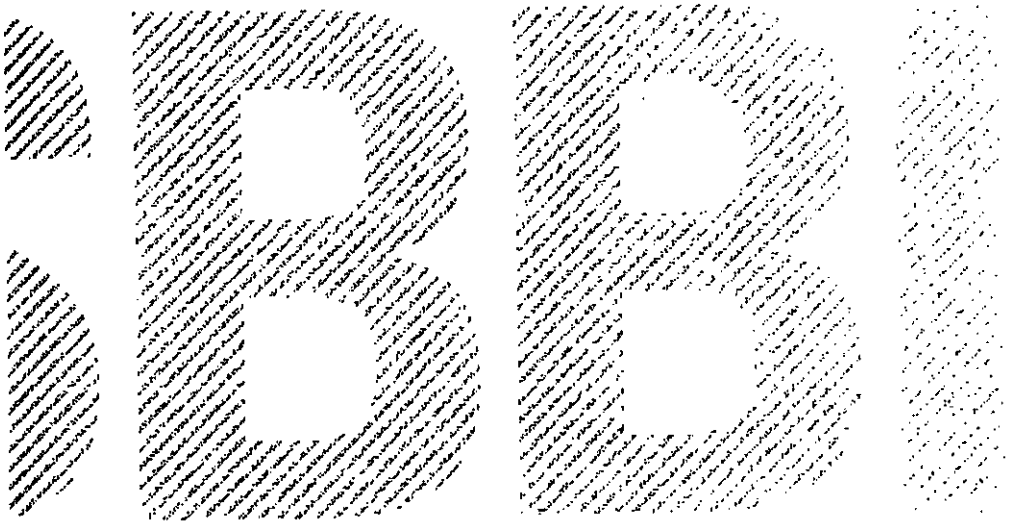
Geometric Mean: $r_G = \left[V_n / V_0 \right]^{1/n} - 1$

Source : Stocks, Bonds, Bills, and Inflation – Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, pp. 30-31, Morningstar, Inc., Chicago, IL

Ibbotson® SBBI®

2008 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2007



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For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

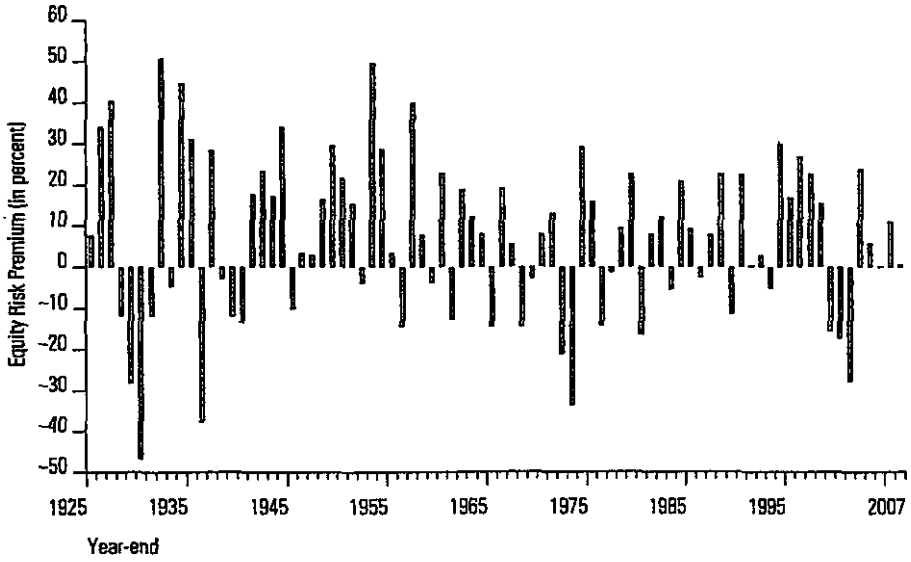
Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

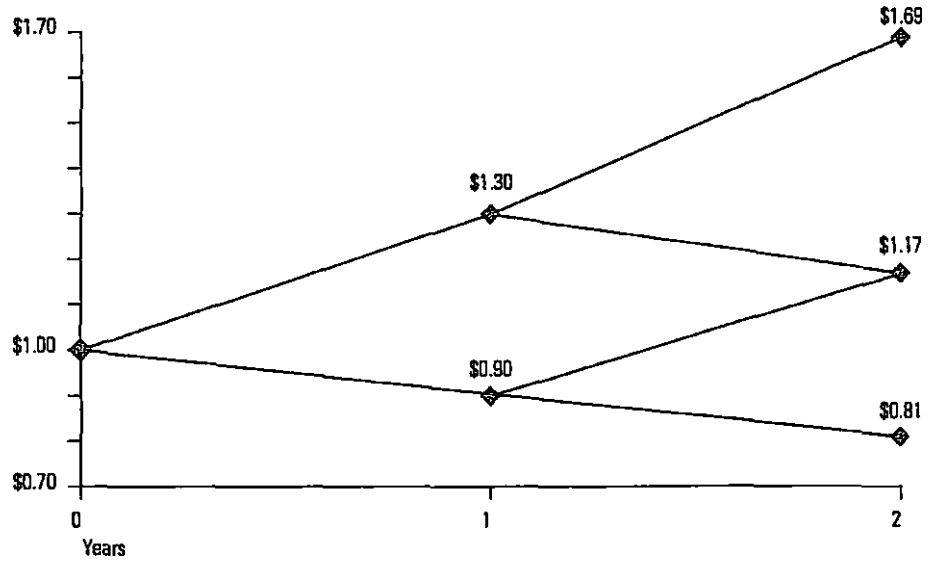
The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

Graph 5-3
Realized Equity Risk Premium Per Year
1926–2007



To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and –10 percent (*i.e., the mean plus or minus one standard deviation*). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.

Graph 5-4



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)\times(1-0.10)]^{\frac{1}{2}}-1=0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

(0.25 × $1.69) =	$0.4225
+ (0.50 × $1.17) =	$0.5850
+ (0.25 × $0.81) =	$0.2025
Total	$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean:

$$\$1\times(1+0.10)^2=\$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1\times(1+0.082)^2=\$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

Appropriate Historical Time Period

The equity risk premium can be estimated using any historical time period. For the U.S., market data exists at least as far back as the late 1800s. Therefore, it is possible to estimate the equity risk premium using data that covers roughly the past 100 years.

Our equity risk premium covers the time period from 1926 to the present. The original data source for the time series comprising the equity risk premium is the Center for Research in Security Prices. CRSP chose to begin their analysis of market returns with 1926 for two main reasons. CRSP determined that the time period around 1926 was approximately when quality financial data became available. They also made a conscious effort to include the period of extreme market volatility from the late twenties and early thirties; 1926 was chosen because it includes one full business cycle of data before the market crash of 1929. These are the most basic reasons why our equity risk premium calculation window starts in 1926.

Implicit in using history to forecast the future is the assumption that investors' expectations for future outcomes conform to past results. This method assumes that the price of taking on risk changes only slowly, if at all, over time. This "future equals the past" assumption is most applicable to a random time-series variable. A time-series variable is random if its value in one period is independent of its value in other periods.

Does the Equity Risk Premium Revert to Its Mean over Time?

Some have argued that the estimate of the equity risk premium is upwardly biased since the stock market is currently priced high. In other words, since there have been several years with extraordinarily high market returns and realized equity risk premia, the expectation is that returns and realized equity risk premia will be lower in the future, bringing the average back to a normalized level. This argument relies on several studies that have tried to determine whether reversion to the mean exists in stock market prices and the equity risk premium.[3] Several academics contradict each other on this topic; moreover, the evidence supporting this argument is neither conclusive nor compelling enough to make such a strong assumption.

Our own empirical evidence suggests that the yearly difference between the stock market total return and the U.S. Treasury bond income return in any particular year is random. Graph 5-3, presented earlier, illustrates the randomness of the realized equity risk premium.

3 Fama, Eugene F., and Kenneth R. French. "Permanent and Temporary Components of Stock Prices," *Journal of Political Economy*, April 1988, pp. 246–273. Poterba, James M., and Lawrence H. Summers. "Mean Reversion in Stock Prices," *Journal of Financial Economics*, October 1988, pp. 27–59. Lo, Andrew W., and A. Craig MacKinlay. "Stock Market Prices Do Not Follow Random Walks: Evidence from a Simple Specification Test," *The Review of Financial Studies*, Spring 1988, pp. 41–66. Fimerty, John D., and Dean Leistikow. "The Behavior of Equity and Debt Risk Premiums: Are They Mean Reverting and Downward-Trending?" *The Journal of Portfolio Management*, Summer 1993, pp. 73–84. Ibbotson, Roger G., and Scott L. Lummer. "The Behavior of Equity and Debt Risk Premiums: Comment," *The Journal of Portfolio Management*, Summer 1994, pp. 98–100. Finnerty, John D., and Dean Leistikow. "The Behavior of Equity and Debt Risk Premiums: Reply to Comment," *The Journal of Portfolio Management*, Summer 1994, pp. 101–102.

A statistical measure of the randomness of a return series is its serial correlation. Serial correlation (or autocorrelation) is defined as the degree to which the return of a given series is related from period to period. A serial correlation near positive one indicates that returns are predictable from one period to the next period and are positively related. That is, the returns of one period are a good predictor of the returns in the next period. Conversely, a serial correlation near negative one indicates that the returns in one period are inversely related to those of the next period. A serial correlation near zero indicates that the returns are random or unpredictable from one period to the next. Table 5-3 contains the serial correlation of the market total returns, the realized long-horizon equity risk premium, and inflation.

Table 5-3
Interpretation of Annual Serial Correlations
1926–2007

Series	Serial Correlation	Interpretation
Large Company Stock Total Returns	0.03	Random
Equity Risk Premium	0.03	Random
Inflation Rates	0.65	Trend

The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year. That is, there is no discernable pattern in the realized *equity risk premium—it is virtually impossible to forecast next year's realized risk premium based* on the premium of the previous year. For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is as likely to be higher as it is lower. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

Table 5-4 also indicates that the equity risk premium varies considerably by decade. The complete decades ranged from a high of 17.9 percent in the 1950s to a low of 0.3 percent in the 1970s, however, thus far the *2000s* have shown a –2.4 percent equity risk premium. *This look at historical equity risk* premium reveals no observable pattern.

Table 5-4
Long-Horizon Equity Risk Premium by Decade
1926–2007

1920s*	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s**	1997-2007
17.6%	2.3%	8.0%	17.9%	4.2%	0.3%	7.9%	12.1%	–2.4%	4.2%

*Based on the period 1926–1929.

**Based on the period 2000–2007.

Finnerty and Leistikow perform more econometrically sophisticated tests of mean reversion in the equity risk premium. Their tests demonstrate that—as we suspected from our simpler tests—the equity risk premium that was realized over 1926 to the present was almost perfectly free of mean reversion and had no statistically identifiable time trends.[4] Lo and MacKinlay conclude, "the rejection of the random walk for weekly returns does not support a mean-reverting model of asset prices."

Choosing an Appropriate Historical Period

The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable.[5] Furthermore, because an average of the realized equity risk premium is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants. The magnitude of how shorter periods can affect the result will be explored later in this chapter.

Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of the last hundred years took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, the development of the European Economic Community, and the attacks of September 11, 2001.

It is even difficult for economists to predict the economic environment of the future. For example, if one were analyzing the stock market in 1987 before the crash, it would be statistically improbable to predict the impending short-term volatility without considering the stock market crash and market volatility of the 1929–1931 period.

Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 82-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to

4 Though the study performed by Finnerty and Leistikow demonstrates that the traditional equity risk premium exhibits no mean reversion or drift, they conclude that, "the processes generating these risk premiums are generally mean-reverting." This conclusion is completely unrelated to their statistical findings and has received some criticism. In addition to examining the traditional equity risk premia, Finnerty and Leistikow include analyses on "real" risk premia as well as separate risk premia for income and capital gains. In their comments on the study, Ibbotson and Lummer show that these "real" risk premia adjust for inflation twice, "creating variables with no economic content." In addition, separating income and capital gains does not shed light on the behavior of the risk premia as a whole.

5 This assertion is further corroborated by data presented in *Global Investing: The Professional's Guide to the World of Capital Markets* (by Roger G. Ibbotson and Gary P. Brinson and published by McGraw-Hill, New York). Ibbotson and Brinson constructed a stock market total return series back to 1790. Even with some uncertainty about the accuracy of the data before the mid-nineteenth century, the results are remarkable. The real (adjusted for inflation) returns that investors received during the three 50-year periods and one 51-year period between 1790 and 1990 did not differ greatly from one another (that is, in a statistically significant amount). Nor did the real returns differ greatly from the overall 201-year average. This finding implies that because real stock-market returns have been reasonably consistent over time, investors can use these past returns as reasonable bases for forming their expectations of future returns.

repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.

A Look at the Historical Results

It is interesting to take a look at the realized returns and realized equity risk premium in the context of the above discussion. Table 5-5 shows the average stock market return and the average (arithmetic mean) realized long-horizon equity risk premium over various historical time periods. Similarly, Graph 5-5 shows the average (arithmetic mean) realized equity risk premium calculated through 2007 for different starting dates. The table and the graph both show that using a longer historical period provides a more stable estimate of the equity risk premium. The reason is that any unique period will not be weighted heavily in an average covering a longer historical period. It better represents the probability of these unique events occurring over a long period of time.

Table 5-5
Stock Market Return and Equity Risk Premium Over Time
1926–2007

Period Length	Period Dates	Large Company Stock Arithmetic Mean Total Return	Long-Horizon Equity Risk Premium
82 Years	1926–2007	12.3%	7.1%
70 Years	1938–2007	12.6%	7.3%
60 Years	1948–2007	13.1%	7.1%
50 Years	1958–2007	12.2%	5.5%
40 Years	1968–2007	11.8%	4.4%
30 Years	1978–2007	14.0%	6.3%
20 Years	1988–2007	13.0%	6.6%
15 Years	1993–2007	11.8%	6.0%
10 Years	1998–2007	7.2%	1.9%
5 Years	2003–2007	13.2%	8.3%

Looking carefully at Graph 5-5 will clarify this point. The graph shows the realized equity risk premium for a series of time periods through 2007, starting with 1926. In other words, the first value on the graph represents the average realized equity risk premium over the period 1926–2007. The next value on the graph represents the average realized equity risk premium over the period 1927–2007, and so on, with the last value representing the average over the most recent five years, 2003–2007. Concentrating on the left side of Graph 5-5, one notices that the realized equity risk premium, when measured over long periods of time, is relatively stable. In viewing the graph from left to right, moving from longer to shorter historical periods, one sees that the value of the realized equity risk premium begins to decline significantly. Why does this occur? The reason is that the severe bear market of 1973–1974 is receiving proportionately more weight in the shorter, more recent average. If you continue to follow the line to the right, however, you will also notice that when 1973 and 1974 fall out of the recent average, the realized equity risk premium jumps up by nearly 1.2 percent.

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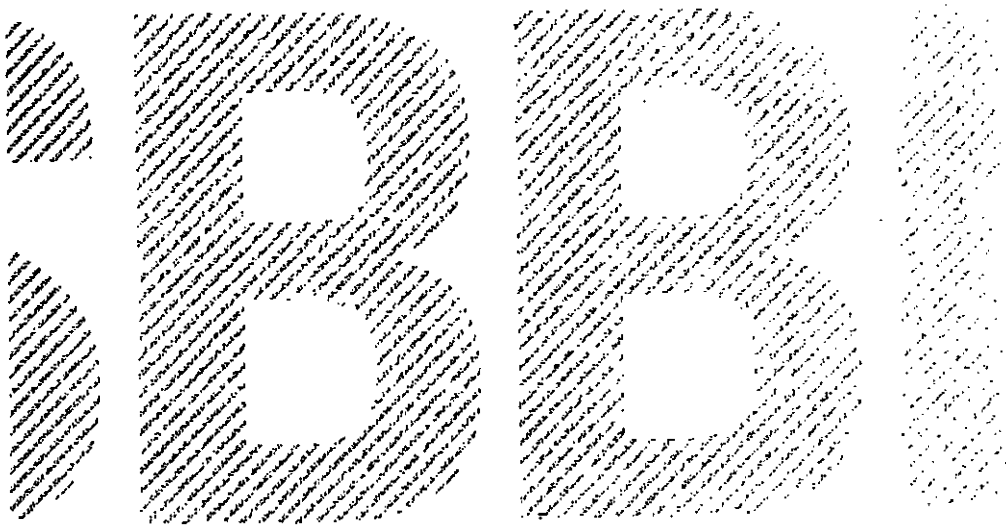

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Table 2-1
Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes
Summary Statistics of Annual Returns

from 1926 to 2007

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	10.4%	12.3%	20.0%	0.03
Income	4.2	4.2	1.6	0.89
Capital Appreciation	6.0	7.8	19.3	0.03
Ibbotson Small Company Stocks				
Total Returns	12.5	17.1	32.6	0.06
Mid-Cap Stocks*				
Total Returns	11.3	14.0	24.4	−0.02
Income	4.0	4.0	1.7	0.89
Capital Appreciation	7.1	9.8	23.7	−0.02
Low-Cap Stocks*				
Total Returns	11.7	15.5	29.0	0.03
Income	3.7	3.7	2.0	0.89
Capital Appreciation	7.9	11.6	28.4	0.02
Micro-Cap Stocks*				
Total Returns	12.5	18.5	38.8	0.08
Income	2.6	2.6	1.8	0.91
Capital Appreciation	9.9	15.8	38.3	0.07
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.4	0.08
Long-Term Government Bonds				
Total Returns	5.5	5.8	9.2	−0.08
Income	5.2	5.2	2.7	0.96
Capital Appreciation	0.1	0.4	8.0	−0.23
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.15
Income	4.7	4.7	2.9	0.96
Capital Appreciation	0.5	0.5	4.4	−0.19
Treasury Bills				
Total Returns	3.7	3.8	3.1	0.91
Inflation	3.0	3.1	4.2	0.65

Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return

*Source: ©2008) CRSP®, *Center for Research in Security Prices. Graduate School of Business. The University of Chicago* used with permission. All rights reserved. www.crsp.chicagogsb.edu
See Chapter 7 for details on decile construction

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For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. There is no evidence that investors expect the historical trend of bond capital losses to be repeated in the future (otherwise, bond prices would be adjusted accordingly). Therefore, historical total returns are biased downward as indicators of future expectations. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

Equitable Gas Company
Calculation of Capital Asset Pricing Model (CAPM) and Empirical CAPM (ECAPM) Using
OTS Witness Plonski's Risk-Free Rate and Beta
and the Proper Morningstar Long-Term Arithmetic Return

Traditional CAPM (1)

OTS Beta	OTS Risk-Free Rate	Long-Term Arithmetic Return	Risk Premium	CAPM Results
0.88	5.30%	12.30%	7.00%	11.46%

Empirical CAPM (2)

OTS Beta	OTS Risk-Free Rate	Long-Term Arithmetic Return	Risk Premium	ECAPM Results
0.88	5.30%	12.30%	7.00%	11.67%

Notes:
(1) The traditional CAPM is calculated by adding the risk-free rate to the product of beta times the risk premium.
(2) The Empirical CAPM (ECAPM) is calculated by adding the risk-free rate to the sum of .25 times the risk premium and .75 times the product of beta times the risk premium.

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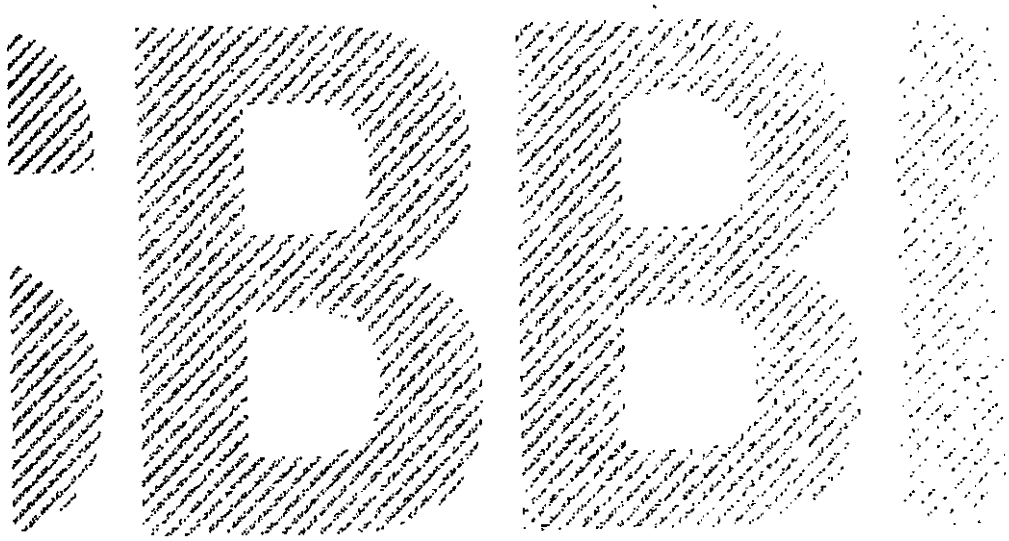

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Chapter 3
The Buildup Method

Estimating the equity cost of capital is a difficult task to which much of modern financial theory is devoted. The equity cost of capital is equal to the expected rate of return for a firm's equity; this return includes all dividends plus any capital gains or losses. A properly specified cost of equity must include, *if appropriate, provisions for flotation costs and certain market inefficiencies that might not be captured* by standard methods for estimating equity rates of return.

There are several widely used and effective methods to estimate the equity cost of capital. The most common of these are: 1) the buildup method, 2) the capital asset pricing model (CAPM), 3) the discounted cash flow (DCF) method, 4) arbitrage pricing theory (APT), and 5) the Fama-French three factor model. This chapter will focus on the buildup method, while Chapter 4 will cover all other cost of equity models.

The Buildup Method for Cost of Equity Capital

The buildup method is an additive model in which the return on an asset is estimated as the sum of a risk-free rate and one or more risk premia. Each premium represents the reward an investor receives for taking on a specific risk. The building blocks are summed arithmetically to form an estimate of the cost of capital.

	Risk-Free Rate
+	Equity Risk Premium
+	Firm Size Premium
+	?
=	**Cost of Equity**

Risk-Free Rate

Since any risky investment should return at least as much as the riskless asset, the risk-free rate is the starting point of the buildup method. The buildup method, the capital asset pricing model, and the Fama-French three factor model all implicitly assume the presence of a single riskless asset, that is, an asset perceived by all investors as having no risk. Selecting the appropriate risk-free rate is discussed in detail in the CAPM section of Chapter 4.

Risk Premia

There are several risk premia that can be used with the buildup method. Some are widely accepted, while others are more controversial. The equity risk premium is the most common; like the risk-free rate, it is a component of the capital asset pricing model and the Fama-French three factor model. The same equity risk premium can be used in each of these models. For additional information on the equity risk premium, see Chapter 5, which has been devoted exclusively to this subject.

Small Stock or Size Premia

A small stock or size premium may also be added in the buildup method to account for the additional risk inherent in small company stocks (for additional information regarding size premia, see Chapter 7, which is devoted to this subject). It is important to note, however, that the size premia presented elsewhere in this publication have been adjusted for beta. In other words, the portion of the excess return on small stocks that can be explained by their higher betas is not included in the size premia. Some assert that a small stock premium that has not been adjusted for beta would be more appropriate for use in the buildup method. This non-beta-adjusted small stock premium can be calculated by subtracting the arithmetic mean of the large company stock return from the arithmetic mean of the small company stock return. Table 3-1 shows the various size premia on both a beta-adjusted and a non-beta-adjusted basis. Table 3-2 shows how the non-beta-adjusted small stock premia are calculated using the arithmetic mean returns from Table 2-1. Calculation of the beta-adjusted size premia is explained in detail in Chapter 7.

Table 3-1
Size Premia on a Beta-Adjusted versus Non-Beta-Adjusted Basis
1926–2007

	Beta-Adjusted Size Premia	Non-Beta-Adjusted Small Stock Premia
Mid-Cap	0.9%	1.8%
Low-Cap	1.6%	3.2%
Micro-Cap	3.7%	6.2%
Ibbotson Small Company Stocks	3.0%	4.8%

Table 3-2
Derivation of Non-Beta Adjusted Small Stock Premia
1926–2007

	Small Company Stock Arithmetic Mean Return		Large Company Stock Arithmetic Mean Return		Non-Beta-Adjusted Small Stock Premia
Mid-Cap	14.0%	–	12.3%	=	1.8%*
Low-Cap	15.5%	–	12.3%	=	3.2%
Micro-Cap	18.5%	–	12.3%	=	6.2%
Ibbotson Small Company Stocks	17.1%	–	12.3%	=	4.8%

**difference due to rounding*

The problem with using a non-beta-adjusted small stock premium is that in doing so one assumes that the company being valued has the same systematic risk (or beta) as the portfolio of small stocks used in the calculation of the size premium. This ignores much of the information that we have regarding market returns. Primarily, different industries tend to have different levels of systematic risk. For example, companies within health services industries tend to have less systematic risk than the market as a whole. Since the beta-adjusted size premium isolates the excess return due to size, it can be applied to a company without making any assumptions regarding the company's systematic risk.

The Size Phenomena Across Industries

One question regularly raised concerning the size premium is whether it is relevant for specific industries. In the past there has been no concrete evidence to counter the contention that a size effect exists for the economy as a whole but may not be relevant to a specific industry. The problem of supporting a size premia for a specific industry has been made difficult by a lack of data for companies in individual industries.

We have attempted to answer this question by performing an industry-specific size effect study. The study uses the Center for Research in Security Prices (CRSP) database and the following methodology:

1. Industries are defined at the two-digit SIC (Standard Industrial Classification) code level. Companies are sorted into industries using the CRSP SIC code classification system. In order to be included in the study, an industry must have a minimum of ten companies for all periods. Any industry containing less than 30 years of data was not included in the study.
2. On a calendar year-end basis, companies are ranked by market capitalization within each industry from largest to smallest. Each industry is split into a "large" and a "small" portfolio with an equal number of companies.
3. A capitalization-weighted return series is calculated for each "large" and "small" portfolio. The excess return for each industry is represented by the "small" portfolio arithmetic return less the "large" portfolio arithmetic return.

The results of the study can be found in Table 7-14. Note that a large majority of industries exhibit returns where small company stocks outperform large company stocks over extended periods.

The excess returns presented in this table should not be construed as size premia. Due to limited data, we have defined size in rather general terms. In addition, the population of companies in most industries is very small. Table 7-14 only provides evidence that smaller companies have generally outperformed larger companies across industries. The size premium study presented earlier in this chapter provides more reliable statistics as they relate to the size premium. In addition, measures of industry risk for use in the buildup model are presented in Table 3-5.

Table 7-14
Size Effect within Industries
Summary Statistics and Excess Returns

(Through Year-end 2007)

			Large Company Group		
SIC Code	Description	Years	Geometric Mean	Arithmetic Mean	Standard Deviation
10	Metal Mining	82	8.57%	12.18%	29.09%
13	Oil and Gas Extraction	45	11.80%	14.78%	25.84%
15	*Building Construction-General Contractors & Op. Builders*	36	9.26%	16.69%	40.95%
16	Hvy. Construction Other than Bldg. Construction-Contractors	37	9.17%	13.15%	32.18%
20	*Food and Kindred Spirits*	82	11.05%	12.65%	18.77%
22	Textile Mill Products	82	6.74%	11.50%	32.34%
23	Apparel & other Finished Products Made from Fabrics & Similar	48	7.54%	12.10%	32.52%
24	Lumber and Wood Products, Except Furniture	45	8.72%	11.34%	25.24%
25	Furniture and Fixtures	38	10.26%	12.49%	21.76%
26	Paper & Allied Products	77	11.53%	14.41%	26.75%
27	Printing, Publishing and Allied Products	47	9.62%	11.70%	20.99%
28	Chemicals and Allied Products	82	11.75%	13.83%	22.17%
29	Petroleum Refining & Related Industries	82	11.80%	13.68%	21.21%
30	Rubber & Miscellaneous Plastics Products	61	11.06%	13.69%	24.83%
31	Leather & Leather Products	45	11.86%	16.29%	33.11%
32	Stone, Clay, Glass & Concrete Products	78	9.08%	12.77%	31.09%
33	Primary Metal Industries	82	8.83%	12.79%	30.46%
34	*Fabricated Metal Products, Except Machinery & Trans. Equip*	82	9.88%	12.34%	22.97%
35	Industrial & Commercial Machinery & Computer Equipment	82	10.85%	14.20%	27.38%
36	Electrical Equipment & Components, Except Computer	82	9.86%	13.49%	28.18%
37	Transportation Equipment	82	11.13%	15.28%	31.66%
38	Measuring, Analyzing & Controlling Instruments	71	12.12%	14.16%	21.64%
39	Miscellaneous Manufacturing Industries	46	8.15%	11.94%	28.35%
40	Railroad Transportation	82	9.76%	12.71%	24.55%
42	Motor Freight Transportation & Warehousing	44	8.20%	12.53%	27.81%
45	Transport by Air	62	6.76%	11.11%	32.15%
48	Communications	45	9.48%	11.78%	21.92%
49	Electric, Gas & Sanitary Services	82	9.03%	11.10%	21.25%
50	Wholesale Trade-Durable Goods	62	10.07%	12.35%	22.98%
51	Wholesale Trade-Nondurable Goods	40	9.80%	12.60%	24.31%
53	*General Merchandise Stores*	82	9.66%	12.81%	28.32%
54	Food Stores	51	11.12%	13.54%	22.99%
56	*Apparel & Accessory Stores*	81	13.56%	17.59%	31.88%
57	Home Furniture, Furnishings, and Equipment Stores	35	11.85%	22.64%	58.73%
58	*Eating and Drinking Places*	39	10.99%	15.29%	32.28%
59	Miscellaneous Retail	45	12.53%	15.85%	28.38%
60	Depository Institutions	39	10.69%	13.04%	21.41%
61	Nondepository Credit Institutions	58	11.94%	14.84%	26.53%
62	Security and Commod. Brokers, Dealers, Exchanges	35	17.50%	23.99%	42.13%
63	Insurance Carriers	39	10.70%	12.48%	19.78%
65	Real Estate	45	7.07%	11.45%	30.33%
67	Holding & Other Investment Offices	78	10.00%	13.11%	24.98%
70	Hotels, Rooming Houses, Camps, & Other Lodging	38	10.95%	16.53%	34.89%
72	Personal Services	38	8.26%	12.73%	30.17%
73	Business Services	45	10.31%	14.81%	31.82%
78	Motion Pictures	57	11.65%	16.18%	32.97%
79	Amusement and Recreation Services	35	12.72%	18.29%	26.85%
80	*Health Services*	35	12.73%	19.18%	34.89%

Table 7-14 *(continued)*
Size Effect within Industries
Summary Statistics and Excess Returns

(Through Year-end 2007)

SIC Code	Description		Small Company Group Geometric Mean	Arithmetic Mean	Standard Deviation	Excess Return
10	Metal Mining	8.74%	16.57%	45.51%	4.38%
13	Oil and Gas Extraction	12.37%	20.28%	45.67%	9.50%
15	Building Construction-General Contractors & Op. Builders	3.59%	13.35%	44.06%	-3.25%
16	Hvy. Construction Other than Bldg. Construction-Contractors	18.60%	23.37%	36.44%	10.22%
20	Food and Kindred Spirits	12.57%	16.09%	29.80%	3.44%
22	*Textile Mill Products*	9.25%	14.76%	34.44%	3.28%
23	Apparel & other Finished Products Made from Fabrics & Similar	5.69%	11.38%	37.52%	-0.72%
24	Lumber and Wood Products, Except Furniture	10.80%	20.58%	52.46%	9.24%
25	Furniture and Fixtures	7.83%	11.94%	29.50%	-0.55%
26	Paper & Allied Products	15.10%	20.45%	41.47%	6.04%
27	Printing, Publishing and Allied Products	14.94%	17.85%	25.20%	6.15%
28	Chemicals and Allied Products	12.85%	18.29%	39.37%	4.45%
29	Petroleum Refining & Related Industries	13.53%	17.93%	31.63%	4.05%
30	Rubber & Miscellaneous Plastics Products	12.28%	16.74%	32.90%	3.06%
31	*Leather & Leather Products*	10.50%	15.46%	34.02%	-0.83%
32	Stone, Clay, Glass & Concrete Products	10.01%	14.75%	32.84%	1.98%
33	*Primary Metal Industries*	13.63%	19.32%	38.17%	6.52%
34	Fabricated Metal Products, Except Machinery & Trans. Equip.	11.88%	17.40%	36.99%	5.06%
35	Industrial & Commercial Machinery & Computer Equipment	12.20%	17.47%	35.22%	3.26%
36	Electrical Equipment & Components, Except Computer	11.83%	19.64%	45.39%	6.15%
37	Transportation Equipment	12.04%	18.20%	37.84%	2.92%
38	Measuring, Analyzing & Controlling Instruments	12.90%	17.73%	34.61%	3.57%
39	Miscellaneous Manufacturing Industries	7.59%	11.92%	31.37%	-0.02%
40	Railroad Transportation	9.80%	15.02%	35.94%	2.31%
42	Motor Freight Transportation & Warehousing	6.48%	12.32%	38.44%	-0.21%
45	*Transport by Air*	8.67%	18.87%	47.53%	5.76%
48	Communications	17.00%	24.85%	45.23%	13.10%
49	*Electric, Gas & Sanitary Services*	10.56%	14.11%	29.34%	3.02%
50	Wholesale Trade-Durable Goods	10.97%	16.01%	35.70%	3.55%
51	Wholesale Trade-Nondurable Goods	8.34%	11.86%	28.05%	-0.74%
53	General Merchandise Stores	8.92%	16.28%	42.81%	3.45%
54	Food Stores	10.42%	14.11%	28.99%	0.58%
56	Apparel & Accessory Stores	11.13%	17.31%	38.88%	-0.27%
57	Home Furniture, Furnishings, and Equipment Stores	14.63%	24.80%	60.41%	2.16%
58	Eating and Drinking Places	1.72%	7.50%	36.30%	-7.79%
59	Miscellaneous Retail	11.59%	16.97%	35.97%	1.32%
60	*Depository Institutions*	14.21%	18.90%	25.13%	3.86%
61	Nondepository Credit Institutions	12.74%	16.67%	29.84%	1.83%
62	Security and Commod Brokers, Dealers, Exchanges	14.85%	21.70%	41.62%	-2.29%
63	Insurance Carriers	12.77%	15.56%	23.78%	3.08%
65	Real Estate	6.42%	11.22%	34.37%	-0.24%
67	Holding & Other Investment Offices	11.07%	15.24%	30.91%	2.13%
70	Hotels, Rooming Houses, Camps, & Other Lodging	6.16%	12.03%	36.48%	-4.50%
72	Personal Services	17.90%	22.10%	31.96%	9.36%
73	Business Services	13.84%	23.17%	58.64%	8.26%
78	*Motion Pictures*	5.38%	13.10%	45.16%	-3.08%
79	Amusement and Recreation Services	10.03%	13.85%	31.27%	-2.44%
80	*Health Services*	14.76%	20.93%	39.89%	2.75%

Coefficients of Determination (R-Squared)
for Hanley's Group of Nine Proxy Companies
and OTS Witness Plonski's Eight Proxy Companies

Ticker Symbol	Company	R Factor	R Squared
	Hanley's Proxy Group of Nine Companies		
ATG	AGL Resources	0.5559	0.3090
ATO	Atmos Energy	0.5860	0.3434
LG	Laclede Group	0.4635	0.2148
GAS	Nicor Inc.	0.5518	0.3045
NWN	Northwest Nat. Gas	0.4230	0.1789
PNY	Piedmont Natural Gas	0.4909	0.2410
SJI	South Jersey Inds.	0.4713	0.2221
SWX	Southwest Gas	0.5090	0.2591
WGL	WGL Holdings Inc.	0.5573	0.3106
	Average	0.5121	0.2648
	OTS Witness Plonski's Proxy Group of Eight Companies		
ATG	AGL Resources	0.5559	0.3090
NFG	National Fuel Gas	0.4763	0.2269
NJR	New Jersey Resources	0.4946	0.2446
GAS	Nicor Inc.	0.5518	0.3045
NST	NSTAR	0.5159	0.2662
PNY	Piedmont Natural Gas	0.4909	0.2410
SJI	South Jersey Inds.	0.4713	0.2221
WGL	WGL Holdings Inc.	0.5573	0.3106
	Average	0.5143	0.2656

Source of Information: Value Line Inc., October, 2008

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

The capital asset pricing model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often, the only asset pricing model taught in these courses.[1]

The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor—poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive "market portfolio" that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it

[1] Although every asset pricing model is a capital asset pricing model, the finance profession employs the acronym CAPM for the specific model of Sharpe (1964), Lintner (1965) and Black (1972) discussed here. Thus throughout the paper we refer to the Sharpe-Lintner-Black model as the CAPM.

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One possibility is that the CAPM's problems are spurious, the result of data dredging—publication-hungry researchers scouring the data and unearthing contradictions that occur in specific samples as a result of chance. A standard response to this concern is to test for similar findings in other samples. Chan, Hamao and Lakonishok (1991) find a strong relation between book-to-market equity (B/M) and average return for Japanese stocks. Capaul, Rowley and Sharpe (1993) observe a similar B/M effect in four European stock markets and in Japan. Fama and French (1998) find that the price ratios that produce problems for the CAPM in U.S. data show up in the same way in the stock returns of twelve non-U.S. major markets, and they are present in emerging market returns. This evidence suggests that the contradictions of the CAPM associated with price ratios are not sample specific.

Explanations: Irrational Pricing or Risk

Among those who conclude that the empirical failures of the CAPM are fatal, two stories emerge. On one side are the behavioralists. Their view is based on evidence that stocks with high ratios of book value to market price are typically firms that have fallen on bad times, while low B/M is associated with growth firms (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1995). The behavioralists argue that sorting firms on book-to-market ratios exposes investor overreaction to good and bad times. Investors *overextrapolate* past performance, resulting in stock prices that are too high for growth (low B/M) firms and too low for distressed (high B/M, so-called value) firms. When the overreaction is eventually corrected, the result is high returns for value stocks and low returns for growth stocks. Proponents of this view include DeBondt and Thaler (1987), Lakonishok, Shleifer and Vishny (1994) and Haugen (1995).

The second story for explaining the empirical contradictions of the CAPM is that they point to the need for a more complicated asset pricing model. The CAPM is based on many unrealistic assumptions. For example, the assumption that investors care only about the mean and variance of one-period portfolio returns is extreme. It is reasonable that investors also care about how their portfolio return covaries with labor income and future investment opportunities, so a portfolio's return variance misses important dimensions of risk. If so, market beta is not a complete description of an asset's risk, and we should not be surprised to find that differences in expected return are not completely explained by differences in beta. In this view, the search should turn to asset pricing models that do a better job explaining average returns.

Merton's (1973) intertemporal capital asset pricing model (ICAPM) is a natural extension of the CAPM. The ICAPM begins with a different assumption about investor objectives. In the CAPM, investors care only about the wealth their portfolio produces at the end of the current period. In the ICAPM, investors are concerned not only with their end-of-period payoff, but also with the opportunities

they will have to consume or invest the payoff. Thus, when choosing a portfolio at time $t - 1$, ICAPM investors consider how their wealth at t might vary with future *state variables*, including labor income, the prices of consumption goods and the nature of portfolio opportunities at t, and expectations about the labor income, consumption and investment opportunities to be available after t.

Like CAPM investors, ICAPM investors prefer high expected return and low return variance. But ICAPM investors are also concerned with the covariances of portfolio returns with state variables. As a result, optimal portfolios are "multifactor efficient," which means they have the largest possible expected returns, given their return variances and the covariances of their returns with the relevant state variables.

Fama (1996) shows that the ICAPM generalizes the logic of the CAPM. That is, if there is risk-free borrowing and lending or if short sales of risky assets are allowed, market clearing prices imply that the market portfolio is multifactor efficient. Moreover, multifactor efficiency implies a relation between expected return and beta risks, but it requires additional betas, along with a market beta, to explain expected returns.

An ideal implementation of the ICAPM would specify the state variables that affect expected returns. Fama and French (1993) take a more indirect approach, perhaps more in the spirit of Ross's (1976) arbitrage pricing theory. They argue that though size and book-to-market equity are not themselves state variables, the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas. In support of this claim, they show that the returns on the stocks of small firms covary more with one another than with returns on the stocks of large firms, and returns on high book-to-market (value) stocks covary more with one another than with returns on low book-to-market (growth) stocks. Fama and French (1995) show that there are similar size and book-to-market patterns in the covariation of fundamentals like earnings and sales.

Based on this evidence, Fama and French (1993, 1996) propose a three-factor model for expected returns,

$$\text{(Three-Factor Model)} \quad E(R_{it}) - R_{ft} = \beta_{iM}[E(R_{Mt}) - R_{ft}] + \beta_{is}E(SMB_t) + \beta_{ih}E(HML_t),$$

In this equation, SMB_t (small minus big) is the difference between the returns on diversified portfolios of small and big stocks, HML_t (high minus low) is the difference between the returns on diversified portfolios of high and low B/M stocks, and the betas are slopes in the multiple regression of $R_{it} - R_{ft}$ on $R_{Mt} - R_{ft}$, SMB_t and HML_t.

For perspective, the average value of the market premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, which is 3.6 standard errors from zero. The

average values of SMB_t and HML_t are 3.6 percent and 5.0 percent per year, and they are 2.1 and 3.1 standard errors from zero. All three premiums are volatile, with annual standard deviations of 21.0 percent ($R_{Mt} - R_{ft}$), 14.6 percent (SMB_t) and 14.2 percent (HML_t) per year. Although the average values of the premiums are large, high volatility implies substantial uncertainty about the true expected premiums.

One implication of the expected return equation of the three-factor model is that the intercept α_i in the time-series regression

$$R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \beta_{is}SMB_t + \beta_{ih}HML_t + e_{it},$$

is zero for all assets i. Using this criterion, Fama and French (1993, 1996) find that the model captures much of the variation in average return for portfolios formed on size, book-to-market equity and other price ratios that cause problems for the CAPM. Fama and French (1998) show that an international version of the model performs better than an international CAPM in describing average returns on portfolios formed on scaled price variables for stocks in 13 major markets.

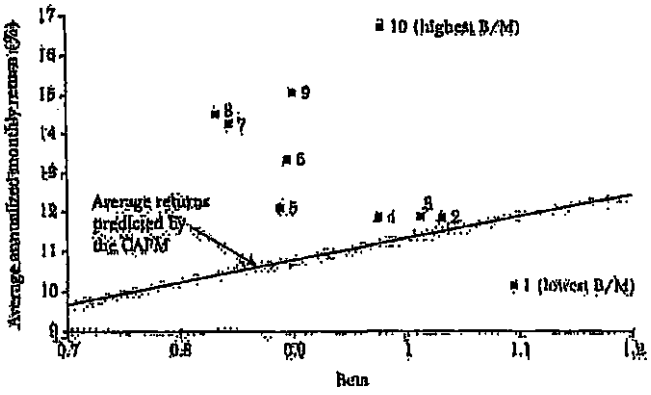
The three-factor model is now widely used in empirical research that requires a model of expected returns. Estimates of α_i from the time-series regression above are used to calibrate how rapidly stock prices respond to new information (for example, Loughran and Ritter, 1995; Mitchell and Stafford, 2000). They are also used to measure the special information of portfolio managers, for example, in Carhart's (1997) study of mutual fund performance. Among practitioners like Ibbotson Associates, the model is offered as an alternative to the CAPM for estimating the cost of equity capital.

From a theoretical perspective, the main shortcoming of the three-factor model is its empirical motivation. The small-minus-big (SMB) and high-minus-low (HML) explanatory returns are not motivated by predictions about state variables of concern to investors. Instead they are brute force constructs meant to capture the patterns uncovered by previous work on how average stock returns vary with size and the book-to-market equity ratio.

But this concern is not fatal. The ICAPM does not require that the additional portfolios used along with the market portfolio to explain expected returns "mimic" the relevant state variables. In both the ICAPM and the arbitrage pricing theory, it suffices that the additional portfolios are well diversified (in the terminology of Fama, 1996, they are multifactor minimum variance) and that they are sufficiently different from the market portfolio to capture covariation in returns and variation in expected returns missed by the market portfolio. Thus, adding diversified portfolios that capture covariation in returns and variation in average returns left unexplained by the market is in the spirit of both the ICAPM and the Ross's arbitrage pricing theory.

The behavioralists are not impressed by the evidence for a risk-based explanation of the failures of the CAPM. They typically concede that the three-factor model captures covariation in returns missed by the market return and that it picks

Figure 3
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on B/M, 1963–2003



market proxies, like the value-weight portfolio of U.S. stocks, that lead to rejections of the model in empirical tests. The contradictions of the CAPM observed when such proxies are used in tests of the model show up as bad estimates of expected returns in applications, for example, estimates of the cost of equity capital that are too low (relative to historical average returns) for small stocks and for stocks with high book-to-market equity ratios. In short, if a market proxy does not work in tests of the CAPM, it does not work in applications.

Conclusions

The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success. In the early empirical work, the Black (1972) version of the model, which can accommodate a flatter tradeoff of average return for market beta, has some success. But in the late 1970s, research begins to uncover variables like size, various price ratios and momentum that add to the explanation of average returns provided by beta. The problems are serious enough to invalidate most applications of the CAPM.

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a

result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low.[7]

The CAPM is also often used to measure the performance of mutual funds and other managed portfolios. The approach, dating to Jensen (1968), is to estimate the CAPM time-series regression for a portfolio and use the intercept (Jensen's alpha) to measure abnormal performance. The problem is that, because of the empirical failings of the CAPM, even passively managed stock portfolios produce abnormal returns if their investment strategies involve tilts toward CAPM problems (Elton, Gruber, Das and Hlavka, 1993). For example, funds that concentrate on low beta stocks, small stocks or value stocks will tend to produce positive abnormal returns relative to the predictions of the Sharpe-Lintner CAPM, even when the fund managers have no special talent for picking winners.

The CAPM, like Markowitz's (1952, 1959) portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

We gratefully acknowledge the comments of John Cochrane, George Constantinides, Richard Leftwich, Andrei Shleifer, René Stulz and Timothy Taylor.

[7] The problems are compounded by the huge standard errors of estimates of the market premium and of betas for individual stocks, which probably suffice to make CAPM estimates of the cost of equity rather meaningless, even if the CAPM holds (Fama and French, 1997; Pastor and Stambaugh, 1999). For example, using the U.S. Treasury bill rate as the riskless interest rate and the CRSP value-weight portfolio of publicly traded U.S. common stocks, the average value of the equity premium $R_M - R_f$ for 1927-2003 is 8.5 percent per year, with a standard error of 2.4 percent. The two standard error range thus runs from 8.5 percent to 13.1 percent, which is sufficient to make most projects appear either profitable or unprofitable. This problem is, however, hardly special to the CAPM. For example, expected returns in all versions of Merton's (1973) ICAPM include a market beta and the expected market premium. Also, as noted earlier the expected values of the size and book-to-market premiums in the Fama-French three-factor model are also estimated with substantial error.

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The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \hat{\alpha} + \beta \times (MRP - \hat{\alpha}) \qquad (6\text{-}5)$$

where $\hat{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\hat{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = $0.0829 + 0.0520\,\beta$ is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$K = 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%)$$
$$= 5.0\% + 1.8\% + 4.2\%$$
$$= 11.0\%$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

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Portfolio Beta Coefficients

A portfolio consisting of low-beta securities will itself have a low beta, since the beta of any set of securities is a weighted average of the individual securities' betas:

$$b_p = \sum_{i=1}^{n} w_i b_i \tag{6-5}$$

Here b_p is the beta of the portfolio, which reflects how volatile the portfolio is in relation to the market index; w_i is the fraction of the portfolio invested in the ith stock; and b_i is the beta coefficient of the ith stock.

If an investor holds a $100,000 portfolio consisting of $10,000 invested in each of 10 stocks, and if each stock has a beta of 0.8, then the portfolio will have $b_p = 0.8$. Thus, the portfolio is less risky than the market, and it should experience relatively narrow price swings and have small rate of return fluctuations.

Now suppose one of the existing stocks is sold and replaced by a stock with $b_i = 2.0$. This action will increase the riskiness of the portfolio from $b_{p1} = 0.8$ to $b_{p2} = 0.92$:

$$b_{p2} = \sum_{i=1}^{n} w_i b_i = 0.9(0.8) + 0.1(2.0) = 0.92.$$

Had a stock with $b_i = 0.2$ been added, the portfolio beta would have declined from 0.8 to 0.74. Adding this stock would, therefore, reduce the riskiness of the portfolio.

The Relationship between Risk and Rates of Return

In the preceding section, we saw that under the CAPM framework, beta is the appropriate measure of a stock's relevant risk. Now we must specify the relationship between risk and return—if beta rises by some specific amount, by how much must the stock's expected return increase to compensate for the increase in risk? To begin, let us define the following terms:

$\hat{k}_i$ = expected rate of return on the ith stock.

k_i = required rate of return on the ith stock. If $\hat{k}_i$ is less than k_i, then you would not purchase this stock, or you would sell it if you owned it.

R_F = riskless rate of return, generally measured by the rate of return on U.S. Treasury securities.

b_i = beta coefficient of the ith stock.

k_M = required rate of return on an average ($b = 1.0$) stock. k_M is also the required rate of return on a portfolio consisting of all stocks, or the market portfolio.

$RP_M = (k_M - R_F)$ = market risk premium. It is the additional return over the riskless rate required to compensate investors for assuming an "average" amount of risk.

$RP_i = b_i(k_M - R_F)$ = risk premium on the *i*th stock. The stock's risk premium is less than, equal to, or greater than the premium on an average stock, depending on whether its beta is less than, equal to, or greater than 1.0. If $b_i = 1.0$, then $RP_i = RP_M$.

The market risk premium, RP_M, depends on the degree of aversion that investors, in the aggregate, have to risk.[11] Let us assume that at the current time Treasury bonds yield $R_F = 8\%$, and an average share of stock has a required return of $k_M = 12\%$. Therefore, the market risk premium is 4 percent:

$$RP_M = k_M - R_F = 12\% - 8\% = 4\%.$$

It follows that, if one stock were twice as risky as some other, its risk premium would be twice as high, and, conversely, if its risk were only half as high, its risk premium would be half as high. Further, we can measure a stock's relative riskiness by its beta coefficient. Therefore, if we know the market risk premium, RP_M, and the stock's beta coefficient, b_i, we can find its risk premium as the product $b_i(RP_M)$. For example, if $b_i = 0.5$ and $RP_M = 4\%$, then RP_i is 2 percent:

$$\text{Risk premium for Stock i} = RP_i = b_i(RP_M) = 0.5(4\%) = 2.0\%. \quad (6\text{-}6)$$

To summarize, given estimates of R_F, k_M, and b_i, we can find the required rate of return on Stock i:

$$\begin{aligned} k_i &= R_F + b_i(k_M - R_F) = R_F + b_i(RP_M) \\ &= 8\% + 0.5(12\% - 8\%) = 8\% + 0.5(4\%) = 10\%. \end{aligned} \quad (6\text{-}7)$$

If some other stock, j, were more risky than Stock i and had $b_j = 2.0$, then its required rate of return would be 16 percent:

$$k_j = 8\% + 2.0(4\%) = 16\%.$$

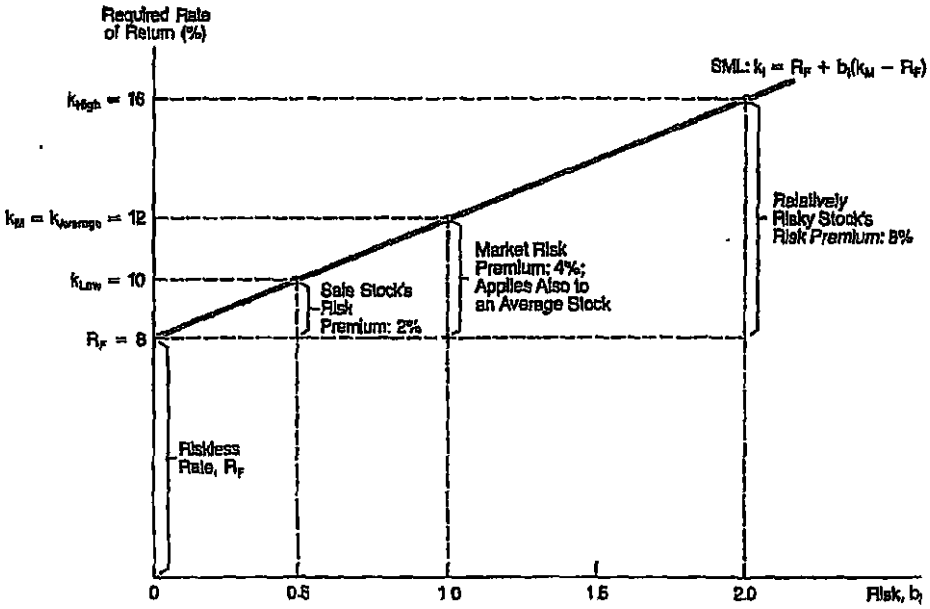
An average stock, with $b = 1.0$, would have a required return of 12 percent, the same as the market return:

$$k_{Average} = 8\% + 1.0(4\%) = 12\% = k_M.$$

Equation 6-7 is often expressed as a graph called the *Security Market Line (SML)*; Figure 6-9 shows the SML when $R_F = 8\%$ and $k_M = 12\%$. Note the following points:

[11] This concept is discussed in some detail in Appendix 6B. It should be noted that the risk premium of an average stock, $k_M - R_F$, cannot be measured with great precision because it is impossible to obtain precise values for k_M. However, empirical studies suggest that, where long-term U.S. Treasury bonds are used to measure R_F and where k_M is the expected return on the S&P 400 Industrial Stocks, the market risk premium varies somewhat from year to year, and it has generally ranged from 3 to 6 percent during the last 20 years.

Figure 6-9
The Security Market Line (SML)



1. Required rates of return are shown on the vertical axis, while risk as measured by beta is shown on the horizontal axis.

2. Riskless securities have $b_i = 0$; therefore, R_F appears as the vertical axis intercept.

3. The slope of the SML reflects the degree of risk aversion in the economy—the greater the average investor's aversion to risk, then (1) the steeper is the slope of the line, (2) the greater is the risk premium for any risky asset, and (3) the higher is the required rate of return on risky assets.[12] These points are discussed further in a later section.

[12]Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8, and as is developed further in Appendix 6A, beta does represent the slope of a line, but *not* the Security Market Line. This confusion arises partly because the SML equation is generally written, in this book and throughout the finance literature, as $k_i = R_F + b_i(k_M - R_F)$, and in this form b_i looks like the slope coefficient and $(k_M - R_F)$ the variable. It would perhaps be less confusing if the second term were written $(k_M - R_F)b_i$, but this is not generally done.

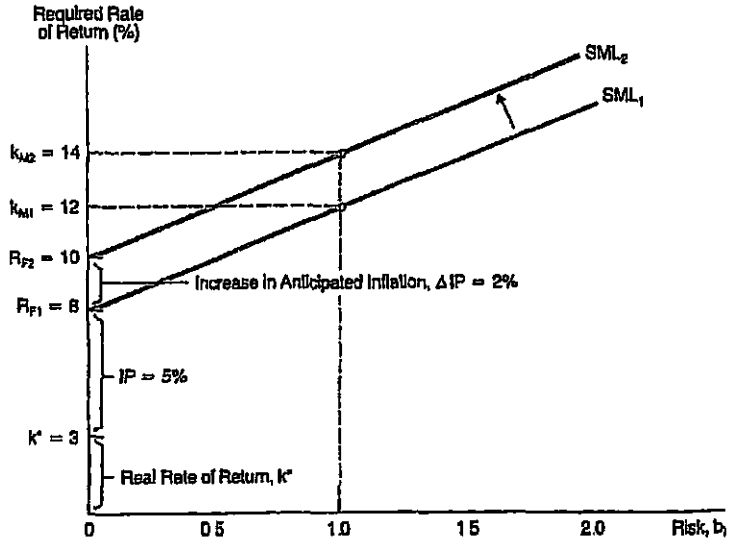
4. The values we worked out for stocks with $b_i = 0.5$, $b_i = 1.0$, and $b_i = 2.0$ agree with the values shown on the graph for k_{Low}, $k_{Average}$, and k_{High}.

The Security Market Line, and a company's position on the line, change over time as interest rates, investors' risk aversion, and individual companies' betas change. Such changes are discussed in the following sections.

The Impact of Inflation

As we saw in Chapter 3, interest amounts to "rent" on borrowed money, or the "price" of money. Thus, R_F is the price of money to a riskless borrower. The existing market risk-free rate is called the *nominal rate*, and it consists of two elements: (1) a *real*, or *inflation-free, rate of return*, k^*, and (2) an *inflation premium*, IP, equal to the anticipated rate of inflation. Thus, $R_F = k^* + IP$. The real rate on risk-free government securities has, historically, ranged from 2 to 4 percent, with a mean of about 3 percent. Thus, if no inflation were expected, risk-free government securities would tend to yield about 3 percent. However, as the expected rate of inflation increases, a premium must be added to the real rate of return to compensate investors for the loss of purchasing

Figure 6-10
Shift in the SML Caused by an Increase in Inflation



6A Calculating Beta Coefficients

The CAPM is an *ex ante* model, which means that all of the variables represent before-the-fact, expected values. In particular, the beta coefficient used in the SML equation should reflect volatility of a given stock versus the market expected during some *future* period. However, people generally calculate betas during some *past* period and then assume that the stocks' relative volatility will remain constant in the future.

To illustrate how betas are calculated, consider Figure 6A-1. The data at the bottom of the figure show the historic realized returns for Stock J and the market for the last five years. The data points were then plotted on the scatter diagram, and a regression line drawn. If all the data points fell on a straight line, as they did in Figure 6-8 in Chapter 6, it would be easy to draw an accurate line. If they do not, then you can fit the line "by eye" as an approximation.

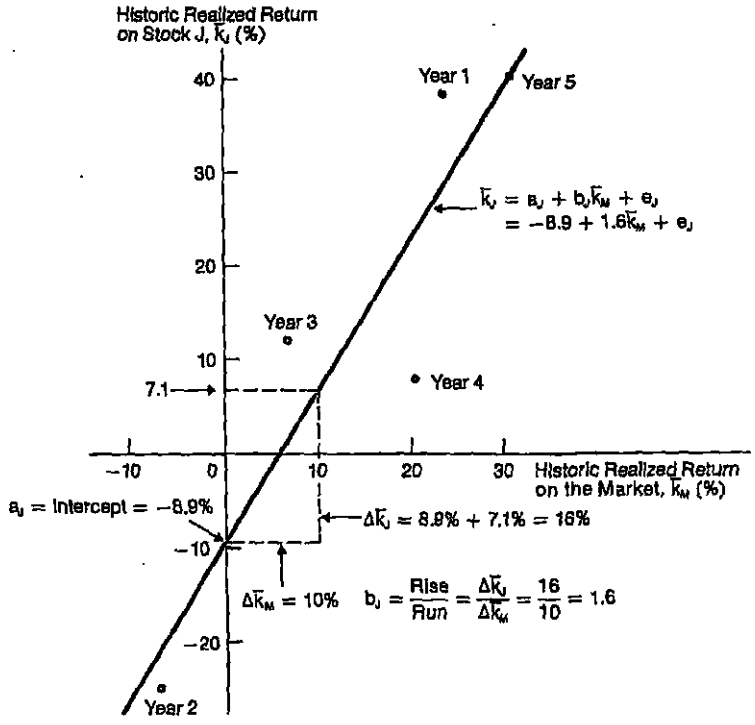
Recall what the term *regression line* or *regression equation* means: The equation $Y = a + bX + e$ is the standard form of a simple linear regression. It states that the dependent variable, Y, is equal to a constant, a, plus b times X, where b is the slope coefficient (or parameter) and X is the "independent" variable, plus an error term, e. Thus, the rate of return on the stock during a given time period depends on what happens to the general stock market, which is measured by $X = \bar{k}_M$.

Once the line has been drawn on the graph paper, we can estimate its intercept and slope, the a and b values in $Y = a + bX$. The intercept, a, is simply the point where the line cuts the vertical axis. The slope coefficient, b, can be estimated by the "rise over run" method. This involves calculating the amount by which $\bar{k}_j$ increases for a given increase in $\bar{k}_M$. For example, we observe (in Figure 6A-1) that $\bar{k}_j$ increases from −8.9 to +7.1 percent (the rise) when $\bar{k}_M$ increases from 0 to 10.00 percent (the run). Thus, the b, the beta coefficient, can be measured as follows:

$$b = \text{Beta} = \frac{\text{Rise}}{\text{Run}} = \frac{\Delta Y}{\Delta X} = \frac{7.1 - (-8.9)}{10.00 - 0.00} = \frac{16.0}{10.00} = 1.6.$$

Note that rise over run is a ratio, and it would be the same if measured using any two arbitrarily selected points on the line.

Figure 6A-1
Calculating Beta Coefficients



Year	Stock J ($\bar{k}_J$)	The Market ($\bar{k}_M$)
1	38.6%	23.8%
2	−24.7	− 7.2
3	12.3	6.6
4	8.2	20.5
5	40.1	30.6
Average $\bar{k}$	14.9%	14.9%
$\sigma_{\bar{k}}$	26.5%	15.1%

The regression line, or equation, enables us to predict a rate of return for Stock J, given a value of $\bar{k}_M$. For example, if $\bar{k}_M$ = 15%, we would predict $\hat{k}_J$ = −8.9% + 1.6(15%) = 15.1%. The actual return would probably differ from the predicted return. This deviation is the error term, e_J, for the year, and it varies randomly from year to year depending on company-specific factors.

In actual practice, monthly rather than annual returns are generally used for $\tilde{k}_j$ and $\tilde{k}_M$, and five years of data are employed. Thus, there would be 5 × 12 = 60 dots on the scatter diagram. Also, in practice one would always use the *least squares method* for finding the regression coefficients a and b; the least squares procedure minimizes the squared values of the error terms, and it is discussed in statistics courses. Note also that the least squares value of beta can be obtained quite easily by computer or even with a calculator that has statistical functions.

Problems

6A-1 You are given the following set of data:

	Historic Rates of Return ($\tilde{k}$)	
Year	NYSE ($\tilde{k}_M$)	Stock Y ($\tilde{k}_Y$)
1	4.0%	3.0%
2	14.3	18.2
3	19.0	9.1
4	−14.7	−6.0
5	−26.5	−15.3
6	37.2	33.1
7	23.8	6.1
8	−7.2	3.2
9	6.6	14.8
10	20.5	24.1
11	30.6	18.0
Mean	9.8%	9.8%
σ	18.7%	13.1%

a. Construct a "standard" graph showing the relationship between returns on Stock Y and the market; then draw a freehand approximation of the regression line. What is the approximate value of the beta coefficient? (If you have a calculator with statistical functions, use it to calculate beta.)
b. Give a verbal interpretation of what the regression line and the beta coefficient show about Stock Y's volatility and relative riskiness as compared with other stocks.
c. Suppose the scatter of points had been more spread out, but the regression line was exactly where your present graph shows it. How would this affect (1) the firm's risk if the stock were held in a one-asset portfolio and (2) the actual risk premium on the stock if the CAPM held exactly? How would the degree of scatter (or the correlation coefficient) affect your confidence in the likelihood that the calculated beta will hold true in the years ahead?
d. Suppose the regression line had been downward sloping, and the beta coefficient had been negative. What would this imply about (1) Stock Y's relative riskiness and (2) its probable risk premium?
e. Construct an illustrative probability distribution graph of returns on portfolios consisting of (1) only Stock Y, (2) 1 percent each of 100 stocks with beta coefficients similar to that of Stock Y, and (3) all

FIFTH EDITION

PRINCIPLES OF CORPORATE FINANCE

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9 Capital Budgeting and Risk

Long before the development of modern theories linking risk and expected return, smart financial managers adjusted for risk in capital budgeting. They realized intuitively that, other things being equal, risky projects are less desirable than safe ones. Therefore financial managers demanded a higher rate of return from risky projects, or they based their decisions on conservative estimates of the cash flows.

Various rules of thumb are often used to make these risk adjustments. For example, many companies estimate the rate of return required by investors in their securities and use the **company cost of capital** to discount the cash flows on all new projects. Since investors require a higher rate of return from a very risky company, such a firm will have a higher company cost of capital and will set a higher discount rate for its new investment opportunities. For example, in Table 8-1 we estimated that investors expected a rate of return of .163 or about 16.5 percent from Microsoft common stock. Therefore, according to the company cost of capital rule, Microsoft should have been using a 16.5 percent discount rate to compute project net present values.[1]

This is a step in the right direction. Even though we can't measure risk or the expected return on risky securities with absolute precision, it is still reasonable to assert that Microsoft faced more risk than the average firm and, therefore, should have demanded a higher rate of return from its capital investments.

But the *company cost of capital rule can also get a firm into trouble if the new* projects are more or less risky than its existing business. Each project should be evaluated at its *own* opportunity cost of capital. This is a clear implication of the value-additivity principle introduced in Chapter 7. For a firm composed of assets A and B, the firm value is

$$\text{Firm value} = PV(AB) = PV(A) + PV(B) = \text{sum of separate asset values}$$

Here PV(A) and PV(B) are valued just as if they were mini-firms in which stockholders could invest directly. Investors would value A by discounting its forecasted cash flows at a rate reflecting the risk of A. They would value B by discounting at a rate reflecting the risk of B. The two discount rates will, in general, be different.

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[1]Microsoft did not use any significant amount of debt financing. Thus its cost of capital is the rate of return investors expect on its common stock. The complications caused by debt are discussed later in this chapter.

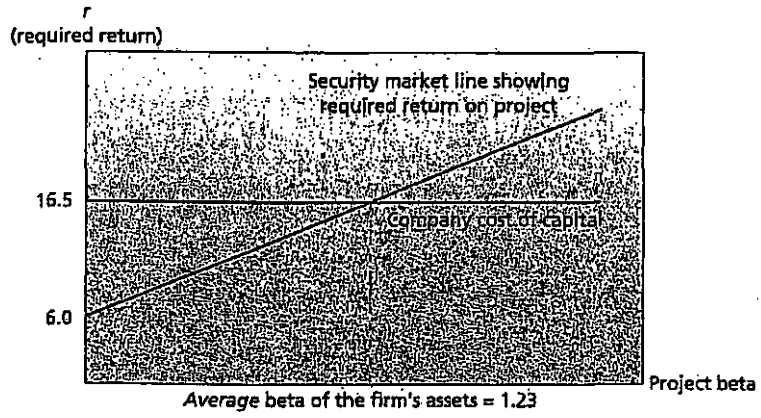


Figure 9-1 A comparison between the company cost of capital rule and the required return under the capital asset pricing model. Microsoft's company cost of capital is about 16.5 percent. This is the correct discount rate only if the project beta is 1.23. In general, the correct discount rate increases as project beta increases. Microsoft should accept projects with rates of return above the security market line relating required return to beta.

If the firm considers investing in a third project C, it should also value C as if C were a mini-firm. That is, the firm should discount the cash flows of C at the expected rate of return that investors would demand to make a separate investment in C. *The true cost of capital depends on the use to which the capital is put.*

This means that Microsoft should accept any project that more than compensates for the *project's beta*. In other words, Microsoft should accept any project lying above the upward-sloping line that links expected return to risk in Figure 9-1. If the project has a high risk, Microsoft needs a higher prospective return than if the project has a low risk. Now contrast this with the company cost of capital rule, which is to accept any project *regardless of its risk* as long as it offers a higher return than the *company's* cost of capital. In terms of Figure 9-1, the rule tells Microsoft to accept any project above the horizontal cost-of-capital line, i.e., any project offering a return of more than 16.5 percent.

It is clearly silly to suggest that Microsoft should demand the same rate of return from a very safe project as from a very risky one. If Microsoft used the company cost of capital rule, it would reject many good low-risk projects and accept many poor high-risk projects. It is also silly to suggest that just because Duke Power has a low company cost of capital, it is justified in accepting projects that Microsoft would reject. If you followed such a rule to its seemingly logical conclusion, you would think it possible to enlarge the company's investment opportunities by investing a large sum in Treasury bills. That would make the common stock safe and create a low company cost of capital.[2]

The notion that each company has some individual discount rate or cost of capital is widespread, but far from universal. Many firms require different returns from different categories of investment. For example, discount rates might be set as follows:

[2]If the present value of an asset depended on the identity of the company that bought it, present values would not add up. Remember, a good project is a good project is a good project.

Category	Discount Rate
Speculative ventures	30%
New products	20%
Expansion of existing business	15% (company cost of capital)
Cost improvement, known technology	10%

The capital asset pricing model is widely used by large corporations to estimate the discount rate. It states

$$\text{Expected project return} = r = r_f + (\text{project beta})(r_m - r_f)$$

To calculate this, you have to figure out the project beta. Before thinking about the betas of individual projects, we will look at some problems you would encounter in using beta to estimate a company's cost of capital. It turns out that beta is difficult to measure accurately for an individual firm: Much greater accuracy can be achieved by looking at an average of similar companies. But then we have to define *similar*. Among other things, we will find that a firm's borrowing policy affects its stock beta. It would be misleading, e.g., to average the betas of Chrysler, which has been a heavy borrower, and General Motors, which has generally borrowed less.

The company cost of capital is the correct discount rate for projects that have the same risk as the company's existing business but *not* for those projects that are safer or riskier than the company's average. The problem is to judge the relative risks of the projects available to the firm. To handle that problem, we will need to dig a little deeper and look at what features make some investments riskier than others. After you know *why* AT&T stock has less market risk than, say, Ford Motor, you will be in a better position to judge the relative risks of capital investment opportunities.

There is still another complication: Project betas can shift over time. Some projects are safer in youth than in old age; others are riskier. In this case, what do we mean by *the* project beta? There may be a separate beta for each year of the project's life. To put it another way, can we jump from the capital asset pricing model, which looks out one period into the future, to the discounted-cash-flow formula that we developed in Chapters 2 and 6 for valuing long-lived assets? Most of the time it is safe to do so, but you should be able to recognize and deal with the exceptions.

We will use the capital asset pricing model, or CAPM, throughout this chapter. But don't infer that the CAPM is the last word on risk and return. The principles and procedures covered in this chapter work just as well with other models such as arbitrage pricing theory (APT). For example, we could have started with an APT estimate of the expected rate of return on Microsoft stock; the discussion of company and project costs of capital would have followed exactly.

9-1 MEASURING BETAS

Suppose that you were considering an across-the-board expansion by your firm. Such an investment would have about the same degree of risk as the existing business. Therefore you should discount the projected flows at the company cost of capital. To estimate that, you could begin by estimating the beta of the company's stock.

An obvious way to measure the beta of the stock is to look at how its price has responded in the past to market movements. For example, in Figure 9-2*a* and *b* we have plotted monthly rates of return from AT&T and Hewlett-Packard against mar-

US CREDIT-Credit market seizures pressure power companies

Wed Oct 1, 2008 4:50pm EDT

By Karen Brettell

NEW YORK, Oct 1 (Reuters) - Debt protection costs for utility companies and other power producers are likely to remain elevated until logjams in the credit markets are cleared, as market seizures are raising concerns over the companies' access to capital.

Credit default swaps on power companies were among the weakest performers on Wednesday, led by a 54 percent move wider in swaps on Dominion Energy (D.N: Quote, Profile, Research, Stock Buzz) to around 102 basis points.

The volatility came after Reliant Energy (RRI.N: Quote, Profile, Research, Stock Buzz) on Monday cut its profit forecast and said it had obtained $1 billion of new financing to replace a credit facility, which sent its shares down as much as 51 percent on Tuesday. For details, see [ID:nN30440144]

"There's lot of ways to speculate (on market moves), but what it fundamentally gets to is frozen liquidity," said Gimme Credit analyst Philip Adams.

American Electric Power Co's (AEP.N: Quote, Profile, Research, Stock Buzz) swaps also weakened 29 percent on Wednesday to 81 basis points, or $81,000 per year for five years to insure $10 million in debt. FirstEnergy Corp's (FE.N: Quote, Profile, Research, Stock Buzz) swaps weakened 23 percent to 102 basis points, Markit data shows.

"Credit market difficulties are starting to have some spillover. It's not just banks, but its companies and industries that depend on functioning financial markets," Adams said.

Reticence to lend to even highly-rated borrowers is making it harder for companies to raise capital and when they do the cost of the debt is high, especially for firms considered more risky.

Reliant, which is rated below investment grade, said it had secured a $650 million senior secured loan with Goldman Sachs at Libor +4.5 percent and another $350 million of convertible preferred debt with First Reserve at an interest rate of 14 percent.

The new capital replaces a $300 million credit facility that Reliant had with Merrill Lynch that enabled the power producer to avoid posting millions of dollars in collateral.

"The company said its decision to end the Merrill Lynch $300 million hedging facility was completely mutual," CreditSights analyst Andy DeVries said in a report on Wednesday.

"We think it has more to do with Reliant knowing it was going to trip the earnings before interest, taxes, depreciation and amortization covenants in the facility owing to the weak results in the Retail segment," he said.

DeVries is "underweight" Reliant's bonds and credit default swaps, citing concerns about the company's earnings outlook.

OUTLOOK

If credit markets stabilize, as is hoped if the government passes a $700 billion bailout bill for the financial industry, swaps on utility companies should stabilize near term, though debt needs through the coming years is likely to hurt their credit profiles.

"Utilities, if they're the right ratings and the right kind of paper, are still kind of perceived as being the safe haven, and near term I wouldn't disagree," said Gimme Credit's Adams.

"My utility outlook for the rest of the decade, though, is that every one of them has capex requirements well in excess of their internal cash generation," he said. "Most of them are going to be net borrowers over the next couple of years, so that if they don't get the right kind of rate treatment I would expect them to slowly deteriorate in credit quality."

Other power producers which generate positive cash flows may fare better, though risks to creditors are that they use cash proceeds to pump up their stock price at the expense of debt holders, Adams said.

(Additional reporting by Matt Daily in New York)

Daily Bond Yields and Key Indicators

Contact Us

Data as of 22-OCT-08

Moody's Daily Long-term Corporate Bond Yield Averages

	Utilities	Industrial	Corporate
Aaa	NA	6.29	6.29
Aa	7.09	6.70	6.90
A	7.80	7.60	7.60
Baa	8.83	9.56	9.25
Avg	7.94	7.69	7.77

Moody's Daily Treasury Yield Averages

Short-Term (3-5 yrs)	1.82
Medium-Term (5-10 yrs)	3.22
Long-Term (10+ yrs)	4.38

Moody's Daily Public Utility Common Stock Yield Averages

Price	199.81
Yield	5.10
New Dividend	10.19

Moody's Commodity and Scrap Price Indexes

Spot Commodity Index	3022.62
Industrial Metals Index	1065.39

* Moody's "Aaa" Utilities index was suspended on 12/10/01. Since 2000, TVA was the only issuer left in the index as a decade of deregulation, debt growth, competition, and consolidation eliminated the rest of the Aaa universe.

Power & Midstream - Industry News
October 21, 2008 4:49 PM ET
By Rosy Lum

During the week ended Oct. 17, a week that the Dow Jones Industrial Average had its highest point gain in the history of the index and central banks around the world injected billions of dollars into the financial system, FirstEnergy Corp., PPL Corp. and PG&E Corp. subsidiaries drummed up $1.3 billion through five debt offerings.

PG&E utility Pacific Gas and Electric Co. completed the largest deal of the week. The company on Oct. 16 offered $600 million of its 8.25% senior notes due Oct. 15, 2018. Net proceeds, which are expected to be approximately $585.4 million, will be used to repay commercial paper and for working capital purposes, the company said.

Banc of America Securities, Citigroup Global Markets and Deutsche Bank Securities acted as joint book managers on the offering.

PPL subsidiary PPL Electric Utilities Corp. on Oct. 14 and Oct. 15 entered into underwriting agreements with a consortium of banks relating to the offering and sale of $400 million of its 7.125% senior secured bonds due 2013.

Net proceeds will partially fund the repayment at maturity of about $485.8 million outstanding aggregate principal amount of its senior secured bonds, 6.25% series, due Aug. 15, 2009. The bonds are scheduled to mature Nov. 30, 2013, subject to early redemption, in whole at any time or in part from time to time.

Ohio Edison Co. on Oct. 15 completed a $275 million offering of its 8.25% series 2008 first mortgage bonds due Oct. 15, 2038, and a $25 million offering of its 8.25% series 2008 first mortgage bonds due Oct. 15, 2018. Net proceeds from the two offerings will be used for capital expenditure and for general corporate purposes. Ohio Edison is a subsidiary of FirstEnergy.

Energy capital offerings for the week ending Oct. 17

Company	Comp. date	Amount offered w/ overallotment ($000)	Offer price (%)
Debt offerings			
PPL Electric Utilities Corp.			
7.125% senior secured bonds due 11/30/13	10/14/08	375,000	99.91
Ohio Edison Co.			
8.250% series 2008 first mortgage bonds due 10/15/38	10/15/08	275,000	97.30
PPL Electric Utilities Corp.			
7.125% senior secured bonds due 11/30/13	10/15/08	25,000	100.088
Ohio Edison Co.			
8.250% series 2008 first mortgage bonds due 10/15/18	10/16/08	25,000	98.942
Pacific Gas and Electric Co.			
8.250% senior notes due 10/15/18	10/16/08	600,000	98.343
Total debt offered		**1,300,000**	

Comprehensive coverage of private placements and Rule 144a transactions may not be possible due to limited disclosure and public documentation. These transactions are presented where available.
Source: SNL Energy

Equitable Gas Company

Energy Capital Offerings by Companies with Bonds Rated A3 by Moody's

During the Week Ending October 17, 2008

Company	Subsidiary	Moody's Bond Rating	Amount ($000's)	Due Date	Nominal Interest Rate	Discount/ Premium	Effective Yield (1)
PPL Corp.	PPL Electric Utilities Corp.	A3	375,000	11/30/2013 (2)	7.125%	99.910%	7.131%
PPL Corp.	PPL Electric Utilities Corp.	A3	25,000	11/30/2013 (2)	7.125%	100.088%	7.119%
PG & E Corp.	Pacific Gas and Electric Co.	A3	600,000	10/15/2018 (3)	8.250%	98.343%	8.389%

Notes:

(1) After discount or premium and before issuance costs.

(2) *Five-Year money.*

(3) Ten-Year Money.

Equitable Gas Company
Example of the Inadequacy of
DCF Return Rate Related to Book Value
When Market Value Exceeds Book Value

Line No.		Based on OCA Witness Parcell's Proxy Group of Gas Distribution Companies		Based on OTS Witness Pionski's Proxy Group of Eight Companies	
		Market Value	Book Value	Market Value	Book Value
1.	Per Share	$ 35.494 (1)	$ 20.036 (2)	$ 34.118 (2)	$ 18.836 (2)
2.	DCF Cost Rate	9.30% (3)	9.30% (3)	10.05% (4)	10.05% (4)
3.	Return in Dollars	$ 3.301	$ 1.863	$ 3.429	$ 1.893
4.	Dividends	$ 1.402 (5)	$ 1.402 (5)	$ 1.375 (6)	$ 1.375 (6)
5.	Growth in Dollars	$ 1.899	$ 0.461	$ 2.054	$ 0.518
6.	Return on Market Value (7)	9.30%	5.25%	10.05%	5.55%
7.	Rate of Growth on Market Value (8)	5.35%	1.30%	6.79%	1.46%

Notes:

(1) Average market price of OCA Witness Parcell's gas distribution (same as FJH proxy) companies as derived from Exhibit ___(DCP-8), page 1 of 4.

(2) From page 2 of Schedule 3 of this Exhibit.

(3) OCA Witness Parcell's recommended common equity cost rates stated on Exhibit_(DCP-1), Shedule 14.

(4) Midpoint of the range of DCF common equity cost rates recommended by OTS Witness Pionski on Schedule 5 of OTS Exhibit 1.

*(5) Dividend per share based upon a 3.95% dividend yield ((3.95% = (3.9% + 4.0%) / 2) from Exhibit DCP-8, page 4 of 4). $1.402 = $35.494 * 3.95%.*

(6) Implicit dividend per share based on adjusted dividend yield of 4.03% used by OTS Witness Pionski in Schedule 5 of OTS Exhibit 1.

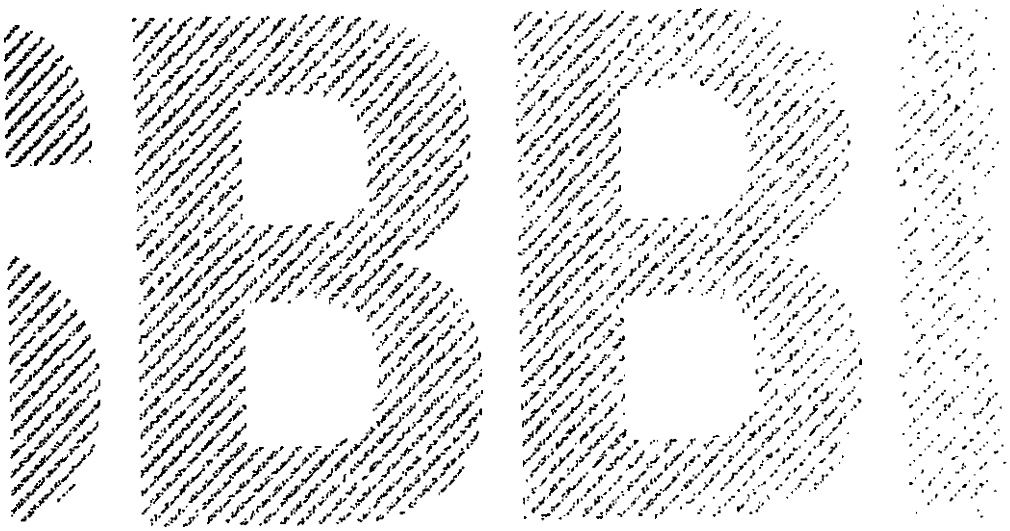
(7) Line 3 / Line 1

(8) Line 5 / Line 1

Ibbotson® SBBI®

2008 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2007



MORNINGSTAR®

The Market Benchmark and Firm Size

Although not restricted to include only the 500 largest companies, the S&P 500 is considered a large company index. The returns of the S&P 500 are capitalization weighted, which means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times number of shares outstanding) at the beginning of that month. The larger companies in the index therefore receive the majority of the weight. The use of the NYSE "Deciles 1–2" series results in an even purer large company index. Yet many valuation professionals are faced with valuing small companies, which historically have had different risk and return characteristics than large companies. If using a large stock index to calculate the equity risk premium, an adjustment is usually needed to account for the different risk and return characteristics of small stocks. This will be discussed further in Chapter 7 on the size premium.

The Risk-Free Asset

The equity risk premium can be calculated for a variety of time horizons when given the choice of risk-free asset to be used in the calculation. The 2008 *Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* provides equity risk premia calculations for short-, intermediate-, and long-term horizons. The short-, intermediate-, and long-horizon equity risk premia are calculated using the income return from a 30-day Treasury bill, a 5-year Treasury bond, and a 20-year Treasury bond, respectively.

Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite. For this reason, it is appropriate in most cases to use the long-horizon equity risk premium for business valuation.

20-Year versus 30-Year Treasuries

Our methodology for estimating the long-horizon equity risk premium makes use of the income return on a 20-year Treasury bond; however, the Treasury currently does not issue a 20-year bond. The 30-year bond that the Treasury recently began issuing again is theoretically more correct due to the long-term nature of business valuation, yet Ibbotson Associates instead creates a series of returns using bonds on the market with approximately 20 years to maturity. The reason for the use of a 20-year maturity bond is that 30-year Treasury securities have only been issued over the relatively recent past, starting in February of 1977, and were not issued at all through the early 2000s.

The same reason exists for why we do not use the 10-year Treasury bond; that is, a long enough history of market data is not available for 10-year bonds. We have persisted in using a 20-year bond to keep the basis of the time series consistent.

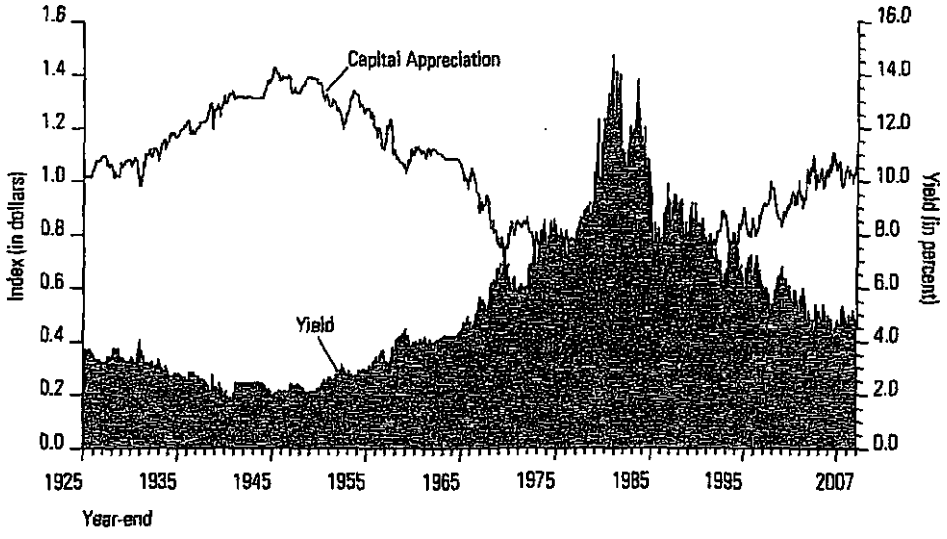
Income Return

Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results

from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[2]

Yields have generally risen on the long-term bond over the 1926–2007 period, so it has experienced negative capital appreciation over much of this time. This trend has turned around since the 1980s, however. Graph 5-2 illustrates the yields on the long-term government bond series compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-2
Long-term Government Bond Yields versus Capital Appreciation Index
1925–2007



2 Please note that the appropriate forward-looking measure of the riskless rate is the yield to maturity on the appropriate-horizon government bond. This differs from the riskless rate used to measure the realized equity risk premium historically. Chapter 4 includes a thorough discussion of riskless rate selection in this context.

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

Table 2-1
Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes
Summary Statistics of Annual Returns

from 1926 to 2007

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	10.4%	12.3%	20.0%	0.03
Income	4.2	4.2	1.6	0.89
Capital Appreciation	6.0	7.8	19.3	0.03
Ibbotson Small Company Stocks				
Total Returns	12.5	17.1	32.6	0.06
Mid-Cap Stocks*				
Total Returns	11.3	14.0	24.4	–0.02
Income	4.0	4.0	1.7	0.89
Capital Appreciation	7.1	9.8	23.7	–0.02
Low-Cap Stocks*				
Total Returns	11.7	15.5	29.0	0.03
Income	3.7	3.7	2.0	0.89
Capital Appreciation	7.9	11.6	28.4	0.02
Micro-Cap Stocks*				
Total Returns	12.5	18.5	38.8	0.08
Income	2.6	2.6	1.8	0.91
Capital Appreciation	9.9	15.8	38.3	0.07
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.4	0.08
Long-Term Government Bonds				
Total Returns	5.5	5.8	9.2	–0.08
Income	5.2	5.2	2.7	0.86
Capital Appreciation	0.1	0.4	8.0	–0.23
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.15
Income	4.7	4.7	2.9	0.96
Capital Appreciation	0.5	0.5	4.4	–0.19
Treasury Bills				
Total Returns	3.7	3.8	3.1	0.91
Inflation	3.0	3.1	4.2	0.65

Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return

*Source: ©2008 CRSP®, Center for Research in Security Prices. Graduate School of Business, The University of Chicago used with permission. All rights reserved. www.crsp.chicagogsb.edu
See Chapter 7 for details on decile construction

Equitable Gas Company
OCA Witness Parcell's CAPM Cost Rates Corrected to Reflect a
Properly Calculated Historical Market Equity Risk Premium

Traditional Capital Asset Pricing Model (1)

	1	2	3	4
Company	Risk-Free Rate (2)	Beta (2)	Market Premium (3)	CAPM Cost Rates
OCA Staff Witness Parcell's Group of Gas Distribution Companies				
AGL Resources Inc.	4.63%	0.85	7.10%	10.67%
Atmos Energy Corp.	4.63%	0.80	7.10%	10.31%
The Laclede Group, Inc.	4.63%	0.80	7.10%	10.31%
NICOR Inc.	4.63%	0.90	7.10%	11.02%
Northwest Natural Gas Co.	4.63%	0.75	7.10%	9.96%
Piedmont Natural Gas Co., Inc.	4.63%	0.80	7.10%	10.31%
South Jersey Industries, Inc.	4.63%	0.80	7.10%	10.31%
Southwest Gas Corp.	4.63%	0.80	7.10%	10.31%
WGL Holdings, Inc.	4.63%	0.85	7.10%	10.67%
Mean				10.43%

Empirical Capital Asset Pricing Model (4)

	1	2	3	4
Company	Risk-Free Rate (2)	Beta (2)	Market Premium (3)	ECAPM Cost Rates
OCA Staff Witness Parcell's Group of Gas Distribution Companies				
AGL Resources Inc.	4.63%	0.85	7.10%	10.93%
Atmos Energy Corp.	4.63%	0.80	7.10%	10.67%
The Laclede Group, Inc.	4.63%	0.80	7.10%	10.67%
NICOR Inc.	4.63%	0.90	7.10%	11.20%
Northwest Natural Gas Co.	4.63%	0.75	7.10%	10.40%
Piedmont Natural Gas Co., Inc.	4.63%	0.80	7.10%	10.67%
South Jersey Industries, Inc.	4.63%	0.80	7.10%	10.67%
Southwest Gas Corp.	4.63%	0.80	7.10%	10.67%
WGL Holdings, Inc.	4.63%	0.85	7.10%	10.93%
Mean				10.76%

Notes:

(1) The traditional Capital Asset Pricing Model (CAPM) is applied as follows: Column 1 + (Column No. 2 * Column No. 4).

(2) From Exhibit_(DCP-1) Schedule 10.

(3) The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2007 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). From Stocks, Bonds, Bills, and Inflation -- Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008.

(4) The empirical CAPM is applied is as follows: Column 1 + (0.25 * Column No. 3) + (0.75 * Column No. 2 * Column No. 3).

Equitable Gas Company
Market-to-Book Ratios, Earnings / Book Ratios and
Inflation for Standard & Poor's Industrial Index and
the Standard & Poor's 500 Composite Index
from 1947 through 2007

Year	Market-to-Book Ratio (1)		Earnings/ Book Ratio (2)				
	S&P Industrial Index (3)	S&P 500 Composite Index (3)	S&P Industrial Index (3)	S&P 500 Composite Index (3)	Inflation (4)	Earnings / Book Ratio - Net of Inflation	
1947	1.23 %	NA	13.0 %	NA	9.0 %	4.0 %	NA
1948	1.13	NA	17.3	NA	2.7	14.6	NA
1949	1.00	NA	16.3	NA	(1.8)	18.1	NA
1950	1.16	NA	18.3	NA	5.8	12.5	NA
1951	1.27	NA	14.4	NA	5.9	8.5	NA
1952	1.29	NA	12.7	NA	0.9	11.8	NA
1953	1.21	NA	12.7	NA	0.6	12.1	NA
1954	1.45	NA	13.5	NA	(0.5)	14.0	NA
1955	1.81	NA	16.0	NA	0.4	15.6	NA
1956	1.92	NA	13.7	NA	2.9	10.8	NA
1957	1.71	NA	12.5	NA	3.0	9.5	NA
1958	1.70	NA	9.8	NA	1.8	8.0	NA
1959	1.94	NA	11.2	NA	1.5	9.7	NA
1960	1.82	NA	10.3	NA	1.5	8.8	NA
1961	2.01	NA	9.8	NA	0.7	9.1	NA
1962	1.83	NA	10.9	NA	1.2	9.7	NA
1963	1.94	NA	11.4	NA	1.7	9.7	NA
1964	2.18	NA	12.3	NA	1.2	11.1	NA
1965	2.21	NA	13.2	NA	1.9	11.3	NA
1966	2.00	NA	13.2	NA	3.4	9.8	NA
1967	2.05	NA	12.1	NA	3.0	9.1	NA
1968	2.17	NA	12.6	NA	4.7	7.9	NA
1969	2.10	NA	12.1	NA	6.1	6.0	NA
1970	1.71	NA	10.4	NA	5.5	4.9	NA
1971	1.99	NA	11.2	NA	3.4	7.8	NA
1972	2.16	NA	12.0	NA	3.4	8.6	NA
1973	1.96	NA	14.6	NA	8.8	5.8	NA
1974	1.39	NA	14.8	NA	12.2	2.6	NA
1975	1.34	NA	12.3	NA	7.0	5.3	NA
1976	1.51	NA	14.5	NA	4.8	9.7	NA
1977	1.38	NA	14.6	NA	6.8	7.8	NA
1978	1.25	NA	15.3	NA	9.0	6.3	NA
1979	1.23	NA	17.2	NA	13.3	3.9	NA
1980	1.31	NA	15.6	NA	12.4	3.2	NA
1981	1.24	NA	14.9	NA	8.9	6.0	NA
1982	1.17	NA	11.3	NA	3.9	7.4	NA
1983	1.45	NA	12.2	NA	3.8	8.4	NA
1984	1.46	NA	14.6	NA	4.0	10.6	NA
1985	1.67	NA	12.2	NA	3.8	8.4	NA
1986	2.02	NA	11.5	NA	1.1	10.4	NA
1987	2.50	NA	15.7	NA	4.4	11.3	NA
1988	2.13	NA	19.0	NA	4.4	14.6	NA
1989	2.56	NA	18.5	NA	4.7	13.8	NA
1990	2.63	NA	16.3	NA	6.1	10.2	NA
1991	2.77	NA	10.8	NA	3.1	7.7	NA
1992	3.29	NA	13.0	NA	2.9	10.1	NA
1993	3.72	NA	15.7	NA	2.8	12.9	NA
1994	3.73	NA	23.0	NA	2.7	20.3	NA
1995	4.06	2.64	22.9	16.0 %	2.5	20.4	13.5 %
1996	4.79	3.00	24.8	16.8	3.3	21.5	13.5
1997	5.88	3.53	24.6	16.3	1.7	22.9	14.6
1998	7.13	4.16	21.3	14.5	1.6	19.7	12.9
1999	8.27	4.76	25.2	17.1	2.7	22.5	14.4
2000	7.51	4.51	23.9	16.2	3.4	20.5	12.8
2001	NA	3.50	NA	7.4	1.6	NA	5.8
2002	NA	2.93	NA	8.3	2.4	NA	5.9
2003	NA	2.78	NA	14.1	1.9	NA	12.2
2004	NA	2.91	NA	15.3	3.3	NA	12.0
2005	NA	2.78	NA	16.4	3.4	NA	13.0
2006	NA	2.75 (5)	NA	17.2	2.5	NA	14.7
2007	NA	2.77 (5)	NA	12.8	4.1	NA	8.7
Average	2.34 %	3.31 %	14.9 %	14.5 %	3.9 %	10.9 %	11.8 %

Notes: (1) Market-to-Book Ratio equals average of the high and low market price for the year divided by the average book value.

(2) Earnings/Book equals earnings per share for the year divided by the average book value.

(3) On January 2, 2001 Standard & Poor's released Global Industry Classification Standard (GICS) price indexes for all Standard & Poor's U.S. indexes. As a result, all S&P indexes have been calculated with a common base of 100 at a start date of December 31, 1994. Also, the GICS industrial sector is not comparable to the former S&P Industrial Index and data for the former S&P Industrial Index has been discontinued.

(4) As measured by the Consumer Price Index (CPI).

(5) Ratios for 2006 / 2007 are based upon estimated book values using the actual average price and the estimated book value calculated by adding the 2006 earnings per share to the 2005 / 2006 book value per share and then subtracting the 2006 / 2007 dividends per share as provided by Standard & Poor's Statistical Record - Current Statistics, March 2008, p. 29.

Source of Information: Standard & Poor's Security Price Index Record, 2000 Edition, p. 40
Standard & Poor's Statistical Service, Current Statistics, January 2001, p. 36
Standard & Poor's Statistical Service, Current Statistics, June 2006, p. 29.
Standard & Poor's Statistical Service, Current Statistics, August 2007, p. 29.
Standard & Poor's Statistical Service, Current Statistics, March 2008, p. 29.
Standard & Poor's Compustat Services, Inc. PC Plus Research Insight Database
Ibbotson Associates, Stocks, Bonds, Bills and Inflation - Valuation Edition 2008 Yearbook, 2008, Table B-15, pp. 256-257.

Equitable Statement No. 5-R
R-2008-2029325
Witness: Frank J. Hanley
Date: 11/9/08

RH5

EQUITABLE GAS COMPANY

R-2008-2029325

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

FAIR RATE OF RETURN

TABLE OF CONTENTS

I. PURPOSE

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

A. My name is Frank J. Hanley and I am a Principal and Director of AUS Consultants. My business address is 155 Gaither Drive, Suite A, Mt. Laurel, New Jersey 08054.

Q. Are you the same Frank J. Hanley who previously filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to rebut certain aspects of the direct testimonies of Office of Trial Staff (OTS) Witness Robert Plonski and Office of Consumer Advocate (OCA) Witness David C. Parcell with regard to issues concerning capital structure and related cost of capital components including the cost rate of common equity capital. My testimony will show that the recommended hypothetical capital structure ratios of Messrs. Plonski and Parcell contain common equity ratios which are too low because of the significant business risks faced by Equitable Gas Company (Equitable or the Company). I also address the inadequacy of Mr. Plonski's short-term debt cost rate as well as the gross inadequacy of the common equity cost rate recommended by each witness, namely Mr. Plonski's 10.05% and Mr. Parcell's 9.30%. Finally, I respond to certain aspects of the critiques of my direct testimony by Messrs. Plonski and Parcell. This testimony is organized by witness.

Q. Have you prepared an exhibit in support of this testimony?

A. Yes, I have. It has been marked for identification as Equitable Exhibit 5A-R and it consists of 23 schedules. Unless specified otherwise, all references to schedules will be to Equitable Exhibit 5A-R.

II. SUMMARY

Q. Please briefly summarize your rebuttal testimony.

A. My testimony explains how both Messrs. Plonski and Parcell fail to recognize the extraordinary risks faced by Equitable related to its small size, lack of adequate rate design protection, and also because of the significant head-to-head competition it faces from other LDCs. As a result, the hypothetical capital structure ratios utilized by each witness are not reflective of Equitable's level of risk. In other words, their recommended capital structure ratios contain an inadequate proportion of common equity capital. Moreover, my testimony explains the errors made by each witness which result in a significant understatement of the overall cost of capital related to Equitable most significantly attributable to their grossly understated recommended common equity cost rates. I should note that there is no dispute as to the proper cost rate for long-term debt capital. Mr. Parcell concurs with the Company's recommended short-term debt cost rate of 3.26%, while Mr. Plonski, incorrectly, does not.

My testimony will address the following issues related to OTS Witness Plonski:

- I will explain why Mr. Plonski's proxy group was ill-chosen and includes one company that is overwhelmingly considered an electric utility; and therefore in no way can be considered a gas distribution company (LDC).
- I will explain why Mr. Plonski's recommended hypothetical capital structure ratio is incorrect because it contains an inadequate common equity ratio because of his failure to recognize Equitable's extraordinary risks attributable to its small size, lack of adequate rate design protection, and significant, unusual, head-to-head competition from other LDCs.
- I will explain why Mr. Plonski's short-term debt cost rate of 2.26% is significantly understated.
- I will explain why Mr. Plonski's recommended common equity cost rate of 10.05% is grossly understated, namely because of his sole reliance on the Discounted Cash Flow method (DCF) as the principal tool in arriving at his recommendation and also by his failure to recognize Equitable's extraordinary risks indicated supra. I will demonstrate the inadequacy of his recommendation by utilizing adjusted allowed rates of return on common equity capital by regulatory commissions and the proper application of other cost of common equity models.
- I will explain why Mr. Plonski's sole reliance upon the DCF method to arrive at his recommended common equity cost rate is at odds with this Commission's consideration of the results of other cost of common equity

models in order to ascertain the reasonableness of an allowed ROE, as well as being at odds with the Efficient Market Hypothesis (EMH).

- I will explain why Mr. Plonski's assumption regarding the trend of interest rates leads to his incorrect and grossly understated recommendation of common equity cost rate.
- I will address Mr. Plonski's incorrect assumptions and inputs into the Capital Asset Pricing Model (CAPM) he used as a check, including an erroneous reliance upon the geometric mean. A result of his "check" is that it is also understated and does not provide valid verification of his understated recommended common equity cost rate derived by use of the DCF method.

My testimony will address the following issues related to OCA Witness Parcell:

- I will show that Mr. Parcell's recommended hypothetical capital structure also contains an inadequate percentage of common equity capital for the same reasons as Mr. Plonski's hypothetical capital structure, discussed supra. Moreover, I will explain why Mr. Parcell's emphasis on Equitable Resources, Inc. (EQT) as to size is misplaced when related to Equitable and how it is contrary to a basic financial tenet.
- I will explain why Mr. Parcell's recommended common equity cost rate of 9.30% suffers from the same infirmities described supra relative to Mr. Plonski, but is even more grossly understated than Mr. Plonski's recommendation of 10.05%.

- I will explain why Mr. Parcell's contention that long-term capital costs are relatively stable is incorrect. In fact, I will show that the trend over the last several years has been up, which has greater relevance since ratemaking is prospective.
- I will explain why Mr. Parcell's contention that the creation of Equitable as a subsidiary of Equitable Resources resulted in reducing Equitable's risks is incorrect from a ratemaking perspective and why his reasoning is at odds with basic financial tenets.
- I will show that Mr. Parcell's sole reliance on the DCF method in arriving at his recommendation is incorrect for the same reasons as Mr. Plonski supra, despite the fact that he incorrectly utilizes other methods as a check.
- I will explain why Mr. Parcell's CAPM calculations and assumptions are incorrect and result in an understatement of the common equity cost rate, even used as a check.
- I will explain why Mr. Parcell's assumptions that there is a direct correlation between market-to-book ratios and the rate of earnings on book common equity are incorrect and lead to an incorrect conclusion derived from his comparable earnings method utilized as a check.

In addition to the foregoing, I respond to many criticisms made of my direct testimony by both Messrs. Plonski and Parcell and demonstrate that such criticisms are without merit.

III. OTS WITNESS ROBERT PLONSKI

A. ANALYSIS OF MR. PLONSKI'S PROXY GROUP

Q. At pages 21-22, Mr. Plonski provides the basis upon which he arrived at his "barometer" companies. Do you have any comments related to his barometer group of eight companies?

A. Yes, I do. First, I should point out that OCA Witness Parcell utilized the same proxy group which I utilize, consisting of nine gas distribution companies. Mr. Plonski's group of eight companies contains three companies that would not have met all of my selection criteria. I have prepared Schedule 1, which consists of two pages. Schedule 1, page 1 shows a comparison of key statistics. For example, reference to Schedule 1, page 1 shows that National Fuel Gas and NSTAR are not included in Value Line edition. More importantly, it is shown that the S.I.C. Code for NSTAR is 4911, Electric Services. This can also be verified by reference to page 2 of Schedule 1, where NSTAR itself indicates that its industry is electric utilities, i.e., S.I.C. Code 4911 – Electric Services. Looking toward the bottom of Schedule 1, page 1, it is shown that New Jersey Resources only derived 33.28% of its revenues from natural gas distribution operations in 2007, while NSTAR derived only 17.18% from gas distribution operations. It is also shown that NSTAR derived only 8.510% of its net operating income from gas distribution operations while only 10.31% of its assets are allocated to gas distribution operations. Clearly, NSTAR does not belong in any group utilized to establish a cost rate for a gas distribution operation. It is also shown that even though National Fuel Gas is considered a gas distribution operation,

only 25.23% of its net operating income in 2007 was derived from gas distribution operations.

Q. What do these data, especially the inclusion of NSTAR in Mr. Plonski's proxy group indicate?

A. The selection criteria indicate to me that his group is not truly representative of the risks associated with a gas distribution operation, much less an operation such as Equitable's which faces extraordinary business risks. Comparative Moody's and S&P bond ratings as well as S&P business and financial risk profiles of the proxy group used by Mr. Plonski with the group used by Mr. Parcell and myself are shown on Schedule 2.

Q. *At page 29, Mr. Plonski claims that your proxy group is too dissimilar for estimating a cost of equity for Equitable.* How do you respond?

A. Mr. Plonski, on page 30, suggests that my proxy group is dissimilar because it is too large. However, Mr. Plonski's group of eight companies is 4.0 times larger than Equitable, while my proxy group of nine companies is only 3.3 times larger than Equitable. This is another factor that makes Mr. Plonski's group actually more dissimilar than mine.

Q. Please explain the information shown on page 3 of Schedule 3.

A. Schedule 3, page 3 is a chart comparing the percentage of proxy companies which have rate decoupling mechanisms and/or weather normalization adjustment mechanisms in effect, whereas Equitable has neither. For Mr. Plonski's group I have excluded NSTAR in the calculations because NSTAR is overwhelmingly an electric

services company and in no way can be representative of a gas distribution operation for the reasons and statistics cited supra. Note that 85.71% of Mr. Plonski's proxy group have rate decoupling mechanisms/weather normalization adjustment mechanisms in place, excluding NSTAR. Thus, it is clear that Equitable is much smaller than Mr. Plonski's proxy group and has none of the rate design protection tools such as rate decoupling and/or weather normalization adjustment mechanisms that are enjoyed by Mr. Plonski's barometer companies.

Q. With regard to significant head-to-head competition faced by Equitable, Mr. Plonski, at page 35, rejects the adjustment that you made of 50 basis points (0.50%) to compensate for that significant competition. Does Mr. Plonski's proxy group face direct head-to-head competition?

A. No. To the best of my knowledge, no gas distribution company that has common stock actively traded would be in any way an appropriate proxy to utilize in a group for purposes of establishing a common equity cost rate having anything like the direct head-to-head competition faced by Equitable. Mr. Plonski claims that there was no provision for the impact of competition. Shown on Schedule 4, which consists of five pages, is the information provided in response to Interrogatory OTS-RR-20-D which contains the information that demonstrates that substantial revenue losses and hence operating margins, have been eroded because of such head-to-head competition. I will have more to say about this subsequently when responding specifically to Mr. Plonski's criticisms of my direct testimony. However, because Mr. Plonski failed to properly consider Equitable's small size, lack of rate design

protection from the vagaries of weather and declining per customer usage, and significant head-to-head competition, his recommended capital structure should be rejected in favor of the hypothetical capital structure that I recommend comprised of 50.00% total debt and 50.00% common equity capital for the reasons described at pages 16-18 of Equitable Statement No. 5.

B. SHORT-TERM DEBT COST RATE

Q. At page 7, Mr. Plonski claims that you developed a short-term debt cost rate based upon a LIBOR rate from Blue Chip Financial Forecasts. Is he correct?

A. No. A careful reading of my testimony at pages 19-20 will reveal that it was based upon a three-month commercial paper rate which averaged 2.26% to which I added 100 basis points to reflect the calculation made by Equitable based upon demand notes payable to Equitable Capital Corp. which are based upon a three-month commercial paper rate plus 100 basis points.

Q. Mr. Plonski accepts the 2.26% commercial paper rate, even though he believes it is a LIBOR rate, but rejects the 100 basis points. Is his rejection of the 100 basis points reasonable?

A. No. It is totally unreasonable, especially in this capital market. I have prepared Schedule 5, which consists of two pages. Page 2 of Schedule 5 is a copy of page 15b from Equitable's 2007 Annual Report to this Commission. There, it is indicated that the average interest rate for short-term loans outstanding was 5.26% as of year-end 2007. Equitable Resources' current weighted average cost of short-term debt is 4.55% based upon utilizing its revolving credit facility agreement. Due to the

extreme capital market conditions currently and probably for many months into the future, combined with its short-term issuer ratings of A-3 at S&P and B-2 at Moody's, Equitable Resources currently cannot access the commercial paper market. Nonetheless, Equitable has continually accounted for its short-term debt cost rates based upon a three-month commercial paper rate plus 100 basis points. The forward-looking cost rate of 3.26% which I adopted in my direct testimony is quite conservative by any current measure. As of today, the actual cost rate would clearly be more than the 4.55% currently experienced by Equitable Resources which is a much larger entity than its subsidiary, Equitable. In view of the foregoing, Mr. Plonski's refusal to accept a short-term debt cost rate of 3.26% is totally unreasonable and should be rejected.

C. COMMON EQUITY COST RATE

Q. Please comment on Mr. Plonski's exclusive reliance upon the DCF model in reaching his recommended common equity cost rate of 10.05%.

A. It is clear that Mr. Plonski relies exclusively upon the DCF, as clearly shown on page 19 of OTS Statement No. 1. I believe that exclusive, even primary, reliance on the DCF model is incorrect.

Q. Please explain why.

A. The goal of a rate of return expert in a proceeding such as this is to attempt to best emulate investors' actions in formulating the required ROE. The DCF model is based upon the EMH, as are all of the other market-based cost of common equity models. The generally-accepted, semi-strong version of the EMH states that

investors are aware of all publicly-available information and that such information is embedded in the market prices they pay. The financial literature is replete with discussions of all cost of common equity models such as the DCF, the Risk Premium Model (RPM), the CAPM and the Comparable Earnings Model (CEM), all four of which are those typically used in utility rate regulation in some form or another. I provided a number of such examples from the financial literature at pages 23-25 of Statement No. 5. Those examples make it clear that the financial literature encourages the use of multiple models and investors are aware of them. In addition, many state regulatory commissions consider a number of cost of common equity models and do not rely upon any single model. There is no empirical evidence which demonstrates that investors rely upon a single model such as the DCF. Moreover, there is also no empirical evidence of which I am aware that proves the DCF model to be a superior predictor of actual earned returns experienced by investors vis-à-vis other cost of common equity models.

In view of the foregoing, and because the EMH requires the assumption that investors take into account multiple cost of equity models when formulating their required rates of return, sole reliance upon any single model, including the DCF, is incorrect.

Q. Are there any indications from recent decisions of this Commission that confirm that other cost of common equity models need to be considered because sole use of an unadjusted DCF model can result in an understatement of the common equity cost rate?

A. Yes. For example, this Commission, in an Opinion and Order in R-00049255 concerning PPL Electric Utilities Corporation, entered December 22, 2004 stated:

> We note that the USDOD recognized that when market price exceeds book value, a constant growth DCF model is less reliable as growth in earnings, and dividends and book value are less likely to be equal under this circumstance. This is a key assumption of the constant growth DCF model. We agree with the USDOD that investors purchasing stock at market prices greater than book value are at greater risk that the price will actually decline in the near future to approach book value, and increasing the risk that growth rates in earnings, dividends, and book value will diverge from each other. *...[T]hose returns indicated by alternative, standard cost estimation techniques provide additional measures so as to test the reasonableness of our DCF-based cost of equity capital rate of 10.70% (10.25 + .45 for financial risk).* (pp 71-72 of Order) (italics added)

Also, this Commission, in its Opinion and Order in R-00038805 concerning Aqua Pennsylvania, Inc. entered August 5, 2004 stated:

> The ALJ recommended a 10.0% cost of equity, relying too heavily on the DCF methodology. *However, the ALJ failed to sufficiently consider the other standard financial models, including Comparable Earnings, the Risk Premium Model, and the CAPM as checks upon the reasonableness of the DCF results.* (p. 62 of Order) (italics added)

The final example that I cite is this Commission's Opinion and Order in R-00973947 concerning United Water Pennsylvania, entered January 29, 1998 when it stated:

> However, we have ... recognized that the sole use of the DCF method can result in an understatement of the common equity cost rates ... *we recognize that it is within our purview to exercise our informed judgment and to consider the risks as evidenced by the Company's CAPM and RP analyses.* (p. 54 of Order) (italics added)

Q. In addition to your calculations of common equity cost rate by the use of other cost of common equity models such as the RPM, the CAPM and CEM, have you made any comparison of Mr. Plonski's recommended 10.05% common equity cost rate against recently-awarded ROEs to LDCs (or the gas operations of combination electric and gas companies) between June 2007 and September 2008?

A. Yes, I have. That information is set forth in Schedule 6. There it is shown that the average awarded ROE in litigated cases was 10.34% relative to an average common equity ratio of 51.59%. These awards contained an average equity risk premium of 4.15% over the yields on A rated public utility bonds. The prospective yield on A rated public utility bonds is 6.59%. That yield plus an equity risk premium of 4.15% and an increment of 0.21% to reflect the average A3 Moody's bond rating of my proxy group (as well as Mr. Plonski's ill-chosen "barometer" group, indicates a 10.95% common equity cost rate before any adjustments to reflect Equitable's extraordinary risks thereby confirming the gross inadequacy of Mr. Plonski's recommended common equity cost rate of 10.05%.

Q. I notice that you also show on Schedule 6, page 1 a current yield on Moody's A rated public utility bonds of 7.80% and an indicated common equity cost rate of 12.16%. Please explain.

A. The recent credit crisis has resulted in a sudden and dramatic shrinkage in availability of capital which has resulted in a significant increase in long-term capital cost rates. On October 22, 2008, the yield on Moody's A rated public utility bonds

was 7.80%. This is dramatically higher than prior forecasts which would have led to the conclusion of a reasonable forecasted yield on A rated public utility bonds of 6.59%. If the current level of interest rates on long-term debt for utility companies holds, my recommended 11.95% common equity cost rate which includes 95 basis points (0.95%) in recognition of Equitable's extraordinary risks described supra as well as at length in my direct testimony, may well prove to be conservative. I will have much more to say about current capital market costs and trends subsequently with regard to Mr. Parcell's testimony.

Q. At page 18, Mr. Plonski concludes that interest rates are expected to remain fairly stable. Do you have a comment?

A. I assume that one can debate what constitutes "relatively stable". However, I believe the information shown on Schedule 7, page 1 shows a complete reversal of trends in that short-term interest rates as measured by the Federal Funds Rate. Since early 2005, the Federal Funds rate rose pretty dramatically to the spring of 2006 and remained constant until late summer of 2007 and has trended downward ever since to the 1.50% level currently. The current level is reflective of an extremely sluggish economy which is very likely in a recession and which has been severely impacted by the dramatic financial crisis attributable to the collapse of the sub-prime mortgage industry (which necessitated a congressional bail-out/rescue plan) of some $700 billion.

Notwithstanding the significant decline in short-term interest rates, long-term interest rates to public utilities have been gradually increasing as measured by the

yield on A rated public utility bonds. Indeed, it is shown on page 1 of Schedule 7 that there has been a recent huge spike in the yield on A rated public utility bonds. The financial crisis which created this spike was discussed on October 23, 2008 by the former Federal Reserve Chairman Alan Greenspan who testified before the House Government Oversight Committee investigating the financial crisis. Mr. Greenspan stated that the crisis "has turned out to be much broader than anything I could have imagined. It has morphed from one gripped by liquidity restraints to one in which fears of insolvency are now paramount." Mr. Greenspan suggested that the financial crisis currently gripping the U.S. will take many months to improve. Consequently, in view of the extremely tight capital markets and the major impact on public utility long-term capital costs discussed and demonstrated in Schedule 19, infra, the current and likely near-term future of capital costs and its significance, it is clear that Mr. Plonski's prognosis that interest rates will "continue to remain fairly stable" is inaccurate and confirms the gross inaccuracy of his recommended capital structure and common equity cost rate.

Q. Please address the flaws related to Mr. Plonski's CAPM which he used as a check.

A. Mr. Plonski's CAPM analysis is flawed for three basic reasons. First, he has incorrectly utilized the geometric mean of an historical total market return in developing his market equity risk premium. Second, even the geometric total market return which he did use is incorrect, and third, he neglected to include an Empirical CAPM (ECAPM) analysis.

Q. Why is the geometric mean return inappropriate when estimating the cost of capital?

A. As discussed in Equitable Statement No. 5 at page 40, line 11 through page 41, line 5 and Schedule 12, pages 3-4 of Exhibit 5A, only the arithmetic mean is appropriate to use when estimating the cost of capital. The arithmetic mean reflects the effect of changing economic conditions on risk premia over time. Because historical total returns and equity risk premium spreads differ in size and direction over time, the arithmetic mean provides insight into the variance and standard deviation of returns. The prospect for variance, i.e., standard deviation, captured in the arithmetic mean, provides the valuable insight needed by investors and rate of return analysts alike to estimate the expected risk associated with investment in common stocks. Absent such insight, investors cannot meaningfully evaluate prospective risk.

Weston and Brigham[1] provide the standard financial textbook definition of the riskiness of an asset when they state:

> The riskiness of an asset is defined in terms of the <u>likely variability of future returns from the asset</u>. (emphasis added)

In addition, Brealey, Myers and Allen state[2]:

> Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.

Investors can only gain insight into relative riskiness by analyzing expected future variability. This is accomplished by the use of the arithmetic mean of a

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1 J. Fred Weston and Eugene F. Brigham, <u>Essentials of Managerial Finance</u>, 3rd Ed., The Dryden Press, 1974, p. 272.

2 Brealey, Myers and Allen, <u>Principles of Corporate Finance</u>, Eighth Edition, McGraw-Hill Irwin, New York, 2006, p. 151.

distribution of returns because the arithmetic mean takes into account all of the returns, thus providing essential insight into the variance and standard deviation of those returns.

Q. Can you show how the arithmetic mean takes into account all of the returns making it appropriate to use when estimating the cost of capital?

A. Yes. Schedule 8, which consists of three pages, graphically illustrates this reality. Page 1 charts the returns on large company stocks for each and every year from 1926 through 2007 from the Morningstar 2008 Valuation Yearbook. It is clear from observing them that there is a distinct bell-shaped pattern to the probability distribution of returns. The arithmetic mean of this distribution of returns takes into account all of those returns in the distribution and thus, the potential variance and standard deviation likely to be experienced in the future when used to estimate the cost of capital. The chart on page 2 of Schedule 8 shows the returns chronologically from 1926 to 2007. It is clear that the returns are random as confirmed by a serial correlation statistic of 0.03 shown by Morningstar on page 6 of Schedule 9 which will be discussed infra. In contrast, page 3 of Schedule 8 demonstrates that when the geometric mean is calculated, only two of the returns are taken into account, namely the initial and terminal years which, in this case, 1926 and 2007 from which a constant rate of return is calculated which provides absolutely no insight into the prospective risk faced by an investor when estimating his or her opportunity cost of capital.

Q. Please explain Schedule 9.

A. Schedule 9, which consists of six pages, contains Morningstar's explanation of why a long-term equity risk premium, which is random, is appropriate and why the use of the arithmetic mean is the only appropriate mean to use when estimating the cost of capital. At page 6 of schedule 9, Morningstar shows that equity risk premia are random and because of this they state:

> The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

In view of the foregoing, it is clear that the arithmetic mean is the only correct mean to use when estimating the cost of capital. Mr. Plonski's reliance upon geometric mean is erroneous and should be rejected.

Q. At page 28 and OTS Statement No. 1 and Schedule No. 9, pages 1 and 2 of OTS Exhibit No. 1, Mr. Plonski refers to his calculated historical S&P 500 market return of 9.81%. Is such return correct to use in estimating the cost of capital?

A. No. It is incorrect for several reasons. I believe that investors would not rely upon an estimate of 9.81% as derived by Mr. Plonski. If investors were looking for long-term historical return on the S&P 500, they would be inclined to utilize the Ibbotson data derived from the Morningstar publication discussed supra, specifically in this instance the Morningstar 2008 Valuation Yearbook of Stocks, Bonds, Bills and Inflation (SBBI). Secondly, Mr. Plonski's use of a geometric mean is incorrect for the reasons discussed supra. I have prepared Schedule 10, which consists of two pages. It is shown on page 2 of Schedule 10 that the arithmetic mean total return over the period 1926 through 2007 was 12.3%. This is the correct mean to use for

the S&P 500. Although use of the geometric mean is incorrect when estimating the cost of capital, please note that the geometric mean return over the long-term period 1926 through 2007 shown by Morningstar is 10.4% which still exceeds Mr. Plonski's 9.81%.

Q. At the bottom of page 27 of his testimony, Mr. Plonski suggests that Ibbotson Associates condones the use of the geometric average and cites a 2004 publication. Is the inference drawn by Mr. Plonski accurate and correct?

A. No. The inference drawn is clearly incorrect. Ibbotson Associates in 2004 referred to past performance. I have prepared Schedule 11, which consists of two pages, from the 2004 Valuation Edition of SBBI. A comparison of page 2 of Schedule 11 (original page 71 from the 2004 Yearbook) with page 2 of Schedule 9, derived from the 2008 Valuation Yearbook will reveal that the wording between the two is identical. The full paragraph from the 2004 Yearbook from which Mr. Plonski excerpted one sentence reads as follows:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. *For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number.* This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return. (italics added for emphasis)

It is clear that Mr. Plonski's excerpt from this paragraph does not support his position.

Q. OTS Witness Plonski did not utilize an ECAPM analysis. Is it correct not to do so?

A. No. As discussed in Equitable Statement No. 5 at page 45, line 21 through page 47, line 4, although numerous tests of the CAPM have confirmed its validity, it has been determined that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the predicted SML. Hence, the traditional CAPM understates the cost rate for common equity for companies with betas less than 1.0 and overstates the cost rate for companies with betas greater than 1.0. Mr. Plonski erred by not employing the ECAPM.

Q. Please explain Schedule 12.

A. I have prepared Schedule 12 which correctly utilizes the traditional CAPM as well as the ECAPM. In other words, I have utilized Mr. Plonski's beta and risk-free rate in each instance but have utilized the long-term average arithmetic mean return in estimating equity risk premium. As can be seen, the CAPM result is an 11.46% cost rate, while the resultant cost rate from application of the ECAPM is 11.67%. These cost rates clearly indicate the gross understatement of common equity cost rate reflected by Mr. Plonski's recommendation of 10.05%. Of course, the CAPM/ECAPM cost rates of 11.46% and 11.67% do not reflect any additional increments to reflect Equitable's significantly greater risks described supra and which will be discussed infra.

D. RESPONSE TO MR. PLONSKI'S CRITIQUE OF THE COMPANY'S COST OF CAPITAL TESTIMONY

Q. **At page 30, Mr. Plonski criticizes your proxy group. He states that it is dissimilar to Equitable because "...demonstrated by his chosen group whose market capitalization is 3.3x larger than the market capitalization he has assumed for Equitable." Please comment.**

A. Mr. Plonski should have examined the market capitalization of his own group of eight companies. As discussed supra, and as shown by the information in Schedule 3, Mr. Plonski's group, based on market capitalization at the same date as my proxy group, is actually larger relative to the market capitalization assumed for Equitable. In addition, I cited other reasons why some of the companies included in Mr. Plonski's "barometer" group are not at all representative of a gas distribution company. This is especially true for NSTAR which is, by any measure, an electric utility. Although it does have gas distribution operations, they are extremely de minimis and as a result, any market data derived from NSTAR is not at all reflective of the risk of investment in a gas distribution utility.

Q. **At pages 31-32, Mr. Plonski refers to your Schedule 1, page 2 of Equitable Exhibit 5A. He seems to take issue with the fact that there is no mathematical precision by averaging the results of three methods to the cost rate of 11.00% which you concluded was appropriate based upon your proxy group and before the additional increments necessary to reflect Equitable's extraordinary risks. How do you respond?**

A. Mr. Plonski erroneously seems to believe that there is some mathematical certainty to estimating the cost rate of common equity capital. He also places undue emphasis upon the relative importance of the DCF method vis-à-vis other methods, including the CAPM. For example, Eugene F. Brigham and Phillip R. Daves[3] state with regard to people experienced in estimating the cost of equity:

> People experienced in estimating the cost of equity recognize that both careful analysis and sound judgment are required. It would be nice to pretend that judgment is unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible – finance is in large part a matter of judgment, and we simply must face that fact.

Moreover, with regard to the significance of the various cost of equity methodologies, Brigham and Daves also state[4]:

> Recent surveys found that the CAPM approach is by far the most widely used method. Although most firms use more than one method, almost 74 percent of respondents in one survey, and 85 percent in the other use the CAPM. This is in sharp contrast to a 1982 survey, which found that only 30 percent of respondents used the CAPM. Approximately 16 percent now use the DCF approach, down from 31 percent in 1982.

If the DCF method was superior to other cost of common equity estimation methods, it seems to me that it would be by far the most widely used methodology in all industries. If a method is superior, it would be superior across all industries. It is not. That is precisely why the financial literature recommends reliance upon multiple models to estimate the cost of common equity capital.

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[3] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, Ninth Edition, Thomson/South-Western, 2007, pp. 332-333.

[4] Id.

I believe that a range of properly calculated CAPM/ECAPM methods utilizing Mr. Plonski's inputs, as corrected in Schedule 12 which range between 11.46% and 11.67% confirm the reasonableness of my finding of 11.00%, which is before the additional necessary increments to reflect Equitable's extraordinary risks attributable to its small size, lack of tariff tools, and head-to-head competition as discussed supra.

Q. At page 32, Mr. Plonski averages in a comparable earnings result to your other cost of equity method results and at pages 40-42 discusses in some detail your comparable earnings method. Did you, in this instance, rely in any way on the comparable earnings methodology in formulating your recommended common equity cost rate?

A. I did not. It is clearly indicated in Footnote 5 of Schedule 1 of Equitable Exhibit 5A and also at page 6, lines 5-6 and at page 54, lines 13 through 19 of Equitable Statement No. 5.

Q. At page 34, Mr. Plonski suggests reasoning why the Commission should reject your upward adjustment of 20 basis points due to Equitable's lack of protection in rate design. Is his reasoning sound?

A. No. Mr. Plonski states that, to the best of his knowledge, the PA PUC has not instituted such programs. That is precisely the point. Because the overwhelming majority of the proxy companies in both of our proxy groups enjoy such rate design protection mechanisms their risk is reduced. Consequently, a common equity cost derived from those groups understates the cost rate of common equity capital to

Equitable which does not have the benefit of those risk-reducing rate design mechanisms.

Mr. Plonski suggests that the basic tenet of these programs is to effectively shift the cost of financial risk from companies and shareholders to the customers of utilities. He is incorrect. First of all, these have nothing to do with financial risk, but everything to do with reducing business risk. When the business risk of the companies is reduced, it lowers the cost of capital, both equity as well as external debt capital raised. Those lower costs are passed on to consumers who do benefit. In addition, the encouragement of conservation certainly benefits those consumers who wish to offset any increases by following the trend that has been in place in the gas distribution industry for years, which is manifested in companies' declining per customer usage. In addition, by taking into account the vagaries of weather, the rate design protection tends to stabilize rates. Consistent with the basic concept of risk, such rate design protection will stabilize customers' bills in contrast to volatile bills that vary not only with commodity cost but also significant variations in weather from the norm upon which base rates were established. Because the Company does not have such rate design protection it would be wrong to punish the Company by refusing to recognize that it is more risky vis-à-vis the proxy companies utilized to estimate the cost rate of common equity capital since the overwhelming majority of those proxy companies have such risk-reducing mechanisms in place.

Q. Please address Mr. Plonski's reference to the study by Professor Annie Wong at pages 30-31.

A. Professor Wong's conclusion about the effect of small size is incorrect and at odds with the overwhelming consensus of distinguished academicians. For example, Brigham[5] states:

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called the "small-firm effect." *On the surface, it would seem to be advantageous to the small firms to provide average returns in the stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.* (emphasis added)

In addition to the foregoing, Schedule 13, which consists of six pages, shows that Morningstar, in its buildup method of calculating the cost of equity, shows that size is an integral, essential part of the cost. Moreover, it can be seen by reference to pages 4 through 6, that the size effect goes across all industries including the utility industry. As shown, the excess return earned by small utilities with S.I.C. Code beginning with 49 over large utilities was 302 basis points (3.02%) over the period 1926-2007. On page 4 of Schedule 13, Morningstar indicates that excess returns presented in that table should not be construed as size premia. They show, however, that excess returns are earned by smaller companies within the electric, gas and sanitary services industry.

Morningstar further indicates that the size premium study presented earlier in this chapter "provides more reliable statistics as they relate to the size premium." It is precisely those premia that I relied upon that provide the more reliable statistics.

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[5] Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition, The Dryden Press, 1989, p. 623.

In addition, although Fama and French recognized some problems with the CAPM, they determined a way to improve the traditional CAPM by developing their three factor model which will be discussed infra. One of the significant inputs into the three factor model is size, i.e., small minus big, defined as the difference between the returns on diversified portfolios of small and big stocks.

Size is company-specific and diversifiable. Professor Wong's study is flawed because she attempted to relate a change in size to beta; and beta accounts for only a small percentage of diversifiable company-specific risk. For example, the average R-squared or coefficient of determination for my proxy group of nine LDCs is 0.2648 while that of Mr. Plonski's group of eight companies is 0.2656.

R-squared of 0.2648 means that 73.52% (1.0000 – 0.2648) of total risk is *unexplained* by beta, while an R-squared of 0.2656 means that 73.44% of total risk is unexplained by beta. Professor Wong's conclusion is incorrect and Mr. Plonski's argument against a size adjustment is erroneous and should be rejected.

Q. **At the bottom of page 34 and at the top of page 35, Mr. Plonski again discusses your upward adjustment to common equity cost rate attributable to Equitable's small size of 25 basis points. He states that it is unwarranted "for the same reasons that size should not be a criterion for selecting a barometer group." Please comment.**

A. I find Mr. Plonski's comment to be amazing. I established no size criterion in establishing my proxy group. Yet, at page 30, Mr. Plonski suggests that my proxy group is too dissimilar to Equitable because it has a market capitalization 3.3 times

larger than the market capitalization assumed for Equitable. As I have demonstrated supra and which is shown on page 1 of Schedule 3, Mr. Plonski's barometer group of eight companies has a market capitalization 4.0 times larger than Equitable's assumed market capitalization. Moreover, it is Mr. Plonski who instituted a size criterion by establishing as part of his barometer group only those companies that "have a customer base of more than 300,000" as indicated on page 15, lines 3-4 of his testimony. In addition, the financial literature is quite clear that size has a direct bearing on common equity cost rate. This was discussed supra as well as at page 10 of Equitable Statement No. 5 and set forth clearly in detail by Morningstar at Schedule 1, pages 12 through 23 of Equitable Exhibit 5A.

Q. At pages 35-36, Mr. Plonski discusses your recommended upward adjustment of 50 basis points to compensate for Equitable's direct head-to-head competition. He suggests that it be rejected. Do you have any comment?

A. Yes, I do. As discussed supra in connection with Schedule 4, Equitable has been facing, and continues to face, significant head-to-head competition from other gas distribution companies. This phenomenon in itself is unique. There are no other gas distribution companies whose common stocks are actively traded and would represent reasonable proxies in establishing a common equity cost rate for Equitable that experience this type of competition, which is significant. Mr. Plonski mentions the number of customers involved is 500 and suggests that it is a de minimis percentage of Equitable's total customer base. Yet, the size of customers has everything to do with significance. Equitable has quantified this type of competition

just since 2001 at some $23 million. Mr. Plonski's comment that because competition is not a new issue and has existed for several decades is irrelevant. What is relevant is that this head-to-head competition is real and it greatly increases Equitable's risk which fairness dictates should be recognized when determining an allowed common equity cost rate which is derived from a group of proxy (or barometer) group of companies that do not face such risk.

Q. **At the top of page 36, Mr. Plonski by the phrasing of the question suggests that it is your testimony that Equitable faces significant competition from electricity. Is his interpretation correct?**

A. No. I do suggest that Equitable has to compete with alternative power sources such as electricity, but it is disingenuous of Mr. Plonski to suggest that I state it is significant. Let me repeat precisely what I state at page 12, lines 3 through 5 of Equitable Statement No. 5:

> Equitable has to compete directly with other LDCs for customers in metropolitan Pittsburgh and western Pennsylvania in addition to competing with alternative power sources such as electricity.

The significant competition clearly is the head-to-head competition with other LDCs. That is why I used the term "in addition to competing with alternative power sources such as electricity."

Q. **At pages 36-37, Mr. Plonski suggests that your risk premium and CAPM results *should be rejected for the determination of the appropriate cost of capital.* Please comment.**

A. Mr. Plonski's reasoning is flawed. The prices investors pay for common stocks reflect the long-term, infinite, investment horizon which is implicit in the constant growth DCF model upon which Mr. Plonski places exclusive reliance as he only employs CAPM in a check, albeit incorrectly as discussed supra. Consequently, it is incorrect for Mr. Plonski to state at page 37 lines 2 through 5 of OTS Statement No. 1 that "regulators can never be certain that economic and regulatory conditions in the future will be the same as those underlying the historical period during which the risk premiums were calculated." In his application of the DCF model, he relies primarily upon a forecasted rate of growth in earnings per share. The constant growth DCF model presumes an infinite growth horizon. How accurate an estimate of the infinite future can an estimate for the next five years be, even if it incorporates five, ten or fifteen years' historical performance? The discussion at pages 39-40 of Statement No. 5 and the information set forth at pages 5 through 8, Schedule 12 of Exhibit 5A, explain why the use of a long-term average historical equity risk premium is appropriate. It does not mean that such a long-term average is constant any more than the growth rate in the DCF model is constant. Neither is constant in the literal sense, but rather is expectationally constant; that is, each is expected to vary randomly around an average expected mean value.

I should again point out that the constant growth DCF model presumes an infinite investment horizon, which in practical terms is a very long period of time. On pages 7 and 8 of Schedule 10, Morningstar states:

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly

> influenced by very good and very poor short-term returns. ...Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 81-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market returns studies can reveal a great deal about the future.

It seems to me that Morningstar is correct that historical event types, albeit not specific events, tend to repeat themselves. For example, the recent financial crisis, which is international in scope, is viewed by some as nearly as significant as the Great Depression of 1929.

Q. At page 38, Mr. Plonski suggests that because practitioners cannot agree on the exact value of each variable that is used "there is a great opportunity to manipulate the CAPM." Is he correct?

A. No. The information shown on page 3, Schedule 12, of Exhibit 5A has been excerpted from Morningstar's SBBI Valuation Edition 2008 Yearbook. It shows equity risk premia realized per year from 1926 through 2007. In the discussion by Morningstar at pages 5 and 6 of Schedule 12, Exhibit 5A, they discuss those equity risk premia and show that the serial correlation of such premia is 0.03, i.e., essentially zero and state:

> A serial correlation near zero indicates that the returns are random or unpredictable from one period to the next. ...The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year ... For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is

> as likely to be higher as it is lower. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

In view of the foregoing, the best expectation of the future infinite horizon is the arithmetic mean of the long-term historic equity risk premia. If Mr. Plonski's presumption about the CAPM model was correct, then the standard DCF model should also be ignored because it presumes a constant growth rate into infinity. Moreover, in the application of the DCF model, academics and practitioners alike cannot agree on the exact value of each variable, i.e., neither as to the precise dividend yield or the proper proxy to use for growth. To criticize the CAPM and the Risk Premium methods because of such reasoning is similar to the pot calling the kettle black.

Q. At page 39, Mr. Plonski questions the credibility of the CAPM. He cites an article by Fama and French from 1992. Please comment.

A. The Fama and French article was soundly rebutted by an article published in the Fall of 1993 in the Journal of Portfolio Management, by Fischer Black, the Black of the famous Sharpe, Lintner, Black SLB model, which Fama and French refer to often in their article. In his rebuttal, Black states:

> Fama and French claim to find evidence against this model. They say that their results 'seem to contradict' the evidence that the slope of the line relating expected return and beta is positive. This is a misstatement, in my view. Even in the period they choose to highlight, they cannot rule out the hypothesis that the slope of the line is positive. Their results for beta and average return are perfectly consistent with the SLB Model.
>
> Moreover, if the line is really flat, that implies dramatic investment opportunity for those who use beta. A person who normally holds

> both stocks and bonds or stocks and cash can shift to a portfolio of similar total risk but higher expected return by emphasizing low-beta stocks.
>
> Beta is a valuable investment tool if the line is as steep as the CAPM predicts. It is even more valuable if the line is flat. No matter how steep the line is, beta is alive and well (page 9).
>
> Announcements of the death of beta seem premature. The evidence that prompts such statements implies more uses for beta than ever. Rational investors, who can borrow freely, whether individuals or firms, should continue to use the CAPM and beta to value investments and to choose portfolio strategy (page 17).

In addition, since that time, Fama and French produced a 2004 article entitled, The Capital Asset Pricing Model: Theory and Evidence. I have prepared Schedule 15, which contains excerpted pages from that article. Note in the introductory paragraph on page 1 of Schedule 15 that Fama and French state:

> The Capital Asset Pricing Model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). *Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often the only asset pricing model taught in these courses.*
> (emphasis added)

Moreover, as discussed supra, Brigham and Daves in their 2007 text[6] state:

> *Recent surveys found that the CAPM approach is by far the most widely used method. Although most firms use more than one method, almost 74 percent of respondents in one survey, and 85 percent in the other, use the CAPM.* This is in sharp contrast to a 1982 survey, which found that only 30 percent of respondents used the CAPM. Approximately 16% now use the DCF approach, down from 31 percent in 1982.
> (emphasis added)

[6] Id.

In view of the foregoing, it is clear that the CAPM is the major asset valuation model. In addition, Fama and French recognize the shortcomings of the traditional or standard CAPM. The empirical CAPM (ECAPM) is a tool utilized to improve the CAPM. In their paper, Fama and French recommend a three factor model, which also takes into account size and book-to-market equity ratios.

Q. At page 38, Mr. Plonski suggests that because the Value Line beta is already adjusted for the tendency of stocks to regress toward one when used in the ECAPM it produces biased results. Please comment.

A. Mr. Plonski's suggestion indicates that he just does not understand the ECAPM. Any suggestion that the ECAPM which uses an adjusted betas double-counts the risk and return adjustment is incorrect. Dr. Morin's explanation is excerpted from *New Regulatory Finance* and contained in Schedule 16 which consists of four pages. For convenience, an excerpt is shown below:

> Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. ... The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. (Page 4 of Schedule 16 – original page 191)

It is clear, therefore, that the ECAPM is a return adjustment and not a beta adjustment. In addition, I have prepared Schedule 17, which consists of nine pages.

It is an excerpt from Financial Management – Theory & Practice, Fourth Edition by Eugene F. Brigham and Louis C. Gapenski. The authors make clear that:

- The Security Market Line (SML) is a line which reflects the degree of risk aversion.
- Beta does represent the slope of a line, but it is not the SML. Specifically, Footnote 12 on page 5 of Schedule 17 states:

> Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8 and as is developed further in Appendix 6A, *beta does represent the slope of a line, but not the Security Market Line.* (emphasis added)

In addition, Appendix 6A of that same literature entitled, "Calculating Beta Coefficients," shown as pages 7 through 9 of Schedule 17, demonstrates the calculations where it is readily seen that beta, which accounts for regression bias and is not a return adjustment, is based upon the slope of a different line. Page 8 shows a graphical depiction of the calculation of beta and it is clearly not the SML. As Morin explains in Schedule 16 at page 4 of 4:

> The ECAPM is a formal recognition that the observed risk-return trade-off is flatter than predicted by the CAPM based on myriad empirical evidence. *The ECAPM and the use of adjusted betas comprise two separate features of asset pricing.* (emphasis added)

In view of the foregoing, Mr. Plonski's assertion that the ECAPM using adjusted betas produces biased results is erroneous.

Q. Please address Mr. Plonski's contention, at page 43 of his testimony, that the DCF method is superior to other methods.

A. His contention is patently incorrect. The EMH confirms that investors take into account all publicly-available information. The financial literature is quite clear that investors are aware of all of the principal models used in public utility rate regulation and, absent empirical evidence to the contrary, one must conclude that all of the methods are taken into account. This is clear from the financial literature referenced at pages 23-25 of Equitable Statement No. 5. In addition, as discussed supra, Brigham and Daves not only discuss other models which should be considered in the exercise of informed expert judgment, but also point out that the model which is predominantly in use is the CAPM. Moreover, this Commission has cited *Lower Paxton* as a basis for utilizing a number of other methods when an ALJ relied too heavily on the DCF methodology (see pages 57-58 of Equitable Statement No. 5).

In view of the foregoing, it should be clear that Mr. Plonski's contention is without merit.

IV. OCA WITNESS DAVID C. PARCELL

A. CAPITAL STRUCTURE

Q. At pages 19 and 20, Mr. Parcell, using the same proxy group of nine LDCs which you utilize, recommends a hypothetical capital structure which includes 47.00% common equity capital. Do you agree with his recommended hypothetical common equity ratio?

A. No. I do not agree because Mr. Parcell states at page 20, lines 21-23 that his proposed hypothetical common equity ratio "more closely matches the average common equity ratio of my proxy group". To reiterate, his proxy group is the same

proxy group which I utilize. Moreover, Mr. Parcell also utilizes the same long-term debt and short-term debt cost rates which I recommend. The problem with Mr. Parcell's recommended common equity ratio is that it suffers from essentially the same impairment as the common equity ratio recommended by Mr. Plonski, albeit Mr. Plonski's proxy group differs from both Mr. Parcell's and mine. That impairment is that Mr. Parcell fails to recognize the extraordinary risks faced by Equitable, discussed in Equitable Statement No. 5 and supra. In Equitable Statement No. 5 at page 17, line 14 through page 18, line 2, I provide the reasoning why a 50% common equity ratio, although conservative, would be the minimal reasonable common equity ratio for Equitable on a stand-alone basis. Specifically, because of its small size, lack of adequate rate design protection and the significant head-to-head competition it experiences, I believe that Equitable's business risk profile would be considered "strong" by S&P in contrast to the "excellent" average of the proxy group utilized by both Mr. Parcell and myself. With an "A" bond rating and financial risk profile of "Intermediate" and a business risk profile of "Strong", the total range of permissible debt would be 35% to 50% which suggests the need to maintain an equity ratio in the 50% to 65% range, with 50% being the minimum.

Q. **At page 17, Mr. Parcell states that "it is apparent that the impact of the reorganization and the creation of Equitable as a subsidiary have the impact of reducing the utility's risks. This is a factor that which should be considered in establishing his cost of equity." Please comment.**

A. The overall cost of capital and fair rate of return which will be allowed by this Commission can only apply to Equitable Gas Company's jurisdictional rate base. The rate of return is applicable to nothing else. A basic principle of finance is that the risk relates to where capital is invested, or put. Schedule 18, which consists of five pages, is an excerpt from Principles of Corporate Finance, Fifth Edition, by Richard A. Brealey and Stewart C. Myers. At page 4 of Schedule 18 (original page 205), the authors make it quite clear when they state:

> *The true cost of capital depends on the use to which the capital is put.* (italics in original)

This means that the cost of capital should relate only to where the capital is put or invested, which in this instance is Equitable's rate base and nothing else. Moreover, Equitable's parent, Equitable Resources, Inc.'s capital structure and cost of capital is irrelevant as it is not in any way representative of the risk associated with a gas distribution operation. From a ratemaking perspective, Equitable has always been treated as if it were a stand-alone entity by using a hypothetical capital structure and determining common equity cost rate based upon proxy gas distribution companies. So, it should be clear that the recent reorganization and Equitable's formation as a ring-fenced subsidiary have no bearing on its ratemaking treatment. Moreover, all three cost of capital witnesses in this proceeding recommend utilizing a hypothetical capital structure based upon proxy (or barometer) groups and also determine a common equity cost rate derived from such groups. In addition, the statistics shown on Schedule 1, page 1 are clearly

demonstrative of the fact that Equitable Resources is no way representative of a gas distribution company.

For the foregoing reasons, Mr. Parcell's recommended capital structure should be rejected in favor of a hypothetical capital structure which is comprised of 50% total debt and 50% common equity capital.

B. COMMON EQUITY COST RATE

Q. At page 8, Mr. Parcell indicates that he "primarily" relied on the DCF methodology and used other methods such as CAPM and comparable earnings as a check. *Do you have any comment?*

A. I have previously addressed the infirmities associated with exclusive, or primary reliance upon the DCF methodology with regard to Mr. Plonski's testimony. Those comments are applicable here and need not be repeated.

Q. At pages 10 through 13, Mr. Parcell discusses trends in interest rates and capital costs. He discusses the current weakness in the economy which has resulted in the decline in capital costs and indicates that this is a factor that should be considered in establishing the current cost of equity for Equitable. Please respond.

A. As discussed supra with regard to Mr. Plonski, we are experiencing a global financial crisis and likely a global recession. Within the United States, our financial crisis has resulted in an extreme tightening of available credit which has resulted in significantly higher capital costs. I have prepared Schedule 19, which consists of five pages, to illustrate the significance of this situation. Pages 1 and 2 are an article

derived from Reuters on October 1. It is entitled, "U.S. CREDIT – Credit Market Seizures Pressure Power Companies". It is clear from this article that because of the credit crisis, and resultant limited availability of capital, even for highly-rated borrowers, the cost is considerably greater. An indication of the dramatic increase in long-term interest rates as evidenced by the chart shown on page 1 of Schedule 7 is confirmed by the yields on Moody's bonds shown on page 3 of Schedule 19. It is shown that on October 22, 2008, the yield on Moody's "A" rated utility bonds was 7.80%. Keep in mind that the prospective yield on A rated public utility bonds that I assumed in making my cost of capital analysis for the risk premium methodology was 6.26% as shown on Line No. 3, Schedule 11, page 1 of Equitable Exhibit 5A.

Additional evidence of just how costly longer term capital has gotten is indicated by the information shown on pages 4 and 5 of Schedule 19. Page 4 shows energy capital offerings for the week ending October 17, 2008. I have shown the effective yields of offerings of three out of the five offerings where the Company's bonds were rated "A3" by Moody's. An "A3" bond rating by Moody's is equal to the average Moody's bond rating for the proxy groups utilized by all witnesses in this proceeding as can be verified by reference to Schedule 2. On page 5 of Schedule 19, it is shown that the two PPL Electric Utilities Corp. offerings had effective yields of 7.131% and 7.119% *and they were for only five-year money with maturities in 2013.* Also note that Pacific Gas & Electric Company's offering had an effective yield of 8.389% which demonstrates clearly that the yield curve is very

steep and that for the often typical 25- or 30-year money, the yields would clearly have been substantially greater in each instance.

Q. Please comment upon the applicability of the range of Mr. Parcell's DCF mean and median cost rates ranging between 8.2% and 9.3% shown and discussed on page 27 of his testimony.

A. A DCF common equity cost rate of 9.3% at this time is so absurdly outside a range of credibility given capital market conditions that it should not be given serious consideration. Nonetheless, a DCF cost rate will mathematically mis-specify investors' required return rate when the market value of common stock differs significantly from its book value. It is a basic assumption of the model. As utility rate of return experts all know, and as I discussed in my direct testimony, market values and book values are seldom at unity. A market-based DCF model will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation.

Utility stocks continue to trade at market-to-book ratios well above unity. As can be determined from the data shown on Line No. 1 of Schedule 20, the market-to-book ratios of the proxy groups utilized by all three cost of capital witnesses, are selling at substantial premiums over book values.

As discussed in Equitable Statement No. 5, at page 28, lines 2-5:

> ...a <u>market-based</u> DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors'

required common equity cost rate when market value is above book value.

Schedule 20 demonstrates that there is no realistic opportunity to earn the market-based rates of return on book value. In this example, the average market price of Mr. Parcell's proxy group of $35.494 is 177.15% in excess of the average book value of $20.036 and the investor expects a total return rate of 9.30%, Mr. Parcell's recommended cost rate. The 9.30% market-based cost rate implies an annual return of $3.301 consisting of $1.402 in dividends and $1.899 in growth (market-price appreciation). When the 9.30% return rate is applied to the book value of $20.036, which is just 56.45% of market value, an opportunity for a total annual return is just $1.863 on book value. With annual dividends of $1.402, there is an opportunity to earn only $0.461 in market-price appreciation which is a mere 1.30% on market price in contrast to the 5.35% growth in market price expected on average by investors. There is no possible way to achieve the expected growth of $1.899 (5.35%) related to an average market price of $35.494 absent a huge cut in annual cash dividends, an unreasonable expectation since such an action by a board of directors is usually indicative of an extremely adverse financial condition. Of course, if the converse situation exists (market prices substantially below their book values), a market-based DCF cost rate applied to the book value of common equity would overstate the cost rate.

On the right hand side of Schedule 20, I have shown similar computations related to the proxy group of all eight companies relied upon by Mr. Plonski. As shown, the expected rate of growth implicit in Mr. Plonski's DCF cost rate of

10.05% is 5.79% but when it is applied to the average book value of $18.836 returns an opportunity for growth in market value of only 1.46%.

Q. Please comment on Mr. Parcell's statement at page 29, lines 7-11 of his direct testimony that "...the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings."

A. Mr. Parcell is incorrect in assuming that CAPM is superior to the single risk premium method. Beta is a measure of systematic risk, which reflects on average only about 26% of company-specific risk as reflected by the average R-squared statistic (or coefficient of determination) resulting from the regression analyses from which Value Line betas were shown on Schedule 14. This means that only 74% of total risk is explained by beta. In contrast, the "simple" risk premium method, which I use in addition to CAPM/ECAPM, DCF and comparable earnings (which I did not consider in this instance), relies upon the use of a company-specific expected bond yield. As shown in Exhibit 5A, Schedule 2, pages 3 through 9, S&P explains how and why the utility bond rating process takes into account all of the diversifiable basic components of business and financial risk. Moreover, I also utilize beta to allocate a total market equity risk premium which is a portion of the total market equity risk premium. Consequently, my approach to the risk premium analysis reflects all company-specific risk (i.e., in the company-specific bond yield which

reflects a diversifiable business and financial risk, plus that non-diversifiable portion which is reflected in beta) and the remainder of all risk is reflected through the use of beta in determining the applicable equity risk premium. In view of the foregoing, Mr. Parcell's comments about the CAPM versus the "simple" risk premium method are incorrect.

Q. Please comment upon Mr. Parcell's estimation of the market return component of his CAPM analysis discussed at pages 30-31.

A.11 Mr. Parcell used the actual achieved rates of earnings on book common equity of the S&P 500 Composite for the period 1978-2007 to calculate an equity risk premium as shown on Schedule 9 of Exhibit__(DCP-1). As discussed previously, both the cost of capital and ratemaking are prospective in nature. And, the underlying theory of the CAPM requires the use of a *market return*. Therefore, the use of historically achieved rates of earnings on book common equity is inconsistent with the very theory of the CAPM. In his alternative CAPM analysis, Mr. Parcell calculates the historic risk premium using Morningstar's average total return on large company stocks from 1926-2007, which are, appropriately, market returns. Thus, Mr. Parcell's CAPM analysis is distorted because he has used returns on book common equity and market returns.

Q. Another element considered by Mr. Parcell in arriving at his estimation of market equity risk premium is that he relied upon the total return on long-term government bonds from the Morningstar, Inc. 2008 Yearbook relating to the

period 1926 through 2007. Is Mr. Parcell's use in the CAPM of the total return on long-term government bonds appropriate?

A. No, it is incorrect. I have prepared Schedule 21 which consists of 5 pages. Pages 1 through 4 contain a discussion by Morningstar related to calculation of the equity risk premium for use in the CAPM. Page 5 is a copy of Table 2-1 from the same publication which represents a summary of total returns, income returns, and capital appreciation of the basic asset classes for the period 1926 through 2007. There are several things to be noted from the Morningstar publication. First, they indicate that the 30-year Treasury Bond yield is "theoretically more correct due to the long-term nature of business valuation."

Moreover, as shown on page 31 of Mr. Parcell's direct testimony, he relied upon a yield on long-term government bonds of 5.8% which represents total return and not income return of 5.2% for the same period of time. Morningstar, Inc. states under the caption "Income Return" at the bottom of page 2 and top of page 3 of Schedule 21:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. *The income return is thus used in the*

estimation of the equity risk premium because it represents the truly riskless portion of the return.[2] (footnote omitted) (italics added)

Thus, his use of the total return on long-term government bonds results in a substantial understatement of CAPM cost rate.

Q. Please comment on Mr. Parcell's direct testimony at lines 17-20 on page 31 wherein he notes that he has used both the arithmetic and geometric mean returns for the S&P 500 group as well as for long-term government bonds tabulated by Morningstar, Inc.

A. As discussed in Equitable Statement No. 5 at page 40, line 11 through page 41, line 5 and as discussed at length supra regarding Mr. Plonski's reliance upon the geometric mean, it is *only* the arithmetic mean return that is appropriate to use when estimating the cost of capital. Those reasons need not be repeated here.

Q. Mr. Hanley, have you recalculated CAPM and ECAPM cost rates utilizing Mr. Parcell's proxy group and a proper long-term arithmetic average market premium?

A. Yes, I have. That information is shown on Schedule 22. As shown, I have utilized Mr. Parcell's risk-free rate of 4.63% and Value Line betas from Schedule 10 of Exhibit__(DCP-1). I utilized a market premium of 7.10% which is the arithmetic mean average *market premium* calculated utilizing the long-term average income return on U.S. government securities of 5.2% and the long-term average total return on large stocks of 12.30% (12.30% - 5.2%). As shown, the average CAPM cost rate for the proxy group is 10.43% while the average ECAPM cost rate is 10.76%.

The foregoing CAPM/ECAPM cost rates show that Mr. Parcell's recommended common equity cost rate is well outside the low end of a range of credibility.

Q. Do you have any comments regarding Mr. Parcell's application of the CEM?

A. Yes. At page 36, Mr. Parcell discusses his recommended range of 9.0% to 10.0%. As support for his conclusion, he cites recent returns of 11.6% to 11.9% and market-to-book ratios of 175% and greater. He concludes that "...the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 11 percent to 12 percent reflect earnings that exceed the cost of equity for those regulated companies." (page 36, lines 21-24). By these statements, it is clear that Mr. Parcell believes that a direct relationship exists between market-to-book ratios and the rates of earnings on book common equity. Such a relationship is supported by neither the academic literature nor a historical analysis of the experience of non-price regulated companies.

Q. *What does the academic literature say about the relationship between allowed regulatory rates of return on common equity and utility market-to-book ratios?*

A. It is very clear from the academic literature that no such relationship exists. The following excerpts are also set forth on page 27 of Equitable Statement No. 5 and are shown here for convenience. Phillips[7] states the following:

> *Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those*

[7] Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utilities Reports, Inc., Arlington, VA, p. 395.

prevailing for stocks of unregulated companies. (italics added for emphasis)

In addition, Bonbright[8] states:

> *In the first place, commissions cannot forecast, except within wide limits, the effect their rate Orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. Moreover, even if a commission did possess the power of control, any attempt to exercise it . . . would result in harmful, uneconomic shifts in public utility rate levels.* (italics added)

Q. Have you performed an analysis to determine whether or not there exists a direct relationship between the market-to-book ratios of non-price regulated companies and their earned rates of return on book common equity?

A. Yes, I have and no such relationship exists. The results of my analysis are presented on Schedule 23. I analyzed the market-to-book ratios and earned rates of return on book common equity for the S&P Industrial Index and its successor, the S&P 500 Composite Index, which does not include public utilities, over a long period of time. On Schedule 23, I have shown the market-to-book ratios, rates of return on book common equity (earnings/book ratios), annual inflation rates, and the earnings/book ratios net of inflation (real rates of earnings) annually for the years 1947 through 2007. In each and every year, the market-to-book ratios equaled or exceeded 1.00 times. In 1949, the only year in which the market-to-book ratio was 1.00 (or 100%), the real rate of earnings on book equity, adjusted for deflation, was 18.1% (16.3% + 1.8%). In contrast, in 1961, when the S&P Industrial Index experienced a market-to-book ratio of 2.01 times, the real rate of earnings on book equity for the Index was

[8] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates, 1988, Public Utilities Reports, Inc., Arlington, VA, p. 334.

only 9.1% (9.8% - 0.7%). In 2007, the preliminary market-to-book ratio for the Index was 2.77 times, while the average real rate of earnings on book equity was just 8.7% (12.8% - 4.1%).

This analysis clearly demonstrates that competitive, non-price regulated companies have never sold below book value, on average, and have sold at book value in only one year since 1947. The data show that there is no relationship between earnings/book ratios and market-to-book ratios.

Because this lack of a relationship between earnings/book ratios and market-to-book ratios covers a 61-year period, 1947 through 2007, it cannot be validly argued that going forward a direct relationship would exist between earnings/book ratios and market-to-book ratios. The analysis shown on Schedule 23, coupled with the supportive academic literature, demonstrate the following:

1. While regulation is a substitute for marketplace competition, it can only influence but not directly control market prices, and, hence, market-to-book ratios; and

2. The rates of return investors expect to achieve on market value have *no meaningful, direct relationship to rates of earnings on book equity.*

C. RESPONSE TO WITNESS PARCELL'S COMMENTS ON COMPANY TESTIMONY

Q. On page 41, lines 26-28, Mr. Parcell states "To make a modification of the DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be." Please comment.

A. I made no modification of DCF cost rates and did not "reprice" stock values. I utilized informed expert judgment upon reviewing all of the indicated DCF cost rates vis-à-vis the cost rate results from application of the other cost of common equity

models which I employed as well as my utilization of a reasonableness check on my recommended common equity cost rate. The basis for the exercise of my informed expert judgment was set forth clearly in Equitable Statement No. 5 at page 34, line 15 through page 35, line 11.

The results of the other cost of common equity models and properly calculated CAPM/ECAPM cost rates for Messrs. Plonski and Parcell ranging from 10.43% to 11.67% (Schedules 22 and 12, respectively) confirm that their recommended common equity cost rates are understated significantly even before consideration of Equitable's extraordinary risks vis-à-vis each witness's proxy group.

Q. At page 42, Mr. Parcell draws on his memory from the 1970's and early 1980's. He states that he can recall no instances in which any AUS witness testified that the DCF result overstated the cost of equity. How do you respond to his memory?

A. In the 1970's and early 1980's, there was no clear trend by regulatory agencies to place great reliance upon the DCF methodology. It was only in later years that many commissions turned toward either exclusive use of the DCF methodology or to place significant weight on it in arriving at an allowed common equity cost rate in a rate proceeding. However, if Mr. Parcell was familiar with cases during that era in which I testified, he would find that my recommended common equity cost rates were much lower than the 15%, 16% or 17% DCF common equity cost rates which were indicated based upon market conditions at those points in time. Because it was not

necessary to emphasize that DCF cost rates were overstated 25 or 30 years ago does not mean that consideration was not given to their overstatement when market/book ratios of many utilities were below 100%. Over my entire career, I have consistently relied upon multiple methodologies including the CAPM and risk premium methods, in accord with the EMH. In so doing, I ameliorate the distortions created by sole reliance upon the DCF method when market values differ significantly from their book values.

Q. At page 43 of his testimony, Mr. Parcell criticizes your use of the long-term holding period returns (1926-2007) published by Morningstar, Inc. in your application of the risk premium methodology. Please comment.

A. Mr. Parcell's criticism of the use of long-term average holding period returns for the period 1926-2007 is incorrect for two reasons. First, Mr. Parcell's criticism of the use of such period is disingenuous as Mr. Parcell himself utilizes such long-term returns in his application of the CAPM as discussed supra. Secondly, for the reasons given in Equitable Statement No. 5 at page 39, line 3 through page 40, line 9 and as explained by Morningstar in detail in Schedule 9 especially at pages 7-8, the use of long-term holding period returns is correct when estimating the cost of capital.

The exclusive use of the long-term arithmetic mean by me, and in part by Mr. Parcell, is consistent with the long-term investment horizon of utilities' common stocks. The typical application of the standard constant growth DCF model used in regulation presumes an infinite, i.e., long-term, investment horizon and a constant growth rate. The presumption of a constant growth rate in the DCF model is no

different than the presumption of a constant equity risk premium based upon long-term historical arithmetic average holding period return as discussed in Statement No. 5, page 43, line 11 through page 44, line 16. As Morin[9] states:

> It is not necessary that *g* be constant year after year to make the model valid. *The growth rate may vary randomly around some average expected value. Random variations around trend are perfectly acceptable, as long as the mean expected growth is constant. The growth rate must be 'expectationally constant' to use formal statistical jargon.* (italics added)

The foregoing confirms that that aspect of the RPM is similar to the growth component of the constant growth DCF model. The use of a very long-term arithmetic mean equity risk premium does not mean that in actuality it is constant year after year in order for the model to be valid. The equity risk premium may vary randomly around some average expected value. As to Mr. Parcell's suggestion that it is somehow incorrect to rely upon the use of long-term average market equity risk premium such as 1926-2007, he contradicts himself by using it in the CAPM as discussed supra. Mr. Parcell's criticism is without merit.

Q. At page 44, Mr. Parcell criticizes your use of the empirical CAPM. Please comment.

A. Mr. Parcell states at lines 10-12 on page 44 of his direct testimony that "[W]hat the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market." This statement reflects a misunderstanding of the

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[9] See page 44 of Equitable Statement No. 5.

empirical CAPM. Mr. Parcell clearly suffers from the same misunderstanding of the ECAPM and beta as Mr. Plonski. This is evidenced by his statement at lines 16-18 on page 44 where he suggests there is no evidence that investors would ignore published betas and rely on hypothetical betas.

This misunderstanding has been addressed fully supra with regard to Mr. Plonski and the supporting data in Schedules 16 and 17. Thus, this issue need not be addressed again.

Q. **At page 45, Mr. Parcell criticizes your application of the CEM by stating at lines 11-13 that "The equivalence of beta values (i.e., the basis for his selection of comparison companies) does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same." Please comment.**

A. Mr. Parcell's comments relative to the equivalence of beta are incorrect. My comparable earnings analysis is not beta-oriented. It is based upon statistics derived from regression analyses of market prices of common stocks. The EMH confirms that the prices paid by investors reflect all relevant risks, i.e., business and financial, market (systematic) and non-market (unsystematic) risks. Regression analyses of those market prices result in meaningful statistics such as betas and standard errors. The use of betas (indicators of market risk) and standard errors of the regressions (indicators of all non-market risk) is logical and consistent with well-founded financial precepts which hold that market prices reflect all elements of risk.

Mr. Parcell cites the Hope Natural Gas case at page 7 of his testimony which states in part:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

The basis of selection of my comparable companies is the regression statistics of market prices which reflect all elements of risk. So, my non-price regulated proxy companies are indeed comparable in total risk to the proxy group of nine LDCs. Mr. Parcell's criticisms are unfounded, but in this instance, however, they are moot as I do not rely upon my CEM results in forming my recommendation as discussed supra with regard to Mr. Plonski's comments.

Q. At page 46, Mr. Parcell takes exception to your adjustment for the small size of Equitable. He suggests that a proper comparison should be Equitable Resources which he describes as "not a small company". Please comment.

A. Mr. Parcell must certainly understand that the cost of capital in this proceeding is going to be applicable only to Equitable's rate base. As shown in Schedule 18 which was discussed supra, the risk, and hence the cost of capital, relates to where the capital is invested (or put). This is a basic financial precept which is simply exemplified by Brealey and Myers in the excerpt from their text shown in Schedule 18. In addition, the recent reorganization has absolutely nothing to do with the size of Equitable and its rate base, which is the same both before and after the reorganization. In fact, it should be clear that the presumption already is that Equitable is less risky than its parent, Equitable Resources, Inc. I have assumed a

bond rating for Equitable equivalent to the average of my proxy group, namely Moody's "A3" whereas the Moody's bond rating for Equitable Resources is "Baa1", i.e., more risky than that assumed for Equitable. Consequently, Equitable is just as risky today as it was prior to the reorganization. Those risks, however, must be recognized, including its small size. The small size factor was discussed in detail supra regarding Mr. Plonski's objections to a small size adjustment and those comments need not be repeated.

Q. At page 47, lines 1 through 14, Mr. Parcell disagrees with your adjustment for lack of rate design protection. Is his disagreement based on logical grounds?

A. No. Mr. Parcell's disagreement is not based on logical grounds. The fact remains that for the most part, those proxy companies have revenue decoupling mechanisms and/or weather normalization adjustment clauses which protect against the vagaries of weather and declining per customer usage. The point is not whether it is relevant that all of the proxy companies have the same type of rate design protection. What does matter is that they have protections that make their revenue streams and operating margins more stable than those of Equitable. Mr. Parcell's objection is unfounded and should be disregarded.

Q. At the bottom of page 47 and the top of page 48 of his testimony, Mr. Parcell takes exception to your 50 basis points adjustment attributable to the extraordinary head-to-head competition faced by Equitable. Please comment on his reasoning.

A. Mr. Parcell's reasoning is not sound. He suggests that "it is noteworthy that Equitable Gas offers distribution rate discounts to certain industrial commercial customers who have competitive options to buy natural gas from other LDCs." The "discounts" are not freely offered. Equitable negotiates rates because the threat of bypass is equivalent to a gun being held to Equitable's head. Negotiated rates are essential in order to maintain the customers, rather than having them leave the system. Assessment of Equitable's extraordinary risk due to head-to-head competition vis-à-vis the proxy group is essential. The greater competition means that there is more risk and more risk requires a greater return than that derived from the proxy companies that do not experience such risk. Mr. Parcell's contentions are unfounded and should be disregarded.

Q. Does that complete your rebuttal testimony?

A. Yes, it does.

Equitable Statement No. 5-SR
R-2008-2029325
Witness: Frank J. Hanley
Date: 11/9/08 RJS

EQUITABLE GAS COMPANY

R-2008-2029325

SURREBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

FAIR RATE OF RETURN

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

A. My name is Frank J. Hanley and I am a Principal and Director of AUS Consultants. My business address is 155 Gaither Drive, Suite A, Mt. Laurel, New Jersey 08054.

Q. Are you the same Frank J. Hanley who previously filed direct and rebuttal testimonies in this proceeding?

A. Yes, I am.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to respond to that portion of the rebuttal testimony of Pennsylvania Office of Small Business Advocate (OSBA) Witness Brian Kalcic as relates to his comments regarding the cost of capital.

Q. Have you prepared an exhibit in support of this testimony?

A. Yes, I have. It has been marked for identification as Equitable Exhibit 5A-SRand consists of one schedule.

Q. At page 17 of his rebuttal testimony, Mr. Kalcic opines that since interest rates and stock prices have declined since cost of capital testimony was filed in this proceeding, that he "would expect such events to reduce both Equitable's test period cost of debt and its required ROE...". Please comment.

A. It seems obvious to me that Mr. Kalcic did not read my rebuttal testimony, particularly at pages 14 and 15 of Equitable Exhibit No. 5-R, as well as the information contained in Schedule 7 of Equitable Exhibit 5A-R. Mr. Kalcic's assessment of the movement in interest rates and his expectations about reducing Equitable's cost of debt and its required ROE just could not be more incorrect as the

trend in long-term capital costs to corporations, including public utilities, has not declined but rather has increased dramatically.

Q. Please elaborate upon the recent dramatic increase in long-term capital costs to corporations.

A. The recent credit crisis has resulted in a sudden and dramatic shrinkage in the availability of capital, which in turn has resulted in a significant increase in long-term capital cost rates. I have prepared Exhibit 5A-SR, Schedule 1, which consists of six pages. Page 1 shows a comparative trend between short-term interest rates as measured by the Federal Funds rate and long-term capital cost rates as measured by the yield on Moody's A rated public utility bonds. As can be gleaned from the chart on page 1, the spread has increased from about 100 basis points in August 2007 to nearly 700 basis points in October 2008. Notwithstanding the significant decline in short-term interest rates, long-term interest rates to public utilities, as measured by the yield on Moody's A rated public utility bonds, have not declined. Rather, it is also shown that there has been a recent huge spike in the yield on corporate bonds, particularly A rated utility bonds. Pages 2 and 3 of Exhibit 5A-SR, Schedule 1 are an article derived from Reuters on October 1, 2008. It is entitled, "*U.S. CREDIT – Credit Market Seizures Pressure Power Companies*". It is clear from this article that, due to the credit crisis and the resultant limited availability of capital, even for highly rated borrowers, its cost has grown considerably greater. The dramatic increase in long-term interest rates is confirmed by the average yield on Moody's A rated utility bonds, which was 7.94% on November 3, 2008, as shown on page 4.

Keep in mind that the prospective yield on A rated public utility bonds that I assumed in my cost of capital analysis for use in my Risk Premium Methodology (RPM) was 6.26%, as shown on Line No. 3, Schedule 11, page 1 of 9 of Equitable Exhibit 5A accompanying my direct testimony. In other words, there has been an *increase* of 168 basis points since then.

Additional evidence of just how costly longer term capital has become is indicated by the information shown on pages 5 and 6 of Exhibit 5A-SR, Schedule 1. Page 5 shows energy capital offerings for the week ending October 17, 2008. I have shown the effective yields on offerings of three out of the five offerings where the companies' bonds were rated A3 by Moody's, which is the same as the average Moody's bond rating of my proxy group of nine gas distribution companies as shown on Schedule 11, page 2 of Equitable Exhibit 5A. On page 6 of Exhibit 5A-SR, Schedule 1, it is shown that the two PPL Electric Utilities Corp. offerings had effective yields of 7.131% and 7.119%. Significantly, these were for only five-year money with maturities in 2013. Also note that Pacific Gas & Electric Company's offering had an effective yield of 8.389% for 10-year money with a maturity in 2018, demonstrating clearly that the yield curve is very steep and that for the often typical 25 or 30 year money, the yields clearly would have been substantially greater in each instance.

Q. Does this mean that your original recommendation of an ROE of 11.95% has become too low to reflect current conditions?

A. Quite frankly, yes. However, I am not recommending an upward revision to the ROE at this time, due to the late stage of this proceeding.

Q. Is it possible that this interest rate spike will be of short duration, so that an 11.95% ROE recommendation will again become more appropriate?

A. No. The financial crisis which created this spike in capital costs was discussed by the Chairman of the Federal Reserve, Ben Bernanke on October 15, 2008, in an address to the Economic Club of New York where he stated, "Stabilization of the financial markets is a critical first step, but even if they stabilize as we hope they will, broader economic recovery will not happen right away." Bernanke said it will take some time to restore normal credit flows and pledged the U.S. central bank would continue to act aggressively to fight the crisis. Moreover, as noted at page 15 of Equitable Statement No. 5-R, on October 23, 2008, former Federal Reserve Chairman Alan Greenspan testified before the House Government Oversight Committee investigating the financial crisis. Mr. Greenspan stated that the crisis "has turned out to be much broader than anything I could have imagined. It has morphed from one gripped by liquidity restrains to one in which fears of insolvency are now paramount." Mr. Greenspan suggested that the financial crisis currently gripping the U.S. will take many months to improve.

Moreover, the observations of Messrs. Bernanke and Greenspan are consistent with the time horizons of the various extraordinary programs that have been initiated by the U.S. Treasury Department and the Federal Reserve System, among other agencies, to stem the impact of the current financial crisis.

Q. At page 18 of his testimony, Mr. Kalcic indicates it would not be reasonable for the Commission to ignore the impact of the current financial crisis when setting Equitable's overall rate of return, including the allowed rate of return on common equity capital. Is he correct?

A. Yes, on this point he is correct. It would not be reasonable for the Commission to ignore the dramatic increase in long-term capital costs which have occurred and are likely to be around for quite some time. An increase in long-term debt capital costs means a significant increase in the cost rate of common equity capital. Equitable has not amended its requested revenue requirement despite the dramatic increase in the cost of capital and it should not be punished by lowering the requested cost of capital that was derived when market conditions were much more favorable.

Q. Does that complete your surrebuttal testimony?

A. Yes, it does.

Equitable Exhibit 5A-SR
R-2008-2029325
Witness: Frank J. Hanley
Date:

EQUITABLE GAS COMPANY

R-2008-2029325

EXHIBIT

TO ACCOMPANY THE

SURREBUTTAL TESTIMONY

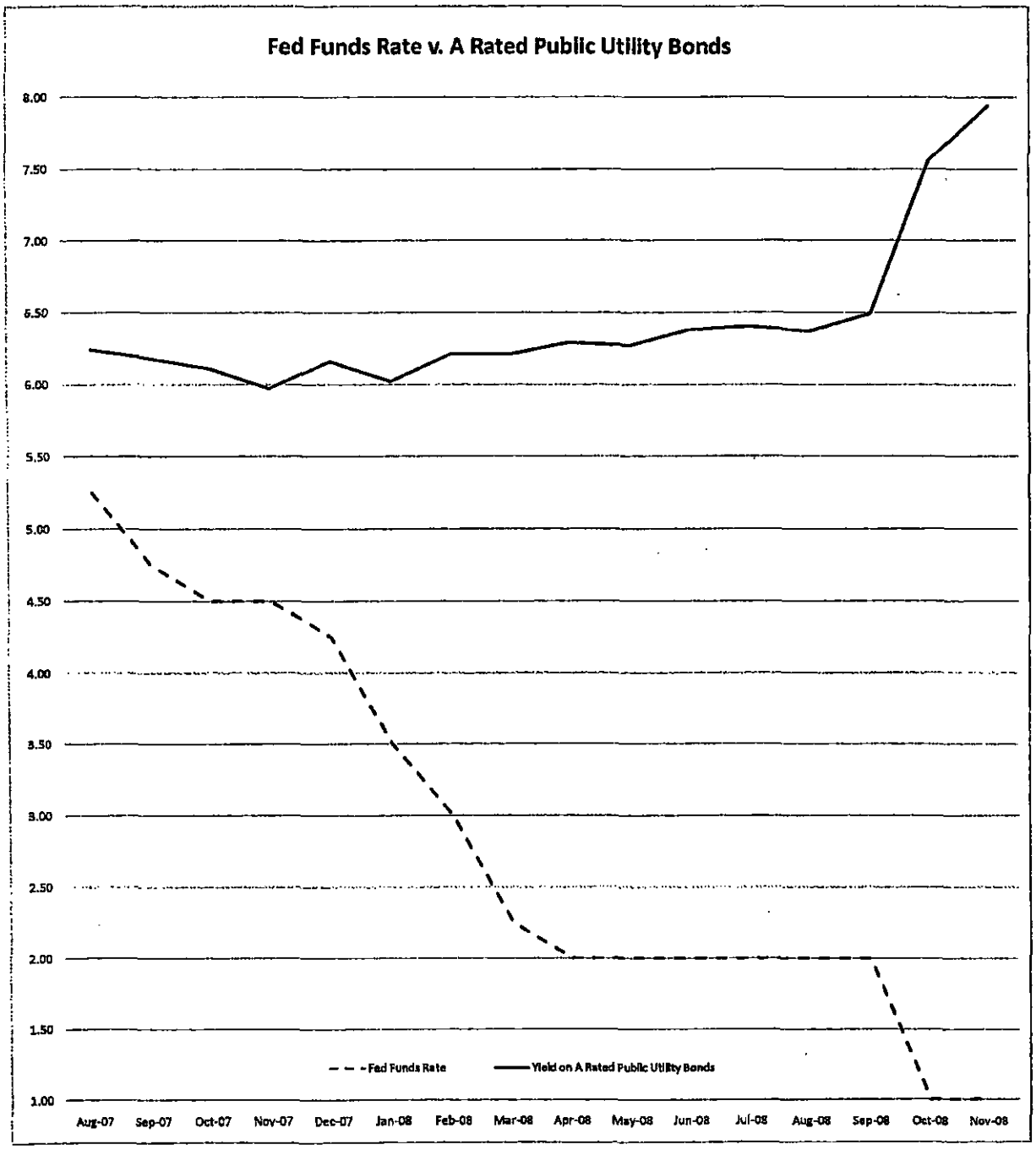
OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

FAIR RATE OF RETURN

Equitable Gas Company
Comparison of Fed Funds Rate
and Yields on A Rated Public Utility Bonds



Sources of Information:
Mergent Bond Record November 2008 Vol. 75, No. 11.
Moody's Credit Trends Daily Bond Yields and Key Indicators
http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html

US CREDIT-Credit market seizures pressure power companies

Wed Oct 1, 2008 4:50pm EDT

By Karen Brettell

NEW YORK, Oct 1 (Reuters) - Debt protection costs for utility companies and other power producers are likely to remain elevated until logjams in the credit markets are cleared, as market seizures are raising concerns over the companies' access to capital.

Credit default swaps on power companies were among the weakest performers on Wednesday, led by a 54 percent move wider in swaps on Dominion Energy (D.N: Quote, Profile, Research, Stock Buzz) to around 102 basis points.

The volatility came after Reliant Energy (RRI.N: Quote, Profile, Research, Stock Buzz) on Monday cut its profit forecast and said it had obtained $1 billion of new financing to replace a credit facility, which sent its shares down as much as 51 percent on Tuesday. For details, see [ID:nN30440144]

"There's lot of ways to speculate (on market moves), but what it fundamentally gets to is frozen liquidity," said Gimme Credit analyst Philip Adams.

American Electric Power Co's (AEP.N: Quote, Profile, Research, Stock Buzz) swaps also weakened 29 percent on Wednesday to 81 basis points, or $81,000 per year for five years to insure $10 million in debt. FirstEnergy Corp's (FE.N: Quote, Profile, Research, Stock Buzz) swaps weakened 23 percent to 102 basis points, Markit data shows.

"Credit market difficulties are starting to have some spillover. It's not just banks, but its companies and industries that depend on functioning financial markets," Adams said.

Reticence to lend to even highly-rated borrowers is making it harder for companies to raise capital and when they do the cost of the debt is high, especially for firms considered more risky.

Reliant, which is rated below investment grade, said it had secured a $650 million senior secured loan with Goldman Sachs at Libor +4.5 percent and another $350 million of convertible preferred debt with First Reserve at an interest rate of 14 percent.

The new capital replaces a $300 million credit facility that Reliant had with Merrill Lynch that enabled the power producer to avoid posting millions of dollars in collateral.

"The company said its decision to end the Merrill Lynch $300 million hedging facility was completely mutual," CreditSights analyst Andy DeVries said in a report on Wednesday.

"We think it has more to do with Reliant knowing it was going to trip the earnings before interest, taxes, depreciation and amortization covenants in the facility owing to the weak results in the Retail segment," he said.

DeVries is "underweight" Reliant's bonds and credit default swaps, citing concerns about the company's earnings outlook.

OUTLOOK

If credit markets stabilize, as is hoped if the government passes a $700 billion bailout bill for the financial industry, swaps on utility companies should stabilize near term, though debt needs through the coming years is likely to hurt their credit profiles.

"Utilities, if they're the right ratings and the right kind of paper, are still kind of perceived as being the safe haven, and near term I wouldn't disagree," said Gimme Credit's Adams.

"My utility outlook for the rest of the decade, though, is that every one of them has capex requirements well in excess of their internal cash generation," he said. "Most of them are going to be net borrowers over the next couple of years, so that if they don't get the right kind of rate treatment I would expect them to slowly deteriorate in credit quality."

Other power producers which generate positive cash flows may fare better, though risks to creditors are that they use cash proceeds to pump up their stock price at the expense of debt holders, Adams said.

(Additional reporting by Matt Daily in New York)

Daily Bond Yields and Key Indicators

Data as of 03-NOV-08

Moody's Daily Long-term Corporate Bond Yield Averages

	Utilities	Industrial	Corporate
Aaa	NA	6.45	6.45
Aa	7.18	6.90	7.04
A	7.94	8.00	7.97
Baa	9.23	9.74	9.49
Avg	8.12	7.77	7.95

Moody's Daily Treasury Yield Averages

Short-Term (3-5 yrs)	1.53
Medium-Term (5-10 yrs)	3.52
Long-Term (10+ yrs)	4.68

Moody's Daily Public Utility Common Stock Yield Averages

Price	214.96
Yield	4.76
New Dividend	10.23

Moody's Commodity and Scrap Price Indexes

Spot Commodity Index	3110.27
Industrial Metals Index	1155.74

* Moody's "Aaa" Utilities Index was suspended on 12/10/01. Since 2000, TVA was the only issuer left in the index as a decade of deregulation, debt growth, competition, and consolidation eliminated the rest of the Aaa universe.

Contact Us

Power & Midstream - Industry News
October 21, 2008 4:49 PM ET
By Rosy Lum

During the week ended Oct. 17, a week that the Dow Jones Industrial Average had its highest point gain in the history of the index and central banks around the world injected billions of dollars into the financial system, FirstEnergy Corp., PPL Corp. and PG&E Corp. subsidiaries drummed up $1.3 billion through five debt offerings.

PG&E utility Pacific Gas and Electric Co. completed the largest deal of the week. The company on Oct. 16 offered $600 million of its 8.25% senior notes due Oct. 15, 2018. Net proceeds, which are expected to be approximately $585.4 million, will be used to repay commercial paper and for working capital purposes, the company said.

Banc of America Securities, Citigroup Global Markets and Deutsche Bank Securities acted as joint book managers on the offering.

PPL subsidiary PPL Electric Utilities Corp. on Oct. 14 and Oct. 15 entered into underwriting agreements with a consortium of banks relating to the offering and sale of $400 million of its 7.125% senior secured bonds due 2013.

Net proceeds will partially fund the repayment at maturity of about $485.8 million outstanding aggregate principal amount of its senior secured bonds, 6.25% series, due Aug. 15, 2009. The bonds are scheduled to mature Nov. 30, 2013, subject to early redemption, in whole at any time or in part from time to time.

Ohio Edison Co. on Oct. 15 completed a $275 million offering of its 8.25% series 2008 first mortgage bonds due Oct. 15, 2038, and a $25 million offering of its 8.25% series 2008 first mortgage bonds due Oct. 15, 2018. Net proceeds from the two offerings will be used for capital expenditure and for general corporate purposes. Ohio Edison is a subsidiary of FirstEnergy.

Energy capital offerings for the week ending Oct. 17

Company	Comp. date	Amount offered w/ overallotment [$000]	Offer price (%)
Debt offerings			
PPL Electric Utilities Corp.			
7.125% senior secured bonds due 11/30/13	10/14/08	375,000	99.91
Ohio Edison Co.			
8.250% series 2008 first mortgage bonds due 10/15/38	10/15/08	275,000	97.90
PPL Electric Utilities Corp.			
7.125% senior secured bonds due 11/30/13	10/15/09	25,000	100.088
Ohio Edison Co.			
8.250% series 2008 first mortgage bonds due 10/15/18	10/16/08	25,000	98.942
Pacific Gas and Electric Co.			
8.250% senior notes due 10/15/18	10/16/08	600,000	98.343
Total debt offered		1,300,000	

Comprehensive coverage of private placements and Rule 144a transactions may not be possible due to limited disclosure and public documentation. These transactions are presented where available.
Source: SNL Energy

Interstate Power and Light Company
Energy Capital Offerings by Companies with Bonds Rated A3 by Moody's
During the Week Ending October 17, 2008

Company	Subsidiary	Moody's Bond Rating	Amount ($000's)	Due Date	Nominal Interest Rate	Discount/ Premium	Effective Yield (1)
PPL Corp.	PPL Electric Utilities Corp.	A3	375,000	11/30/2013 (2)	7.125%	99.910%	7.131%
PPL Corp.	PPL Electric Utilities Corp.	A3	25,000	11/30/2013 (2)	7.125%	100.088%	7.119%
PG & E Corp.	Pacific Gas and Electric Co.	A3	600,000	10/15/2018 (3)	8.250%	98.343%	8.389%

Notes:
(1) After discount or premium and before issuance costs.
(2) Five-Year money.
(3) Ten-Year Money.

Equitable Statement No. 6-R
Docket No. R-2008-2029325
Witness: Russell A. Feingold
Date: 11/19/08 RAF

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Russell A. Feingold

PREPARED REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black & Veatch Corporation as a Vice President and I lead the Rate & Regulatory Advisory Group of its Enterprise Management Solutions Division.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (THE "COMMISSION") IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony in this proceeding on behalf of Equitable Gas Company ("Equitable" or the "Company") concerning its filed cost of service studies.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to the testimony of the Office of Trial Staff ("OTS"), the Office of Consumer Advocate ("OCA"), the Pennsylvania Office of Small Business Advocate ("OSBA"), and the Independent Oil and Gas Association of Pennsylvania ("IOGA") related to the Company's cost of service studies and associated customer cost analyses. I will specifically respond to the claims made in the direct testimonies of OTS witness Jeremy Hubert, OCA witness Glenn Watkins, OSBA witness Brian Kalcic, and IOGA witness Diane Meyer Burgraff related to the manner in which the Company's cost of service studies, and associated customer cost analyses, should be conducted, and the treatment of Equitable's current Appalachian Gathering Service ("AGS") rate schedule within these cost of service studies.

III. Summary of Findings and Recommendations

Q. CAN YOU PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS RELATED TO THESE PARTIES' PRESENTATIONS?

A. Yes. Based on my review of the points and underlying support provided by witnesses Hubert, Watkins, Kalcic, and Meyer Burgraff concerning the Company's cost of service studies, I have reached the following findings and recommendations:

1. I have considered certain of the adjustments to the Company's cost of service studies recommended by Mr. Watkins and Mr. Kalcic, and agree that those particular adjustments are warranted in light of the oversights made on my part that affected these cost studies. I have incorporated these adjustments into the Company's cost of service studies and have

reflected them in a revised exhibit I am filing with my rebuttal testimony.

2. Since I continue to believe that it is appropriate to use a peak demand allocation basis and to recognize a customer component of distribution mains in the Company's cost of service study, I recommend that the Commission use in its evaluation of Equitable's class revenues and rates the midpoint of the range of results derived from the Company's revised cost of service studies described above.

3. The criticisms raised by Mr. Hubert and Mr. Watkins concerning the Company's customer cost analysis should be rejected because they are based upon either the inconsistent application of definitions for direct and indirect customer costs, or they misinterpret or ignore the precedent of the Commission on the issue of deriving a cost basis for evaluating a utility's monthly customer charge.

4. The position of Mrs. Meyer Burgraff concerning the treatment of Rate AGS in the Company's cost of service studies should be rejected because it violates well accepted costing principles and fails to properly recognize those entities that have caused Equitable to incur the costs of its gathering system.

IV. Revisions to the Company's Cost of Service Studies

Q. HAVE YOU MADE CERTAIN ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED COST OF SERVICE STUDIES?

A. Yes. Based on the points raised by Mr. Kalcic and Mr. Watkins, I have made the following adjustments to the Company's cost of service studies:

1. I have modified the income tax calculation by class to treat operation and maintenance ("O&M") expenses and interest expenses as deductions to pre-tax income as described by Mr. Watkins at pages 13-14 of his direct testimony.
2. I have directly assigned to the Company's Residential class certain cost components in Account Nos. 904 and 908 associated with its Customer Assistance Program ("CAP") as described in the Company's response to OSBA Data Request I-4.
3. I have eliminated the effect of the change in item 2 above to the internally generated, composite cost allocation factors used to assign overhead and administrative costs to the Company's classes of service. As I discuss below, however, only a small adjustment to labor expense was required. Adjustments to the O&M cost allocation factors to which Mr. Watkins refers to in his direct testimony are not appropriate.

The Exhibit that I have included with my rebuttal testimony reflects these changes and presents revised cost of service study results for purposes of evaluating Equitable's class revenues and rates.

Q. PLEASE DESCRIBE THE EXHIBIT YOU HAVE PREPARED TO REFLECT THE ABOVE-DESCRIBED CHANGES TO THE COMPANY'S COST OF SERVICE STUDIES.

A. I am sponsoring the following revised cost of service study related exhibit and schedules:

- Equitable Exhibit No. 6-R, Schedule 1 – presents a summary of results for the Company's cost of service studies described below.
- Equitable Exhibit No. 6-R, Schedule 2 – presents Equitable's cost of service study at present rates based on a design day demand allocation method with a customer component of distribution mains.
- Equitable Exhibit No. 6-R, Schedule 3 – presents Equitable's cost of service study at present rates based on a peak and average demand allocation method without a customer component of distribution mains.
- Equitable Exhibit No. 6-R, Schedule 4 - presents Equitable's cost of service study at proposed rates based on a design day demand allocation method with a customer component of distribution mains.
- Equitable Exhibit No. 6-R, Schedule 5 - presents Equitable's cost of service study at proposed rates based on a peak and average demand allocation method without a customer component of distribution mains.
- Equitable Exhibit No. 6-R, Schedule 6 – presents a cost analysis supporting minimum charges for all rate schedules.

Q. PLEASE EXPLAIN THE IMPACT OF THESE CHANGES ON THE COMPANY'S COST OF SERVICE STUDY RESULTS.

A. While these changes cause the class rates of return to change under present rates, they have not changed materially under the Company's proposed class

revenues. The reason for this outcome is that the adjustment associated with the income tax calculation only affects the class rates of return at present rates. The other two adjustments (the direct assignment of CAP costs to the RS class and the associated minor adjustments to certain internal allocation factors) have very little effect on the class rates of return under the Company's proposed class revenues and rates. This is because the CAP costs directly assigned to the RS class are slightly over $1 million while total expenses assigned to that class approach $100 million.

These summary results are observed by comparing Equitable Exhibit No. 6-R, Schedule 1 to Exhibit IV-B-1(E).

Q. PLEASE EXPLAIN THE IMPACT OF THE ABOVE DESCRIBED CHANGES ON THE COMPANY'S CUSTOMER COST ANALYSES PRESENTED IN EXHIBIT IV-B-9.

A. The results of the Company's customer cost analysis presented in Exhibit IV-B-9 have not materially changed due to the above described changes to the cost of service studies. Specifically, the customer cost level for the RS class has slightly increased while the customer cost levels for the GSS and GSL rate classes have decreased.

Q. WHY IS IT NOT APPROPRIATE TO ACCEPT MR. WATKINS' CLAIM THAT CERTAIN OF THE INTERNAL ALLOCATION FACTORS IN THE COMPANY'S COST OF SERVICE STUDIES SHOULD BE ADJUSTED TO

REFLECT THE DIRECT ASSIGNMENT OF CAP-RELATED COSTS IN ACCOUNT NOS. 904 AND 908?

A. Mr. Watkins's claim is not correct, except for a small adjustment to labor expenses. The only internal allocation factors that refer to CAP costs are used to assign small portions of the Company's rate base (i.e., Prepayments and Accounts Payable – Other), which have no direct assignments, and, therefore, should include all expense components. The O&M allocation factors that Mr. Watkins refers to in his direct testimony do not reference the 900 series of accounts. They reference the 800 series of accounts, and so they are not affected by the direct assignments of portions of Account Nos. 904 and 908.

A&G costs are allocated based on total labor expenses. Since Account No. 904 includes no labor expenses, no adjustment to allocation factors was necessary. The labor expenses in Account No. 908 were split in the same ratio as the total account costs (41% non-CAP, 59% CAP). This adjustment had a very small effect on the results of the Company's cost of service studies.

V. Reliance on the Company's Cost of Service Studies

Q. PLEASE SUMMARIZE THE POSITIONS OF OTS, OCA, OSBA, AND IOGA ON USE OF THE COMPANY'S COST OF SERVICE STUDIES FOR RATE DESIGN PURPOSES.

A. The positions of these parties on this issue are as follows:

- OTS – Mr. Michael Gruber has accepted that the cost of service studies performed by the Company "were done and calculated properly" and

recommends that the Peak & Average Study, with no customer component of distribution mains, (as revised in Equitable Exhibit No. 6-R, Schedules 3 and 5) be used to evaluate the Company's class revenue and rate levels.

- OCA – Mr. Watkins has conducted a cost of service study using the Peak and Average demand allocation method, with no customer component of distribution mains, that relies upon many of the direct assignments and allocation factors contained in the Company' cost of service study presented in Equitable Exhibit No. 6-R, Schedules 3 and 5 (as revised). Both his cost study and the Company's revised cost study referenced above derive relatively similar rates of return by class.
- OSBA – Mr. Kalcic recommends that the cost of service studies prepared on his behalf by the Company (see responses to OSBA Data Request Set II-4 and II-5) be used to evaluate the Company's class revenues and rate levels. These cost studies use the Design Day demand allocation method, with no customer component of distribution mains, and allocate the revenues and costs associated with competitive service discounts to all rate classes.
- IOGA – Mrs. Meyer Burgraff recommends that the cost of service studies prepared on her behalf by the Company (see responses to IOGA Data Request Set VI-5) be used to evaluate the Company's class revenues and rate levels. As the Company has done, separate cost studies were performed using either a Design Day or Peak & Average demand allocation method, while the Peak & Average cost studies excluded a

customer component of distribution mains. In addition, the AGS rate class has been eliminated from each of the cost of service studies presented by IOGA.

Q. PLEASE COMMENT ON THE COST OF SERVICE STUDIES PRESENTED BY THESE PARTIES.

A. First, a majority of the parties have chosen the Peak & Average Method as an acceptable demand cost allocation method. Next, all parties except IOGA do not recognize a customer component of distribution mains in their cost of service studies. Finally, all parties except IOGA preferred to conduct, and to rely upon, a single cost of service study, rather than multiple cost studies, for purposes of evaluating class cost responsibility.

While the Company has conducted a cost of service study using the Peak & Average Method with no customer component of distribution mains, it also conducted a cost study using a Design Day Method (also accepted by OSBA) with a customer component of distribution mains (also accepted by IOGA). As I pointed out at pages 24-25 of my direct testimony, this "multiple study approach" was chosen by the Company to identify the boundaries of cost responsibility among its classes of service. The use of more than one cost allocation methodology attempts to recognize the use of judgment inherent in performing cost of service studies and provides this Commission with a reasonable and useable range of results. Although the majority of the parties have chosen to present a single cost of service study, I strongly urge the

Commission to consider the use of a range of cost study results to evaluate class cost responsibility as the Company has presented in this proceeding.

Q. AT PAGE 10 OF HIS DIRECT TESTIMONY, MR. WATKINS ADDRESSES THE SHORTCOMINGS HE CLAIMS EXIST WITH A DESIGN DAY DEMAND ALLOCATION METHOD. HOW DO YOU RESPOND TO HIS CLAIMS?

A. First, Mr. Watkins claims that a peak responsibility method is not appropriate for Equitable because "mains are utilized each and every day of the year and recognition of annual usage (throughput) is a logical basis for cost assignment." I believe this method standing alone relies too heavily on the use of "throughput" as a reliable cost allocation basis.

The use of a commodity-based allocation factor (such as the Peak & Average Method) assigns more cost to higher load factor customers and less cost to lower load factor customers than under the cost-causation based Design Day method that I presented. On most gas distribution systems, the practical result of such an allocation is to reduce costs for residential customers and increase costs for industrial or large volume customers. The rationale for using a commodity-based allocation factor is usually discussed by cost analysts supporting such a method by arguing that the gas distribution system would not be built if it were not for customers' commodity consumption. Their argument relies upon the concept I characterize as the "commodity delivery function." The concept of a "commodity delivery function" relates to the notion that a gas distribution utility delivers a gas commodity through its distribution system. In other words, these cost analysts

view the "commodity delivery function" as the reason for the existence of gas distribution utilities, and it is the reason why those facilities were originally installed. While it is obvious that all customers utilize the utility's gas distribution system to receive delivery service, that fact provides little, if any, insight into the manner in which the utility incurs costs to provide such service.

In reality, customers value the availability of the design day capacity when it is needed and are willing to pay for that capacity because of the importance of service reliability under design day conditions. Once capacity is available to serve the design day, commodity use during all other days of the year has no impact at all on a utility's system costs. Simply stated, annual usage does not cause any delivery system costs to be incurred by the utility.

Second, Mr. Watkins argues at page 10, lines 12-14 of his direct testimony that another shortcoming of the peak responsibility method is that the "design day" is a moving target over time. I disagree with his argument, and find it rather surprising that he would raise this point, considering that the Peak & Average Method relies upon the exact same "design day" for the "Peak" component of the resulting allocation factor. The reasons why the Company's design day demand is the most appropriate demand measure for use in both the Design Day and Peak & Average Methods were presented at pages 19-22 of my direct testimony.

Q. AT PAGES 8-9 OF HIS DIRECT TESTIMONY, MR. WATKINS PRESENTS ARGUMENTS TO SUPPORT HIS CLAIM THAT A CUSTOMER COMPONENT FOR DISTRIBUTION MAINS IS INAPPROPRIATE FOR USE IN THE

COMPANY'S COST OF SERVICE STUDIES. HOW DO YOU RESPOND TO HIS ARGUMENTS?

A. I disagree with his arguments for a variety of reasons. At lines 16-19, Mr. Watkins states "First and foremost, the classification of distribution plant as partially customer, partially demand-related results from the view that the assignment of these plant items to classes based solely on a demand allocator would not be equitable to some classes... When classifying individual accounts within distribution plant, analysts sometimes do not consider how a distribution system is designed and connected."

The allocation of a portion of distribution mains costs on a customer basis is done because of the way the utility's gas distribution system is designed and operated. Customer-related costs include the costs incurred to attach a customer to the utility's gas distribution system. The customer attachment is made pursuant to the Company's service obligation as defined by, for example, its residential line extension policy. That policy dictates the maximum feet of main that the Company must provide without charge to the customer. That portion of the cost of main is directly related to the customer for whom the main is installed. There is a direct relationship between the feet (or miles) of main installed by the utility and the number of customers it serves. More customers implies more feet (or more miles) of main. Thus, there is a customer component of mains in any reasonable determination of cost causation that is based on the way the distribution system is designed and operated.

In addition, the minimum size of main required and installed is the same for nearly all residential customers, therefore nearly all residential customers have the same cost of service because they use the same main, service and meter and regulator.

Mr. Watkins provided several additional reasons why a customer component of distribution mains is inappropriate;

- Purchasing economies of scale which are caused by the desire to minimize the overall cost of the distribution system result in overcapacity.
- Most components of the distribution system are oversized for reasons such as "pressure equalization, safety, reliability, and growth uncertainty."
- Historical asset records, which are the source of data for minimum size and zero-intercept studies that are prepared to determine the customer component of mains, are "far from perfect, especially in older systems such as Equitable."
- "...the utilization and operation of a particular distribution system currently may be significantly different than when the system was constructed; i.e., a large decrease in customers, loads, and throughput."

All of Mr. Watkins' further arguments presented above merely describe hypothetical issues. He has provided no evidence that any of the issues apply to Equitable. In addition, he has not proven, or even stated, the effect that these issues would have on the cost of service studies if they were relevant to Equitable, or why,

if true, they would support his claim that there is no customer component of distribution mains.

Q. PLEASE SUMMARIZE YOUR POSITION ON THE RECOGNITION OF A CUSTOMER COMPONENT OF DISTRIBUTION MAINS IN THE COMPANY'S COST OF SERVICE STUDIES.

A. I believe that recognizing a customer component of distribution mains is a reasonable and proper cost allocation method to use when conducting a gas utility's cost of service study. At the same time, I do understand that this Commission's preference is to treat the costs of distribution mains without recognizing a customer component. However, I also believe it is important that the Commission have the benefit of a cost of service study for Equitable that reflects a customer component of distribution mains so that the impact on class cost responsibility can be evaluated within the broader context of the various cost allocation methods used elsewhere in the gas distribution utility industry. To ignore the customer component of distribution mains would be to ignore a key factor affecting the cost of distribution mains - the number of customers served by the utility.

Q. PLEASE DISCUSS MR. KALCIC'S CLAIM ON PAGE 7 OF HIS DIRECT TESTIMONY REGARDING THE TREATMENT OF "COMPETITIVE SERVICE DISCOUNTS" WITHIN THE COMPANY'S COST OF SERVICE STUDIES.

A. Mr. Kalcic claims that all customers benefit from the Company retaining those customers who have the ability due to competition to leave the utility's gas

system. Therefore, he contends that all customers should share the cost of "discounts" offered to those competitively-positioned customers to remain on the system.

Q. HOW DO YOU RESPOND TO THIS CLAIM?

A. Equitable negotiates rates with customers that have competitive alternatives to its natural gas service. I do not agree, in the first instance, with Mr. Kalcic's characterization of the negotiation process as one involving "competitive service discounts." Even accepting Mr. Kalcic's characterization, I do not agree that "competitive service discounts" offered by Equitable should be allocated among all rate classes. Every customer in every rate class contributes to fixed costs and provides benefits to all other customers by remaining on the system, not just customers receiving "competitive service discounts." Similarly, all customers benefit from the utility being able to absorb uncollectible accounts expense, however, the associated expense is allocated among the rate classes based on the lost revenue from uncollectible accounts caused only by particular rate classes.

VI. Conducting the Company's Customer Cost Analysis

Q. PLEASE SUMMARIZE THE POSITIONS OF MR. HUBERT AND MR. WATKINS CONCERING THE COMPANY'S CUSTOMER COST ANALYSIS PRESENTED IN EXHIBIT IV-B-9.

A. Each of these witnesses rejected the Company's customer cost analysis and prepared alternative cost analyses which are discussed in their direct testimonies.

The customer cost analysis prepared by Mr. Hubert is presented in OTS Exhibit No. 5, Schedule 19 and the customer cost analysis prepared by Mr. Watkins is presented in Schedule GAW-5. Both witnesses contend that the Company's customer cost analysis should exclude certain indirect costs based on either their definitions of direct and indirect customer costs or their interpretations of the precedent of the Commission on the issue of deriving a cost basis for evaluating a utility's monthly customer charge. Based on their customer cost analyses, Mr. Hubert and Mr. Watkins conclude that the Company incurs either $21.97 per month or $13.14 per month, respectively, in customer-related costs for each Rate RS customer.

Q. DO YOU AGREE WITH THE CUSTOMER COST ANALYSES CONDUCTED BY THESE WITNESSES?

A. No. Each of these customer cost analyses are too narrowly focused and fail to capture the true customer-related costs that should be recovered through the Company's monthly customer charges. These alternative cost analyses should be rejected because they are based upon either the inconsistent application of definitions for direct and indirect customer costs, or they misinterpret or ignore the precedent of the Commission on the issue of deriving a cost basis for evaluating a utility's monthly customer charge.

Q. PLEASE EXPLAIN WHY THE CUSTOMER COST ANALYSIS CONDUCTED BY MR. HUBERT SHOULD BE REJECTED.

A. First, Mr. Hubert has conducted his customer cost analysis using an inconsistent application of definitions for direct and indirect costs. At page 36, lines 10-12 of his direct testimony, Mr. Hubert defines direct customer costs as related to items the Company "must have in place to serve customers each month. These costs increase each time a new customer is added, or decreases when a customer is lost." He defines indirect customer costs at lines 12-14 to "include costs that do not change if a customer joins or leaves the system, but could be considered customer related costs incurred in the provision of service." Despite these definitions, Mr. Hubert failed to include the direct customer costs associated with House Regulators, House Regulator Installations, Industrial Measuring & Regulating Station Equipment, and Installations on Customer Premises reflected in Account Nos. 383, 384, 385, and 386. These plant accounts total approximately $23 million in rate base for the RS class. He also failed to include the direct customer costs associated with the services portion of Mains and Services Expense – Account No. 874 which amounts to approximately $1.6 million for the RS class.

Regarding his inclusion of what he defines as indirect customer costs, he failed to include any Intangible or General Plant accounts and a number of indirect customer costs in the O&M Distribution Expense, Customer Service Expense, A&G Expense, and General Taxes categories. The specific accounts he failed to include in his customer cost analysis are as follows:

1. Intangible Plant – Account Nos. 301-303
2. General Plant – Account Nos. 389-399
3. Operation Supervision and Engineering – Account No. 870

4. Distribution Rents – Account No. 881

5. Other Expenses – Account No. 880

6. A&G Salaries – Account No. 920

7. Office Supplies & Expenses – Account No. 921

8. Outside Services Employed – Account No. 923

9. Rents – Account No. 931

10. Property Insurance – Account No. 924

11. General Taxes

Despite these exclusions, Mr. Hubert still chose to include in his customer cost analysis certain other indirect customer costs in the O&M Distribution Expense and A&G Expense categories including:

1. Maintenance Supervision & Engineering – Account No. 885

2. Injuries & Damages – Account No. 925

3. Employee Pensions and Benefits – Account No. 926

In my view, this varying treatment of both direct and indirect customer costs within Mr. Hubert's customer cost analysis highlights his inconsistent application of cost definitions to the Company's customer-related cost of service and his misinterpretation, or misapplication, of the Commission's precedents in this area.

Q. IN YOUR OPINION, DID MR. HUBERT RELY UPON THE COMMISSION'S DECISION IN AN AQUA PENNSYLVANIA RATE CASE (DOCKET NO.R-00038805) FOR GUIDANCE IN CONDUCTING HIS CUSTOMER COST ANALYSIS?

A. Yes. Although, as I explained above, I believe Mr. Hubert misinterpreted the Commission's direction on this subject because of the many cost exclusions he made in his customer cost analysis. In the above-cited rate proceeding, the Commission found that the OTS' proposed limitation of costs to only services and meters was "unreasonably narrow." The Commission concluded that it was appropriate to include in a utility's customer cost analysis the cost of customer equipment (computers), and also meter and service line maintenance. In addition, the Commission found "that it is reasonable and proper to include allocated portions of indirect costs, such as employee benefits, local taxes, and other general and administrative costs." In making these determinations, the Commission did caution that these are indirect costs which may be considered for inclusion in the customer cost analysis, and recovered through the monthly customer charge, but such claims are subject to scrutiny on a case-by-case basis.

In my view, this decision provides a reasoned basis to include in the Company's customer cost analysis all of the above-described direct and indirect costs excluded by Mr. Hubert in his customer cost analysis

Q. PLEASE EXPLAIN WHY IT IS REASONABLE AND PROPER TO INCLUDE IN THE COMPANY'S CUSTOMER COST ANALYSIS THE DIRECT AND INDIRECT COSTS EXCLUDED BY MR. HUBERT.

A. In my opinion, the Commission precedent stated above justifies the inclusion of these costs in the Company's customer cost analysis. Furthermore, each of these excluded cost elements were classified as customer-related costs in the

Company's cost of service studies. As I discussed in my direct testimony, the guiding principle used in the Company's cost of service studies to define customer-related costs was that "customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas."

With this definition and the Commission precedent, I believe it is reasonable and proper to include in the Company's customer cost analysis all of the costs classified as customer-related in its cost of service studies. For example, all of the excluded plant accounts stated above are direct customer costs and should be included in the Company's customer cost analysis. Mains and Services Expense also is a direct customer cost. The Company's Intangible Plant accounts include the software costs of its customer billing systems. Allocated portions of the Company's General Plant accounts support its plant accounts that are characterized as customer-related. Finally, allocated portions of the Company's various O&M, Customer Service, A&G, and General Taxes are properly characterized as customer costs based on either: (1) the specific activities reflected in these accounts (e.g., the costs of computer systems and customer operations included in Outside Services – Account No. 923); or (2) the relationship of the costs in the account to the number of customers served. That type of relationship is the same one that warranted their treatment as customer-related costs in the Company's cost of service studies.

Q. PLEASE COMMENT ON MR. HUBERT'S CLAIM AT PAGE 37 OF HIS DIRECT TESTIMONY THAT THE COMPANY SHOULD INCLUDE OTHER REVENUE IT RECEIVES FROM CUSTOMERS AS AN OFFSET TO THE CUSTOMER COSTS REFLECTED IN ITS CUSTOMER COST ANALYSIS.

A. Mr. Hubert's claim should be rejected. The costs included in the monthly customer charges should be assessed on a standalone basis and must be collected from customers each month for the Company to maintain a revenue stream that is relatively predictable and fixed, consistent with the nature of the underlying costs that support this charge. Other revenue is not a predictable revenue source and should not reduce the Company's monthly customer charges.

Q. DO YOU HAVE ANY OTHER COMMENTS RELATIVE TO MR. HUBERT'S CUSTOMER COST ANALYSIS?

A. Yes. While Mr. Gruber accepted the Company's cost of service study presented in Exhibit IV-B-1(B) for purposes of evaluating class revenues, at the same time, Mr. Hubert chose to ignore parts of that cost study for purposes of deriving his customer cost analysis. In my opinion, if you accept as appropriate the characterization, classification, and allocation of certain costs in a cost of service study as being customer-related, as Mr. Gruber has done, you cannot then turn around and characterize those same costs as not being customer-related in deriving the cost support for the utility's monthly customer charges, as Mr. Hubert has done. If this is done, you are effectively treating fixed, customer-related costs as though they were volumetric costs for rate design purposes, thereby, overstating

the level of the utility's volumetric charges. With the continuing declines in use per customer experienced in the gas distribution utility segment of the natural gas industry, it would be ill-advised to artificially raise such consumption-based charges through this type of ratemaking approach.

For all the reasons I stated above, the Commission should reject Mr. Hubert's customer cost analysis.

Q. PLEASE EXPLAIN WHY THE CUSTOMER COST ANALYSIS CONDUCTED BY MR. WATKINS SHOULD BE REJECTED.

A. His customer cost analysis should be rejected for two reasons. First, he has taken an even more narrowly focused approach to recognizing customer-related costs compared to the approach used by Mr. Hubert. This approach fails to capture many costs that are influenced by the number of customers served by the Company. Second, the customer cost analysis conducted by Mr. Watkins ignores the precedent of this Commission on the issue of deriving a cost basis for evaluating a utility's monthly customer charge. As a result, his customer cost analysis severely understates the true level of customer costs incurred by the Company. In doing so, Mr. Watkins has effectively mischaracterized numerous costs as being volumetric in nature rather than customer-related. Using this approach, he has devised a basis for their inclusion in the consumption-based components of the Company's rate structure. In my opinion, it is indefensible to treat fixed, customer costs as though they were a function of the volumetric consumption of a utility's customers.

For the reasons I mentioned above, this is exactly the wrong ratemaking treatment for costs that are fixed in nature. The Commission should reject Mr. Watkins' customer cost analysis.

VII. Treatment of the Company's Current AGS Rate Schedule Within its Cost of Service Studies

Q. DO YOU AGREE WITH MRS. MEYER BURGRAFF'S CONTENTION THAT THE COMPANY'S COST OF SERVICE STUDIES IMPROPERLY TREAT ITS COSTS OF GATHERING FACILITIES?

A. No. It is my opinion that the treatment of the costs of the Company's gathering facilities within its cost of service studies is appropriate because it is reflective of cost causative principles and is consistent with the primary purpose of conducting a cost of service study for a utility such as Equitable.

Q. PLEASE EXPLAIN WHY YOUR TREATMENT OF THE COST OF THE COMPANY'S GATHERING FACILITIES IS REFLECTIVE OF COST CAUSATIVE PRINCIPLES.

A. Very simply, the cost of service studies that I conducted assigned, or otherwise allocated, the cost of the Company's gathering facilities based upon well accepted cost causation principles that I discussed in my direct testimony. Based on an evaluation of the Company's gathering facilities and associated expenses, I concluded that such costs should be directly assigned or allocated to the AGS rate class consistent with the particular services provided under the AGS rate schedule.

For its plant in service accounts, the Company provided the specific direct assignments of plant facilities supporting gathering service based on its detailed plant accounting records. This plant information was extracted primarily from the Production and Gathering (Account Nos. 304-338) and Transmission (Account Nos. 365-370) categories. General plant facilities directly assignable to Rate AGS were provided to me by the Company from its detailed plant accounting records. Other General Plant costs that were allocated to Rate AGS came from the remaining General Plant account costs that were functionalized to the Production and Gathering and Transmission categories. Intangible Plant costs included in Account No. 303 – Miscellaneous that were allocated to Rate AGS consisted of Mobile Data and Mobile Field Services software and related equipment to support the Company's field personnel. The costs that were allocated to Rate AGS were those costs in Account No. 303 that were classified to the Production and Gathering and Transmission categories.

Certain A&G expenses were directly assigned to Rate AGS based on Company estimates of the level of effort expended to satisfy the requirements of the AGS rate class. Direct assignments were made to Rate AGS for the following accounts:

1. A&G Salaries (Account No. 920) - Expected distribution of time worked by management on AGS matters
2. Miscellaneous Maintenance Expense (Account No. 932) – Information Technology ("IT") expenses for maintenance of systems

3. Outside Services Employed (Account No. 923) – estimated legal and consulting expenses associated with AGS customers.

For all other expenses, costs were allocated to Rate AGS based on its proportionate share of the costs classified to the Production and Gathering and Transmission categories using the various cost allocation factors detailed in the Company's cost of service study exhibits and workpapers.

Q. PLEASE EXPLAIN WHY YOUR TREATMENT OF THE COST OF THE COMPANY'S GATHERING FACILITIES IS CONSISTENT WITH THE PRIMARY PURPOSE OF CONDUCTING A COST OF SERVICE STUDY FOR A UTILITY.

A. My treatment of the cost of the Company's gathering facilities in its cost of service studies recognized that it was necessary and appropriate to assign Equitable's total cost of service to each of its existing rate classes for use in evaluating class revenue levels and class rate structures. To evaluate the current revenue and associated rate levels of the Company's AGS rate class, the Company's cost of service studies directly assigned, or allocated, to this class each cost of service component that supported the provision of gas gathering service reflected in the AGS rate schedule.

Q. THROUGHOUT HER DIRECT TESTIMONY, MRS. MEYER BURGRAFF CLAIMS THAT THE BENEFICIARIES OF THE COMPANY'S GATHERING SYSTEM SHOULD BEAR THE COST RESPONSIBILITY. HOW DO YOU RESPOND TO HER "BENEFITS" PERSPECTIVE?

A. I disagree with her "benefits" perspective and her suggestion at page 10, lines 23-25 of her direct testimony that "who benefits" and "cost causation" are synonymous concepts for purposes of conducting a utility's cost of service study. Contrary to her view, well accepted cost allocation principles do not "mandate" that utility investment and expenses be allocated to the customers who benefit from them. Rather, the conduct of cost of service studies for utilities is grounded in objective, cost causation principles. These principles were the ones I adhered to throughout the cost of service studies I prepared for the Company. Even if we assume for sake of argument that her "who benefits" concept is a relevant consideration, Mrs. Meyer Burgraff ignores the fact that the gas producers and marketers she represents are the primary beneficiaries of the Company's gathering system. Very simply, the Company's gathering system enables these gas producers and marketers to move their gas supplies to market. Using her concept of "benefits" to assign gathering system costs, it is, in fact, her clients who should bear the cost responsibility for such facilities, and not the Company's end-use customers.

Q. AT PAGE 2, LINES 9-13 OF HER DIRECT TESTIMONY, MRS. MEYER BURGRAFF CONTENDS THAT THE COMPANY'S PROPOSAL FOR RATE AGS "WHICH WOULD SHIFT THE COST RESPONSIBILITY TO

PRODUCERS AND MARKETERS IS COMPLETLY AT ODDS WITH WELL ACCEPTED COST ASSIGNMENT PRINCIPLES" DO YOU AGREE WITH HER CONTENTION?

A. No. First, inherent in the fact that Rate AGS is an existing rate schedule means there already is "cost responsibility" associated with the AGS rate class. Second, the Company has chosen to increase that cost responsibility guided by the results of its cost of service studies that indicate Rate AGS is not paying its fair share of the Company's total cost of service. For Mrs. Meyer Burgraff to contend that the Company is somehow "shifting" cost responsibility to the market participants served under the AGS rate schedule is misleading and not supported by the fact that the revenue generated from current rates under this rate class is inadequate to enable Equitable to recover the costs incurred to serve this rate class.

Ultimately, Equitable is shifting cost responsibility to the AGS rate class because of cost causation - not contrary to it. Any one of the Company's cost of service studies indicate that the revenue generated by this rate class is inadequate to recover the costs incurred to serve it."

Q. IN THE PEOPLES NATURAL GAS COMPANY RATE CASE CITED BY MRS. MEYER BURGRAFF, WHY DIDN'T YOU TREAT THAT UTILITY'S GAS GATHERING FACILITIES, WITHIN ITS COST OF SERVICE STUDY, IN A SIMILAR MANNER TO HOW YOU TREATED THE GAS GATHERING FACILITIES OWNED BY EQUITABLE IN THIS RATE PROCEEDING?

A. In that rate proceeding, I recommended that the costs of the gas gathering facilities owned by Peoples Natural Gas Company ("Peoples") be allocated only to system supply and "self help" customers because gas distribution utilities did not offer unbundled utility services at that time and Peoples did not have a gathering service rate. As a point of reference, Mrs. Meyer Burgraff was the Director of Rates for Peoples in 1983 and was closely involved in the preparation and filing of that utility's rate case. As I stated in my direct testimony in this rate proceeding, a cost of service study is conducted to assign to each customer or rate class its proportionate share of the utility's total cost of service. Because utility rates in the natural gas distribution industry were not unbundled at that time, there was no rate class for the provision of gathering service and no opportunity for me to assign a proportionate share of Peoples' total cost of service in its cost of service study to a rate class that simply did not exist.

Q. BACK IN 1983, DID GAS DISTRIBUTION UTILITIES LIKE PEOPLES REGULARLY OFFER UNBUNDLED SERVICES TO ITS CUSTOMERS?

A. No. Over 25 years ago when Peoples filed the rate case cited by Mrs. Meyer Burgraff, the structure of the gas industry was fundamentally very different, in many respects, than it is today. First, unbundled services for a gas distribution utility simply did not exist. Transportation service as we know it today did not exist for the simple reason that interstate gas pipelines had not yet unbundled the cost of their system gas supplies from the costs of their underlying delivery services. Order No. 436 addressing the unbundling of pipeline services and rates would not

be issued for another two years. Also at that time, gas distribution utilities such as Peoples did not yet have the ability and responsibility to directly acquire its gas supplies from gas producers or marketers. In 1983, the U.S. spot market for natural gas was just in its infancy relative to its maturity in today's market. These utilities purchased system supply gas from interstate pipelines under fully bundled, demand-commodity pricing structures. Finally, in 1983, the wellhead price of natural gas across the U.S. averaged just $2.59 per Mcf.

Q. FROM THE POSITIONS TAKEN BY MRS. MEYER BURGRAFF, SHE APPEARS TO LEAVE THE IMPRESSION THAT GAS PRODUCERS AND MARKETERS LOCATED ELSEWHERE DO NOT PAY FOR THE COSTS OF GAS GATHERING FACILITIES THAT ARE REQUIRED TO MOVE THEIR GAS SUPPLIES TO MARKET? IS IT CORRECT FOR HER TO LEAVE THIS IMPRESSION?

A. No. This impression that she leaves is fundamentally wrong and misplaced when one recognizes the important role gas gathering facilities play in today's natural gas marketplace and how the costs of those facilities are typically recovered from customers. As the natural gas industry evolved into an unbundled service and pricing structure, there was an increased emphasis placed on charging customers only for the services they required. In addition, there was a strong desire to directly charge suppliers of natural gas (i.e., gas producers and marketers) the various unbundled services that they required (e.g., gas balancing, backup, and storage), on

behalf of their end-use customers, to move their gas supplies to market. In my view, both these considerations are an integral part of today's natural gas marketplace.

First, within the context of the interstate natural gas pipeline segment, Section 1(b) of the Natural Gas Act exempts "gathering of natural gas" from jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The FERC uses the "primary function" to determine whether a facility is devoted to jurisdictional interstate transportation or non-jurisdictional gathering of natural gas. Before Order No. 436, interstate gas pipelines did not perform transportation-only or gathering-only services. Rather, they used all their facilities, including any gathering facilities they owned, to provide bundled transportation and sale for resale service, for which they charged a single bundled rate. As part of its landmark Order No. 436 (issued in October 1985) the FERC required that the rates for open-access transportation service "separately identify cost components attributable to transportation, storage, and gathering costs." In the 1989 Rate Design Policy Statement, the FERC stated its preference for a full unbundling of gathering service from transportation, so that shippers would only pay for the services they actually used. Ultimately, most pipelines with gathering facilities did unbundle their gathering services, either in their Order No. 436 restructuring proceedings or in rate cases. With these changes, it is the gas producers and marketers that pay for the costs of these gas gathering facilities.

Second, in some states where a high level of gas production exists, the move towards unbundled services and rates prompted regulatory commissions to reconsider how gathering assets should be treated for ratemaking purposes. For

example, in 1999, the State of Oklahoma Corporation Commission ordered that Oklahoma Natural Gas Company ("ONEOK") unbundle its gathering and storage assets from its sales and transportation service rates, remove them from utility regulation, and price its gathering and storage services on a market basis. With this change, it is the gas producers and marketers that pay for the costs of these gas gathering facilities.

Finally, numerous gas utilities structure their transportation service rates so that they can charge gas producers and marketers directly for the deliverability-related services they require to transport their gas supplies to market. These services typically include gas balancing and banking, backup gas supplies, gas pooling, and certain storage-related services. In fact, the Company's General and Firm Pooling Service tariffs (Rates GPS and FPS) apply directly to such market participants.

Q. DO YOU AGREE WITH MRS. MEYER BURGRAFF'S RECOMMENDATION MADE AT PAGES 28-29 OF HER DIRECT TESTIMONY THAT THE COMMISSION RELY UPON THE COST OF SERVICE STUDIES YOU PREPARED IN RESPONSE TO IOGA DATA REQUEST VI-5?

A. No. With the existence of Rate AGS, those cost of service studies performed according to the directions of the IOGA do not represent the appropriate apportionment of the Company's total cost of service to its currently effective classes of service. As such, they should not be used to evaluate the costs incurred to

provide service under the Company's rate schedules, and to derive the necessary changes in class revenue and rate levels to properly reflect such costs.

Q. DOES THIS COMPLETE YOUR PREPARED TESTIMONY?

A. Yes

Equitable Gas Company
Equitable Exhibit No. 6-R

Schedule	Title
Schedule 1	Summary of Results for Cost of Service Studies
Schedule 2	Cost of Service Study, Present Rates, Design Day Method
Schedule 3	Cost of Service Study, Present Rates, Peak and Average Method
Schedule 4	Cost of Service Study, Proposed Rates, Design Day Method
Schedule 5	Cost of Service Study, Proposed Rates, Peak and Average Method
Schedule 6	Cost Analysis Supporting Minimum Charges

EQUITABLE GAS COMPANY
DOCKET NO. R-2008-2029325
COST OF SERVICE STUDY- SUMMARY OF RESULTS

EQUITABLE EXHIBIT 6-R
SCHEDULE 1
SHEET 1 OF 1

Peak Demand w/Customer Component

Rate Class	Present Rates Rate of Return	Present Rates Relative Rate of Return	Proposed Rates Rate of Return	Proposed Rates Relative Rate of Return	Proposed Revenue	Present Revenue	Revenue Change
Residential Service (RS)	2.42%	0.64	7.70%	0.87	$ 148,351	$ 108,301	$ 40,050
General Service - Small (GSS)	12.51%	3.29	16.55%	1.86	$ 16,022	$ 14,590	$ 1,432
General Service - Large (GSL)	8.81%	2.32	11.19%	1.26	$ 32,425	$ 29,475	$ 2,950
Appalachian Gathering Service (AGS)	-2.15%	-0.56	8.89%	1.00	$ 12,844	$ 5,326	$ 7,518
Total	3.80%	1.00	8.89%	1.00	$ 209,642	$ 157,692	$ 51,950

Peak & Average w/o Customer Component

Residential Service (RS)	3.19%	0.84	9.25%	1.04	$ 148,351	$ 108,301	$ 40,050
General Service - Small (GSS)	11.83%	3.11	15.60%	1.75	$ 16,022	$ 14,590	$ 1,432
General Service - Large (GSL)	5.09%	1.34	6.10%	0.69	$ 32,425	$ 29,475	$ 2,950
Appalachian Gathering Service (AGS)	-2.15%	-0.56	8.89%	1.00	$ 12,844	$ 5,326	$ 7,518
Total	3.80%	1.00	8.89%	1.00	$ 209,642	$ 157,692	$ 51,950

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Revenues at Current Rates					
1	Operating Revenue	157,631	108,258	14,584	29,463	5,326
2	Other revenue / Adjustments	61	43	6	12	0
3	Net revenues	157,693	108,301	14,590	29,475	5,326
4	Operating Expenses					
5	Operations, Customer, A&G	105,498	81,410	6,239	11,620	6,230
6	Depreciation expense	23,471	17,076	1,160	3,720	1,515
7	Taxes other than income	2,186	1,542	177	449	18
8	Operating expenses	131,155	100,027	7,576	15,789	7,763
9	Income tax expense	4,348	(1,677)	2,736	4,903	(1,615)
10	Total Operating Expenses	135,503	98,350	10,312	20,692	6,149
11	**Income at Present Rates**	22,190	9,951	4,278	8,783	(822)
12	**Rate Base**	583,253	411,080	34,202	99,658	38,312
13	**Return on Rate Base at Present Rates**	3.80%	2.42%	12.51%	8.81%	(2.15%)
14	Revenue Requirement at Full Cost of Service	209,642	155,670	12,114	29,011	12,846
15	Operating expenses	131,155	100,027	7,576	15,789	7,763
16	Income tax expense	25,531	17,995	1,497	4,362	1,677
17	Additional expenses	1,103	1,103	0	0	0
18		157,790	119,125	9,073	20,151	9,440
19	**Income at Full Cost of Service**	51,852	36,545	3,041	8,860	3,406
20	**Return on Rate Base at Full Cost of Service**	8.89%	8.89%	8.89%	8.89%	8.89%
21	**Revenue INCREASE (DECREASE) to Achieve Full Cost of Service**	**51,949**	**47,369**	**(2,476)**	**(464)**	**7,520**

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
			REV. REQ. BY FUNCTIONAL CLASSIFICATION- TOTAL			
	PRODUCTION & GATHERING					
1	Commodity Component	10,017	789	128	438	8,662
2		10,017	789	128	438	8,662
	STORAGE					
3	Demand Component	10,033	8,556	985	491	0
4		10,033	8,556	985	491	0
	TRANSMISSION					
5	Demand Component	3,859	253	31	126	3,449
6		3,859	253	31	126	3,449
	DISTRIBUTION					
7	Demand Component	68,658	41,052	5,068	22,240	299
8	Customer Component	51,109	46,423	2,636	1,906	144
9		119,767	87,474	7,704	24,146	443
	ONSITE					
10	Customer Component	65,966	58,598	3,265	3,810	292
11		65,966	58,598	3,265	3,810	292
	TOTAL REVENUE REQUIREMENT					
12	Demand Component	82,550	49,860	6,084	22,857	3,748
13	Commodity Component	10,017	789	128	438	8,662
14	Customer Component	117,074	105,021	5,902	5,716	436
15	Total	209,641	155,670	12,114	29,011	12,846
16	Increase (Decrease) for Full COS	51,949	47,369	(2,476)	(464)	7,520

		Total		Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
				REV. REQ. BY FUNCTIONAL CLASSIFICATION- UNITIZED			
	PRODUCTION & GATHERING						
17	Commodity Component		$ / mcf	$0.04	$0.03	$0.02	$0.60
	STORAGE						
18	Demand Component		$ / mcf-month	$1.81	$1.69	$0.21	$0.00
	TRANSMISSION						
19	Demand Component		$ / mcf-month	$0.05	$0.05	$0.05	$0.24
	DISTRIBUTION						
20	Demand Component		$ / mcf-month	$8.70	$8.67	$9.49	$0.02
21	Customer Component		$ / cust-month	$16.17	$13.81	$86.18	$0.01
	ONSITE						
22	Customer Component		$ / cust-month	$20.41	$17.11	$172.26	$0.02
	TOTAL REVENUE REQUIREMENT						
23	Demand Component		$ / mcf-month	$10.57	$10.41	$9.75	$0.26
24	Commodity Component		$ / mcf	$0.04	$0.03	$0.02	$0.60
25	Customer Component		$ / cust-month	$36.58	$30.92	$258.44	$0.03
26	Demand Allocator X 1000	637	Peak	393	49	195	0
27	Commodity Allocator X 1000	61,075	Gas_Deliver_w/AGS	22,187	3,805	20,639	14,444
28	Customer Allocator X 1000	3,084	Bills_All	2,871	191	22	-

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE						
	I. GAS PLANT IN SERVICE						
	A. INTANGIBLE PLANT						
1	Organization	301	50	35	3	9	3
2	Intangible Plant - Software- Labor	303Lab	3,342	2,287	286	495	274
3	Intangible Plant - Software- Customer	303Cust	2,743	2,553	170	20	0
4	Intangible Plant - Software- Plant	303Plt	2,485	1,851	130	504	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	14,549	967	112	0
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248	21,275	1,556	1,140	277
	B. PRODUCTION & GATHERING PLANT						
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	0	0	0	28,445
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	28,445	0	0	0	28,445
	C. STORAGE PLANT						
9	Storage Plant	360-368	0	0	0	0	0
10	*Subtotal - STORAGE PLANT*	360-368	0	0	0	0	0
	D. TRANSMISSION PLANT						
11	Transmission plant	365-370	106	66	8	33	0
12	Transmission - Mains	367	1,243	767	95	381	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	0	0	0	14,171
14	Transmission - Mains - Direct Assign.	367 DA	16,830	0	0	0	16,830
15	Subtotal - TRANSMISSION PLANT	365-370	32,350	832	103	413	31,001
	E. DISTRIBUTION PLANT						
16	Land and Land Rights	374	1,893	1,429	102	362	0
17	Land and Land Rights - Direct Assign.	374 DA	564	0	0	564	0
18	Structures and Improvements	375	2,111	1,593	113	404	0
19	Mains	376	457,729	306,578	33,870	117,281	0
20	Mains - Direct Assign.	376 DA	10,267	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	9,950	1,233	4,943	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	276	34	137	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	0	0	0	0
25	Services	380	226,432	213,758	2,209	10,465	0
26	Meters	381	17,775	12,344	1,821	3,610	0
27	Meter Installations	382	9,208	6,395	943	1,870	0
28	House Regulators	383	5,656	3,852	865	939	0
29	House Regulator Installations	384	1,514	1,031	231	251	0
30	Ind. Meas. & Reg. Station Equip.	385	441	0	0	441	0
31	Property on Customers' Premises	386	15,838	14,394	356	1,087	0
32	Other Equipment	387	324	0	324	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793	571,601	42,101	154,092	0

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT						
34	Land and Land Rights	389	78	56	4	15	3
35	Structures and Improvements	390	7,842	5,599	422	1,552	269
36	Structures and Improvements - Direct Assign.	390 DA	67	0	0	0	67
37	Office Furniture and Equipment	391	12,224	8,727	658	2,420	420
38	Office Furniture and Equipment - Direct Assign.	391 DA	2	0	0	0	2
39	Transportation Equipment	392	10,288	7,345	553	2,036	353
40	Stores Equipment	393	47	34	3	9	2
41	Tools & Garage Equipment	394	4,271	3,049	230	845	147
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	0	0	0	26
43	Laboratory Equipment	395	0	0	0	0	0
44	Power Operated Equipment	396	3,155	2,253	170	625	108
45	Communication Equipment	397	6,923	4,942	372	1,370	238
46	Communication Equipment - Direct Assign.	397 DA	6	0	0	0	6
47	Miscellaneous Equipment	398	32	23	2	6	1
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	0	0	156	0
49	Subtotal - GENERAL PLANT	389-399	45,118	32,028	2,413	9,035	1,641
50	**TOTAL UTILITY PLANT**		897,955	625,735	46,174	164,681	61,365
	II. DEPRECIATION RESERVE						
51	Intangible Plant	108	8,236	7,225	529	387	95
52	*Production & Gathering Plant*	*108.2*	*0*	*0*	0	*0*	*0*
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	0	0	0	8,153
54	Local Storage Plant	108.3	0	0	0	0	0
55	Transmission Plant	108.4	658	406	50	202	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	0	0	0	11,969
57	Mains	109	130,432	85,603	9,434	35,395	0
58	Services	109	83,524	78,849	815	3,860	0
59	Meters	109	12,975	9,011	1,329	2,635	0
60	Distr Other	109	13,987	9,809	983	3,196	0
61	General Plant	109	19,396	13,848	1,043	3,839	666
62	General Plant - Direct Assign.	108.8 DA	21	0	0	0	21
63	**TOTAL DEPRECIATION RESERVE**	108	289,353	204,751	14,182	49,515	20,904
	III. OTHER RATE BASE ITEMS						
64	Materials and Supplies		887	634	48	176	30
65	Current Gas Storage		75,176	64,111	7,384	3,681	0
66	Prepayments		234	173	17	34	10
67	Deferred Income Taxes - Depreciation		(102,286)	(75,891)	(5,653)	(20,743)	0
68	Deferred Income Taxes - Direct Assign.		(2,423)	0	0	0	(2,423)
69	Deferred ITC		(4,903)	(3,638)	(271)	(994)	0
70	Customer Deposits		(3,370)	(2,775)	(209)	(385)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(36,684)	(17,387)	1,317	(18,232)	(2,382)
72	**TOTAL RATE BASE (Excl. Working Capital)**		571,917	403,597	33,308	96,933	38,079
73	Working Capital	131	11,335	7,483	895	2,725	233
74	**TOTAL RATE BASE**		583,253	411,080	34,202	99,658	38,312

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES						
	I. OPERATION & MAINTENANCE EXPENSE						
	A. PRODUCTION & GATHERING EXPENSES						
75	Operations Expense	750-756	1,043	0	0	0	1,043
76	Maintenance Expense	761-765	1,766	0	0	0	1,766
77	Subtotal - Production and Gathering	750-765	2,809	0	0	0	2,809
	B. OTHER GAS SUPPLY EXPENSES						
78	Natural gas field line purchases	801	0	0	0	0	0
79	Natural gas transmission line purchases	803	0	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	0	0	0	0
81	Other Natural Gas Purchases	805	0	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	0	0	0	0
84	Gas Withdrawn from Storage	808	0	0	0	0	0
85	Gas Delivered to Storage	808	0	0	0	0	0
86	Other Gas Supply Expense	813	391	279	44	68	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391	279	44	68	0
	C. NATURAL GAS STORAGE						
88	LNG Operating Exp Admin	840	0	0	0	0	0
89	Operating Exp- Admin	850	0	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0	0	0	0	0
	D. TRANSMISSION EXPENSES						
91	Transmission expenses	856-863					
92	Subtotal- Transmission Expenses	856-863	0	0	0	0	0
	E. DISTRIBUTION EXPENSES						
93	Operation Supv & Engineering	870	1,773	1,313	100	360	0
94	Load Dispatching	871	112	53	9	50	0
95	Compressor Station Fuel and Power	873	0	0	0	0	0
96	Mains and Services Expenses	874	5,088	3,721	258	988	120
97	Meas. & Reg. Station Expense General	875	100	62	8	31	0
98	Meas. & Reg. Station Expense Industrial	876	0	0	0	0	0
99	Meter & House Regulator Expenses	878	6,062	4,193	685	1,184	0
100	Customer Installation Expense	879	62	62	0	0	0
101	Other Expenses - Safety and Environmental	880	632	395	43	123	71
102	Other Expenses	880	650	454	52	144	0
103	Distribution Rents	881	602	446	34	122	0
104	Maint. Supervision & Engineering	885	885	578	94	212	0
105	Maintenance of Structures & Improvements	886	516	384	27	105	0
106	Maint. of Mains	887	5,521	3,624	399	1,498	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	735	91	365	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	10	6	1	3	0
109	Maint. of Services	892	663	626	8	31	0
110	Maint. of Meters & House Regulators	893	107	74	12	21	0
111	Maintenance of Other Equipment	894	67	50	4	14	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042	16,776	1,824	5,250	191
113	***TOTAL OPERATION & MAINTENANCE EXPENSES***		27,242	17,055	1,868	5,318	3,000

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES						
114	Customer Service - Administrative	901	225	210	14	2	0
115	Meter Reading Expenses	902	587	546	36	4	0
116	Customer Records & Collection Expense	903	10,270	9,561	636	74	0
117	Uncollectible Accounts	904	8,883	8,339	191	353	0
118	Uncollectible Accounts- CAP	904CAP	16,167	16,167	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	0	0	0	0
120	TOTAL CUSTOMER ACCOUNTS EXPENSES		36,132	34,823 193.9%	877 3/1	432 684	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES						
121	Operation Supervision	907	0	0	0	0	0
122	Customer Assist- Other	908	210	196	13	2	0
123	Customer Assist- CAP	908CAP	299	299	0	0	0
124	Other Customer Service & Informational Expense	910	698	698	0	0	0
125	Supervision	911	0	0	0	0	0
126	Demonstration	912	660	0	591	68	0
127	Adverstising expense	913	24	0	22	3	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891	1,193	626	73	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		38,024	36,015	1,503	505	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES						
	A. Labor-Related:						
130	Administrative & General Salaries	920	5,940	4,084	512	895	449
131	Administrative & General Salaries - Direct Assign.	920 DA	550	0	0	0	550
132	Office Supplies & Expenses	921	817	562	70	123	62
133	Outside Services Employed - Resid.	923	180	180	0	0	0
134	Outside Services Employed - Labor	923l	3,637	2,501	313	548	275
135	Injuries & Damages	925Labor	338	233	29	51	26
136	Employee Pensions and Benefits	926	5,725	3,936	493	863	433
137	Rents	931	4,025	2,768	347	607	304
138	Subtotal - O&M Accounts 920-923, 925L, 926		21,213	14,263	1,765	3,087	2,098
	B. Plant-Related:						
139	Property Insurance	924	335	240	18	66	12
140	*Outside Services Employed-plant*	*923p*	*135*	*97*	*7*	*27*	*5*
141	Injuries & Damages	925Plant	4,130	2,949	222	817	142
142	Misc. Maintenance Expense	932	1,228	872	66	246	45
143	Misc. Maintenance Expense - Direct Assign.	932 DA	50	0	0	0	50
144	Subtotal - O&M Accounts 924-925P		5,879	4,156	313	1,157	253
	C. Other-Related:						
145	Administrative Expenses Transferred	922	(37)	(24)	(2)	(7)	(3)
146	Outside Services Employed-cust	923c	5,083	4,732	315	36	0
147	Outside Services Employed-plant-O&M	923p-om	7,021	4,593	418	1,342	668
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	200	0	0	0	200
149	Regulatory Commission Expenses	928	517	370	36	111	0
150	General Advertising Expense	930.1	201	144	14	43	0
151	Miscellaneous General Expenses	930.2	156	105	9	28	15
152	Subtotal - O&M Accounts 928-935		13,142	9,920	789	1,554	879
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		40,234	28,340	2,867	5,797	3,230
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)**		105,499	81,410	6,239	11,620	6,230

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE						
155	Intangible Plant	180Int	2,439	2,140	157	115	28
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	0	0	0	631
157	Local Storage Plant	180Stor	0	0	0	0	0
158	Transmission Plant	180Trans	9	5	1	3	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	0	0	0	704
160	Mains (Distribution)	180Mains	6,999	4,594	506	1,899	0
161	Services	180Services	5,815	5,489	57	269	0
162	Meters	180Meters	796	553	82	162	0
163	Distr Other	180Dist	2,003	1,404	141	458	0
164	General Plant	180Gen	4,071	2,890	218	815	148
165	General Plant - Direct Assign.	180Gen DA	4	0	0	0	4
166	Adjustments		0	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	23,471	17,076	1,160	3,720	1,515
	VI. TAXES						
	A. General Taxes						
168	PA PUC Assessment		1,139	805	111	224	0
169	Local property taxes		63	47	4	13	0
170	Public utilty reality tax		519	385	30	104	0
171	State capital stock tax		447	297	32	100	18
172	Miscellaneous tax		17	8	1	8	0
173	Subtotal- Taxes Other Than Income Taxes	408	2,186	1,542	177	449	18
	B. Income Tax Expense						
174	State Income Tax expense		(1,009)	389	(635)	(1,138)	375
175	Federal Income Tax expense		5,363	(2,069)	3,375	6,048	(1,991)
176	Investment Tax Credit - Amortization		(6)	2	(3)	(6)	2
177	Subtotal- Income tax expense		4,348	(1,677)	2,736	4,903	(1,615)
178	**TOTAL TAX EXPENSE**		6,534	(135)	2,914	5,352	(1,598)
179	**TOTAL EXPENSES**		135,504	98,350	10,312	20,692	6,149
	3. REVENUES at Present Rates						
180	Sales and Transport Revenue	480-483	154,865	105,632	14,510	29,396	5,326
181	Forfeited Discounts		1,558	1,462	34	62	0
182	Miscellaneous Service Revenue		1,209	1,163	40	5	0
183	Other Operating Revenue		61	43	6	12	0
184	Subtotal- Gas Revenues, net		157,693	108,301	14,590	29,475	5,326
185	**TOTAL REVENUE**		157,693	108,301	14,590	29,475	5,326
186	**TOTAL EXPENSES**		135,504	98,350	10,312	20,692	6,149
187	**NET INCOME at Present Rates**		22,189	9,951	4,278	8,783	(822)
				0	0	0	0

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport						
209	Accounts Receivable- Gas		0	0	0	0	0
210	Accounts Receivable- Other		0	0	0	0	0
211	Accrued Gas Revenues		0	0	0	0	0
212	Accounts Receivable, Total		0	0	0	0	0
213	Gas, LNG in Storage		0	0	0	0	0
214	*Inventories & Other, Total*		*0*	*0*	*0*	*0*	*0*
215	Accounts Payable, Natural Gas		3,330	1,585	272	1,474	0
216	*Accounts Payable, Other- Labor*		2,867	1,975	248	434	210
217	Accounts Payable, Other- O&MxGas		5,395	4,107	389	868	32
218	Accounts Payable, Total		11,592	7,667	908	2,776	242
219	Accrued interest		(1,083)	(773)	(58)	(214)	(37)
220	Other, net		826	590	44	163	28
221	Defd Items & Other, Total		(257)	(184)	(14)	(51)	(9)
222	Total Working Capital		11,335	7,483	895	2,725	233

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	1. RATE BASE								
	I. GAS PLANT IN SERVICE								
	A. INTANGIBLE PLANT								
1	Organization	301	50	RATEBASE	2	6	2	36	4
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	266	0	8	1,514	1,554
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	0	0	0	0	2,743
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	0	0	0	2,485	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	ONSITE	0	0	0	0	15,628
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248		268	6	10	4,035	19,928
	B. PRODUCTION & GATHERING PLANT								
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	28,445	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	28,445		28,445	0	0	0	0
	C. STORAGE PLANT								
9	Storage Plant	360-368	0	None	0	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0	0
	D. TRANSMISSION PLANT								
11	Transmission plant	365-370	106	TRANS	0	0	106	0	0
12	Transmission - Mains	367	1,243	TRANS	0	0	1,243	0	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	0	0	14,171	0	0
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	0	0	16,830	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	32,350		0	0	32,350	0	0
	E. DISTRIBUTION PLANT								
16	Land and Land Rights	374	1,893	DIST	0	0	0	1,893	0
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	0	0	0	564	0
18	Structures and Improvements	375	2,111	DIST	0	0	0	2,111	0
19	Mains	376	457,729	DIST	0	0	0	457,729	0
20	Mains - Direct Assign.	376 DA	10,267	DIST	0	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	0	0	0	16,126	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	0	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	0	0	0	447	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	DIST	0	0	0	0	0
25	Services	380	226,432	DIST	0	0	0	226,432	0
26	Meters	381	17,775	ONSITE	0	0	0	0	17,775
27	Meter Installations	382	9,208	ONSITE	0	0	0	0	9,208
28	House Regulators	383	5,656	ONSITE	0	0	0	0	5,656
29	House Regulator Installations	384	1,514	ONSITE	0	0	0	0	1,514
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	0	0	0	0	441
31	Property on Customers' Premises	386	15,838	ONSITE	0	0	0	0	15,838
32	Other Equipment	387	324	DIST	0	0	0	324	0
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793		0	0	0	717,361	50,432

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	F. GENERAL PLANT								
34	Land and Land Rights	389	78	PLANT	3	0	3	68	5
35	*Structures and Improvements*	390	7,842	PLANT	269	0	306	6,789	477
36	Structures and Improvements - Direct Assign.	390 DA	67	PLANT_AGS	42	0	25	0	0
37	Office Furniture and Equipment	391	12,224	PLANT	420	0	477	10,583	744
38	Office Furniture and Equipment - Direct Assign.	391 DA	2	PLANT_AGS	1	0	1	0	0
39	Transportation Equipment	392	10,288	PLANT	353	0	402	8,907	626
40	Stores Equipment	393	47	PLANT	2	0	2	41	3
41	Tools & Garage Equipment	394	4,271	PLANT	147	0	167	3,698	260
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	16	0	10	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0	0
44	Power Operated Equipment	396	3,155	PLANT	108	0	123	2,732	192
45	Communication Equipment	397	6,923	PLANT	238	0	270	5,993	421
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	4	0	2	0	0
47	Miscellaneous Equipment	398	32	PLANT	1	0	1	28	2
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	0	0	3	143	10
49	Subtotal - GENERAL PLANT	389-399	45,118		1,604	0	1,792	38,981	2,740
50	**TOTAL UTILITY PLANT**		897,955		30,317	6	34,152	760,378	73,101
	II. DEPRECIATION RESERVE								
51	Intangible Plant	108	8,236	INTANG_PT	91	2	3	1,371	6,768
52	Production & Gathering Plant	108.2	0	PRODGATH	0	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	PRODGATH	8,153	0	0	0	0
54	*Local Storage Plant*	108.3	0	None	0	0	0	0	0
55	Transmission Plant	108.4	658	TRANS	0	0	658	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	0	0	11,969	0	0
57	Mains	109	130,432	DIST	0	0	0	130,432	0
58	Services	109	83,524	DIST	0	0	0	83,524	0
59	Meters	109	12,975	ONSITE	0	0	0	0	12,975
60	Distr Other	109	13,987	DIST_xMSM	0	0	0	6,916	7,072
61	General Plant	109	19,396	PLANT	666	0	757	16,793	1,181
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	13	0	8	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	289,353		8,924	2	13,396	239,035	27,996
	III. OTHER RATE BASE ITEMS								
64	Materials and Supplies		887	PLANT	30	0	35	768	54
65	*Current Gas Storage*		75,176	STOR	0	75,176	0	0	0
66	Prepayments		234	O&MxGas	13	0	1	97	122
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	0	0	(2,027)	(93,674)	(6,586)
68	Deferred Income Taxes - Direct Assign.		(2,423)	PLANT_AGS	(1,522)	0	(901)	0	0
69	Deferred ITC		(4,903)	PLANTxAGS	0	0	(97)	(4,490)	(316)
70	Customer Deposits		(3,370)	DIST	0	0	0	(3,370)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(36,684)		(1,478)	75,176	(2,988)	(100,669)	(6,725)
72	**TOTAL RATE BASE (Excl. Working Capital)**		571,917		19,915	75,180	17,768	420,674	38,380
73	Working Capital	131	11,335		3,858	0	28	3,315	4,135
74	**TOTAL RATE BASE**		583,253		23,773	75,180	17,795	423,989	42,515

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	2. EXPENSES								
	I. OPERATION & MAINTENANCE EXPENSE								
	A. PRODUCTION & GATHERING EXPENSES								
75	Operations Expense	750-756	1,043	PRODGATH	1,043	0	0	0	0
76	Maintenance Expense	761-765	1,766	PRODGATH	1,766	0	0	0	0
77	Subtotal - Production and Gathering	750-765	2,809		2,809	0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES								
78	Natural gas field line purchases	801	0	None	0	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0	0
86	Other Gas Supply Expense	813	391	PRODGATH	391	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391		391	0	0	0	0
	C. NATURAL GAS STORAGE								
88	LNG Operating Exp Admin	840	0	None	0	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0	0
	D. TRANSMISSION EXPENSES								
91	Transmission expenses	856-863	0	None	0	0	0	0	0
92	Subtotal- Transmission Expenses	856-863	0		0	0	0	0	0
	E. DISTRIBUTION EXPENSES								
93	Operation Supv & Engineering	870	1,773	DIST_PT	0	0	0	1,656	116
94	Load Dispatching	871	112	PRODGATH	112	0	0	0	0
95	Compressor Station Fuel and Power	873	(0)	DIST	0	0	0	(0)	0
96	Mains and Services Expenses	874	5,088	MAIN_SERV_TRANMAIN	0	0	129	4,959	0
97	Meas. & Reg. Station Expense General	875	100	DIST	0	0	0	100	0
98	Meas. & Reg. Station Expense Industrial	876	0	ONSITE	0	0	0	0	0
99	Meter & House Regulator Expenses	878	6,062	ONSITE	0	0	0	0	6,062
100	Customer Installation Expense	879	62	ONSITE	0	0	0	0	62
101	Other Expenses - Safety and Environmental	880	632	O&MxAcct880	81	0	3	377	172
102	Other Expenses	880	650	O&MxAcct880	83	0	3	387	177
103	Distribution Rents	881	602	DIST_PT	0	0	0	562	40
104	Maint. Supervision & Engineering	885	885	DIST	0	0	0	885	0
105	Maintenance of Structures & Improvements	886	516	DIST	0	0	0	516	0
106	Maint. of Mains	887	5,521	DIST	0	0	0	5,521	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	DIST	0	0	0	1,192	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	10	DIST	0	0	0	10	0
109	Maint. of Services	892	663	ONSITE	0	0	0	0	663
110	Maint. of Meters & House Regulators	893	107	ONSITE	0	0	0	0	107
111	Maintenance of Other Equipment	894	67	DIST	0	0	0	67	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042		276	0	135	16,232	7,399
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		27,242		3,475	0	135	16,232	7,399

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	II. CUSTOMER ACCOUNTS EXPENSES								
114	Customer Service - Administrative	901	225	ONSITE	0	0	0	0	225
115	Meter Reading Expenses	902	587	ONSITE	0	0	0	0	587
116	Customer Records & Collection Expense	903	10,270	ONSITE	0	0	0	0	10,270
117	Uncollectible Accounts	904	8,883	ONSITE	0	0	0	0	8,883
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	0	0	0	0	16,167
119	Miscellaneous Customer Accounts Expenses	905	0	ONSITE	0	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		36,132		0	0	0	0	36,132
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES								
121	Operation Supervision	907	0	None	0	0	0	0	0
122	Customer Assist- Other	908	210	DIST	0	0	0	210	0
123	Customer Assist- CAP	908CAP	299	DIST	0	0	0	299	0
124	Other Customer Service & Informational Expense	910	698	DIST	0	0	0	698	0
125	Supervision	911	0	DIST	0	0	0	0	0
126	Demonstration	912	660	DIST	0	0	0	660	0
127	*Adverstising expense*	913	24	*DIST*	0	0	0	24	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891		0	0	0	1,891	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		38,024		0	0	0	1,891	36,132
	IV. ADMINISTRATIVE & GENERAL EXPENSES								
	A. Labor-Related:								
130	Administrative & General Salaries	920	5,940	LABOR	473	0	15	2,690	2,762
131	Administrative & General Salaries - Direct Assign.	920 DA	550	LABOR	44	0	1	249	256
132	Office Supplies & Expenses	921	817	LABOR	65	0	2	370	380
133	Outside Services Employed - Resid.	923	180	LABOR	14	0	0	81	84
134	Outside Services Employed - Labor	923l	3,637	LABOR	290	0	9	1,647	1,691
135	Injuries & Damages	925Labor	338	LABOR	27	0	1	153	157
136	Employee Pensions and Benefits	926	5,725	LABOR	456	0	14	2,593	2,662
137	Rents	931	4,025	LABOR	321	0	10	1,823	1,872
138	Subtotal - O&M Accounts 920-923, 925L, 926		21,213		1,691	0	53	9,606	9,864
	B. Plant-Related:								
139	Property Insurance	924	335	PLANT	12	0	13	290	20
140	Outside Services Employed-plant	923p	135	PLANT	5	0	5	117	8
141	Injuries & Damages	925Plant	4,130	PLANT	142	0	161	3,576	251
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	44	0	49	1,061	75
143	Misc. Maintenance Expense - Direct Assign.	932 DA	50	GENERAL PT	2	0	2	43	3
144	Subtotal - O&M Accounts 924-925P		5,879		203	0	230	5,087	358
	C. Other-Related:								
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	(3)	0	(1)	(27)	(6)
146	Outside Services Employed-cust	923c	5,083	DIST	0	0	0	5,083	0
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	568	0	155	5,131	1,167
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	200	PLANT_O&M	16	0	4	146	33
149	Regulatory Commission Expenses	928	517	PLANT_O&M	42	0	11	378	86
150	General Advertising Expense	930.1	201	PLANT_O&M	16	0	4	147	33
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	13	0	3	114	26
152	Subtotal - O&M Accounts 928-935		13,142		652	0	177	10,972	1,340
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		40,234		2,546	0	461	25,666	11,561
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)**		105,499		6,022	0	596	43,789	55,092

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	V. DEPRECIATION EXPENSE								
155	Intangible Plant	180Int	2,439	INTANG_PT	27	1	1	406	2,005
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	PRODGATH_PT	631	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0	0
158	Transmission Plant	180Trans	9	TRANS	0	0	9	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	0	0	704	0	0
160	Mains (Distribution)	180Mains	6,999	DIST	0	0	0	6,999	0
161	Services	180Services	5,815	DIST	0	0	0	5,815	0
162	Meters	180Meters	796	ONSITE	0	0	0	0	796
163	Distr Other	180Dist	2,003	DIST_xMSM	0	0	0	990	1,012
164	General Plant	180Gen	4,071	GENERAL PT	145	0	162	3,518	247
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	3	0	2	0	0
166	Adjustments		0	None	0	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	23,471		806	1	876	17,728	4,060
	VI. TAXES								
	A. General Taxes								
168	PA PUC Assessment		1,139	DIST	0	0	0	1,139	0
169	Local property taxes		63	PLANTxAGS	0	0	1	58	4
170	Public utilty reality tax		519	PLANTxAGS	0	0	10	475	33
171	State capital stock tax		447	RATEBASE	18	58	14	325	33
172	Miscellaneous tax		17	PRODGATH	17	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	2,186		35	58	25	1,998	70
	B. Income Tax Expense								
174	State Income Tax expense		(1,009)	Pre-Tax	16	(545)	(88)	(1,338)	946
175	Federal Income Tax expense		5,363	Pre-Tax	(87)	2,896	468	7,111	(5,026)
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	0	(3)	(0)	(7)	5
177	Subtotal- Income tax expense		4,348		(70)	2,348	380	5,765	(4,075)
178	**TOTAL TAX EXPENSE**		6,534		(35)	2,406	405	7,763	(4,005)
179	**TOTAL EXPENSES**		135,504		6,792	2,406	1,878	69,280	55,148
	3. REVENUES at Present Rates								
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	7,399	7,411	2,851	88,474	48,730
181	Forfeited Discounts		1,558	ONSITE	0	0	0	0	1,558
182	Miscellaneous Service Revenue		1,209	ONSITE	0	0	0	0	1,209
183	Other Operating Revenue		61	DIST	0	0	0	61	0
184	Subtotal- Gas Revenues, net		157,693		7,399	7,411	2,851	88,535	51,497
185	**TOTAL REVENUE**		157,693		7,399	7,411	2,851	88,535	51,497
186	**TOTAL EXPENSES**		135,504		6,792	2,406	1,878	69,280	55,148
187	**NET INCOME at Present Rates**		22,189		607	5,005	973	19,255	(3,651)

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	SUMMARY								
188	Total revenues		157,693		7,399	7,411	2,851	88,535	51,497
189	Total Operating Expenses		105,499		6,022	0	596	43,789	55,092
190	Depreciation Expense		23,471		806	1	876	17,728	4,060
191	Taxes other than Income		2,186		35	58	25	1,998	70
192	Total Other Expenses		25,657		841	58	902	19,725	4,131
193	Income tax expense		4,348		(70)	2,348	380	5,765	(4,075)
194	Total expenses		135,504		6,792	2,406	1,878	69,280	55,148
195	NET INCOME at Present Rates		22,189		607	5,005	973	19,255	(3,651)
196	**Total Rate Base**		**583,253**		**23,773**	**75,180**	**17,795**	**423,989**	**42,515**
197									
	REVENUE REQUIREMENTS								
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%	8.89%
199	Using Target for System								
200	Rate Base		583,253		23,773	75,180	17,795	423,989	42,515
201	Operating expenses		105,499		6,022	0	596	43,789	55,092
202	Depreciation expense		23,471		806	1	876	17,728	4,060
203	Taxes other than Income		2,186		35	58	25	1,998	70
204	Operating expenses to recover		131,156		6,862	58	1,498	63,515	59,222
205	Target Return on Rate Base- After taxes		51,851		2,113	6,684	1,582	37,693	3,780
206	Income taxes to recover		25,531		1,041	3,291	779	18,560	1,861
207	Additional expenses		1,103	ONSITE	0	0	0	0	1,103
208	**TOTAL REVENUE REQUIREMENT**		209,642		10,017	10,033	3,859	119,767	65,966

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	Working Capital Subreport								
209	Accounts Receivable- Gas		0	None	0	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0	0
215	Accounts Payable, Natural Gas		3,330	PRODGATH	3,330	0	0	0	0
216	Accounts Payable, Other- Labor		2,867	LABOR	228	0	7	1,298	1,333
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	308	0	31	2,239	2,818
218	Accounts Payable, Total		11,592		3,867	0	38	3,538	4,150
219	Accrued interest		(1,083)	PLANT	(37)	0	(42)	(938)	(66)
220	Other, net		826	PLANT	28	0	32	715	50
221	Defd Items & Other, Total		(257)		(9)	0	(10)	(223)	(16)
222	Total Working Capital		11,335		3,858	0	28	3,315	4,135

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION				
					PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	LABOR REPORT								
			Labor $	Labor %					
	PRODUCTION AND GATHERING:								
223	Production and Gathering O&M	750-765	1,164	41%	1,164	0	0	0	0
224	Purchased Gas Expense	807	0	0%	0	0	0	0	0
225	Other Gas Supply Expense	813	0	0%	0	0	0	0	0
226	Sub Production		1,164		1,164	0	0	0	0
	STORAGE:								
227	LNG Operating Exp Admin	840	0	0	0	0	0	0	0
228	Operating Exp- Admin	850	0	0	0	0	0	0	0
229	Sub Storage		0		0	0	0	0	0
	TRANSMISSION:								
230	Transmission expenses	856-863	0	0%	0	0	0	0	0
231	Sub Transmission		0		0	0	0	0	0
	DISTRIBUTION:								
232	Operation Supv & Engineering	870	1,251	71%	0	0	0	1,169	82
233	Load Dispatching	871	77	69%	77	0	0	0	0
234	Compressor Station Fuel and Power	873	0	0%	0	0	0	0	0
235	Mains and Services Expenses	874	1,527	30%	0	0	39	1,489	0
236	Meas. & Reg. Station Expense General	875	40	40%	0	0	0	40	0
237	Meas. & Reg. Station Expense Industrial	876	0	61%	0	0	0	0	0
238	Meter & House Regulator Expenses	878	2,825	47%	0	0	0	0	2,825
239	Customer Installation Expense	879	6	10%	0	0	0	0	6
240	Other Expenses - Safety and Environmental	880	172	27%	22	0	1	103	47
241	Other Expenses	880	177	27%	23	0	1	106	48
242	Maint. Supervision & Engineering	885	605	68%	0	0	0	605	0
243	Maintenance of Structures & Improvements	886	166	32%	0	0	0	166	0
244	Maint. of Mains	887	2,262	41%	0	0	0	2,262	0
245	Maint Of Meas. & Reg. Station Expense General	889	608	51%	0	0	0	608	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	7	69%	0	0	0	7	0
247	Maint. of Services	892	300	45%	0	0	0	0	300
248	Maint. of Meters & House Regulators	893	46	43%	0	0	0	0	46
249	Maintenance of Other Equipment	894	45	66%	0	0	0	45	0
250	Sub Distribution		10,116	43%	122	0	40	6,599	3,355
	OnSite:								
251	Customer Service - Administrative	901	174	77%	0	0	0	0	174
252	Meter Reading Expenses	902	144	25%	0	0	0	0	144
253	Customer Records & Collection Expense	903	3,828	37%	0	0	0	0	3,828
254	Operation Supervision	907	0	0%	0	0	0	0	0
255	Customer Assist- Other	908	117	56%	0	0	0	117	0
256	Customer Assist- CAP	908CAP	168	56%	0	0	0	168	0
257	Supervision	911	0	79%	0	0	0	0	0
258	Demonstration	912	420	64%	0	0	0	420	0
259	Sub OnSite		4,850		0	0	0	705	4,145
260	**TOTAL:**		16,130	16,130	1,285	0	40	7,304	7,500

NOTE: The Labor % above are applied to the functionally classified account balances.

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	1. RATE BASE						
	I. GAS PLANT IN SERVICE						
	A. INTANGIBLE PLANT						
1	Organization	301	36	DISTBASE	22	0	14
2	Intangible Plant - Software- Labor	303Lab	1,514	DISTLABOR	1,072	0	441
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0
4	Intangible Plant - Software- Plant	303Plt	2,485	DISTPT	1,427	0	1,058
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	4,035		2,522	0	1,513
	B. PRODUCTION & GATHERING PLANT						
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0
	C. STORAGE PLANT						
9	Storage Plant	360-368	0	None	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0
	D. TRANSMISSION PLANT						
11	Transmission plant	365-370	0	None	0	0	0
12	Transmission - Mains	367	0	None	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0
	E. DISTRIBUTION PLANT						
16	Land and Land Rights	374	1,893	DISTOnlyPT	1,087	0	806
17	Land and Land Rights - Direct Assign.	374 DA	564	DEMAND	564	0	0
18	Structures and Improvements	375	2,111	DISTOnlyPT	1,212	0	899
19	Mains	376	457,729	MAINS	380,831	0	76,899
20	Mains - Direct Assign.	376 DA	10,267	DEMAND	10,267	0	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DEMAND	16,126	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DEMAND	1,469	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DEMAND	447	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0
25	Services	380	226,432	CUST	0	0	226,432
26	Meters	381	0	None	0	0	0
27	Meter Installations	382	0	None	0	0	0
28	House Regulators	383	0	None	0	0	0
29	House Regulator Installations	384	0	None	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	DEMAND	0	0	0
31	Property on Customers' Premises	386	0	DEMAND	0	0	0
32	Other Equipment	387	324	CUST	0	0	324
33	Subtotal - DISTRIBUTION PLANT	374-387	717,361		412,002	0	305,359

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	F. GENERAL PLANT						
34	Land and Land Rights	389	68	DISTPT	39	0	29
35	*Structures and Improvements*	390	6,769	DISTPT	3,899	0	2,890
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0
37	Office Furniture and Equipment	391	10,583	DISTPT	6,078	0	4,505
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0
39	*Transportation Equipment*	392	8,907	DISTPT	5,116	0	3,792
40	Stores Equipment	393	41	DISTPT	23	0	17
41	Tools & Garage Equipment	394	3,698	DISTPT	2,124	0	1,574
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0
43	Laboratory Equipment	395	0	DISTPT	0	0	0
44	Power Operated Equipment	396	2,732	DISTPT	1,569	0	1,163
45	Communication Equipment	397	5,993	DISTPT	3,442	0	2,551
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0
47	Miscellaneous Equipment	398	28	DISTPT	16	0	12
48	Miscellaneous Equipment - Direct Assign.	398 DA	143	DISTPT	82	0	61
49	Subtotal - GENERAL PLANT	389-399	38,981		22,388	0	16,593
50	**TOTAL UTILITY PLANT**		760,378		436,912	0	323,466
	II. DEPRECIATION RESERVE						
51	Intangible Plant	108	1,371	DISTPT_INT	857	0	514
52	Production & Gathering Plant	108.2	0	None	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0
57	Mains	109	130,432	MAINS	108,519	0	21,913
58	Services	109	83,524	CUST	0	0	83,524
59	Meters	109	0	None	0	0	0
60	Distr Other	109	6,916	DISTPT_xMSM	6,304	0	612
61	*General Plant*	109	16,793	DISTPT	9,645	0	7,148
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	239,035		125,324	0	113,711
	III. OTHER RATE BASE ITEMS						
64	Materials and Supplies		768	DISTPT	441	0	327
65	Current Gas Storage		0	None	0	0	0
66	Prepayments		97	DISTO&MxGas	55	0	42
67	*Deferred Income Taxes - Depreciation*		*(93,674)*	DISTPT	*(53,800)*	0	*(39,874)*
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0
69	Deferred ITC		(4,490)	DISTPT	(2,579)	0	(1,911)
70	Customer Deposits		(3,370)	CUST	0	0	(3,370)
71	**TOTAL OTHER RATE BASE ITEMS**		(100,669)		(55,882)	0	(44,786)
72	**TOTAL RATE BASE (Excl. Working Capital)**		420,674		255,706	0	164,968
73	Working Capital	131	3,315		2,068	0	1,247
74	**TOTAL RATE BASE**		423,989		257,774	0	166,215

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	2. EXPENSES						
	I. OPERATION & MAINTENANCE EXPENSE						
	A. PRODUCTION & GATHERING EXPENSES						
75	Operations Expense	750-756	0	None	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0
	B. OTHER GAS SUPPLY EXPENSES						
78	Natural gas field line purchases	801	0	None	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0
	C. NATURAL GAS STORAGE						
88	LNG Operating Exp Admin	840	0	None	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0
90	*Subtotal - NATURAL GAS STORAGE*	*840-850*	*0*		*0*	*0*	*0*
	D. TRANSMISSION EXPENSES						
91	Transmission expenses	856-863					
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0
	E. DISTRIBUTION EXPENSES						
93	Operation Supv & Engineering	870	1,656	DISTOnlyPT	951	0	705
94	*Load Dispatching*	871	0	None	0	0	0
95	Compressor Station Fuel and Power	873	(0)	None	0	0	0
96	Mains and Services Expenses	874	4,959	MAIN&SERVICE	2,793	0	2,166
97	Meas. & Reg. Station Expense General	875	100	DEMAND	100	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0
101	Other Expenses - Safety and Environmental	880	377	DISTO&MxA/C88	266	0	111
102	Other Expenses	880	387	DISTO&MxA/C88	274	0	114
103	Distribution Rents	881	562	DISTOnlyPT	323	0	239
104	Maint. Supervision & Engineering	885	885	DISTLABOR	627	0	258
105	Maintenance of Structures & Improvements	886	516	DISTOnlyPT	296	0	220
106	Maint. of Mains	887	5,521	MAINS	4,594	0	928
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	DEMAND	1,192	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	10	DEMAND	10	0	0
109	Maint. of Services	892	0	None	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0
111	Maintenance of Other Equipment	894	67	DISTOnlyPT	39	0	29
112	Subtotal - DISTRIBUTION EXPENSES	870-894	16,232		11,464	0	4,769
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		16,232		11,464	0	4,769

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	II. CUSTOMER ACCOUNTS EXPENSES						
114	Customer Service - Administrative	901	0	None	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES						
121	Operation Supervision	907	0	None	0	0	0
122	Customer Assist- Other	908	210	CUST	0	0	210
123	Customer Assist- CAP	908CAP	299	CUST	0	0	299
124	Other Customer Service & Informational Expense	910	698	CUST	0	0	698
125	Supervision	911	0	CUST	0	0	0
126	Demonstration	912	660	CUST	0	0	660
127	Adverstising expense	913	24	CUST	0	0	24
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891		0	0	1,891
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		1,891		0	0	1,891
	IV. ADMINISTRATIVE & GENERAL EXPENSES						
	A. Labor-Related:						
130	Administrative & General Salaries	920	2,690	DISTLABOR	1,906	0	784
131	Administrative & General Salaries - Direct Assign.	920 DA	249	DISTLABOR	176	0	73
132	Office Supplies & Expenses	921	370	DISTLABOR	262	0	108
133	Outside Services Employed - Resid.	923	81	DISTLABOR	58	0	24
134	Outside Services Employed - Labor	923I	1,647	DISTLABOR	1,167	0	480
135	Injuries & Damages	925Labor	153	DISTLABOR	109	0	45
136	Employee Pensions and Benefits	926	2,593	DISTLABOR	1,837	0	756
137	Rents	931	1,823	DISTLABOR	1,291	0	531
138	Subtotal - O&M Accounts 920-923, 925L, 926		9,606		6,806	0	2,800
	B. Plant-Related:						
139	Property Insurance	924	290	DISTPT	167	0	124
140	Outside Services Employed-plant	923p	117	DISTPT	67	0	50
141	Injuries & Damages	925Plant	3,576	DISTPT	2,054	0	1,522
142	Misc. Maintenance Expense	932	1,061	DISTPT_GEN	609	0	452
143	Misc. Maintenance Expense - Direct Assign.	932 DA	43	DISTPT_GEN	25	0	18
144	Subtotal - O&M Accounts 924-925P		5,087		2,922	0	2,166
	C. Other-Related:						
145	Administrative Expenses Transferred	922	(27)	DIST_PT_O&M	(17)	0	(10)
146	Outside Services Employed-cust	923c	5,083	CUST	0	0	5,083
147	Outside Services Employed-plant-O&M	923p-om	5,131	DIST_PT_O&M	3,285	0	1,846
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	146	DIST_PT_O&M	94	0	53
149	Regulatory Commission Expenses	928	378	DIST_PT_O&M	242	0	136
150	*General Advertising Expense*	930.1	147	DIST_PT_O&M	94	0	53
151	Miscellaneous General Expenses	930.2	114	DISTPT_GEN	66	0	49
152	Subtotal - O&M Accounts 928-935		10,972		3,763	0	7,209
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		25,666		13,491	0	12,175
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)**		43,789		24,955	0	18,835

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	V. DEPRECIATION EXPENSE						
155	Intangible Plant	180Int	406	DISTPT_INT	254	0	152
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0
160	Mains (Distribution)	180Mains	6,999	MAINS	5,823	0	1,176
161	Services	180Services	5,815	CUST	0	0	5,815
162	Meters	180Meters	0	None	0	0	0
163	*Distr Other*	180Dist	990	DISTPT_xMSM	903	0	88
164	General Plant	180Gen	3,518	DISTPT_GEN	2,020	0	1,497
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0
166	Adjustments		0	None	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	17,728		9,000	0	8,728
	VI. TAXES						
	A. General Taxes						
168	PA PUC Assessment		1,139	CUST	0	0	1,139
169	Local property taxes		58	DISTPT	33	0	25
170	Public utilty reality tax		475	DISTPT	273	0	202
171	State capital stock tax		325	DISTBASE	198	0	127
172	Miscellaneous tax		0	DISTPT	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	1,998		504	0	1,494
	B. Income Tax Expense						
174	State Income Tax expense		(1,338)	PreTax-DIST	(924)	0	(414)
175	Federal Income Tax expense		7,111	PreTax-DIST	4,911	0	2,200
176	Investment Tax Credit - Amortization		(7)	PreTax-DIST	(5)	0	(2)
177	Subtotal- Income tax expense		5,765		3,982	0	1,783
178	**TOTAL TAX EXPENSE**		7,763		4,486	0	3,277
179	**TOTAL EXPENSES**		69,280		38,440	0	30,840
	3. REVENUES at Present Rates						
180	Sales and Transport Revenue	480-483	88,474	RevReq_PF-Dist	50,719	0	37,755
181	Forfeited Discounts		0	None	0	0	0
182	Miscellaneous Service Revenue		0	RevReq_PF-Dist	0	0	0
183	Other Operating Revenue		61	CUST	0	0	61
184	Subtotal- Gas Revenues, net		88,535		50,719	0	37,816
185	***TOTAL REVENUE***		*88,535*		*50,719*	*0*	*37,816*
186	**TOTAL EXPENSES**		69,280		38,440	0	30,840
187	**NET INCOME at Present Rates**		19,255		12,278	0	6,976

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	SUMMARY						
188	Total revenues		88,535		50,719	0	37,816
189	Total Operating Expenses		43,789		24,955	0	18,835
190	Depreciation Expense		17,728		9,000	0	8,728
191	Taxes other than Income		1,998		504	0	1,494
192	Total Other Expenses		19,725		9,504	0	10,221
193	Income tax expense		5,765		3,982	0	1,783
194	Total expenses		69,280		38,440	0	30,840
195	*NET INCOME at Present Rates*		19,255		12,278	0	6,976
196	**Total Rate Base**		**423,989**		**257,774**	**0**	**166,215**
197							
	REVENUE REQUIREMENTS						
198	Target ROR		8.89%		8.89%	8.89%	8.89%
199	Using Target for System						
200	Rate Base		423,989		257,774	0	166,215
201	Operating expenses		43,789		24,955	0	18,835
202	Depreciation expense		17,728		9,000	0	8,728
203	Taxes other than Income		1,998		504	0	1,494
204	Operating expenses to recover		63,515		34,459	0	29,056
205	Target Return on Rate Base- After taxes		37,693		22,916	0	14,777
206	Income taxes to recover		18,560	49.2%	11,284	0	7,276
207	Additional expenses		0	0.0%	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		119,767		68,658	0	51,109

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	Working Capital Subreport						
209	Accounts Receivable- Gas		0	DISTO&MxGas	0	0	0
210	Accounts Receivable- Other		0	DISTO&MxGas	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0
212	Accounts Receivable, Total		0		0	0	0
213	Gas, LNG in Storage		0	None	0	0	0
214	Inventories & Other, Total		0		0	0	0
215	Accounts Payable, Natural Gas		0	DISTO&MxGas	0	0	0
216	Accounts Payable, Other- Labor		1,298	DISTLABOR	920	0	378
217	Accounts Payable, Other- O&MxGas		2,239	DISTO&MxGas	1,276	0	963
218	Accounts Payable, Total		3,538		2,196	0	1,342
219	Accrued interest		(938)	DISTPT	(539)	0	(399)
220	Other, net		715	DISTPT	411	0	304
221	Defd Items & Other, Total		(223)		(128)	0	(95)
222	Total Working Capital		3,315		2,068	0	1,247

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE							
	I. GAS PLANT IN SERVICE							
	A. INTANGIBLE PLANT							
1	Organization	301	2	P&G_RATEBASE-E	0	0	0	2
2	Intangible Plant - Software- Labor	303Lab	266	PRDGTHPT-E	0	0	0	266
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	268		0	0	0	268
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	AGS Direct	0	0	0	28,445
8	*Subtotal - PRODUCTION & GATHERING PLANT*	*304-338*	*28,445*		*0*	*0*	*0*	*28,445*
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	3	PRDGTHPT-E	0	0	0	3
35	Structures and Improvements	390	269	PRDGTHPT-E	0	0	0	269
36	Structures and Improvements - Direct Assign.	390 DA	42	AGS Direct	0	0	0	42
37	Office Furniture and Equipment	391	420	PRDGTHPT-E	0	0	0	420
38	Office Furniture and Equipment - Direct Assign.	391 DA	1	AGS Direct	0	0	0	1
39	Transportation Equipment	392	353	PRDGTHPT-E	0	0	0	353
40	Stores Equipment	393	2	PRDGTHPT-E	0	0	0	2
41	Tools & Garage Equipment	394	147	PRDGTHPT-E	0	0	0	147
42	Tools & Garage Equipment - Direct Assign.	394 DA	16	AGS Direct	0	0	0	16
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	108	PRDGTHPT-E	0	0	0	108
45	Communication Equipment	397	238	PRDGTHPT-E	0	0	0	238
46	Communication Equipment - Direct Assign.	397 DA	4	AGS Direct	0	0	0	4
47	Miscellaneous Equipment	398	1	PRDGTHPT-E	0	0	0	1
48	Miscellaneous Equipment - Direct Assign.	398 DA	0	None	0	0	0	0
49	Subtotal - GENERAL PLANT	389-399	1,604		0	0	0	1,604
50	**TOTAL UTILITY PLANT**		30,317		0	0	0	30,317
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	91	PRDGTHPT-E	0	0	0	91
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	AGS Direct	0	0	0	8,153
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	666	PRDGTHPT-E	0	0	0	666
62	General Plant - Direct Assign.	108.8 DA	13	AGS Direct	0	0	0	13
63	**TOTAL DEPRECIATION RESERVE**	108	8,924		0	0	0	8,924
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		30	PRDGTHPT-E	0	0	0	30
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		13	PRDGTHO&MXGAS-C	5	1	1	6
67	Deferred Income Taxes - Depreciation		0	None	0	0	0	0
68	Deferred Income Taxes - Direct Assign.		(1,522)	AGS Direct	0	0	0	(1,522)
69	Deferred ITC		0	None	0	0	0	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(1,478)		5	1	1	(1,486)
72	**TOTAL RATE BASE (Excl. Working Capital)**		19,915		5	1	2	19,908
73	Working Capital	131	3,858		1,741	298	1,617	201
74	**TOTAL RATE BASE**		23,773		1,746	299	1,619	20,109

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	1,043	PRDGTHPT-E	0	0	0	1,043
76	Maintenance Expense	761-765	1,766	PRDGTHPT-E	0	0	0	1,766
77	Subtotal - Production and Gathering	750-765	2,809		0	0	0	2,809
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	391	Account813	279	44	68	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391		279	44	68	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	*Subtotal- Transmission Expenses*	*856-863*	*0*	*None*	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	112	Gas_Deliveries	53	9	50	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	81	PRDGTHO&MxA/C880	8	1	3	68
102	Other Expenses	880	83	P&G_O&Mx880xAGS	55	9	19	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	276		116	19	72	68
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		3,475		395	64	139	2,877

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	*Appalachian* Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	*Customer Service - Administrative*	*901*	*0*	*None*	*0*	*0*	*0*	*0*
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSE							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES E**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	473	PRDGTHLABOR-E	20	3	15	435
131	Administrative & General Salaries - Direct Assign.	920 DA	44	AGS Direct	0	0	0	44
132	Office Supplies & Expenses	921	65	PRDGTHLABOR-E	3	0	2	60
133	Outside Services Employed - Resid.	923	14	RS Direct	14	0	0	0
134	Outside Services Employed - Labor	923l	290	PRDGTHLABOR-E	12	2	9	267
135	Injuries & Damages	925Labor	27	PRDGTHLABOR-E	1	0	1	25
136	Employee Pensions and Benefits	926	456	PRDGTHLABOR-E	19	3	14	420
137	Rents	931	321	PRDGTHLABOR-E	13	2	10	295
138	Subtotal - O&M Accounts 920-923, 925L, 926		1,691		83	12	51	1,545
	B. Plant-Related:							
139	Property Insurance	924	12	PRDGTHPT-E	0	0	0	12
140	Outside Services Employed-plant	923p	5	PRDGTHPT-E	0	0	0	5
141	Injuries & Damages	925Plant	142	PRDGTHPT-E	0	0	0	142
142	Misc. Maintenance Expense	932	44	P&G_PT_GEN-E	0	0	0	44
143	Misc. Maintenance Expense - Direct Assign.	932 DA	2	AGS Direct	0	0	0	2
144	Subtotal - O&M Accounts 924-925P		203		0	0	0	203
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(3)	P&G_PT_O&M-E	(0)	(0)	(0)	(3)
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	568	P&G_PT_O&M-E	32	5	11	519
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	16	AGS Direct	0	0	0	16
149	Regulatory Commission Expenses	928	42	P&G_PT_O&MxAGS-E	28	4	10	0
150	General Advertising Expense	930.1	16	P&G_PT_O&MxAGS-E	11	2	4	0
151	Miscellaneous General Expenses	930.2	13	P&G_PT_O&M-E	1	0	0	12
152	Subtotal - O&M Accounts 928-935		652		71	11	25	545
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		2,546		154	23	76	2,293
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Ga**		6,022		549	87	216	5,170

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	27	PRDGTHPT-E	0	0	0	27
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	AGS Direct	0	0	0	631
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	*Meters*	*180Meters*	0	*None*	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	145	P&G_PT_GEN-E	0	0	0	145
165	General Plant - Direct Assign.	180Gen DA	3	AGS Direct	0	0	0	3
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	806		0	0	0	806
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		0	None	0	0	0	0
170	Public utilty reality tax		0	None	0	0	0	0
171	State capital stock tax		18	PRDGTHPT-E	0	0	0	18
172	Miscellaneous tax		17	Gas_Deliveries	8	1	8	0
173	Subtotal- Taxes Other Than Income Taxes	408	35		8	1	8	18
	B. Income Tax Expense							
174	State Income Tax expense		16	PreTax-PRDGTH-E	(468)	(63)	(120)	667
175	Federal Income Tax expense		(87)	PreTax-PRDGTH-E	2,489	334	636	(3,546)
176	Investment Tax Credit - Amortization		0	PreTax-PRDGTH-E	(3)	(0)	(1)	4
177	Subtotal- Income tax expense		(70)		2,018	271	516	(2,875)
178	**TOTAL TAX EXPENSE**		(35)		2,026	273	523	(2,857)
179	**TOTAL EXPENSES**		6,792		2,575	359	739	3,119
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	7,399	Delivery_Rev	5,047	693	1,405	254
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		7,399		5,047	693	1,405	254
185	**TOTAL REVENUE**		7,399		5,047	693	1,405	254
186	**TOTAL EXPENSES**		6,792		2,575	359	739	3,119
187	**NET INCOME at Present Rates**		607		2,472	334	666	(2,864)

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		7,399		5,047	693	1,405	254
189	Total Operating Expenses		6,022		549	87	216	5,170
190	Depreciation Expense		806		0	0	0	806
191	Taxes other than Income		35		8	1	8	18
192	Total Other Expenses		841		8	1	8	824
193	Income tax expense		(70)		2,018	271	516	(2,875)
194	Total expenses		6,792		2,575	359	739	3,119
195	*NET INCOME at Present Rates*		607		2,472	334	666	(2,864)
196	**Total Rate Base**		**23,773**		**1,746**	**299**	**1,619**	**20,109**
197	Return at Present Rates							
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		23,773		1,746	299	1,619	20,109
201	Operating expenses		6,022		549	87	216	5,170
202	Depreciation expense		806		0	0	0	806
203	Taxes other than Income		35		8	1	8	18
204	Operating expenses to recover		6,862		557	88	223	5,994
205	Target Return on Rate Base- After taxes		2,113		155	27	144	1,788
206	Income taxes to recover		1,041	49.2%	76	13	71	880
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		10,017		789	128	438	8,662

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	*Accounts Receivable, Total*		*0*		*0*	*0*	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		3,330	Gas_Deliveries	1,585	272	1,474	0
216	Accounts Payable, Other- Labor		228	PRDGTHLABOR-E	10	2	7	210
217	Accounts Payable, Other- O&MxGas		308	Gas_Deliveries	147	25	136	0
218	Accounts Payable, Total		3,867		1,741	298	1,617	210
219	Accrued interest		(37)	PRDGTHPT-E	0	0	0	(37)
220	Other, net		28	PRDGTHPT-E	0	0	0	28
221	Defd Items & Other, Total		(9)		0	0	0	(9)
222	Total Working Capital		3,858		1,741	298	1,617	201

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	*Production and Gathering O&M*	*750-765*	1,164		*0*	*0*	*0*	1,164
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		1,164		0	0	0	1,164
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	77		37	6	34	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	22		2	0	1	19
241	Other Expenses	880	23		15	2	5	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		122		54	9	40	19
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	*Operation Supervision*	907	*0*		*0*	*0*	*0*	*0*
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	***Sub OnSite***		*0*		*0*	*0*	*0*	*0*
260	TOTAL:		1,285		54	9	40	1,182

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	6	STOR_RATEBASE-D	5	1	0	0
2	Intangible Plant - Software- Labor	303Lab	0	None	0	0	0	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	6		5	1	0	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	0	None	0	0	0	0
35	Structures and Improvements	390	0	None	0	0	0	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	0	None	0	0	0	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	0	None	0	0	0	0
40	Stores Equipment	393	0	None	0	0	0	0
41	Tools & Garage Equipment	394	0	None	0	0	0	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	0	None	0	0	0	0
45	Communication Equipment	397	0	None	0	0	0	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	0	None	0	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	0	None	0	0	0	0
49	Subtotal - GENERAL PLANT	389-399	0		0	0	0	0
50	**TOTAL UTILITY PLANT**		6		5	1	0	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	2	STOR_RATEBASE-D	2	0	0	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	0	None	0	0	0	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	2		2	0	0	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		0	None	0	0	0	0
65	Current Gas Storage		75,176	Storage	64,111	7,384	3,681	0
66	Prepayments		0	None	0	0	0	0
67	Deferred Income Taxes - Depreciation		0	None	0	0	0	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		0	None	0	0	0	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		75,176		64,111	7,384	3,681	0
72	**TOTAL RATE BASE (Excl. Working Capital)**		75,180		64,114	7,384	3,681	0
73	Working Capital	131	0		0	0	0	0
74	**TOTAL RATE BASE**		75,180		64,114	7,384	3,681	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	0	None	0	0	0	0
102	Other Expenses	880	0	None	0	0	0	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	0		0	0	0	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	0	None	0	0	0	0
131	Administrative & General Salaries - Direct Assign.	920 DA	0	None	0	0	0	0
132	Office Supplies & Expenses	921	0	None	0	0	0	0
133	Outside Services Employed - Resid.	923	0	None	0	0	0	0
134	Outside Services Employed - Labor	923l	0	None	0	0	0	0
135	Injuries & Damages	925Labor	0	None	0	0	0	0
136	Employee Pensions and Benefits	926	0	None	0	0	0	0
137	Rents	931	0	None	0	0	0	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		0		0	0	0	0
	B. Plant-Related:							
139	Property Insurance	924	0	None	0	0	0	0
140	Outside Services Employed-plant	923p	0	None	0	0	0	0
141	Injuries & Damages	925Plant	0	None	0	0	0	0
142	Misc. Maintenance Expense	932	0	None	0	0	0	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	0	None	0	0	0	0
144	Subtotal - O&M Accounts 924-925P		0		0	0	0	0
	C. Other-Related:							
145	Administrative Expenses Transferred	922	0	None	0	0	0	0
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	0	None	0	0	0	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	0	None	0	0	0	0
149	Regulatory Commission Expenses	928	0	None	0	0	0	0
150	General Advertising Expense	930.1	0	None	0	0	0	0
151	Miscellaneous General Expenses	930.2	0	None	0	0	0	0
152	Subtotal - O&M Accounts 928-935		0		0	0	0	0
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		0		0	0	0	0
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G**		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	1	STOR_RATEBASE-D	1	0	0	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	0	None	0	0	0	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	1		1	0	0	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		0	None	0	0	0	0
170	Public utilty reality tax		0	None	0	0	0	0
171	State capital stock tax		58	Storage	49	6	3	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	58		49	6	3	0
	B. Income Tax Expense							
174	State Income Tax expense		(545)	PreTax-Stor-D	(331)	(50)	(137)	(27)
175	Federal Income Tax expense		2,896	PreTax-Stor-D	1,760	266	727	143
176	Investment Tax Credit - Amortization		(3)	PreTax-Stor-D	(2)	(0)	(1)	(0)
177	Subtotal- Income tax expense		2,348		1,427	215	590	116
178	**TOTAL TAX EXPENSE**		2,406		1,476	221	592	116
179	**TOTAL EXPENSES**		2,406		1,477	221	592	116
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	7,411	Delivery_Rev	5,055	694	1,407	255
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		7,411		5,055	694	1,407	255
185	**TOTAL REVENUE**		7,411		5,055	694	1,407	255
186	**TOTAL EXPENSES**		2,406		1,477	221	592	116
187	**NET INCOME at Present Rates**		5,005		3,578	473	814	139

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		7,411		5,055	694	1,407	255
189	Total Operating Expenses		0		0	0	0	0
190	Depreciation Expense		1		1	0	0	0
191	Taxes other than Income		58		49	6	3	0
192	Total Other Expenses		58		50	6	3	0
193	Income tax expense		2,348		1,427	215	590	116
194	Total expenses		2,406		1,477	221	592	116
195	NET INCOME at Present Rates		5,005		3,578	473	814	139
196	**Total Rate Base**		75,180		64,114	7,384	3,681	0
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		75,180		64,114	7,384	3,681	0
201	Operating expenses		0		0	0	0	0
202	Depreciation expense		1		1	0	0	0
203	Taxes other than Income		58		49	6	3	0
204	Operating expenses to recover		58		50	6	3	0
205	Target Return on Rate Base- After taxes		6,684		5,700	656	327	0
206	Income taxes to recover		3,291	49.2%	2,807	323	161	0
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		10,033		8,556	985	491	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		0	None	0	0	0	0
217	Accounts Payable, Other- O&MxGas		0	None	0	0	0	0
218	Accounts Payable, Total		0		0	0	0	0
219	Accrued interest		0	None	0	0	0	0
220	Other, net		0	None	0	0	0	0
221	Defd Items & Other, Total		0		0	0	0	0
222	Total Working Capital		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	0		0	0	0	0
241	Other Expenses	880	0		0	0	0	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		0		0	0	0	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		0		0	0	0	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	2	TRAN_RATEBASE-D	(0)	(0)	(0)	2
2	Intangible Plant - Software- Labor	303Lab	8	TRANSLABOR-D	0	0	0	8
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	10		0	0	0	9
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0	None	0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	*Subtotal - STORAGE PLANT*	*360-368*	*0*		*0*	*0*	*0*	*0*
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	106	Peak	66	8	33	0
12	Transmission - Mains	367	1,243	Peak	767	95	381	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	AGS Direct	0	0	0	14,171
14	Transmission - Mains - Direct Assign.	367 DA	16,830	AGS Direct	0	0	0	16,830
15	*Subtotal - TRANSMISSION PLANT*	*365-370*	*32,350*		*832*	*103*	*413*	*31,001*
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	3	Peak	2	0	1	0
35	Structures and Improvements	390	306	Peak	189	23	94	0
36	Structures and Improvements - Direct Assign.	390 DA	25	AGS Direct	0	0	0	25
37	Office Furniture and Equipment	391	477	Peak	294	36	146	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	1	AGS Direct	0	0	0	1
39	*Transportation Equipment*	392	*402*	Peak	*248*	31	123	*0*
40	Stores Equipment	393	2	Peak	1	0	1	0
41	Tools & Garage Equipment	394	167	Peak	103	13	51	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	10	AGS Direct	0	0	0	10
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	123	Peak	76	9	38	0
45	*Communication Equipment*	397	270	Peak	167	21	83	0
46	Communication Equipment - Direct Assign.	397 DA	2	AGS Direct	0	0	0	2
47	Miscellaneous Equipment	398	1	Peak	1	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	3	GSL Direct	0	0	3	0
49	Subtotal - GENERAL PLANT	389-399	1,792		1,081	134	540	38
50	**TOTAL UTILITY PLANT**		34,152		1,913	237	954	31,048
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	3	TRAN_RATEBASE-D	(0)	(0)	(0)	3
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	658	Peak	406	50	202	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	AGS Direct	0	0	0	11,969
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	757	Peak	467	58	232	0
62	General Plant - Direct Assign.	108.8 DA	8	AGS Direct	0	0	0	8
63	**TOTAL DEPRECIATION RESERVE**	108	13,396		873	108	434	11,981
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		35	Peak	21	3	11	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		1	Peak	1	0	0	0
67	Deferred Income Taxes - Depreciation		(2,027)	TRAN_PTxAGS-D	(1,250)	(155)	(621)	0
68	Deferred Income Taxes - Direct Assign.		(901)	AGS Direct	0	0	0	(901)
69	Deferred ITC		(97)	TRAN_PTxAGS-D	(60)	(7)	(30)	0
70	Customer Deposits		0	None	0	0	0	0
71	***TOTAL OTHER RATE BASE ITEMS***		*(2,988)*		*(1,288)*	*(160)*	*(640)*	*(901)*
72	**TOTAL RATE BASE (Excl. Working Capital)**		17,768		(248)	(31)	(120)	18,167
73	Working Capital	131	28		17	2	8	0
74	**TOTAL RATE BASE**		17,795		(231)	(29)	(112)	18,167

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	129	TRANS_MAINS-D	5	1	3	120
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	3	TRANO&MxA/C880-D	0	0	0	3
102	Other Expenses	880	3	TRANO&Mx880xAGS-D	2	0	1	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	135		8	1	4	123
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		135		8	1	4	123

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	15	TRANSLABOR-D	1	0	0	14
131	Administrative & General Salaries - Direct Assign.	920 DA	1	AGS Direct	0	0	0	1
132	Office Supplies & Expenses	921	2	TRANSLABOR-D	0	0	0	2
133	Outside Services Employed - Resid.	923	0	RS Direct	0	0	0	0
134	Outside Services Employed - Labor	923l	9	TRANSLABOR-D	1	0	0	8
135	Injuries & Damages	925Labor	1	TRANSLABOR-D	0	0	0	1
136	Employee Pensions and Benefits	926	14	TRANSLABOR-D	1	0	0	13
137	Rents	931	10	TRANSLABOR-D	1	0	0	9
138	Subtotal - O&M Accounts 920-923, 925L, 926		53		3	0	1	48
	B. Plant-Related:							
139	Property Insurance	924	13	Peak	8	1	4	0
140	Outside Services Employed-plant	923p	5	Peak	3	0	2	0
141	Injuries & Damages	925Plant	161	Peak	99	12	49	0
142	Misc. Maintenance Expense	932	49	TRAN_PT_GEN-D	29	4	15	1
143	Misc. Maintenance Expense - Direct Assign.	932 DA	2	AGS Direct	0	0	0	2
144	Subtotal - O&M Accounts 924-925P		230		140	17	70	3
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(1)	TRAN_PT-D	(0)	(0)	(0)	(1)
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	155	TRAN_PT-D	4	0	2	148
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	4	AGS Direct	0	0	0	4
149	Regulatory Commission Expenses	928	11	TRAN_PTxAGS-D	7	1	3	0
150	General Advertising Expense	930.1	4	TRAN_PTxAGS-D	3	0	1	0
151	Miscellaneous General Expenses	930.2	3	TRAN_PT-D	0	0	0	3
152	Subtotal - O&M Accounts 928-935		177		14	2	7	155
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		461		157	19	78	206
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G:**		596		165	20	82	329

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	1	TRAN_RATEBASE-D	(0)	(0)	(0)	1
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	9	Peak	5	1	3	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	AGS Direct	0	0	0	704
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	162	TRAN_PT_GEN-D	98	12	49	3
165	General Plant - Direct Assign.	180Gen DA	2	AGS Direct	0	0	0	2
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	876		103	13	51	710
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		1	Peak	1	0	0	0
170	Public utilty reality tax		10	Peak	6	1	3	0
171	State capital stock tax		14	Peak	8	1	4	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	25		16	2	8	0
	B. Income Tax Expense							
174	State Income Tax expense		(88)	PreTax-Tran-D	(176)	(25)	(43)	155
175	Federal Income Tax expense		468	PreTax-Tran-D	935	131	226	(824)
176	Investment Tax Credit - Amortization		(0)	PreTax-Tran-D	(1)	(0)	(0)	1
177	Subtotal- Income tax expense		380		758	106	183	(668)
178	**TOTAL TAX EXPENSE**		405		774	108	191	(668)
179	**TOTAL EXPENSES**		1,878		1,042	141	324	371
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	2,851	Delivery_Rev	1,944	267	541	98
181	*Forfeited Discounts*		*0*	*None*	*0*	*0*	*0*	*0*
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		2,851		1,944	267	541	98
185	**TOTAL REVENUE**		2,851		1,944	267	541	98
186	**TOTAL EXPENSES**		1,878		1,042	141	324	371
187	**NET INCOME at Present Rates**		973		903	126	217	(273)

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		2,851		1,944	267	541	98
189	Total Operating Expenses		596		165	20	82	329
190	Depreciation Expense		876		103	13	51	710
191	Taxes other than Income		25		16	2	8	0
192	Total Other Expenses		902		118	15	59	710
193	Income tax expense		380		758	106	183	(668)
194	Total expenses		1,878		1,042	141	324	371
195	NET INCOME at Present Rates		973		903	126	217	(273)
196	**Total Rate Base**		17,795		(231)	(29)	(112)	18,167
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		17,795		(231)	(29)	(112)	18,167
201	Operating expenses		596		165	20	82	329
202	Depreciation expense		876		103	13	51	710
203	Taxes other than Income		25		16	2	8	0
204	Operating expenses to recover		1,498		283	35	141	1,039
205	Target Return on Rate Base- After taxes		1,582		(21)	(3)	(10)	1,615
206	Income taxes to recover		779	49.2%	(10)	(1)	(5)	795
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		3,859		253	31	126	3,449

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		7	Peak	4	1	2	0
217	Accounts Payable, Other- O&MxGas		31	Peak	19	2	9	0
218	Accounts Payable, Total		38		23	3	12	0
219	Accrued interest		(42)	Peak	(26)	(3)	(13)	0
220	Other, net		32	Peak	20	2	10	0
221	Defd Items & Other, Total		(10)		(6)	(1)	(3)	0
222	Total Working Capital		28		17	2	8	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	*Sub Transmission*		*0*		*0*	*0*	*0*	*0*
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	39		2	0	1	36
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	1		0	0	0	1
241	Other Expenses	880	1		1	0	0	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		40		2	0	1	37
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		40		2	0	1	37

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	22	DIST_RATEBASE-D	13	2	7	0
2	Intangible Plant - Software- Labor	303Lab	1,072	DISTLABOR-D	647	80	346	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	1,427	DISTOnlyPT-D	856	106	466	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	2,522		1,515	188	819	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	1,087	Peak	671	83	333	0
17	Land and Land Rights - Direct Assign.	374 DA	564	GSL Direct	0	0	564	0
18	Structures and Improvements	375	1,212	Peak	748	93	371	0
19	Mains	376	380,831	Peak	234,991	29,110	116,730	0
20	Mains - Direct Assign.	376 DA	10,267	GSL Direct	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	Peak	9,950	1,233	4,943	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	GSL Direct	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	Peak	276	34	137	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	412,002		246,635	30,553	134,815	0

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	39	DISTPT-D	23	3	13	0
35	Structures and Improvements	390	3,899	DISTPT-D	2,334	289	1,276	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	6,078	DISTPT-D	3,639	451	1,989	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	5,116	DISTPT-D	3,062	379	1,674	0
40	Stores Equipment	393	23	DISTPT-D	14	2	8	0
41	Tools & Garage Equipment	394	2,124	DISTPT-D	1,271	157	695	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	1,569	DISTPT-D	939	116	513	0
45	Communication Equipment	397	3,442	DISTPT-D	2,061	255	1,126	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	16	DISTPT-D	10	1	5	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	82	GSL Direct	0	0	82	0
49	Subtotal - GENERAL PLANT	389-399	22,388		13,353	1,654	7,381	0
50	**TOTAL UTILITY PLANT**		436,912		261,504	32,395	143,014	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	857	DISTPT-D_INT	515	64	278	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	108,519	DISTMAIN-D	65,204	8,077	35,238	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	6,304	DISTPT-DxMSM	3,512	435	2,358	0
61	General Plant	109	9,645	DISTPT-D	5,773	715	3,156	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	125,324		75,003	9,291	41,030	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		441	DISTPT-D	264	33	144	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		55	DISTO&MXGAS-D	36	5	13	1
67	Deferred Income Taxes - Depreciation		(53,800)	DISTPT-D	(32,206)	(3,990)	(17,604)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(2,579)	DISTPT-D	(1,544)	(191)	(844)	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(55,882)		(33,450)	(4,143)	(18,290)	1
72	**TOTAL RATE BASE (Excl. Working Capital)**		255,706		153,050	18,960	83,694	1
73	Working Capital	131	2,068		1,305	168	563	32
74	**TOTAL RATE BASE**		257,774		154,355	19,128	84,257	33

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	*Subtotal - OTHER GAS SUPPLY EXPENSES*	*800-813*	*0*		*0*	*0*	*0*	*0*
	C. NATURAL GAS STORAGE							
88	*LNG Operating Exp Admin*	*840*	*0*	*None*	*0*	*0*	*0*	*0*
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	951	DISTOnlyPT-D	570	71	310	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	2,793	DISTMAIN-SERV-D	1,678	208	907	0
97	Meas. & Reg. Station Expense General	875	100	Peak	62	8	31	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	*Customer Installation Expense*	*879*	*0*	*None*	*0*	*0*	*0*	*0*
101	Other Expenses - Safety and Environmental	880	266	DISTO&MxA/C880-D	160	20	86	0
102	Other Expenses	880	274	DISTO&Mx880xAGS-D	165	20	88	0
103	*Distribution Rents*	*881*	323	DISTOnlyPT-D	193	24	105	0
104	Maint. Supervision & Engineering	885	627	DISTLABOR-D	378	47	202	0
105	Maintenance of Structures & Improvements	886	296	DISTOnlyPT-D	178	22	97	0
106	Maint. of Mains	887	4,594	DISTMAIN-D	2,760	342	1,492	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	Peak	735	91	365	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	10	Peak	6	1	3	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	39	DISTPT-D	23	3	13	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	11,464		6,909	856	3,699	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		11,464		6,909	856	3,699	0

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	*General Service* - Small (GSS)	*General Service* - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	*Miscellaneous Customer Accounts Expenses*	*905*	*0*	*None*	*0*	*0*	*0*	*0*
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPEN							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	*Demonstration*	912	*0*	*None*	*0*	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EX**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	1,906	DISTLABOR-D	1,149	142	614	0
131	Administrative & General Salaries - Direct Assign.	920 DA	176	AGS Direct	0	0	0	176
132	Office Supplies & Expenses	921	262	DISTLABOR-D	158	20	84	0
133	Outside Services Employed - Resid.	923	58	RS Direct	58	0	0	0
134	Outside Services Employed - Labor	923l	1,167	DISTLABOR-D	704	87	376	0
135	Injuries & Damages	925Labor	109	DISTLABOR-D	65	8	35	0
136	Employee Pensions and Benefits	926	1,837	DISTLABOR-D	1,108	137	592	0
137	Rents	931	1,291	DISTLABOR-D	779	96	416	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		6,806		4,021	491	2,117	176
	B. Plant-Related:							
139	Property Insurance	924	167	DISTPT-D	100	12	55	0
140	Outside Services Employed-plant	923p	67	DISTPT-D	40	5	22	0
141	Injuries & Damages	925Plant	2,054	DISTPT-D	1,229	152	672	0
142	Misc. Maintenance Expense	932	609	DISTPT_GEN-D	363	45	201	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	25	AGS Direct	0	0	0	25
144	Subtotal - O&M Accounts 924-925P		2,922		1,733	215	949	25
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(17)	DIST_PT_O&M-D	(10)	(1)	(6)	(0)
146	*Outside Services Employed-cust*	923c	*0*	*None*	*0*	*0*	*0*	*0*
147	Outside Services Employed-plant-O&M	923p-om	3,285	DIST_PT_O&M-D	1,973	244	1,068	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	94	AGS Direct	0	0	0	94
149	Regulatory Commission Expenses	928	242	DIST_PT_O&MxAGS-D	145	18	79	0
150	General Advertising Expense	930.1	94	DIST_PT_O&MxAGS-D	57	7	31	0
151	Miscellaneous General Expenses	930.2	66	DIST_PT_O&M-D	39	5	21	0
152	Subtotal - O&M Accounts 928-935		3,763		2,204	273	1,192	94
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		13,491		7,958	979	4,259	295
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and**		24,955		14,867	1,835	7,958	295

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	254	DISTPT-D_INT	152	19	82	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	*Transmission Plant - Direct Assign.*	*180Trans DA*	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	5,823	DISTMAIN-D	3,499	433	1,891	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	903	DISTPT-DxMSM	503	62	338	0
164	General Plant	180Gen	2,020	DISTPT_GEN-D	1,205	149	666	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	9,000		5,359	664	2,977	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		33	TOTALPLANTxAGS	25	2	7	0
170	Public utilty reality tax		273	TOTALPLANTxAGS	203	15	55	0
171	State capital stock tax		198	DISTPT-D	118	15	65	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	504		346	31	126	0
	B. Income Tax Expense							
174	State Income Tax expense		(924)	PreTax-Dist-D	(1,006)	(176)	410	(153)
175	Federal Income Tax expense		4,911	PreTax-Dist-D	5,344	934	(2,179)	812
176	Investment Tax Credit - Amortization		(5)	PreTax-Dist-D	(6)	(1)	2	(1)
177	Subtotal- Income tax expense		3,982		4,333	757	(1,766)	659
178	**TOTAL TAX EXPENSE**		4,486		4,679	789	(1,640)	659
179	**TOTAL EXPENSES**		38,440		24,905	3,287	9,295	953
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	50,719	Delivery_Rev	34,595	4,752	9,627	1,744
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		50,719		34,595	4,752	9,627	1,744
185	**TOTAL REVENUE**		50,719		34,595	4,752	9,627	1,744
186	**TOTAL EXPENSES**		38,440		24,905	3,287	9,295	953
187	**NET INCOME at Present Rates**		12,278		9,690	1,465	333	791

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		50,719		34,595	4,752	9,627	1,744
189	Total Operating Expenses		24,955		14,867	1,835	7,958	295
190	Depreciation Expense		9,000		5,359	664	2,977	0
191	*Taxes other than Income*		504		346	31	126	0
192	Total Other Expenses		9,504		5,706	695	3,103	0
193	Income tax expense		3,982		4,333	757	(1,766)	659
194	Total expenses		38,440		24,905	3,287	9,295	953
195	NET INCOME at Present Rates		12,278		9,690	1,465	333	791
196	**Total Rate Base**		257,774		154,355	19,128	84,257	33
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		257,774		154,355	19,128	84,257	33
201	Operating expenses		24,955		14,867	1,835	7,958	295
202	Depreciation expense		9,000		5,359	664	2,977	0
203	Taxes other than Income		504		346	31	126	0
204	Operating expenses to recover		34,459		20,573	2,530	11,061	295
205	Target Return on Rate Base- After taxes		22,916		13,722	1,700	7,490	3
206	Income taxes to recover		11,284	49.2%	6,757	837	3,688	1
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		68,658		41,052	5,068	22,240	299

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		920	DISTLABOR-D	555	69	296	0
217	Accounts Payable, Other- O&MxGas		1,276	DISTO&MXGAS-D	827	109	309	32
218	Accounts Payable, Total		2,196		1,382	178	605	32
219	Accrued interest		(539)	DISTPT-D	(322)	(40)	(176)	0
220	Other, net		411	DISTPT-D	246	30	134	0
221	Defd Items & Other, Total		(128)		(77)	(9)	(42)	0
222	Total Working Capital		2,068		1,305	168	563	32

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	671		402	50	219	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	838		504	62	272	0
236	Meas. & Reg. Station Expense General	875	40		25	3	12	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	73		44	5	23	0
241	Other Expenses	880	75		45	6	24	0
242	Maint. Supervision & Engineering	885	429		258	32	138	0
243	Maintenance of Structures & Improvements	886	95		57	7	31	0
244	Maint. of Mains	887	1,882		1,131	140	611	0
245	Maint Of Meas. & Reg. Station Expense General	889	608		375	46	186	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	7		4	1	2	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	26		15	2	8	0
250	**Sub Distribution**		4,744		2,861	354	1,528	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	*TOTAL:*		4,744		2,861	354	1,528	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE							
	I. GAS PLANT IN SERVICE							
	A. INTANGIBLE PLANT							
1	Organization	301	14	DIST_RATEBASE-C	13	0	0	0
2	Intangible Plant - Software- Labor	303Lab	441	DISTLABOR-C	343	81	17	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	*Intangible Plant - Software- Plant*	*303Plt*	*1,058*	*DISTOnlyPT-C*	*995*	*24*	*38*	*0*
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	1,513		1,351	106	56	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - *PRODUCTION & GATHERING PLANT*	304-338	*0*		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	806	DISTOnlyPT-C	758	19	29	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	899	DISTOnlyPT-C	845	21	33	0
19	Mains	376	76,899	Cust_Avg	71,588	4,760	551	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	226,432	Service_Invest	213,758	2,209	10,465	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	324	GSS Direct	0	324	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	305,359		286,949	7,331	11,078	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	29	DISTPT-C	27	1	1	0
35	Structures and Improvements	390	2,890	DISTPT-C	2,716	69	105	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	4,505	DISTPT-C	4,233	108	163	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	3,792	DISTPT-C	3,563	91	138	0
40	Stores Equipment	393	17	DISTPT-C	16	0	1	0
41	Tools & Garage Equipment	394	1,574	DISTPT-C	1,479	38	57	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	1,163	DISTPT-C	1,093	28	42	0
45	Communication Equipment	397	2,551	DISTPT-C	2,397	61	93	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	12	DISTOnlyPT-C	11	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	61	GSL Direct	0	0	61	0
49	Subtotal - GENERAL PLANT	389-399	16,593		15,536	397	661	0
50	**TOTAL UTILITY PLANT**		323,466		303,836	7,834	11,795	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	514	DISTPT-C_INT	459	36	19	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	21,913	Cust_Avg	20,399	1,356	157	0
58	Services	109	83,524	Service_Invest	78,849	815	3,860	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	612	DISTPT-CxMSM	483	109	19	0
61	General Plant	109	7,148	DISTPT-C	6,717	172	259	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	113,711		106,908	2,488	4,315	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		327	DISTPT-C	307	8	12	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		42	DISTO&MXGAS-C	32	4	5	1
67	Deferred Income Taxes - Depreciation		(39,874)	DISTPT-C	(37,470)	(957)	(1,447)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(1,911)	DISTPT-C	(1,796)	(46)	(69)	0
70	Customer Deposits		(3,370)	Deposits	(2,775)	(209)	(385)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(44,786)		(41,702)	(1,201)	(1,884)	1
72	**TOTAL RATE BASE (Excl. Working Capital)**		164,968		155,226	4,145	5,597	1
73	Working Capital	131	1,247		999	132	117	0
74	**TOTAL RATE BASE**		166,215		156,224	4,277	5,713	1

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	705	DISTOnlyPT-C	663	16	26	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	2,166	DISTMAIN-SERV-C	2,038	50	79	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	111	DISTO&MxA/C880-C	103	4	3	0
102	Other Expenses	880	114	DISTO&Mx880xAGS-C	106	5	3	0
103	Distribution Rents	881	239	DISTOnlyPT-C	225	5	9	0
104	Maint. Supervision & Engineering	885	258	DISTLABOR-C	200	47	10	0
105	Maintenance of Structures & Improvements	886	220	DISTPT-C	206	5	8	0
106	Maint. of Mains	887	928	Cust_Avg	864	57	7	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	29	DISTPT-C	27	1	1	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	4,769		4,432	191	146	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		4,769		4,432	191	146	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPEN							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	210	Acct901-903,908	196	13	2	0
123	Customer Assist- CAP	908CAP	299	RS Direct	299	0	0	0
124	Other Customer Service & Informational Expense	910	698	Account910	698	0	0	0
125	Supervision	911	0	Account911-916	0	0	0	0
126	Demonstration	912	660	Account911-916	0	591	68	0
127	Adverstising expense	913	24	Account911-916	0	22	3	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EX**		1,891		1,193	626	73	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES**		1,891		1,193	626	73	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	784	DISTLABOR-C	609	144	31	0
131	Administrative & General Salaries - Direct Assign.	920 DA	73	AGS Direct	0	0	0	73
132	Office Supplies & Expenses	921	108	DISTLABOR-C	84	20	4	0
133	Outside Services Employed - Resid.	923	24	RS Direct	24	0	0	0
134	Outside Services Employed - Labor	923l	480	DISTLABOR-C	373	88	19	0
135	Injuries & Damages	925Labor	45	DISTLABOR-C	35	8	2	0
136	Employee Pensions and Benefits	926	756	DISTLABOR-C	587	139	30	0
137	Rents	931	531	DISTLABOR-C	413	98	21	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		2,800		2,124	497	107	73
	B. Plant-Related:							
139	Property Insurance	924	124	DISTPT-C	116	3	4	0
140	Outside Services Employed-plant	923p	50	DISTPT-C	47	1	2	0
141	Injuries & Damages	925Plant	1,522	DISTPT-C	1,430	37	55	0
142	Misc. Maintenance Expense	932	452	DISTPT_GEN-C	423	11	18	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	18	AGS Direct	0	0	0	18
144	Subtotal - O&M Accounts 924-925P		2,166		2,016	52	79	18
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(10)	DIST_PT_O&M-C	(9)	(0)	(0)	0
146	Outside Services Employed-cust	923c	5,083	Cust_Avg	4,732	315	36	0
147	Outside Services Employed-plant-O&M	923p-om	1,846	DIST_PT_O&M-C	1,725	59	62	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	53	AGS Direct	0	0	0	53
149	Regulatory Commission Expenses	928	136	DIST_PT_O&MxAGS-C	127	4	5	0
150	General Advertising Expense	930.1	53	DIST_PT_O&MxAGS-C	49	2	2	0
151	Miscellaneous General Expenses	930.2	49	DIST_PT_O&M-C	45	2	2	0
152	Subtotal - O&M Accounts 928-935		7,209		6,670	381	106	53
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		12,175		10,810	929	292	144
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and**		18,835		16,435	1,746	510	144

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	152	DISTPT-C_INT	136	11	6	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	1,176	Cust_Avg	1,095	73	8	0
161	Services	180Services	5,815	Service_Invest	5,489	57	269	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	88	DISTPT-CxMSM	69	16	3	0
164	General Plant	180Gen	1,497	DISTPT_GEN-C	1,402	36	60	0
165	*General Plant - Direct Assign.*	*180Gen DA*	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	8,728		8,191	192	345	0
	VI. TAXES							
	A. General Taxes							
168	PA PUC Assessment		1,139	Delivery_RevxAGS	805	111	224	0
169	Local property taxes		25	TOTALPLANTxAGS	18	1	5	0
170	Public utilty reality tax		202	TOTALPLANTxAGS	151	11	41	0
171	State capital stock tax		127	RATEBASExAGS	96	8	23	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	1,494		1,070	131	293	0
	B. Income Tax Expense							
174	State Income Tax expense		(414)	PreTax-Dist-C	469	(142)	(619)	(122)
175	Federal Income Tax expense		2,200	PreTax-Dist-C	(2,493)	757	3,288	648
176	Investment Tax Credit - Amortization		(2)	PreTax-Dist-C	3	(1)	(3)	(1)
177	Subtotal- Income tax expense		1,783		(2,021)	614	2,666	525
178	**TOTAL TAX EXPENSE**		3,277		(952)	745	2,959	525
179	**TOTAL EXPENSES**		30,840		23,674	2,683	3,814	669
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	37,755	Delivery_Rev	25,752	3,538	7,167	1,299
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		61	Delivery_RevxAGS	43	6	12	0
184	Subtotal- Gas Revenues, net		37,816		25,796	3,543	7,179	1,299
185	**TOTAL REVENUE**		37,816		25,796	3,543	7,179	1,299
186	**TOTAL EXPENSES**		30,840		23,674	2,683	3,814	669
187	**NET INCOME at Present Rates**		6,976		2,121	861	3,365	630

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	*General Service - Small (GSS)*	*General Service - Large (GSL)*	Appalachian Gathering Service (AGS)
	SUMMARY							
188	*Total revenues*		37,816		25,796	3,543	7,179	1,299
189	Total Operating Expenses		18,835		16,435	1,746	510	144
190	Depreciation Expense		8,728		8,191	192	345	0
191	Taxes other than Income		1,494		1,070	131	293	0
192	Total Other Expenses		10,221		9,261	323	638	0
193	Income tax expense		1,783		(2,021)	614	2,666	525
194	Total expenses		30,840		23,674	2,683	3,814	669
195	NET INCOME at Present Rates		6,976		2,121	861	3,365	630
196	**Total Rate Base**		166,215		156,224	4,277	5,713	1
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		166,215		156,224	4,277	5,713	1
201	Operating expenses		18,835		16,435	1,746	510	144
202	Depreciation expense		8,728		8,191	192	345	0
203	Taxes other than Income		1,494		1,070	131	293	0
204	Operating expenses to recover		29,056		25,696	2,069	1,148	144
205	Target Return on Rate Base- After taxes		14,777		13,888	380	508	0
206	Income taxes to recover		7,276	49.2%	6,839	187	250	0
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		51,109		46,423	2,636	1,906	144

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	*Accounts Receivable- Other*		*0*	*None*	*0*	*0*	*0*	*0*
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		378	DISTLABOR-C	294	70	15	0
217	Accounts Payable, Other- O&MxGas		963	ONSITEO&MxGASxAGS-C	794	64	105	0
218	Accounts Payable, Total		1,342		1,088	134	120	0
219	Accrued interest		(399)	DISTPT-C	(375)	(10)	(14)	0
220	Other, net		304	DISTPT-C	286	7	11	0
221	Defd Items & Other, Total		(95)		(89)	(2)	(3)	0
222	Total Working Capital		1,247		999	132	117	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	498		468	11	18	0
233	*Load Dispatching*	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	650		612	15	24	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	30		28	1	1	0
241	Other Expenses	880	31		29	1	1	0
242	Maint. Supervision & Engineering	885	176		137	32	7	0
243	Maintenance of Structures & Improvements	886	71		66	2	3	0
244	Maint. of Mains	887	380		354	24	3	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	19		18	0	1	0
250	**Sub Distribution**		1,855		1,712	87	56	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	*Meter Reading Expenses*	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	117		109	7	1	0
256	Customer Assist- CAP	908CAP	168		168	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	420		0	376	44	0
259	**Sub OnSite**		705		277	383	44	0
260	TOTAL:		2,560		1,989	470	101	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	4	ONSITE_RATEBASE-C	3	0	0	0
2	Intangible Plant - Software- Labor	303Lab	1,554	ONSITELABOR-C	1,297	125	132	0
3	Intangible Plant - Software- Customer	303Cust	2,743	Cust_Avg	2,553	170	20	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	Cust_Avg	14,549	967	112	0
6	Subtotal - INTANGIBLE ASSETS	301-303	19,928		18,402	1,262	264	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	*Meas. & Reg. Stat. Equip. - Odorization*	*378odr*	*0*	*None*	*0*	*0*	*0*	*0*
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	17,775	Meter_Invest	12,344	1,821	3,610	0
27	Meter Installations	382	9,208	Meter_Invest	6,395	943	1,870	0
28	*House Regulators*	*383*	*5,656*	*Account 383/384*	*3,852*	*865*	*939*	*0*
29	House Regulator Installations	384	1,514	Account 383/384	1,031	231	251	0
30	Ind. Meas. & Reg. Station Equip.	385	441	GSL Direct	0	0	441	0
31	Property on Customers' Premises	386	15,838	Account386	14,394	356	1,087	0
32	Other Equipment	387	0	None	0	0	0	0
33	*Subtotal - DISTRIBUTION PLANT*	*374-387*	*50,432*		*38,017*	*4,217*	*8,199*	*0*

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	5	ONSITEPT-C	4	0	1	0
35	Structures and Improvements	390	477	ONSITEPT-C	360	40	78	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	744	ONSITEPT-C	561	62	121	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	626	ONSITEPT-C	472	52	102	0
40	Stores Equipment	393	3	ONSITEPT-C	2	0	0	0
41	Tools & Garage Equipment	394	260	ONSITEPT-C	196	22	42	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	192	ONSITEPT-C	145	16	31	0
45	Communication Equipment	397	421	ONSITEPT-C	318	35	68	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	*Miscellaneous Equipment*	*398*	2	ONSITEPT-C	1	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	10	GSL Direct	0	0	10	0
49	Subtotal - GENERAL PLANT	389-399	2,740		2,058	228	454	0
50	**TOTAL UTILITY PLANT**		73,101		58,477	5,708	8,917	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	6,768	ONSITEPT-C_INT	6,250	429	90	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	12,975	Meter_Invest	9,011	1,329	2,635	0
60	*Distr Other*	*109*	7,072	*ONSITE-CxMSM*	5,814	438	820	0
61	General Plant	109	1,181	ONSITEPT-C	890	99	192	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	27,996		21,964	2,295	3,737	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		54	ONSITEPT-C	41	5	9	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		122	ONSITEO&MXGAS-C	99	8	13	2
67	Deferred Income Taxes - Depreciation		(6,586)	ONSITEPT-C	(4,964)	(551)	(1,071)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(316)	ONSITEPT-C	(238)	(26)	(51)	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(6,725)		(5,062)	(565)	(1,100)	2
72	**TOTAL RATE BASE (Excl. Working Capital)**		38,380		31,450	2,848	4,080	2
73	Working Capital	131	4,135		3,422	294	419	0
74	**TOTAL RATE BASE**		42,515		34,872	3,142	4,499	2

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. *EXPENSES*							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	*Gas Delivered to Storage*	*808*	*0*	*None*	*0*	*0*	*0*	*0*
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	116	ONSITEDistPT-C	80	13	24	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	*Meas. & Reg. Station Expense Industrial*	*876*	*0*	*None*	*0*	*0*	*0*	*0*
99	Meter & House Regulator Expenses	878	6,062	ONSITE-MR-C	4,193	685	1,184	0
100	Customer Installation Expense	879	62	RS Direct	62	0	0	0
101	Other Expenses - Safety and Environmental	880	172	ONSITEO&MxA/C880-C	123	18	31	0
102	Other Expenses	880	177	ONSITEO&Mx880xAGS-C	127	18	32	0
103	Distribution Rents	881	40	ONSITEDistPT-C	27	4	8	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	663	Service_Invest	626	6	31	0
110	Maint. of Meters & House Regulators	893	107	ONSITE-MR-C	74	12	21	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	7,398		5,311	757	1,330	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		7,398		5,311	757	1,330	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	225	Acct901-903,908	210	14	2	0
115	Meter Reading Expenses	902	587	Acct901-903,908	546	36	4	0
116	Customer Records & Collection Expense	903	10,270	Acct901-903,908	9,561	636	74	0
117	Uncollectible Accounts	904	8,883	Account904	8,339	191	353	0
118	Uncollectible Accounts- CAP	904CAP	16,167	RS Direct	16,167	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		36,132		34,823	877	432	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		36,132		34,823	877	432	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	2,762	ONSITELABOR-C	2,305	222	235	0
131	Administrative & General Salaries - Direct Assign.	920 DA	256	AGS Direct	0	0	0	256
132	*Office Supplies & Expenses*	*921*	*380*	*ONSITELABOR-C*	*317*	*31*	*32*	*0*
133	Outside Services Employed - Resid.	923	84	RS Direct	84	0	0	0
134	Outside Services Employed - Labor	923l	1,691	ONSITELABOR-C	1,411	136	144	0
135	Injuries & Damages	925Labor	157	ONSITELABOR-C	131	13	13	0
136	Employee Pensions and Benefits	926	2,662	ONSITELABOR-C	2,222	214	227	0
137	Rents	931	1,872	ONSITELABOR-C	1,562	150	159	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		9,864		8,032	766	811	256
	B. Plant-Related:							
139	Property Insurance	924	20	ONSITEPT-C	15	2	3	0
140	Outside Services Employed-plant	923p	8	ONSITEPT-C	6	1	1	0
141	Injuries & Damages	925Plant	251	ONSITEPT-C	189	21	41	0
142	Misc. Maintenance Expense	932	75	ONSITEPT_GEN-C	56	6	12	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	3	AGS Direct	0	0	0	3
144	Subtotal - O&M Accounts 924-925P		358		267	30	58	3
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(6)	ONSITE_PT_O&M-C	(4)	(1)	(1)	0
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	1,167	ONSITE_PT_O&M-C	859	108	200	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	33	AGS Direct	0	0	0	33
149	Regulatory Commission Expenses	928	86	Onsi_PT_O&MxAGS-C	63	8	15	0
150	General Advertising Expense	930.1	33	Onsi_PT_O&MxAGS-C	25	3	6	0
151	Miscellaneous General Expenses	930.2	26	ONSITE_PT_O&M-C	19	2	4	0
152	Subtotal - O&M Accounts 928-935		1,340		961	121	224	33
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		11,561		9,260	917	1,092	292
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G**		55,092		49,394	2,551	2,855	292

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	2,005	ONSITEPT-C_INT	1,851	127	27	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	796	Meter_Invest	553	82	162	0
163	Distr Other	180Dist	1,012	ONSITE-CxMSM	832	63	117	0
164	General Plant	180Gen	247	ONSITEPT_GEN-C	186	21	41	0
165	*General Plant - Direct Assign.*	*180Gen DA*	0	*None*	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	4,060		3,422	292	347	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		4	ONSITEPT-C	3	0	1	0
170	Public utilty reality tax		33	ONSITEPT-C	25	3	5	0
171	State capital stock tax		33	ONSITEPT-C	25	3	5	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	70		53	6	11	0
	B. Income Tax Expense							
174	State Income Tax expense		946	PreTax-OnSi-C	1,902	(179)	(630)	(146)
175	Federal Income Tax expense		(5,026)	PreTax-OnSi-C	(10,104)	953	3,349	776
176	Investment Tax Credit - Amortization		5	PreTax-OnSi-C	10	(1)	(3)	(1)
177	Subtotal- Income tax expense		(4,075)		(8,192)	773	2,715	629
178	**TOTAL TAX EXPENSE**		(4,005)		(8,139)	779	2,727	629
179	**TOTAL EXPENSES**		55,148		44,677	3,621	5,928	921
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	48,730	Delivery_Rev	33,238	4,566	9,250	1,676
181	Forfeited Discounts		1,558	Account904	1,462	34	62	0
182	Miscellaneous Service Revenue		1,209	Misc_Ser_Rev	1,163	40	5	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		51,497		35,864	4,640	9,316	1,676
185	**TOTAL REVENUE**		51,497		35,864	4,640	9,316	1,676
186	**TOTAL EXPENSES**		55,148		44,677	3,621	5,928	921
187	**NET INCOME at Present Rates**		(3,651)		(8,812)	1,019	3,388	755

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		51,497		35,864	4,640	9,316	1,676
189	Total Operating Expenses		55,092		49,394	2,551	2,855	292
190	Depreciation Expense		4,060		3,422	292	347	0
191	*Taxes other than Income*		70		53	6	11	0
192	Total Other Expenses		4,131		3,475	298	358	0
193	Income tax expense		(4,075)		(8,192)	773	2,715	629
194	Total expenses		55,148		44,677	3,621	5,928	921
195	NET INCOME at Present Rates		(3,651)		(8,812)	1,019	3,388	755
196	**Total Rate Base**		42,515		34,872	3,142	4,499	2
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	*Using Target for System*							
200	Rate Base		42,515		34,872	3,142	4,499	2
201	Operating expenses		55,092		49,394	2,551	2,855	292
202	Depreciation expense		4,060		3,422	292	347	0
203	Taxes other than Income		70		53	6	11	0
204	Operating expenses to recover		59,222		52,869	2,848	3,213	292
205	Target Return on Rate Base- After taxes		3,780		3,100	279	400	0
206	Income taxes to recover		1,861	49.2%	1,526	138	197	0
207	Additional expenses		1,103	RS Direct	1,103	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		65,966		58,598	3,265	3,810	292

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	*Accrued Gas Revenues*		*0*	*None*	*0*	*0*	*0*	*0*
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		1,333	ONSITELABOR-C	1,112	107	113	0
217	Accounts Payable, Other- O&MxGas		2,818	ONSITEO&MxGASxAGS-C	2,321	188	308	0
218	Accounts Payable, Total		4,150		3,434	295	421	0
219	Accrued interest		(66)	ONSITEPT-C	(50)	(6)	(11)	0
220	Other, net		50	ONSITEPT-C	38	4	8	0
221	Defd Items & Other, Total		(16)		(12)	(1)	(3)	0
222	Total Working Capital		4,135		3,422	294	419	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	82		56	9	17	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	2,825		1,954	319	552	0
239	Customer Installation Expense	879	6		6	0	0	0
240	Other Expenses - Safety and Environmental	880	47		34	5	8	0
241	Other Expenses	880	48		35	5	9	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	300		283	3	14	0
248	Maint. of Meters & House Regulators	893	46		32	5	9	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		3,355		2,400	346	609	0
	OnSite:							
251	Customer Service - Administrative	901	174		162	11	1	0
252	Meter Reading Expenses	902	144		134	9	1	0
253	Customer Records & Collection Expense	903	3,828		3,563	237	27	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	*Supervision*	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		4,145		3,859	257	30	0
260	TOTAL:		7,500		6,259	603	638	0

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	1. RATE BASE									
	I. GAS PLANT IN SERVICE									
	A. INTANGIBLE PLANT									
1	Organization	301	50	RATEBASE	PRDGTHBASE	P&G_RATEBASE-E	STORBASE	OR_RATEBAS	TRANBASE	RAN_RATEBASE-
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	TRANSLABOR-D
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	-	-	-	-	-	-
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	-	-	-	-	-	-
5	Miscellaneous Intangible Plant - READI	303READI	15,628	ONSITE	-	-	-	-	-	-
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248							
	B. PRODUCTION & GATHERING PLANT									
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	COMMODITY	AGS Direct	-	-	-	-
8	Subtotal - PRODUCTION & GATHERING I	304-338	28,445							
	C. STORAGE PLANT									
9	Storage Plant	360-368	0	-	-	-	-	-	-	-
10	Subtotal - STORAGE PLANT	360-368	0							
	D. TRANSMISSION PLANT									
11	Transmission plant	365-370	106	TRANS	-	-	-	-	DEMAND	Peak
12	Transmission - Mains	367	1,243	TRANS	-	-	-	-	DEMAND	Peak
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	-	-	-	-	DEMAND	AGS Direct
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	-	-	-	-	DEMAND	AGS Direct
15	Subtotal - TRANSMISSION PLANT	365-370	32,350							
	E. DISTRIBUTION PLANT									
16	Land and Land Rights	374	1,893	DIST	-	-	-	-	-	-
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	-	-	-	-	-	-
18	Structures and Improvements	375	2,111	DIST	-	-	-	-	-	-
19	Mains	376	457,729	DIST	-	-	-	-	-	-
20	Mains - Direct Assign.	376 DA	10,267	DIST	-	-	-	-	-	-
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	-	-	-	-	-	-
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	-	-	-	-	-	-
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	-	-	-	-	-	-
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	-	-	-	-	-	-	-
25	Services	380	226,432	DIST	-	-	-	-	-	-
26	Meters	381	17,775	ONSITE	-	-	-	-	-	-
27	Meter Installations	382	9,208	ONSITE	-	-	-	-	-	-
28	House Regulators	383	5,656	ONSITE	-	-	-	-	-	-
29	House Regulator Installations	384	1,514	ONSITE	-	-	-	-	-	-
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	-	-	-	-	-	-
31	Property on Customers' Premises	386	15,838	ONSITE	-	-	-	-	-	-
32	Other Equipment	387	324	DIST	-	-	-	-	-	-
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	1. RATE BASE								
	I. GAS PLANT IN SERVICE								
	A. INTANGIBLE PLANT								
1	Organization	301	50	RATEBASE	DISTBASE	DIST_RATEBASE-D	DIST_RATEBASE-C	ONSITE_RB	ONSITE_RATEBASE-C
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	-	-	-	CUST	Cust_Avg
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	DISTPT	DISTOnlyPT-D	DISTOnlyPT-C	-	-
5	Miscellaneous Intangible Plant - READI	303READI	15,628	ONSITE	-	-	-	CUST	Cust_Avg
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248						
	B. PRODUCTION & GATHERING PLANT								
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	-	-	-	-	-
8	Subtotal - PRODUCTION & GATHERING I	304-338	28,445						
	C. STORAGE PLANT								
9	Storage Plant	360-368	0	-	-	-	-	-	-
10	Subtotal - STORAGE PLANT	360-368	0						
	D. TRANSMISSION PLANT								
11	Transmission plant	365-370	106	TRANS	-	-	-	-	-
12	Transmission - Mains	367	1,243	TRANS	-	-	-	-	-
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	-	-	-	-	-
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	-	-	-	-	-
15	Subtotal - TRANSMISSION PLANT	365-370	32,350						
	E. DISTRIBUTION PLANT								
16	Land and Land Rights	374	1,893	DIST	DISTOnlyPT	Peak	DISTOnlyPT-C	-	-
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	DEMAND	GSL Direct	-	-	-
18	Structures and Improvements	375	2,111	DIST	DISTOnlyPT	Peak	DISTOnlyPT-C	-	-
19	Mains	376	457,729	DIST	MAINS	Peak	Cust_Avg	-	-
20	Mains - Direct Assign.	376 DA	10,267	DIST	DEMAND	GSL Direct	-	-	-
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	DEMAND	Peak	-	-	-
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	DEMAND	GSL Direct	-	-	-
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	DEMAND	Peak	-	-	-
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	-	-	-	-	-	-
25	Services	380	226,432	DIST	CUST	-	Service_Invest	-	-
26	Meters	381	17,775	ONSITE	-	-	-	CUST	Meter_Invest
27	Meter Installations	382	9,208	ONSITE	-	-	-	CUST	Meter_Invest
28	House Regulators	383	5,656	ONSITE	-	-	-	CUST	Account 383/384
29	House Regulator Installations	384	1,514	ONSITE	-	-	-	CUST	Account 383/384
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	-	-	-	CUST	GSL Direct
31	Property on Customers' Premises	386	15,838	ONSITE	-	-	-	CUST	Account386
32	Other Equipment	387	324	DIST	CUST	-	GSS Direct	-	-
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	F. GENERAL PLANT									
34	Land and Land Rights	389	78	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
35	Structures and Improvements	390	7,842	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
36	Structures and Improvements - Direct Assi	390 DA	67	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
37	Office Furniture and Equipment	391	12,224	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
38	Office Furniture and Equipment - Direct As	391 DA	2	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
39	Transportation Equipment	392	10,288	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
40	Stores Equipment	393	47	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
41	Tools & Garage Equipment	394	4,271	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
43	Laboratory Equipment	395	0	-	-	-	-	-	-	-
44	Power Operated Equipment	396	3,155	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
45	Communication Equipment	397	6,923	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
47	Miscellaneous Equipment	398	32	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	-	-	-	-	DEMAND	GSL Direct
49	Subtotal - GENERAL PLANT	389-399	45,118							
50	TOTAL UTILITY PLANT									
	II. DEPRECIATION RESERVE									
51	Intangible Plant	108	8,236	INTANG_PT	PRDGTHPT	PRDGTHPT-E	DEMAND	OR_RATEBAS	DEMAND	TRAN_RATEBASE-I
52	Production & Gathering Plant	108.2	0	-	-	-	-	-	-	-
53	Production & Gathering Plant - Direct Assig	108.2 DA	8,153	PRODGATH	COMMODITY	AGS Direct	-	-	-	-
54	Local Storage Plant	108.3	0	-	-	-	-	-	-	-
55	Transmission Plant	108.4	658	TRANS	-	-	-	-	DEMAND	Peak
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	-	-	-	-	DEMAND	AGS Direct
57	Mains	109	130,432	DIST	-	-	-	-	-	-
58	Services	109	83,524	DIST	-	-	-	-	-	-
59	Meters	109	12,975	ONSITE	-	-	-	-	-	-
60	Distr Other	109	13,987	DIST_xMSM	-	-	-	-	-	-
61	General Plant	109	19,396	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
63	TOTAL DEPRECIATION RESERVE	108	289,353							
	III. OTHER RATE BASE ITEMS									
64	Materials and Supplies		887	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak
65	Current Gas Storage		75,176	STOR	-	-	DEMAND	Storage	-	-
66	Prepayments		234	O&MxGas	PRDGTHO&MxGas-E	PRDGTHO&MXGAS-C	-	-	DEMAND	Peak
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	-	-	-	-	DEMAND	TRAN_PTxAGS-D
68	Deferred Income Taxes - Direct Assign.		(2,423)	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
69	Deferred ITC		(4,903)	PLANTxAGS	-	-	-	-	DEMAND	TRAN_PTxAGS-D
70	Customer Deposits		(3,370)	DIST	-	-	-	-	-	-
71	TOTAL OTHER RATE BASE ITEMS		(36,684)							
72	TOTAL RATE BASE (Excl. Working Capita		571,917							
73	Working Capital	131	11,335							
74	TOTAL RATE BASE		583,253							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	F. GENERAL PLANT								
34	Land and Land Rights	389	78	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
35	Structures and Improvements	390	7,842	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
36	Structures and Improvements - Direct Assi	390 DA	67	PLANT_AGS	-	-	-	-	-
37	Office Furniture and Equipment	391	12,224	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
38	Office Furniture and Equipment - Direct As	391 DA	2	PLANT_AGS	-	-	-	-	-
39	Transportation Equipment	392	10,288	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
40	Stores Equipment	393	47	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
41	Tools & Garage Equipment	394	4,271	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	-	-	-	-	-
43	Laboratory Equipment	395	0	-	-	-	-	-	-
44	Power Operated Equipment	396	3,155	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
45	Communication Equipment	397	6,923	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	-	-	-	-	-
47	Miscellaneous Equipment	398	32	PLANT	DISTPT	DISTPT-D	DISTOnlyPT-C	CUST	ONSITEPT-C
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	DISTPT	GSL Direct	GSL Direct	CUST	GSL Direct
49	Subtotal - GENERAL PLANT	389-399	45,118						
50	TOTAL UTILITY PLANT								
	II. DEPRECIATION RESERVE								
51	Intangible Plant	108	8,236	INTANG_PT	DISTPT_INT	DISTPT-D_INT	DISTPT-C_INT	CUST	ONSITEPT-C_INT
52	Production & Gathering Plant	108.2	0	-	-	-	-	-	-
53	Production & Gathering Plant - Direct Assig	108.2 DA	8,153	PRODGATH	-	-	-	-	-
54	Local Storage Plant	108.3	0	-	-	-	-	-	-
55	Transmission Plant	108.4	658	TRANS	-	-	-	-	-
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	-	-	-	-	-
57	Mains	109	130,432	DIST	MAINS	DISTMAIN-D	Cust_Avg	-	-
58	Services	109	83,524	DIST	CUST	-	Service_Invest	-	-
59	Meters	109	12,975	ONSITE	-	-	-	CUST	Meter_Invest
60	Distr Other	109	13,987	DIST_xMSM	DISTPT_xMSM	DISTPT-DxMSM	DISTPT-CxMSM	CUST	ONSITE-CxMSM
61	General Plant	109	19,396	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	-	-	-	-	-
63	TOTAL DEPRECIATION RESERVE	108	289,353						
	III. OTHER RATE BASE ITEMS								
64	Materials and Supplies		887	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
65	Current Gas Storage		75,176	STOR	-	-	-	-	-
66	Prepayments		234	O&MxGas	DISTO&MxGas	DISTO&MXGAS-D	DISTO&MXGAS-C	ONSITEO&MxGas	ONSITEO&MXGAS-C
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
68	Deferred Income Taxes - Direct Assign.		(2,423)	PLANT_AGS	-	-	-	-	-
69	Deferred ITC		(4,903)	PLANTxAGS	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
70	Customer Deposits		(3,370)	DIST	CUST	-	Deposits	-	-
71	TOTAL OTHER RATE BASE ITEMS		(36,684)						
72	TOTAL RATE BASE (Excl. Working Capita		571,917						
73	Working Capital	131	11,335						
74	TOTAL RATE BASE		583,253						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	2. EXPENSES									
	I. OPERATION & MAINTENANCE EXPEN									
	A. PRODUCTION & GATHERING EXPEN									
75	Operations Expense	750-756	1,043	PRODGATH	PRDGTHPT	PRDGTHPT-E	-	-	-	-
76	Maintenance Expense	761-765	1,766	PRODGATH	PRDGTHPT	PRDGTHPT-E	-	-	-	-
77	Subtotal - Production and Gathering	750-765								
	B. OTHER GAS SUPPLY EXPENSES		0							
78	Natural gas field line purchases	801	0	-	-	-	-	-	-	-
79	Natural gas transmission line purchases	803	0	-	-	-	-	-	-	-
80	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-	-
81	Other Natural Gas Purchases	805	0	-	-	-	-	-	-	-
82	Well Expenses - Purchased Gas	807	0	-	-	-	-	-	-	-
83	Maintenance of Purchased Gas Meas. Sta.	807	0	-	-	-	-	-	-	-
84	Gas Withdrawn from Storage	808	0	-	-	-	-	-	-	-
85	Gas Delivered to Storage	808	0	-	-	-	-	-	-	-
86	Other Gas Supply Expense	813	391	PRODGATH	COMMODITY	Account813	-	-	-	-
87	Subtotal - OTHER GAS SUPPLY EXPENS	800-813	391							
	C. NATURAL GAS STORAGE									
88	LNG Operating Exp Admin	840	0	-	-	-	-	-	-	-
89	Operating Exp- Admin	850	0	-	-	-	-	-	-	-
90	Subtotal - NATURAL GAS STORAGE	840-850	0							
	D. TRANSMISSION EXPENSES									
91	Transmission expenses	856-863	0	-	-	-	-	-	-	-
92	Subtotal- Transmission Expenses	856-863	0							
	E. DISTRIBUTION EXPENSES									
93	Operation Supv & Engineering	870	1,773	DIST_PT	-	-	-	-	-	-
94	Load Dispatching	871	112	PRODGATH	COMMODITY	Gas_Deliveries	-	-	-	-
95	Compressor Station Fuel and Power	873	(0)	-	-	-	-	-	-	-
96	Mains and Services Expenses	874	5,088	N_SERV_TRANM	-	-	-	-	TRANS_MAIN	TRANS_MAINS-D
97	Meas. & Reg. Station Expense General	875	100	DIST	-	-	-	-	-	-
98	Meas. & Reg. Station Expense Industrial	876	0	-	-	-	-	-	-	-
99	Meter & House Regulator Expenses	878	6,062	ONSITE	-	-	-	-	-	-
100	Customer Installation Expense	879	62	ONSITE	-	-	-	-	-	-
101	Other Expenses - Safety and Environmenta	880	632	O&MxAcct880	PRDGTHO&MxA/C880	PRDGTHO&MxA/C880	-	-	DEMAND	RANO&MxA/C880-
102	Other Expenses	880	650	O&MxAcct880	PRDGTHO&MxA/C880	P&G_O&Mx880xAGS	-	-	DEMAND	RANO&Mx880xAGS
103	Distribution Rents	881	602	DIST_PT	-	-	-	-	-	-
104	Maint. Supervision & Engineering	885	885	DIST	-	-	-	-	-	-
105	Maintenance of Structures & Improvements	886	516	DIST	-	-	-	-	-	-
106	Maint. of Mains	887	5,521	DIST	-	-	-	-	-	-
107	Maint Of Meas. & Reg. Station Expense Ge	889	1,192	DIST	-	-	-	-	-	-
108	Maint Of Meas. & Reg. Sta. Exp. City Gate	891	10	DIST	-	-	-	-	-	-
109	Maint. of Services	892	663	ONSITE	-	-	-	-	-	-
110	Maint. of Meters & House Regulators	893	107	ONSITE	-	-	-	-	-	-
111	Maintenance of Other Equipment	894	67	DIST	-	-	-	-	-	-
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042							
113	TOTAL OPERATION & MAINTENANCE E		27,242							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	2. EXPENSES								
	I. OPERATION & MAINTENANCE EXPEN								
	A. PRODUCTION & GATHERING EXPEN								
75	Operations Expense	750-756	1,043	PRODGATH	-	-	-	-	-
76	Maintenance Expense	761-765	1,766	PRODGATH	-	-	-	-	-
77	Subtotal - Production and Gathering	750-765							
	B. OTHER GAS SUPPLY EXPENSES		0						
78	Natural gas field line purchases	801	0	-	-	-	-	-	-
79	Natural gas transmission line purchases	803	0	-	-	-	-	-	-
80	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-
81	Other Natural Gas Purchases	805	0	-	-	-	-	-	-
82	Well Expenses - Purchased Gas	807	0	-	-	-	-	-	-
83	Maintenance of Purchased Gas Meas. Sta.	807	0	-	-	-	-	-	-
84	Gas Withdrawn from Storage	808	0	-	-	-	-	-	-
85	Gas Delivered to Storage	808	0	-	-	-	-	-	-
86	*Other Gas Supply Expense*	*813*	*391*	*PRODGATH*	-	-	-	-	-
87	Subtotal - OTHER GAS SUPPLY EXPENS	800-813	391						
	C. NATURAL GAS STORAGE								
88	LNG Operating Exp Admin	840	0	-	-	-	-	-	-
89	Operating Exp- Admin	850	0	-	-	-	-	-	-
90	Subtotal - NATURAL GAS STORAGE	840-850	0						
	D. TRANSMISSION EXPENSES								
91	*Transmission expenses*	*856-863*	0	-	-	-	-	-	-
92	Subtotal- Transmission Expenses	856-863	0						
	E. DISTRIBUTION EXPENSES								
93	Operation Supv & Engineering	870	1,773	DIST_PT	DISTOnlyPT	DISTOnlyPT-D	DISTOnlyPT-C	CUST	ONSITEDistPT-C
94	Load Dispatching	871	112	PRODGATH	-	-	-	-	-
95	Compressor Station Fuel and Power	873	(0)	-	-	-	-	-	-
96	Mains and Services Expenses	874	5,088	N_SERV_TRANM	MAIN&SERVICE	DISTMAIN-SERV-D	DISTMAIN-SERV-C	-	-
97	Meas. & Reg. Station Expense General	875	100	DIST	DEMAND	Peak	-	-	-
98	Meas. & Reg. Station Expense Industrial	876	0	-	-	-	-	-	-
99	Meter & House Regulator Expenses	878	6,062	ONSITE	-	-	-	CUST	ONSITE-MR-C
100	Customer Installation Expense	879	62	ONSITE	-	-	-	CUST	RS Direct
101	Other Expenses - Safety and Environment	880	632	O&MxAcct880	DISTO&MxA/C880	DISTO&MxA/C880-D	DISTO&MxA/C880-C	ONSITEO&MxA/C880	ONSITEO&MxA/C880-C
102	Other Expenses	880	650	O&MxAcct880	DISTO&MxA/C880	DISTO&Mx880xAGS-D	DISTO&Mx880xAGS-C	ONSITEO&MxA/C880	ONSITEO&Mx880xAGS-C
103	Distribution Rents	881	602	DIST_PT	DISTOnlyPT	DISTOnlyPT-D	DISTOnlyPT-C	CUST	ONSITEDistPT-C
104	Maint. Supervision & Engineering	885	885	DIST	DISTLABOR	DISTLABOR-D	DISTLABOR-C	-	-
105	Maintenance of Structures & Improvement	886	516	DIST	DISTOnlyPT	DISTOnlyPT-D	DISTPT-C	-	-
106	Maint. of Mains	887	5,521	DIST	MAINS	DISTMAIN-D	Cust_Avg	-	-
107	Maint Of Meas. & Reg. Station Expense Ge	889	1,192	DIST	DEMAND	Peak	-	-	-
108	Maint Of Meas. & Reg. Sta. Exp. City Gate	891	10	DIST	DEMAND	Peak	-	-	-
109	Maint. of Services	892	663	ONSITE	-	-	-	CUST	Service_Invest
110	Maint. of Meters & House Regulators	893	107	ONSITE	-	-	-	CUST	ONSITE-MR-C
111	Maintenance of Other Equipment	894	67	DIST	DISTOnlyPT	DISTPT-D	DISTPT-C	-	-
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042						
113	TOTAL OPERATION & MAINTENANCE E		27,242						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	II. CUSTOMER ACCOUNTS EXPENSES									
114	Customer Service - Administrative	901	225	ONSITE	-	-	-	-	-	-
115	Meter Reading Expenses	902	587	ONSITE	-	-	-	-	-	-
116	Customer Records & Collection Expense	903	10,270	ONSITE	-	-	-	-	-	-
117	Uncollectible Accounts	904	8,883	ONSITE	-	-	-	-	-	-
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	-	-	-	-	-	-
119	Miscellaneous Customer Accounts Expens	905	0	-	-	-	-	-	-	-
120	TOTAL CUSTOMER ACCOUNTS EXPEN:		36,132							
	III. CUSTOMER SERVICE & INFORMATIC									
121	Operation Supervision	907	0	-	-	-	-	-	-	-
122	Customer Assist- Other	908	210	DIST	-	-	-	-	-	-
123	Customer Assist- CAP	908CAP	299	DIST	-	-	-	-	-	-
124	Other Customer Service & Informational E>	910	698	DIST	-	-	-	-	-	-
125	Supervision	911	0	-	-	-	-	-	-	-
126	Demonstration	912	660	DIST	-	-	-	-	-	-
127	Adverstising expense	913	24	DIST	-	-	-	-	-	-
128	TOTAL CUSTOMER SERVICE & INFORM		1,891							
129	TOTAL CUSTOMER ACCOUNTS, SERVI(		38,024							
	IV. ADMINISTRATIVE & GENERAL EXPE!									
	A. Labor-Related:									
130	Administrative & General Salaries	920	5,940	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
131	Administrative & General Salaries - Direct /	920 DA	550	LABOR	COMMODITY	AGS Direct	-	-	DEMAND	AGS Direct
132	Office Supplies & Expenses	921	817	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
133	Outside Services Employed - Resid.	923	180	LABOR	COMMODITY	RS Direct	-	-	-	-
134	Outside Services Employed - Labor	923I	3,637	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
135	Injuries & Damages	925Labor	338	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
136	Employee Pensions and Benefits	926	5,725	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
137	Rents	931	4,025	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
138	Subtotal - O&M Accounts 920-923, 925L, 9		21,213							
	B. Plant-Related:									
139	Property Insurance	924	335	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak
140	Outside Services Employed-plant	923p	135	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak
141	Injuries & Damages	925Plant	4,130	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	PRDGTHPT	P&G_PT_GEN-E	-	-	DEMAND	TRAN_PT_GEN-D
143	Misc. Maintenance Expense - Direct Assigr	932 DA	50	GENERAL PT	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
144	Subtotal - O&M Accounts 924-925P		5,879							
	C. Other-Related:									
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
146	Outside Services Employed-cust	923c	5,083	DIST	-	-	-	-	-	-
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
148	Outside Services Employed-plant-O&M - D	923p-om DA	200	PLANT_O&M	COMMODITY	AGS Direct	-	-	DEMAND	AGS Direct
149	Regulatory Commission Expenses	928	517	PLANT_O&M	COMMODITY	P&G_PT_O&MxAGS-E	-	-	DEMAND	TRAN_PTxAGS-D
150	General Advertising Expense	930.1	201	PLANT_O&M	COMMODITY	P&G_PT_O&MxAGS-E	-	-	DEMAND	TRAN_PTxAGS-D
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
152	Subtotal - O&M Accounts 928-935									
153	TOTAL ADMINISTRATIVE & GENERAL E:		40,234							
154	TOTAL OPERATING EXPENSES (Excl De		105,499							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	II. CUSTOMER ACCOUNTS EXPENSES								
114	Customer Service - Administrative	901	225	ONSITE	-	-	-	CUST	Acct901-903,908
115	Meter Reading Expenses	902	587	ONSITE	-	-	-	CUST	Acct901-903,908
116	Customer Records & Collection Expense	903	10,270	ONSITE	-	-	-	CUST	Acct901-903,908
117	Uncollectible Accounts	904	8,883	ONSITE	-	-	-	CUST	Account904
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	-	-	-	CUST	RS Direct
119	Miscellaneous Customer Accounts Expens	905	0	-	-	-	-	-	-
120	TOTAL CUSTOMER ACCOUNTS EXPEN:		36,132						
	III. CUSTOMER SERVICE & INFORMATIC								
121	Operation Supervision	907	0	-	-	-	-	-	-
122	Customer Assist- Other	908	210	DIST	CUST	-	Acct901-903,908	-	-
123	Customer Assist- CAP	908CAP	299	DIST	CUST	-	RS Direct	-	-
124	Other Customer Service & Informational E>	910	698	DIST	CUST	-	Account910	-	-
125	Supervision	911	0	-	-	-	-	-	-
126	Demonstration	912	660	DIST	CUST	-	Account911-916	-	-
127	Adverstising expense	913	24	DIST	CUST	-	Account911-916	-	-
128	TOTAL CUSTOMER SERVICE & INFORM		1,891						
129	TOTAL CUSTOMER ACCOUNTS, SERVI(		38,024						
	IV. ADMINISTRATIVE & GENERAL EXPEI								
	A. Labor-Related:								
130	Administrative & General Salaries	920	5,940	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
131	Administrative & General Salaries - Direct /	920 DA	550	LABOR	DISTLABOR	AGS Direct	AGS Direct	CUST	AGS Direct
132	Office Supplies & Expenses	921	817	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
133	Outside Services Employed - Resid.	923	180	LABOR	DISTLABOR	RS Direct	RS Direct	CUST	RS Direct
134	Outside Services Employed - Labor	923l	3,637	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
135	Injuries & Damages	925Labor	338	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
136	Employee Pensions and Benefits	926	5,725	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
137	Rents	931	4,025	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
138	Subtotal - O&M Accounts 920-923, 925L, 9		21,213						
	B. Plant-Related:								
139	Property Insurance	924	335	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
140	Outside Services Employed-plant	923p	135	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
141	Injuries & Damages	925Plant	4,130	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	DISTPT_GEN	DISTPT_GEN-D	DISTPT_GEN-C	CUST	ONSITEPT_GEN-C
143	Misc. Maintenance Expense - Direct Assigr	932 DA	50	GENERAL PT	DISTPT_GEN	AGS Direct	AGS Direct	CUST	AGS Direct
144	Subtotal - O&M Accounts 924-925P		5,879						
	C. Other-Related:								
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
146	Outside Services Employed-cust	923c	5,083	DIST	CUST	-	Cust_Avg	-	- -
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
148	Outside Services Employed-plant-O&M - D	923p-om DA	200	PLANT_O&M	DIST_PT_O&M	AGS Direct	AGS Direct	CUST	AGS Direct
149	Regulatory Commission Expenses	928	517	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&MxAGS-D	DIST_PT_O&MxAGS-C	CUST	Onsi_PT_O&MxAGS-C
150	General Advertising Expense	930.1	201	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&MxAGS-D	DIST_PT_O&MxAGS-C	CUST	Onsi_PT_O&MxAGS-C
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	DISTPT_GEN	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
152	Subtotal - O&M Accounts 928-935								
153	TOTAL ADMINISTRATIVE & GENERAL E:		40,234						
154	TOTAL OPERATING EXPENSES (Excl De		105,499						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	V. DEPRECIATION EXPENSE									
155	Intangible Plant	180Int	2,439	INTANG_PT	PRDGTHPT	PRDGTHPT-E	DEMAND	OR_RATEBASI	DEMAND	RAN_RATEBASE-I
156	Production & Gathering Plant - Direct Assig	180ProdGth DA	631	PRODGATH_PT	COMMODITY	AGS Direct	-	-	-	-
157	Local Storage Plant	180Stor	0	-	-	-	-	-	-	-
158	Transmission Plant	180Trans	9	TRANS	-	-	-	-	DEMAND	Peak
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	-	-	-	-	DEMAND	AGS Direct
160	Mains (Distribution)	180Mains	6,999	DIST	-	-	-	-	-	-
161	*Services*	*180Services*	*5,815*	*DIST*	-	-	-	-	-	-
162	Meters	180Meters	796	ONSITE	-	-	-	-	-	-
163	Distr Other	180Dist	2,003	DIST_xMSM	-	-	-	-	-	-
164	General Plant	180Gen	4,071	GENERAL PT	PRDGTHPT	P&G_PT_GEN-E	-	-	DEMAND	TRAN_PT_GEN-D
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
166	Adjustments		0	-	-	-	-	-	-	-
167	TOTAL DEPRECIATION EXPENSE	403	23,471							
			0	-	-	-	-	-	-	-
	VI. TAXES		0	-	-	-	-	-	-	-
	A. General Taxes		0	-	-	-	-	-	-	-
168	PA PUC Assessment		1,139	DIST	-	-	-	-	-	-
169	Local property taxes		63	PLANTxAGS	-	-	-	-	DEMAND	Peak
170	Public utilty reality tax		519	PLANTxAGS	-	-	-	-	DEMAND	Peak
171	State capital stock tax		447	RATEBASE	PRDGTHBASE	PRDGTHPT-E	STORBASE	Storage	TRANBASE	Peak
172	Miscellaneous tax		17	PRODGATH	COMMODITY	Gas_Deliveries	-	-	-	-
173	Subtotal- Taxes Other Than Income Taxes	408	2,186							
	B. Income Tax Expense									
174	State Income Tax expense		(1,009)	Pre-Tax	PreTax-PRDGTH	PreTax-PRDGTH-E	PreTax-STOR	PreTax-Stor-D	DEMAND	PreTax-Tran-D
175	Federal Income Tax expense		5,363	Pre-Tax	PreTax-PRDGTH	PreTax-PRDGTH-E	PreTax-STOR	PreTax-Stor-D	DEMAND	PreTax-Tran-D
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	-	-	PreTax-STOR	PreTax-Stor-D	-	-
177	Subtotal- Income tax expense		4,348							
178	TOTAL TAX EXPENSE		6,534							
179	TOTAL EXPENSES									
	3. REVENUES at Present Rates									
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	COMMODITY	Delivery_Rev	DEMAND	Delivery_Rev	DEMAND	Delivery_Rev
181	Forfeited Discounts		1,558	ONSITE	-	-	-	-	-	-
182	Miscellaneous Service Revenue		1,209	ONSITE	-	-	-	-	-	-
183	Other Operating Revenue		61	DIST	-	-	-	-	-	-
184	Subtotal- Gas Revenues, net		157,693							
185	TOTAL REVENUE		157,693							
186	TOTAL EXPENSES		135,504							
187	NET INCOME at Present Rates		22,189							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	V. DEPRECIATION EXPENSE								
155	Intangible Plant	180Int	2,439	INTANG_PT	DISTPT_INT	DISTPT-D_INT	DISTPT-C_INT	CUST	ONSITEPT-C_INT
156	Production & Gathering Plant - Direct Assig	180ProdGth DA	631	PRODGATH_PT	-	-	-	-	-
157	Local Storage Plant	180Stor	0	-	-	-	-	-	-
158	Transmission Plant	180Trans	9	TRANS	-	-	-	-	-
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	-	-	-	-	-
160	Mains (Distribution)	180Mains	6,999	DIST	MAINS	DISTMAIN-D	Cust_Avg	-	-
161	Services	180Services	5,815	DIST	CUST	-	Service_Invest	-	-
162	Meters	180Meters	796	ONSITE	-	-	-	CUST	Meter_Invest
163	Distr Other	180Dist	2,003	DIST_xMSM	DISTPT_xMSM	DISTPT-DxMSM	DISTPT-CxMSM	CUST	ONSITE-CxMSM
164	General Plant	180Gen	4,071	GENERAL PT	DISTPT_GEN	DISTPT_GEN-D	DISTPT_GEN-C	CUST	ONSITEPT_GEN-C
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	-	-	-	-	-
166	Adjustments		0	-	-	-	-	-	-
167	TOTAL DEPRECIATION EXPENSE	403	23,471						
			0	-	-	-	-	-	-
	VI. TAXES		0	-	-	-	-	-	-
	A. General Taxes		0	-	-	-	-	-	-
168	PA PUC Assessment		1,139	DIST	CUST	-	Delivery_RevxAGS	-	-
169	Local property taxes		63	PLANTxAGS	DISTPT	TOTALPLANTxAGS	TOTALPLANTxAGS	CUST	ONSITEPT-C
170	Public utilty reality tax		519	PLANTxAGS	DISTPT	TOTALPLANTxAGS	TOTALPLANTxAGS	CUST	ONSITEPT-C
171	State capital stock tax		447	RATEBASE	DISTBASE	DISTPT-D	RATEBASExAGS	CUST	ONSITEPT-C
172	Miscellaneous tax		17	PRODGATH	-	-	-	-	-
173	Subtotal- Taxes Other Than Income Taxes	408	2,186						
	B. Income Tax Expense								
174	State Income Tax expense		(1,009)	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
175	Federal Income Tax expense		5,363	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
177	Subtotal- Income tax expense		4,348						
178	TOTAL TAX EXPENSE		6,534						
179	TOTAL EXPENSES								
	3. REVENUES at Present Rates								
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	RevReq_PF-Dist	Delivery_Rev	Delivery_Rev	CUST	Delivery_Rev
181	Forfeited Discounts		1,558	ONSITE	-	-	-	CUST	Account904
182	*Miscellaneous Service Revenue*		*1,209*	*ONSITE*	-	-	-	*CUST*	*Misc_Ser_Rev*
183	Other Operating Revenue		61	DIST	CUST	-	Delivery_RevxAGS	-	-
184	Subtotal- Gas Revenues, net		157,693						
185	TOTAL REVENUE		157,693						
186	TOTAL EXPENSES		135,504						
187	NET INCOME at Present Rates		22,189						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	Working Capital Subreport									
209	Accounts Receivable- Gas		0	-	-	-	-	-	-	-
210	Accounts Receivable- Other		0	-	-	-	-	-	-	-
211	Accrued Gas Revenues		0	-	-	-	-	-	-	-
212	Accounts Receivable, Total		0							
213	Gas, LNG in Storage		0	-	-	-	-	-	-	-
214	Inventories & Other, Total		0							
215	*Accounts Payable, Natural Gas*		*3,330*	*PRODGATH*	*COMMODITY*	*Gas_Deliveries*	-	-	-	-
216	Accounts Payable, Other- Labor		2,867	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	Peak
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	COMMODITY	Gas_Deliveries	-	-	DEMAND	Peak
218	Accounts Payable, Total		11,592							
219	Accrued interest		(1,083)	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak
220	Other, net		826	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak
221	*Defd Items & Other, Total*		(257)							
222	Total Working Capital		11,335							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	Working Capital Subreport								
209	Accounts Receivable- Gas		0	-	-	-	-	-	-
210	Accounts Receivable- Other		0	-	-	-	-	-	-
211	Accrued Gas Revenues		0	-	-	-	-	-	-
212	Accounts Receivable, Total		0						
213	Gas, LNG in Storage		0	-	-	-	-	-	-
214	*Inventories & Other, Total*		0						
215	Accounts Payable, Natural Gas		3,330	PRODGATH	-	-	-	-	-
216	Accounts Payable, Other- Labor		2,867	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	DISTO&MxGas	DISTO&MXGAS-D	)NSITEO&MxGASxAGS-	CUST	)NSITEO&MxGASxAGS-
218	Accounts Payable, Total		11,592						
219	Accrued interest		(1,083)	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
220	Other, net		826	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
221	Defd Items & Other, Total		(257)						
222	Total Working Capital		11,335						

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Revenues at Current Rates					
1	Operating Revenue	157,631	108,258	14,584	29,463	5,326
2	Other revenue / Adjustments	61	43	6	12	0
3	Net revenues	157,693	108,301	14,590	29,475	5,326
4	Operating Expenses					
5	Operations, Customer, A&G	105,498	78,139	6,321	14,808	6,230
6	Depreciation expense	23,471	15,836	1,211	4,909	1,515
7	Taxes other than income	2,186	1,473	180	514	18
8	Operating expenses	131,155	95,448	7,713	20,231	7,763
9	Income tax expense	4,348	876	2,655	2,432	(1,615)
10	Total Operating Expenses	135,503	96,325	10,367	22,663	6,149
11	**Income at Present Rates**	22,190	11,976	4,223	6,812	(822)
12	**Rate Base**	583,253	375,385	35,688	133,862	38,317
13	**Return on Rate Base at Present Rates**	3.80%	3.19%	11.83%	5.09%	(2.15%)
14	Revenue Requirement at Full Cost of Service	209,642	146,356	12,448	37,991	12,847
15	Operating expenses	131,155	95,448	7,713	20,231	7,763
16	Income tax expense	25,531	16,432	1,562	5,860	1,677
17	Additional expenses	1,103	1,103	0	0	0
18		157,790	112,984	9,275	26,091	9,440
19	**Income at Full Cost of Service**	51,852	33,372	3,173	11,900	3,406
20	**Return on Rate Base at Full Cost of Service**	8.89%	8.89%	8.89%	8.89%	8.89%
21	**Revenue INCREASE (DECREASE) to Achieve Full Cost of Service**	**51,949**	**38,054**	**(2,143)**	**8,516**	**7,520**

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
			REV. REQ. BY FUNCTIONAL CLASSIFICATION- TOTAL			
	PRODUCTION & GATHERING					
1	Commodity Component	10,017	789	128	438	8,662
2		10,017	789	128	438	8,662
	STORAGE					
3	Demand Component	10,033	8,556	985	491	0
4		10,033	8,556	985	491	0
	TRANSMISSION					
5	Demand Component	3,859	224	32	154	3,449
6		3,859	224	32	154	3,449
	DISTRIBUTION					
7	Demand Component	81,062	43,186	6,222	31,302	351
8	Customer Component	38,706	35,002	1,815	1,797	93
9		119,767	78,188	8,037	33,098	444
	ONSITE					
10	Customer Component	65,966	58,598	3,265	3,810	292
11		65,966	58,598	3,265	3,810	292
	TOTAL REVENUE REQUIREMENT					
12	Demand Component	94,953	51,967	7,240	31,947	3,800
13	Commodity Component	10,017	789	128	438	8,662
14	Customer Component	104,671	93,600	5,080	5,606	385
15	Total	209,641	146,356	12,448	37,991	12,847
16	Increase (Decrease) for Full COS	51,949	38,054	(2,143)	8,516	7,520

		Total		Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
				REV. REQ. BY FUNCTIONAL CLASSIFICATION- UNITIZED			
	PRODUCTION & GATHERING						
17	Commodity Component		$ / mcf	$0.04	$0.03	$0.02	$0.60
	STORAGE						
18	Demand Component		$ / mcf-month	$1,303.20	$1,037.68	$109.53	$0.00
	TRANSMISSION						
19	Demand Component		$ / mcf-month	$34.13	$34.06	$34.23	$0.24
	DISTRIBUTION						
20	Demand Component		$ / mcf-month	$6,577.89	$6,552.05	$6,979.32	$0.02
21	Customer Component		$ / cust-month	$12.19	$9.51	$81.24	$0.01
	ONSITE						
22	Customer Component		$ / cust-month	$20.41	$17.11	$172.26	$0.02
	TOTAL REVENUE REQUIREMENT						
23	Demand Component		$ / mcf-month	$7,915.22	$7,623.80	$7,123.09	$0.26
24	Commodity Component		$ / mcf	$0.04	$0.03	$0.02	$0.60
25	Customer Component		$ / cust-month	$32.60	$26.61	$253.49	$0.03
26	Demand Allocator %	1	Peak&Avg	1	0	0	0
27	Commodity Allocator X 1000	61,075	Gas_Deliver_w/AGS	22,187	3,805	20,639	14,444
28	Customer Allocator X 1000	3,084	Bills_All	2,871	191	22	-

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	*General Service* - Small (GSS)	*General Service* - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE						
	I. GAS PLANT IN SERVICE						
	A. INTANGIBLE PLANT						
1	Organization	301	50	32	3	11	3
2	Intangible Plant - Software- Labor	303Lab	3,342	2,155	284	630	274
3	Intangible Plant - Software- Customer	303Cust	2,743	2,553	170	20	0
4	Intangible Plant - Software- Plant	303Plt	2,485	1,651	139	696	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	14,549	967	112	0
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248	20,940	1,563	1,469	277
	B. PRODUCTION & GATHERING PLANT						
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	0	0	0	28,445
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	28,445	0	0	0	28,445
	C. STORAGE PLANT						
9	Storage Plant	360-368	0	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0	0	0	0	0
	D. TRANSMISSION PLANT						
11	Transmission plant	365-370	106	58	8	40	0
12	Transmission - Mains	367	1,243	680	98	464	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	0	0	0	14,171
14	Transmission - Mains - Direct Assign.	367 DA	16,830	0	0	0	16,830
15	Subtotal - TRANSMISSION PLANT	365-370	32,350	738	107	504	31,001
	E. DISTRIBUTION PLANT						
16	Land and Land Rights	374	1,893	1,274	108	510	0
17	Land and Land Rights - Direct Assign.	374 DA	564	0	0	564	0
18	Structures and Improvements	375	2,111	1,421	120	569	0
19	Mains	376	457,729	250,431	36,224	171,074	0
20	Mains - Direct Assign.	376 DA	10,267	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	8,823	1,276	6,027	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	244	35	167	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	0	0	0	0
25	Services	380	226,432	213,758	2,209	10,465	0
26	Meters	381	17,775	12,344	1,821	3,610	0
27	Meter Installations	382	9,208	6,395	943	1,870	0
28	House Regulators	383	5,656	3,852	865	939	0
29	House Regulator Installations	384	1,514	1,031	231	251	0
30	Ind. Meas. & Reg. Station Equip.	385	441	0	0	441	0
31	Property on Customers' Premises	386	15,838	14,394	356	1,087	0
32	Other Equipment	387	324	0	324	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793	513,968	44,513	209,312	0

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT						
34	Land and Land Rights	389	78	50	4	21	3
35	Structures and Improvements	390	7,842	5,032	446	2,095	269
36	Structures and Improvements - Direct Assign.	390 DA	67	0	0	0	67
37	Office Furniture and Equipment	391	12,224	7,844	694	3,266	420
38	Office Furniture and Equipment - Direct Assign.	391 DA	2	0	0	0	2
39	Transportation Equipment	392	10,288	6,601	584	2,749	353
40	Stores Equipment	393	47	30	3	13	2
41	Tools & Garage Equipment	394	4,271	2,741	243	1,141	147
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	0	0	0	26
43	Laboratory Equipment	395	0	0	0	0	0
44	Power Operated Equipment	396	3,155	2,024	179	843	108
45	Communication Equipment	397	6,923	4,442	393	1,850	238
46	Communication Equipment - Direct Assign.	397 DA	6	0	0	0	6
47	Miscellaneous Equipment	398	32	21	2	9	1
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	0	0	156	0
49	Subtotal - GENERAL PLANT	389-399	45,118	28,785	2,549	12,143	1,641
50	**TOTAL UTILITY PLANT**		897,955	564,431	48,731	223,427	61,365
	II. DEPRECIATION RESERVE						
51	Intangible Plant	108	8,236	7,112	531	499	95
52	Production & Gathering Plant	108.2	0	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	0	0	0	8,153
54	Local Storage Plant	108.3	0	0	0	0	0
55	Transmission Plant	108.4	658	360	52	246	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	0	0	0	11,969
57	Mains	109	130,432	69,796	10,096	50,540	0
58	Services	109	83,524	78,849	815	3,860	0
59	Meters	109	12,975	9,011	1,329	2,635	0
60	Distr Other	109	13,987	9,361	1,000	3,627	0
61	General Plant	109	19,396	12,446	1,102	5,183	666
62	General Plant - Direct Assign.	108.8 DA	21	0	0	0	21
63	**TOTAL DEPRECIATION RESERVE**	108	289,353	186,934	14,925	66,590	20,904
	III. OTHER RATE BASE ITEMS						
64	Materials and Supplies		887	569	50	237	30
65	Current Gas Storage		75,176	64,111	7,384	3,681	0
66	Prepayments		234	170	17	36	10
67	Deferred Income Taxes - Depreciation		(102,286)	(68,224)	(5,973)	(28,090)	0
68	Deferred Income Taxes - Direct Assign.		(2,423)	0	0	0	(2,423)
69	Deferred ITC		(4,903)	(3,270)	(286)	(1,346)	0
70	Customer Deposits		(3,370)	(2,775)	(209)	(385)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(36,684)	(9,419)	983	(25,867)	(2,382)
72	**TOTAL RATE BASE (Excl. Working Capital)**		571,917	368,077	34,790	130,971	38,079
73	Working Capital	131	11,335	7,308	898	2,891	238
74	**TOTAL RATE BASE**		583,253	375,385	35,688	133,862	38,317

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES						
	I. OPERATION & MAINTENANCE EXPENSE						
	A. PRODUCTION & GATHERING EXPENSES						
75	*Operations Expense*	750-756	1,043	0	0	0	1,043
76	Maintenance Expense	761-765	1,766	0	0	0	1,766
77	Subtotal - Production and Gathering	750-765	2,809	0	0	0	2,809
	B. OTHER GAS SUPPLY EXPENSES						
78	Natural gas field line purchases	801	0	0	0	0	0
79	Natural gas transmission line purchases	803	0	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	0	0	0	0
81	Other Natural Gas Purchases	805	0	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	0	0	0	0
84	Gas Withdrawn from Storage	808	0	0	0	0	0
85	Gas Delivered to Storage	808	0	0	0	0	0
86	Other Gas Supply Expense	813	391	279	44	68	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391	279	44	68	0
	C. NATURAL GAS STORAGE						
88	LNG Operating Exp Admin	840	0	0	0	0	0
89	Operating Exp- Admin	850	0	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0	0	0	0	0
	D. TRANSMISSION EXPENSES						
91	Transmission expenses	856-863					
92	Subtotal- Transmission Expenses	856-863	0	0	0	0	0
	E. DISTRIBUTION EXPENSES						
93	Operation Supv & Engineering	870	1,773	1,180	105	488	0
94	Load Dispatching	871	112	53	9	50	0
95	Compressor Station Fuel and Power	873	0	0	0	0	0
96	Mains and Services Expenses	874	5,088	3,319	275	1,373	120
97	Meas. & Reg. Station Expense General	875	100	55	8	37	0
98	Meas. & Reg. Station Expense Industrial	876	0	0	0	0	0
99	Meter & House Regulator Expenses	878	6,062	4,193	685	1,184	0
100	Customer Installation Expense	879	62	62	0	0	0
101	Other Expenses - Safety and Environmental	880	632	359	45	157	71
102	Other Expenses	880	650	417	54	179	0
103	Distribution Rents	881	602	400	36	166	0
104	Maint. Supervision & Engineering	885	885	501	93	291	0
105	Maintenance of Structures & Improvements	886	516	343	29	144	0
106	Maint. of Mains	887	5,521	2,955	427	2,139	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	652	94	445	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	10	6	1	4	0
109	Maint. of Services	892	663	626	6	31	0
110	Maint. of Meters & House Regulators	893	107	74	12	21	0
111	Maintenance of Other Equipment	894	67	45	4	19	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042	15,239	1,883	6,728	191
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		27,242	15,518	1,928	6,795	3,000

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES						
114	Customer Service - Administrative	901	225	210	14	2	0
115	Meter Reading Expenses	902	587	546	36	4	0
116	Customer Records & Collection Expense	903	10,270	9,561	636	74	0
117	Uncollectible Accounts	904	8,883	8,339	191	353	0
118	Uncollectible Accounts- CAP	904CAP	16,167	16,167	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	0	0	0	0
120	TOTAL CUSTOMER ACCOUNTS EXPENSES		36,132	34,823 193.9%	877 3/1	432 684	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES						
121	Operation Supervision	907	0	0	0	0	0
122	Customer Assist- Other	908	210	196	13	2	0
123	Customer Assist- CAP	908CAP	299	299	0	0	0
124	Other Customer Service & Informational Expense	910	698	698	0	0	0
125	Supervision	911	0	0	0	0	0
126	Demonstration	912	660	0	591	68	0
127	Adverstising expense	913	24	0	22	3	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891	1,193	626	73	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		38,024	36,015	1,503	505	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES						
	A. Labor-Related:						
130	Administrative & General Salaries	920	5,940	3,849	508	1,134	449
131	Administrative & General Salaries - Direct Assign.	920 DA	550	0	0	0	550
132	Office Supplies & Expenses	921	817	529	70	156	62
133	Outside Services Employed - Resid.	923	180	180	0	0	0
134	Outside Services Employed - Labor	923l	3,637	2,357	311	694	275
135	Injuries & Damages	925Labor	338	219	29	65	26
136	Employee Pensions and Benefits	926	5,725	3,710	490	1,093	433
137	Rents	931	4,025	2,608	344	768	304
138	Subtotal - O&M Accounts 920-923, 925L, 926		21,213	13,453	1,751	3,910	2,098
	B. Plant-Related:						
139	Property Insurance	924	335	215	19	90	12
140	Outside Services Employed-plant	923p	135	87	8	36	5
141	Injuries & Damages	925Plant	4,130	2,650	235	1,104	142
142	Misc. Maintenance Expense	932	1,228	784	69	331	45
143	Misc. Maintenance Expense - Direct Assign.	932 DA	50	0	0	0	50
144	Subtotal - O&M Accounts 924-925P		5,879	3,736	331	1,560	253
	C. Other-Related:						
145	Administrative Expenses Transferred	922	(37)	(22)	(2)	(9)	(3)
146	Outside Services Employed-cust	923c	5,083	4,732	315	36	0
147	Outside Services Employed-plant-O&M	923p-om	7,021	4,144	435	1,775	668
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	200	0	0	0	200
149	Regulatory Commission Expenses	928	517	336	37	144	0
150	General Advertising Expense	930.1	201	131	14	56	0
151	Miscellaneous General Expenses	930.2	156	96	9	37	15
152	Subtotal - O&M Accounts 928-935		13,142	9,417	808	2,038	879
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		40,234	26,606	2,890	7,508	3,230
154	***TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)***		105,499	78,139	6,321	14,808	6,230

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation: Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE						
155	Intangible Plant	180Int	2,439	2,106	157	148	28
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	0	0	0	631
157	Local Storage Plant	180Stor	0	0	0	0	0
158	Transmission Plant	180Trans	9	5	1	3	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	0	0	0	704
160	Mains (Distribution)	180Mains	6,999	3,745	542	2,712	0
161	Services	180Services	5,815	5,489	57	269	0
162	Meters	180Meters	796	553	82	162	0
163	Distr Other	180Dist	2,003	1,340	143	519	0
164	General Plant	180Gen	4,071	2,598	230	1,096	148
165	General Plant - Direct Assign.	180Gen DA	4	0	0	0	4
166	Adjustments		0	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	23,471	15,836	1,211	4,909	1,515
	VI. TAXES						
	A. General Taxes						
168	PA PUC Assessment		1,139	805	111	224	0
169	Local property taxes		63	42	4	17	0
170	*Public utilty reality tax*		519	349	31	139	0
171	State capital stock tax		447	269	33	127	18
172	Miscellaneous tax		17	8	1	8	0
173	Subtotal- Taxes Other Than Income Taxes	408	2,186	1,473	180	514	18
	B. Income Tax Expense						
174	State Income Tax expense		(1,009)	(203)	(616)	(564)	375
175	Federal Income Tax expense		5,363	1,081	3,274	2,999	(1,991)
176	Investment Tax Credit - Amortization		(6)	(1)	(3)	(3)	2
177	Subtotal- Income tax expense		4,348	876	2,655	2,432	(1,615)
178	**TOTAL TAX EXPENSE**		6,534	2,350	2,835	2,946	(1,596)
179	**TOTAL EXPENSES**		135,504	96,325	10,367	22,663	6,149
	3. REVENUES at Present Rates						
180	Sales and Transport Revenue	480-483	154,865	105,632	14,510	29,396	5,326
181	Forfeited Discounts		1,558	1,462	34	62	0
182	Miscellaneous Service Revenue		1,209	1,163	40	5	0
183	Other Operating Revenue		61	43	6	12	0
184	Subtotal- Gas Revenues, net		157,693	108,301	14,590	29,475	5,326
185	**TOTAL REVENUE**		157,693	108,301	14,590	29,475	5,326
186	**TOTAL EXPENSES**		135,504	96,325	10,367	22,663	6,149
187	**NET INCOME at Present Rates**		22,189	11,976	4,223	6,812	(822)
				0	0	0	0

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY						
188	Total revenues		157,693	108,301	14,590	29,475	5,326
189	Total Operating Expenses		105,499	78,139	6,321	14,808	6,230
190	Depreciation Expense		23,471	15,836	1,211	4,909	1,515
191	Taxes other than Income		2,186	1,473	180	514	18
192	Total Other Expenses		25,657	17,309	1,392	5,423	1,533
193	Income tax expense		4,348	876	2,655	2,432	(1,615)
194	Total expenses		135,504	96,325	10,367	22,663	6,149
195	NET INCOME at Present Rates		22,189	11,976	4,223	6,812	(822)
196	**Total Rate Base**		**583,253**	**375,385**	**35,688**	**133,862**	**38,317**
197							
	REVENUE REQUIREMENTS						
198	Target ROR		8.89%	8.89%	8.89%	8.89%	8.89%
199	Using Target for System						
200	Rate Base		583,253	375,385	35,688	133,862	38,317
201	Operating expenses		105,499	78,139	6,321	14,808	6,230
202	Depreciation expense		23,471	15,836	1,211	4,909	1,515
203	Taxes other than Income		2,186	1,473	180	514	18
204	Operating expenses to recover		131,156	95,448	7,713	20,231	7,763
205	Target Return on Rate Base- After taxes		51,851	33,372	3,173	11,900	3,406
206	Income taxes to recover	21,183	25,531	16,432	1,562	5,860	1,677
207	Additional expenses		1,103	1,103	0	0	0
208	***TOTAL REVENUE REQUIREMENT***		*209,642*	*146,356*	*12,448*	*37,991*	*12,847*
	Effective tax rate		32.99%	32.99%	32.99%	32.99%	32.99%
	Class Actual RORs		3.80%	3.19%	11.83%	5.09%	(2.15%)

	Account Description	Account Code	Total Allocated Dollars	TOTAL Class Allocation			
				Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport						
209	Accounts Receivable- Gas		0	0	0	0	0
210	Accounts Receivable- Other		0	0	0	0	0
211	Accrued Gas Revenues		0	0	0	0	0
212	Accounts Receivable, Total		0	0	0	0	0
213	Gas, LNG in Storage		0	0	0	0	0
214	*Inventories & Other, Total*		*0*	*0*	*0*	*0*	*0*
215	Accounts Payable, Natural Gas		3,330	1,585	272	1,474	0
216	Accounts Payable, Other- Labor		2,867	1,861	246	550	210
217	Accounts Payable, Other- O&MxGas		5,395	4,027	395	936	37
218	Accounts Payable, Total		11,592	7,473	912	2,960	247
219	Accrued interest		(1,083)	(695)	(62)	(289)	(37)
220	Other, net		826	530	47	221	28
221	Defd Items & Other, Total		(257)	(165)	(15)	(69)	(9)
222	Total Working Capital		11,335	7,308	898	2,891	238

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	1. RATE BASE								
	I. GAS PLANT IN SERVICE								
	A. INTANGIBLE PLANT								
1	Organization	301	50	RATEBASE	2	6	2	36	4
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	266	0	8	1,514	1,554
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	0	0	0	0	2,743
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	0	0	0	2,485	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	ONSITE	0	0	0	0	15,628
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248		268	6	10	4,035	19,928
	B. PRODUCTION & GATHERING PLANT								
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	28,445	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	28,445		28,445	0	0	0	0
	C. STORAGE PLANT								
9	Storage Plant	360-368	0	None	0	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0	0
	D. TRANSMISSION PLANT								
11	Transmission plant	365-370	106	TRANS	0	0	106	0	0
12	Transmission - Mains	367	1,243	TRANS	0	0	1,243	0	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	0	0	14,171	0	0
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	0	0	16,830	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	32,350		0	0	32,350	0	0
	E. DISTRIBUTION PLANT								
16	Land and Land Rights	374	1,893	DIST	0	0	0	1,893	0
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	0	0	0	564	0
18	Structures and Improvements	375	2,111	DIST	0	0	0	2,111	0
19	Mains	376	457,729	DIST	0	0	0	457,729	0
20	Mains - Direct Assign.	376 DA	10,267	DIST	0	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	0	0	0	16,126	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	0	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	0	0	0	447	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	DIST	0	0	0	0	0
25	Services	380	226,432	DIST	0	0	0	226,432	0
26	Meters	381	17,775	ONSITE	0	0	0	0	17,775
27	Meter Installations	382	9,208	ONSITE	0	0	0	0	9,208
28	House Regulators	383	5,656	ONSITE	0	0	0	0	5,656
29	House Regulator Installations	384	1,514	ONSITE	0	0	0	0	1,514
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	0	0	0	0	441
31	Property on Customers' Premises	386	15,838	ONSITE	0	0	0	0	15,838
32	Other Equipment	387	324	DIST	0	0	0	324	0
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793		0	0	0	717,361	50,432

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	F. GENERAL PLANT								
34	Land and Land Rights	389	78	PLANT	3	0	3	68	5
35	Structures and Improvements	390	7,842	PLANT	269	0	306	6,789	477
36	Structures and Improvements - Direct Assign.	390 DA	67	PLANT_AGS	42	0	25	0	0
37	Office Furniture and Equipment	391	12,224	PLANT	420	0	477	10,583	744
38	Office Furniture and Equipment - Direct Assign.	391 DA	2	PLANT_AGS	1	0	1	0	0
39	Transportation Equipment	392	10,288	PLANT	353	0	402	8,907	626
40	Stores Equipment	393	47	PLANT	2	0	2	41	3
41	Tools & Garage Equipment	394	4,271	PLANT	147	0	167	3,698	260
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	16	0	10	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0	0
44	Power Operated Equipment	396	3,155	PLANT	108	0	123	2,732	192
45	Communication Equipment	397	6,923	PLANT	238	0	270	5,993	421
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	4	0	2	0	0
47	Miscellaneous Equipment	398	32	PLANT	1	0	1	28	2
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	0	0	3	143	10
49	Subtotal - GENERAL PLANT	389-399	45,118		1,604	0	1,792	38,981	2,740
50	**TOTAL UTILITY PLANT**		897,955		30,317	6	34,152	760,378	73,101
	II. DEPRECIATION RESERVE								
51	Intangible Plant	108	8,236	INTANG_PT	91	2	3	1,371	6,768
52	Production & Gathering Plant	108.2	0	PRODGATH	0	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	PRODGATH	8,153	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0	0
55	Transmission Plant	108.4	658	TRANS	0	0	658	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	0	0	11,969	0	0
57	Mains	109	130,432	DIST	0	0	0	130,432	0
58	Services	109	83,524	DIST	0	0	0	83,524	0
59	Meters	109	12,975	ONSITE	0	0	0	0	12,975
60	Distr Other	109	13,987	DIST_xMSM	0	0	0	6,916	7,072
61	General Plant	109	19,396	PLANT	666	0	757	16,793	1,181
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	13	0	8	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	289,353		8,924	2	13,396	239,035	27,996
	III. OTHER RATE BASE ITEMS								
64	*Materials and Supplies*		*887*	PLANT	*30*	*0*	*35*	768	54
65	Current Gas Storage		75,176	STOR	0	75,176	0	0	0
66	Prepayments		234	O&MxGas	13	0	1	97	122
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	0	0	(2,027)	(93,674)	(6,586)
68	*Deferred Income Taxes - Direct Assign.*		(2,423)	PLANT_AGS	(1,522)	0	(901)	0	0
69	Deferred ITC		(4,903)	PLANTxAGS	0	0	(97)	(4,490)	(316)
70	Customer Deposits		(3,370)	DIST	0	0	0	(3,370)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(36,684)		(1,478)	75,176	(2,988)	(100,669)	(6,725)
72	**TOTAL RATE BASE (Excl. Working Capital)**		571,917		19,915	75,180	17,768	420,674	38,380
73	Working Capital	131	11,335		3,858	0	28	3,315	4,135
74	**TOTAL RATE BASE**		583,253		23,773	75,180	17,795	423,989	42,515

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	2. EXPENSES								
	I. OPERATION & MAINTENANCE EXPENSE								
	A. PRODUCTION & GATHERING EXPENSES								
75	Operations Expense	750-756	1,043	PRODGATH	1,043	0	0	0	0
76	Maintenance Expense	761-765	1,766	PRODGATH	1,766	0	0	0	0
77	Subtotal - Production and Gathering	750-765	2,809		2,809	0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES								
78	Natural gas field line purchases	801	0	None	0	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0	0
86	Other Gas Supply Expense	813	391	PRODGATH	391	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391		391	0	0	0	0
	C. NATURAL GAS STORAGE								
88	LNG Operating Exp Admin	840	0	None	0	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0	0
	D. TRANSMISSION EXPENSES								
91	Transmission expenses	856-863	0	None	0	0	0	0	0
92	Subtotal- Transmission Expenses	856-863	0		0	0	0	0	0
	E. DISTRIBUTION EXPENSES								
93	Operation Supv & Engineering	870	1,773	DIST_PT	0	0	0	1,656	116
94	Load Dispatching	871	112	PRODGATH	112	0	0	0	0
95	Compressor Station Fuel and Power	873	(0)	DIST	0	0	0	(0)	0
96	Mains and Services Expenses	874	5,088	MAIN_SERV_TRANMAIN	0	0	129	4,959	0
97	Meas. & Reg. Station Expense General	875	100	DIST	0	0	0	100	0
98	Meas. & Reg. Station Expense Industrial	876	0	ONSITE	0	0	0	0	0
99	Meter & House Regulator Expenses	878	6,062	ONSITE	0	0	0	0	6,062
100	*Customer Installation Expense*	879	62	ONSITE	0	0	0	0	62
101	Other Expenses - Safety and Environmental	880	632	O&MxAcct880	81	0	3	377	172
102	Other Expenses	880	650	O&MxAcct880	83	0	3	387	177
103	Distribution Rents	881	602	DIST_PT	0	0	0	562	40
104	Maint. Supervision & Engineering	885	885	DIST	0	0	0	885	0
105	Maintenance of Structures & Improvements	886	516	DIST	0	0	0	516	0
106	Maint. of Mains	887	5,521	DIST	0	0	0	5,521	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	DIST	0	0	0	1,192	0
108	*Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station*	891	10	DIST	0	0	0	10	0
109	Maint. of Services	892	663	ONSITE	0	0	0	0	663
110	Maint. of Meters & House Regulators	893	107	ONSITE	0	0	0	0	107
111	Maintenance of Other Equipment	894	67	DIST	0	0	0	67	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042		276	0	135	16,232	7,399
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		27,242		3,475	0	135	16,232	7,399

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	II. CUSTOMER ACCOUNTS EXPENSES								
114	Customer Service - Administrative	901	225	ONSITE	0	0	0	0	225
115	Meter Reading Expenses	902	587	ONSITE	0	0	0	0	587
116	Customer Records & Collection Expense	903	10,270	ONSITE	0	0	0	0	10,270
117	Uncollectible Accounts	904	8,883	ONSITE	0	0	0	0	8,883
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	0	0	0	0	16,167
119	Miscellaneous Customer Accounts Expenses	905	0	ONSITE	0	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		36,132		0	0	0	0	36,132
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES								
121	Operation Supervision	907	0	None	0	0	0	0	0
122	Customer Assist- Other	908	210	DIST	0	0	0	210	0
123	Customer Assist- CAP	908CAP	299	DIST	0	0	0	299	0
124	Other Customer Service & Informational Expense	910	698	DIST	0	0	0	698	0
125	Supervision	911	0	DIST	0	0	0	0	0
126	Demonstration	912	660	DIST	0	0	0	660	0
127	*Adverstising expense*	913	24	*DIST*	0	0	0	24	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891		0	0	0	1,891	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		38,024		0	0	0	1,891	36,132
	IV. ADMINISTRATIVE & GENERAL EXPENSES								
	A. Labor-Related:								
130	Administrative & General Salaries	920	5,940	LABOR	473	0	15	2,690	2,762
131	Administrative & General Salaries - Direct Assign.	920 DA	550	LABOR	44	0	1	249	256
132	Office Supplies & Expenses	921	817	LABOR	65	0	2	370	380
133	Outside Services Employed - Resid.	923	180	LABOR	14	0	0	81	84
134	Outside Services Employed - Labor	923l	3,637	LABOR	290	0	9	1,647	1,691
135	Injuries & Damages	925Labor	338	LABOR	27	0	1	153	157
136	Employee Pensions and Benefits	926	5,725	LABOR	456	0	14	2,593	2,662
137	Rents	931	4,025	LABOR	321	0	10	1,823	1,872
138	Subtotal - O&M Accounts 920-923, 925L, 926		21,213		1,691	0	53	9,606	9,864
	B. Plant-Related:								
139	Property Insurance	924	335	PLANT	12	0	13	290	20
140	Outside Services Employed-plant	923p	135	PLANT	5	0	5	117	8
141	Injuries & Damages	925Plant	4,130	PLANT	142	0	161	3,576	251
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	44	0	49	1,061	75
143	Misc. Maintenance Expense - Direct Assign.	932 DA	50	GENERAL PT	2	0	2	43	3
144	Subtotal - O&M Accounts 924-925P		5,879		203	0	230	5,087	358
	C. Other-Related:								
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	(3)	0	(1)	(27)	(6)
146	Outside Services Employed-cust	923c	5,083	DIST	0	0	0	5,083	0
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	568	0	155	5,131	1,167
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	200	PLANT_O&M	16	0	4	146	33
149	Regulatory Commission Expenses	928	517	PLANT_O&M	42	0	11	378	86
150	General Advertising Expense	930.1	201	PLANT_O&M	16	0	4	147	33
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	13	0	3	114	26
152	Subtotal - O&M Accounts 928-935		13,142		652	0	177	10,972	1,340
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		40,234		2,546	0	461	25,666	11,561
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)**		105,499		6,022	0	596	43,789	55,092

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	V. DEPRECIATION EXPENSE								
155	Intangible Plant	180Int	2,439	INTANG_PT	27	1	1	406	2,005
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	PRODGATH_PT	631	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0	0
158	Transmission Plant	180Trans	9	TRANS	0	0	9	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	0	0	704	0	0
160	Mains (Distribution)	180Mains	6,999	DIST	0	0	0	6,999	0
161	*Services*	*180Services*	*5,815*	*DIST*	*0*	*0*	*0*	*5,815*	*0*
162	Meters	180Meters	796	ONSITE	0	0	0	0	796
163	Distr Other	180Dist	2,003	DIST_xMSM	0	0	0	990	1,012
164	General Plant	180Gen	4,071	GENERAL PT	145	0	162	3,518	247
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	3	0	2	0	0
166	Adjustments		0	None	0	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	23,471		806	1	876	17,728	4,060
	VI. TAXES								
	A. General Taxes								
168	PA PUC Assessment		1,139	DIST	0	0	0	1,139	0
169	Local property taxes		63	PLANTxAGS	0	0	1	58	4
170	Public utilty reality tax		519	PLANTxAGS	0	0	10	475	33
171	State capital stock tax		447	RATEBASE	18	58	14	325	33
172	Miscellaneous tax		17	PRODGATH	17	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	2,186		35	58	25	1,998	70
	B. Income Tax Expense								
174	State Income Tax expense		(1,009)	Pre-Tax	16	(545)	(88)	(1,338)	946
175	*Federal Income Tax expense*		5,363	*Pre-Tax*	(87)	*2,896*	*468*	*7,111*	(5,026)
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	0	(3)	(0)	(7)	5
177	Subtotal- Income tax expense		4,348		(70)	2,348	380	5,765	(4,075)
178	**TOTAL TAX EXPENSE**		6,534		(35)	2,406	405	7,763	(4,005)
179	**TOTAL EXPENSES**		135,504		6,792	2,406	1,878	69,280	55,148
	3. REVENUES at Present Rates								
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	7,399	7,411	2,851	88,474	48,730
181	Forfeited Discounts		1,558	ONSITE	0	0	0	0	1,558
182	Miscellaneous Service Revenue		1,209	ONSITE	0	0	0	0	1,209
183	Other Operating Revenue		61	DIST	0	0	0	61	0
184	Subtotal- Gas Revenues, net		157,693		7,399	7,411	2,851	88,535	51,497
185	**TOTAL REVENUE**		157,693		7,399	7,411	2,851	88,535	51,497
186	**TOTAL EXPENSES**		135,504		6,792	2,406	1,878	69,280	55,148
187	**NET INCOME at Present Rates**		22,189		607	5,005	973	19,255	(3,651)

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	SUMMARY								
188	Total revenues		157,693		7,399	7,411	2,851	88,535	51,497
189	Total Operating Expenses		105,499		6,022	0	596	43,789	55,092
190	Depreciation Expense		23,471		806	1	876	17,728	4,060
191	Taxes other than Income		2,186		35	58	25	1,998	70
192	Total Other Expenses		25,657		841	58	902	19,725	4,131
193	Income tax expense		4,348		(70)	2,348	380	5,765	(4,075)
194	Total expenses		135,504		6,792	2,406	1,878	69,280	55,148
195	NET INCOME at Present Rates		22,189		607	5,005	973	19,255	(3,651)
196	**Total Rate Base**		**583,253**		**23,773**	**75,180**	**17,795**	**423,989**	**42,515**
197									
	REVENUE REQUIREMENTS								
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%	8.89%
199	Using Target for System								
200	Rate Base		583,253		23,773	75,180	17,795	423,989	42,515
201	Operating expenses		105,499		6,022	0	596	43,789	55,092
202	Depreciation expense		23,471		806	1	876	17,728	4,060
203	Taxes other than Income		2,186		35	58	25	1,998	70
204	Operating expenses to recover		131,156		6,862	58	1,498	63,515	59,222
205	Target Return on Rate Base- After taxes		51,851		2,113	6,684	1,582	37,693	3,780
206	Income taxes to recover		25,531		1,041	3,291	779	18,560	1,861
207	Additional expenses		1,103	ONSITE	0	0	0	0	1,103
208	**TOTAL REVENUE REQUIREMENT**		209,642		10,017	10,033	3,859	119,767	65,966

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	Working Capital Subreport								
209	Accounts Receivable- Gas		0	None	0	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0	0
215	Accounts Payable, Natural Gas		3,330	PRODGATH	3,330	0	0	0	0
216	Accounts Payable, Other- Labor		2,867	LABOR	228	0	7	1,298	1,333
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	308	0	31	2,239	2,818
218	Accounts Payable, Total		11,592		3,867	0	38	3,538	4,150
219	Accrued interest		(1,083)	PLANT	(37)	0	(42)	(938)	(66)
220	Other, net		826	PLANT	28	0	32	715	50
221	Defd Items & Other, Total		(257)		(9)	0	(10)	(223)	(16)
222	Total Working Capital		11,335		3,858	0	28	3,315	4,135

	Account Description	Account Code	Account Balance	Allocation Factor	FUNCTIONALIZATION				
					PRODUCTION & GATHERING	STORAGE	TRANSMISSION	DISTRIBUTION	ONSITE
	LABOR REPORT								
			Labor $	Labor %					
	PRODUCTION AND GATHERING:								
223	Production and Gathering O&M	750-765	1,164	41%	1,164	0	0	0	0
224	Purchased Gas Expense	807	0	0%	0	0	0	0	0
225	Other Gas Supply Expense	813	0	0%	0	0	0	0	0
226	Sub Production		1,164		1,164	0	0	0	0
	STORAGE:								
227	LNG Operating Exp Admin	840	0	0	0	0	0	0	0
228	Operating Exp- Admin	850	0	0	0	0	0	0	0
229	Sub Storage		0		0	0	0	0	0
	TRANSMISSION:								
230	Transmission expenses	856-863	0	0%	0	0	0	0	0
231	Sub Transmission		0		0	0	0	0	0
	DISTRIBUTION:								
232	Operation Supv & Engineering	870	1,251	71%	0	0	0	1,169	82
233	Load Dispatching	871	77	69%	77	0	0	0	0
234	Compressor Station Fuel and Power	873	0	0%	0	0	0	0	0
235	Mains and Services Expenses	874	1,527	30%	0	0	39	1,489	0
236	Meas. & Reg. Station Expense General	875	40	40%	0	0	0	40	0
237	Meas. & Reg. Station Expense Industrial	876	0	61%	0	0	0	0	0
238	Meter & House Regulator Expenses	878	2,825	47%	0	0	0	0	2,825
239	Customer Installation Expense	879	6	10%	0	0	0	0	6
240	Other Expenses - Safety and Environmental	880	172	27%	22	0	1	103	47
241	Other Expenses	880	177	27%	23	0	1	106	48
242	Maint. Supervision & Engineering	885	605	68%	0	0	0	605	0
243	Maintenance of Structures & Improvements	886	166	32%	0	0	0	166	0
244	Maint. of Mains	887	2,262	41%	0	0	0	2,262	0
245	Maint Of Meas. & Reg. Station Expense General	889	608	51%	0	0	0	608	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	7	69%	0	0	0	7	0
247	Maint. of Services	892	300	45%	0	0	0	0	300
248	Maint. of Meters & House Regulators	893	46	43%	0	0	0	0	46
249	Maintenance of Other Equipment	894	45	66%	0	0	0	45	0
250	Sub Distribution		10,116	43%	122	0	40	6,599	3,355
	OnSite:								
251	Customer Service - Administrative	901	174	77%	0	0	0	0	174
252	Meter Reading Expenses	902	144	25%	0	0	0	0	144
253	Customer Records & Collection Expense	903	3,828	37%	0	0	0	0	3,828
254	Operation Supervision	907	0	0%	0	0	0	0	0
255	Customer Assist- Other	908	117	56%	0	0	0	117	0
256	Customer Assist- CAP	908CAP	168	56%	0	0	0	168	0
257	Supervision	911	0	79%	0	0	0	0	0
258	Demonstration	912	420	64%	0	0	0	420	0
259	Sub OnSite		4,850		0	0	0	705	4,145
260	**TOTAL:**		16,130	16,130	1,285	0	40	7,304	7,500

NOTE: The Labor % above are applied to the functionally classified account balances.

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	1. RATE BASE						
	I. GAS PLANT IN SERVICE						
	A. INTANGIBLE PLANT						
1	Organization	301	36	DISTBASE	26	0	10
2	Intangible Plant - Software- Labor	303Lab	1,514	DISTLABOR	1,252	0	261
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0
4	Intangible Plant - Software- Plant	303Plt	2,485	DISTPT	1,695	0	790
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	4,035		2,974	0	1,062
	B. PRODUCTION & GATHERING PLANT						
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0
8	*Subtotal - PRODUCTION & GATHERING PLANT*	*304-338*	*0*		*0*	*0*	*0*
	C. STORAGE PLANT						
9	Storage Plant	360-368	0	None	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0
	D. TRANSMISSION PLANT						
11	Transmission plant	365-370	0	None	0	0	0
12	Transmission - Mains	367	0	None	0	0	0
13	*Transmission plant - Direct Assign.*	*365-370 DA*	*0*	*None*	*0*	*0*	*0*
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0
	E. DISTRIBUTION PLANT						
16	Land and Land Rights	374	1,893	DISTOnlyPT	1,291	0	601
17	Land and Land Rights - Direct Assign.	374 DA	564	DEMAND	564	0	0
18	Structures and Improvements	375	2,111	DISTOnlyPT	1,440	0	671
19	Mains	376	457,729	MAINS	457,729	0	0
20	Mains - Direct Assign.	376 DA	10,267	DEMAND	10,267	0	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DEMAND	16,126	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DEMAND	1,469	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DEMAND	447	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0
25	Services	380	226,432	CUST	0	0	226,432
26	Meters	381	0	None	0	0	0
27	Meter Installations	382	0	None	0	0	0
28	House Regulators	383	0	None	0	0	0
29	House Regulator Installations	384	0	None	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	DEMAND	0	0	0
31	Property on Customers' Premises	386	0	DEMAND	0	0	0
32	Other Equipment	387	324	CUST	0	0	324
33	Subtotal - DISTRIBUTION PLANT	374-387	717,361		489,333	0	228,028

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	F. GENERAL PLANT						
34	Land and Land Rights	389	68	DISTPT	46	0	21
35	Structures and Improvements	390	6,789	DISTPT	4,631	0	2,158
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0
37	Office Furniture and Equipment	391	10,583	DISTPT	7,219	0	3,364
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0
39	Transportation Equipment	392	8,907	DISTPT	6,076	0	2,831
40	Stores Equipment	393	41	DISTPT	28	0	13
41	*Tools & Garage Equipment*	*394*	*3,698*	*DISTPT*	*2,522*	*0*	*1,175*
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0
43	Laboratory Equipment	395	0	DISTPT	0	0	0
44	Power Operated Equipment	396	2,732	DISTPT	1,863	0	868
45	Communication Equipment	397	5,993	DISTPT	4,088	0	1,905
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0
47	Miscellaneous Equipment	398	28	DISTPT	19	0	9
48	Miscellaneous Equipment - Direct Assign.	398 DA	143	DISTPT	97	0	45
49	Subtotal - GENERAL PLANT	389-399	38,981		26,590	0	12,391
50	**TOTAL UTILITY PLANT**		760,378		518,697	0	241,481
	II. DEPRECIATION RESERVE						
51	Intangible Plant	108	1,371	DISTPT_INT	1,010	0	361
52	*Production & Gathering Plant*	*108.2*	*0*	*None*	*0*	*0*	*0*
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0
57	Mains	109	130,432	MAINS	130,432	0	0
58	Services	109	83,524	CUST	0	0	83,524
59	Meters	109	0	None	0	0	0
60	Distr Other	109	6,916	DISTPT_xMSM	6,435	0	481
61	General Plant	109	16,793	DISTPT	11,455	0	5,338
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	239,035		149,331	0	89,704
	III. OTHER RATE BASE ITEMS						
64	*Materials and Supplies*		768	DISTPT	524	0	244
65	Current Gas Storage		0	None	0	0	0
66	Prepayments		97	DISTO&MxGas	65	0	32
67	Deferred Income Taxes - Depreciation		(93,674)	DISTPT	(63,898)	0	(29,776)
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0
69	Deferred ITC		(4,490)	DISTPT	(3,063)	0	(1,427)
70	Customer Deposits		(3,370)	CUST	0	0	(3,370)
71	**TOTAL OTHER RATE BASE ITEMS**		(100,669)		(66,372)	0	(34,297)
72	**TOTAL RATE BASE (Excl. Working Capital)**		*420,674*		*303,194*	*0*	*117,480*
73	Working Capital	131	3,315		2,420	0	895
74	**TOTAL RATE BASE**		423,989		305,615	0	118,374

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	2. EXPENSES						
	I. OPERATION & MAINTENANCE EXPENSE						
	A. PRODUCTION & GATHERING EXPENSES						
75	Operations Expense	750-756	0	None	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0
	B. OTHER GAS SUPPLY EXPENSES						
78	Natural gas field line purchases	801	0	None	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0
	C. NATURAL GAS STORAGE						
88	LNG Operating Exp Admin	840	0	None	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0
	D. TRANSMISSION EXPENSES						
91	Transmission expenses	856-863					
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0
	E. DISTRIBUTION EXPENSES						
93	Operation Supv & Engineering	870	1,656	DISTOnlyPT	1,130	0	526
94	Load Dispatching	871	0	None	0	0	0
95	Compressor Station Fuel and Power	873	(0)	None	0	0	0
96	Mains and Services Expenses	874	4,959	MAIN&SERVICE	3,342	0	1,617
97	Meas. & Reg. Station Expense General	875	100	DEMAND	100	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0
101	Other Expenses - Safety and Environmental	880	377	DISTO&MxA/C88(	312	0	65
102	Other Expenses	880	387	DISTO&MxA/C88(	321	0	67
103	Distribution Rents	881	562	DISTOnlyPT	383	0	179
104	Maint. Supervision & Engineering	885	885	DISTLABOR	732	0	153
105	Maintenance of Structures & Improvements	886	516	DISTOnlyPT	352	0	164
106	Maint. of Mains	887	5,521	MAINS	5,521	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	DEMAND	1,192	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	10	DEMAND	10	0	0
109	Maint. of Services	892	0	None	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0
111	Maintenance of Other Equipment	894	67	DISTOnlyPT	46	0	21
112	Subtotal - DISTRIBUTION EXPENSES	870-894	16,232		13,441	0	2,792
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		16,232		13,441	0	2,792

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	II. CUSTOMER ACCOUNTS EXPENSES						
114	Customer Service - Administrative	901	0	None	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0
118	*Uncollectible Accounts- CAP*	904CAP	0	None	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES						
121	Operation Supervision	907	0	None	0	0	0
122	Customer Assist- Other	908	210	CUST	0	0	210
123	Customer Assist- CAP	908CAP	299	CUST	0	0	299
124	Other Customer Service & Informational Expense	910	698	CUST	0	0	698
125	Supervision	911	0	CUST	0	0	0
126	Demonstration	912	660	CUST	0	0	660
127	Adverstising expense	913	24	CUST	0	0	24
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		1,891		0	0	1,891
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**		1,891		0	0	1,891
	IV. ADMINISTRATIVE & GENERAL EXPENSES						
	A. Labor-Related:						
130	Administrative & General Salaries	920	2,690	DISTLABOR	2,225	0	464
131	Administrative & General Salaries - Direct Assign.	920 DA	249	DISTLABOR	206	0	43
132	Office Supplies & Expenses	921	370	DISTLABOR	306	0	64
133	Outside Services Employed - Resid.	923	81	DISTLABOR	67	0	14
134	Outside Services Employed - Labor	923l	1,647	DISTLABOR	1,363	0	284
135	Injuries & Damages	925Labor	153	DISTLABOR	127	0	26
136	Employee Pensions and Benefits	926	2,593	DISTLABOR	2,145	0	448
137	Rents	931	1,823	DISTLABOR	1,508	0	315
138	Subtotal - O&M Accounts 920-923, 925L, 926		9,606		7,947	0	1,659
	B. Plant-Related:						
139	Property Insurance	924	290	DISTPT	198	0	92
140	Outside Services Employed-plant	923p	117	DISTPT	80	0	37
141	Injuries & Damages	925Plant	3,576	DISTPT	2,439	0	1,137
142	Misc. Maintenance Expense	932	1,061	DISTPT_GEN	724	0	337
143	Misc. Maintenance Expense - Direct Assign.	932 DA	43	DISTPT_GEN	29	0	14
144	Subtotal - O&M Accounts 924-925P		5,087		3,470	0	1,617
	C. Other-Related:						
145	Administrative Expenses Transferred	922	(27)	DIST_PT_O&M	(20)	0	(7)
146	*Outside Services Employed-cust*	923c	*5,083*	*CUST*	*0*	*0*	*5,083*
147	Outside Services Employed-plant-O&M	923p-om	5,131	DIST_PT_O&M	3,874	0	1,257
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	146	DIST_PT_O&M	110	0	36
149	Regulatory Commission Expenses	928	378	DIST_PT_O&M	285	0	93
150	General Advertising Expense	930.1	147	DIST_PT_O&M	111	0	36
151	Miscellaneous General Expenses	930.2	114	DISTPT_GEN	78	0	36
152	Subtotal - O&M Accounts 928-935		10,972		4,439	0	6,534
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		25,666		15,856	0	9,809
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Gas Supply)**		43,789		29,297	0	14,492

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	V. DEPRECIATION EXPENSE						
155	*Intangible Plant*	180Int	406	DISTPT_INT	299	0	107
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0
160	Mains (Distribution)	180Mains	6,999	MAINS	6,999	0	0
161	Services	180Services	5,815	CUST	0	0	5,815
162	Meters	180Meters	0	None	0	0	0
163	Distr Other	180Dist	990	DISTPT_xMSM	921	0	69
164	General Plant	180Gen	3,518	DISTPT_GEN	2,400	0	1,118
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0
166	Adjustments		0	None	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	17,728		10,619	0	7,109
	VI. TAXES						
	A. General Taxes						
168	PA PUC Assessment		1,139	CUST	0	0	1,139
169	Local property taxes		58	DISTPT	39	0	18
170	Public utility reality tax		475	DISTPT	324	0	151
171	State capital stock tax		325	DISTBASE	234	0	91
172	Miscellaneous tax		0	DISTPT	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	1,998		598	0	1,399
	B. Income Tax Expense						
174	State Income Tax expense		(1,338)	PreTax-DIST	(1,105)	0	(233)
175	Federal Income Tax expense		7,111	PreTax-DIST	5,873	0	1,238
176	Investment Tax Credit - Amortization		(7)	PreTax-DIST	(6)	0	(1)
177	Subtotal- Income tax expense		5,765		4,761	0	1,004
178	**TOTAL TAX EXPENSE**		7,763		5,359	0	2,404
179	**TOTAL EXPENSES**		69,280		45,276	0	24,004
	3. REVENUES at Present Rates						
180	Sales and Transport Revenue	480-483	88,474	RevReq_PF-Dist	59,881	0	28,592
181	Forfeited Discounts		0	None	0	0	0
182	Miscellaneous Service Revenue		0	RevReq_PF-Dist	0	0	0
183	Other Operating Revenue		61	CUST	0	0	61
184	Subtotal- Gas Revenues, net		88,535		59,881	0	28,654
185	**TOTAL REVENUE**		88,535		59,881	0	28,654
186	**TOTAL EXPENSES**		69,280		45,276	0	24,004
187	**NET INCOME at Present Rates**		19,255		14,606	0	4,649

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	SUMMARY						
188	Total revenues		88,535		59,881	0	28,654
189	Total Operating Expenses		43,789		29,297	0	14,492
190	Depreciation Expense		17,728		10,619	0	7,109
191	Taxes other than Income		1,998		598	0	1,399
192	Total Other Expenses		19,725		11,217	0	8,508
193	Income tax expense		5,765		4,761	0	1,004
194	Total expenses		69,280		45,276	0	24,004
195	NET INCOME at Present Rates		19,255		14,606	0	4,649
196	**Total Rate Base**		**423,989**		**305,615**	**0**	**118,374**
197							
	REVENUE REQUIREMENTS						
198	Target ROR		8.89%		8.89%	8.89%	8.89%
199	Using Target for System						
200	Rate Base		423,989		305,615	0	118,374
201	Operating expenses		43,789		29,297	0	14,492
202	Depreciation expense		17,728		10,619	0	7,109
203	*Taxes other than Income*		1,998		598	0	1,399
204	Operating expenses to recover		63,515		40,514	0	23,000
205	Target Return on Rate Base- After taxes		37,693		27,169	0	10,523
206	Income taxes to recover		18,560	49.2%	13,378	0	5,182
207	Additional expenses		0	0.0%	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		119,767		81,062	0	38,706

	Account Description	Account Code	DISTRIBUTION Dollars	Allocation Factor	CLASSIFICATION DISTRIBUTION Demand	Commodity	Customer
	Working Capital Subreport						
209	Accounts Receivable- Gas		0	DISTO&MxGas	0	0	0
210	Accounts Receivable- Other		0	DISTO&MxGas	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0
212	Accounts Receivable, Total		0		0	0	0
213	Gas, LNG in Storage		0	None	0	0	0
214	Inventories & Other, Total		0		0	0	0
215	Accounts Payable, Natural Gas		0	DISTO&MxGas	0	0	0
216	Accounts Payable, Other- Labor		1,298	DISTLABOR	1,074	0	224
217	Accounts Payable, Other- O&MxGas		2,239	DISTO&MxGas	1,498	0	741
218	Accounts Payable, Total		3,538		2,572	0	965
219	Accrued interest		(938)	DISTPT	(640)	0	(298)
220	Other, net		715	DISTPT	488	0	227
221	Defd Items & Other, Total		(223)		(152)	0	(71)
222	Total Working Capital		3,315		2,420	0	895

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE							
	I. GAS PLANT IN SERVICE							
	A. INTANGIBLE PLANT							
1	Organization	301	2	P&G_RATEBASE-E	0	0	0	2
2	Intangible Plant - Software- Labor	303Lab	266	PRDGTHPT-E	0	0	0	266
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	268		0	0	0	268
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	AGS Direct	0	0	0	28,445
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	28,445		0	0	0	28,445
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	3	PRDGTHPT-E	0	0	0	3
35	Structures and Improvements	390	269	PRDGTHPT-E	0	0	0	269
36	Structures and Improvements - Direct Assign.	390 DA	42	AGS Direct	0	0	0	42
37	Office Furniture and Equipment	391	420	PRDGTHPT-E	0	0	0	420
38	Office Furniture and Equipment - Direct Assign.	391 DA	1	AGS Direct	0	0	0	1
39	Transportation Equipment	392	353	PRDGTHPT-E	0	0	0	353
40	Stores Equipment	393	2	PRDGTHPT-E	0	0	0	2
41	Tools & Garage Equipment	394	147	PRDGTHPT-E	0	0	0	147
42	Tools & Garage Equipment - Direct Assign.	394 DA	16	AGS Direct	0	0	0	16
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	108	PRDGTHPT-E	0	0	0	108
45	Communication Equipment	397	238	PRDGTHPT-E	0	0	0	238
46	Communication Equipment - Direct Assign.	397 DA	4	AGS Direct	0	0	0	4
47	Miscellaneous Equipment	398	1	PRDGTHPT-E	0	0	0	1
48	Miscellaneous Equipment - Direct Assign.	398 DA	0	None	0	0	0	0
49	Subtotal - GENERAL PLANT	389-399	1,604		0	0	0	1,604
50	**TOTAL UTILITY PLANT**		30,317		0	0	0	30,317
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	91	PRDGTHPT-E	0	0	0	91
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	8,153	AGS Direct	0	0	0	8,153
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	*Services*	*109*	*0*	*None*	*0*	*0*	*0*	*0*
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	666	PRDGTHPT-E	0	0	0	666
62	*General Plant - Direct Assign.*	*108.8 DA*	13	*AGS Direct*	0	0	0	13
63	**TOTAL DEPRECIATION RESERVE**	108	8,924		0	0	0	8,924
	III. OTHER RATE BASE ITEMS							
64	*Materials and Supplies*		*30*	*PRDGTHPT-E*	*0*	0	0	30
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		13	PRDGTHO&MXGAS-C	5	1	1	6
67	Deferred Income Taxes - Depreciation		0	None	0	0	0	0
68	Deferred Income Taxes - Direct Assign.		(1,522)	AGS Direct	0	0	0	(1,522)
69	Deferred ITC		0	None	0	0	0	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(1,478)		5	1	1	(1,486)
72	**TOTAL RATE BASE (Excl. Working Capital)**		19,915		5	1	2	19,908
73	Working Capital	131	3,858		1,741	298	1,617	201
74	**TOTAL RATE BASE**		23,773		1,746	299	1,619	20,109

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	1,043	PRDGTHPT-E	0	0	0	1,043
76	Maintenance Expense	761-765	1,766	PRDGTHPT-E	0	0	0	1,766
77	Subtotal - Production and Gathering	750-765	2,809		0	0	0	2,809
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	391	Account813	279	44	68	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	391		279	44	68	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	112	Gas_Deliveries	53	9	50	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	81	PRDGTHO&MxA/C880	8	1	3	68
102	Other Expenses	880	83	P&G_O&Mx880xAGS	55	9	19	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	276		116	19	72	68
113	***TOTAL OPERATION & MAINTENANCE EXPENSES***		3,475		395	64	139	2,877

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	*Uncollectible Accounts- CAP*	*904CAP*	*0*	None	*0*	*0*	*0*	*0*
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSE							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP.**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES E**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	473	PRDGTHLABOR-E	20	3	15	435
131	Administrative & General Salaries - Direct Assign.	920 DA	44	AGS Direct	0	0	0	44
132	Office Supplies & Expenses	921	65	PRDGTHLABOR-E	3	0	2	60
133	Outside Services Employed - Resid.	923	14	RS Direct	14	0	0	0
134	Outside Services Employed - Labor	923l	290	PRDGTHLABOR-E	12	2	9	267
135	Injuries & Damages	925Labor	27	PRDGTHLABOR-E	1	0	1	25
136	Employee Pensions and Benefits	926	456	PRDGTHLABOR-E	19	3	14	420
137	Rents	931	321	PRDGTHLABOR-E	13	2	10	295
138	Subtotal - O&M Accounts 920-923, 925L, 926		1,691		83	12	51	1,545
	B. Plant-Related:							
139	Property Insurance	924	12	PRDGTHPT-E	0	0	0	12
140	Outside Services Employed-plant	923p	5	PRDGTHPT-E	0	0	0	5
141	Injuries & Damages	925Plant	142	PRDGTHPT-E	0	0	0	142
142	Misc. Maintenance Expense	932	44	P&G_PT_GEN-E	0	0	0	44
143	Misc. Maintenance Expense - Direct Assign.	932 DA	2	AGS Direct	0	0	0	2
144	Subtotal - O&M Accounts 924-925P		203		0	0	0	203
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(3)	P&G_PT_O&M-E	(0)	(0)	(0)	(3)
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	568	P&G_PT_O&M-E	32	5	11	519
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	16	AGS Direct	0	0	0	16
149	Regulatory Commission Expenses	928	42	P&G_PT_O&MxAGS-E	28	4	10	0
150	General Advertising Expense	930.1	16	P&G_PT_O&MxAGS-E	11	2	4	0
151	Miscellaneous General Expenses	930.2	13	P&G_PT_O&M-E	1	0	0	12
152	Subtotal - O&M Accounts 928-935		652		71	11	25	545
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		2,546		154	23	76	2,293
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and Ga**		6,022		549	87	216	5,170

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	27	PRDGTHPT-E	0	0	0	27
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	631	AGS Direct	0	0	0	631
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	145	P&G_PT_GEN-E	0	0	0	145
165	General Plant - Direct Assign.	180Gen DA	3	AGS Direct	0	0	0	3
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	806		0	0	0	806
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		0	None	0	0	0	0
170	Public utilty reality tax		0	None	0	0	0	0
171	State capital stock tax		18	PRDGTHPT-E	0	0	0	18
172	Miscellaneous tax		17	Gas_Deliveries	8	1	8	0
173	Subtotal- Taxes Other Than Income Taxes	408	35		8	1	8	18
	B. Income Tax Expense							
174	State Income Tax expense		16	PreTax-PRDGTH-E	(468)	(63)	(120)	667
175	Federal Income Tax expense		(87)	PreTax-PRDGTH-E	2,489	334	636	(3,546)
176	Investment Tax Credit - Amortization		0	PreTax-PRDGTH-E	(3)	(0)	(1)	4
177	Subtotal- Income tax expense		(70)		2,018	271	516	(2,875)
178	**TOTAL TAX EXPENSE**		(35)		2,026	273	523	(2,857)
179	**TOTAL EXPENSES**		6,792		2,575	359	739	3,119
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	7,399	Delivery_Rev	5,047	693	1,405	254
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		7,399		5,047	693	1,405	254
185	**TOTAL REVENUE**		7,399		5,047	693	1,405	254
186	**TOTAL EXPENSES**		6,792		2,575	359	739	3,119
187	**NET INCOME at Present Rates**		607		2,472	334	666	(2,864)

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		7,399		5,047	693	1,405	254
189	Total Operating Expenses		6,022		549	87	216	5,170
190	Depreciation Expense		806		0	0	0	806
191	Taxes other than Income		35		8	1	8	18
192	Total Other Expenses		841		8	1	8	824
193	Income tax expense		(70)		2,018	271	516	(2,875)
194	Total expenses		6,792		2,575	359	739	3,119
195	NET INCOME at Present Rates		607		2,472	334	666	(2,864)
196	**Total Rate Base**		**23,773**		**1,746**	**299**	**1,619**	**20,109**
197	Return at Present Rates							
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		23,773		1,746	299	1,619	20,109
201	Operating expenses		6,022		549	87	216	5,170
202	Depreciation expense		806		0	0	0	806
203	Taxes other than Income		35		8	1	8	18
204	Operating expenses to recover		6,862		557	88	223	5,994
205	Target Return on Rate Base- After taxes		2,113		155	27	144	1,788
206	Income taxes to recover		1,041	49.2%	76	13	71	880
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		10,017		789	128	438	8,662

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		3,330	Gas_Deliveries	1,585	272	1,474	0
216	*Accounts Payable, Other- Labor*		*228*	*PRDGTHLABOR-E*	*10*	*2*	*7*	*210*
217	Accounts Payable, Other- O&MxGas		308	Gas_Deliveries	147	25	136	0
218	Accounts Payable, Total		3,867		1,741	298	1,617	210
219	Accrued interest		(37)	PRDGTHPT-E	0	0	0	(37)
220	Other, net		28	PRDGTHPT-E	0	0	0	28
221	Defd Items & Other, Total		(9)		0	0	0	(9)
222	Total Working Capital		3,858		1,741	298	1,617	201

	Account Description	Account Code	PRODUCTION & GATH COMMODITY Dollars	Allocation Allocation Factor	PRODUCTION & GATHERING COMMODITY Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	1,164		0	0	0	1,164
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		1,164		0	0	0	1,164
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	77		37	6	34	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	22		2	0	1	19
241	Other Expenses	880	23		15	2	5	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		122		54	9	40	19
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		1,285		54	9	40	1,182

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	*Organization*	301	6	STOR_RATEBASE-D	5	1	0	0
2	Intangible Plant - Software- Labor	303Lab	0	None	0	0	0	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	6		5	1	0	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	*Ind. Meas. & Reg. Station Equip.*	*385*	*0*	*None*	*0*	*0*	*0*	*0*
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	0	None	0	0	0	0
35	Structures and Improvements	390	0	None	0	0	0	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	0	None	0	0	0	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	0	None	0	0	0	0
40	Stores Equipment	393	0	None	0	0	0	0
41	Tools & Garage Equipment	394	0	None	0	0	0	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	0	None	0	0	0	0
45	Communication Equipment	397	0	None	0	0	0	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	0	None	0	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	0	None	0	0	0	0
49	Subtotal - GENERAL PLANT	389-399	0		0	0	0	0
50	**TOTAL UTILITY PLANT**		6		5	1	0	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	2	STOR_RATEBASE-D	2	0	0	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	0	None	0	0	0	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	2		2	0	0	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		0	None	0	0	0	0
65	Current Gas Storage		75,176	Storage	64,111	7,384	3,681	0
66	Prepayments		0	None	0	0	0	0
67	Deferred Income Taxes - Depreciation		0	None	0	0	0	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		0	None	0	0	0	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		75,176		64,111	7,384	3,681	0
72	**TOTAL RATE BASE (Excl. Working Capital)**		75,180		64,114	7,384	3,681	0
73	Working Capital	131	0		0	0	0	0
74	**TOTAL RATE BASE**		75,180		64,114	7,384	3,681	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	0	None	0	0	0	0
102	Other Expenses	880	0	None	0	0	0	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	0		0	0	0	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	*Customer Service - Administrative*	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	0	None	0	0	0	0
131	Administrative & General Salaries - Direct Assign.	920 DA	0	None	0	0	0	0
132	Office Supplies & Expenses	921	0	None	0	0	0	0
133	Outside Services Employed - Resid.	923	0	None	0	0	0	0
134	Outside Services Employed - Labor	923l	0	None	0	0	0	0
135	Injuries & Damages	925Labor	0	None	0	0	0	0
136	Employee Pensions and Benefits	926	0	None	0	0	0	0
137	Rents	931	0	None	0	0	0	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		0		0	0	0	0
	B. Plant-Related:							
139	Property Insurance	924	0	None	0	0	0	0
140	Outside Services Employed-plant	923p	0	None	0	0	0	0
141	Injuries & Damages	925Plant	0	None	0	0	0	0
142	Misc. Maintenance Expense	932	0	None	0	0	0	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	0	None	0	0	0	0
144	Subtotal - O&M Accounts 924-925P		0		0	0	0	0
	C. Other-Related:							
145	Administrative Expenses Transferred	922	0	None	0	0	0	0
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	0	None	0	0	0	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	0	None	0	0	0	0
149	Regulatory Commission Expenses	928	0	None	0	0	0	0
150	General Advertising Expense	930.1	0	None	0	0	0	0
151	*Miscellaneous General Expenses*	*930.2*	0	*None*	0	0	0	0
152	Subtotal - O&M Accounts 928-935		0		0	0	0	0
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		0		0	0	0	0
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G**		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	1	STOR_RATEBASE-D	1	0	0	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	0	None	0	0	0	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	1		1	0	0	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		0	None	0	0	0	0
170	Public utilty reality tax		0	None	0	0	0	0
171	State capital stock tax		58	Storage	49	6	3	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	58		49	6	3	0
	B. Income Tax Expense							
174	State Income Tax expense		(545)	PreTax-Stor-D	(331)	(50)	(137)	(27)
175	Federal Income Tax expense		2,896	PreTax-Stor-D	1,760	266	727	143
176	Investment Tax Credit - Amortization		(3)	PreTax-Stor-D	(2)	(0)	(1)	(0)
177	Subtotal- Income tax expense		2,348		1,427	215	590	116
178	**TOTAL TAX EXPENSE**		2,406		1,476	221	592	116
179	**TOTAL EXPENSES**		2,406		1,477	221	592	116
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	7,411	Delivery_Rev	5,055	694	1,407	255
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		7,411		5,055	694	1,407	255
185	**TOTAL REVENUE**		7,411		5,055	694	1,407	255
186	**TOTAL EXPENSES**		2,406		1,477	221	592	116
187	**NET INCOME at Present Rates**		5,005		3,578	473	814	139

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		7,411		5,055	694	1,407	255
189	Total Operating Expenses		0		0	0	0	0
190	Depreciation Expense		1		1	0	0	0
191	Taxes other than Income		58		49	6	3	0
192	Total Other Expenses		58		50	6	3	0
193	Income tax expense		2,348		1,427	215	590	116
194	Total expenses		2,406		1,477	221	592	116
195	NET INCOME at Present Rates		5,005		3,578	473	814	139
196	**Total Rate Base**		75,180		64,114	7,384	3,681	0
197								
	REVENUE REQUIREMENTS							
198	*Target ROR*		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		75,180		64,114	7,384	3,681	0
201	Operating expenses		0		0	0	0	0
202	Depreciation expense		1		1	0	0	0
203	Taxes other than Income		58		49	6	3	0
204	Operating expenses to recover		58		50	6	3	0
205	Target Return on Rate Base- After taxes		6,684		5,700	656	327	0
206	Income taxes to recover		3,291	49.2%	2,807	323	161	0
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		10,033		8,556	985	491	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		0	None	0	0	0	0
217	Accounts Payable, Other- O&MxGas		0	None	0	0	0	0
218	Accounts Payable, Total		0		0	0	0	0
219	Accrued interest		0	None	0	0	0	0
220	*Other, net*		*0*	*None*	*0*	*0*	*0*	*0*
221	Defd Items & Other, Total		0		0	0	0	0
222	Total Working Capital		0		0	0	0	0

	Account Description	Account Code	STORAGE DEMAND Dollars	Allocation Factor	STORAGE DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	*Meter & House Regulator Expenses*	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	0		0	0	0	0
241	Other Expenses	880	0		0	0	0	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		0		0	0	0	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		0		0	0	0	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	2	TRAN_RATEBASE-D	(0)	(0)	(0)	2
2	Intangible Plant - Software- Labor	303Lab	8	TRANSLABOR-D	0	0	0	8
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	*Miscellaneous Intangible Plant - READI*	*303READI*	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	10		0	0	0	9
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0	None	0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	106	Peak&Avg	58	8	40	0
12	Transmission - Mains	367	1,243	Peak&Avg	680	98	464	0
13	Transmission plant - Direct Assign.	365-370 DA	14,171	AGS Direct	0	0	0	14,171
14	Transmission - Mains - Direct Assign.	367 DA	16,830	AGS Direct	0	0	0	16,830
15	Subtotal - TRANSMISSION PLANT	365-370	32,350		738	107	504	31,001
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	0		0	0	0	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	3	Peak&Avg	2	0	1	0
35	Structures and Improvements	390	306	Peak&Avg	168	24	114	0
36	Structures and Improvements - Direct Assign.	390 DA	25	AGS Direct	0	0	0	25
37	Office Furniture and Equipment	391	477	Peak&Avg	261	38	178	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	1	AGS Direct	0	0	0	1
39	Transportation Equipment	392	402	Peak&Avg	220	32	150	0
40	Stores Equipment	393	2	Peak&Avg	1	0	1	0
41	Tools & Garage Equipment	394	167	Peak&Avg	91	13	62	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	10	AGS Direct	0	0	0	10
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	123	Peak&Avg	67	10	46	0
45	Communication Equipment	397	270	Peak&Avg	148	21	101	0
46	Communication Equipment - Direct Assign.	397 DA	2	AGS Direct	0	0	0	2
47	Miscellaneous Equipment	398	1	Peak&Avg	1	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	3	GSL Direct	0	0	3	0
49	Subtotal - GENERAL PLANT	389-399	1,792		958	139	658	38
50	**TOTAL UTILITY PLANT**		34,152		1,697	245	1,162	31,048
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	3	TRAN_RATEBASE-D	(0)	(0)	(0)	3
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	658	Peak&Avg	360	52	246	0
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	AGS Direct	0	0	0	11,969
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	0	None	0	0	0	0
61	General Plant	109	757	Peak&Avg	414	60	283	0
62	General Plant - Direct Assign.	108.8 DA	8	AGS Direct	0	0	0	8
63	**TOTAL DEPRECIATION RESERVE**	108	13,396		774	112	529	11,981
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		35	Peak&Avg	19	3	13	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		1	Peak&Avg	1	0	0	0
67	Deferred Income Taxes - Depreciation		(2,027)	TRAN_PTxAGS-D	(1,109)	(160)	(757)	0
68	Deferred Income Taxes - Direct Assign.		(901)	AGS Direct	0	0	0	(901)
69	Deferred ITC		(97)	TRAN_PTxAGS-D	(53)	(8)	(36)	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(2,988)		(1,142)	(165)	(780)	(901)
72	**TOTAL RATE BASE (Excl. Working Capital)**		17,768		(220)	(32)	(147)	18,167
73	Working Capital	131	28		15	2	10	0
74	**TOTAL RATE BASE**		17,795		(205)	(30)	(137)	18,167

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	*Natural gas transmission line purchases*	*803*	0	*None*	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	*LNG Operating Exp Admin*	*840*	0	*None*	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	0	None	0	0	0	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	129	TRANS_MAINS-D	5	1	3	120
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	3	TRANO&MxA/C880-D	0	0	0	3
102	Other Expenses	880	3	TRANO&Mx880xAGS-D	2	0	1	0
103	Distribution Rents	881	0	None	0	0	0	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	Maintenance of Structures & Improvements	886	0	None	0	0	0	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	*Maintenance of Other Equipment*	*894*	0	*None*	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	135		7	1	5	123
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		135		7	1	5	123

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		0		0	0	0	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	15	TRANSLABOR-D	1	0	0	14
131	Administrative & General Salaries - Direct Assign.	920 DA	1	AGS Direct	0	0	0	1
132	*Office Supplies & Expenses*	*921*	*2*	*TRANSLABOR-D*	*0*	*0*	*0*	*2*
133	Outside Services Employed - Resid.	923	0	RS Direct	0	0	0	0
134	Outside Services Employed - Labor	923l	9	TRANSLABOR-D	0	0	0	8
135	Injuries & Damages	925Labor	1	TRANSLABOR-D	0	0	0	1
136	Employee Pensions and Benefits	926	14	TRANSLABOR-D	1	0	0	13
137	Rents	931	10	TRANSLABOR-D	0	0	0	9
138	Subtotal - O&M Accounts 920-923, 925L, 926		53		3	0	2	48
	B. Plant-Related:							
139	Property Insurance	924	13	Peak&Avg	7	1	5	0
140	Outside Services Employed-plant	923p	5	Peak&Avg	3	0	2	0
141	Injuries & Damages	925Plant	161	Peak&Avg	88	13	60	0
142	Misc. Maintenance Expense	932	49	TRAN_PT_GEN-D	26	4	18	1
143	Misc. Maintenance Expense - Direct Assign.	932 DA	2	AGS Direct	0	0	0	2
144	Subtotal - O&M Accounts 924-925P		230		124	18	85	3
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(1)	TRAN_PT-D	(0)	(0)	(0)	(1)
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	155	TRAN_PT-D	4	1	2	148
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	4	AGS Direct	0	0	0	4
149	Regulatory Commission Expenses	928	11	TRAN_PTxAGS-D	6	1	4	0
150	General Advertising Expense	930.1	4	TRAN_PTxAGS-D	2	0	2	0
151	Miscellaneous General Expenses	930.2	3	TRAN_PT-D	0	0	0	3
152	Subtotal - O&M Accounts 928-935		177		12	2	8	155
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		461		140	20	95	206
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G**		596		146	21	100	329

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	1	TRAN_RATEBASE-D	(0)	(0)	(0)	1
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	9	Peak&Avg	5	1	3	0
159	Transmission Plant - Direct Assign.	180Trans DA	704	AGS Direct	0	0	0	704
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	0	None	0	0	0	0
164	General Plant	180Gen	162	TRAN_PT_GEN-D	86	13	59	3
165	General Plant - Direct Assign.	180Gen DA	2	AGS Direct	0	0	0	2
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	876		91	13	63	710
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		1	Peak&Avg	1	0	0	0
170	Public utilty reality tax		10	Peak&Avg	6	1	4	0
171	State capital stock tax		14	Peak&Avg	7	1	5	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	25		14	2	9	0
	B. Income Tax Expense							
174	State Income Tax expense		(88)	PreTax-Tran-D	(179)	(24)	(39)	155
175	Federal Income Tax expense		468	PreTax-Tran-D	953	130	209	(824)
176	Investment Tax Credit - Amortization		(0)	PreTax-Tran-D	(1)	(0)	(0)	1
177	Subtotal- Income tax expense		380		772	105	170	(668)
178	**TOTAL TAX EXPENSE**		405		786	107	179	(668)
179	**TOTAL EXPENSES**		1,878		1,024	142	341	371
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	2,851	Delivery_Rev	1,944	267	541	98
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		2,851		1,944	267	541	98
185	**TOTAL REVENUE**		2,851		1,944	267	541	98
186	**TOTAL EXPENSES**		1,878		1,024	142	341	371
187	**NET INCOME at Present Rates**		973		921	126	200	(273)

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		2,851		1,944	267	541	98
189	*Total Operating Expenses*		*596*		*146*	*21*	*100*	*329*
190	Depreciation Expense		876		91	13	63	710
191	Taxes other than Income		25		14	2	9	0
192	Total Other Expenses		902		105	15	72	710
193	Income tax expense		380		772	105	170	(668)
194	Total expenses		1,878		1,024	142	341	371
195	NET INCOME at Present Rates		973		921	126	200	(273)
196	**Total Rate Base**		17,795		(205)	(30)	(137)	18,167
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		17,795		(205)	(30)	(137)	18,167
201	Operating expenses		596		146	21	100	329
202	Depreciation expense		876		91	13	63	710
203	Taxes other than Income		25		14	2	9	0
204	Operating expenses to recover		1,498		251	36	172	1,039
205	Target Return on Rate Base- After taxes		1,582		(18)	(3)	(12)	1,615
206	Income taxes to recover		779	49.2%	(9)	(1)	(6)	795
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		3,859		224	32	154	3,449

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	*Inventories & Other, Total*		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		7	Peak&Avg	4	1	3	0
217	Accounts Payable, Other- O&MxGas		31	Peak&Avg	17	2	11	0
218	Accounts Payable, Total		38		21	3	14	0
219	*Accrued interest*		(42)	Peak&Avg	(23)	(3)	(16)	0
220	Other, net		32	Peak&Avg	18	3	12	0
221	Defd Items & Other, Total		(10)		(5)	(1)	(4)	0
222	Total Working Capital		28		15	2	10	0

	Account Description	Account Code	TRANSMISSION DEMAND Dollars	Allocation Factor	TRANSMISSION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	0		0	0	0	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	39		1	0	1	36
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	1		0	0	0	1
241	Other Expenses	880	1		0	0	0	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	*Maint. of Services*	*892*	*0*		*0*	*0*	*0*	*0*
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		40		2	0	1	37
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	*Customer Records & Collection Expense*	*903*	*0*		*0*	*0*	*0*	*0*
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	*Supervision*	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		40		2	0	1	37

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	26	DIST_RATEBASE-D	14	2	10	0
2	Intangible Plant - Software- Labor	303Lab	1,252	DISTLABOR-D	672	97	483	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	1,695	DISTOnlyPT-D	905	131	659	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	2,974		1,591	230	1,153	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	1,291	Peak&Avg	706	102	483	0
17	Land and Land Rights - Direct Assign.	374 DA	564	GSL Direct	0	0	564	0
18	Structures and Improvements	375	1,440	Peak&Avg	788	114	538	0
19	Mains	376	457,729	Peak&Avg	250,431	36,224	171,074	0
20	Mains - Direct Assign.	376 DA	10,267	GSL Direct	0	0	10,267	0
21	Meas. & Reg. Stat. Equip. - General	378	16,126	Peak&Avg	8,823	1,276	6,027	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	GSL Direct	0	0	1,469	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	Peak&Avg	244	35	167	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	489,333		260,992	37,751	190,589	0

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	46	DISTPT-D	25	4	18	0
35	Structures and Improvements	390	4,631	DISTPT-D	2,470	357	1,804	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	7,219	DISTPT-D	3,850	557	2,812	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	6,076	DISTPT-D	3,241	469	2,366	0
40	Stores Equipment	393	28	DISTPT-D	15	2	11	0
41	Tools & Garage Equipment	394	2,522	DISTPT-D	1,345	195	982	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	1,863	DISTPT-D	994	144	726	0
45	Communication Equipment	397	4,088	DISTPT-D	2,181	315	1,592	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	19	DISTPT-D	10	1	7	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	97	GSL Direct	0	0	97	0
49	Subtotal - GENERAL PLANT	389-399	26,590		14,130	2,044	10,416	0
50	**TOTAL UTILITY PLANT**		518,897		276,714	40,025	202,158	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	1,010	DISTPT-D_INT	540	78	391	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	130,432	DISTMAIN-D	69,796	10,096	50,540	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	6,435	DISTPT-DxMSM	3,185	461	2,789	0
61	General Plant	109	11,455	DISTPT-D	6,110	884	4,462	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	149,331		79,631	11,518	58,182	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		524	DISTPT-D	280	40	204	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		65	DISTO&MXGAS-D	40	6	17	2
67	Deferred Income Taxes - Depreciation		(63,898)	DISTPT-D	(34,081)	(4,930)	(24,887)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(3,063)	DISTPT-D	(1,634)	(236)	(1,193)	0
70	Customer Deposits		0	None	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(66,372)		(35,394)	(5,120)	(25,859)	2
72	**TOTAL RATE BASE (Excl. Working Capital)**		303,194		161,689	23,387	118,117	2
73	Working Capital	131	2,420		1,427	202	755	37
74	**TOTAL RATE BASE**		305,615		163,116	23,589	118,871	39

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	1,130	DISTOnlyPT-D	603	87	439	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	3,342	DISTMAIN-SERV-D	1,788	259	1,295	0
97	Meas. & Reg. Station Expense General	875	100	Peak&Avg	55	8	37	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	312	DISTO&MxA/C880-D	167	24	120	0
102	Other Expenses	880	321	DISTO&Mx880xAGS-D	172	25	124	0
103	Distribution Rents	881	383	DISTOnlyPT-D	205	30	149	0
104	Maint. Supervision & Engineering	885	732	DISTLABOR-D	393	57	282	0
105	Maintenance of Structures & Improvements	886	352	DISTOnlyPT-D	188	27	137	0
106	Maint. of Mains	887	5,521	DISTMAIN-D	2,955	427	2,139	0
107	Maint Of Meas. & Reg. Station Expense General	889	1,192	Peak&Avg	652	94	445	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	10	Peak&Avg	6	1	4	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	46	DISTPT-D	25	4	18	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	13,441		7,207	1,043	5,191	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		13,441		7,207	1,043	5,191	0

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPEN							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EX**		0		0	0	0	0
129	***TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES***		*0*		*0*	*0*	*0*	*0*
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	2,225	DISTLABOR-D	1,194	173	859	0
131	Administrative & General Salaries - Direct Assign.	920 DA	206	AGS Direct	0	0	0	206
132	Office Supplies & Expenses	921	306	DISTLABOR-D	164	24	118	0
133	Outside Services Employed - Resid.	923	67	RS Direct	67	0	0	0
134	Outside Services Employed - Labor	923l	1,363	DISTLABOR-D	731	106	526	0
135	Injuries & Damages	925Labor	127	DISTLABOR-D	68	10	49	0
136	Employee Pensions and Benefits	926	2,145	DISTLABOR-D	1,151	166	828	0
137	Rents	931	1,508	DISTLABOR-D	809	117	582	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		7,947		4,184	595	2,961	206
	B. Plant-Related:							
139	Property Insurance	924	198	DISTPT-D	106	15	77	0
140	Outside Services Employed-plant	923p	80	DISTPT-D	43	6	31	0
141	Injuries & Damages	925Plant	2,439	DISTPT-D	1,301	188	950	0
142	Misc. Maintenance Expense	932	724	DISTPT_GEN-D	385	56	284	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	29	AGS Direct	0	0	0	29
144	Subtotal - O&M Accounts 924-925P		3,470		1,834	265	1,342	29
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(20)	DIST_PT_O&M-D	(11)	(2)	(8)	(0)
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	3,874	DIST_PT_O&M-D	2,072	300	1,503	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	110	AGS Direct	0	0	0	110
149	Regulatory Commission Expenses	928	285	DIST_PT_O&MxAGS-D	153	22	111	0
150	General Advertising Expense	930.1	111	DIST_PT_O&MxAGS-D	59	9	43	0
151	Miscellaneous General Expenses	930.2	78	DIST_PT_O&M-D	42	6	30	0
152	Subtotal - O&M Accounts 928-935		4,439		2,315	335	1,679	110
153	***TOTAL ADMINISTRATIVE & GENERAL EXPENSES***		*15,856*		*8,333*	*1,196*	*5,982*	*346*
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and**		29,297		15,540	2,238	11,173	346

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	299	DISTPT-D_INT	160	23	116	0
156	Production & Gathering Plant - Direct Assign.	180ProdGth DA	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	6,999	DISTMAIN-D	3,745	542	2,712	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	921	DISTPT-DxMSM	456	66	399	0
164	General Plant	180Gen	2,400	DISTPT_GEN-D	1,275	184	940	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	10,619		5,637	815	4,167	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		39	TOTALPLANTxAGS	26	2	11	0
170	Public utilty reality tax		324	TOTALPLANTxAGS	217	19	88	0
171	State capital stock tax		234	DISTPT-D	125	18	91	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	598		368	39	190	0
	B. Income Tax Expense							
174	State Income Tax expense		(1,105)	PreTax-Dist-D	(1,536)	(193)	804	(181)
175	Federal Income Tax expense		5,873	PreTax-Dist-D	8,160	1,027	(4,274)	960
176	Investment Tax Credit - Amortization		(6)	PreTax-Dist-D	(8)	(1)	4	(1)
177	Subtotal- Income tax expense		4,761		6,616	833	(3,466)	779
178	**TOTAL TAX EXPENSE**		5,359		6,984	872	(3,275)	779
179	**TOTAL EXPENSES**		45,276		28,161	3,925	12,065	1,124
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	59,881	Delivery_Rev	40,844	5,611	11,367	2,060
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		0	None	0	0	0	0
184	Subtotal- Gas Revenues, net		59,881		40,844	5,611	11,367	2,060
185	**TOTAL REVENUE**		59,881		40,844	5,611	11,367	2,060
186	**TOTAL EXPENSES**		45,276		28,161	3,925	12,065	1,124
187	**NET INCOME at Present Rates**		14,606		12,684	1,685	(699)	935

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		59,881		40,844	5,611	11,367	2,060
189	Total Operating Expenses		29,297		15,540	2,238	11,173	346
190	Depreciation Expense		10,619		5,637	815	4,167	0
191	Taxes other than Income		598		368	39	190	0
192	Total Other Expenses		11,217		6,005	854	4,358	0
193	Income tax expense		4,761		6,616	833	(3,466)	779
194	Total expenses		45,276		28,161	3,925	12,065	1,124
195	NET INCOME at Present Rates		14,606		12,684	1,685	(699)	935
196	**Total Rate Base**		305,615		163,116	23,589	118,871	39
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		305,615		163,116	23,589	118,871	39
201	Operating expenses		29,297		15,540	2,238	11,173	346
202	Depreciation expense		10,619		5,637	815	4,167	0
203	Taxes other than Income		598		368	39	190	0
204	Operating expenses to recover		40,514		21,545	3,093	15,531	346
205	Target Return on Rate Base- After taxes		27,169		14,501	2,097	10,568	3
206	Income taxes to recover		13,378	49.2%	7,140	1,033	5,203	2
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		81,062		43,186	6,222	31,302	351

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	*Inventories & Other, Total*		*0*		*0*	*0*	*0*	*0*
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		1,074	DISTLABOR-D	576	83	414	0
217	Accounts Payable, Other- O&MxGas		1,498	DISTO&MXGAS-D	932	130	399	37
218	Accounts Payable, Total		2,572		1,508	213	814	37
219	Accrued interest		(640)	DISTPT-D	(341)	(49)	(249)	0
220	Other, net		488	DISTPT-D	260	38	190	0
221	Defd Items & Other, Total		(152)		(81)	(12)	(59)	0
222	Total Working Capital		2,420		1,427	202	755	37

	Account Description	Account Code	DISTRIBUTION DEMAND Dollars	Allocation Factor	DISTRIBUTION DEMAND Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	*Production and Gathering O&M*	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	797		426	62	310	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	1,003		537	78	389	0
236	Meas. & Reg. Station Expense General	875	40		22	3	15	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	85		46	7	33	0
241	Other Expenses	880	87		47	7	34	0
242	Maint. Supervision & Engineering	885	501		269	39	193	0
243	Maintenance of Structures & Improvements	886	113		61	9	44	0
244	Maint. of Mains	887	2,262		1,211	175	877	0
245	Maint Of Meas. & Reg. Station Expense General	889	608		333	48	227	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	7		4	1	3	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	30		16	2	12	0
250	**Sub Distribution**		5,535		2,969	429	2,136	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		0		0	0	0	0
260	TOTAL:		5,535		2,969	429	2,136	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	*General Service - Small (GSS)*	*General Service - Large (GSL)*	Appalachian Gathering Service (AGS)
	1. RATE BASE							
	I. GAS PLANT IN SERVICE							
	A. INTANGIBLE PLANT							
1	Organization	301	10	DIST_RATEBASE-C	10	0	0	0
2	Intangible Plant - Software- Labor	303Lab	261	DISTLABOR-C	186	62	14	0
3	Intangible Plant - Software- Customer	303Cust	0	None	0	0	0	0
4	Intangible Plant - Software- Plant	303Plt	790	DISTOnlyPT-C	746	8	37	0
5	Miscellaneous Intangible Plant - READI	303READI	0	None	0	0	0	0
6	Subtotal - INTANGIBLE ASSETS	301-303	1,062		941	70	51	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	Subtotal - TRANSMISSION PLANT	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	601	DISTOnlyPT-C	568	6	28	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	671	DISTOnlyPT-C	633	7	31	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	226,432	Service_Invest	213,758	2,209	10,465	0
26	Meters	381	0	None	0	0	0	0
27	Meter Installations	382	0	None	0	0	0	0
28	House Regulators	383	0	None	0	0	0	0
29	House Regulator Installations	384	0	None	0	0	0	0
30	Ind. Meas. & Reg. Station Equip.	385	0	None	0	0	0	0
31	Property on Customers' Premises	386	0	None	0	0	0	0
32	Other Equipment	387	324	GSS Direct	0	324	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	228,028		214,959	2,545	10,524	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	21	DISTPT-C	20	0	1	0
35	Structures and Improvements	390	2,158	DISTPT-C	2,034	24	100	0
36	*Structures and Improvements - Direct Assign.*	*390 DA*	*0*	*None*	*0*	*0*	*0*	*0*
37	Office Furniture and Equipment	391	3,364	DISTPT-C	3,171	38	155	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	2,831	DISTPT-C	2,669	32	131	0
40	Stores Equipment	393	13	DISTPT-C	12	0	1	0
41	Tools & Garage Equipment	394	1,175	DISTPT-C	1,108	13	54	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	868	DISTPT-C	819	10	40	0
45	Communication Equipment	397	1,905	DISTPT-C	1,796	21	88	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	9	DISTOnlyPT-C	8	0	0	0
48	Miscellaneous Equipment - Direct Assign.	398 DA	45	GSL Direct	0	0	45	0
49	Subtotal - GENERAL PLANT	389-399	12,391		11,638	138	615	0
50	**TOTAL UTILITY PLANT**		241,481		227,539	2,752	11,190	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	361	DISTPT-C_INT	320	24	17	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	83,524	Service_Invest	78,849	815	3,860	0
59	Meters	109	0	None	0	0	0	0
60	Distr Other	109	481	DISTPT-CxMSM	362	101	18	0
61	General Plant	109	5,338	DISTPT-C	5,032	60	246	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	**TOTAL DEPRECIATION RESERVE**	108	89,704		84,563	999	4,142	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		244	DISTPT-C	230	3	11	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		32	DISTO&MXGAS-C	25	3	4	1
67	*Deferred Income Taxes - Depreciation*		(29,776)	DISTPT-C	(28,070)	(332)	(1,374)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(1,427)	DISTPT-C	(1,345)	(16)	(66)	0
70	Customer Deposits		(3,370)	Deposits	(2,775)	(209)	(385)	0
71	**TOTAL OTHER RATE BASE ITEMS**		(34,297)		(31,936)	(552)	(1,810)	1
72	**TOTAL RATE BASE (Excl. Working Capital)**		117,480		111,040	1,201	5,238	1
73	Working Capital	131	895		703	102	90	0
74	**TOTAL RATE BASE**		118,374		111,743	1,303	5,328	1

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	526	DISTOnlyPT-C	497	5	24	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	1,617	DISTMAIN-SERV-C	1,526	16	75	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	0	None	0	0	0	0
100	Customer Installation Expense	879	0	None	0	0	0	0
101	Other Expenses - Safety and Environmental	880	65	DISTO&MxA/C880-C	60	1	3	0
102	*Other Expenses*	*880*	67	*DISTO&Mx880xAGS-C*	*62*	*2*	*3*	*0*
103	Distribution Rents	881	179	DISTOnlyPT-C	169	2	8	0
104	Maint. Supervision & Engineering	885	153	DISTLABOR-C	109	36	8	0
105	Maintenance of Structures & Improvements	886	164	DISTPT-C	155	2	8	0
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	0	None	0	0	0	0
109	Maint. of Services	892	0	None	0	0	0	0
110	Maint. of Meters & House Regulators	893	0	None	0	0	0	0
111	Maintenance of Other Equipment	894	21	DISTPT-C	20	0	1	0
112	*Subtotal - DISTRIBUTION EXPENSES*	*870-894*	2,792		2,598	64	130	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		2,792		2,598	64	130	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	0	None	0	0	0	0
115	Meter Reading Expenses	902	0	None	0	0	0	0
116	Customer Records & Collection Expense	903	0	None	0	0	0	0
117	Uncollectible Accounts	904	0	None	0	0	0	0
118	Uncollectible Accounts- CAP	904CAP	0	None	0	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		0		0	0	0	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPEN							
121	Operation Supervision	907	0	None	0	0	0	0
122	*Customer Assist- Other*	*908*	*210*	*Acct901-903,908*	*196*	*13*	*2*	*0*
123	Customer Assist- CAP	908CAP	299	RS Direct	299	0	0	0
124	Other Customer Service & Informational Expense	910	698	Account910	698	0	0	0
125	Supervision	911	0	Account911-916	0	0	0	0
126	Demonstration	912	660	Account911-916	0	591	68	0
127	Adverstising expense	913	24	Account911-916	0	22	3	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EX**		1,891		1,193	626	73	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES**		1,891		1,193	626	73	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	*920*	*464*	*DISTLABOR-C*	*330*	*110*	25	*0*
131	Administrative & General Salaries - Direct Assign.	920 DA	43	AGS Direct	0	0	0	43
132	Office Supplies & Expenses	921	64	DISTLABOR-C	45	15	3	0
133	Outside Services Employed - Resid.	923	14	RS Direct	14	0	0	0
134	Outside Services Employed - Labor	923l	284	DISTLABOR-C	202	67	15	0
135	Injuries & Damages	925Labor	26	DISTLABOR-C	19	6	1	0
136	Employee Pensions and Benefits	926	448	DISTLABOR-C	318	106	24	0
137	Rents	931	315	DISTLABOR-C	224	74	17	0
138	Subtotal - O&M Accounts 920-923, 925L, 926		1,659		1,152	378	85	43
	B. Plant-Related:							
139	Property Insurance	924	92	DISTPT-C	87	1	4	0
140	Outside Services Employed-plant	923p	37	DISTPT-C	35	0	2	0
141	Injuries & Damages	925Plant	1,137	DISTPT-C	1,071	13	52	0
142	Misc. Maintenance Expense	932	337	DISTPT_GEN-C	317	4	17	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	14	AGS Direct	0	0	0	14
144	Subtotal - O&M Accounts 924-925P		1,617		1,510	18	75	14
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(7)	DIST_PT_O&M-C	(6)	(0)	(0)	0
146	Outside Services Employed-cust	923c	5,083	Cust_Avg	4,732	315	36	0
147	Outside Services Employed-plant-O&M	923p-om	1,257	DIST_PT_O&M-C	1,177	21	58	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	36	AGS Direct	0	0	0	36
149	Regulatory Commission Expenses	928	93	DIST_PT_O&MxAGS-C	87	2	4	0
150	General Advertising Expense	930.1	36	DIST_PT_O&MxAGS-C	34	1	2	0
151	Miscellaneous General Expenses	930.2	36	DIST_PT_O&M-C	34	1	2	0
152	Subtotal - O&M Accounts 928-935		6,534		6,057	339	102	36
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		9,809		8,719	735	263	93
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and**		14,492		12,510	1,425	465	93

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	107	DISTPT-C_INT	95	7	5	0
156	*Production & Gathering Plant - Direct Assign.*	*180ProdGth DA*	0	None	0	0	0	0
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	*Services*	*180Services*	*5,815*	*Service_Invest*	*5,489*	*57*	*269*	*0*
162	Meters	180Meters	0	None	0	0	0	0
163	Distr Other	180Dist	69	DISTPT-CxMSM	52	15	3	0
164	General Plant	180Gen	1,118	DISTPT_GEN-C	1,050	12	56	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	7,109		6,686	91	332	0
	VI. TAXES							
	A. General Taxes							
168	PA PUC Assessment		1,139	Delivery_RevxAGS	805	111	224	0
169	Local property taxes		18	TOTALPLANTxAGS	12	1	5	0
170	Public utilty reality tax		151	TOTALPLANTxAGS	101	9	41	0
171	State capital stock tax		91	RATEBASExAGS	63	6	22	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	1,399		981	126	292	0
	B. Income Tax Expense							
174	State Income Tax expense		(233)	PreTax-Dist-C	410	(106)	(443)	(94)
175	Federal Income Tax expense		1,238	PreTax-Dist-C	(2,177)	564	2,352	500
176	Investment Tax Credit - Amortization		(1)	PreTax-Dist-C	2	(1)	(2)	(1)
177	Subtotal- Income tax expense		1,004		(1,765)	457	1,907	405
178	**TOTAL TAX EXPENSE**		2,404		(784)	583	2,199	405
179	***TOTAL EXPENSES***		*24,004*		*18,412*	*2,099*	*2,997*	*499*
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	28,592	Delivery_Rev	19,503	2,679	5,427	983
181	Forfeited Discounts		0	None	0	0	0	0
182	Miscellaneous Service Revenue		0	None	0	0	0	0
183	Other Operating Revenue		61	Delivery_RevxAGS	43	6	12	0
184	Subtotal- Gas Revenues, net		28,654		19,546	2,685	5,439	983
185	**TOTAL REVENUE**		28,654		19,546	2,685	5,439	983
186	**TOTAL EXPENSES**		24,004		18,412	2,099	2,997	498
187	**NET INCOME at Present Rates**		4,649		1,134	586	2,443	486

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	*Total revenues*		*28,654*		*19,546*	*2,685*	*5,439*	*983*
189	Total Operating Expenses		14,492		12,510	1,425	465	93
190	Depreciation Expense		7,109		6,686	91	332	0
191	Taxes other than Income		1,399		981	126	292	0
192	Total Other Expenses		8,508		7,667	217	624	0
193	Income tax expense		1,004		(1,765)	457	1,907	405
194	Total expenses		24,004		18,412	2,099	2,997	498
195	NET INCOME at Present Rates		4,649		1,134	586	2,443	486
196	**Total Rate Base**		118,374		111,743	1,303	5,328	1
197								
	REVENUE REQUIREMENTS							
198	Target ROR		8.89%		8.89%	8.89%	8.89%	8.89%
199	Using Target for System							
200	Rate Base		118,374		111,743	1,303	5,328	1
201	Operating expenses		14,492		12,510	1,425	465	93
202	Depreciation expense		7,109		6,686	91	332	0
203	Taxes other than Income		1,399		981	126	292	0
204	Operating expenses to recover		23,000		20,176	1,642	1,090	93
205	Target Return on Rate Base- After taxes		10,523		9,934	116	474	0
206	Income taxes to recover		5,182	49.2%	4,891	57	233	0
207	Additional expenses		0	0.0%	0	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		38,706		35,002	1,815	1,797	93

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		224	DISTLABOR-C	159	53	12	0
217	Accounts Payable, Other- O&MxGas		741	ONSITEO&MxGASxAGS-C	611	49	81	0
218	Accounts Payable, Total		965		770	102	93	0
219	Accrued interest		(298)	DISTPT-C	(281)	(3)	(14)	0
220	Other, net		227	DISTPT-C	214	3	10	0
221	Defd Items & Other, Total		(71)		(67)	(1)	(3)	0
222	Total Working Capital		895		703	102	90	0

	Account Description	Account Code	DISTRIBUTION CUSTOMER Dollars	Allocation Factor	DISTRIBUTION CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	371		351	4	17	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	485		458	5	22	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	0		0	0	0	0
239	Customer Installation Expense	879	0		0	0	0	0
240	Other Expenses - Safety and Environmental	880	18		16	0	1	0
241	Other Expenses	880	18		17	0	1	0
242	Maint. Supervision & Engineering	885	104		74	25	6	0
243	Maintenance of Structures & Improvements	886	53		50	1	2	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Statior	891	0		0	0	0	0
247	Maint. of Services	892	0		0	0	0	0
248	Maint. of Meters & House Regulators	893	0		0	0	0	0
249	Maintenance of Other Equipment	894	14		13	0	1	0
250	**Sub Distribution**		1,064		980	35	50	0
	OnSite:							
251	Customer Service - Administrative	901	0		0	0	0	0
252	Meter Reading Expenses	902	0		0	0	0	0
253	Customer Records & Collection Expense	903	0		0	0	0	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	117		109	7	1	0
256	Customer Assist- CAP	908CAP	168		168	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	420		0	376	44	0
259	**Sub OnSite**		705		277	383	44	0
260	TOTAL:		1,769		1,257	418	94	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	1. RATE BASE				3	4	5	6
	I. GAS PLANT IN SERVICE				3	4	5	6
	A. INTANGIBLE PLANT							
1	Organization	301	4	ONSITE_RATEBASE-C	3	0	0	0
2	Intangible Plant - Software- Labor	303Lab	1,554	ONSITELABOR-C	1,297	125	132	0
3	Intangible Plant - Software- Customer	303Cust	2,743	Cust_Avg	2,553	170	20	0
4	Intangible Plant - Software- Plant	303Plt	0	None	0	0	0	0
5	Miscellaneous Intangible Plant - READI	303READI	15,628	Cust_Avg	14,549	967	112	0
6	Subtotal - INTANGIBLE ASSETS	301-303	19,928		18,402	1,262	264	0
	B. PRODUCTION & GATHERING PLANT							
7	Production and Gathering - Direct Assign.	304-338 DA	0	None	0	0	0	0
8	Subtotal - PRODUCTION & GATHERING PLANT	304-338	0		0	0	0	0
	C. STORAGE PLANT							
9	Storage Plant	360-368	0	None	0	0	0	0
10	Subtotal - STORAGE PLANT	360-368	0		0	0	0	0
	D. TRANSMISSION PLANT							
11	Transmission plant	365-370	0	None	0	0	0	0
12	Transmission - Mains	367	0	None	0	0	0	0
13	Transmission plant - Direct Assign.	365-370 DA	0	None	0	0	0	0
14	Transmission - Mains - Direct Assign.	367 DA	0	None	0	0	0	0
15	*Subtotal - TRANSMISSION PLANT*	365-370	0		0	0	0	0
	E. DISTRIBUTION PLANT							
16	Land and Land Rights	374	0	None	0	0	0	0
17	Land and Land Rights - Direct Assign.	374 DA	0	None	0	0	0	0
18	Structures and Improvements	375	0	None	0	0	0	0
19	Mains	376	0	None	0	0	0	0
20	Mains - Direct Assign.	376 DA	0	None	0	0	0	0
21	Meas. & Reg. Stat. Equip. - General	378	0	None	0	0	0	0
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	0	None	0	0	0	0
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	0	None	0	0	0	0
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	None	0	0	0	0
25	Services	380	0	None	0	0	0	0
26	Meters	381	17,775	Meter_Invest	12,344	1,821	3,610	0
27	Meter Installations	382	9,208	Meter_Invest	6,395	943	1,870	0
28	House Regulators	383	5,656	Account 383/384	3,852	865	939	0
29	House Regulator Installations	384	1,514	Account 383/384	1,031	231	251	0
30	Ind. Meas. & Reg. Station Equip.	385	441	GSL Direct	0	0	441	0
31	Property on Customers' Premises	386	15,838	Account386	14,394	356	1,087	0
32	Other Equipment	387	0	None	0	0	0	0
33	Subtotal - DISTRIBUTION PLANT	374-387	50,432		38,017	4,217	8,199	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	F. GENERAL PLANT							
34	Land and Land Rights	389	5	ONSITEPT-C	4	0	1	0
35	Structures and Improvements	390	477	ONSITEPT-C	360	40	78	0
36	Structures and Improvements - Direct Assign.	390 DA	0	None	0	0	0	0
37	Office Furniture and Equipment	391	744	ONSITEPT-C	561	62	121	0
38	Office Furniture and Equipment - Direct Assign.	391 DA	0	None	0	0	0	0
39	Transportation Equipment	392	626	ONSITEPT-C	472	52	102	0
40	Stores Equipment	393	3	ONSITEPT-C	2	0	0	0
41	Tools & Garage Equipment	394	260	ONSITEPT-C	196	22	42	0
42	Tools & Garage Equipment - Direct Assign.	394 DA	0	None	0	0	0	0
43	Laboratory Equipment	395	0	None	0	0	0	0
44	Power Operated Equipment	396	192	ONSITEPT-C	145	16	31	0
45	Communication Equipment	397	421	ONSITEPT-C	318	35	68	0
46	Communication Equipment - Direct Assign.	397 DA	0	None	0	0	0	0
47	Miscellaneous Equipment	398	2	ONSITEPT-C	1	0	0	0
48	*Miscellaneous Equipment - Direct Assign.*	*398 DA*	10	*GSL Direct*	0	0	10	0
49	Subtotal - GENERAL PLANT	389-399	2,740		2,058	228	454	0
50	**TOTAL UTILITY PLANT**		73,101		58,477	5,708	8,917	0
	II. DEPRECIATION RESERVE							
51	Intangible Plant	108	6,768	ONSITEPT-C_INT	6,250	429	90	0
52	Production & Gathering Plant	108.2	0	None	0	0	0	0
53	Production & Gathering Plant - Direct Assign.	108.2 DA	0	None	0	0	0	0
54	Local Storage Plant	108.3	0	None	0	0	0	0
55	Transmission Plant	108.4	0	None	0	0	0	0
56	Transmission Plant - Direct Assign.	108.4 DA	0	None	0	0	0	0
57	Mains	109	0	None	0	0	0	0
58	Services	109	0	None	0	0	0	0
59	Meters	109	12,975	Meter_Invest	9,011	1,329	2,635	0
60	Distr Other	109	7,072	ONSITE-CxMSM	5,814	438	820	0
61	General Plant	109	1,181	ONSITEPT-C	890	99	192	0
62	General Plant - Direct Assign.	108.8 DA	0	None	0	0	0	0
63	***TOTAL DEPRECIATION RESERVE***	*108*	27,996		21,964	2,295	3,737	0
	III. OTHER RATE BASE ITEMS							
64	Materials and Supplies		54	ONSITEPT-C	41	5	9	0
65	Current Gas Storage		0	None	0	0	0	0
66	Prepayments		122	ONSITEO&MXGAS-C	99	8	13	2
67	Deferred Income Taxes - Depreciation		(6,586)	ONSITEPT-C	(4,964)	(551)	(1,071)	0
68	Deferred Income Taxes - Direct Assign.		0	None	0	0	0	0
69	Deferred ITC		(316)	ONSITEPT-C	(238)	(26)	(51)	0
70	*Customer Deposits*		0	*None*	0	0	0	0
71	**TOTAL OTHER RATE BASE ITEMS**		(6,725)		(5,062)	(565)	(1,100)	2
72	**TOTAL RATE BASE (Excl. Working Capital)**		38,380		31,450	2,848	4,080	2
73	Working Capital	131	4,135		3,422	294	419	0
74	**TOTAL RATE BASE**		42,515		34,872	3,142	4,499	2

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	2. EXPENSES							
	I. OPERATION & MAINTENANCE EXPENSE							
	A. PRODUCTION & GATHERING EXPENSES							
75	Operations Expense	750-756	0	None	0	0	0	0
76	Maintenance Expense	761-765	0	None	0	0	0	0
77	Subtotal - Production and Gathering	750-765	0		0	0	0	0
	B. OTHER GAS SUPPLY EXPENSES							
78	Natural gas field line purchases	801	0	None	0	0	0	0
79	Natural gas transmission line purchases	803	0	None	0	0	0	0
80	Natural Gas City Gate Purchases	804	0	None	0	0	0	0
81	Other Natural Gas Purchases	805	0	None	0	0	0	0
82	Well Expenses - Purchased Gas	807	0	None	0	0	0	0
83	Maintenance of Purchased Gas Meas. Sta.	807	0	None	0	0	0	0
84	Gas Withdrawn from Storage	808	0	None	0	0	0	0
85	Gas Delivered to Storage	808	0	None	0	0	0	0
86	Other Gas Supply Expense	813	0	None	0	0	0	0
87	Subtotal - OTHER GAS SUPPLY EXPENSES	800-813	0		0	0	0	0
	C. NATURAL GAS STORAGE							
88	LNG Operating Exp Admin	840	0	None	0	0	0	0
89	Operating Exp- Admin	850	0	None	0	0	0	0
90	Subtotal - NATURAL GAS STORAGE	840-850	0		0	0	0	0
	D. TRANSMISSION EXPENSES							
91	Transmission expenses	856-863						
92	Subtotal- Transmission Expenses	856-863	0	None	0	0	0	0
	E. DISTRIBUTION EXPENSES							
93	Operation Supv & Engineering	870	116	ONSITEDistPT-C	80	13	24	0
94	Load Dispatching	871	0	None	0	0	0	0
95	Compressor Station Fuel and Power	873	0	None	0	0	0	0
96	Mains and Services Expenses	874	0	None	0	0	0	0
97	Meas. & Reg. Station Expense General	875	0	None	0	0	0	0
98	Meas. & Reg. Station Expense Industrial	876	0	None	0	0	0	0
99	Meter & House Regulator Expenses	878	6,062	ONSITE-MR-C	4,193	685	1,184	0
100	Customer Installation Expense	879	62	RS Direct	62	0	0	0
101	Other Expenses - Safety and Environmental	880	172	ONSITEO&MxA/C880-C	123	18	31	0
102	Other Expenses	880	177	ONSITEO&Mx880xAGS-C	127	18	32	0
103	Distribution Rents	881	40	ONSITEDistPT-C	27	4	8	0
104	Maint. Supervision & Engineering	885	0	None	0	0	0	0
105	*Maintenance of Structures & Improvements*	*886*	*0*	*None*	*0*	*0*	*0*	*0*
106	Maint. of Mains	887	0	None	0	0	0	0
107	Maint Of Meas. & Reg. Station Expense General	889	0	None	0	0	0	0
108	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0	None	0	0	0	0
109	Maint. of Services	892	663	Service_Invest	626	6	31	0
110	Maint. of Meters & House Regulators	893	107	ONSITE-MR-C	74	12	21	0
111	Maintenance of Other Equipment	894	0	None	0	0	0	0
112	Subtotal - DISTRIBUTION EXPENSES	870-894	7,398		5,311	757	1,330	0
113	**TOTAL OPERATION & MAINTENANCE EXPENSES**		7,398		5,311	757	1,330	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	II. CUSTOMER ACCOUNTS EXPENSES							
114	Customer Service - Administrative	901	225	Acct901-903,908	210	14	2	0
115	Meter Reading Expenses	902	587	Acct901-903,908	546	36	4	0
116	Customer Records & Collection Expense	903	10,270	Acct901-903,908	9,561	636	74	0
117	*Uncollectible Accounts*	*904*	*8,883*	*Account904*	8,339	191	353	*0*
118	Uncollectible Accounts- CAP	904CAP	16,167	RS Direct	16,167	0	0	0
119	Miscellaneous Customer Accounts Expenses	905	0	None	0	0	0	0
120	**TOTAL CUSTOMER ACCOUNTS EXPENSES**		36,132		34,823	877	432	0
	III. CUSTOMER SERVICE & INFORMATIONAL EXPENSI							
121	Operation Supervision	907	0	None	0	0	0	0
122	Customer Assist- Other	908	0	None	0	0	0	0
123	Customer Assist- CAP	908CAP	0	None	0	0	0	0
124	Other Customer Service & Informational Expense	910	0	None	0	0	0	0
125	Supervision	911	0	None	0	0	0	0
126	Demonstration	912	0	None	0	0	0	0
127	Adverstising expense	913	0	None	0	0	0	0
128	**TOTAL CUSTOMER SERVICE & INFORMATIONAL EXP**		0		0	0	0	0
129	**TOTAL CUSTOMER ACCOUNTS, SERVICES & SALES I**		36,132		34,823	877	432	0
	IV. ADMINISTRATIVE & GENERAL EXPENSES							
	A. Labor-Related:							
130	Administrative & General Salaries	920	2,762	ONSITELABOR-C	2,305	222	235	0
131	Administrative & General Salaries - Direct Assign.	920 DA	256	AGS Direct	0	0	0	256
132	Office Supplies & Expenses	921	380	ONSITELABOR-C	317	31	32	0
133	Outside Services Employed - Resid.	923	84	RS Direct	84	0	0	0
134	Outside Services Employed - Labor	923l	1,691	ONSITELABOR-C	1,411	136	144	0
135	Injuries & Damages	925Labor	157	ONSITELABOR-C	131	13	13	0
136	Employee Pensions and Benefits	926	2,662	ONSITELABOR-C	2,222	214	227	0
137	Rents	931	1,872	ONSITELABOR-C	1,562	150	159	0
138	*Subtotal - O&M Accounts 920-923, 925L, 926*		9,864		8,032	766	811	256
	B. Plant-Related:							
139	Property Insurance	924	20	ONSITEPT-C	15	2	3	0
140	Outside Services Employed-plant	923p	8	ONSITEPT-C	6	1	1	0
141	Injuries & Damages	925Plant	251	ONSITEPT-C	189	21	41	0
142	Misc. Maintenance Expense	932	75	ONSITEPT_GEN-C	56	6	12	0
143	Misc. Maintenance Expense - Direct Assign.	932 DA	3	AGS Direct	0	0	0	3
144	Subtotal - O&M Accounts 924-925P		358		267	30	58	3
	C. Other-Related:							
145	Administrative Expenses Transferred	922	(6)	ONSITE_PT_O&M-C	(4)	(1)	(1)	0
146	Outside Services Employed-cust	923c	0	None	0	0	0	0
147	Outside Services Employed-plant-O&M	923p-om	1,167	ONSITE_PT_O&M-C	859	108	200	0
148	Outside Services Employed-plant-O&M - Direct Assign.	923p-om DA	33	AGS Direct	0	0	0	33
149	Regulatory Commission Expenses	928	86	Onsi_PT_O&MxAGS-C	63	8	15	0
150	General Advertising Expense	930.1	33	Onsi_PT_O&MxAGS-C	25	3	6	0
151	Miscellaneous General Expenses	930.2	26	ONSITE_PT_O&M-C	19	2	4	0
152	Subtotal - O&M Accounts 928-935		1,340		961	121	224	33
153	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**		11,561		9,260	917	1,092	292
154	**TOTAL OPERATING EXPENSES (Excl Depr, Tax and G:**		55,092		49,394	2,551	2,855	292

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	V. DEPRECIATION EXPENSE							
155	Intangible Plant	180Int	2,005	ONSITEPT-C_INT	1,851	127	27	0
156	*Production & Gathering Plant - Direct Assign.*	*180ProdGth DA*	*0*	*None*	*0*	*0*	*0*	*0*
157	Local Storage Plant	180Stor	0	None	0	0	0	0
158	Transmission Plant	180Trans	0	None	0	0	0	0
159	Transmission Plant - Direct Assign.	180Trans DA	0	None	0	0	0	0
160	Mains (Distribution)	180Mains	0	None	0	0	0	0
161	Services	180Services	0	None	0	0	0	0
162	Meters	180Meters	796	Meter_Invest	553	82	162	0
163	Distr Other	180Dist	1,012	ONSITE-CxMSM	832	63	117	0
164	General Plant	180Gen	247	ONSITEPT_GEN-C	186	21	41	0
165	General Plant - Direct Assign.	180Gen DA	0	None	0	0	0	0
166	Adjustments		0	None	0	0	0	0
167	**TOTAL DEPRECIATION EXPENSE**	403	4,060		3,422	292	347	0
	VI. TAXES							
168	PA PUC Assessment		0	None	0	0	0	0
169	Local property taxes		4	ONSITEPT-C	3	0	1	0
170	Public utilty reality tax		33	ONSITEPT-C	25	3	5	0
171	*State capital stock tax*		33	*ONSITEPT-C*	25	3	5	0
172	Miscellaneous tax		0	None	0	0	0	0
173	Subtotal- Taxes Other Than Income Taxes	408	70		53	6	11	0
	B. Income Tax Expense							
174	State Income Tax expense		946	PreTax-OnSi-C	1,902	(179)	(630)	(146)
175	Federal Income Tax expense		(5,026)	PreTax-OnSi-C	(10,104)	953	3,349	776
176	*Investment Tax Credit - Amortization*		5	PreTax-OnSi-C	10	(1)	(3)	(1)
177	Subtotal- Income tax expense		(4,075)		(8,192)	773	2,715	629
178	**TOTAL TAX EXPENSE**		(4,005)		(8,139)	779	2,727	629
179	**TOTAL EXPENSES**		55,148		44,677	3,621	5,928	921
	3. REVENUES at Present Rates							
180	Sales and Transport Revenue	480-483	48,730	Delivery_Rev	33,238	4,566	9,250	1,676
181	Forfeited Discounts		1,558	Account904	1,462	34	62	0
182	Miscellaneous Service Revenue		1,209	Misc_Ser_Rev	1,163	40	5	0
183	Other Operating Revenue		0	None	0	0	0	0
184	*Subtotal- Gas Revenues, net*		*51,497*		*35,864*	*4,640*	*9,316*	*1,676*
185	**TOTAL REVENUE**		51,497		35,864	4,640	9,316	1,676
186	**TOTAL EXPENSES**		55,148		44,677	3,621	5,928	921
187	**NET INCOME at Present Rates**		(3,651)		(8,812)	1,019	3,388	755

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	SUMMARY							
188	Total revenues		51,497		35,864	4,640	9,316	1,676
189	Total Operating Expenses		55,092		49,394	2,551	2,855	292
190	Depreciation Expense		4,060		3,422	292	347	0
191	Taxes other than Income		70		53	6	11	0
192	Total Other Expenses		4,131		3,475	298	358	0
193	Income tax expense		(4,075)		(8,192)	773	2,715	629
194	Total expenses		55,148		44,677	3,621	5,928	921
195	NET INCOME at Present Rates		(3,651)		(8,812)	1,019	3,388	755
196	**Total Rate Base**		42,515		34,872	3,142	4,499	2
197								
	REVENUE REQUIREMENTS							
198	*Target ROR*		*8.89%*		*8.89%*	*8.89%*	*8.89%*	*8.89%*
199	Using Target for System							
200	Rate Base		42,515		34,872	3,142	4,499	2
201	Operating expenses		55,092		49,394	2,551	2,855	292
202	*Depreciation expense*		*4,060*		3,422	292	347	*0*
203	Taxes other than Income		70		53	6	11	0
204	Operating expenses to recover		59,222		52,869	2,848	3,213	292
205	Target Return on Rate Base- After taxes		3,780		3,100	279	400	0
206	Income taxes to recover		1,861	49.2%	1,526	138	197	0
207	Additional expenses		1,103	RS Direct	1,103	0	0	0
208	**TOTAL REVENUE REQUIREMENT**		65,966		58,598	3,265	3,810	292

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	Working Capital Subreport							
209	Accounts Receivable- Gas		0	None	0	0	0	0
210	Accounts Receivable- Other		0	None	0	0	0	0
211	Accrued Gas Revenues		0	None	0	0	0	0
212	Accounts Receivable, Total		0		0	0	0	0
213	Gas, LNG in Storage		0	None	0	0	0	0
214	Inventories & Other, Total		0		0	0	0	0
215	Accounts Payable, Natural Gas		0	None	0	0	0	0
216	Accounts Payable, Other- Labor		1,333	ONSITELABOR-C	1,112	107	113	0
217	Accounts Payable, Other- O&MxGas		2,818	ONSITEO&MxGASxAGS-C	2,321	188	308	0
218	Accounts Payable, Total		4,150		3,434	295	421	0
219	Accrued interest		(66)	ONSITEPT-C	(50)	(6)	(11)	0
220	Other, net		50	ONSITEPT-C	38	4	8	0
221	Defd Items & Other, Total		(16)		(12)	(1)	(3)	0
222	Total Working Capital		4,135		3,422	294	419	0

	Account Description	Account Code	ONSITE CUSTOMER Dollars	Allocation Factor	ONSITE CUSTOMER Class Allocation			
					Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
	LABOR REPORT							
	PRODUCTION AND GATHERING:							
223	Production and Gathering O&M	750-765	0		0	0	0	0
224	Purchased Gas Expense	807	0		0	0	0	0
225	Other Gas Supply Expense	813	0		0	0	0	0
226	Sub Production		0		0	0	0	0
	STORAGE:							
227	LNG Operating Exp Admin	840						
228	Operating Exp- Admin	850						
229	Sub Storage		0		0	0	0	0
	TRANSMISSION:							
230	Transmission expenses	856-863						
231	Sub Transmission		0		0	0	0	0
	DISTRIBUTION:							
232	Operation Supv & Engineering	870	82		56	9	17	0
233	Load Dispatching	871	0		0	0	0	0
234	Compressor Station Fuel and Power	873	0		0	0	0	0
235	Mains and Services Expenses	874	0		0	0	0	0
236	Meas. & Reg. Station Expense General	875	0		0	0	0	0
237	Meas. & Reg. Station Expense Industrial	876	0		0	0	0	0
238	Meter & House Regulator Expenses	878	2,825		1,954	319	552	0
239	Customer Installation Expense	879	6		6	0	0	0
240	Other Expenses - Safety and Environmental	880	47		34	5	8	0
241	Other Expenses	880	48		35	5	9	0
242	Maint. Supervision & Engineering	885	0		0	0	0	0
243	Maintenance of Structures & Improvements	886	0		0	0	0	0
244	Maint. of Mains	887	0		0	0	0	0
245	Maint Of Meas. & Reg. Station Expense General	889	0		0	0	0	0
246	Maint Of Meas. & Reg. Sta. Exp. City Gate Check Station	891	0		0	0	0	0
247	Maint. of Services	892	300		283	3	14	0
248	Maint. of Meters & House Regulators	893	46		32	5	9	0
249	Maintenance of Other Equipment	894	0		0	0	0	0
250	**Sub Distribution**		3,355		2,400	346	609	0
	OnSite:							
251	Customer Service - Administrative	901	174		162	11	1	0
252	Meter Reading Expenses	902	144		134	9	1	0
253	Customer Records & Collection Expense	903	3,828		3,563	237	27	0
254	Operation Supervision	907	0		0	0	0	0
255	Customer Assist- Other	908	0		0	0	0	0
256	Customer Assist- CAP	908CAP	0		0	0	0	0
257	Supervision	911	0		0	0	0	0
258	Demonstration	912	0		0	0	0	0
259	**Sub OnSite**		4,145		3,859	257	30	0
260	TOTAL:		7,500		6,259	603	638	0

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	1. RATE BASE									
	I. GAS PLANT IN SERVICE									
	A. INTANGIBLE PLANT									
1	Organization	301	50	RATEBASE	PRDGTHBASE	P&G_RATEBASE-E	STORBASE	OR_RATEBASI	TRANBASE	RAN_RATEBASE-I
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	TRANSLABOR-D
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	-	-	-	-	-	-
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	-	-	-	-	-	-
5	Miscellaneous Intangible Plant - READI	303READI	15,628	ONSITE	-	-	-	-	-	-
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248							
	B. PRODUCTION & GATHERING PLANT									
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	COMMODITY	AGS Direct	-	-	-	-
8	Subtotal - PRODUCTION & GATHERING I	304-338	28,445							
	C. STORAGE PLANT									
9	Storage Plant	360-368	0	-	-	-	-	-	-	-
10	Subtotal - STORAGE PLANT	360-368	0							
	D. TRANSMISSION PLANT									
11	Transmission plant	365-370	106	TRANS	-	-	-	-	DEMAND	Peak&Avg
12	Transmission - Mains	367	1,243	TRANS	-	-	-	-	DEMAND	Peak&Avg
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	-	-	-	-	DEMAND	AGS Direct
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	-	-	-	-	DEMAND	AGS Direct
15	Subtotal - TRANSMISSION PLANT	365-370	32,350							
	E. DISTRIBUTION PLANT									
16	Land and Land Rights	374	1,893	DIST	-	-	-	-	-	-
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	-	-	-	-	-	-
18	Structures and Improvements	375	2,111	DIST	-	-	-	-	-	-
19	Mains	376	457,729	DIST	-	-	-	-	-	-
20	Mains - Direct Assign.	376 DA	10,267	DIST	-	-	-	-	-	-
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	-	-	-	-	-	-
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	-	-	-	-	-	-
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	-	-	-	-	-	-
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	-	-	-	-	-	-	-
25	Services	380	226,432	DIST	-	-	-	-	-	-
26	Meters	381	17,775	ONSITE	-	-	-	-	-	-
27	Meter Installations	382	9,208	ONSITE	-	-	-	-	-	-
28	House Regulators	383	5,656	ONSITE	-	-	-	-	-	-
29	House Regulator Installations	384	1,514	ONSITE	-	-	-	-	-	-
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	-	-	-	-	-	-
31	Property on Customers' Premises	386	15,838	ONSITE	-	-	-	-	-	-
32	Other Equipment	387	324	DIST	-	-	-	-	-	-
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	1. RATE BASE								
	I. GAS PLANT IN SERVICE								
	A. INTANGIBLE PLANT								
1	Organization	301	50	RATEBASE	DISTBASE	DIST_RATEBASE-D	DIST_RATEBASE-C	ONSITE_RB	ONSITE_RATEBASE-C
2	Intangible Plant - Software- Labor	303Lab	3,342	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
3	Intangible Plant - Software- Customer	303Cust	2,743	ONSITE	-	-	-	CUST	Cust_Avg
4	Intangible Plant - Software- Plant	303Plt	2,485	DIST	DISTPT	DISTOnlyPT-D	DISTOnlyPT-C	-	-
5	*Miscellaneous Intangible Plant - READI*	*303READI*	*15,628*	*ONSITE*	-	-	-	*CUST*	*Cust_Avg*
6	Subtotal - INTANGIBLE ASSETS	301-303	24,248						
	B. PRODUCTION & GATHERING PLANT								
7	Production and Gathering - Direct Assign.	304-338 DA	28,445	PRODGATH	-	-	-	-	-
8	Subtotal - PRODUCTION & GATHERING I	304-338	28,445						
	C. STORAGE PLANT								
9	Storage Plant	360-368	0	-	-	-	-	-	-
10	*Subtotal - STORAGE PLANT*	*360-368*	*0*						
	D. TRANSMISSION PLANT								
11	Transmission plant	365-370	106	TRANS	-	-	-	-	-
12	Transmission - Mains	367	1,243	TRANS	-	-	-	-	-
13	Transmission plant - Direct Assign.	365-370 DA	14,171	TRANS	-	-	-	-	-
14	Transmission - Mains - Direct Assign.	367 DA	16,830	TRANS	-	-	-	-	-
15	Subtotal - TRANSMISSION PLANT	365-370	32,350						
	E. *DISTRIBUTION PLANT*								
16	Land and Land Rights	374	1,893	DIST	DISTOnlyPT	Peak&Avg	DISTOnlyPT-C	-	-
17	Land and Land Rights - Direct Assign.	374 DA	564	DIST	DEMAND	GSL Direct	-	-	-
18	Structures and Improvements	375	2,111	DIST	DISTOnlyPT	Peak&Avg	DISTOnlyPT-C	-	-
19	Mains	376	457,729	DIST	MAINS	Peak&Avg	-	-	-
20	Mains - Direct Assign.	376 DA	10,267	DIST	DEMAND	GSL Direct	-	-	-
21	Meas. & Reg. Stat. Equip. - General	378	16,126	DIST	DEMAND	Peak&Avg	-	-	-
22	Meas. & Reg. Stat. Equip. - Direct Assign.	378 DA	1,469	DIST	DEMAND	GSL Direct	-	-	-
23	Meas. & Reg. Stat. Equip. - Odorization	378odr	447	DIST	DEMAND	Peak&Avg	-	-	-
24	Meas. & Reg. Stat. Equip. - City Gate	379	0	-	-	-	-	-	-
25	Services	380	226,432	DIST	CUST	-	Service_Invest	-	-
26	Meters	381	17,775	ONSITE	-	-	-	CUST	Meter_Invest
27	Meter Installations	382	9,208	ONSITE	-	-	-	CUST	Meter_Invest
28	House Regulators	383	5,656	ONSITE	-	-	-	CUST	Account 383/384
29	House Regulator Installations	384	1,514	ONSITE	-	-	-	CUST	Account 383/384
30	Ind. Meas. & Reg. Station Equip.	385	441	ONSITE	-	-	-	CUST	GSL Direct
31	Property on Customers' Premises	386	15,838	ONSITE	-	-	-	CUST	Account386
32	Other Equipment	387	324	DIST	CUST	-	GSS Direct	-	-
33	Subtotal - DISTRIBUTION PLANT	374-387	767,793						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	F. GENERAL PLANT									
34	Land and Land Rights	389	78	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
35	Structures and Improvements	390	7,842	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
36	Structures and Improvements - Direct Assi	390 DA	67	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
37	Office Furniture and Equipment	391	12,224	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
38	Office Furniture and Equipment - Direct As	391 DA	2	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
39	Transportation Equipment	392	10,288	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
40	Stores Equipment	393	47	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
41	Tools & Garage Equipment	394	4,271	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
43	Laboratory Equipment	395	0	-	-	-	-	-	-	-
44	Power Operated Equipment	396	3,155	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
45	Communication Equipment	397	6,923	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
47	Miscellaneous Equipment	398	32	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	-	-	-	-	DEMAND	GSL Direct
49	Subtotal - GENERAL PLANT	389-399	45,118							
50	TOTAL UTILITY PLANT									
	II. DEPRECIATION RESERVE									
51	Intangible Plant	108	8,236	INTANG_PT	PRDGTHPT	PRDGTHPT-E	DEMAND	OR_RATEBAS	DEMAND	TRAN_RATEBASE-
52	Production & Gathering Plant	108.2	0	-	-	-	-	-	-	-
53	Production & Gathering Plant - Direct Assig	108.2 DA	8,153	PRODGATH	COMMODITY	AGS Direct	-	-	-	-
54	Local Storage Plant	108.3	0	-	-	-	-	-	-	-
55	Transmission Plant	108.4	658	TRANS	-	-	-	-	DEMAND	Peak&Avg
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	-	-	-	-	DEMAND	AGS Direct
57	Mains	109	130,432	DIST	-	-	-	-	-	-
58	Services	109	83,524	DIST	-	-	-	-	-	-
59	Meters	109	12,975	ONSITE	-	-	-	-	-	-
60	Distr Other	109	13,987	DIST_xMSM	-	-	-	-	-	-
61	General Plant	109	19,396	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
63	TOTAL DEPRECIATION RESERVE	108	289,353							
	III. OTHER RATE BASE ITEMS									
64	Materials and Supplies		887	PLANT	PRDGTHPT	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
65	Current Gas Storage		75,176	STOR	-	-	DEMAND	Storage	-	-
66	Prepayments		234	O&MxGas	PRDGTHO&MxGas-E	PRDGTHO&MXGAS-C	-	-	DEMAND	Peak&Avg
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	-	-	-	-	DEMAND	TRAN_PTxAGS-D
68	Deferred Income Taxes - Direct Assign.		(2,423)	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
69	Deferred ITC		(4,903)	PLANTxAGS	-	-	-	-	DEMAND	TRAN_PTxAGS-D
70	Customer Deposits		(3,370)	DIST	-	-	-	-	-	-
71	TOTAL OTHER RATE BASE ITEMS		(36,684)							
72	TOTAL RATE BASE (Excl. Working Capita		571,917							
73	Working Capital	131	11,335							
74	TOTAL RATE BASE		583,253							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	F. GENERAL PLANT								
34	Land and Land Rights	389	78	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
35	Structures and Improvements	390	7,842	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
36	Structures and Improvements - Direct Assi	390 DA	67	PLANT_AGS	-	-	-	-	-
37	Office Furniture and Equipment	391	12,224	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
38	Office Furniture and Equipment - Direct As:	391 DA	2	PLANT_AGS	-	-	-	-	-
39	Transportation Equipment	392	10,288	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
40	Stores Equipment	393	47	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
41	Tools & Garage Equipment	394	4,271	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
42	Tools & Garage Equipment - Direct Assign.	394 DA	26	PLANT_AGS	-	-	-	-	-
43	Laboratory Equipment	395	0	-	-	-	-	-	-
44	Power Operated Equipment	396	3,155	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
45	Communication Equipment	397	6,923	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
46	Communication Equipment - Direct Assign.	397 DA	6	PLANT_AGS	-	-	-	-	-
47	Miscellaneous Equipment	398	32	PLANT	DISTPT	DISTPT-D	DISTOnlyPT-C	CUST	ONSITEPT-C
48	Miscellaneous Equipment - Direct Assign.	398 DA	156	PLANTxAGS	DISTPT	GSL Direct	GSL Direct	CUST	GSL Direct
49	Subtotal - GENERAL PLANT	389-399	45,118						
50	*TOTAL UTILITY PLANT*								
	II. DEPRECIATION RESERVE								
51	Intangible Plant	108	8,236	INTANG_PT	DISTPT_INT	DISTPT-D_INT	DISTPT-C_INT	CUST	ONSITEPT-C_INT
52	Production & Gathering Plant	108.2	0	-	-	-	-	-	-
53	Production & Gathering Plant - Direct Assig	108.2 DA	8,153	PRODGATH	-	-	-	-	-
54	Local Storage Plant	108.3	0	-	-	-	-	-	-
55	Transmission Plant	108.4	658	TRANS	-	-	-	-	-
56	Transmission Plant - Direct Assign.	108.4 DA	11,969	TRANS	-	-	-	-	-
57	Mains	109	130,432	DIST	MAINS	DISTMAIN-D	-	-	-
58	Services	109	83,524	DIST	CUST	-	Service_Invest	-	-
59	Meters	109	12,975	ONSITE	-	-	-	CUST	Meter_Invest
60	Distr Other	109	13,987	DIST_xMSM	DISTPT_xMSM	DISTPT-DxMSM	DISTPT-CxMSM	CUST	ONSITE-CxMSM
61	General Plant	109	19,396	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
62	General Plant - Direct Assign.	108.8 DA	21	PLANT_AGS	-	-	-	-	-
63	TOTAL DEPRECIATION RESERVE	108	289,353						
	III. OTHER RATE BASE ITEMS								
64	Materials and Supplies		887	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
65	*Current Gas Storage*		75,176	STOR	-	-	-	-	-
66	Prepayments		234	O&MxGas	DISTO&MxGas	DISTO&MXGAS-D	DISTO&MXGAS-C	ONSITEO&MxGas	ONSITEO&MXGAS-C
67	Deferred Income Taxes - Depreciation		(102,286)	PLANTxAGS	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
68	Deferred Income Taxes - Direct Assign.		(2,423)	PLANT_AGS	-	-	-	-	-
69	Deferred ITC		(4,903)	PLANTxAGS	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
70	Customer Deposits		(3,370)	DIST	CUST	-	Deposits	-	-
71	TOTAL OTHER RATE BASE ITEMS		(36,684)						
72	TOTAL RATE BASE (Excl. Working Capita		571,917						
73	Working Capital	131	11,335						
74	TOTAL RATE BASE		583,253						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	2. EXPENSES									
	I. OPERATION & MAINTENANCE EXPEN									
	A. PRODUCTION & GATHERING EXPEN									
75	Operations Expense	750-756	1,043	PRODGATH	PRDGTHPT	PRDGTHPT-E	-	-	-	-
76	Maintenance Expense	761-765	1,766	PRODGATH	PRDGTHPT	PRDGTHPT-E	-	-	-	-
77	Subtotal - Production and Gathering	750-765								
	B. OTHER GAS SUPPLY EXPENSES		0							
78	Natural gas field line purchases	801	0	-	-	-	-	-	-	-
79	Natural gas transmission line purchases	803	0	-	-	-	-	-	-	-
80	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-	-
81	Other Natural Gas Purchases	805	0	-	-	-	-	-	-	-
82	Well Expenses - Purchased Gas	807	0	-	-	-	-	-	-	-
83	Maintenance of Purchased Gas Meas. Sta.	807	0	-	-	-	-	-	-	-
84	Gas Withdrawn from Storage	808	0	-	-	-	-	-	-	-
85	*Gas Delivered to Storage*	808	0	-	-	-	-	-	-	-
86	Other Gas Supply Expense	813	391	PRODGATH	COMMODITY	Account813	-	-	-	-
87	Subtotal - OTHER GAS SUPPLY EXPENS	800-813	391							
	C. NATURAL GAS STORAGE									
88	LNG Operating Exp Admin	840	0	-	-	-	-	-	-	-
89	Operating Exp- Admin	850	0	-	-	-	-	-	-	-
90	Subtotal - NATURAL GAS STORAGE	840-850	0							
	D. TRANSMISSION EXPENSES									
91	Transmission expenses	856-863	0	-	-	-	-	-	-	-
92	Subtotal- Transmission Expenses	856-863	0							
	E. DISTRIBUTION EXPENSES									
93	Operation Supv & Engineering	870	1,773	DIST_PT	-	-	-	-	-	-
94	Load Dispatching	871	112	PRODGATH	COMMODITY	Gas_Deliveries	-	-	-	-
95	*Compressor Station Fuel and Power*	873	*(0)*	-	-	-	-	-	-	-
96	Mains and Services Expenses	874	5,088	N_SERV_TRANM	-	-	-	-	TRANS_MAINS	TRANS_MAINS-D
97	Meas. & Reg. Station Expense General	875	100	DIST	-	-	-	-	-	-
98	Meas. & Reg. Station Expense Industrial	876	0	-	-	-	-	-	-	-
99	Meter & House Regulator Expenses	878	6,062	ONSITE	-	-	-	-	-	-
100	Customer Installation Expense	879	62	ONSITE	-	-	-	-	-	-
101	Other Expenses - Safety and Environment	880	632	O&MxAcct880	PRDGTHO&MxA/C880	PRDGTHO&MxA/C880	-	-	DEMAND	RANO&MxA/C880-
102	Other Expenses	880	650	O&MxAcct880	PRDGTHO&MxA/C880	P&G_O&Mx880xAGS	-	-	DEMAND	RANO&Mx880xAGS
103	Distribution Rents	881	602	DIST_PT	-	-	-	-	-	-
104	Maint. Supervision & Engineering	885	885	DIST	-	-	-	-	-	-
105	Maintenance of Structures & Improvement	886	516	DIST	-	-	-	-	-	-
106	Maint. of Mains	887	5,521	DIST	-	-	-	-	-	-
107	Maint Of Meas. & Reg. Station Expense Ge	889	1,192	DIST	-	-	-	-	-	-
108	Maint Of Meas. & Reg. Sta. Exp. City Gate	891	10	DIST	-	-	-	-	-	-
109	Maint. of Services	892	663	ONSITE	-	-	-	-	-	-
110	Maint. of Meters & House Regulators	893	107	ONSITE	-	-	-	-	-	-
111	*Maintenance of Other Equipment*	*894*	*67*	*DIST*	-	-	-	-	-	-
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042							
113	TOTAL OPERATION & MAINTENANCE E		27,242							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	2. EXPENSES								
	I. OPERATION & MAINTENANCE EXPEN								
	A. PRODUCTION & GATHERING EXPENS								
75	Operations Expense	750-756	1,043	PRODGATH	-	-	-	-	-
76	Maintenance Expense	761-765	1,766	PRODGATH	-	-	-	-	-
77	Subtotal - Production and Gathering	750-765							
	B. OTHER GAS SUPPLY EXPENSES		0						
78	Natural gas field line purchases	801	0	-	-	-	-	-	-
79	Natural gas transmission line purchases	803	0	-	-	-	-	-	-
80	Natural Gas City Gate Purchases	804	0	-	-	-	-	-	-
81	Other Natural Gas Purchases	805	0	-	-	-	-	-	-
82	Well Expenses - Purchased Gas	807	0	-	-	-	-	-	-
83	Maintenance of Purchased Gas Meas. Sta.	807	0	-	-	-	-	-	-
84	Gas Withdrawn from Storage	808	0	-	-	-	-	-	-
85	Gas Delivered to Storage	808	0	-	-	-	-	-	-
86	Other Gas Supply Expense	813	391	PRODGATH	-	-	-	-	-
87	Subtotal - OTHER GAS SUPPLY EXPENS	800-813	391						
	C. NATURAL GAS STORAGE								
88	LNG Operating Exp Admin	840	0	-	-	-	-	-	-
89	Operating Exp- Admin	850	0	-	-	-	-	-	-
90	Subtotal - NATURAL GAS STORAGE	840-850	0						
	D. TRANSMISSION EXPENSES								
91	Transmission expenses	856-863	0	-	-	-	-	-	-
92	Subtotal- Transmission Expenses	856-863	0						
	E. DISTRIBUTION EXPENSES								
93	Operation Supv & Engineering	870	1,773	DIST_PT	DISTOnlyPT	DISTOnlyPT-D	DISTOnlyPT-C	CUST	ONSITEDistPT-C
94	Load Dispatching	871	112	PRODGATH	-	-	-	-	-
95	Compressor Station Fuel and Power	873	(0)	-	-	-	-	-	-
96	Mains and Services Expenses	874	5,088	N_SERV_TRANM	MAIN&SERVICE	DISTMAIN-SERV-D	DISTMAIN-SERV-C	-	-
97	Meas. & Reg. Station Expense General	875	100	DIST	DEMAND	Peak&Avg	-	-	-
98	Meas. & Reg. Station Expense Industrial	876	0	-	-	-	-	-	-
99	Meter & House Regulator Expenses	878	6,062	ONSITE	-	-	-	CUST	ONSITE-MR-C
100	Customer Installation Expense	879	62	ONSITE	-	-	-	CUST	RS Direct
101	Other Expenses - Safety and Environmenta	880	632	O&MxAcct880	DISTO&MxA/C880	DISTO&MxA/C880-D	DISTO&MxA/C880-C	ONSITEO&MxA/C880	ONSITEO&MxA/C880-C
102	Other Expenses	880	650	O&MxAcct880	DISTO&MxA/C880	DISTO&Mx880xAGS-D	DISTO&Mx880xAGS-C	ONSITEO&MxA/C880	ONSITEO&Mx880xAGS-C
103	Distribution Rents	881	602	DIST_PT	DISTOnlyPT	DISTOnlyPT-D	DISTOnlyPT-C	CUST	ONSITEDistPT-C
104	Maint. Supervision & Engineering	885	885	DIST	DISTLABOR	DISTLABOR-D	DISTLABOR-C	-	-
105	Maintenance of Structures & Improvements	886	516	DIST	DISTOnlyPT	DISTOnlyPT-D	DISTPT-C	-	-
106	Maint. of Mains	887	5,521	DIST	MAINS	DISTMAIN-D	-	-	-
107	Maint Of Meas. & Reg. Station Expense Ge	889	1,192	DIST	DEMAND	Peak&Avg	-	-	-
108	Maint Of Meas. & Reg. Sta. Exp. City Gate	891	10	DIST	DEMAND	Peak&Avg	-	-	-
109	Maint. of Services	892	663	ONSITE	-	-	-	CUST	Service_Invest
110	Maint. of Meters & House Regulators	893	107	ONSITE	-	-	-	CUST	ONSITE-MR-C
111	Maintenance of Other Equipment	894	67	DIST	DISTOnlyPT	DISTPT-D	DISTPT-C	-	-
112	Subtotal - DISTRIBUTION EXPENSES	870-894	24,042						
113	TOTAL OPERATION & MAINTENANCE E		27,242						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	II. CUSTOMER ACCOUNTS EXPENSES									
114	Customer Service - Administrative	901	225	ONSITE	-	-	-	-	-	-
115	Meter Reading Expenses	902	587	ONSITE	-	-	-	-	-	-
116	Customer Records & Collection Expense	903	10,270	ONSITE	-	-	-	-	-	-
117	Uncollectible Accounts	904	8,883	ONSITE	-	-	-	-	-	-
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	-	-	-	-	-	-
119	Miscellaneous Customer Accounts Expens	905	0	-	-	-	-	-	-	-
120	TOTAL CUSTOMER ACCOUNTS EXPEN!		36,132							
	III. CUSTOMER SERVICE & INFORMATIC									
121	Operation Supervision	907	0	-	-	-	-	-	-	-
122	Customer Assist- Other	908	210	DIST	-	-	-	-	-	-
123	Customer Assist- CAP	908CAP	299	DIST	-	-	-	-	-	-
124	Other Customer Service & Informational E>	910	698	DIST	-	-	-	-	-	-
125	Supervision	911	0	-	-	-	-	-	-	-
126	Demonstration	912	660	DIST	-	-	-	-	-	-
127	Adverstising expense	913	24	DIST	-	-	-	-	-	-
128	TOTAL CUSTOMER SERVICE & INFORM		1,891							
129	TOTAL CUSTOMER ACCOUNTS, SERVIC		38,024							
	IV. ADMINISTRATIVE & GENERAL EXPEI									
	A. Labor-Related:									
130	Administrative & General Salaries	920	5,940	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
131	Administrative & General Salaries - Direct A	920 DA	550	LABOR	COMMODITY	AGS Direct	-	-	DEMAND	AGS Direct
132	Office Supplies & Expenses	921	817	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
133	Outside Services Employed - Resid.	923	180	LABOR	COMMODITY	RS Direct	-	-	-	-
134	Outside Services Employed - Labor	923l	3,637	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
135	Injuries & Damages	925Labor	338	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
136	Employee Pensions and Benefits	926	5,725	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
137	Rents	931	4,025	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	TRANSLABOR-D
138	Subtotal - O&M Accounts 920-923, 925L, 9		21,213							
	B. Plant-Related:									
139	Property Insurance	924	335	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
140	Outside Services Employed-plant	923p	135	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
141	Injuries & Damages	925Plant	4,130	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	PRDGTHPT	P&G_PT_GEN-E	-	-	DEMAND	TRAN_PT_GEN-D
143	Misc. Maintenance Expense - Direct Assigr	932 DA	50	GENERAL PT	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
144	Subtotal - O&M Accounts 924-925P		5,879							
	C. Other-Related:									
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
146	Outside Services Employed-cust	923c	5,083	DIST	-	-	-	-	-	-
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
148	Outside Services Employed-plant-O&M - D	923p-om DA	200	PLANT_O&M	COMMODITY	AGS Direct	-	-	DEMAND	AGS Direct
149	Regulatory Commission Expenses	928	517	PLANT_O&M	COMMODITY	P&G_PT_O&MxAGS-E	-	-	DEMAND	TRAN_PTxAGS-D
150	General Advertising Expense	930.1	201	PLANT_O&M	COMMODITY	P&G_PT_O&MxAGS-E	-	-	DEMAND	TRAN_PTxAGS-D
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	COMMODITY	P&G_PT_O&M-E	-	-	DEMAND	TRAN_PT-D
152	Subtotal - O&M Accounts 928-935									
153	TOTAL ADMINISTRATIVE & GENERAL E:		40,234							
154	TOTAL OPERATING EXPENSES (Excl De		105,499							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	II. CUSTOMER ACCOUNTS EXPENSES								
114	Customer Service - Administrative	901	225	ONSITE	-	-	-	CUST	Acct901-903,908
115	Meter Reading Expenses	902	587	ONSITE	-	-	-	CUST	Acct901-903,908
116	Customer Records & Collection Expense	903	10,270	ONSITE	-	-	-	CUST	Acct901-903,908
117	Uncollectible Accounts	904	8,883	ONSITE	-	-	-	CUST	Account904
118	Uncollectible Accounts- CAP	904CAP	16,167	ONSITE	-	-	-	CUST	RS Direct
119	Miscellaneous Customer Accounts Expens	905	0	-	-	-	-	-	-
120	TOTAL CUSTOMER ACCOUNTS EXPEN:		36,132						
	III. CUSTOMER SERVICE & INFORMATIC								
121	Operation Supervision	907	0	-	-	-	-	-	-
122	Customer Assist- Other	908	210	DIST	CUST	-	Acct901-903,908	-	-
123	Customer Assist- CAP	908CAP	299	DIST	CUST	-	RS Direct	-	-
124	Other Customer Service & Informational E>	910	698	DIST	CUST	-	Account910	-	-
125	Supervision	911	0	-	-	-	-	-	-
126	Demonstration	912	660	DIST	CUST	-	Account911-916	-	-
127	Adverstising expense	913	24	DIST	CUST	-	Account911-916	-	-
128	TOTAL CUSTOMER SERVICE & INFORM		1,891						
129	TOTAL CUSTOMER ACCOUNTS, SERVIC		38,024						
	IV. ADMINISTRATIVE & GENERAL EXPEI								
	A. Labor-Related:								
130	Administrative & General Salaries	920	5,940	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
131	Administrative & General Salaries - Direct /	920 DA	550	LABOR	DISTLABOR	AGS Direct	AGS Direct	CUST	AGS Direct
132	Office Supplies & Expenses	921	817	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
133	Outside Services Employed - Resid.	923	180	LABOR	DISTLABOR	RS Direct	RS Direct	CUST	RS Direct
134	Outside Services Employed - Labor	923l	3,637	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
135	Injuries & Damages	925Labor	338	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
136	Employee Pensions and Benefits	926	5,725	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
137	Rents	931	4,025	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
138	Subtotal - O&M Accounts 920-923, 925L, 9		21,213						
	B. Plant-Related:								
139	Property Insurance	924	335	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
140	Outside Services Employed-plant	923p	135	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
141	Injuries & Damages	925Plant	4,130	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
142	Misc. Maintenance Expense	932	1,228	GENERAL PT	DISTPT_GEN	DISTPT_GEN-D	DISTPT_GEN-C	CUST	ONSITEPT_GEN-C
143	Misc. Maintenance Expense - Direct Assigr	932 DA	50	GENERAL PT	DISTPT_GEN	AGS Direct	AGS Direct	CUST	AGS Direct
144	Subtotal - O&M Accounts 924-925P		5,879						
	C. Other-Related:								
145	Administrative Expenses Transferred	922	(37)	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
146	Outside Services Employed-cust	923c	5,083	DIST	CUST	-	Cust_Avg	-	-
147	Outside Services Employed-plant-O&M	923p-om	7,021	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
148	Outside Services Employed-plant-O&M - D	923p-om DA	200	PLANT_O&M	DIST_PT_O&M	AGS Direct	AGS Direct	CUST	AGS Direct
149	Regulatory Commission Expenses	928	517	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&MxAGS-D	DIST_PT_O&MxAGS-C	CUST	Onsi_PT_O&MxAGS-C
150	General Advertising Expense	930.1	201	PLANT_O&M	DIST_PT_O&M	DIST_PT_O&MxAGS-D	DIST_PT_O&MxAGS-C	CUST	Onsi_PT_O&MxAGS-C
151	Miscellaneous General Expenses	930.2	156	PLANT_O&M	DISTPT_GEN	DIST_PT_O&M-D	DIST_PT_O&M-C	CUST	ONSITE_PT_O&M-C
152	Subtotal - O&M Accounts 928-935								
153	TOTAL ADMINISTRATIVE & GENERAL E:		40,234						
154	TOTAL OPERATING EXPENSES (Excl De		105,499						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	V. DEPRECIATION EXPENSE									
155	Intangible Plant	180Int	2,439	INTANG_PT	PRDGTHPT	PRDGTHPT-E	DEMAND	OR_RATEBAS	DEMAND	TRAN_RATEBASE-I
156	Production & Gathering Plant - Direct Assig	180ProdGth DA	631	PRODGATH_PT	COMMODITY	AGS Direct	-	-	-	-
157	Local Storage Plant	180Stor	0	-	-	-	-	-	-	-
158	Transmission Plant	180Trans	9	TRANS	-	-	-	-	DEMAND	Peak&Avg
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	-	-	-	-	DEMAND	AGS Direct
160	Mains (Distribution)	180Mains	6,999	DIST	-	-	-	-	-	-
161	Services	180Services	5,815	DIST	-	-	-	-	-	-
162	Meters	180Meters	796	ONSITE	-	-	-	-	-	-
163	Distr Other	180Dist	2,003	DIST_xMSM	-	-	-	-	-	-
164	General Plant	180Gen	4,071	GENERAL PT	PRDGTHPT	P&G_PT_GEN-E	-	-	DEMAND	TRAN_PT_GEN-D
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	PRDGTHPT	AGS Direct	-	-	DEMAND	AGS Direct
166	Adjustments		0	-	-	-	-	-	-	-
167	TOTAL DEPRECIATION EXPENSE	403	23,471							
			0	-	-	-	-	-	-	-
	VI. TAXES		0	-	-	-	-	-	-	-
	A. General Taxes		0	-	-	-	-	-	-	-
168	PA PUC Assessment		1,139	DIST	-	-	-	-	-	-
169	Local property taxes		63	PLANTxAGS	-	-	-	-	DEMAND	Peak&Avg
170	Public utilty reality tax		519	PLANTxAGS	-	-	-	-	DEMAND	Peak&Avg
171	State capital stock tax		447	RATEBASE	PRDGTHBASE	PRDGTHPT-E	STORBASE	Storage	TRANBASE	Peak&Avg
172	Miscellaneous tax		17	PRODGATH	COMMODITY	Gas_Deliveries	-	-	-	-
173	Subtotal- Taxes Other Than Income Taxes	408	2,186							
	B. Income Tax Expense									
174	State Income Tax expense		(1,009)	Pre-Tax	PreTax-PRDGTH	PreTax-PRDGTH-E	PreTax-STOR	PreTax-Stor-D	DEMAND	PreTax-Tran-D
175	Federal Income Tax expense		5,363	Pre-Tax	PreTax-PRDGTH	PreTax-PRDGTH-E	PreTax-STOR	PreTax-Stor-D	DEMAND	PreTax-Tran-D
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	-	-	PreTax-STOR	PreTax-Stor-D	-	-
177	Subtotal- Income tax expense		4,348							
178	TOTAL TAX EXPENSE		6,534							
179	TOTAL EXPENSES									
	3. REVENUES at Present Rates									
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	COMMODITY	Delivery_Rev	DEMAND	Delivery_Rev	DEMAND	Delivery_Rev
181	Forfeited Discounts		1,558	ONSITE	-	-	-	-	-	-
182	Miscellaneous Service Revenue		1,209	ONSITE	-	-	-	-	-	-
183	Other Operating Revenue		61	DIST	-	-	-	-	-	-
184	Subtotal- Gas Revenues, net		157,693							
185	TOTAL REVENUE		157,693							
186	TOTAL EXPENSES		135,504							
187	NET INCOME at Present Rates		22,189							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	V. DEPRECIATION EXPENSE								
155	Intangible Plant	180Int	2,439	INTANG_PT	DISTPT_INT	DISTPT-D_INT	DISTPT-C_INT	CUST	ONSITEPT-C_INT
156	Production & Gathering Plant - Direct Assig	180ProdGth DA	631	PRODGATH_PT	-	-	-	-	-
157	Local Storage Plant	180Stor	0	-	-	-	-	-	-
158	Transmission Plant	180Trans	9	TRANS	-	-	-	-	-
159	Transmission Plant - Direct Assign.	180Trans DA	704	TRANS	-	-	-	-	-
160	Mains (Distribution)	180Mains	6,999	DIST	MAINS	DISTMAIN-D	-	-	-
161	Services	180Services	5,815	DIST	CUST	-	Service_Invest	-	-
162	Meters	180Meters	796	ONSITE	-	-	-	CUST	Meter_Invest
163	Distr Other	180Dist	2,003	DIST_xMSM	DISTPT_xMSM	DISTPT-DxMSM	DISTPT-CxMSM	CUST	ONSITE-CxMSM
164	General Plant	180Gen	4,071	GENERAL PT	DISTPT_GEN	DISTPT_GEN-D	DISTPT_GEN-C	CUST	ONSITEPT_GEN-C
165	General Plant - Direct Assign.	180Gen DA	4	PLANT_AGS	-	-	-	-	-
166	Adjustments		0	-	-	-	-	-	-
167	TOTAL DEPRECIATION EXPENSE	403	23,471						
			0	-	-	-	-	-	-
	VI. TAXES		0	-	-	-	-	-	-
	A. General Taxes		0	-	-	-	-	-	-
168	PA PUC Assessment		1,139	DIST	CUST	-	Delivery_RevxAGS	-	-
169	Local property taxes		63	PLANTxAGS	DISTPT	TOTALPLANTxAGS	TOTALPLANTxAGS	CUST	ONSITEPT-C
170	Public utilty reality tax		519	PLANTxAGS	DISTPT	TOTALPLANTxAGS	TOTALPLANTxAGS	CUST	ONSITEPT-C
171	State capital stock tax		447	RATEBASE	DISTBASE	DISTPT-D	RATEBASExAGS	CUST	ONSITEPT-C
172	Miscellaneous tax		17	PRODGATH	-	-	-	-	-
173	Subtotal- Taxes Other Than Income Taxes	408	2,186						
	B. Income Tax Expense								
174	State Income Tax expense		(1,009)	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
175	Federal Income Tax expense		5,363	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
176	Investment Tax Credit - Amortization		(6)	Pre-Tax	PreTax-DIST	PreTax-Dist-D	PreTax-Dist-C	CUST	PreTax-OnSi-C
177	Subtotal- Income tax expense		4,348						
178	TOTAL TAX EXPENSE		6,534						
179	TOTAL EXPENSES								
	3. REVENUES at Present Rates								
180	Sales and Transport Revenue	480-483	154,865	RevReq_Prop	RevReq_PF-Dist	Delivery_Rev	Delivery_Rev	CUST	Delivery_Rev
181	Forfeited Discounts		1,558	ONSITE	-	-	-	CUST	Account904
182	*Miscellaneous Service Revenue*		*1,209*	*ONSITE*	-	-	-	*CUST*	*Misc_Ser_Rev*
183	Other Operating Revenue		61	DIST	CUST	-	Delivery_RevxAGS	-	-
184	Subtotal- Gas Revenues, net		157,693						
185	TOTAL REVENUE		157,693						
186	TOTAL EXPENSES		135,504						
187	NET INCOME at Present Rates		22,189						

	Account Description	Account	Total Dollars	Functional Allocator	PRODUCTION & GATHERING		STORAGE		TRANSMISSION	
					Classification Allocator	Commodity Allocator	Classification Allocator	Demand Allocator	Classification Allocator	Demand Allocator
	Working Capital Subreport									
209	Accounts Receivable- Gas		0	-	-	-	-	-	-	-
210	*Accounts Receivable- Other*		0	-	-	-	-	-	-	-
211	Accrued Gas Revenues		0	-	-	-	-	-	-	-
212	Accounts Receivable, Total		0							
213	Gas, LNG in Storage		0	-	-	-	-	-	-	-
214	Inventories & Other, Total		0							
215	Accounts Payable, Natural Gas		3,330	PRODGATH	COMMODITY	Gas_Deliveries	-	-	-	-
216	Accounts Payable, Other- Labor		2,867	LABOR	COMMODITY	PRDGTHLABOR-E	-	-	DEMAND	Peak&Avg
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	COMMODITY	Gas_Deliveries	-	-	DEMAND	Peak&Avg
218	Accounts Payable, Total		11,592							
219	Accrued interest		(1,083)	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
220	Other, net		826	PLANT	COMMODITY	PRDGTHPT-E	-	-	DEMAND	Peak&Avg
221	*Defd Items & Other, Total*		*(257)*							
222	Total Working Capital		11,335							

	Account Description	Account	Total Dollars	Functional Allocator	DISTRIBUTION Classification Allocator	DISTRIBUTION Demand Allocator	DISTRIBUTION Customer Allocator	ONSITE Classification Allocator	ONSITE Customer Allocator
	Working Capital Subreport								
209	Accounts Receivable- Gas		0	-	-	-	-	-	-
210	Accounts Receivable- Other		0	-	-	-	-	-	-
211	Accrued Gas Revenues		0	-	-	-	-	-	-
212	Accounts Receivable, Total		0						
213	Gas, LNG in Storage		0	-	-	-	-	-	-
214	Inventories & Other, Total		0						
215	Accounts Payable, Natural Gas		3,330	PRODGATH	-	-	-	-	-
216	Accounts Payable, Other- Labor		2,867	LABOR	DISTLABOR	DISTLABOR-D	DISTLABOR-C	CUST	ONSITELABOR-C
217	Accounts Payable, Other- O&MxGas		5,395	O&MxGas	DISTO&MxGas	DISTO&MXGAS-D	)NSITEO&MxGASxAGS-	CUST	)NSITEO&MxGASxAGS-
218	Accounts Payable, Total		11,592						
219	Accrued interest		(1,083)	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
220	Other, net		826	PLANT	DISTPT	DISTPT-D	DISTPT-C	CUST	ONSITEPT-C
221	Defd Items & Other, Total		(257)						
222	Total Working Capital		11,335						

EQUITABLE GAS COMPANY
DOCKET NO. R-2008-2029325
COST OF SERVICE STUDY- PROPOSED RATES, DESIGN DAY METHOD

EQUITABLE EXHIBIT NO. 6-R
SCHEDULE 4
SHEET 1 OF 1

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
1	Revenue Incr. (Decr.) Full Cost of Service	51,948	47,369	(2,476)	(464)	7,520
2	**Proposed Revenue Allocation**	**51,950**	**40,050**	**1,432**	**2,950**	**7,518**
	Revenue at Proposed Revenue Allocation					
3	Present rate Operating revenue	157,631	108,258	14,584	29,463	5,326
4	Proposed Increase / Decrease	51,950	40,050	1,432	2,950	7,518
5	Proposed Revenue before Other / Adj	209,581	148,308	16,016	32,413	12,844
6	Other revenue / Adjustments	61	43	6	12	0
7	**Revenue at Proposed Revenue Allocation**	209,643	148,351	16,022	32,425	12,844
8	Operating expenses	131,155	100,027	7,576	15,789	7,763
9	Pre-tax income	78,488	48,324	8,446	16,636	5,081
10	Income tax expense	25,531	15,580	2,787	5,489	1,676
11	Additional expenses	1,103	1,103	0	0	0
12	**Net income at Proposed Revenue Allocation**	**51,853**	**31,641**	**5,660**	**11,147**	**3,405**
13	Rate Base	583,253	411,080	34,202	99,658	38,312
14	**Return at Proposed Revenue Allocation**	**8.89%**	**7.70%**	**16.55%**	**11.19%**	**8.89%**
15	Relative Return at Present Rates	1.00	0.64	3.29	2.32	(0.56)
16	Relative Return at Proposed Revenue	1.00	0.87	1.86	1.26	1.00

EQUITABLE GAS COMPANY
DOCKET NO. R-2008-2029325
COST OF SERVICE STUDY- PROPOSED RATES, PEAK AND AVERAGE METHOD

EQUITABLE EXHIBIT NO. 6-R
SCHEDULE 5
SHEET 1 OF 1

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)	Appalachian Gathering Service (AGS)
1	Revenue Incr. (Decr.) Full Cost of Service	51,948	38,054	(2,143)	8,516	7,520
2	**Proposed Revenue Allocation**	**51,950**	**40,050**	**1,432**	**2,950**	**7,518**
	Revenue at Proposed Revenue Allocation					
3	Present rate Operating revenue	157,631	108,258	14,584	29,463	5,326
4	Proposed Increase / Decrease	51,950	40,050	1,432	2,950	7,518
5	Proposed Revenue before Other / Adj	209,581	148,308	16,016	32,413	12,844
6	Other revenue / Adjustments	61	43	6	12	0
7	**Revenue at Proposed Revenue Allocation**	209,643	148,351	16,022	32,425	12,844
8	Operating expenses	131,155	95,448	7,713	20,231	7,763
9	Pre-tax income	78,488	52,903	8,310	12,194	5,081
10	Income tax expense	25,531	17,090	2,742	4,023	1,676
11	Additional expenses	1,103	1,103	0	0	0
12	**Net income at Proposed Revenue Allocation**	**51,853**	**34,709**	**5,568**	**8,171**	**3,405**
13	Rate Base	583,253	375,385	35,688	133,862	38,317
14	**Return at Proposed Revenue Allocation**	**8.89%**	**9.25%**	**15.60%**	**6.10%**	**8.89%**
15	Relative Return at Present Rates	1.00	0.84	3.11	1.34	(0.56)
16	Relative Return at Proposed Revenue	1.00	1.04	1.75	0.69	1.00

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs- Summary				
1	Rate Base- Distribution function	166,214	156,224	4,277	5,713
2	Rate Base- OnSite function	42,513	34,872	3,142	4,499
3		208,727	191,096	7,419	10,212
4	Rate of Return	8.89%	8.89%	8.89%	8.89%
5	Return on rate base	18,556	16,988	660	908
6	Income Tax gross-up	9,137	8,365	325	447
7	Operating expenses- Distribution	20,185	17,505	1,877	803
8	Operating expenses- OnSite	54,869	49,447	2,557	2,866
9	Depreciation expense- Distribution	8,728	8,191	192	345
10	Depreciation expense- OnSite	4,060	3,422	292	347
11	Additional expense	1,103	1,103	0	0
12		116,638	105,021	5,902	5,716
13	Average Bills X 1000	3,084	2,871	191	22
14	Average Monthly Cost	$37.82	$36.58	$30.92	$258.44

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs- Details				
	Distribution Function				
15	Mains- Cost	76,899	71,588	4,760	551
16	Mains- Acc Depr	(21,913)	(20,399)	(1,356)	(157)
17	Mains- ADIT	(9,478)	(8,828)	(582)	(68)
18		45,508	42,360	2,822	327
19	Services- Cost	226,432	213,758	2,209	10,465
20	Services- Acc Depr	(83,524)	(78,849)	(815)	(3,860)
21	Services- ADIT	(27,915)	(26,362)	(270)	(1,283)
22		114,993	108,547	1,124	5,321
23	Other Rate Base	5,713	5,317	331	65
24	Total Rate Base	166,214	156,224	4,277	5,713
	Mains				
25	Return on Rate Base	4,046	3,766	251	29
26	Income Tax gross-up	1,992	1,854	124	14
27	Maintenance of Mains	928	864	57	7
28	Mains & Services expense	549	511	34	4
29	Mains Depreciation exp	1,176	1,095	73	8
30		8,690	8,089	539	62
	Services				
31	Return on Rate Base	10,223	9,650	100	473
32	Income Tax gross-up	5,034	4,752	49	233
33	Maintenance of Services	0	0	0	0
34	Mains & Services expense	1,617	1,526	16	75
35	Services Depreciation exp	5,815	5,489	57	269
36		22,688	21,417	222	1,049
	Balance of Distribution				
37	Return on Rate Base	508	473	29	6
38	Income Tax gross-up	250	233	14	3
39	Uncollectible Accounts	0	0	0	0
40	Operating & Maintenance	17,091	14,604	1,770	717
41	Depreciation expense	1,737	1,607	62	68
42		19,586	16,916	1,876	794
43	**Total Distribution Customer**	50,965	46,423	2,636	1,906

	Customer Costs- Details (Continued)	Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	OnSite Function				
44	Meters- Cost	26,983	18,739	2,764	5,480
45	Meters- Acc Depr	(12,975)	(9,011)	(1,329)	(2,635)
46	Meters- ADIT	0	0	0	0
47		14,008	9,728	1,435	2,845
48	Other Rate Base	28,505	25,144	1,707	1,654
49	Total Rate Base	42,513	34,872	3,142	4,499
50	Meters / Utility Plant	46.7%	40.4%	67.6%	74.8%
	Meters				
51	Return on Rate Base	1,245	865	128	253
52	Income Tax gross-up	613	426	63	125
53	Meters expense	6,062	4,193	685	1,184
54	Maintenance of Meters	107	74	12	21
55	Meters Depreciation exp	796	553	82	162
56		8,824	6,110	969	1,744
	Balance of OnSite				
57	Return on Rate Base	2,534	2,235	152	147
58	Income Tax gross-up	1,248	1,101	75	72
59	Meter Reading	587	546	36	4
60	Customer Records and Collection	10,270	9,561	636	74
61	Uncollectible Accounts	8,883	8,339	191	353
62	Operating & Maintenance	28,960	26,734	996	1,230
63	Depreciation expense	3,264	2,869	210	185
64	Additional expense	1,103	1,103	0	0
65		56,850	52,488	2,296	2,066
66	**Total OnSite Customer**	65,673	58,598	3,265	3,810
	Summary of Customer Costs				
67	Distribution Customer	50,965	46,423	2,636	1,906
68	Onsite Customer	65,673	58,598	3,265	3,810
69	Total Customer Component	116,638	105,021	5,902	5,716
70	Average Bills X 1000	3,084	2,871	191	22
71	Average Monthly Cost	$37.82	$36.58	$30.92	$258.44

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Summary of Monthly Customer Costs Per Customer				
	Mains				
72	Return / Tax	$1.96	$1.96	$1.96	$1.96
73	Depreciation	0.48	0.48	0.48	0.48
74	Operating expense	0.38	0.38	0.38	0.38
75		2.82	2.82	2.82	2.82
	Services				
76	Return / Tax	4.95	5.02	0.78	31.92
77	Depreciation	0.52	0.53	0.08	3.38
78	Operating expense	1.89	1.91	0.30	12.15
79		7.36	7.46	1.16	47.45
	Meters				
80	Return / Tax	0.60	0.45	1.00	17.07
81	Depreciation	2.00	1.49	3.65	54.48
82	Operating expense	0.26	0.19	0.43	7.31
83		2.86	2.13	5.08	78.86
	Other Rate Base (Return, Tax, Depr)				
84	Return / Tax	1.47	1.41	1.42	10.32
85	Depreciation	1.62	1.56	1.43	11.44
86		3.09	2.97	2.84	21.75
87	Uncollectible accounts	2.88	2.90	1.00	15.95
88	Meter Reading	0.19	0.19	0.19	0.19
89	Customer Records and Collection	3.33	3.33	3.33	3.33
90	Other Operating & Maint	14.93	14.40	14.49	88.08
91	Additional expense	0.36	0.38	0.00	0.00
92		$37.82	$36.58	$30.92	$258.44

EQUITABLE GAS COMPANY
DOCKET NO. R-2008-2029325
COST OF SERVICE STUDY- PRESENT RATES, PEAK AND AVERAGE METHOD

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs- Summary				
1	Rate Base- Distribution function	118,374	111,743	1,303	5,328
2	Rate Base- OnSite function	42,513	34,872	3,142	4,499
3		160,887	146,614	4,445	9,827
4	Rate of Return	*8.89%*	*8.89%*	*8.89%*	*8.89%*
5	Return on rate base	14,303	13,034	395	874
6	Income Tax gross-up	7,043	6,418	195	430
7	Operating expenses- Distribution	15,799	13,490	1,551	758
8	Operating expenses- OnSite	54,869	49,447	2,557	2,866
9	Depreciation expense- Distribution	7,109	6,686	91	332
10	Depreciation expense- OnSite	4,060	3,422	292	347
11	Additional expense	1,103	1,103	0	0
12		*104,286*	*93,600*	*5,080*	*5,606*
13	Average Bills X 1000	3,084	2,871	191	22
14	Average Monthly Cost	$33.81	$32.60	$26.61	$253.49

EQUITABLE GAS COMPANY
DOCKET NO. R-2008-2029325
COST OF SERVICE STUDY- PRESENT RATES, PEAK AND AVERAGE METHOD

		Total	*Residential* Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs- Details				
	Distribution Function				
15	Mains- Cost	0	0	0	0
16	Mains- Acc Depr	0	0	0	0
17	Mains- ADIT	0	0	0	0
18		0	0	0	0
19	Services- Cost	226,432	213,758	2,209	10,465
20	Services- Acc Depr	(83,524)	(78,849)	(815)	(3,860)
21	Services- ADIT	(27,922)	(26,370)	(267)	(1,285)
22		114,986	108,539	1,127	5,320
23	Other Rate Base	3,388	3,204	176	8
24	Total Rate Base	118,374	111,743	1,303	5,328
	Mains				
25	Return on Rate Base	0	0	0	0
26	Income Tax gross-up	0	0	0	0
27	Maintenance of Mains	0	0	0	0
28	Mains & Services expense	0	0	0	0
29	Mains Depreciation exp	0	0	0	0
30		0	0	0	0
	Services				
31	Return on Rate Base	10,222	9,649	100	473
32	Income Tax gross-up	5,033	4,751	49	233
33	Maintenance of Services	0	0	0	0
34	Mains & Services expense	1,617	1,526	16	75
35	Services Depreciation exp	5,815	5,489	57	269
36		22,687	21,416	222	1,049
	Balance of Distribution				
37	Return on Rate Base	301	285	16	1
38	Income Tax gross-up	148	140	8	0
39	Uncollectible Accounts	0	0	0	0
40	Operating & Maintenance	14,182	11,964	1,535	683
41	Depreciation expense	1,294	1,197	34	63
42		15,926	13,586	1,592	747
43	***Total Distribution Customer***	38,613	35,002	1,815	1,797

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Customer Costs- Details (Continued)				
	OnSite Function				
44	Meters- Cost	26,983	18,739	2,764	5,480
45	Meters- Acc Depr	(12,975)	(9,011)	(1,329)	(2,635)
46	Meters- ADIT	0	0	0	0
47		14,008	9,728	1,435	2,845
48	Other Rate Base	28,505	25,144	1,707	1,654
49	Total Rate Base	42,513	34,872	3,142	4,499
50	Meters / Utility Plant	46.7%	40.4%	67.6%	74.8%
	Meters				
51	Return on Rate Base	1,245	865	128	253
52	*Income Tax gross-up*	613	426	63	125
53	Meters expense	6,062	4,193	685	1,184
54	Maintenance of Meters	107	74	12	21
55	Meters Depreciation exp	796	553	82	162
56		8,824	6,110	969	1,744
	Balance of OnSite				
57	Return on Rate Base	2,534	2,235	152	147
58	Income Tax gross-up	1,248	1,101	75	72
59	Meter Reading	587	546	36	4
60	Customer Records and Collection	10,270	9,561	636	74
61	Uncollectible Accounts	8,883	8,339	191	353
62	Operating & Maintenance	28,960	26,734	996	1,230
63	Depreciation expense	3,264	2,869	210	185
64	Additional expense	1,103	1,103	0	0
65		56,850	52,488	2,296	2,066
66	**Total OnSite Customer**	65,673	58,598	3,265	3,810
	Summary of Customer Costs				
67	Distribution Customer	38,613	35,002	1,815	1,797
68	Onsite Customer	65,673	58,598	3,265	3,810
69	Total Customer Component	104,286	93,600	5,080	5,606
70	Average Bills X 1000	3,084	2,871	191	22
71	Average Monthly Cost	$33.81	$32.60	$26.61	$253.49

		Total	Residential Service (RS)	General Service - Small (GSS)	General Service - Large (GSL)
	Summary of Monthly Customer Costs Per Customer				
	Mains				
72	Return / Tax	$0.00	$0.00	$0.00	$0.00
73	Depreciation	0.00	0.00	0.00	0.00
74	Operating expense	0.00	0.00	0.00	0.00
75		0.00	0.00	0.00	0.00
	Services				
76	Return / Tax	4.95	5.02	0.78	31.91
77	Depreciation	0.52	0.53	0.08	3.38
78	Operating expense	1.89	1.91	0.30	12.15
79		7.36	7.46	1.16	47.44
	Meters				
80	Return / Tax	0.60	0.45	1.00	17.07
81	Depreciation	2.00	1.49	3.65	54.48
82	Operating expense	0.26	0.19	0.43	7.31
83		2.86	2.13	5.08	78.86
	Other Rate Base (Return, Tax, Depr)				
84	Return / Tax	1.37	1.31	1.31	9.97
85	Depreciation	1.48	1.42	1.28	11.22
86		2.85	2.73	2.59	21.19
87	Uncollectible accounts	2.88	2.90	1.00	15.95
88	Meter Reading	0.19	0.19	0.19	0.19
89	Customer Records and Collection	3.33	3.33	3.33	3.33
90	Other Operating & Maint	13.99	13.48	13.26	86.52
91	Additional expense	0.36	0.38	0.00	0.00
92		$33.81	$32.60	$26.61	$253.49

Equitable Statement No. 6-SR
Docket No. R-2008-2029325
Witness: Russell A. Feingold
Date: 11/18/08
RAS

EQUITABLE GAS COMPANY

Prepared Surrebuttal Testimony of

Russell A. Feingold

PREPARED SURREBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black & Veatch Corporation as a Vice President and I lead the Rate & Regulatory Advisory Group of its Enterprise Management Solutions Division.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT AND REBUTTAL TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (THE "COMMISSION") IN THIS PROCEEDING?

A. Yes. I previously submitted direct and rebuttal testimony in this proceeding on behalf of Equitable Gas Company ("Equitable" or the "Company") concerning its filed cost of service studies.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of the Pennsylvania Office of Small Business Advocate ("OSBA") related to the Company's cost of service studies. I will specifically respond to the claim made in the rebuttal testimony of OSBA witness Brian Kalcic related to the treatment of Equitable's current Appalachian Gathering Service ("AGS") rate schedule within its cost of service studies.

I. Treatment of the Company's Current AGS Rate Schedule Within its Cost of Service Studies

Q. AT PAGE 16 OF HIS REBUTTAL TESTIMONY, MR. KALCIC PRESENTS AN ALTERNATIVE COST ALLOCATION APPROACH TO THE COMPANY'S TREATMENT OF RATE AGS WITHIN ITS COST OF SERVICE STUDIES. DO YOU HAVE ANY CONCERNS WITH REGARD TO HIS RECOMMENDATION?

A. Yes. It is my opinion that the alternative treatment of the costs of the Company's gathering facilities within its cost of service studies presented by Mr. Kalcic is inappropriate because it is not reflective of cost causative principles and it is inconsistent with the way that the rates of a gas distribution utility, such as Equitable, are designed.

Q. PLEASE EXPLAIN WHY MR. KALCIC'S ALTERNATIVE TREATMENT OF THE COST OF THE COMPANY'S GATHERING FACILITIES IS NOT REFLECTIVE OF COST CAUSATIVE PRINCIPLES.

A. Very simply, his alternative costing approach for Rate AGS fails to recognize the well accepted cost causation principles that I discussed in my direct testimony and that I elaborated upon in my rebuttal testimony in response to the claims of the Independent Oil and Gas Association ("IOGA") related to the treatment of Equitable's gathering system costs in its cost of service studies. Based on an evaluation of the Company's gathering facilities and associated expenses, I concluded that such costs should be directly assigned or allocated to the AGS rate class consistent with the particular services provided under the AGS rate schedule. Obviously, the alternative approach recommended by Mr. Kalcic does not reflect a direct assignment of the costs of the Company's gathering system to Rate AGS. Rather, his alternative approach is based on a volumetric allocation of those costs between a very small group of retail delivery customers and those served under Rate AGS.

Q. HOW WERE THESE RETAIL CUSTOMERS THAT ARE SERVED FROM THE COMPANY'S GATHERING SYSTEM TREATED IN ITS COST OF SERVCE STUDIES?

A. These customers were treated for costing purposes no differently than any other retail delivery customer served by Equitable. In other words, these customers were assigned distribution-related costs associated with their specific meters, regulators, service lines, and a proportionate share of the costs of the Company's total system of distribution mains, as well all other operating, maintenance, customer service, administrative and general expenses incurred by the Company to provide gas delivery service. Under Mr. Kalcic's alternative approach, however, he would

allocate additional costs to these customers under the presumption that the distribution-related cost elements indicated above did not sufficiently reflect the total costs of providing gas delivery service to this isolated group of retail customers.

Q. IS IT APPROPRIATE TO ISOLATE A VERY SMALL GROUP OF THE COMPANY'S RETAIL DELIVERY SERVICE CUSTOMERS AS MR. KALCIC HAS DONE IN HIS ALTERNATIVE COSTING APPROACH AND ATTEMPT TO ALLOCATE TO THEM A PORTION OF THE COST OF EQUITABLE'S GATHERING SYSTEM?

A. No. Just as any other delivery service customer served by Equitable, those customers have already received a fair and reasonable share of the total costs of delivery service by virtue of the fact that they were treated identically to all of the Company's other retail customers in its cost of service studies. Yet, Mr. Kalcic's alternative approach of isolating certain retail customers, and then volumetrically allocating costs to them, effectively treats the geographic location of each customer as a primary determinant in how costs should be allocated to these customers. This alternative approach ignores the cost causative characteristics of the Company's gathering facilities and, in my opinion, would result in an over allocation of costs to the Company's retail customers.

Q. PLEASE EXPLAIN WHY MR. KALCIC'S ALTERNATIVE TREATMENT OF THE COST OF THE COMPANY'S GATHERING FACILITIES IS

INCONSISTENT WITH THE WAY THAT THE RATES OF A GAS DISTRIBUTION UTILITY, SUCH AS EQUITABLE, ARE DESIGNED.

A. The alternative approach recommended by Mr. Kalcic effectively ignores the fact that virtually all gas distribution utility rates are designed on a postage stamp basis. This means that all customers within the same rate class pay the same amount for gas delivery service regardless of where they are geographically located within the utility's service territory. Under Mr. Kalcic's alternative costing approach, the specific geographic location of Equitable's retail customers immediately becomes a primary factor that will directly impact the manner in which costs are allocated to the Company's various rate classes. This approach quickly becomes a slippery slope, however, because it opens up a wide range of options that others can easily use to shift costs between and within customer groups on the basis of location. Taking this location-based costing approach to its logical end, customers located in close proximity to the interstate pipelines that supply natural gas to the utility's distribution system would be allocated less costs while customers located at the far ends of the utility's distribution system would be allocated more costs. This outcome is completely contrary to the practice of utilities basing their rates on the average cost to serve a class of customers, and it is not an approach that I recommend this Commission should even consider.

Q. DOES THIS COMPLETE YOUR PREPARED TESTIMONY?

A. Yes

Equitable Statement No. 7-R
Docket No. 2008-2029325
Witness: Sandra L. Gagorik
Date: 11/19 2008

RJS

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Sandra L. Gagorik

PREPARED REBUTTAL TESTIMONY OF SANDRA L. GAGORIK

I. Witness Background

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

A. My name is Sandra L. Gagorik. I am employed by Equitable Gas Company ("Equitable" or "Company") as Manager, Universal Service and Community Outreach. My business address is 200 Allegheny Center, Pittsburgh, PA 15212-5352.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony, which has been marked as Equitable Statement No. 7. In that testimony I described Equitable's several bill-payment and energy-related programs and services to assist low-income and older adult customers. I also proposed two adjustments: (1) New funding of Equitable's Hardship Repair Fund to allow for continuation of that program through a waiver of the Commission's LIURP regulations at 52 Pa. Code Chapter 58; and (2) Upward revision of the Company's maximum level of assistance for furnace repair/replacement from $1,250 to $2,000, for repair/replacement of gas lines from $750 to $1,000, and a combined maximum from $1,250 to $2,500, ***if*** the Company's proposal for new funding of the Hardship Repair Fund through waiver of LIURP regulations is approved. In addition, I referenced an increase to LIURP funding that was proposed by Equitable witness Jeffery Mitchell.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony, I will respond to the testimony of Office of Trial Staff ("OTS") Witness Amanda Gordon to the extent that Ms. Gordon presented testimony concerning program modifications to Equitable's energy-related programs and services for low-income and older adult customers. To the extent Ms. Gordon addressed expense claims associated with these programs, Equitable Witness John Quinn will respond.

Q. HAVE YOU REVIEWED MS. GORDON'S DIRECT TESTIMONY AND EXHIBITS, INCLUDING HER SUPPLEMENTAL TESTIMONY AND EXHIBITS?

A. Yes, I have reviewed each of those statements and exhibits.

Q. TO WHAT ISSUES RAISED BY MS. GORDON DO YOU RESPOND?

A. With respect to the several programs and their parameters to which I testified, Ms. Gordon has recommended rejection of Equitable's request that the Commission waive LIURP regulations to allow Equitable to use any unspent funds to continue funding of the Hardship Repair Fund ("HRF"). Ms. Gordon also proposed adding a maximum CAP credit of $1,000 to Equitable's Customer Assistance Program, or CAP. I will address each of those proposals.

III. The Proposed OTS Adjustments

A. LIURP

Q. FOR WHAT REASONS DID OTS WITNESS GORDON RECOMMEND REJECTION OF EQUITABLE'S REQUEST THAT THE COMMISSION

WAIVE ITS LIURP REGULATIONS TO ALLOW EQUITABLE TO REDIRECT ANY UNSPENT LIURP FUNDS TO THE COMPANY'S HARDSHIP REPAIR FUND?

A. Ms. Gordon stated she opposed our proposal on the grounds that there has not been an excess in LIURP funding since 2005 and that LIURP provides the same services as those of the Hardship Repair Fund.

Q. DO YOU AGREE WITH MS. GORDON?

A. No.

Q. WHY NOT?

A. In my direct testimony, I stated that the Company proposes to increase funding for LIURP consistent with the program funding identified at 52 Pa. Code §58.4. If accepted, this proposal would equate to an increase in LIURP funding of $62,439, as outlined in our supporting information for the future test year at Exhibit III, Item: §53.53 III.A.17, sheet 9 of 11.

Q. WITH THIS INCREASE, IS IT POSSIBLE THAT THERE MAY BE EXCESS LIURP FUNDING?

A. Yes. Based on historical spending, it is possible that if Equitable's proposal to increase the level of LIURP funding in accordance with the Commission's regulations is approved, there may be an excess of LIURP funding

Q. IS THIS THE ONLY REASON YOU DISAGREE WITH MS. GORDON'S POSITION?

A. No. While Ms. Gordon is correct in her statement that LIURP provides similar services as the HRF, she fails to recognize that not all low-income households with heating equipment or gas line problems are eligible for LIURP.

Q. WHY WOULD A LOW-INCOME CUSTOMER NOT BE ELIGIBLE FOR LIURP?

A. The LIURP regulations at 52 Pa. Code §58.10 identify eligibility as highest usage, greatest arrearages, and low income status. While we target high use CAP customers for LIURP, those customers not in CAP only qualify for LIURP if annual normalized usage exceeds 200.0 Mcf and the customer's balance is greater than $750. There are many households that do not qualify for LIURP and could benefit from hardship repairs if the situation arises.

Q. WHAT IF THE CUSTOMER QUALIFIED FOR LIURP?

A. As I stated in my testimony, the HRF is a fund of last resort. If there are other resources available, such as Crisis, the customer would be referred to those programs to resolve the issue. In the same way, if the customer qualified for LIURP, the equipment or gas line problem would be handled through LIURP.

Q. WOULD IT BE CORRECT TO STATE THAT THE HARDSHIP REPAIR FUND IS A PROGRAM TO ASSIST LOW-INCOME HOUSEHOLDS WITH HEATING OR GAS LINE PROBLEMS WHEN THERE ARE NO OTHER SOURCES OF ASSISTANCE?

A. Yes. HRF is a program that can help customers who have no other means to obtain repairs, and who, but for the HRF, would obtain no relief at all. Since the Hardship Repair Fund acts as an additional resource, and only when necessary, I do not

understand Ms. Gordon's resistance. Equitable has proposed an increase in LIURP funds and, with a waiver of LIURP regulations, any excess funds would be made available to those with heating equipment and/or gas line problems. Equitable believes that this is a reasonable solution to a real problem

B. The CAP Program

Q. WHAT DID OTS WITNESS GORDON PROPOSE WITH RESPECT TO EQUITABLE'S CAP PROGRAM?

A. Ms. Gordon proposed that Equitable impose a maximum CAP credit of $1,000, beyond which CAP customers will remain responsible for their bills. She states that failing to impose a maximum CAP credit eliminates personal responsibility and allows a CAP customer to "enjoy an unlimited supply of gas at the expense of that burden falling on non-CAP customers."[1]

Q. DO YOU AGREE WITH MS. GORDON'S RECOMMENDATION TO IMPOSE A CAP CREDIT MAXIMUM UNDER EQUITABLE'S CAP PROGRAM?

A. No. In its comments in response to the Commission's Request for Comments on Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms at Docket No. M-00051923, the Office of Consumer Advocate ("OCA") stated that consumption limits "assume that low-income customers have significant control over their usage and that the limits will prompt them to respond with

[1] Direct Testimony of Amanda Gordon, Office of Trial Staff, in PA PUC v. Equitable Gas Company, Docket No. R-2008-2029325, page 4.

conservation."[2] OCA further stated that statistics show that low-income consumers have limited usage management due to factors beyond their control.

Q. DID THE COMMISSION ADDRESS THE ISSUE OF A CAP MAXIMUM CREDIT AND THE CAP PARTICIPANTS' USAGE IN THE PROCEEDING AT DOCKET NO. M-00051923?

A. Yes. In its Final Investigatory Order at Docket No. M-00051923 ("Final Investigatory Order"), the Commission confirmed that "no universal service evaluation has shown that CAP customers increase usage after enrollment in CAP."[3]

Q. HAS THE COMMISSION PROVIDED ANY GUIDANCE WITH RESPECT TO THE IMPOSITION OF LIMITS IF THE CONSUMPTION IS BEYOND THE ABILITY OF THE HOUSEHOLD TO CONTROL?

A. Yes. According to the Commission's Policy Statement on Customer Assistance Programs at 52 Pa. Code §69.265, if a household's consumption is beyond its ability to control, the household would qualify for an exemption from CAP control features, including both maximum credit and consumption limits.

Q. ARE THERE OTHER EXEMPTIONS?

A. Yes. The Commission set forth several exemptions in its Policy Statement at 52 Pa. Code §69.265(3)(vi).

Q. DO THESE EXEMPTIONS ALSO APPLY TO THE MAXIMUM CAP CREDIT?

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[2] Comments of the Office of Consumer Advocate to Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket No. M-00051923, page 50.

[3] Final Investigatory Order – Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms, Docket No. M-00051923, page 47.

A. Yes. The exemptions apply to any Commission-recognized CAP control feature, which would include features such as consumption limits, high usage, or maximum CAP credits. Therefore, if a customer exceeded the maximum CAP credit due to a situation beyond the household's ability to control, the household would be exempted from the limit on CAP credits.

Q. DID MS. GORDON PROPOSE THE $1,000 MAXIMUM CAP CREDIT IN ANY PRIOR EQUITABLE PROCEEDING?

A. Yes. She proposed the $1,000 maximum CAP credit in Equitable's Universal Service and Energy Conservation Plan submission and Petition for Approval to Increase the Level of Funding for its Customer Assistance Program at Docket Nos. M-00061959 and P-00062240.

Q. WHAT WAS THE RESULT IN THAT PROCEEDING?

A. The Commission approved a Joint Settlement on September 27, 2007, with respect to which the OTS was a signatory party. The settlement included a usage monitoring component but did not include a maximum CAP credit for its Universal Service and Energy Conservation Plan. This plan is in effect until the end of 2009.

Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE WITH RESPECT TO USAGE MONITORING?

A. Our statistics show that only about nine percent of the CAP customers have usage exceeding 110 percent of historical consumption patterns adjusted for weather as allowed by the Commission's policy statement.

Q. DO YOU KNOW WHAT PERCENTAGE OF THOSE ACCOUNTS QUALIFIES FOR AN EXEMPTION AS OUTLINED IN THE CAP POLICY STATEMENT?

A. No. We are currently in the process of issuing a Request for Proposal to have these customers contacted to: (1) Discuss the need to reduce consumption and share conservation techniques; and (2) Determine whether the household qualifies for an exemption.

Q. DO YOU ANTICIPATE THAT MANY OF THE CAP CUSTOMERS WHO EXCEED THE 110 PERCENT OF HISTORICAL USAGE WILL QUALIFY FOR AN EXEMPTION?

A. Yes. A little over 44 percent of the CAP accounts are coded as renters and another 15 percent are not coded. If the landlord does not make home improvements to reduce heat loss, there is little that the home's occupants can do. For those who own their home, their limited incomes preclude significant upgrades.

Q. HOW DOES THIS AFFECT MS. GORDON'S CALCULATION IF THESE CUSTOMERS QUALIFY FOR AN EXEMPTION?

A. If Ms. Gordon's calculation assumes that all CAP accounts would be limited to a $1,000 CAP credit annually, then she has overstated her deduction related to the implementation of a maximum CAP credit. Equitable witness John Quinn will address this issue in his response.

Q. HAS THE COMMISSION FORMALLY ADOPTED A MAXIMUM CAP CREDIT OF $1,000 FOR NATURAL GAS HEAT?

A. No. In its Final Investigatory Order entered December 18, 2006, the Commission recommended that utilities consider revising their maximum CAP credits to match a

recommendation made by PPL. It also ordered the Law Bureau, assisted by the Bureau of Consumer Services, to prepare a Commission order revising the Policy Statement consistent with its Order and to initiate a proposed rulemaking to incorporate its recommendations into the regulations in Title 52 of the Pennsylvania Code.

Q. HAS THE PROPOSED RULEMAKING BEEN FINALIZED?

A. No. An Order and Proposed Policy Statement at Docket No. M-00072036 was entered on September 5, 2007, and published in the Pennsylvania Bulletin on November 10, 2007, with comments due on January 9, 2008. To date, no further action has been taken.

Q. WOULD A CUSTOMER WHO EXCEEDS A MAXIMUM CAP CREDIT QUALIFY FOR LIURP?

A. The answer is a qualified yes. We have previously weatherized customers who exceed the maximum CAP credit even though their usage is lower as a result of the LIURP weatherization. We also have customers who do not meet the LIURP usage requirements but exceed the maximum CAP credit due to the household's extremely low income.

Q. IS THERE ANY OTHER REASON WHY A CUSTOMER WOULD RECEIVE CAP CREDITS IN EXCESS OF THE MAXIMUM?

A. Yes. CAP credits are only applied to the customer's account when the CAP account is up to date. If a customer is behind in payments for an extended period and ultimately catches up, the accumulated credits would be applied to the account and may exceed a CAP credit maximum.

Q. IS THIS A FREQUENT OCCURRENCE?

A. It is not unusual to have customers that may be one payment or less behind for extended periods. We encourage these customers to bring their CAP accounts up to date in order to have the pending CAP credits applied.

Q. SHOULD EQUITABLE BE REQUIRED TO IMPLEMENT A MAXIMUM CAP CREDIT?

A. No. For all the reasons stated above, as well as the fact that Equitable already has a usage monitoring program in its present plan, Equitable should be permitted to complete its existing program and assess the results prior to its next Universal Service Plan filing without having to implement an intervening maximum cap credit.

Q. WHEN WILL EQUITABLE FILE ANOTHER UNIVERSAL SERVICE PLAN?

A. Equitable is required to submit a new plan by June 1, 2009.

IV. Conclusion

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony as necessary to the extent further information in response to discovery requests becomes available.

Equitable Statement No. 8-R
Docket No. 2008-2029325
Witness: David W. Ross
Date: 11/19 2008

RWS

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

David W. Ross

PREPARED REBUTTAL TESTIMONY OF DAVID W. ROSS

I. Witness Background

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

A. My name is David Ross. I am the Director of Planning for Equitable Gas Company ("Equitable" or "Company"). My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony, which has been marked as Equitable Statement No. 8. In that testimony I addressed Equitable's cash working capital claim, and specifically the lead/lag study used to support that claim.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony, I will respond to the testimonies of Office of Trial Staff ("OTS") Witness Debra Backer and Office of Consumer Advocate ("OCA") Witness Lafayette Morgan to the extent that each of those witnesses testified concerning Equitable's lead/lag study and the Company's claim for cash working capital ("CWC") in this proceeding.

III. Summary of Adjustments Equitable Does Not Oppose

Q. HAVE YOU REVIEWED MS. BACKER'S AND MR. MORGAN'S DIRECT TESTIMONIES AND EXHIBITS?

A. Yes, I have.

Q. DO YOU AGREE WITH MS. BACKER'S AND MR. MORGAN'S GENERAL DESCRIPTIONS OF THE PURPOSE FOR CWC AND THE METHOD FOR CALCULATING A LEAD/LAG STUDY?

A. Yes, generally, I think all three of us agree on the purpose of a claim for CWC in this proceeding and the methodology for preparing a lead/lag study.

Q. WHAT IS YOUR REACTION TO THOSE WITNESSES' SPECIFIC ADJUSTMENTS TO THE COMPANY'S CWC CLAIM?

A. Both Ms. Backer and Mr. Morgan have proposed adjustments to Equitable's CWC claim based either on their perceived errors in Equitable's calculation of a particular entry's lead or lag time, or to reflect updates or corrections to Equitable's study that became known through the discovery process. I do not oppose adjustments that are based upon data that became available subsequent to Equitable's preparation of its filing. Also, I do not oppose four of the adjustments by OTS and OCA witnesses to address errors in the Company's study discovered after its preparation. However, many of the OTS and OCA adjustments predicated on Company error or simply proposed as a better calculation are themselves erroneous and should be rejected.

Q. WOULD YOU PLEASE FIRST IDENTIFY THOSE ADJUSTMENTS PROPOSED BY MS. BACKER OR MR. MORGAN WITH WHICH YOU AGREE?

A. Yes. Ms. Backer proposed an adjustment to remove the second property insurance claim covering November 1, 2007 – November 1, 2008 for an expense amount of $130,635 resulting in ($23,383,588) dollar days because there were two payments made in 2007. The removal of this second property insurance claim decreases the

Company's CWC claim by $15,797. While it is accurate that Equitable experienced two payments in calendar year 2007, normally the Company has only one such expense, so I agree with Ms. Backer's adjustment to remove the second payment.

Ms. Backer also updated the punitive claim on the Injuries and Damages Insurance worksheet to reflect the correct dates associated with that claim. I agree with Ms. Backer that the correction changes the mid-point of the period from 5/9/08 to a day in February. However, for reasons unclear to me, Ms. Backer's calculation has the mid-point as 2/9/08, rather than 2/10/08, as I calculate it. Thus, if I use the correct mid-point of the period of 2/10/08, the correct effect of these adjustments is to decrease the Company's CWC claim by $24,664, as shown on my Schedule DWR-Rebuttal-1, page 1 of 5.

With respect to Mr. Morgan's adjustments, he proposed to adjust the service period used for executive health exams. In the Company's work papers, the Company calculated the lag days based upon the service that began on January 1, 2007, and extended through December 31, 2007, since these exams occur and are paid for throughout the year. According to Mr. Morgan, however, since each individual is offered one health exam annually and health exams occurred on specific dates for each of the individuals, he adjusted the lag days for executive health exams using the date on which the exam occurred as the service period. The effect of this adjustment is to decrease the Company's CWC claim by $3,125. Mr. Morgan also made a correction to the non-union short-term incentive compensation amount based on the Company's response to OTS-RE-18-D. The correct short-term

incentive compensation amount paid was $3,650,116 instead of the $3,555,439. I can accept these adjustments of Mr. Morgan.

The remaining adjustments proposed by each of the OTS and OCA witnesses, however, I believe are recommended based either upon an erroneous understanding of the Company's calculation or an ill-supported theory, and should be rejected.

IV. Summary of Adjustments Equitable Opposes

Q. PLEASE SUMMARIZE THE ADJUSTMENTS RECOMMENDED BY OTS AND OCA WITNESSES THAT YOU RECOMMEND BE REJECTED.

A. Ms. Backer proposed two adjustments with which I disagree: (1) A reduction of the Company's revenue lag days from 49.29 to 47.29, based upon her reduction of the billing lag days from 4.88 to 2.88 lag days, which is based on an ill-supported theory; and (2) An increase in the Company's claim of 35.47 lag days to 36.84 lag days for other O&M expenses, which is in error.

OCA Witness Morgan proposed several adjustments that I recommend the Commission reject because they are premised upon assumptions that are erroneous or false, or upon proposed theories that are not supportable. These adjustments include: (1) Restating the payment lag days associated with Equitable's payment of short-term incentive compensation; (2) Adjusting the 401(k) lag days to correspond to his adjustment to the payment of short-term incentive compensation; (3) Adjusting the Corporate Services lag; (4) Adjusting the pension and benefits lag days; (5) Adjusting the taxes other than income lag days; and finally (6) Adjusting the lead-lag study to account for various adjustments to Equitable's O&M expenses and taxes.

V. OTS Witness Backer's CWC Adjustments

Q. WOULD YOU PLEASE RESPOND FIRST TO OTS WITNESS BACKER'S ADJUSTMENTS TO THE COMPANY'S CWC CLAIM, STARTING WITH THE COMPANY'S BILLING LAG DAY CALCULATION?

A. Yes.

Ms. Backer claims that the Company's breakdown of the 4.88 days (Days 1-3 the meters are read; Day 3 the readings are loaded into the Customer Information System (CIS) where consumption is generated along with audit exceptions; Day 4 audit exceptions are reviewed; and Day 5 bills are sent to the printer and mailed), does not support the Company's claim. She claims that three days to read the meters is excessive and that actually only two days at most are necessary. She further claims that a whole day to hold all the bills for audit exceptions of the total bills is excessive.

Secondly, Ms. Backer proposed to reduce Equitable's billing lag day calculation by two days, from 4.88 to 2.88 lag days, based upon her review of Equitable's adjustment in its prior base rate case at Docket No. R-00963858. Ms. Backer asserts that in that proceeding, Equitable ~~agreed to use of 4~~ corrected its billing lag days to 4 instead of the 7 billing lag days claimed. Also, subsequent to that proceeding, Equitable implemented an Automated Meter Reading (AMR) system. Ms. Backer claims that the reduction of the billing lag is a more accurate representation of how billing should be more efficient now with an AMR system.

Q. IS MS. BACKER CORRECT IN HER ADJUSTMENTS?

A. No.

Q. WOULD YOU PLEASE EXPLAIN WHY NOT, ADDRESSING FIRST THE ACTUAL OPERATIONS OF EQUITABLE'S BILLING SYSTEM?

A. Yes. First, Ms. Backer does not recognize that the that the number of days from the actual read date (Day 3, the expected read date or the date that the CIS system is expecting an actual meter read) to the date that the bills are placed in the mail is a function of the operations and procedures of the Company's Customer Information System (the system that generates consumption, audits, and bills, that get sent to customers), and not how the Company reads its meters (automated through the drive-by mobile AMR system or manually). Based on the Company's CIS procedures and operating functionality, the Company must have all of the meters read for each billing cycle by the expected read date (Day 3) or the CIS will have to estimate consumption. Estimating consumption, especially in the winter months, causes calls to the call center, disputes, and complaints, all of which lead to higher O&M expenses. For operational reasons, the Company tries to read meters at least one day in advance of the expected read date, which would be Day 2. The rational for reading the meters in advance of the expected read date (Day 3 or the day that the CIS system is expecting the reads) is to allow for interruptions or delays due to weather, equipment failure, labor issues, etc. Any one of these or other disrupting factors can cause the Company to miss up to 20,000 reads in a single day. Reading at least one day in advance of the expected read date is common practice across the industry for those companies that have drive-by mobile AMR systems according to Itron, the predominant AMR vendor that serves the electric, gas, and water markets.

In addition, there is one billing cycle that contains all of the large volume customers that must be read the last two calendar days of the month. These customers are spread across the Company's entire PA distribution system. Because of the geographical spread of these customers, it takes two days to read these meters even with a drive-by mobile AMR system. This is one of the reasons that it is necessary for the Company to have the flexibility to read meters at least two days in advance of the expected read date.

The other factor that Ms. Backer does not take into consideration in her testimony is intervening weekends and holidays between meter reads and data loads. When meters are read on Friday, they do not get loaded into the billing system until Monday. This adds two to three additional days to the billing lag for each weekend and holiday.

Ms. Backer asserted in her response to Equitable discovery (EGC-III-11) that it is excessive to hold up to 91.7% to 94.5% of the bills that do not have audit exceptions and that these bills should be mailed separately from the remainder of Equitable's bills. This, again, fails to consider the actual operations of the Company's system. Holding all bills until audits are conducted and cleared is a function of how the Company's CIS system works. It simply is not possible to send part of the bills on one day and the remainder the next day. The additional day is necessary.

Thus, the Company's inclusion in its billing lag days of 1 day for audit exceptions and 1 day for operational reasons, including recognition of the inclusion of weekends and holidays, not only accurately reflects how Equitable actually bills its

customers, but also presents a more accurate representation of Equitable's billing process.

Q. WHAT IS YOUR RESPONSE TO MS. BACKER'S COMPARISON OF EQUITABLE'S BILLING LAG DAY CLAIM IN THIS CASE WITH THE COMPANY'S CLAIM IN ITS LAST BASE RATE CASE PROCEEDING AT DOCKET NO. R-00963838?

A. Ms. Backer fails to consider several factors that distinguish Equitable's present claim from that made in its last base rate case, all of which further render her adjustment invalid.

In its last base rate case, Equitable read only half of the meters every month manually and estimated the other half. This means that in the last rate case, the Company used meter readers to go to customer residences to physically read meters (Manual Meter Reading). Now with a drive-by mobile AMR system, Equitable reads all of the meters every month. Under the Company's AMR system, customer information is loaded on to a mobile meter reading collector that is placed into a vehicle. The meter reader then drives the vehicle past each customer's residence and collects the meter reads through a radio frequency device that is attached to the meters. The vehicle then returns at the end of the day similar to the way a meter reader did in the prior rate case. The drive-by mobile AMR system was installed in lieu of hiring twice as many meter readers to read the meters in a manual mode as the Company had done previously. It was the Company's expectation that installing the AMR system to consistently provide all our customers actual monthly reads would decrease the cost to read meters, decrease the number of calls to the call

center, decrease the number of disputes and complaints related to meter reads, and decrease the number of meter reading work orders (where a meter read comes in and is incorrect and a service person has to be sent to the customer's residence to re-read the meters). All of this has proven to be correct and is the basis for Mr. Rettger's testimony, upon which Ms. Backer relies for her adjustment, that the AMR provides accurate and timely reads in an efficient way. That does not mean, however, that the billing lag days should be set to some artificial level as Ms. Backer proposes.

Also, in the last rate case, Equitable used the expected meter read dates (which is Day 3 in this filing). In this filing, however, Equitable is using actual meter read dates. In the last base rate case the actual meter read dates were not available.

The final item that is different in this base rate case compared to the previous case is that in the Company's last case, there were no gathering meters, and today Equitable has gathering meters. These meters increase the billing lag because of the way that gathering meters are read. The gathering meters have charts that need to be pulled and sent out to a third party to interpret the data. Gathering meters have a billing lag days of 29.46 days. As a component of the Company's total billing lag days, the use of gathering meters adds an additional .28 billing lag days to the Company's total.

Q. OTS WITNESS BACKER ALSO IDENTIFIES SIX OTHER UTILITIES WHICH SHE CLAIMS HAVE BILLING LAG DAYS THAT ARE BELOW WHAT EQUITABLE CLAIMS IN THIS PROCEEDING. DO YOU HAVE ANY RESPONSE?

A. Yes. With respect to the other utilities that Ms. Backer identifies as examples of what the Company's billing lag should be, this list lacks the rigor and understanding

that are necessary in order for Ms. Backer to come to the comparative conclusions she draws.

Q. WOULD YOU PLEASE EXPLAIN WHAT YOU MEAN?

A. Yes. Ms. Backer has no knowledge or understanding of the processes and procedures these utilities employ, or how their procedures may differ either among them or as between them and Equitable. Yet differences in billing procedures and processes can be the source of significant differences in lag days.

As one example, one of the companies that Ms. Backer uses as a benchmark is the Duquesne Light Company, which has a billing lag of 2 days. Duquesne Light Company has a fixed network AMR system. Unlike Equitable's system, Duquesne's fixed network system does not require an employee to physically drive by a residence to read meters. A fixed network AMR system reads meters in an instant, or as long as it takes for the information to travel from the meter through the network and into Duquesne's servers and its customer information system. In fact, a utility with a fixed network system could read its meters and load data into the company's CIS system on the same day, thus eliminating two days in the billing lag process (if they read one day in advance of the actual read date on which their customer information system was expecting the read to be processed).

In the case of water companies, some water companies read their meters quarterly. Others do not even have meters and bill their customers a flat fee each month.

In response to discovery, Ms. Backer was unable to provide any knowledge or explanation as to how any of the utilities that she identified either read their meters or how their billing and customer information systems operated. Of the six utilities

she identified, she prepared testimony in only one (the Columbia gas proceeding at Docket No. R-20082011621) and stated that she did not rely on input from other individuals in preparation of her testimony. She also stated, again in response to discovery, that a breakdown of the billing procedures is not even requested from utilities when she finds the lag numbers to be reasonable. As she apparently found Columbia's billing lag days acceptable, she requested no breakdown of how the lag days were developed and was not able to express any understanding how Columbia's system differs from Equitable's.

Ms. Backer's comparison of Equitable's billing lag day calculation to those of other utilities lacks the rigor and understanding necessary to support her adjustment to decrease the Company's billing lag by two days. Ms. Backer's claim should be rejected. Equitable's billing lag days should be based on Equitable's actual experience, and not on a comparison to other systems about which Ms. Backer has no knowledge.

A copy of Ms. Backer's discovery responses on which I rely is attached to this rebuttal testimony as Schedule DWR-Rebuttal-2.

Q. WHAT DID MS. BACKER PROPOSE WITH RESPECT TO EQUITABLE'S PROPOSED PAYMENT LAG FOR THE COMPANY'S OTHER O&M EXPENSE?

A. Ms. Backer proposed an adjustment to increase the Company's claim for lag days for other O&M expenses by 1.37 lag days to reflect a correction to the Company's lag days associated with the payment of expenses to Sherman & Associates. Mr. Morgan proposed this adjustment as well.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. The Commission should reject this adjustment.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD REJECT MS. BACKER'S AND MR. MORGAN'S PROPOSALS TO INCREASE LAG DAYS BY 1.37 FOR THE COMPANY'S OTHER O&M EXPENSES?

A. It is correct that the outside services ("OSS") worksheet for the Sherman & Associates invoice contained an error for the period covering May 2007. The invoice was actually paid on June 28, 2007, and not May 22, 2007, as the Company reflected in its original filing. When the correct payment date is used, it is also correct that the lag days increase from 6 days to 43 days, the dollar days increase from $91,148 to $653,213, and the Other O&M –OSS Grand Total amount changes to $296,959,209.

However, correcting this one invoice payment date does not have the effect that both Ms. Backer and Mr. Morgan attribute to it in their adjustments. As demonstrated on my Exhibit DWR-Rebuttal-1, page 2 of 5, combining the Other O&M expenses lag days with the Company's correction to the Sherman invoice yields total expense lag days of 35.49 not 36.84. The reason for the OTS and OCA witnesses' error is that both of them omitted from their final CWC calculations the expense lag days associated with Retiree Benefits. If you add the Retiree Benefits lag days, which neither party contested, back into the calculation, the corrected expense lag days associated with Other O&M expenses, after correcting the payment date for the Sherman invoice, is 35.49. This change leads to a decrease to the Company's CWC claim of $1,682.

VI. OCW Witness Morgan's CWC Adjustments

Q. YOU PREVIOUSLY IDENTIFIED SEVERAL ADJUSTMENTS PROPOSED BY OCA WITNESS MORGAN TO EQUITABLE'S CWC CLAIM WITH WHICH YOU DISAGREE. WOULD YOU PLEASE ADDRESS THESE ADJUSTMENTS, STARTING FIRST WITH MR. MORGAN'S ADJUSTMENTS TO EQUITABLE'S PAYMENT OF SHORT-TERM INCENTIVE COMPENSATION AND THE RELATED ADJUSTMENT HE PROPOSES TO THE COMPANY'S 401-K LAG DAYS AS A RESULT OF HIS INCENTIVE PAYMENT ADJUSTMENT?

A. Yes. As I stated, I disagree with Witness Morgan's adjustment for Equitable's payment of short-term incentive compensation. Mr. Morgan recalculated the service period lag associated with short-term incentive payments to reflect a lag consisting of the entire 2006 calendar year. He does this based upon his explanation that the incentive payments are earned throughout the entire prior year, and therefore the service lag should reflect the entire year. The effect of his recalculation of service period is to treat the service lag as if the short term incentive compensation were received every day during 2006.

Mr. Morgan's adjustment is wrong. First and foremost, the short–term incentive payment is wholly discretionary. It is neither fixed nor incurred until the Company undertakes and concludes its review after year end book closings in January, and only upon consideration of many factors, which include but are not limited to employee performance in the prior year. Thus, the Company has no payment obligation throughout the entire 2006 period, as assumed in Mr. Morgan's

recalculation. In fact, the Company does not incur a payment obligation until it concludes its review in January, following the completion of the prior calendar year, hence the source of the Company's original service period of January 14-27, 2007. While Equitable understands Mr. Morgan's analysis, the fact remains that Equitable's service lag should be based more closely on when the short-term incentive compensation expense is actually incurred, which is not during the entire prior calendar year period. As an accommodation to Mr. Morgan, Equitable has recalculated the service lag associated with the short-term incentive compensation in a manner consistent with Mr. Morgan's calculation of the lag associated with Equitable's payment for annual executive health care exams. In other words, Equitable has corrected the service period to be the date on which the payment occurs. Equitable has accepted Mr. Morgan's health exam adjustment. To be consistent, Mr. Morgan should accept Equitable's treatment of the short-term incentive compensation service lag in the same manner.

In sum, Equitable's payment of short-term incentive compensation is one payment, made annually, to the eligible employees, based upon a discretionary decision reached in January of the year following performance. Using Mr. Morgan's service period from 1/1/2006 to 12/31/2006 to calculate the payment lag on that period is not appropriate. We have corrected the service period of the short term incentive compensation's lag days using the date on which the payment occurred as the service period, consistent with Mr. Morgan's treatment for executive health exams. The service period used should be the same as the payment date. The resulting amounts and dollar days have been reflected in the overall lag days for payroll

presented on Schedule DWR-Rebuttal-1 page 5 of 5, and reflects an increase of $155,133 to the Company's CWC claim.

Q. WHAT ABOUT MR. MORGAN'S ACCOMPANYING ADJUSTMENT TO THE 401(k) PLAN?

A. Mr. Morgan's adjustment for the 401(k) plan also is not appropriate, but for different reasons.

The Company does not have a 401(k) plan matching contribution for its short-term incentive compensation program in Pennsylvania. The Company's matching contribution for the 401(k) plan applies only to twenty union personnel in West Virginia. Accordingly, an adjustment to the 401(k) plan service lag is not appropriate at all in Pennsylvania. The company has removed the 401(k) matching contribution expense $1,365 and dollar days $22,514. The resulting amounts and dollar days have been reflected in the overall lag days for Employee Benefits. The impact of this removal has a very minimal impact on the Company's CWC, which is an increase of $25. This is shown on Schedule DWR-Rebuttal 1, page 1.

Q. WHAT DID OCA WITNESS MORGAN PROPOSE WITH RESPECT TO EQUITABLE'S CALCULATION OF THE CORPORATE SERVICES LAG?

A. Mr. Morgan speculated that because for 8 of the 12 months of Corporate Service expenses the costs are exactly the same, they therefore could not have been actual costs. Mr. Morgan also used the revenue lag days (49.29 days) instead of 14.71 days as the Company's calculation, contending that use of the revenue lag days is appropriate because it reflects how the account is really settled (through an

accounting entry) and should be treated as non-cash expense, rather than a cash expense.

Q. WHAT IS YOUR RESPONSE TO MR. MORGAN'S ADJUSTMENT TO THE LAG FOR CORPORATE SERVICES?

A. I disagree with his adjustment.

The Company tries to eliminate duplicate services to save money by centralizing some services and ultimately billing them back to affiliated companies based upon actual use. Corporate Shared Services include services such as Procurement, Facility & Rents, Safety & Environmental, Corporate Overhead and Central IT. Each corporate affiliate is billed its proportionate share of the services used based on the annual budgeted amounts. The Company reconciles these charges on a quarterly basis, not per month. Thus, it is erroneous for Mr. Morgan to conclude that the bills are estimates because for 8 of the 12 months the costs are the same. This is due only to the fact that the reconciliations occur quarterly, not monthly, and therefore month-to-month variations are not necessarily reflected. Plus, services such as those that are included in corporate shared services are not generally of the nature that fluctuate greatly from month to month. Thus, the reconciliations generally do not reflect major shifts between budgeted and actual amounts.

Mr. Morgan is also incorrect to presume that because there is no "cash payment," that the books are settled through accounting entries that have no corresponding CWC component. There are no third party invoices or checks, because all these charges are settled with affiliated activity at the end of month. However, even though there are no actual cash payments made on these particular expenses

themselves, every month the Company reconciles all the transactions with all affiliated parties and a wire transfer request is issued every month to settle all inter-company transactions. Thus, Mr. Morgan's characterization of this as a "non-cash transaction" is not correct, since the Company ultimately does have to issue a wire transfer to reflect actual payment for actual services rendered.

If the Company did not have Corporate Shared Services, the Company would have to hire its own personnel to provide these services which would increase payroll expenses. The use of corporate services is cost efficient, and the calculation of the service lag based upon the actual cost of services for which a wire transfer is made is appropriate.

Q. OCA WITNESS MORGAN ALSO PRESENTED AN ADJUSTMENT TO EQUITABLE'S PENSION AND BENEFITS LAG DAYS CONSISTENT WITH HIS ADJUSTMENTS FOR THE PAYMENT OF SHORT-TERM INCENTIVE COMPENSATION AND THE ANNUAL EXECUTIVE HEALTH EXAM. WOULD YOU PLEASE BRIEFLY DESCRIBE WHAT MR. MORGAN PROPOSED WITH RESPECT TO THESE EXPENSE PAYMENT LAGS?

A. Mr. Morgan presented an adjustment to Equitable's pension and benefits lag days based on two components of costs in that category. The first component is the lag days for the 401(k) matching contribution based on the short-term incentive compensation service period. The second component is the service period used for executive health exams.

Q. IS MR. MORGAN'S ADJUSTMENT VALID?

A. Only in part. It is not valid for the first component (the 401(k) matching contribution). It is valid for the second component (the annual executive health exams).

Q. WOULD YOU PLEASE EXPLAIN?

A. Mr. Morgan's adjustment for the first component relates to pension and benefits from the 401(k) matching contribution based on the short-term incentive compensation payment. It is not appropriate. As I already explained, Equitable does not offer a 401(k) matching contribution on the short-term incentive compensation for Pennsylvania employees.

As to the second component, adjusting the service period for executive health exams based upon the date the exam occurred is valid because the Company has accepted Mr. Morgan's adjustment to be consistent with Mr. Morgan's reasoning that a one time payment that happens on a specific day should not be treated as if it were performed every day during the year.

Q. WHAT WAS OCA WITNESS MORGAN'S ADJUSTMENT TO TAXES OTHER THAN INCOME LAG DAYS?

A. Mr. Morgan recalculated the Taxes Other Than Income lag by including payroll taxes at a payment equal to the payroll lag days. Mr. Morgan claimed that payroll taxes are included in Taxes Other Than Income based upon his reference to the Company's Future Test Year Exhibit III-A-17, Sheets 4 and 6.

Q. IS MR. MORGAN'S ADJUSTMENT VALID?

A. No.

Q. WOULD YOU PLEASE EXPLAIN WHY NOT?

A. Mr. Morgan's adjustment is not valid. As I stated in my direct testimony and further in the Company's responses to OTS-RE-18-D and OCA-I-41, Equitable Gas Company pays payroll taxes to ADP (Automated Data Processing the Company's payroll services vendor) at the same time payroll expenses are paid. The Company's calculation of payroll taxes was included in the payroll expenses and not in the Taxes Other Than Income amounts, as Mr. Morgan incorrectly states. The $2,185,866 Taxes Other Than Income Expense used in the Company's calculation of cash working capital ties to the Company's Future Test Year in Exhibit III-A-17, Sheet 6 of 11, line 10, which is the sum of line 5 through 9. This amount does not include the Payroll Taxes in the amount of $1,638,209, appearing on line 4 which is the sum of lines 1 through 3. I have attached my responses to OTS-RE-18-D and OCA-I-41 as Schedule DWR-Rebuttal-3.

Q. DOES OCA WITNESS MORGAN PRESENT ANY OTHER ADJUSTMENT TO EQUITABLE'S CASH WORKING CAPITAL CLAIM FOR WHICH A RESPONSE IS APPROPRIATE?

A. Yes. In his direct testimony, Mr. Morgan states that based upon the testimony of OCA Witness Colton, the Company overstated its projected universal service costs by $10,380,693. In his exhibit LKM-20, then, Mr. Morgan presents an adjustment to O&M expenses that includes this amount.

Q. IS THERE AN IMPACT FROM THIS ADJUSTMENT ON THE COMPANY'S CASH WORKING CAPITAL CLAIM?

A. There should not be, because as presented by Equitable in its original filing, universal service costs were included in the Company's claim for uncollectibles. As

even Mr. Morgan's Schedule LKM-6, page 1 of 10, confirms, there is no CWC lag (revenue or expense) associated with uncollectibles. However, as incorporated into the OCA's adjustments by Mr. Morgan, there is.

Q. WHAT IS THAT IMPACT?

While Equitable Witness Quinn will address Mr. Colton's actual adjustment, I must point out and correct the unnecessary CWC implication that has resulted from Mr. Morgan's inclusion of it in his adjustments.

Mr. Morgan included OCA Witness Colton's $10,380,693 expense adjustment in his $12,879,423 adjustment to Other O&M Expenses (see Mr. Morgan's Schedule LKM-6, page 1). Unlike uncollectibles, Other O&M Expenses have an expense lag associated with them. So, Mr. Morgan has created an impact on and adjustment to the Company's CWC claim based upon inclusion of his negative O&M adjustment for universal service, when in fact that adjustment, if made, should have been made to uncollectibles where there is no CWC impact.

Q. WHAT IS THE EFFECT OF YOUR CORRECTION TO MR. MORGAN'S ADJUSTMENT?

A. The effect is to add back $392,348 to Mr. Morgan's CWC calculation. As Equitable Witness Quinn addresses, OCA Witness Colton's adjustment to the Company's *universal services expenses should not be accepted. If any such adjustment is* adopted by the Commission, however, it should be included in the Company's claim for uncollectibles, and there should be no corresponding impact on the Company's CWC claim.

Q. FINALLY, OCA WITNESS MORGAN TESTIFIED THAT HE MADE SEVERAL ADJUSTMENTS IN THE LEAD/LAG STUDY TO REFLECT ADJUSTMENTS HE MADE TO EQUITABLE'S O&M EXPENSES AND TAXES IN THE COST OF SERVICE STUDY. DO YOU AGREE WITH THOSE ADJUSTMENTS?

A. I agree that when the Commission establishes the final expenses in determining the Company's cost of service, corresponding adjustments will have to be made to incorporate those actual dollar figures into Equitable's final lead/lag study. However, those adjustments need to be based upon the final adjustments as adopted by the Commission. Since several of Mr. Morgan's and Ms. Backer's O&M adjustments are erroneous, correcting the Company's lead/lag study at this time would be premature and reflect adjustments that I believe the Commission should reject.

VII. Equitable's Revised CWC Claim

Q. BASED UPON THOSE ADJUSTMENTS WITH WHICH YOU AGREE ABOVE, WOULD YOU PLEASE SUMMARIZE AND EXPLAIN EQUITABLE'S UPDATED CLAIM FOR CWC?

A. As a result of the adjustments discussed above, I am recommending an adjustment to increase cash working capital by $109,890. This adjustment is presented on Schedule DWR-Rebuttal-1, page 1.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony as necessary to the extent further information in response to discovery requests becomes available.

	Original Lead/Lag Days	Corrected Lead/Lag Days		Incr/(Decr) CWC
Other O&M Expenses	35.47	35.49		
C Leon and Sherman and Associates			$	(1,682)
Injuries and Damages:	(164.74)	(161.67)		
(1) Removed the second property insurance			$	(15,797)
(2) Punitive claims: changed from 11/8/07-11/08/08 to 8/11/07-8/11/08			$	(24,664)
Pension and Benefits-Active Employees	11.03	11.19		
(1) Executive Health exams			$	(3,125)
(2) Removed 401(k) matching: $1,365			$	25
Payroll Expenses				
STIP	17.09	14.74	$	155,133
Total Adjustments To Cash Working Capital			$	109,890

As submitted June 30, 2008

	Amount of Expense	Dollar Days
Vehicle	2,296,752	80,726,976
Commercial Card	1,271,630	19,928,455
Other	11,640,164	399,128,278
OSS	6,226,919	296,397,129
Postage	848,033	24,098,883
Retiree Benefits	3,446,372	92,426,848
	25,729,870	912,706,569

WEIGHTED AVERAGE DAYS 35.47

After the adjustments

	Amount of Expense	Dollar Days	
Vehicle	2,296,752	80,726,976	
Commercial Card	1,271,630	19,928,455	
Other	11,640,164	399,128,278	
OSS	6,226,919	296,959,209	1/
Postage	848,033	24,098,883	
Retiree Benefits	3,446,372	92,426,848	
	25,729,870	913,268,648	

WEIGHTED AVERAGE DAYS 35.49

Notes:
1/ Changed one invoice payment for C Leon Sherman & Assoicates from 5/22/2007 to 6/28/2007

Equitable Gas Company

Injuries and Damages Insurance
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Directors and Officers Liability						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	$ 125,093	$ (22,641,831)
3/27/2007	3/27/2008	9/26/2007	4/2/2007	(177.00)	19,670	(3,481,502)
Fiduciary Liability						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	38,134	(6,902,183)
Crime						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	782	(141,593)
3/27/2007	3/27/2008	9/26/2007	11/7/2007	42.00	89	3,758
Automobile						
8/11/2007	8/11/2008	2/10/2008	8/21/2007	(173.00)	41,779	(7,227,822)
Excess Liability						
8/11/2007	8/11/2008	2/10/2008	8/14/2007	(180.00)	216,185	(38,913,253)
8/11/2007	8/11/2008	2/10/2008	8/16/2007	(178.00)	708,044	(126,031,917)
Property 1/						
11/1/2006	11/1/2007	5/2/2007	1/28/2007	(94.50)	158,512	(14,979,412)
11/1/2007	11/1/2008	5/2/2008	11/16/2007	(168.00)	4,376	(735,084)
Property -Surplus						
11/1/2006	11/1/2007	5/2/2007	1/10/2007	(112.50)	6,743	(758,626)
Broker Fees						
9/1/2006	9/1/2007	3/2/2007	1/2/2007	(59.50)	14,338	(853,081)
9/1/2006	9/1/2007	3/2/2007	4/2/2007	30.50	14,245	434,473
9/1/2007	9/1/2008	3/2/2008	9/28/2007	(156.00)	14,153	(2,207,884)
9/1/2007	9/1/2008	3/2/2008	10/2/2007	(152.00)	14,153	(2,151,271)
8/11/2007	8/11/2008	2/10/2008	12/12/2007	(60.00)	38,623	(2,317,380)
Punitive 2/						
8/11/2007	8/11/2008	2/10/2008	8/31/2007	(163.00)	16,976	(2,767,015)
8/11/2007	8/11/2008	2/10/2008	8/31/2007	(163.00)	15,706	(2,560,135)
Worker Compensation (excess)						
8/11/2007	8/11/2008	2/10/2008	8/31/2007	(163.00)	90,446	(14,742,773)
Bonds						
11/1/2007	11/30/2008	5/16/2008	12/30/2007	(138.50)	772	(106,937)
10/1/2007	10/31/2008	4/16/2008	11/30/2007	(138.00)	715	(98,648)
9/1/2007	9/30/2008	3/16/2008	10/30/2007	(138.50)	280	(38,780)
8/1/2007	8/31/2008	2/15/2008	9/30/2007	(138.00)	29	(3,958)
7/1/2007	7/31/2008	1/15/2008	8/30/2007	(138.00)	4,336	(598,409)
6/1/2007	6/30/2008	12/15/2007	7/30/2007	(138.50)	161	(22,299)
5/1/2007	5/31/2008	11/15/2007	6/30/2007	(138.00)	1,695	(233,960)
4/1/2007	4/30/2008	10/15/2007	5/30/2007	(138.50)	1,702	(235,699)
3/1/2007	3/31/2008	9/15/2007	4/30/2007	(138.00)	257	(35,397)
2/1/2007	2/29/2008	8/16/2007	3/30/2007	(139.50)	2,338	(326,193)
1/1/2007	1/31/2008	7/17/2007	2/28/2007	(139.50)	1,388	(193,626)
12/1/2006	12/31/2007	6/16/2007	1/30/2007	(137.50)	393	(54,038)
TOTAL					$ 1,552,113	$ (250,922,476)
WEIGHTED AVERAGE DAYS				(161.67)		

Notes:
1/ Removed second property insurance
2/ Changed from 11/8/2007-11/8/2008 to 8/11/2007-8/11/2008

Equitable Gas Company
Pensions and Benefits
For The Twelve Months Ended December 31, 2007

	Lag Days		Amount			Dollar Days
Total 401(k) Match & Retirement Contribution		$	1,944,377	1/	$	32,082,227
Total 401(k) Admin Fees			1,398			127,849
Total ESPP Discount			26,607			557,948
Total ESPP Admin Fees			15,813			1,821,280
Total HSA Company Contribution			162,250			(28,356,500)
Total HSA Account Fees			8,232			72,322
Total Medical Claims, Admin & Enrollment Fees Actives			2,736,530			24,628,772
Total Active Vision			61,489			2,435,075
Total Executive Health Exams			9,225	2/		-
Total Active Life, AD&D, LTD			182,935			7,197,330
Total Active Dental			242,987			7,766,042
Total Employee Assistance Program			14,770			140,129
Total Aon Admin Fees			148,394			13,680,486
ACTIVE EMPLOYEE BENEFITS		$	5,555,008		$	62,152,960
WEIGHTED AVERAGE DAYS	11.19					

Notes:
1/ Removed $1,365
2/ Changed the service period per Mr. Morgan's adjustment

Equitable Gas Company

Payroll (Include FICA, FUTA, SUTA,Local, State and Federal Taxes)
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)	
Payroll- Non-Union							
12/18/2006	12/31/2006	12/24/2006	1/10/2007	16.50	663,113	$ 10,941,372	
1/1/2007	1/14/2007	1/7/2007	1/24/2007	16.50	663,604	$ 10,949,464	
2/6/2007	2/6/2007	2/6/2007	2/6/2007	-	3,650,116	$ -	1/
1/15/2007	1/28/2007	1/21/2007	2/7/2007	16.50	665,254	$ 10,976,696	
1/29/2007	2/11/2007	2/4/2007	2/21/2007	16.50	656,666	$ 10,834,985	
2/12/2007	2/25/2007	2/18/2007	3/7/2007	16.50	650,454	$ 10,732,489	
2/26/2007	3/11/2007	3/4/2007	3/21/2007	16.50	682,704	$ 11,264,622	
3/12/2007	3/25/2007	3/18/2007	4/4/2007	16.50	658,826	$ 10,870,631	
3/26/2007	4/8/2007	4/1/2007	4/18/2007	16.50	657,239	$ 10,844,448	
4/9/2007	4/22/2007	4/15/2007	5/2/2007	16.50	663,850	$ 10,953,517	
4/23/2007	5/6/2007	4/29/2007	5/16/2007	16.50	669,857	$ 11,052,641	
5/7/2007	5/20/2007	5/13/2007	5/30/2007	16.50	664,132	$ 10,958,178	
5/21/2007	6/3/2007	5/27/2007	6/13/2007	16.50	666,519	$ 10,997,560	
6/4/2007	6/17/2007	6/10/2007	6/27/2007	16.50	663,067	$ 10,940,598	
6/18/2007	7/1/2007	6/24/2007	7/11/2007	16.50	664,692	$ 10,970,725	
7/2/2007	7/15/2007	7/8/2007	7/25/2007	16.50	662,533	$ 10,931,794	
7/16/2007	7/29/2007	7/22/2007	8/8/2007	16.50	649,673	$ 10,719,597	
7/30/2007	8/12/2007	8/5/2007	8/22/2007	16.50	648,531	$ 10,700,760	
8/13/2007	8/26/2007	8/19/2007	9/5/2007	16.50	635,798	$ 10,490,665	
8/27/2007	9/9/2007	9/2/2007	9/19/2007	16.50	640,892	$ 10,571,425	
9/10/2007	9/23/2007	9/16/2007	10/3/2007	16.50	591,651	$ 9,762,245	
9/24/2007	10/7/2007	9/30/2007	10/17/2007	16.50	593,444	$ 9,791,825	
10/8/2007	10/21/2007	10/14/2007	10/31/2007	16.50	596,533	$ 9,842,789	
10/22/2007	11/4/2007	10/28/2007	11/14/2007	16.50	598,294	$ 9,871,849	
11/5/2007	11/18/2007	11/11/2007	11/28/2007	16.50	590,987	$ 9,751,290	
11/19/2007	12/2/2007	11/25/2007	12/12/2007	16.50	629,265	$ 10,382,879	
12/3/2007	12/16/2007	12/9/2007	12/26/2007	16.50	589,239	$ 9,722,448	
	TOTAL			13.54	$ 20,366,934	$ 275,827,491	

Equitable Gas Company

Payroll (Include FICA, FUTA, SUTA,Local, State and Federal Taxes)
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)	
12/18/2006	12/31/2006	12/24/2006	1/12/2007	18.50	$ 393,762	$ 7,284,592	
1/1/2007	1/14/2007	1/7/2007	1/26/2007	18.50	$ 386,120	$ 7,143,218	
2/6/2007	2/6/2007	2/6/2007	2/6/2007	-	$ 656,326	$ -	2/
1/15/2007	1/28/2007	1/21/2007	2/9/2007	18.50	$ 369,857	$ 6,842,359	
1/29/2007	2/11/2007	2/4/2007	2/23/2007	18.50	$ 374,081	$ 6,920,495	
2/12/2007	2/25/2007	2/18/2007	3/9/2007	18.50	$ 387,406	$ 7,167,050	
2/26/2007	3/11/2007	3/4/2007	3/23/2007	18.50	$ 373,400	$ 6,907,904	
3/12/2007	3/25/2007	3/18/2007	4/4/2007	16.50	$ 330,927	$ 5,460,295	
3/26/2007	4/8/2007	4/1/2007	4/20/2007	18.50	$ 351,323	$ 6,499,475	
4/9/2007	4/22/2007	4/15/2007	5/4/2007	18.50	$ 347,062	$ 6,420,646	
4/23/2007	5/6/2007	4/29/2007	5/18/2007	18.50	$ 334,124	$ 6,181,290	
5/7/2007	5/20/2007	5/13/2007	6/1/2007	18.50	$ 336,230	$ 6,220,264	
5/21/2007	6/3/2007	5/27/2007	6/15/2007	18.50	$ 353,260	$ 6,535,307	
6/4/2007	6/17/2007	6/10/2007	6/29/2007	18.50	$ 337,679	$ 6,247,055	
6/18/2007	7/1/2007	6/24/2007	7/13/2007	18.50	$ 341,521	$ 6,318,131	
7/2/2007	7/15/2007	7/8/2007	7/27/2007	18.50	$ 345,752	$ 6,396,418	
7/16/2007	7/29/2007	7/22/2007	8/10/2007	18.50	$ 333,438	$ 6,168,603	
7/30/2007	8/12/2007	8/5/2007	8/24/2007	18.50	$ 347,811	$ 6,434,508	
8/13/2007	8/26/2007	8/19/2007	9/7/2007	18.50	$ 337,253	$ 6,239,172	
8/27/2007	9/9/2007	9/2/2007	9/21/2007	18.50	$ 335,121	$ 6,199,732	
9/10/2007	9/23/2007	9/16/2007	10/5/2007	18.50	$ 331,445	$ 6,131,739	
9/24/2007	10/7/2007	9/30/2007	10/19/2007	18.50	$ 352,580	$ 6,522,721	
10/8/2007	10/21/2007	10/14/2007	11/2/2007	18.50	$ 355,828	$ 6,582,810	
10/22/2007	11/4/2007	10/28/2007	11/16/2007	18.50	$ 355,294	$ 6,572,939	
11/5/2007	11/18/2007	11/11/2007	11/30/2007	18.50	$ 375,779	$ 6,951,905	
11/19/2007	12/2/2007	11/25/2007	12/14/2007	18.50	$ 395,601	$ 7,318,624	
12/3/2007	12/16/2007	12/9/2007	12/28/2007	18.50	$ 351,392	$ 6,500,744	
	TOTAL			17.21	$ 9,890,372	$ 170,167,997	
	GRAND TOTAL				$ 30,257,306	$ 445,995,488	
	WEIGHTED AVERAGE DAYS			14.74			

Notes:
1/ Changed Period Covered to the date of the payment & the dollar amount
2/ Changed Period Covered to the date of the payment

3. With respect to each expert witness, identify each witness whose testimony will rely on input from other individuals. For each witness identified, please identify the other individuals and describe the input they are providing.

Answer: The expert witnesses who have provided testimony in this proceeding have not relied upon input from other individuals in the preparation of their respective testimony.

Pennsylvania Public Utility Commission

v.

Equitable Gas Company

Docket No. R-2008-2029325

Responses of the Office of Trial Staff
Witness: Debra Backer, Analyst
to Equitable Gas Company
Set II

1. **Reference page 18 sample billing lags of other Utilities (PG Energy, Columbia Gas, Duquesne Light, Aqua, Met Ed, Penelec).**

   C. **Please provide a fully detailed breakdown of the billing procedures that support the billing lags for each of the utilities that you have referenced having billing lag days of less than 4.88.**

   Response: The information requested is not available. A breakdown of the billing procedures is not requested from utilities when the lag numbers are found to be reasonable.

Pennsylvania Public Utility Commission

v.

Equitable Gas Company

Docket No. R-2008-2029325

Responses of the Office of Trial Staff
Witness: Debra Backer, Analyst
to Equitable Gas Company
Set III

4. **Of the six utilities identified by Ms. Backer on page 18 of her direct testimony ("other utilities"), please identify for which of those other utilities Ms. Backer prepared testimony; for which of those other utilities Ms. Backer reviewed the testimonies of other parties in the case, including OTS, and for which of those utilities Ms. Backer has billing lag claims.**

Response: The sample companies provided the billing lags that the companies originally filed in base rate cases. Since they were acceptable, no testimony was necessary on the CWC billing lags. A list of the Companies Ms. Backer prepared testimony for is in her Direct Testimony, OTS Statement No. 2, Appendix A.

Pennsylvania Public Utility Commission

v.

Equitable Gas Company

Docket No. R-2008-2029325

Responses of the Office of Trial Staff
Witness: Debra Backer, Analyst
to Equitable Gas Company
Set III

5. **For each of the six billing lags identified by Ms. Backer on page 18 of her direct testimony for other utilities, please identify the source of the billing lags and specifically how they were developed. Also identify whether the billing lag was that presented by the utility or some other party, and what action, if any, the Commission took with respect to the specific billing lag.**

Response: The billing lags for the sample provided in Ms. Backer's Direct Testimony, OTS Statement No. 2, were filed by the companies in base rate proceedings. Since the lag days were acceptable, a breakdown of how the lag days were developed was not requested from the companies.

Pennsylvania Public Utility Commission

v.

Equitable Gas Company

Docket No. R-2008-2029325

Responses of the Office of Trial Staff
Witness: Debra Backer, Analyst
to Equitable Gas Company
Set III

11. **Is it Ms. Backer's position that Equitable should send out bills for the 91.7% to 94.5% of accounts that do not create audit exceptions one day earlier than it send out bills for those 5.5% to 8.3% of accounts for which an audit exception was created?**

Response: Yes. As stated in Ms. Backer's Direct Testimony, OTS Statement No. 2, page 17, starting on line 22, a whole day to hold all bills for the 5.5% to 8.3% audit exceptions is excessive and does not consider the other 91.7% to 94.5% whose accounts did not create the audit exceptions.

Docket No. R-2008-2029325
Item: OTS-RE-18-D
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Trial Staff

Item: OTS-RE-18-D

Reference Exhibit VI, Vol. 1, Item 18, p. 11 of 32, Payroll Non-Union.

A. Reference pay period 1/14/07 through 1/27/07. Explain the expense amount of $3,557,439 and why this expense increased by $2,893,835 from the previous pay period 1/1/07 through 1/14/07 in the amount of $663,604.

B. If the increase in the expense in Part A is due to a bonus, provide documentation of the bonus, how many employees received the bonus and how the amount was determined.

C. Are the taxes withheld actually paid on the same day as payroll, and if so, provide documentation to support your answer.

Response:

A. This expense is the gross bonus payment along with the Company portion of taxes for the non-union payroll group. In the process of reviewing this expense, a mistake was made in the original filing; the actual expense was $ 3,650,116.25 as the attached supporting document for part C shows.

B. There were 213 employees who received bonus checks. Please see the attached document which is a report from ADP for the payroll bonus transaction.

The purpose of the Company Short-Term Incentive Plan (STIP) is to maintain a competitive level of total cash compensation for the Company's employees. The Company can reward performance based on the overall performance of the Company, the business segment, and the individual contribution of each employee.

C. Yes. Please refer to page 5 of David Ross's testimony. Please see the attached document which is a wire transfer of funds from Equitable Resources to ADP. The taxes paid were a portion of the overall wire.

Liability Recap	Taxes Debited	Federal Income Tax		823,828.44		
		Earned Income Credit Advances		.00		
		Social Security - EE		187,166.93		
		Social Security - ER		187,166.94		
		Social Security Adj - EE		.00		
		Medicare - EE		48,978.12		
		Medicare - ER		48,978.10		
		Medicare Adj - EE		.00		
		Federal Unemployment Tax		3,455.34		
		State Income Tax		106,847.80		
		State Unemployment Insurance - EE		2,953.61		
		State Unemployment/Disability Ins - ER		37,194.32		
		State Unemployment Insurance Adj - EE		.00		
		State Disability Insurance - EE		.00		
		State Disability Insurance Adj - EE		.00		
		Workers' Benefit Fund Assessment - EE		.00		
		Workers' Benefit Fund Assessment - ER		.00		
		Local Income Tax		31,286.76		
		School District Tax		.00		
		Total Taxes Debited Acct. No. 167-0137	Tran/ABA 043000261		1,477,888.36	
	Other Transfers	Wage Garnishments Acct. No. 167-0137	Tran/ABA 043201691		1,061.31	
		Total Amount Debited From Your Account				1,478,899.67
	Bank Debits and Other Liability	Checks			2,171,216.68	
		Direct Deposit			.00	
		Adjustments/Prepay/Voids			.00	
	Taxes - Your Responsibility	None This Payroll				

Total Liability
1,478,899.67
3,650,116.25
3,650,116.25
3,650,116.25

Net Pay	Checks				2,171,216.58	
	Direct Deposits				.00	
	Subtotal Net Pay					2,171,216.58
	Adjustments				.00	
	Total Net Pay Liability (Not Cash)					2,171,216.58

Taxes			You are responsible for Depositing these amounts		Amount debited from your account		
Federal	Agency	Rate	EE withheld	ER contrib.	EE withheld	ER contrib.	
	Federal Income Tax				823,826.44		
	Earned Income Credit Advances						
	Social Security				167,168.93	167,168.94	
	Medicare				48,978.12	48,978.10	
	Federal Unemployment Tax					3,485.34	
	Subtotal Federal				1,039,973.49	239,632.38	1,299,585.87
State	PA State Income Tax				99,829.80		
	PA State Unemployment/Disability Ins-ER 7.5680					38,136.51	
	PA State Unemployment Insurance-EE				2,953.61		
	Subtotal PA				102,783.41	38,136.51	138,919.92
	WV State Income Tax				7,018.00		
	WV State Unemployment/Disability Ins-ER 1.5000					1,057.81	
	Subtotal WV				7,018.00	1,057.81	8,075.81
Local	104A Lower Burrell				9.20		
	104D Kennedy T				82.15		
	104E Hopewell T				218.25		
	104M W Mifflin A				132.78		
	104V Belmont Boro				30.50		
	106A Franklin Par				900.85		
	106B Mccandless T				110.70		
	106D Ross T				756.00		
	106E Shaler T				172.25		
	106F W View B				179.50		
	106H Plum B				60.60		
	106K Dormont B				24.30		
	106M W Mifflin B				132.78		
	106O Castle Shann				28.25		
	106P N Versailles				176.00		
	106Q S Fayette S				155.55		
	106S N Huntingdon				280.50		
	106T S Park T				112.50		
	106W Moon T				4,368.00		
	110C Jefferson B				110.35		
	110G Murrysville				1,284.95		

Taxes			You are responsible for Depositing these amounts		Amount debited from your account	
Local	Agency	Rate	EE withheld	ER contrib.	EE withheld	ER contrib.
(continued)	110H Robinson T				360.00	
	110K Nottingham T				413.10	
	110M Penn T				515.60	
	110O Ohio T				307.10	
	110X Wayne T				32.15	
	110Z Mt Oliver B				178.15	
	1102 Manor T				39.90	
	1106 Forward T				49.90	
	1114 Irwin B				58.50	
	112A Wilkinsburg				1,200.00	
	112B Economy B				53.15	
	112C Blawnox B				188.75	
	1123 Pennsbury Vi				35.35	
	1124 Rochester B				77.25	
	1126 Rochester A				20.68	
	1132 White T R				60.75	
	1133 Indiana Asd				91.13	
	1135 Manor Boro A				15.68	
	1136 Penn Traffor				15.68	
	114A Monroeville				209.68	
	114B Whitehall B				61.95	
	1140 Oakdale B				95.95	
	1141 Cook T				22.45	
	1154 Rochester T				20.68	
	1157 W Leechburg				41.30	
	117P Pittsburgh S				352.30	
	140P Pittsburgh C				5,757.00	
	182B Middlesex T				207.60	
	182F Munhall B				271.30	
	182I Oakmont B				1,517.05	
	182K Peters T				183.30	
	182M Pleasant Hl				111.33	
	182N Smith T				89.75	
	182P Washington T				210.00	
	182Q W Jefferson				111.33	
	182S Burgettstown				89.75	
	192J Jefferson T				157.35	
	193S Slippery Roc				163.80	
	194W Quaker Vale				120.15	
	195A Avalon B				37.25	
	195R Rosslyn Farm				62.05	

Taxes			You are responsible for Depositing these amounts		Amount debited from your account		
Local	Agency	Rate	EE withheld	ER contrib.	EE withheld	ER contrib.	
(continued)	195S Seven Fields				52.45		
	195W Wilkins T				160.00		
	196B Bellevue B				312.23		
	196P Punxsutawney				11.10		
	196R Richland T				154.85		
	197A Adams T				891.50		
	197B Baldwin T				36.06		
	197C Cecil T				267.85		
	197D Daugherty T				250.00		
	197R Redbank T				39.90		
	197W Hempfield T				104.10		
	201N N Buffalo T				124.45		
	205A Sharpsburg B				59.30		
	205G Cranberry T				1,269.50		
	205I Kittanning T				39.90		
	205Q Arnold C				33.00		
	205V Buffalo T				1,101.60		
	210B Baldwin B				413.65		
	210G Findlay T				125.70		
	210Q Beaver B				103.45		
	210T Bethel T				41.00		
	210X Aleppo Towns				120.15		
	210Y Pine T				463.95		
	212A Mt Lebanon T				1,228.81		
	212B Upper St. Cl				123.89		
	212C Bethel Park				732.49		
	213Z N Braddock B				17.95		
	339P Penn Hills T				229.80		
	401G Northgate Sc				37.25		
	401P Plumcreek T				41.00		
	401R Rayburn T				32.40		
	Subtotal Local				31,286.76		31,286.76
	Total Taxes		.00	.00	1,291,081.68	276,896.70	1,477,858.36
	Amount ADP Debited From Account 167-0137		Trsn/ABA 043000261				1,477,858.36

Excludes Taxes That Are Your Responsibility

Other	Wage Garnishments	1,031.31	
Transfers	Amount ADP Debited From Account 167-0137	Trsn/ABA 043201601	1,031.31
Total Amount ADP Debited From Your Accounts			1,478,889.67

WIRE TRANSFER REQUEST

Funds to be transferred on 2/6/2007 Originating Company 1332

Debit Information (Wire Funds from)

Company	Equitable Resources
Bank	Mellon
A/C Title	General
A/C Number	178-5196
Amount	$ 6,335,476.51

Credit Information (Wire Funds to)

Company	ADP
Bank & ABA #:	Bankers Trust Company
A/C Title	ADP Payroll Deposit Custodial Account
A/C Number:	00153170
Reference:	ABA No. 021001033
Repetitive # (optional)	

Prepared by: Date 1.26.07
Approved: Date 01/26/07

Accounting Distribution

1336	VZ4	198455.CSG			A		$159,817.63
1336	VZ5	198455.CSG			A		$62,130.37
1336	WNP	198455.CSG			A		$601,770.41
1336	WQ8	198455.CSG			A		$1,901,151.87
1336	WQD	198455.CSG			A		$1,478,899.67
1336	WQG	198455.CSG			A		$1,683,718.76
1336	WQJ	198455.CSG			A		$46,944.23
1336	WQQ	198455.CSG			A		$401,043.57
	TOTAL						$6,335,476.51

Items below to be completed by Treasury.

Transfer:
Wire Transfer No.:
Transfer Date:
Approval (Treasury):

Docket No. R-2008-2029325
Item: OCA-I-41
Respondent: David W. Ross
Position: Director, Planning

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-I-41

With reference to Exhibit VI, Item 18, page 11, please provide documentation supporting the payment of payroll taxes (FICA, FUTA & SUTA) for the first quarter of 2007.

Response:

As discussed in David Ross' testimony and further in the response to OTS-RE-18-D, Equitable Gas Company pays payroll taxes to ADP at the same time payroll expenses are paid. ADP files and pays payroll taxes on behalf of Equitable Gas Company.

Equitable Statement No. 13-R
Witness: Fredrick K. Dalena
Docket No. R-2008-2029325
Date: 11/19/08

P/S

EQUITABLE GAS COMPANY

PREPARED REBUTTAL TESTIMONY
OF
FREDRICK K. DALENA

PREPARED REBUTTAL TESTIMONY OF FREDRICK K. DALENA

I. Witness Background and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Fredrick K. Dalena. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Equitable Resources as Chief Commercial Officer.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am a graduate of The Pennsylvania State University with a B.S. in Petroleum and Natural Gas Engineering and The University of Pittsburgh with a Masters of Business Administration. In 1983, I joined Equitable Gas Company as a Technical Fieldman in the field operations department. Since that time I have held a number of managerial positions of increasing responsibility at Equitable Resources including Vice President and General Manager of ERI Services, an unregulated marketing company, Vice President of Commercial Operations of Equitrans, L.P., an interstate pipeline company and, most recently, Senior Vice President of Commercial Operations of Equitable Gas Company.

Q. WHAT WERE YOUR RELEVANT DUTIES AND RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF COMMERCIAL OPERATIONS?

As Senior Vice President of Commercial Operations, I was responsible for the gas supply function of Equitable Gas Company in Pennsylvania, West Virginia and Kentucky.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE REGULATORY AGENCIES?

A. Yes. I submitted testimony in the Joint Application proceeding at PaPUC Docket No. A-122250F5000 which concerned Equitable Resources' proposed acquisition of Dominion Peoples and Dominion Hope. I also have submitted testimony before the Federal Energy Regulatory Commission.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony will respond to the direct testimonies of Diane Meyer Burgraff submitted by the Independent Oil and Gas Association of Pennsylvania ("IOGA") and James L. Crist submitted jointly by IOGA and Hess Corporation. My rebuttal testimony will address Rate AGS and how it impacts Pennsylvania production, the cost of gas supplies available to Equitable, the value to Equitable's customers of Pennsylvania production, and the ability of Equitable to substitute Pennsylvania production for gas deliveries from interstate pipelines.

Q. HAVE YOU REVIEWED THE TESTIMONY OF IOGA WITNESS BURGRAFF AND IOGA/HESS WITNESS CRIST?

A. Yes. I have reviewed their individual statements of direct testimony. Ms. Burgraff offers testimony as an independent consultant retained by IOGA to address cost allocation, rate structure and the application of Rate AGS. Mr. Crist, also an independent consultant, has been retained by IOGA and Hess to address least cost natural gas supply, Pennsylvania producer issues, the agency program and related marketer issues.

III. Rate AGS and Pennsylvania Production

Q. HOW HAS EQUITABLE BEEN INVOLVED IN THE DEVELOPMENT OF PENNSYLVANIA PRODUCED GAS OVER THE PAST SEVERAL YEARS?

A. Over the past 8 years, 2000 through 2007, Equitable has invested capital in excess of $19 million in gathering lines and other gathering related facilities including compression and dehydration equipment. The Company also has incurred significant gathering related operation and maintenance (O&M) expenses. For example, during 2006 and 2007, the Company's annual gathering related O&M expenses were $2.64 million and $2.95 million, respectively. These investments have opened up Appalachian production areas in Western Pennsylvania expanding the ability of Appalachian producers, including members of IOGA, to bring Pennsylvania produced natural gas to market. A measure of the success of the investment is shown by the substantial and significant increase in Pennsylvania produced gas purchased by Equitable for purchased gas cost purposes. From 2004 through 2007, Equitable's purchases of local Pennsylvania produced gas increased

from 2.0 Bcf annually to 9.2 Bcf annually and the dollars it paid to local Pennsylvania producers for gas delivered directly into the Equitable system increased from $11.4 million to $72.9 million, an increase of $61.50 million on an annual basis. As I discuss at length in my testimony, having received the benefits from the over quadrupling of access to gathering capacity, it is only appropriate that producers pay for the cost of the investment and operation of the facilities that were installed for them to deliver their gas to a market.

Q. DOES EQUITABLE CONTINUE TO SUPPORT THE DEVELOPMENT OF PENNSYLVANIA PRODUCED NATURAL GAS?

A. Yes, we do and the significant increase in the amount of Pennsylvania production delivered into the Equitable distribution system provides proof of that fact. However, unlike the IOGA witnesses who seem to be laboring under the false assumption that Pennsylvania produced gas is both low-cost and capable of displacing gas supply services, Equitable recognizes the limitations attributable to such gas. More specifically, Equitable rejects any assertion that Pennsylvania production can or should be substituted for gas supplies derived from either the Southwest or from other Appalachian supply areas such as West Virginia and, unless producers are required to pay Rate AGS, Equitable also rejects the idea that Pennsylvania production is low-cost.

Q. IOGA WITNESS CRIST BELIEVES THAT EQUITABLE SHOULD BE ABLE TO DISPLACE VARIOUS OTHER SOURCES OF GAS, PARTICULARLY

THAT DELIVERED THROUGH INTERSTATE PIPELINES, WITH PENNSYLVANIA PRODUCTION. DO YOU AGREE?

A. No, I do not. In my opinion, it is inappropriate to compare from an operational (and cost) standpoint, Pennsylvania production to interstate pipeline gas from the Southwest, as their delivery characteristics are so dissimilar. The approximately 50,000 Dth/day of Pennsylvania production received into the Equitable distribution system comes primarily from the Apollo gathering facilities. This gas is produced from thousands of wells behind over 1,500 meters. The volumes delivered are relatively constant on a daily basis. To restrict these volumes requires physically shutting in meters, one meter at a time. Accordingly, there is also no way to rapidly increase the level of daily throughput when warranted by customer demand. I consider Pennsylvania produced gas to fulfill a base load function for the Equitable system, meaning that system receipts of this gas can not generally be any higher than the daily system burn.

Interstate gas from the Southwest serves a different and absolutely vital function. This gas supply is necessary to satisfy peaking needs and respond to the hourly variability of customer usage patterns. Equitable is able to increase and decrease its deliveries from no gas received to its full contract demand in a matter of hours. Because this gas is required for peaking purposes, it does not flow every day. However, if I were to use it in the same manner as Pennsylvania production, namely as a base load supply, and calculate the cost of the gas at a 100% load factor, as I show on Exhibit FKD Rebuttal-1, the cost of Southwest supplies is very attractive compared to the cost of Pennsylvania production and it provides greater operational flexibility that local production can not match. Additionally, I have the ability to

release this capacity from time to time in the marketplace and credit back a portion of the revenue received to PGC customers.

Q. IF COMPARING PENNSYLVANIA PRODUCTION WITH SOUTHWEST PIPELINE SUPPLIES IS NOT APPROPRIATE, IS THERE A SUPPLY THAT WOULD PROVIDE A BETTER COMPARISON?

A. I believe Equitable's other Appalachian (primarily in West Virginia) gas supply delivered through Equitrans to be a more appropriate comparison. The supply is derived from thousands of wells attached to a gathering system, much like the Pennsylvania production. The main distinguishing characteristic is that these other Appalachian supplies are noticeably less expensive than Pennsylvania production. This is primarily because the producers providing the supply have agreed to absorb the costs of Equitrans' gathering fees of $0.54/Dth and the lost and unaccounted (retainage) rate of approximately 10.5% (Exhibit FKD Rebuttal-1). In other words, these West Virginia producers have agreed to do essentially what Rate AGS requires Pennsylvania producers to do -- price their product to compete with alternative gas supply options.

Q. ARE THERE ANY ADDITIONAL BENEFITS ASSOCIATED WITH THIS OTHER APPALACHIAN GAS SUPPLY?

A. Yes. In contrast with Pennsylvania production, this other Appalachian supply has access to storage and is delivered to Equitable through an interstate pipeline. From a gas supply perspective, the ability to inject this gas into storage

when system demand is low or deliver it directly to Equitable's city gate during higher periods of demand is a more operationally attractive option.

Q. HOW DID YOU DETERMINE THE RELATIVE COST OF THESE GAS SUPPLIES?

A. Attached to my testimony as Exhibit FDK Rebuttal-1 is a schedule that demonstrates the costs of the various supply sources. I believe it provides a true and accurate description of both the commodity costs and any appropriate delivery-related charges to transport the gas to Equitable's city gate.

Q. MS. BURGRAFF STATES A NUMBER OF REASONS WHY RATE SCHEDULE AGS SHOULD BE REJECTED BY THE COMMISSION. DO YOU AGREE WITH HER CONCERNS?

A. I do not. Equitable witness Russell Feingold will address Ms. Burgraff's contention that the Company's cost of service studies improperly attempt to recover gathering costs from producers. More specifically, Mr. Feingold will rebut Ms. Burgraff's contention that it is a well-accepted cost allocation principle to equate "who benefits" from a utility service with "cost causation." However, even if one were to accept Ms. Burgraff's flawed logic, the facts suggest that there is no demonstrative "benefit" being bestowed on PGC customers from the availability of Pennsylvania production. As I have shown, Pennsylvania production is not low-cost, does it offer the operational flexibility of interstate deliveries, and it is a supply source that can easily be replaced if producers were to leave the gathering system.

Q. ARE YOU SAYING EQUITABLE DOES NOT NEED THE PENNSYLVANIA PRODUCTION?

A. As I have pointed out in my testimony, Pennsylvania produced gas is not a low-cost supply. It also lacks the flexibility that interstate delivered gas affords Equitable. More importantly, Equitable could operate its distribution system without any of the Pennsylvania production, except for the small amount needed to serve the 3,620 distribution customers on the gathering facilities. At the time Equitable acquired the Apollo system, it was transporting approximately 1 Bcf of third-party production. If tomorrow we were to return to that 1 Bcf level from the more than 12.4 Bcf per year delivered today, I am confident Equitable's distribution operations would be unaffected. Equitable operated for over 100 years without this Pennsylvania production, and if Rate AGS were to have the effect of limiting or reducing future gathering volumes, Equitable's customers would be unaffected.

That does not mean that we are desirous of losing our Pennsylvania produced supply. It offers supply diversity, is relatively reliable and Equitable recognizes the obvious economic development importance of continuing to promote its development. However, we do not believe it should be subsidized by our ratepayers. The simple fact is that it is Pennsylvania producers who have derived the benefit from the expansion of gathering facilities. Prior to Equitable acquiring Apollo, producer gas was shut-in for part of the year and third-party throughput was only about 8% of what it is today. Equitable's customers do not need IOGA's production, but to have any viable market available to them, the IOGA producers need Equitable's customers.

Q. AREN'T THE GATHERING FACILITIES ALSO USED TO SERVE DISTRIBUTION CUSTOMERS, AND, IF SO, SHOULDN'T THE COST OF THESE FACILITIES BE RECOVERED FROM DISTRIBUTION CUSTOMERS?

A. Although both Mr. Crist and Ms. Burgraff attempt to argue that these gathering facilities serve a mixed purpose justifying recovery of their costs from distribution ratepayers, this argument misses the mark. Distribution facilities generally have supply and demand in relative balance. If I were to take this same approach to analyze the Apollo facilities, Equitable would need less than 1Bcf to serve all of our distribution customer needs on the gathering facilities. In fact, over 12.4 Bcf of third-party gas annually moves through these facilities, making them a significant net exporter of natural gas. The incremental investments made in the last seven years were not designed to satisfy residential customer demand in Apollo. These investments were solely driven by producers desiring to move more natural gas to market. This is particularly true of the most significant recent investment, the Limestone Project, as its sole purpose is to effectuate the movement of gas off the gathering system and into a non-affiliated interstate pipeline. None of that gas is ultimately redelivered to Equitable, nor does the movement of this gas afford Equitable any opportunity to reduce other upstream interstate capacity costs as one IOGA witness suggests.

Q. IF THAT IS THE CASE, WHY DID EQUITABLE CONSTRUCT THE LIMESTONE PROJECT?

A. Equitable has encouraged the expansion of Pennsylvania production and willingly attempted to find a market for this gas on our distribution facilities.

Equitable witness Mr. Rafferty discusses this project in more detail in his rebuttal testimony. However, as I have shown on Exhibit FKD Rebuttal-2, the Equitable market for base load gas supply has now reached saturation, ie. Pennsylvania Appalachian supply is equal to the LDC's baseload demand.

Q. WOULD YOU EXPLAIN EXHIBIT FKD REBUTTAL – 2?

A. Yes, the graph visually compares the amount of Pennsylvania Appalachian supply that enters the distribution system to the system demand (customer usage) that is consumed on the distribution system. The bottom (flat) line represents Pennsylvania Appalachian supply. The top line represents the system demand. As you can see from the relationship between the two lines, during the period of April through October, that supply and demand are roughly equal. Therefore, the graph demonstrates that there is simply no room for additional non-flexible baseload supply.

Q. HOW DO YOU EXPLAIN EQUITABLE'S SUPPORT IN ITS 2004 1307(f) PROCEEDING OF THE RECOVERY OF GATHERING COSTS FROM GAS SALES CUSTOMERS?

A. Ms. Burgraff puts great stock in the Company's 2004 1307(f) proposal to recover incremental gathering facility costs from PGC customers. What she fails to point out is how dissimilar the Company's 2004 proposal is from what IOGA would have the Commission do in this proceeding. While it is indeed true that the Company sought PGC recovery of some $6 million in gathering costs, the Company specifically did not seek rate base (whether as distribution or as gathering) treatment

of these costs. Instead, they were to be recovered over a six-year period upon demonstrating offsetting PGC gas cost savings. Essentially, the proposal would have placed no new costs on PGC customers - - the facilities charge was to be recouped by gas cost reductions. As it turned out, the Company was overly optimistic about the level of savings, and this 1307(f) proposal was made several years before the high level of unaccounted for gas on the gathering facilities was discovered. If I could honestly say that Pennsylvania production would reduce PGC costs by the cost of service related to these facilities, I would have no problem with agreeing that Equitable's distribution customers should absorb the Rate AGS costs. However, I have demonstrated that Pennsylvania production is simply not low-cost, nor does its relative reliability warrant a distribution customer subsidy of producers of over $12 million dollars annually before any recognition of lost and unaccounted for gas. In the end, Equitable is a distribution company. It is not an interstate pipeline. It does not have an unlimited ability to either consume or transport Pennsylvania production. And most importantly, we do not operate Equitable as a producer benevolent society. Our distribution customers deserve better than that and we believe that Rate AGS places the costs of the gathering facilities squarely where they belong.

Q. MS. BURGRAFF BELIEVES THAT RATE AGS SEEKS TO RECOVER COSTS FROM "SUPPLIERS" WHICH SHE CONTENDS IS CONTRARY TO TRADITIONAL RATEMAKING PRINCIPLES. DO YOU AGREE?

A. Ms. Burgraff contends that IOGA's producer community does nothing more than supply a commodity and, thus, it is not proper to charge them for gathering

facilities costs. I might agree with her if the Pennsylvania production was a necessary part of Equitable's system supply. However, as I have previously stated, IOGA overstates the importance to Equitable of Pennsylvania production. It is neither low-cost nor of any particular benefit to Equitable's PGC or transportation customers, as gas can be acquired more economically from other areas. Equitable did not expand its gathering assets because our customers desperately needed Pennsylvania production. Equitable witness Mr. Rafferty has shown that Pennsylvania producers were the driving force in the expansion of gathering facilities, and the most recent project, the Limestone Compressor Station, supports that claim as producers are the clear beneficiary of the project. Equitable's gathering assets are not distribution facilities and were not intended to become part of the distribution plant. Instead, they constitute a separate rate base that consists of gathering plant, field compression and low pressure transmission lines that combine to serve a gathering function. The beneficiaries of these gathering facilities are the IOGA producers - - and they are being provided a gathering service, without which they would have little or no market for their gas, although I will leave it to counsel to address whether gathering service is a Pennsylvania jurisdictional service under the Public Utility Code. I would note that Equitable offers producers a market price, plus basis differential, for their gas supplies. We do not attempt to "low-ball" the price solely because they may lack other viable markets. In return, Equitable asks that producers, not distribution customers, incur the costs incidental in creating access to markets for Pennsylvania production.

Q. ARE YOU CONCERNED THAT THE COMMISSION'S APPROVAL OF RATE AGS WOULD AFFECT OTHER UTILITIES IN THE STATE THAT OWN GATHERING ASSETS OR HAVE AN ADVERSE EFFECT ON THE AVAILABILITY TO EQUITABLE CUSTOMERS OF LOCAL PRODUCTION?

A. I am not overly concerned in either instance. I can think of no situation where I would generally be supportive of distribution customers subsidizing production gathering assets, with the lone exception of a gas supply that is a critical part of the Company's supply portfolio. By that I mean that without such production, the utility would be unable to meet customer demands. That is clearly not the case here. Further, although I have no doubt that some producers may flee the Equitable system if they can access a system that will subsidize their gathering costs, Equitable can readily survive a reduction in the availability of Pennsylvania production, and distribution customers will not suffer as these volumes can be replaced by gas from other supply sources at similar or lower cost.

Q. WHAT ABOUT MS. BURGRAFF'S CONTENTION THAT IOGA PRODUCERS SHOULD BEAR NONE OF THE COSTS FOR LOST AND UNACCOUNTED FOR GAS, OR EVEN GAS USED FOR COMPRESSION?

A. Let me initially address the company-used gas cost (compression) issue. Equitable is a distribution company first and foremost. As such, it does not have any compression on its distribution facilities. This is because the majority of the gas delivered to Equitable is received from interstate pipelines operating at pressures in excess of 500 psig. Equitable sells its gas to customers at pressures generally of less than 1 psig. Therefore, from the time the gas is received at the city-gates it is

constantly undergoing a reduction in pressure brought about by a series of regulators until it is delivered to customers. On the other hand, gas received from gathering systems requires a significant amount of field compression. There are a number of compressor stations on the gathering system and each maintains the pipeline pressure necessary to facilitate the production of gas from the many wells attached to the gathering lines. Without the compression, gathering throughput would be noticeably reduced. As such, these compression costs, and the fuel necessary to accommodate gathering, are clearly costs that should be borne by producers.

As for the unaccounted for gas issues, Equitable acquired the Apollo gathering assets in 1999. At that time, we were unaware of any significant level of unaccounted for gas as the entire gathering system was moving only approximately 1 Bcf per year of third-party production. Additionally, at that time, the system was being operated at an average line pressure of roughly 8 psig. Today, we are moving approximately 12.4 Bcf of third-party production annually at pipeline pressures in excess of 40 psig. We believe that these increased volumes and higher operating pressures are the major contributors to the increase in unaccounted for gas. Preliminary studies have suggested that unaccounted for gas may be as high as 20%. We are continuing our actions to identify the major sources for unaccounted for gas. These actions include upgrades to measurement and abandonment of sections of pipelines that produce high levels of unaccounted for gas. Nevertheless, the cost of making significant improvements in a gathering system that dates back to 1917 will not be insignificant and it may even require the shut-in of low volume wells. On the other hand, if Equitable were to operate the gathering system the way Apollo did - - at less than 8 psig and approximately 1 Bcf of third-party throughput annually - - the

level of unaccounted for gas could be significantly reduced. The party that benefits from the increased throughput and higher operating pressures is clearly IOGA, yet it wants all of the costs of operating the system to fall either on PGC customers and transporters or on Equitable's shareholders.

Q. FINALLY, MS. BURGRAFF STATES THAT IF PRODUCERS MUST PAY RATE AGS, THEY WILL SIMPLY SHIFT THE RECOVERY OF THESE COSTS FROM BASE RATES INTO PGC COSTS. DO YOU AGREE?

A. As I have indicated previously, Equitable pays a market based price for Pennsylvania production. That will continue if Rate AGS is approved as filed, and producers will pay the cost of Rate AGS from the proceeds of their gas sales. Ms. Burgraff suggests that if Rate AGS is approved producers will demand a market based rate plus the cost of Rate AGS as the price they will accept from Equitable, effectively moving these costs into the PGC. I can state unequivocally that will not happen. If producers were to demand such a price, Equitable would simply refuse to buy the gas, as Equitable has many other gas supply options.

Q. HAVE YOU REVIEWED THE TESTIMONY OF HESS/IOGA WITNESS CRIST?

A. Yes, I have. He makes the same points and invokes the same flawed analysis that Ms. Burgraff employed. He starts with an assumption - - that Pennsylvania produced gas is low-cost - - and then bootstraps an argument that, because of this price advantage, Equitable must encourage Pennsylvania production

and force its distribution customers to pay for it. He also suggests that absent this subsidy new well drilling on Equitable will cease or producers will drill out of state.

Q. DID HE PROVIDE ANY PROOF THE PENNSYLVANIA PRODUCED GAS IS LOW-COST?

A. He did not. Instead, he invokes a theme that Pennsylvania production is necessary to "have enough gas supply to provide for adequate volumes especially during time of cold weather." If Mr. Crist had any actual knowledge of the Equitable system - - and the fact that we do not have any on-system storage as he claims - - he would know that Pennsylvania gas is our base load supply. It is not now, nor will it ever be short of a monumental investment in infrastructure, become anything more than a minimal supplier during "cold weather." I have explained previously the inflexibility of Pennsylvania produced supply and will not belabor that point. Suffice it to say, Equitable can operate efficiently, both summer and winter, without a reliance on Pennsylvania production.

Q. WHAT ABOUT THE OTHER "BENEFITS" OF PENNSYLVANIA PRODUCTION THAT MR. CRIST REFERENCES IN LINES 4-9, P. 7 OF HIS DIRECT TESTIMONY?

A. Mr. Crist mentions that Pennsylvania production also benefits Equitable's PGC customers by providing supply diversity, reducing interstate pipeline demand costs, and reducing compression costs. Unfortunately, he is wrong in each instance. Although supply diversity is nice, it does not warrant paying the costs of the gathering system's operation solely to secure this "benefit" for PGC customers.

Second, I have already addressed the fact that Pennsylvania production is base load supply and cannot realistically ever substitute for interstate deliveries as it lacks operational flexibility. Finally, since the only compression on the Equitable system is in conjunction with gathering, there is no possibility that increasing Pennsylvania production deliveries will reduce compression costs. Instead, it will increase compression costs.

Q. MR. CRIST REFERENCES THE COMMISSION'S TRANSPORTATION REGULATIONS AS SUPPORT FOR A CONTENTION THAT EQUITABLE IS OBLIGATED TO TRANSPORT PENNSYLVANIA PRODUCTION. DO YOU AGREE WITH HIS CONTENTION?

A. I am not a lawyer but I have reviewed the circa 1987 regulations that he cited. These regulations deal with transportation, not gathering, and they also contain a provision that Mr. Crist failed to include. Section 60.1 provides:

> The transportation of natural gas by jurisdictional utilities is in the public interest. Transportation service should be provided under terms, conditions and rates which minimize the shifting of costs to retail customers and provide the natural gas utility with an opportunity to recover the fixed costs incurred to serve the transportation service customers . . . .

Although I am not convinced that this regulation has any relationship to a gathering service such as Rate AGS, nevertheless, I think it is important to note the tenor of the regulation - - namely that rate subsidies and shifting of costs should not be allowed. Absent approving Rate AGS, producers will be the recipients of a sizable subsidy from PGC and transportation customers.

Q. HAS EQUITABLE ENCOURAGED PENNSYLVANIA PRODUCTION?

A. I believe the testimony of Mr. Rafferty clearly evidences that Equitable has encouraged Pennsylvania production. However, as I have stated previously, Equitable is not an interstate pipeline. Our ability to take Pennsylvania production is limited by the fact that this production is delivered from the gathering system into the distribution operations at the northern end of our facilities and dependent on corresponding customer usage. Pennsylvania production can be neither quickly increased nor quickly reduced; thus, it has characteristics that ill serve a distribution utility with significant peaking demand.

Q. MR. CRIST SUGGESTS THAT EQUITABLE MIGHT WANT TO RESTRICT PENNSYLVANIA PRODUCTION SO THAT IT CAN BUY MORE GAS FROM AFFILIATED MARKETERS. IS THIS TRUE?

A. Equitable does not buy any Equitable' Resources-owned production, nor does it buy gas from affiliated marketers on any regular basis.

Q. MR. CRIST ALSO SUGGESTS THAT EQUITABLE'S USE OF EQUITRANS, LP, AN AFFILIATED INTERSTATE PIPELINE, IS SOLELY TO BENEFIT EQUITABLE RESOURCES AT THE EXPENSE OF PENNSYLVANIA PRODUCERS. DO YOU HAVE ANY COMMENT ABOUT THIS CONTENTION?

A. When all else fails, Mr. Crist invokes the hobglobin of affiliated transactions as a reason for Equitable to attempt to curtail Pennsylvania production. There is nothing secretive about Equitable's relationship with Equitrans. In fact, Equitable's

service agreements and capacity entitlements have been reviewed in practically every Equitable 1307(f) filing since Equitrans was created in 1986. Equitable relies on Equitrans for gathering services, storage services, transportation and the redelivery of gas procured on other interstate pipelines. I have demonstrated that these interstate delivered gas volumes, unlike Pennsylvania production, are truly low cost and also afford the utility the operational flexibility that Pennsylvania production simply can not. Equitable believes that its mix of services provided by Equitrans provides for the optimal operation of the distribution system and none of these costs has ever been disallowed.

Q. MR. CRIST CLAIMS THAT THERE IS NO CLEAR DISTINCTION BETWEEN EQUITABLE'S GATHERING SYSTEM AND ITS DISTRIBUTION SYSTEM. DO YOU AGREE?

A. I do not. The gathering system was not constructed to serve distribution customers. The fact that customers opportunistically were connected to these gathering lines does not change their function. The Equitable gathering system is a net exporter of natural gas. Some 25 times more gas is exported from the gathering system than is consumed on the gathering system by the distribution customers located along the gathering lines. It is indeed farfetched to conclude that Apollo Gas Company constructed in excess of 860 miles of pipeline to serve 3,620 customers. To suggest as does Mr. Crist - - that the pipelines were built to serve residential customers and that thousands of wells just happened to be developed along the path of the pipelines - - is not only factually incorrect, but it would make no economic sense.

Q. MR. CRIST SEEMS TO SUGGEST THAT MANY OF THE PRODUCERS ARE CAPTIVE TO THE EQUITABLE SYSTEM. DO YOU HAVE ANY COMMENT?

A. Yes, I do. I assume a producer thoroughly evaluates all of its delivery options, economic alternatives, and associated risks before deciding to acquire mineral rights and drill a well. In my opinion, Equitable has been exceedingly producer friendly given its track record of adding Pennsylvania Appalachian gas to its gathering system. Pennsylvania production on the old Apollo system used to be curtailed part of the year. Furthermore, recognizing our inability to continue to take increasing volumes of Pennsylvania production, Equitable constructed the Limestone Compressor to off-load production into an interstate pipeline. To the extent Limestone results in gas that currently flows into Equitable now being redelivered into the interstate market, it will allow producers to drill additional wells for delivery to Equitable's distribution system to replace the volumes diverted to the interstate market. However, at the end of the day, Pennsylvania producers must recognize that Equitable is a finite market. Absent additional investment to build capacity to other markets, the receipt of Pennsylvania gas is limited to its customer usage. New Pennsylvania production has no "right" to displace current competitively priced supply, nor does Equitable have any obligation to expand its facilities to accommodate increased Pennsylvania production at the expense of PGC and transport customers. Within reason, Equitable is committed to working with Pennsylvania producers. However, when they become unreasonable, as is the case

here, we have no option but to require that they conform their activity to what is in the best interest of our distribution customers.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

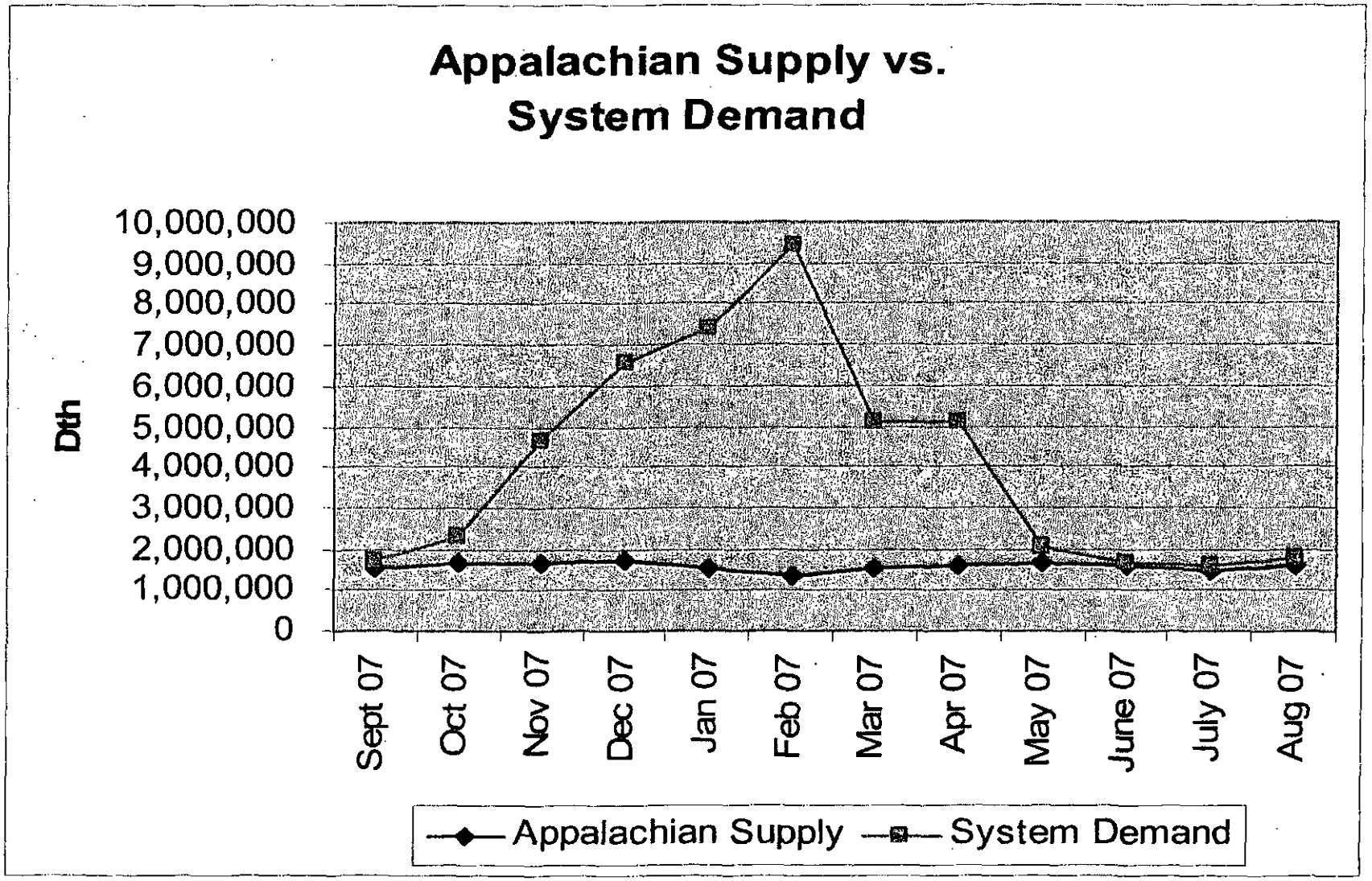
A. Yes.

Equitable Gas Company
Purchase Gas Cost Analysis
Interstate vs Appalachian
Exhibit FKD Rebuttal-1
Nymex Settle (Oct 2008) **$7.4720**

Pennsylvania Appalachian		
Index	**$7.4720**	**$ 7.4720**
Premium	$0.4000	$ 0.4000
Less: Retainage	$ -	$ -
Less: Gathering	$ -	$ -
Net Purchase Price	**$7.8720**	**$ 7.8720**
Assumed LUF	10.00%	20.00%
(1 - retainage %)	0.9000	0.8000
Gathering cost	$0.8900	$ 0.8900
Citygate Price	***$9.6367***	***$10.7300***

Interstate	TETCO ETX
Index or Purchase Price	**$ 6.5300**
(1 - retainage %)	0.9415
Index adj for retainage	$ 6.9357
Transport	$ 0.0287
Firm 100%	$ 0.4079
Equitrans/M2 Market	**$ 7.3724**
(1 - retainage %)	0.9628
Index adj for retainage	$ 7.6572
Transport	$ 0.0976
Firm 100%	$ 0.1646
Citygate Price	***$ 7.9194***

Equitrans Gathering	*Retainage @ 10.50%*
Index	**$ 7.4720**
Premium	$ 0.4000
Less: Retainage	$ (0.8266)
Less: Gathering	$ (0.5400)
Net Purchase Price	**$ 6.5054**
(1 - retainage %)	0.9628
Index adj for retainage	$ 6.7568
Transport	$ 0.0976
Firm 100%	$ 0.1646
Citygate Price	***$ 7.0190***


Appalachian Supply vs.
System Demand
Dth
10,000,000
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
Sept 07
Oct 07
Nov 07
Dec 07
Jan 07
Feb 07
Mar 07
Apr 07
May 07
June 07
July 07
Aug 07
Appalachian Supply
System Demand

Equitable Statement No. 14-R
Witness: Stephen C. Rafferty
Docket No. R-2008-2029325
Date: 11/19/08

P35

EQUITABLE GAS COMPANY

PREPARED REBUTTAL TESTIMONY
OF
STEPHEN C. RAFFERTY

PREPARED REBUTTAL TESTIMONY OF STEPHEN C. RAFFERTY

Witness Background and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Stephen C. Rafferty. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Equitable Resources as Sr. Vice-President, Equity Sales and Gathering.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I attended the University of Pittsburgh and earned a Bachelor of Science Degree in Civil Engineering in 1986. I continued my education with graduate work and earned a Masters in Business Administration (MBA) degree from the Indiana University of Pennsylvania in 1990. I have also completed several technical and industry related courses and seminars pertaining to my job responsibilities.

Professionally, I began my career in 1986 as a Civil Engineer with the Pennsylvania Department of Transportation. In 1988, I accepted a position with Equitable Gas Company as a Technical Fieldman. In 1989, I was promoted to the position of Customer Service Foreman. In 1991, I was promoted to the position of District Foreman. These operational positions were within the Distribution Department and included responsibility for utilizing a unionized labor force to schedule work and

complete assignments. These positions provided an excellent background in understanding gas pressures and flows and the manner in which supplies are distributed within the Company's service territories. In 1995, I was promoted to the position of Load Research and Planning Coordinator in the Gas Management Department with responsibility for gas supply / demand forecasting. Between January 1997 and January 2008, I held a succession of positions of increasing responsibility within the Gas Supply, most recently as Vice-President, Utility Asset Management. In January 2008, I was promoted to my current position.

Q. WHY IS YOUR TESTIMONY RELEVANT IN THIS INSTANT PROCEEDING?

A. As an Equitable Gas Company employee and its Vice-President, Utility Asset Management, I was intimately involved in creating, negotiating and administering the Company's Rate Schedule AGS. Furthermore, during the time spent in the gas supply department I gained first hand knowledge and experience with the operations of the former Apollo and Carnegie assets.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE REGULATORY AGENCIES?

A. Yes. I submitted testimony before the Pennsylvania Public Utility Commission in Equitable's 1997, 1998, 1999, 2000, 2001, 2002, 2003 and 2004 1307(f) proceedings at Docket Nos. R-00973895, R-00984279, R-00994601, R-00005067, R-00016132, R-00027135, R-00038166 and R-00049154, respectively. In addition, I testified before this Commission in Equitable's 1998 Service Expansion Application at Docket No. A-121100 F0003 and in the Company's 1999 restructuring proceeding at Docket No. R-00994784. I also submitted testimony before the Public Service Commission of West Virginia in Equitable's 1998 and

2004 annual gas cost review proceedings. I also submitted testimony in the Joint Application proceeding at Docket No. A-122250F5000 which concerned Equitable Resources' proposed acquisition of Dominion People's and Dominion Hope.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony will respond to the direct testimonies of Diane Meyer Burgraff, Keith Mangini, Mike Hillebrand, D. Marc Jacobs and Milissa Bauer, submitted by the Independent Oil and Gas Association of Pennsylvania ("IOGA") and James L. Crist submitted jointly by IOGA and Hess Corporation. To begin with, I will provide a brief description of the Company's gathering and distribution facilities as they existed before and after the acquisition of the former Apollo and Carnegie Companies. Next, I will provide the history of Rate Schedule AGS, the reasons why it was created and its evolution over the last six years. I will discuss the benefits received by the producers from the implementation of Rate Schedule AGS, including the completion of the Company's NAOP Program, as well as the Limestone Compressor Project. Furthermore, I will discuss why the continuation of Rate Schedule AGS should be approved by the PUC as just and reasonable and why producers, or marketers that purchase supplies directly from these same producers, should bear the cost responsibility for this system. Finally, I will address the IOGA witnesses concerns that their respective company's production is captive and that the rates they are assessed under Rate Schedule AGS were not negotiated and I will respond to their claims that Equitable's refusal to set new taps is not warranted.

HAVE YOU REVIEWED THE TESTIMONY OF IOGA WITNESSES BURGRAFF, MANGINI, HILLEBRAND, JACOBS AND BAUER AND IOGA/HESS WITNESS CRIST?

A. Yes. I have reviewed their individual statements of direct testimony. Ms. Burgraff offers testimony as an independent consultant retained by IOGA to address cost allocation, rate structure and the application of Rate AGS. Mr. Crist, also an independent consultant, was retained by IOGA and Hess to address least cost natural gas supply, Pennsylvania producer issues, the Agency Program and marketer issues. Messrs. Mangini and Hillebrand are President and Vice President of Huntley & Huntley, Inc., respectively. Mr. Jacobs is a Vice President of Penneco Oil Company. Ms. Bauer is a Vice President of Administration of Kriebel Minerals, Inc. Their testimony addresses gathering service and facilities. Although Messrs. Mangini, Hillebrand and Jacobs and Ms. Bauer each state that they are testifying on behalf of IOGA, their testimony fails to explain in what way they are authorized to testify on behalf of anyone but their own individual employer either in regard to the IOGA formal complaint proceeding or Equitable's base rate proceeding.

Description of Gathering Facilities

Q. BEFORE ADDRESSING THE TESTIMONY OF THE OTHER PARTIES WITNESSES CAN YOU PROVIDE BACKGROUND INFORMATION ABOUT THE COMPANY'S GATHERING SYSTEM AND FACILITIES?

A. Prior to the acquisition of the Carnegie Natural Gas Company and its affiliated subsidiaries, such as the Apollo Gas Company, from USX-Marathon Group on December 15, 1999, Equitable did not possess gathering plant. In other words, Equitable's system was purely a distribution system. There were no gathering lines, no compressors, no dehydration units, or other significant non-distribution facilities. Equitable's facilities were used to provide delivery service to its distribution customers. Furthermore, the local production that was attached to these distribution facilities, at that time, was of no real significance. After this acquisition, however, Equitable's system changed significantly.

Q. PLEASE DESCRIBE THE FORMER APOLLO AND CARNEGIE GAS COMPANIES?

A. The former Apollo and Carnegie Gas Companies were operated as an integrated natural gas system consisting mostly of gathering lines, field compression, low-pressure transmission lines and some local distribution facilities located in West Virginia and Pennsylvania. These gathering systems feed natural gas into field compressors which, in turn, deliver this gas into feeder lines that eventually transport the gas through subsequent compressor stations towards the metropolitan Pittsburgh area. This acquisition resulted in Equitable now having gathering lines, compressors and dehydration units, as well as having a significant amount of local production attached to these facilities.

Q. PLEASE DESCRIBE THE RESOURCES UTILIZED BY THE FORMER APOLLO AND CARNEGIE COMPANIES TO SERVE THEIR CUSTOMERS PRIOR TO THE ACQUISITION BY EQUITABLE RESOURCES.

A. The gas supplies used to serve these rate districts consisted primarily of local Appalachian production purchases. At the time of that acquisition, the Apollo Rate District transported approximately 1 Bcf of local Appalachian production to serve the 3,620 customers on its gathering facilities. On the other hand, the Carnegie Rate District customers were served through a firm transportation contract on Texas Eastern Transmission Company. Those supplies were then transported on Carnegie Interstate Pipeline Company to Carnegie Rate District distribution facilities.

Q. WAS THERE A DIFFERENCE IN HOW APOLLO OPERATED ITS FACILITIES AS ITS CUSTOMER DEMAND REQUIREMENTS CHANGED DURING THE YEAR?

A. Yes, there was. The distribution customers on the Apollo gathering system are primarily residential customers whose demand requirements are dictated by the weather. Therefore, their demand requirements are much higher in the winter than they are during the summer. Apollo would curtail gas supplies during the low-demand seasons by physically shutting-in the local production. They would leave enough supply on the gathering system so that service to these distribution customers could be maintained. Furthermore, it is my understanding that as a condition for the producer to have their gas not shut-in, they had to accept a substantially lower purchase price.

Q. WAS IT POSSIBLE FOR APOLLO TO TRANSPORT THIS GAS ELSEWHERE SO THAT SHUT-INS WERE NOT NECESSARY?

A. No. Apollo did not have the gathering infrastructure and compressors necessary to move this gas elsewhere. If they did not shut-in this "excess"

production, line pressures would increase, the lost and unaccounted for ("LUF") would increase and the operational integrity of the system would be jeopardized.

Rate AGS

Q. WITNESS BURGRAFF PRESENTS A HISTORY OF RATE AGS. DO YOU AGREE WITH HER PRESENTATION?

A. No. Equitable's current Rate Schedule AGS – Appalachian Gathering Service, has evolved over the last several years as a direct result of Equitable's acquisition of the gathering assets of the former Apollo Gas Company, as well as the subsequent acquisition of the gathering assets from Equitable Field Services.

Q. CAN YOU DESCRIBE THE EVOLUTION OF RATE SCHEDULE AGS?

A. Shortly after Equitable's acquisition of the Apollo Gas Company gathering assets, the Company was approached by several producers that had production located in the immediate vicinity of the Hill Compressor Station (located in Washington Township, Westmoreland County, PA) and the Fisher Compressor Station (located in Redbank Township, Armstrong County, PA). These facilities were located in the Apollo Rate District. The producers in this area wanted the opportunity to flow additional volumes and avoid the curtailments that they were accustomed to when the Apollo Gas Company operated the system. Equitable was able to develop mitigation and enhancement strategies at these two locations in an effort to move additional volumes year-round. I have attached to my rebuttal testimony as Attachment SCR-1 a letter to these certain producers, dated September 23, 2002, describing these two projects in more detail. As a condition for Equitable

to make the necessary investments at each of those compressor stations, the Company wanted reimbursement from the producers that directly benefited from those investments. Also attached to my rebuttal testimony, as Attachment SCR-2, are several executed letters whereby those producers agreed to the fees suggested by the Company in return for the investments to the compressor stations and the ability to flow additional production. The results of the Company's investments at each of those locations were positive and the producers were able to flow more gas as curtailments were less than they would have been otherwise. During the next several months, word traveled in the producing community and other producers began to make inquires as to opportunities for them to flow additional supply and avoid the need for curtailments. On November 14, 2002, I met personally with representatives of IOGA (at their offices in Wexford, PA) and it is my recollection that these initiatives were discussed.

Q. WAS THERE OPPOSITION BY THE PRODUCERS WHEN EQUITABLE GAS BEGAN IMPLEMENTING THESE CHARGES OR FEES IN 2002?

A. No.

Q. WHAT HAPPENED NEXT?

A. A short time later, during 2003, Equitable filed an Application, at Docket No. G-00031009, seeking approval for an affiliated transaction designed to acquire additional gathering facilities in Armstrong and Indiana Counties, PA, from Equitable Field Services. These gathering facilities overlapped and were contiguous with Equitable's Apollo facilities and in some instances were actually duplicative. Equitable Gas and Equitable Field Services referred to these facilities as the PA-North Gathering system. These same facilities were also sometimes referred to as

the "Crooked Creek" facilities. Equitable Field Services had FERC-approved gathering rates and retainage charges in place at the time it elected to sell those properties. As part of its filing, Equitable requested and was granted approval by the PA PUC to implement Rate Schedule AGS – Apollo Gathering Service. I have attached to my rebuttal testimony Rate Schedule AGS – Apollo Gathering Service as Attachment SCR-3.

Q. WHY WAS IT NECESSARY TO IMPLEMENT RATE SCHEDULE AGS-APOLLO GATHERING SERVICE AT THAT TIME?

A. As I stated earlier, Equitable Field Services had FERC-approved gathering charges and retainage charges that were assessed to producers for production that was directly connected to these gathering facilities. Equitable did not have an existing rate schedule that would permit the assessment of those same charges. On the other hand, Equitable did have contracts in place with those producers that specified what the charges would be. Since Equitable was not proposing any increase in its existing rates by virtue of the proposed acquisition, it needed a mechanism to fund the acquisition and the improvements that would occur in the future. Absent this mechanism, Rate Schedule AGS, Equitable would not have acquired those facilities and made the improvements.

Q. WHY DIDN'T EQUITABLE MAKE RATE AGS APPLICABLE TO THE PA-NORTH GATHERING SYSTEM ONLY? IN OTHER WORDS, WHY WAS IT APPLICABLE THROUGHOUT THE ENTIRE APOLLO DISTRICT?

A. Equitable envisioned combining the Apollo assets with the Pa- North Gathering System (Crooked Creek) to create operational efficiencies and eliminate duplicative facilities since these assets were contiguous with one another.

Furthermore, the recent successes associated with the compressor station projects described earlier, along with the support of the producing community, led the Company to believe that the producing community was willing to pay for other projects that directly benefited them, including the improvements that were planned for these gathering facilities.

The contiguous nature of the Apollo gathering system and the PA – North gathering system (Crooked Creek) made it nearly impossible to keep them separated as the Company made efficiency improvements. These improvements included, among other things, interconnecting the two systems and eliminating duplicative facilities. Furthermore, the Company took a "macro" approach to optimizing these assets to increase local production and believed that all producers would benefit. This is the reason the "Applicability" section of Rate Schedule – AGS included the entire Apollo District and not just the PA- North Gathering System.

Q. WAS RATE SCHEDULE AGS – APOLLO GATHERING SERVICE APPROVED AS FILED?

A. Yes.

Q. WAS THERE OPPOSITION BY THE PRODUCERS WHEN EQUITABLE GAS CONTINUED IMPLEMENTING THESE CHARGES IN 2003?

A. No.

Q. WAS EQUITABLE GAS REQUIRED TO FILE RATE SCHEDULE AGS – APOLLO GATHERING SERVICE IN ORDER TO ASSESS THESE CHARGES TO THE PRODUCERS?

A. I am not a lawyer. Whether gathering services, as opposed to utility distribution services, are subject to the Commission's jurisdiction, is not entirely clear to me. I would note that there are contracts with producers for all of the Pennsylvania production that provide for the recovery of the Rate Schedule AGS charges, regardless of whether a tariff is or is not necessary. These contracts were negotiated at arms-length and in good faith. Without these producer commitments as evidenced by these contracts, the significant expansion of the assets to increase Pennsylvania production would not have gone forward. Instead, Equitable would have operated the Apollo District much like it was in the past and the curtailments and the producer shut-ins would have continued.

Q. WHEN DID RATE SCHEDULE AGS – APOLLO GATHERING SERVICE CHANGE TO RATE SCHEDULE AGS – APPALACHIAN GATHERING SERVICE?

A. The following year, as part of Equitable's 2004 Section 1307(f) proceeding at Docket No. R-00049154, the Company proposed to change the name of Rate Schedule AGS from Apollo Gathering Service to Appalachian Gathering Service.

Q. WERE THERE CHANGES OTHER THAN THE NAME OR TITLE?

A. Yes. In the "Applicability" section, the Company included the Equitable District along with the Apollo District. I have attached to my rebuttal testimony, Attachment SCR-4, Rate Schedule AGS – Apollo Gathering Service. By adding the Equitable District as applicable, the tariff encompassed deliveries made directly into the distribution system.

Q. WHY DID THE COMPANY BELIEVE IT WAS NECESSARY TO MAKE THESE CHANGES TO RATE SCHEDULE AGS?

A. Between 2002 and 2004, the Company had continued to make investments to the gathering facilities since Rate Schedule AGS – Apollo Gathering Service was first implemented. Those investments and the ensuing increases in local production were received favorably by the producers and the producing community. Furthermore, Equitable identified several new projects, referred to as the Company's Northern Asset Optimization Program ("NAOP"), and described in detail during the same 2004 Section 1307(f) proceeding, that would enable these local production volumes to continue to increase substantially. I will discuss the Company's NAOP Program and the benefits received by all producers later in my testimony. The completion of these projects provided benefits to not only producers on the gathering systems but also to producers that delivered gas directly into the distribution system. Therefore, it is only appropriate that all producers, regardless of whether they deliver into the gathering system or the distribution system, be assessed charges in accordance with Rate Schedule AGS.

Q. WAS RATE SCHEDULE AGS – APPALACHIAN GATHERING SERVICE APPROVED AS FILED IN EQUITABLE'S 2004 1307(F) PROCEEDING?

A. Yes.

Q. WAS THERE OPPOSITION BY THE PRODUCERS WHEN EQUITABLE GAS CONTINUED IMPLEMENTING THESE CHARGES TO ALL PRODUCERS IN 2004?

A. No. There was no significant opposition to the Company's Rate Schedule AGS until IOGA filed a formal complaint in September 2006 at Docket No C-20066800 and an Amended Formal Complaint in February 2008, nearly 4 years after Equitable had started assessing some form of Rate Schedule AGS.

Q. HOW DOES EQUITABLE APPLY RATE SCHEDULE AGS?

A. Rate Schedule AGS is currently assessed to all producers, regardless of whether their production is delivered into gathering facilities, distribution facilities or low-pressure transmission facilities. The Company does not distinguish between the three types of facilities since all producers have benefited from the Company's investments in its gathering, compression and low-pressure transmission facilities.

Q. HOW DOES EQUITABLE NEGOTIATE RATE SCHEDULE AGS?

A. Typically, Rate Schedule AGS is negotiated for a term that ranges from one year up to three years. The term and purchase price are negotiated between the Company and the producer, or designated representatives of the two companies. As stated previously, these negotiations are conducted at arms-length and between two parties of equal bargaining position. Once an agreement is reached, a confirmation or appendix to the Gas Purchase Contract is developed and executed by both parties. This confirmation or appendix becomes part of a legal, binding contract.

Q. DO ALL PRODUCERS PAY THE SAME RATE AGS?

A. No. Not all producers are assessed the same rates. The gathering related charges contractually agreed to range from $0.00/dth up to $1.00/dth. The retainage charges contractually agreed to range from 0.00% to 7.5% of the gross volume delivered to Equitable Gas.

Rate AGS Benefits / NAOP Program / Limestone Compressor Project

Q. DO YOU BELIEVE RATE AGS HAS PROVIDED A MECHANISM FOR THE COMPANY TO MAKE INFRASTRUCTURE INVESTMENTS THAT DIRECTLY BENEFIT LOCAL APPALACHIAN PRODUCERS?

A. Absolutely. Attached to my rebuttal testimony as Attachment SCR-5 is a diagram that identifies the increase in local Appalachian production that has occurred since 2000, when Equitable acquired the Apollo gathering assets. It is readily apparent that these volumes have increased substantially over the years. This increase would never have been possible without the Company's investments in its infrastructure, including the NAOP Program.

Q. CAN YOU SUMMARIZE THE COMPANY'S NAOP PROPOSAL THAT WAS SUBMITTED DURING THE 2004 SECTION 1307F PROCEEDING?

A. The Company's NAOP originally consisted of five projects designed to increase pipeline capacity, lower pressures on the gathering and distribution systems and ultimately increase local Appalachian production everywhere. These projects included various gathering, compression and lower-pressure transmission assets formerly associated with the Apollo and Carnegie Gas Companies, as well as assets belonging to Equitable Gas.

Q. HAVE THESE PROJECTS AND BENEFITS EVER BEEN COMMUNICATED TO LOCAL PRODUCERS?

A. Yes, they have. As an example, I have attached Attachment SCR-6 to my rebuttal testimony that is an email to Huntley & Huntley explaining why the Company believes it is valid to assess all producers a charge in accordance with Rate Schedule AGS, regardless of whether they deliver into "distribution" facilities or into "gathering" facilities. Also attached to my rebuttal testimony as Attachment

SCR-7, is a newsletter published by IOGA, dated winter 2005, that identifies for all of their members the same five projects associated with the Company's NAOP Program.

Q. WERE THERE OTHER PROJECTS THAT THE COMPANY CONSIDERED OR COMPLETED THAT WOULD PROMOTE AND INCREASE LOCAL PRODUCTION EVEN FURTHER?

A. Yes, there are two projects that are either completed or in the design phase. These projects are the Limestone Compressor Station and the Fisher Compressor Station. The Limestone Compressor Station is located in the extreme northwest part of the Company's service territory in Limestone Township, Clarion County, PA. The Fisher Compressor Station is located in the extreme northeast part of the Company's service territory in Redbank Township, Armstrong County, PA. Both of these projects involve adding new compressor stations and dehydration units that are designed to discharge 12,000 dth/day. The discharge from these two stations would be delivered into Dominion Transmission and would not enter the Company's distribution facilities.

Q. WHY CAN'T THIS PRODUCTION ALSO BE USED TO MEET THE DEMAND REQUIREMENTS OF EQUITABLE'S DISTRIBUTION CUSTOMERS?

A. There is not enough demand on Equitable's distribution system to accommodate additional production and there is no other outlet. As Equitable witness Dalena explains in his rebuttal testimony, the local production that is delivered into the distribution system is baseload in nature. Stated differently, the minimum level of demand experienced on the distribution system is what can be satisfied by local production. All demand above that minimum level has to come

from the interstate pipelines since those pipelines are the only ones that have the flexibility to increase/decrease deliveries rapidly, based on the changing demand patterns. At the present time, Equitable's distribution system has reached a saturation threshold. I will discuss this issue in more detail later in my testimony. This is precisely the reason the interconnection with Dominion Transmission was essential for designing the Limestone Compressor Station.

Q. WHAT IS THE CURRENT STATUS OF THESE TWO PROJECTS?

A. The Fisher Station project is still on the drawing board. The design work has been nearly completed. On the other hand, the Limestone Station project is nearing the commissioning phase. The Company expects that the commissioning of that station will occur in the next several weeks.

Q. CAN YOU DESCRIBE THE LIMESTONE PROJECT IN MORE DETAIL?

A. The Company has invested approximately $13 million to install approximately 10,000 feet of 8" steel mainline (1,000 psig MAOP) and two 1,350 horsepower units, along with a dehydration unit, to facilitate the northwest movement of 12,000 dth/day of local production into Dominion Transmission.

Q. WHY DID THE COMPANY DECIDE TO DESIGN AND MOVE FORWARD WITH THAT PARTICULAR PROJECT?

A. The Company was approached by several producers in the area who were looking for additional outlets for their production. Through a collaborative effort with these producers, the Company designed and constructed this project.

Q. DID THESE PRODUCERS HAVE INPUT INTO THE DEVELOPMENT OF THIS PROJECT?

A. Absolutely. The Company would never invest that amount of money without having assurances that the project was worthwhile. The Company met numerous times with producers in the area, as well as IOGA representatives, seeking assurances that they, indeed, wanted this project completed.

Q. WOULD YOU CONSIDER THIS TO BE A COLLABORATIVE EFFORT, ANOTHER ONE OF THE RECOMMENDATIONS THAT WITNESS BURGRAFF SUGGESTS?

A. Yes. As a former employee in the gas supply department of Equitable Gas Company during the last 11 plus years, I, along with others, have spent a considerable amount of time working closely with local producers. Producers have approached the Company on a regular basis looking for ways to optimize their drilling programs and their production opportunities.

Q. DID THE COMPANY OBTAIN ADVANCE COMMITMENTS FROM PRODUCERS BEFORE MAKING THE DECISION TO COMPLETE THE LIMESTONE COMPRESSOR STATION PROJECT?

A. Yes. Attached to my rebuttal testimony as Attachment SCR-8 is a copy of the letter that was sent to the larger producers that originally made inquiries and that would benefit directly from that project. Also contained in Exhibit-SCR-14R-8 is documentation that producers executed the letter and agreed to the fees beforehand.

Captive Production and Rate AGS Negotiations

Q. CAN YOU SUMMARIZE THE IOGA PRODUCER WITNESSES JACOBS, MANGINI, HILLEBRAND AND BAUER TESTIMONIES THAT THEIR COMPANIES ARE "CAPTIVE" TO EQUITABLE?

A. Penneco witness Jacobs testifies that his company operates in western Pennsylvania and they have 800 wells connected to the pipelines of other utilities, including Dominion Peoples, T. W. Phillips, Columbia Gas of PA and Columbia Gas Transmission. Huntley & Huntley witness Mangini testifies his company also operates in western Pennsylvania and that many of their wells are located in towns or boroughs that are suburban in character and are located in the greater Pittsburgh area. None of Huntley & Huntley's wells in western Pennsylvania are connected to any other pipeline system. Witness Mangini claims that of the 300 existing wells, 225 are realistically captive to Equitable and only a few produce into Dominion Peoples. Witness Hillebrand corroborates witness Mangini's testimony by stating that Huntley & Huntley's wells are located in boroughs and townships within Allegheny County. Witness Bauer testifies that Kriebel is a producer of Pennsylvania natural gas in western Pennsylvania. They currently have 317 active wells feeding gas into Equitable's pipeline system. Out of the 317 wells, she state that about 96 are completely captive to Equitable while the rest of the wells are located such that Dominion Peoples is a viable alternative pipeline system.

Q. DO YOU AGREE WITH THEIR CLAIMS THAT THESE WELLS ARE CAPTIVE?

A. No, I do not. As explained by each of these witnesses, their companies operate in numerous townships and boroughs within western Pennsylvania. Witness Mangini states that Huntley & Huntley's system includes roughly fifty miles of gas

pipeline and their coverage area in western Pennsylvania is roughly twenty miles long and five miles wide. When one considers the number of wells that each of these companies drills and maintains, it is apparent their acreage covers considerable distances.

Q. IS EQUITABLE THE ONLY PIPELINE IN WESTERN PENNSYLVANIA THAT THESE PRODUCERS HAVE ACCESS TO?

A. No, it is not. The following local distribution companies operate in western Pennsylvania: Equitable Gas Company; T. W. Phillips; Columbia Gas of PA; Dominion Peoples and National Fuel Gas. In addition to these companies, there are numerous interstate pipelines that have operations and facilities in western Pennsylvania including: Equitrans, LP; Columbia Gas Transmission; Dominion Transmission; National Fuel Supply; Tennessee Gas Pipeline and Texas Eastern Transmission.

Q. CAN THESE PRODUCERS READILY ACCESS THE OTHER PIPELINES IDENTIFIED ABOVE?

A. All of the pipelines mentioned above have extensive operations in western Pennsylvania. However, these other pipelines may or may not have the infrastructure or capacity necessary to receive the production from these producers. The interstate pipelines will typically have the capacity, but there may be additional cost considerations for the producer, in addition to the gathering related charges.

Q. WHAT OTHER COST CONSIDERATIONS ARE THERE FOR A PRODUCER WHEN DETERMINING WHICH PIPELINE TO PRODUCE INTO?

A. Typically, the producer will take into consideration the amount of capacity that is available, including the ability to flow gas year-round. Operating pressures

are also an important consideration. The higher the pressures, the more the producer has to spend on compression to be able to produce its gas into the pipeline. In addition to the initial costs for the compressor, there are on-going operating and maintenance costs. The producer also needs to consider the gas quality specifications of the pipeline it wishes to deliver into. More stringent gas quality specifications may require the producer to add dehydration equipment. Again, as with a compressor, there are on-going operating and maintenance costs associated with dehydration units. There are costs associated with the tap itself. Higher pressure, larger diameter pipelines have much higher costs associated with the tap. Similarly, costs vary for the meter and regulator stations and associated telemetry instrumentation. All of these issues are considered by the producer in determining which pipeline is best to produce into so that costs are minimized and revenues/returns for their investors are maximized.

Q. WHY DO YOU BELIEVE THESE PRODUCERS ELECTED TO DRILL AND PRODUCE THE MAJORITY OF THEIR WELLS INTO EQUITABLE?

A. Equitable has invested in the infrastructure by building and replacing pipelines, adding and upgrading compression and dehydration facilities to create capacity for these producers. Equitable incurred these costs instead of the producer. Furthermore, the rates charged by Equitable, under Rate Schedule AGS, are cost competitive, otherwise these producers would have elected to produce their gas into another system.

Q. DO YOU HAVE AN EXAMPLE OF THIS?

A. Attached to my rebuttal testimony as Attachment SCR-9 is an email from Kriebel Gas describing their ability to move gas from one system to another in an

effort to obtain the cheapest rate(s). Most of the larger producers have the ability to move gas between various systems in an effort to optimize production as well as minimize costs. Furthermore, witness Bauer even testifies that "...because of a significant increase in the cost of another tap (DiCesare) and increased gathering rates demanded by Equitable, we moved production from the DiCesare well to Dominion Peoples."

Q. ARE YOU AWARE OF OTHER LDC'S IN THE COMMONWEALTH THAT ASSESS A GATHERING CHARGE OR A SIMILAR TYPE CHARGE TO PRODUCERS FOR UTILIZATION OF COMPANY FACILITIES IN AN EFFORT TO INCREASE LOCAL PRODUCTION?

A. Dominion Peoples currently charges fees to producers under the Production Enhancement Agreement ("PA PES"). This PA PES is essentially charging producers for gathering related facilities and investments with "the number one goal of Dominion Peoples being to move more production gas." The quote is taken from an IOGA presentation that is attached to my rebuttal testimony as Attachment SCR-10 which describes Dominion People's PA PES program in more detail.

Q. WITNESS BURGRAFF BELIEVES THAT IF RATE AGS IS PERMITTED TO REMAIN EFFECTIVE AND PRODUCERS AND MARKETERS ARE REQUIRED TO PAY FOR ALL OF THE COSTS ASSOCIATED WITH INSTALLING, OPERATING AND MAINTAINING GATHERING FACILITIES THAT THIS COULD LIMIT THE AVAILABLITY OF PENNSYLVANIA PRODUCTION. DO YOU AGREE?

A. No. Two of the largest utilities in western Pennsylvania, Equitable Gas and Dominion Peoples, have been charging producers for several years for investments

associated with installing, operating and maintaining gathering related facilities. Both utilities have continued to witness increased production levels during this time, in spite of those charges. Furthermore, the fees assessed these producers represent a small percentage of the value of the increased production. To illustrate this point, I have attached to my rebuttal testimony Attachment SCR-11 that identifies: (1) the annual dollars paid; (2) the annual volumes purchased; and, (3) the annual fees collected pursuant to Rate Schedule AGS for Penneco, Huntley & Huntley and Kriebel, during the period 2000 through 2007.

Q. CAN YOU SUMMARIZE THAT SCHEDULE?

A. Yes. **Penneco** - production increased from 8,054 dth in 2000 to 410,368 dth in 2007. Total purchases during this seven-year period were 2,055,111 dth and the total dollars paid were $11,658,372. Rate Schedule AGS fees collected were $388,290 or 3.33% of the total dollars paid.

Huntley & Huntley - production increased from 306,741 dth in 2000 to 1,433,901 dth in 2007. Total purchases during this seven-year period were 6,680,773 dth and the total dollars paid were $48,218,068. Rate Schedule AGS fees collected were $860,604 or 1.78% of the total dollars paid.

Kriebel - production increased from 269,566 dth in 2001 to 975,260 dth in 2007. Total purchases during this six-year period were 4,516,506 dth and the total dollars paid were $29,941,201. Rate Schedule AGS fees collected were $993,067 or 3.32% of the total dollars paid.

Q. WHAT HAVE YOU CONCLUDED WITH REGARDS TO THESE PRODUCERS AND THE RATE SCHEDULE AGS FEES THAT WERE ASSESSED DURING THIS PERIOD?

A. Although the fees collected each year increased, these producers continued to add wells and increase production. I might add that this schedule only captures the volumes that were purchased by Equitable Gas. The numbers only go higher when one factors in the additional volumes that were sold to marketers. In summary, if the past is any indication of the future, witness Burgraff is absolutely wrong in stating that "if Rate AGS is permitted to remain effective and producers and marketers are forced into paying for all of the costs associated with installing, operating and maintaining gathering facilities that this could create adverse consequences on the availability of Pennsylvania production." The dramatic increase in local production experienced by these producers during the last several years is clear evidence that Rate Schedule AGS does not adversely impact local production on Equitable's facilities.

Q. DO YOU BELIEVE THE SAME PHENOMENON HAS OCURRED ELSEWHERE?

A. Yes, I do. I believe if one was to make inquiries in regards to the Dominion Peoples system, one would find they have experienced substantial increases in Pennsylvania production as well, in spite of the PA PES fees that are assessed on their system.

Q. THESE WITNESSES CLAIM THAT THE CHARGES THEY PAY UNDER RATE AGS ARE NOT NEGOTIATED. DO YOU AGREE?

A. Absolutely not. I have met personally with these individuals and representatives of their companies during the last several years to discuss these rates. I find it troubling that these witnesses have no recollection of the meetings we have had and I question their sincerity. Each of these witnesses describes in great

detail the correspondence associated with new tap requests but appears to have a memory lapse concerning rate negotiations. In any event, if the rates were not negotiated, wouldn't Equitable simply charge the highest fees possible, i.e. $1.00/dth and 7.5% to everyone? Attached to my rebuttal testimony as Attachment SCR-12 is an email from Huntley & Huntley that portrays the negotiation process. This email is representative of the type of correspondence that regularly occurs between Company representatives and the producing community.

Equitable's refusal to set new meters

Q. CAN YOU SUMMARIZE WITNESS JACOBS' CONCERNS REGARDING EQUITABLE'S REFUSAL TO MAKE NEW TAPS AND SET NEW METERS?

A. Witness Jacobs states that the Trafford Borough #1 well was completed June 19, 2008 and the Emmick Unit well was drilled August 28, 2008. He states Penneco learned in the beginning of September 2008 that Equitable was claiming it could not set requested taps because its gathering pipelines were operating at full capacity. He then states that Equitable's refusal to set these taps has harmed Penneco in several ways.

Q. DO YOU AGREE WITH HIS STATEMENTS?

A. I do not. I have several emails from witness Jacobs that I have attached as Attachment SCR-13 that discuss the flow restrictions on Equitable's system. These emails are dated November 7, 2006, January 3, 2007, January 5, 2007 and May 14, 2007. Witness Jacobs knew well in advance of drilling those two wells that Equitable was experiencing operational problems and flow restrictions. In fact, in

one of the emails he acknowledges this by stating "we have been anxious to realize some of the relief that was speculated as a result of system improvements and extensions." Furthermore, in another email, Equitable denied the tap request for Penneco's Braddock site because of operational reasons.

Q. HAS WITNESS JACOBS PROVIDED ANY TESTIMONY OR DOCUMENTATION THAT WOULD INDICATE THAT THE TAPS FOR THESE WELLS WERE APPROVED PRIOR TO THEM BEING DRILLED?

A. I have reviewed his testimony and did not see where Equitable had approved the tap requests prior to them being drilled. Witness Jacobs and Penneco, for that matter, made a decision to drill at their own risk.

Q. DOES WITNESS BAUER CLAIM THAT KRIEBEL IS BEING HARMED BECAUSE EQUITABLE HAS REFUSED TO MAKE NEW TAPS AND SET NEW METERS?

A. No. The tap request she has identified in her testimony is not on Equitable Gas' facilities. It is on Equitable Gathering, LLC's facilities and it is my understanding that those facilities should be operational before year-end.

Q. DOES KRIEBEL HAVE ANY WELLS THAT HAVE BEEN DRILLED AND WHICH EQUITABLE GAS HAS REFUSED TO MAKE NEW TAPS AND SET NEW METERS?

A. Not to my knowledge. If there are, she has not identified them in her testimony.

Q. WHY DO YOU BELIEVE THIS TO BE THE CASE?

A. Attached to my testimony as Attachment SCR-14 is an email from Kriebel, dated January 25, 2007, that states "...we have been restricted since July 2006 when

the MAOP was set at 40#. Any idea if this pressure is ever expected to go down?" It appears that Kriebel was aware of the operational restrictions and elected to drill elsewhere.

Q. CAN YOU SUMMARIZE WITNESSES MANGINI'S AND HILLEBRAND'S CONCERNS REGARDING EQUITABLE'S REFUSAL TO MAKE NEW TAPS AND SET NEW METERS?

A. These witnesses state that their company completed the construction of five new production wells in the last two months of 2007. They claim that Equitable advised them that these taps would not be installed unless Huntley & Huntley agreed to pay a $0.50/dth gathering charge and 5% shrinkage. They contend that Equitable then demanded higher rates, and most recently Equitable said it cannot accept the new gas because its gathering pipelines allegedly are operating at full capacity.

Q. WAS HUNTLEY & HUNTLEY AWARE OF THE COMPANY'S OPERATING CONDITIONS AND THAT THE FACILITIES WERE OPERATING NEAR FULL CAPACITY?

A. I believe so. I have several emails from witness Hillebrand that I have attached as Attachment SCR-15 that discuss the flow restrictions on Equitable's system. These emails are dated January 2007 and August 2007. I believe these witnesses knew well in advance of drilling those wells that Equitable was experiencing operational problems and flow restrictions.

Q. IS EQUITABLE OPERATING AT FULL CAPACITY?

A. Equitable witness Dalena discusses the delicate balance between the Pennsylvania deliveries and Equitable's current need for additional supplies. He

also states that the gathering system may have some limited additional capacity due to the Limestone Project. Certainly, in the non-heating season, Equitable does not need additional Pennsylvania production. Although we could conceivably take additional Pennsylvania production in the winter, on a limited basis and at certain locations, such as on certain parts of the distribution system where the supply is received closer to where it is consumed, Equitable would then have to go through the difficult task of determining which producer's production would be curtailed after the heating season ends. This curtailment would be one meter at a time and be extremely labor intensive. Instead, we have taken the position any prudent distribution operator would take and attempted to match our Pennsylvania production closely with our baseload demand.

Q. BUT WHAT ABOUT CLAIMS BY PRODUCERS THAT CERTAIN PIPELINES ARE NOT OPERATING AT THEIR MAXIMUM ALLOWABLE OPERATING PRESSURES AND THEREFORE SHOULD BE ABLE TO ACCEPT ADDITIONAL PRODUCTION?

A. Equitable operates an integrated system, but not all of its pipelines are the same size or operate at the same pressures. Generally, capacity is limited not by the size of the pipeline a producer is connected to, but rather by the smaller diameter pipelines further downstream on the distribution system. Similar to a chain being as strong as its weakest link, a distribution system is limited by downstream pipeline configurations and the inability to physically redeliver gas to other locations on the system where demand may be greater. Pennsylvania production comes into Equitable's distribution system at the northern-most part of its service territory and

cannot be readily redelivered throughout the distribution system to areas having greater demand.

Q. HAS EITHER OF THESE WITNESSES PROVIDED TESTIMONY OR DOCUMENTATION THAT WOULD INDICATE THESE WELLS WERE APPROVED PRIOR TO BEING DRILLED?

A. I have reviewed their testimony and did not see where Equitable had approved the tap requests prior to them being drilled. Huntley & Huntley made a decision to drill at their own risk.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes.

ATTACHMENT – SCR - 1

EQUITABLE GAS

200 Allegheny Center
Pittsburgh, PA 15212-5352
www.SRafferty@eqt.com

TEL. 412.395.3268
FAX 412.395.3335

Date: September 23, 2002

Dear Producer,

As you may be aware, Equitable Gas Company ("Equitable") has made numerous enhancements to its Apollo District during the past two years in an effort to stimulate and increase local Appalachian production. During this time, Equitable has incurred significant costs in operating, maintaining and improving the distribution facilities in this area, without seeking reimbursement from local producers. Unfortunately, these investments cannot continue without some type of reimbursement. We have enjoyed an excellent working relationship with the producing community in the past and we regret that current economic conditions have forced us to take this action.

Equitable is willing to continue making improvements, change operating conditions where feasible and ultimately increase local Appalachian production if producers are willing to compensate Equitable for the costs incurred. Any producer that is not willing to compensate Equitable for these costs may be prohibited from flowing incremental volumes and may possibly be curtailed during low-demand periods. Equitable is seeking reimbursement from only those producers that will benefit from these on-going projects.

Specifically, Equitable has two additional projects that will be undertaken in the next several weeks if demand warrants. These projects are described in more detail below:

(1). Hill Station, Washington Township, Westmoreland County

Equitable will begin manually operating the Hill Compressor Station. Currently, local production is "free-flowing" in this area. Operating the Hill Compressor Station will increase local production approximately 1,000 Mcf/day. Equitable is seeking reimbursement of $0.30/dth for use of this facility, in addition to any other fees already being assessed. This number may be revised once actual operating costs are determined.

(2). Fisher Station, Redbank Township, Armstrong County

Equitable will increase the discharge MAOP associated with the Fisher Compressor Station. Preliminary estimates indicate an additional 1,500 Mcf/day will flow from this improvement. Equitable is seeking reimbursement of $0.25/dth for use of this facility, in addition to any other fees already being assessed. This number may be revised once actual operating costs are determined.

Again, these charges are applicable only to those wells that are directly affected by these projects. Please call me at (412) 395-3268 if you have any questions or need additional information. Please call Fred Workman at (412) 395-3295 to confirm those meters that are affected by these projects.

If the above terms and conditions are acceptable, please sign and date in the space provided below and return to me by fax at 412-395-3335.

Accepted and Agreed to
this _____ day of _____

By: _____

Title: _____

Sincerely,

Stephen C. Rafferty,
Director, Gas Acquisition &
Management

ATTACHMENT – SCR - 2

Fax

To: Stephen Rafferty

Of: Equitable Gas

Fax: 412-395-3335

Pages: 1, including this cover sheet.

Date: November 8, 2002

(2) Fisher Station, Redbank Township, Armstrong County

Equitable will increase the discharge MAOP associated with the Fisher Compression Station. Preliminary estimates indicate an additional 1,500 Mcf/day will flow from this improvement. Equitable is seeking reimbursement of $0.25/dth for use of this facility, in addition to any other fees already being assessed. This number may be revised once actual operating costs are determined.

Agreement is conditioned upon the following:

(1) If Equitable's projects, within thirty (30) days after their completion, do not enable D.K. Gas, Inc. to place additional natural gas production (monthly production in excess of current levels) into the Equitable Transmission Line, D.K. Gas reserves the right to discontinue its payment of $0.25/dth fee.

(2) D.K. Gas, Inc. reserves the right to reject an increase (based on actual operating costs) in excess of the $0.25/dth.

Accepted and Agreed to this 8th day of November, 2002

By: Lisa Kirkpatrick

Title: Corporate Secretary

From the desk of...

D.K. GAS, INC.
P.O. BOX 228

HAWTHORN, PA 16230
(814) 385-5621
Fax: (814) 385-5318

D.E. LIMITED FAMILY PARTNERSHIP

R.D. 5, Box 28 • Punxsutawney, PA 15767
Phone: 814-938-0800 • Fax: 814-938-0900
E-mail: del@groundhog.net

call Randy @ Jt.
30,000/month
meter 2125 - co. gen plant

October 16, 2002
VIA FACSIMILE

Mr. Steve Rafferty
Equitable Gas
200 Allegheny Center
Pittsburgh, PA 15212-5352

RE: Compensation charges, Fisher Station

Dear Steve:

As we discussed Equitable Gas has made some improvements to the Fisher Station and the pipeline system leading away from the station. These improvements should in the future increase Equitable ability to move gas out of this area and into the Pittsburgh market. This should benefit not only the independent producers but end users and Equitable.

DE Limited is considering participation at some level to help defray some of the costs associated with these upgrades and the on going maintenance they will require. However, after talking to several other producers on this system it is apparent that not all companies have agreed to the fees presented in your September 23rd letter. As you are aware DEL has not signed off on that letter and so we are not subject to any fee.

However, as stated above we would consider participating at some level but feel that a meeting with Equitable and all of the producers that will be paying this fee is a must before we can give anymore consideration to this matter. DEL would be glad to help set up a meeting at your convenience.

Sincerely,

Mike McMeans

Mike McMeans
Manager

cc: Stan Berdell
Lloyd Cravener
Bill Gregg
Randy Doverspike
Jeff Lundy, Esq.
Chip Glunt

File:gasequitablecompressorchrafferty10142002

EQUITABLE GAS

200 Allegheny Center
Pittsburgh, PA 15212-5352
www.SRafferty@eqt.com

TEL 412.395.3268
FAX 412.395.3335

Date: September 23, 2002

Dear Producer,

As you may be aware, Equitable Gas Company ("Equitable") has made numerous enhancements to its Apollo District during the past two years in an effort to stimulate and increase local Appalachian production. During this time, Equitable has incurred significant costs in operating, maintaining and improving the distribution facilities in this area, without seeking reimbursement from local producers. Unfortunately, these investments cannot continue without some type of reimbursement. We have enjoyed an excellent working relationship with the producing community in the past and we regret that current economic conditions have forced us to take this action.

Equitable is willing to continue making improvements, change operating conditions where feasible and ultimately increase local Appalachian production if producers are willing to compensate Equitable for the costs incurred. Any producer that is not willing to compensate Equitable for these costs may be prohibited from flowing incremental volumes and may possibly be curtailed during low-demand periods. Equitable is seeking reimbursement from only those producers that will benefit from these on-going projects.

Specifically, Equitable has two additional projects that will be undertaken in the next several weeks if demand warrants. These projects are described in more detail below:

(1). Hill Station, Washington Township, Westmoreland County

Equitable will begin manually operating the Hill Compressor Station. Currently, local production is "free-flowing" in this area. Operating the Hill Compressor Station will increase local production approximately 1,000 Mcf/day. Equitable is seeking reimbursement of $0.30/dth for use of this facility, in addition to any other fees already being assessed. This number may be revised once actual operating costs are determined.

(2). Fisher Station, Redbank Township, Armstrong County

Equitable will increase the discharge MAOP associated with the Fisher Compressor Station. Preliminary estimates indicate an additional 1,500 Mcf/day will flow from this improvement. Equitable is seeking reimbursement of $0.25/dth for use of this facility, in addition to any other fees already being assessed . This number may be revised once actual operating costs are determined.

Again, these charges are applicable only to those wells that are directly affected by these projects. Please call me at (412) 395-3268 if you have any questions or need additional information. Please call Fred Workman at (412) 395-3295 to confirm those meters that are affected by these projects.

If the above terms and conditions are acceptable, please sign and date in the space provided below and return to me by fax at 412-395-3335. The above items are acceptable with the attached agreed upon terms and conditions.

Accepted and Agreed to
this 26th day of Nov., 2002

By: M J Bowey

Title: VP of Admin

Sincerely,

Stephen C. Rafferty,
Director, Gas Acquisition &
Management

EQUITABLE GAS

200 Allegheny Center
Pittsburgh, PA 15212-5352
www.SRafferty@eqt.com

TEL 412.395.3268
FAX 412.395.3335

Kriebel Gas and Equitable Gas Agreed to the following conditions regarding the Apollo Reimbursement Program.

1. Specify the Meter Names and Numbers effected by this Agreement.

   Ozog Thompson, T5080
   McKown, T1853-56A
   Gaston Lumber 02, T1853-53A

2. The term of this agreement is until June 30, 2003. At the end of the term, if Equitable is still recovering costs from the upgrade to the systems, then Equitable and Kriebel will agreed to a new term.

Initially beside each of the above 2 items will show agreement by both parties.

SNYDER BROTHERS, INC.

P.O. Box 1022, One Glade Park East
Kittanning, PA 16201
Phone (724) 548-8101 FAX (724) 545-8243
www.snyderassociatedcos.com

December 12, 2002

Mr. Steve Rafferty
Equitable Gas Company
200 Allegheny Center
Pittsburgh, PA 15212-5352

Dear Steve:

Enclosed please find our signed agreement for Hill Station and Fisher Station. As noted on the agreement this covers our meters 2143 and 5077. This contract will become effective with the setting of the meter on our request for the Rankin/Toy well. Also, meter 5077 that we acquired from Mid East Oil Company needs to be added to our existing gas sales agreement and could be turned on immediately.

Please notify Dave Bucholz upon receipt of this letter so he can start on his end.

Sincerely,

SNYDER BROTHERS, INC.

Lloyd W. Cravener

LWC/lsc

Enclosure

equitable.rafferty.12.12.02.ltr.wpd

EQUITABLE GAS

200 Allegheny Center
Pittsburgh, PA 15212-5352
www.SRafferty@eqt.com

TEL 412.395.3268
FAX 412.395.3335

Date: September 23, 2002

Dear Producer,

As you may be aware, Equitable Gas Company ("Equitable") has made numerous enhancements to its Apollo District during the past two years in an effort to stimulate and increase local Appalachian production. During this time, Equitable has incurred significant costs in operating, maintaining and improving the distribution facilities in this area, without seeking reimbursement from local producers. Unfortunately, these investments cannot continue without some type of reimbursement. We have enjoyed an excellent working relationship with the producing community in the past and we regret that current economic conditions have forced us to take this action.

Equitable is willing to continue making improvements, change operating conditions where feasible and ultimately increase local Appalachian production if producers are willing to compensate Equitable for the costs incurred. Any producer that is not willing to compensate Equitable for these costs may be prohibited from flowing incremental volumes and may possibly be curtailed during low-demand periods. Equitable is seeking reimbursement from only those producers that will benefit from these on-going projects.

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(2). Fisher Station, Redbank Township, Armstrong County

Equitable will increase the discharge MAOP associated with the Fisher Compressor Station. Preliminary estimates indicate an additional 1,500 Mcf/day will flow from this improvement. Equitable is seeking reimbursement of $0.25/dth for use of this facility, in addition to any other fees already being assessed . This number may be revised once actual operating costs are determined.

Applies only to Snyder Brothers, Inc. meters #5077 and #2143.

Again, these charges are applicable only to those wells that are directly affected by these projects. Please call me at (412) 395-3268 if you have any questions or need additional information. Please call Fred Workman at (412) 395-3295 to confirm those meters that are affected by these projects.

If the above terms and conditions are acceptable, please sign and date in the space provided below and return to me by fax at 412-395-3335.

Accepted and Agreed to
this 26th day of November

By: [signature]

Title: President

Sincerely,

[signature]

Stephen C. Rafferty
Director, Gas Acquisition & Management

* Term: Will be effective through August 31, 2003 and renegotiated upon contract renewal.

ATTACHMENT – SCR - 3

RATE AGS - APOLLO GATHERING SERVICE (C)

APPLICABILITY

This rate schedule shall be applicable throughout the Apollo District for natural gas produced in and available for redelivery in the Apollo District.

AVAILABILITY

Service under this rate schedule is available to any party desiring to transport gas through the gathering system for redelivery into the Company's Apollo District provided that there exits: (1) a gas purchase agreement with the Company; or, a gas purchase agreement with a third-party having service under a Company transportation Rate Schedule has been executed; and (2) compliance with the provisions of this Rate Schedule and with all other provisions of this Tariff.

RATE

The applicable rate for this service shall be determined by negotiation. The Company shall retain a separate quantity of gas for fuel, loss and unaccounted for gas required to provide this gathering service.

TERM

The term for service shall be a minimum of one (1) year from the commencement of deliveries of gas supplies.

CHARACTER OF SERVICE

Equitable's only obligation under this Rate Schedule shall be to receive gas from any Appalachian receipt point and to permit that gas to flow against the existing pressure in Equitable's facilities. Equitable shall not be obligated to lower such line pressure by compression or otherwise to accommodate receipts from local Appalachian producers under this Rate Schedule.

Service under this Rate Schedule shall be subject to Operational Flow Orders pursuant to Section 11.13 of the Rules and Regulations of this Tariff. Nothing in this Rate Schedule shall limit Equitable's right to interrupt service or to take other action as may be required to alleviate conditions which threaten the integrity of its system.

(C) Indicates Change.

ATTACHMENT – SCR - 4

RATE AGS - APPALACHIAN GATHERING SERVICE (C)

APPLICABILITY

These rates shall be applicable throughout the territory served by the Company, i.e., Equitable and Apollo Districts. (C)

AVAILABILITY

Service under this rate schedule is available to any party desiring to transport gas through the gathering system for redelivery into the Company's service territory i.e., Equitable and Apollo Districts, provided that there exists: (1) a gas purchase agreement with the Company; or, a gas purchase agreement with a third-party; and (2) compliance with the provisions of this Rate Schedule and with all other provisions of this Tariff. (C)

RATE

The applicable rate for this service shall be determined by negotiation. The Company shall retain a separate quantity of gas for fuel, loss and unaccounted for gas required to provide this gathering service.

TERM

The term for service shall be a minimum of one (1) year from the commencement of deliveries of gas supplies.

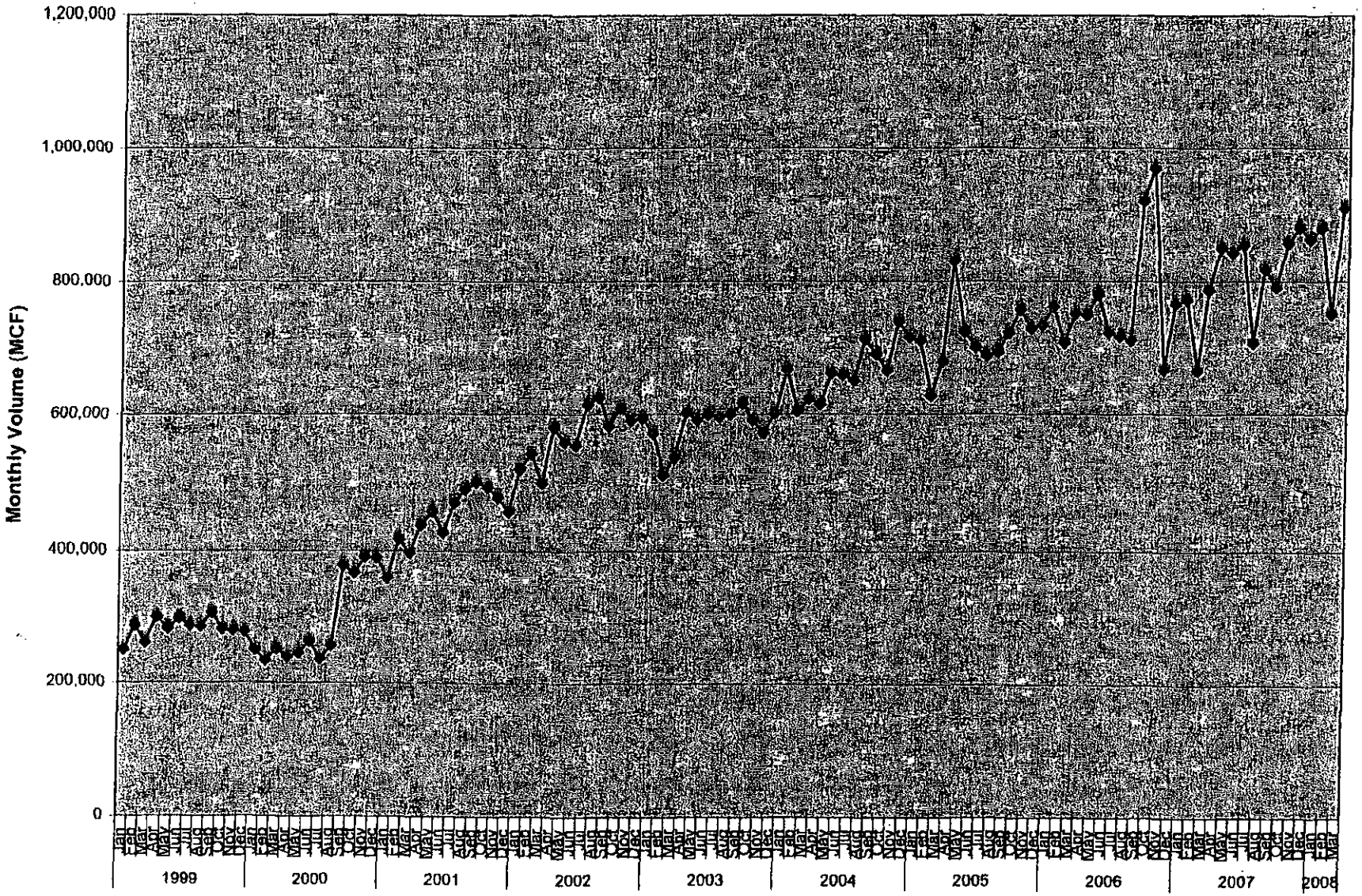
CHARACTER OF SERVICE

Equitable's only obligation under this Rate Schedule shall be to receive gas from any Appalachian receipt point and to permit that gas to flow against the existing pressure in Equitable's facilities. Equitable shall not be obligated to lower such line pressure by compression or otherwise to accommodate receipts from local Appalachian producers under this Rate Schedule.

Service under this Rate Schedule shall be subject to Operational Flow Orders pursuant to Section 11.13 of the Rules and Regulations of this Tariff. Nothing in this Rate Schedule shall limit Equitable's right to interrupt service or to take other action as may be required to alleviate conditions which threaten the integrity of its system.

(C) Indicates Change

ATTACHMENT – SCR - 5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1,000,000
800,000
600,000
400,000
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0
Monthly Volume (MCF)
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

ATTACHMENT – SCR - 6

Rafferty, Stephen

From: Rafferty, Stephen

Sent: Thursday, August 16, 2007 10:22 AM

To: 'mhillebrand@huntleyinc.com'

Cc: Keith Mangini

Subject: RE: follow-up items

Keith, Mike,
I appreciate your thoughts on this and your willingness to keep an open mind....just to give you a better understanding of where I am coming from...we are investing significant capital in our distribution/gathering systems (upwards of $20 MM next year). Although you think this doesn't benefit you directly, it does. The volumes coming in at Creighton/Springdale are creating operational issues for us, as you are aware. rather than curtailing you (and other producers north of you) I have proposed (and it has been approved) to invest $10 MM and move gas north into Dominion. This will minimize the gas that is currently being moved southward. The end result is you will be able to deliver more into our system. I recognize the gathering charges cause some concern, however, without the improvements we have made and without the ongoing investments, your volumes would have remained flat and possibly decreased because other producers would have continued to bring additional gas into the system...I think there are other opportunities to bring value to you, e.g, Boyce Park...look forward to discussing this more...I'm around all next week so pick a day and I can meet you (except Monday morning)...

ATTACHMENT – SCR - 7

IOGA NEWS

Independent Oil & Gas Association of Pennsylvania Winter 2005, Number 191

Producers Review Dominion Peoples Proposal

Producers on the Dominion Peoples system are reviewing documents for a proposed production enhancement service on the DP system. As of Friday March 4th over 60 percent of the local production volumes on DP had signed, accepted and returned the documents.

The Production Enhancement Service proposes to accomplish three distinct services. First, the PES will continue the operation of compressors originally contracted in 2002 to increase volume throughput on the DP system. The second service is the commitment of Dominion to spend an additional five million dollars over the next six years to further enhance the ability of the DP system to handle and move local production. This service will include a project review committee made up of local producers to be designated by IOGA as well as DP to review and approve which projects receive funding.

The third and final service is the installation and operation of dehydration equipment on Dominion Peoples with corresponding amendment of the company's gas quality standards. Under the contract proposal, Dominion Peoples will provide dehydration service and will allow local production to meet new less stringent water vapor standards than the contract requirement of less than five pounds per million cubic feet of gas. For meters delivering gas at pressures below 200 psi the standard will be water vapor saturation level of natural gas at 50 degrees F. For meters delivering at above 200 psi the standard will be water vapor saturation level of natural gas at 32 degrees F.

Participation in the service program is voluntary; however, Dominion Peoples has indicated its intent to enforce existing gas contract quality standards for non-participants.

IOGA became involved in negotiations on this proposal last summer. Dominion Peoples approached IOGA to notify the association of the company's intent to enforce the water vapor portion of gas quality standards for local production and transportation gas. The association suggested that compliance cost would be prohibitive and that the company's centralized facilities would be a more appropriate location for dehydration equipment.

Dominion Peoples countered that this approach would only make sense with the continued operation of compression on their system. The company was unwilling to negotiate a separate dehydration service, without the corresponding continuation of the original PEP project.

From these original positions, IOGA sought to negotiate the best deal possible to give producers an option other than meeting the five pounds per million standard from the gas purchase and transportation contracts. Members of the Association's Executive Committee negotiated on behalf of the association for the last six months. The resulting proposal was presented by DP and IOGA in early February at four meetings at the Four Points Sheraton in Greensburg. The Executive Committee of IOGA believes that they were successful in obtaining the most favorable terms from DP that were possible under the circumstances. Any individual producer that, for any reason, is interested in negotiating directly with

DP for the production of such producer is free to do so and is not bound by the proposal negotiated by the Executive Committee of IOGA.

Peoples is proposing to release long-term contracts of 25 years or longer duration for meters producing less than 10 mcf per day with a three-year transition to full market pricing. The company also agrees not to oppose an effort at the PUC by IOGA to have DP purchase natural gas at a BTU rather than MCF basis.

The agreement also prevents Dominion Peoples from instituting any gathering fees during the duration of the agreement as well as preventing a large-scale sale of the company's gathering assets. These are considered very important issues by the association.

Finally, IOGA will provide collection and administration services to Dominion Peoples relating to this project through a wholly owned subsidiary of IOGA. A subsidiary, known as Pennsylvania Independent Producers Service Company, will receive an administrative fee for such services that will, after payment of operating expenses, be distributed to IOGA and utilized for purposes consistent with IOGA's charter. IOGA will be responsible for default risk by marketers involved in the program billing.

IOGA is pleased to have been able to provide a reasonable option to producers on water vapor standards. In the end, it will be the individual producer's decision as to whether or not this is an option appropriate to their particular needs.

EPA Extends Permit Deadline

The US Environmental Protection Agency announced on March 7, 2005 that it is extending the regulatory deadline that would require Stormwater permit coverage for oil and gas construction activities that disturb between one and five acres of land until June 12, 2006. The current deadline would have expired on Thursday March 10, 2005. EPA states that the additional time will be used to "consider comments raised by stakeholders and to consider the economic, legal and procedural implications raised by controlling Stormwater discharges from these sites".

EPA is also proposing to develop a regulation by September 12, 2005 that would address the discharges from these oil and gas construction sites. The process will include at least one public meeting to discuss current industry Stormwater control practices.

IOGA of PA has been actively involved in this issue for years. IOGA holds that the exemption of oil and gas activities from NPDES permitting for oil and gas activities includes construction activities of oil and gas facilities. We believe that EPA has not only exceeded its regulatory authority on this issue, but actually broke the law by attempting to regulate a practice exempted by Congress. The exemption is found in 402(l)(2) of the Clean Water Act.

IOGA joined other industry associations as well as some individual companies challenging the EPA March 2003 rule, which for the first time in a final agency action required a Stormwater permit for construction activities at oil and gas sites.

EPA considers clearing, grading, and excavation operations at oil and gas sites to be "construction activities" not oil and gas activities. The industry challenge to the permit requirement is pending in the U.S. Court of Appeals for the Fifth Circuit, which covers Texas, Louisiana, and Mississippi.

In a related lawsuit the same trade associations are challenging EPA's construction general permit and fact sheet issued in July 2003. The oil and gas industry filed this challenge in the Fifth Circuit also, while construction industry groups challenged the permit in other federal courts. A lottery drawing under federal court rules assigned

the case to the Seventh Circuit covering Indiana, Illinois and Wisconsin.

The impact of Stormwater permitting in cost and delay could literally cripple the US producing industry. It is imperative that the association exhaust every possible avenue to overturn this abuse of regulatory authority.

IOGA PA Intervenes on CPA Tariff Issue

IOGA of Pennsylvania has intervened at the Pennsylvania Public Utility Commission against a proposal by Columbia Gas of Pennsylvania to add gas quality restrictions to the Columbia tariff. IOGA opposes the change which would restrict the company's flexibility to deal with quality related issues, particularly water vapor.

As with all distribution utilities, CPA has language in their gas purchase contracts relating to gas quality. As long as this remains a contract issue, the producer and utility have some flexibility to pursue options in dealing with gas quality. Adding the language to the tariff, however, essentially carves the standards in stone.

Gas quality issues are emerging as one of the most serious problems facing Pennsylvania producers. Concerns within the pipeline industry about pipeline integrity are driving the concerns. Potentially onerous standards by the US Department of Transportation to protect pipeline integrity have created a mood approaching panic in the pipeline industry.

IOGA PA Intervenes in CIPCO Rate Case

In January, IOGA PA joined with IOGA WVA in their intervention, before FERC, to oppose the Equitrans, L.P. rate case for a substantial increase on the CIPCO district gathering facilities and its rates for the Crooked Creek gathering system in Pennsylvania.

On November 30, 2004, Equitrans filed a limited Section 4 rate case before FERC, to become effective as of December 1, 2004. As far as we can determine, CIPCO intends to increase its retention from 5.4 % to 11.85 % and its gathering rate from $.538/DTH to $.62/DTH. This increase has affected producers in Fayette, Greene and Washington counties.

IOGA PA believes that CIPCO's proposed rates are exorbitant and that FERC should deny or reduce the increase. If IOGA PA is successful in its intervention, CIPCO will be required to refund any excessive amounts paid by producers retroactive to December, 2004.

Randy Rich of the law firm of Bracewell & Patterson, L.L.P. represents both IOGA PA and IOGA WVA.

Equitable Projects Reviewed

-Steve Rafferty, Equitable Gas Co.

In January 2004, Equitable Gas began a major capital improvement program in the Apollo district known as the Northern Asset Optimization Program. This Program is designed to increase pipeline capacity, lower pressures on the gathering system and ultimately increase local Appalachian production on the Equitable distribution system. This Program includes five separate capital projects, which are: the M67 Pipeline Renewal; the Creighton Compressor Station Upgrade; the Shoemaker Compressor Station Gas Dehydrator Replacement and Valve Automation; the Port Perry, North Versailles, interconnect; and the Saltsburg, Penn Hills, interconnect.

The first project relates to the M67 transmission line, which runs through Allegheny, Butler and Armstrong Counties, traversing many communities, connecting the Shoemaker Compressor Station to the Creighton Compressor Station in the Apollo District. Over the next few months, approximately 19,000 feet of this pipeline will be renewed throughout 11 various sections.

Once this renewed pipe has been placed in service, the entire 20 miles of the M67 system will have been upgraded to increase the Maximum Allowable Operating Pressure (MAOP) from 99 pounds to 150 pounds, which matches the maximum design outlet pressure of the Shoemaker Compressor Station.

At the same time the M67 pipeline is being renewed, major renovations are underway at Creighton Station. The two 1,350 horsepower Cooper engines at Creighton are being overhauled and rebuilt to "Clean Burn" specifications. In addition, all of the compressors, station piping, and coolers are being renovated and upgraded from 400 pounds MAOP to 500 pounds MAOP.

During the summer, Equitable began work at Shoemaker Compressor Station to replace the gas dehydrator and automate the yard valves. This work will facilitate the movement of additional gas on the suction side of Shoemaker Station.

Finally, the Port Perry and Saltsburg interconnects will facilitate the bi-directional movement of gas after it has been discharged from Creighton Station.

ATTACHMENT – SCR - 8

EQUITABLE
GAS
"Delivering Everyday Excellence"

Date: May 1, 2007

Dear Producer,

As you may be aware, Equitable Gas Company ("Equitable") has made numerous enhancements to the former Apollo District during the past several years in an effort to stimulate and increase local Appalachian production. During this time, Equitable has incurred significant costs in operating, maintaining and improving the distribution/gathering facilities in this area.

Equitable is willing to continue making improvements, change operating conditions where feasible and ultimately increase local Appalachian production if producers are willing to compensate Equitable for some of the costs incurred. Any producer that is not willing to compensate Equitable for these costs may be prohibited from flowing incremental volumes and may possibly be curtailed during low-demand periods. Equitable is seeking reimbursement from only those producers that will directly benefit from these on-going projects.

Specifically, Equitable has a project that will be undertaken in the next several months if demand warrants. This project is described in more detail below:

(1). Eshbaugh Interconnection with Dominion Transmission, Clarion County, PA
Install 10,000 feet of 8" steel mainline (1,000 psig MAOP). Install (2) 1,350 BHP units and a dehydration unit in an effort to facilitate the northwest movement of 10,000 – 12,000 dth/day into Dominion Transmission.

Equitable is proposing an *incremental gathering charge* equal to $0.25/dth. This incremental charge will be in addition to any other applicable charges currently being assessed. This incremental charge is specifically related to the project described above and will be assessed on only those meters that directly benefit from the completion of this project.

If the above terms and conditions are acceptable, please sign and date in the space provided below and return to me by fax at 412-395-3335.

Accepted and Agreed to
this _____ day of _____

By: _____

Title: _____

Sincerely,

Stephen C. Rafferty,
Vice-President, Utility
Asset Management

Rafferty, Stephen

From: Rafferty, Stephen
Sent: Thursday, May 31, 2007 12:00 PM
To: 'Lloyd Cravener'
Subject: RE: INTERCONNECT

I met with Kriebel yesterday....we are moving forward with the project as I indicated in our meeting. The steel pipe is being coated at Durabond as we speak and should be ready for installation mid-June...compressors and de-hy are on order...

-----Original Message-----
From: Lloyd Cravener [mailto:lloyd.cravener@snydercos.com]
Sent: Thursday, May 31, 2007 10:57 AM
To: Rafferty, Stephen
Cc: Dave Snyder
Subject: INTERCONNECT

Steve,

Dave Snyder has spoken to Jim Kriebel recently concerning the Northern interconnect we met on the other day. He indicated that Kriebel signed the same intentional letter that we did. This should spur the approval of a capital expenditure for the project. We would like to see this happen so we could be flowing better by the end of summer if possible. Please give me an update.

Lloyd

ATTACHMENT – SCR - 9

Rafferty, Stephen

From: Rafferty, Stephen
Sent: Friday, January 26, 2007 10:06 AM
To: 'MBauer@kriebelgas.com'
Subject: Re: Line in Armstrong County

I'm in new york.... I'll call you monday to discuss

Sent using BlackBerry

-----Original Message-----
From: Milissa Bauer <MBauer@kriebelgas.com>
To: Rafferty, Stephen <SRafferty@eqt.com>
Sent: Fri Jan 26 09:30:03 2007
Subject: RE: Line in Armstrong County

Yes. Since there has been no relief in the system for almost 8 months, and I expect that it will be at least 6 months after the merger goes through before this system can be upgraded to address the issues, I need to move this gas somewhere. Prior to the MAOP problem with the system, we were able to easily move the gas on Apollo. We have the Powers meter setting on Equitrans currently. With the current size of that meter, I can probably get 300 of the 500 to it pretty easily. If we up sized that meter, I can probably get the rest of the gas to it also. However, I would be losing about $1.00 per mcf. That was why I wanted to see if we could get the shrink or gathering down. Do you think that is possible?

Milissa Bauer
Vice President of Administration
(814) 226-4160, ext. 115
-----Original Message-----
From: SRafferty@eqt.com [mailto:SRafferty@eqt.com]
Sent: Thursday, January 25, 2007 7:35 PM
To: Milissa Bauer
Subject: Re: Line in Armstrong County

Is this the same gas as fisher?

Sent using BlackBerry

-----Original Message-----
From: Milissa Bauer <MBauer@kriebelgas.com>
To: Rafferty, Stephen <SRafferty@eqt.com>
Sent: Thu Jan 25 13:58:19 2007
Subject: RE: Line in Armstrong County

Steve:
We have gas backed up on the Apollo system in Armstrong County. I would estimate it is about 500 mcfs per day. We may consider going to Equitrans if there is room to move on the retainage percent. Is that possible or are they pretty much etched in stone?

Milissa Bauer
Vice President of Administration
(814) 226-4160, ext. 115

-----Original Message-----
From: SRafferty@eqt.com [mailto:SRafferty@eqt.com]
Sent: Thursday, January 25, 2007 10:23 AM
To: Milissa Bauer
Subject: Re: Line in Armstrong County

ATTACHMENT – SCR - 10

Dominion Peoples

Production Enhancement Agreement

PA PES/Project Review

Committee Update

Project Review Committee

- Part of Dominion Peoples/IOGA PA PES Terms
- Charter
  - Three IOGA representatives
  - Three Dominion Peoples representatives
- Identify and implement $5M worth of system enhancements over 6 year term of agreement
- Committed $3M through 2008
- Spent to date - $1,240,000
- Current Fee Structure:
  - Gathering & Distribution (under 200 psi) is $.27
  - Transmission Systems (over 200 psi) is $.14

Dominion

Committee Members

- IOGA Representatives
  - Don Sprouse - Chairman
    - Kriebel Gas
  - Len Paugh
    - Range Resources Appalachia LLC
  - Craig Neal
    - Dominion Exploration & Production Inc
- Dominion Representatives
  - Jim Gray – Vice Chairman
    - Supervisor Delivery
  - Frank Milfeit
    - Manager, Delivery Operations
  - Mike Warcholak
    - Supervisor Delivery Operations

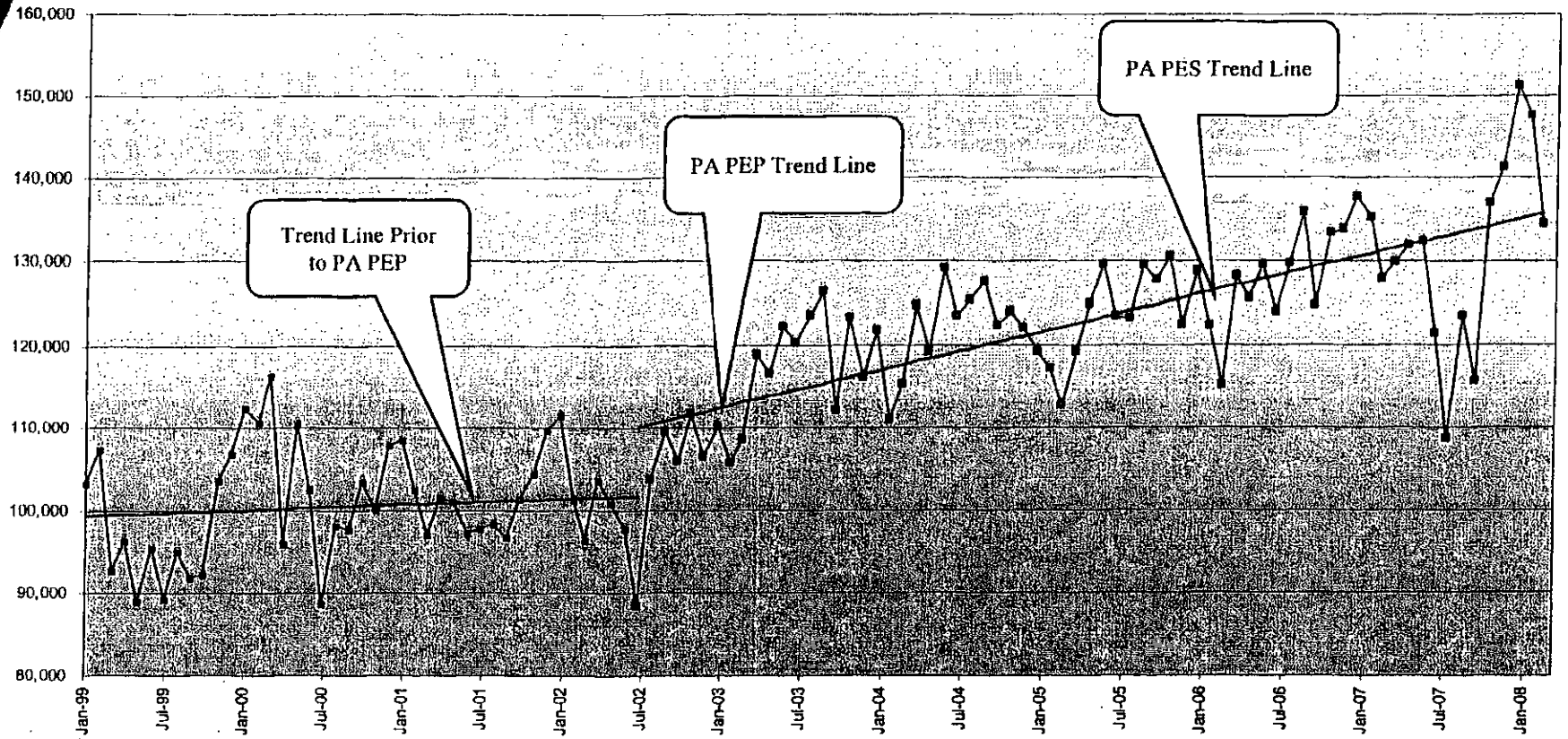
Dominion

Criteria for Project Review

- Number of producers impacted
- Volumes impacted
- Cost/Incremental Volume
- Geographical location in Pennsylvania
- Overall economic impact to the Producer and Dominion
- Implementation time frame
- Preference for local production for summer/winter customer base load

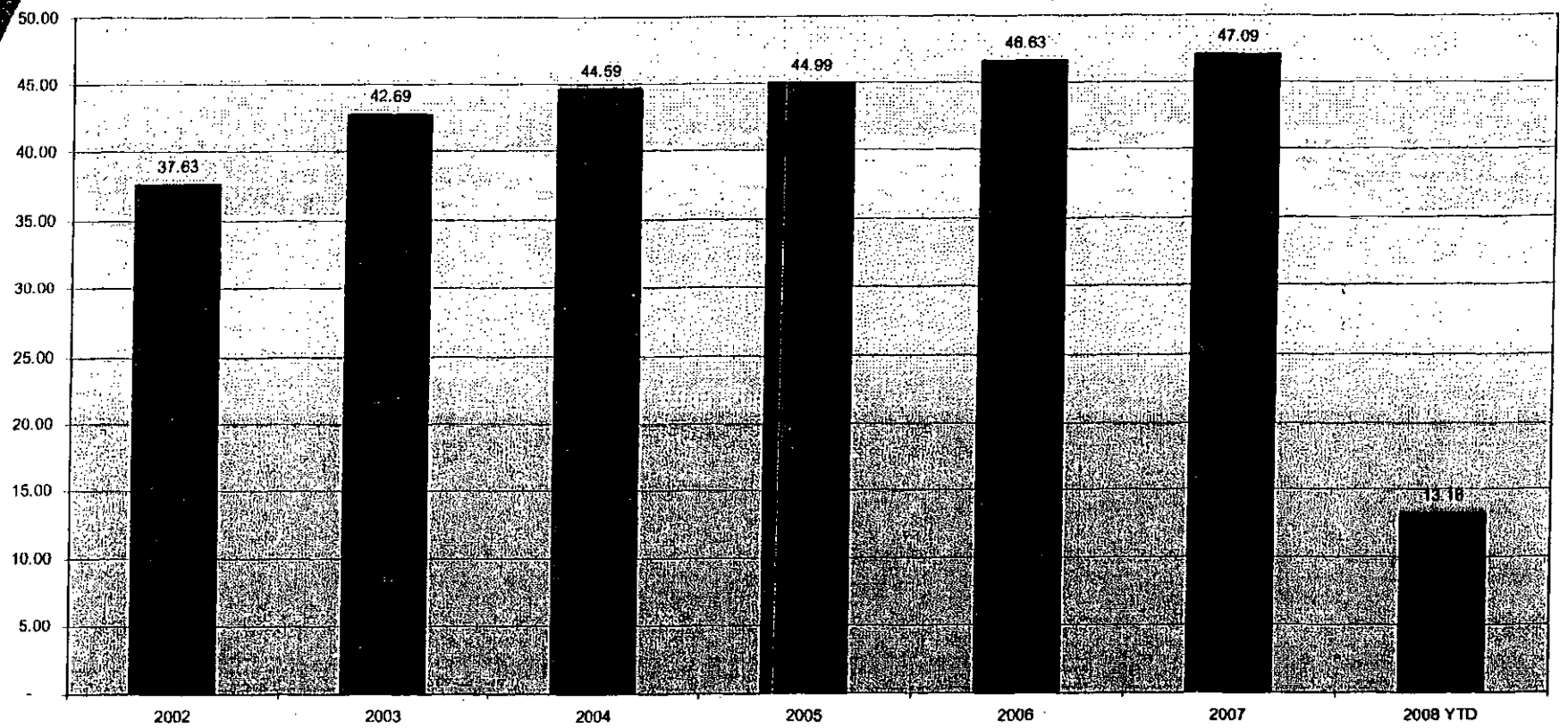
Dominion

Dominion Peoples Production Volumes



Dominion

Dominion Peoples Production Volumes BCF/Year



Dominion

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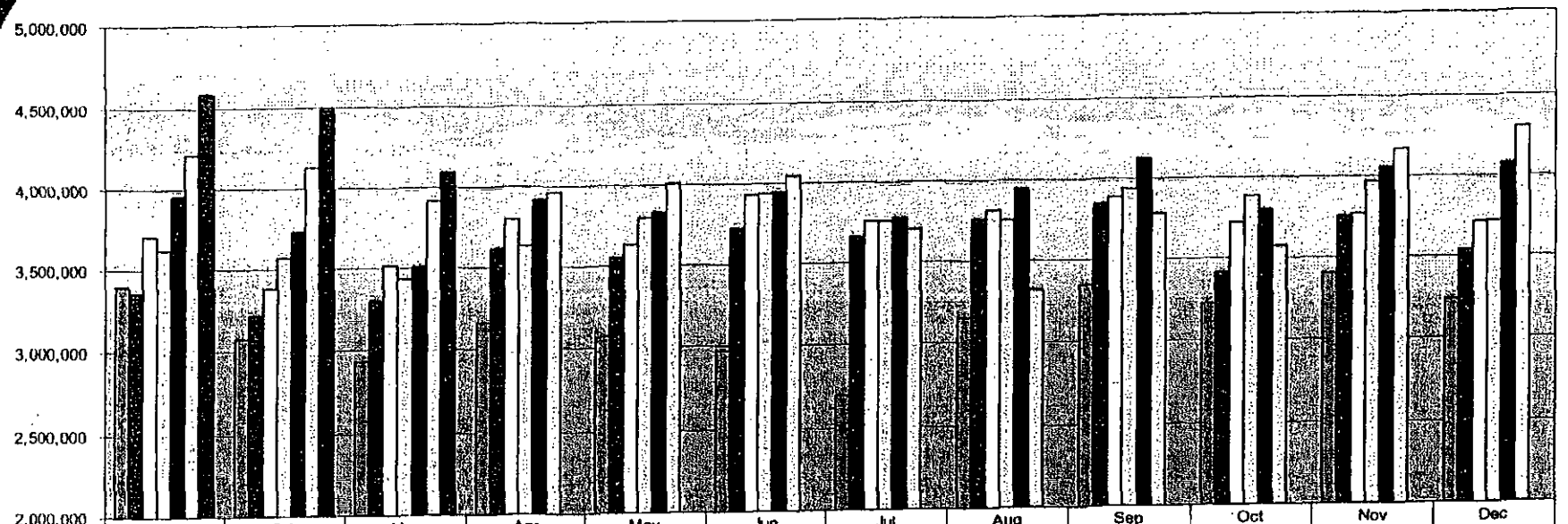

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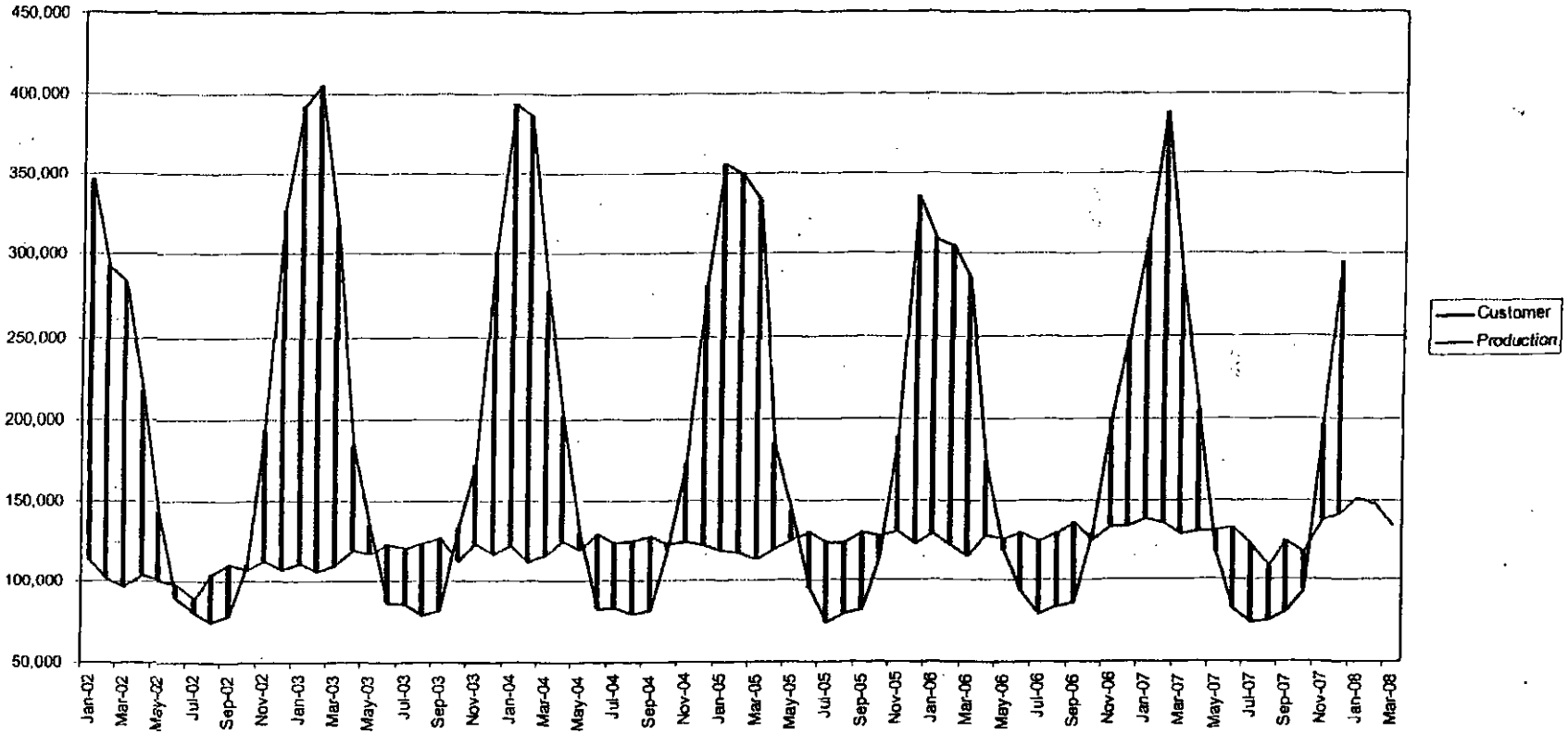
2003	3,349,391	3,213,744	3,299,303	3,613,541	3,542,658	3,719,200	3,658,990	3,759,597	3,840,327	3,407,206	3,750,723	3,531,542
2004	3,704,490	3,373,818	3,508,511	3,795,271	3,623,970	3,926,285	3,756,540	3,810,740	3,879,562	3,722,740	3,769,873	3,715,277
2005	3,621,816	3,563,228	3,427,399	3,624,825	3,798,349	3,938,496	3,755,133	3,748,315	3,935,889	3,884,869	3,969,911	3,722,138
2006	3,949,000	3,724,285	3,500,581	3,909,428	3,826,867	3,942,295	3,777,425	3,943,446	4,127,595	3,797,317	4,061,192	4,074,397
2007	4,212,767	4,127,775	3,915,661	3,961,488	4,003,252	4,046,204	3,700,769	3,310,671	3,779,386	3,564,211	4,174,044	4,296,802
2008 YTD	4,585,794	4,483,457	4,091,303									

Dominion

Customer Load Volumes vs. Production Volumes



Dominion

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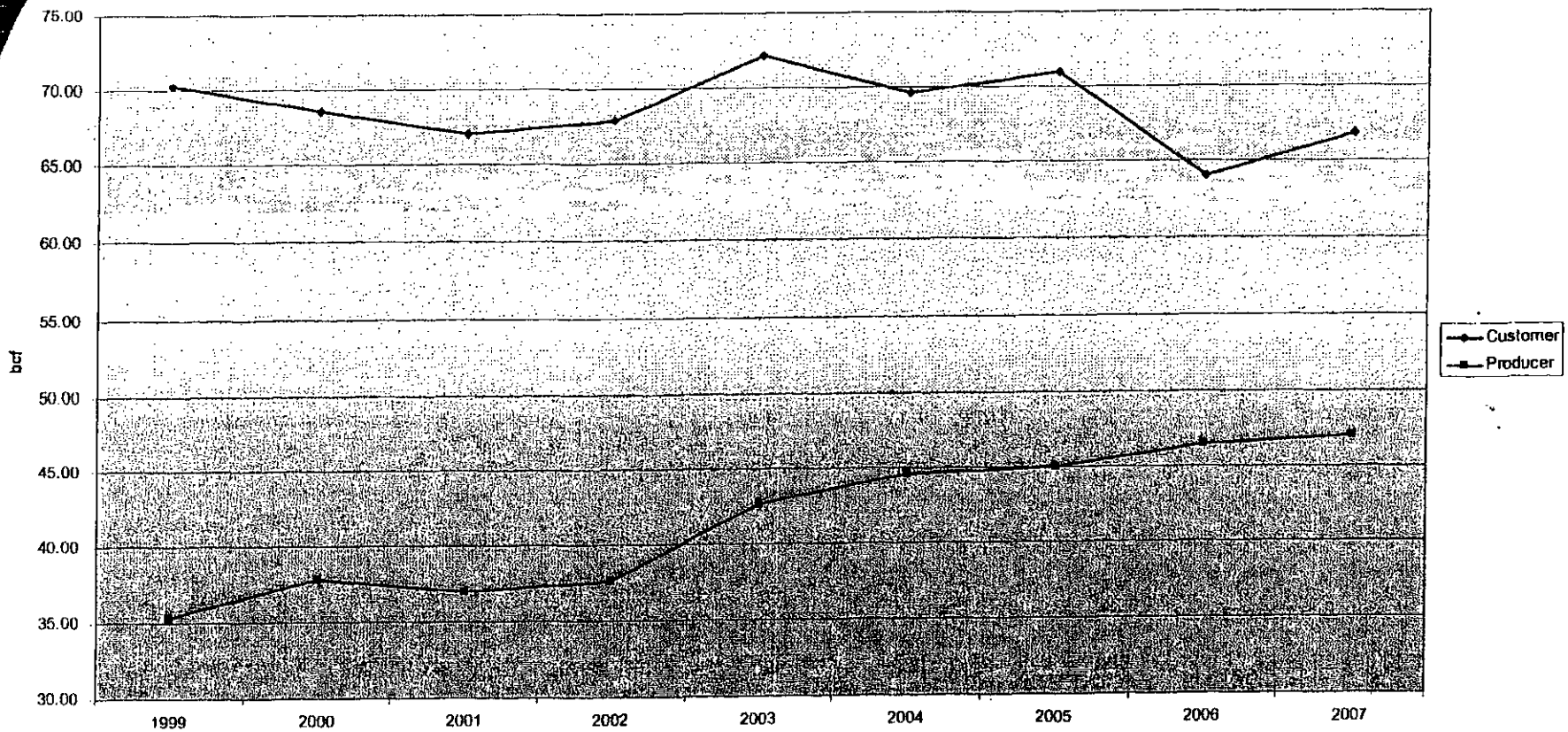
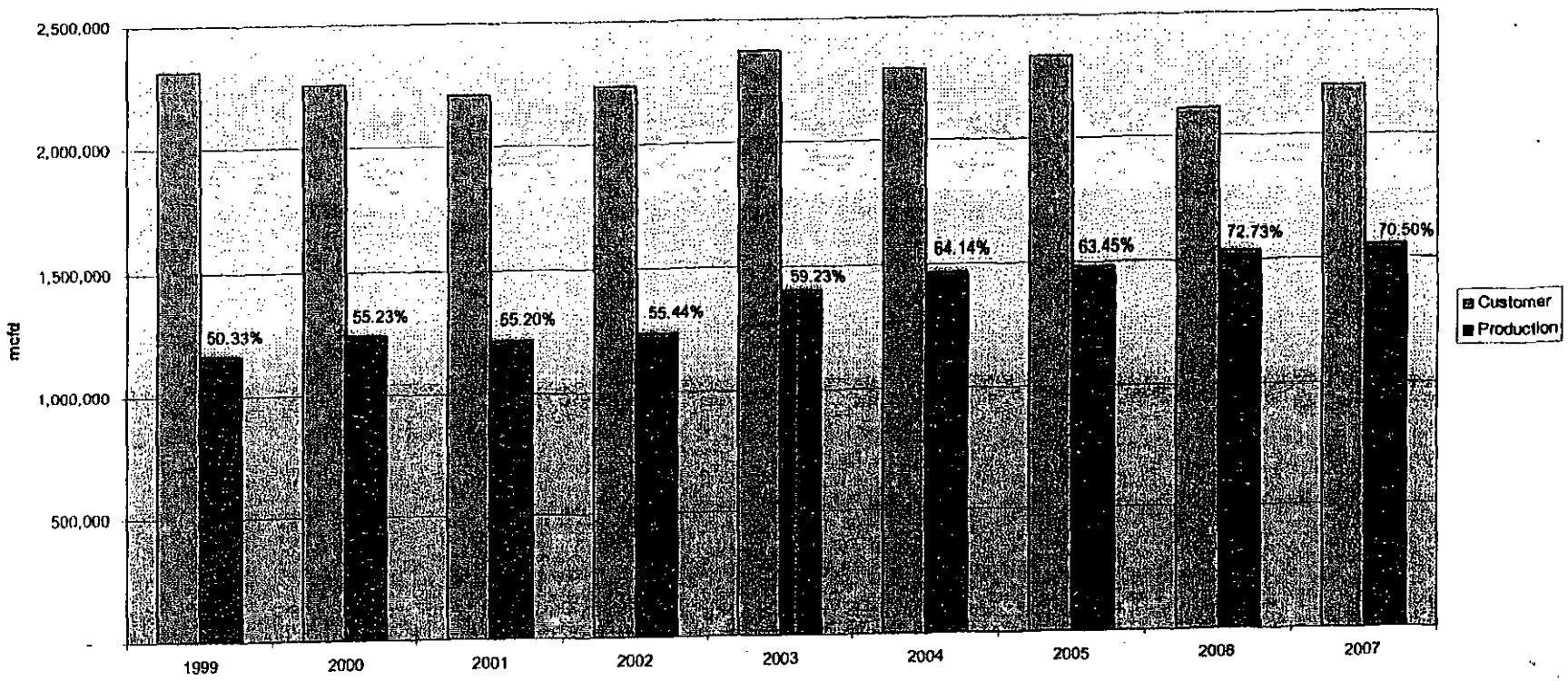


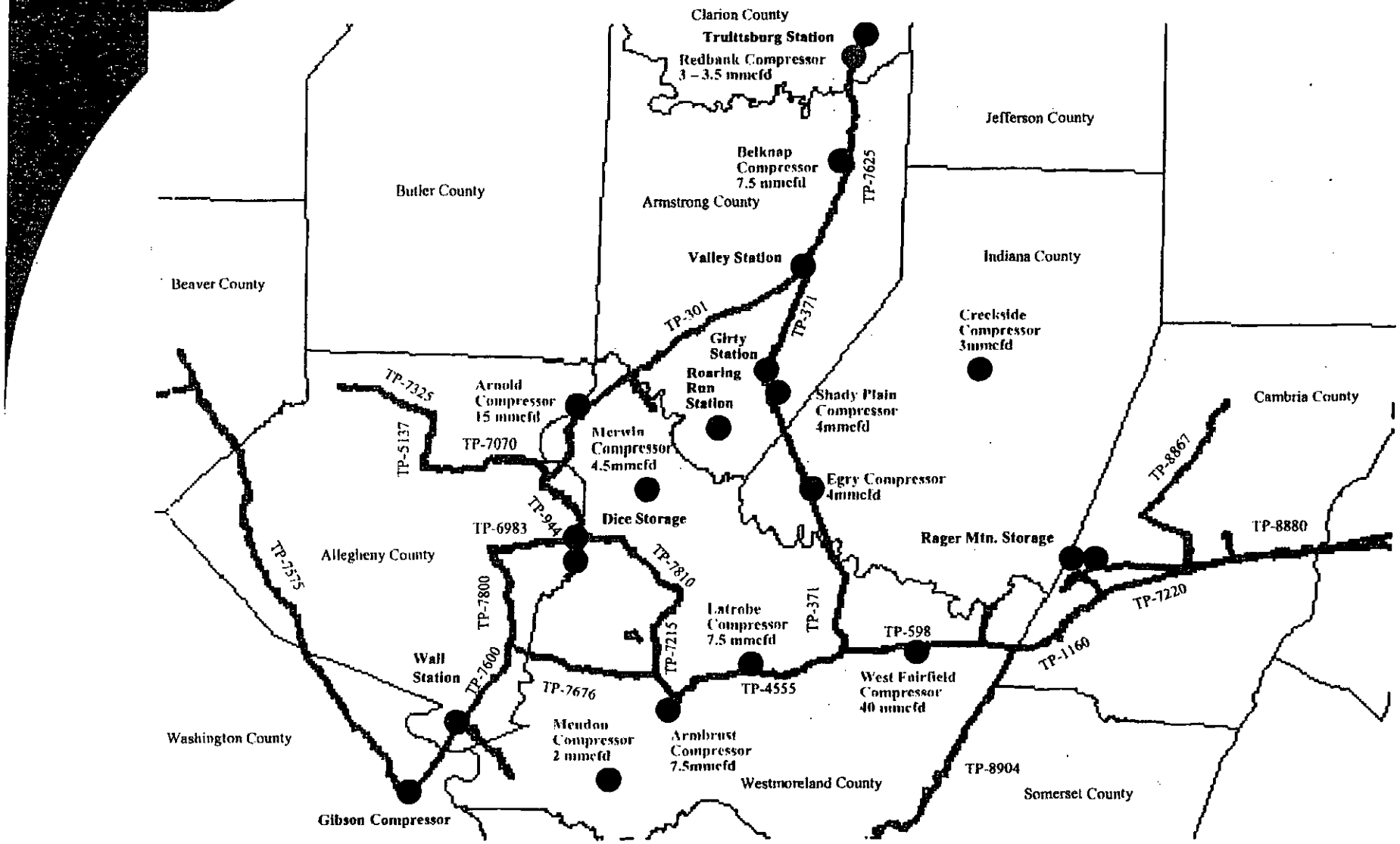
Dominion

Percentage of Production Volumes vs. Customer Load



Dominion

Dominion Peoples Map



Dominion

Pipeline Integrity Projects

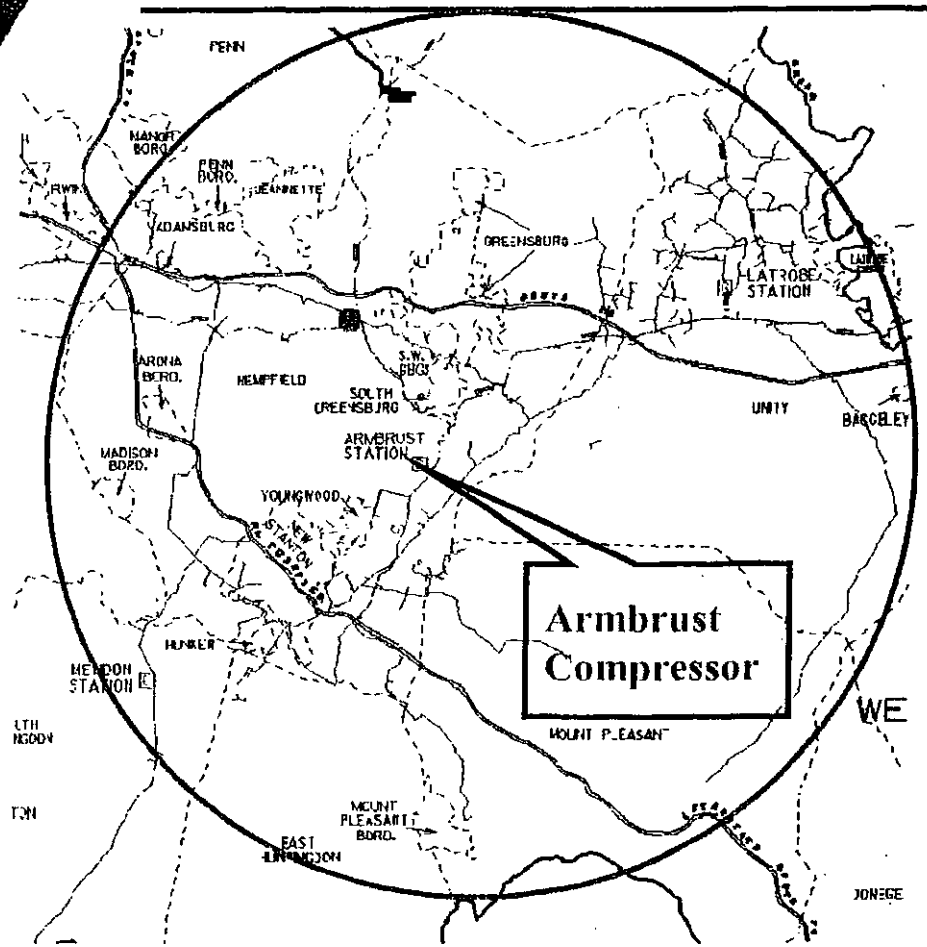
- 2008 Pipeline Integrity Projects
  - Installation of Dehydration Stations @ the following Compressor Stations
    - Armbrust
    - Latrobe
    - Belknap
    - Egry
    - Redbank
  - Installation of Smart Pig Traps on TP-7676 & TP-598.
  - Cleaning & Smart Pigging of TP-7676 & TP-598
    - Dominion Peoples will decide if Pipelines will be Pigged in 2008
  - **The Number one of Goal of Dominion Peoples is to move more Production Gas**

Dominion

Dominion

PA PES Projects Completed or in Progress

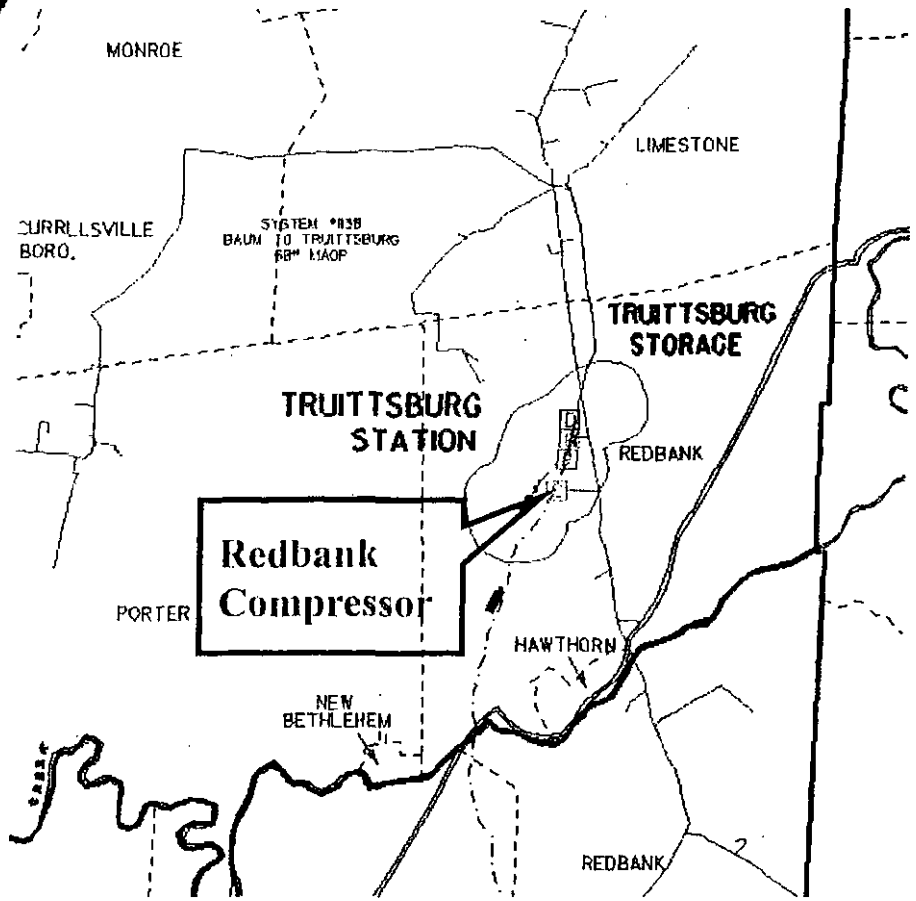
Ambrust Compressor Upgrade



- Replaced existing Armbrust compressor station unit with 945 HP unit
- Increase throughput from 4.5 mmcf/d to 7.5 mmcf/d
- 45 producers impacted
- $897,000 to replace unit
- Completed September 2006
- Cylinders replaced to buck higher discharge pressures. Completed June 2007.

Dominion

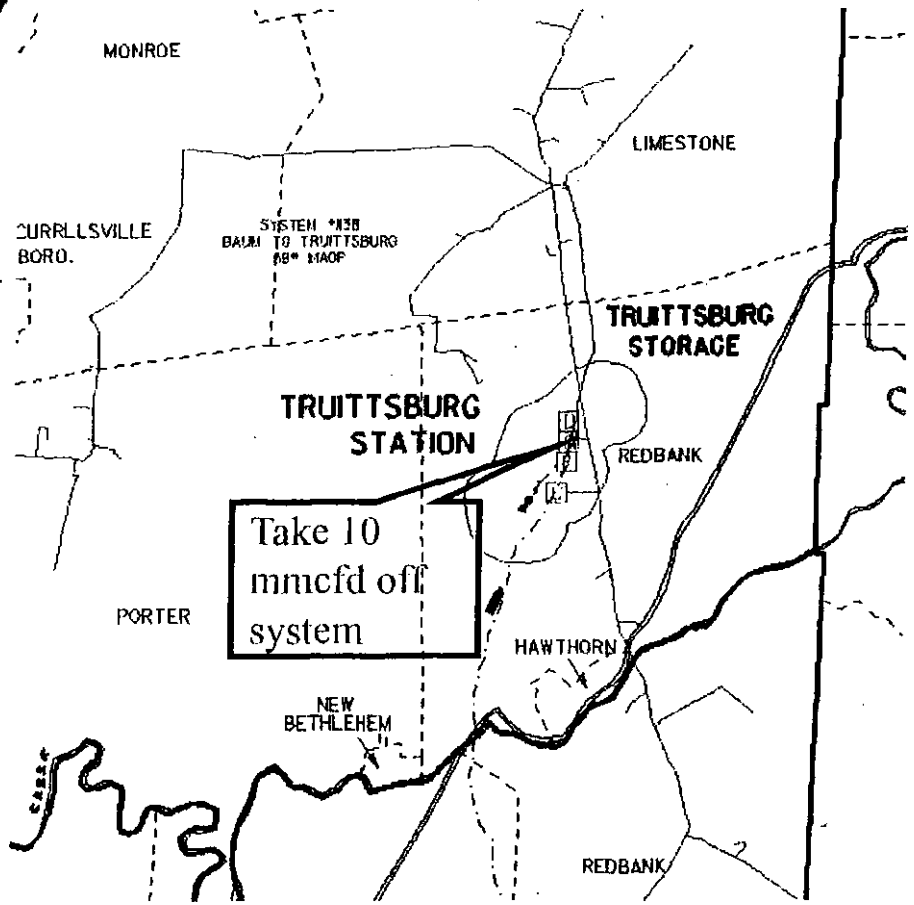
Redbank Compressor



- Install new compressor station utilizing old Armbrust unit to move up to 3.5 mmcf/d of gas out of 48# system into TP-7625
- 60 producers impacted
- $1.2 million proposed budget
- Project is currently under construction
- Projected completion date is late Spring of 2008

Dominion

Off System @ Truittsburg



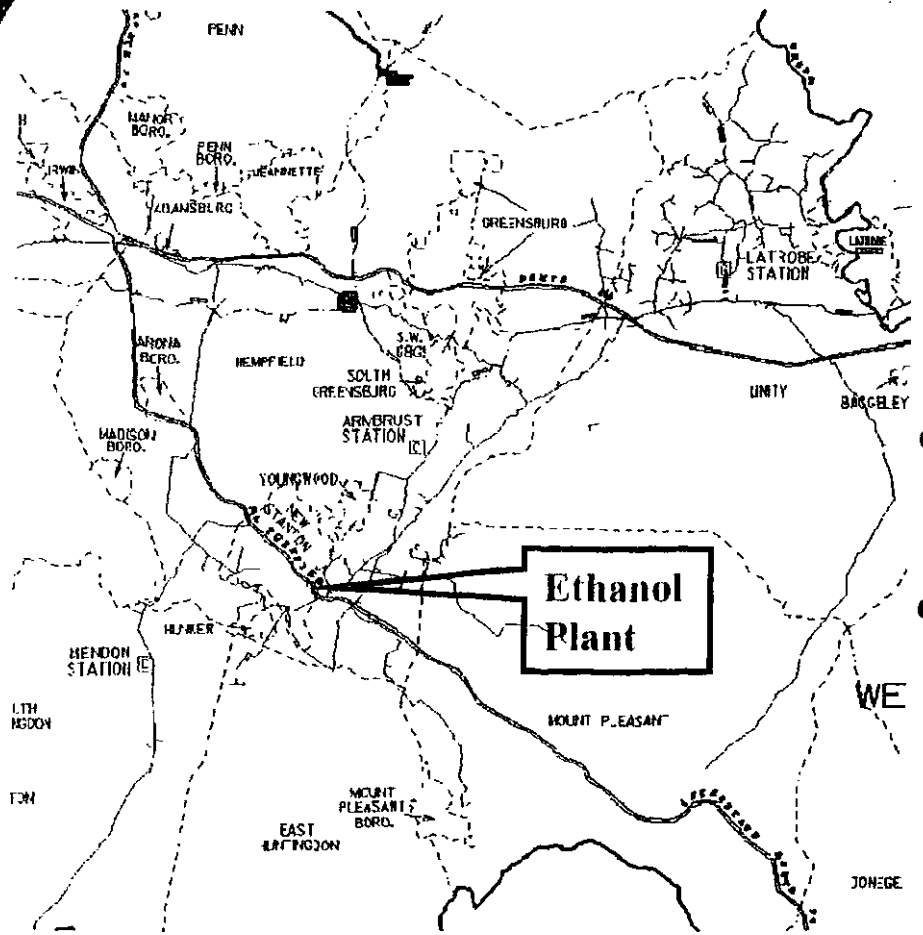
- Take 10 mmcfd off system to DTI
- Offered monthly to marketers as interruptible service for bid
- All producers impacted
- No Cost to PA PES
- Goal is to have Available all year round
- Project completed 4/2006

Dominion

Dominion

Investigating Future Projects

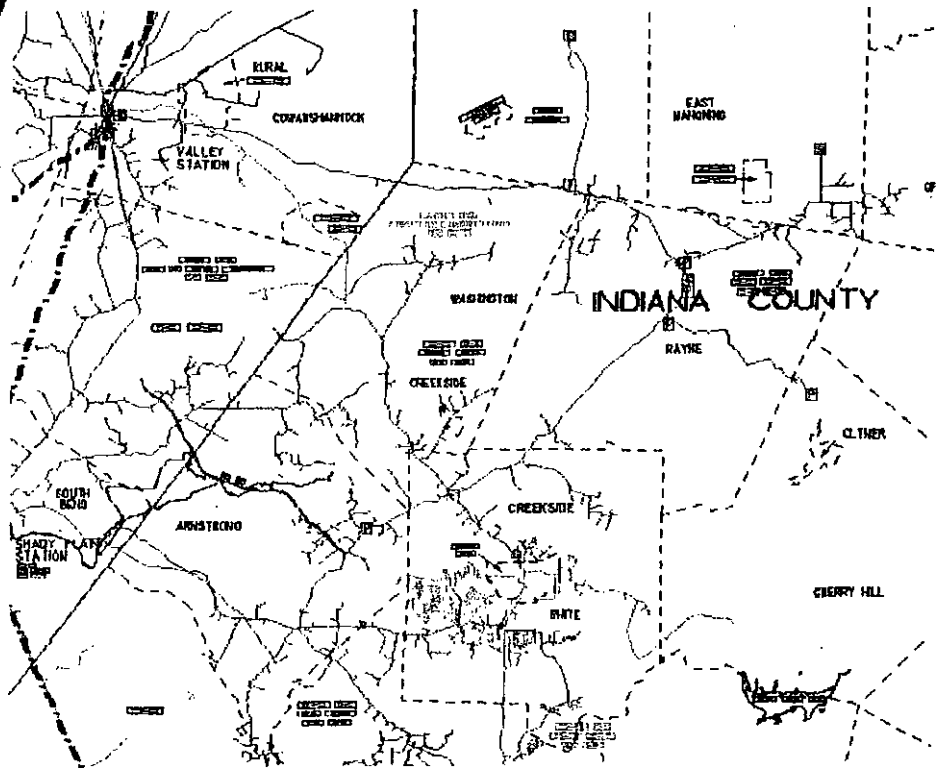
New Load on Dominion Peoples



- Dominion Peoples recently secured the Commonwealth Renewable Energy Ethanol Plant
- Creates an outlet for up to 20 mmcfd
- Third quarter 2009

Dominion

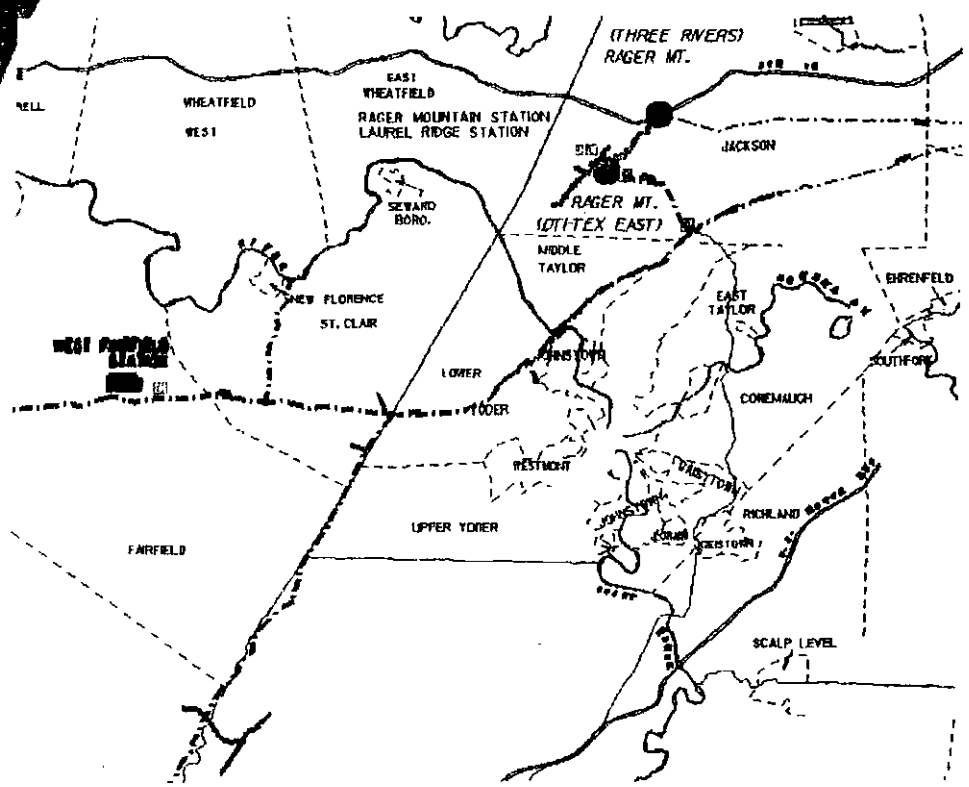
System Enhancements to Girty Indiana Loop



- Install Drips to remove fluids
- Pig lines that currently have Pig Launchers and Receivers to improve gas flow
- 64 producers impacted

Dominion

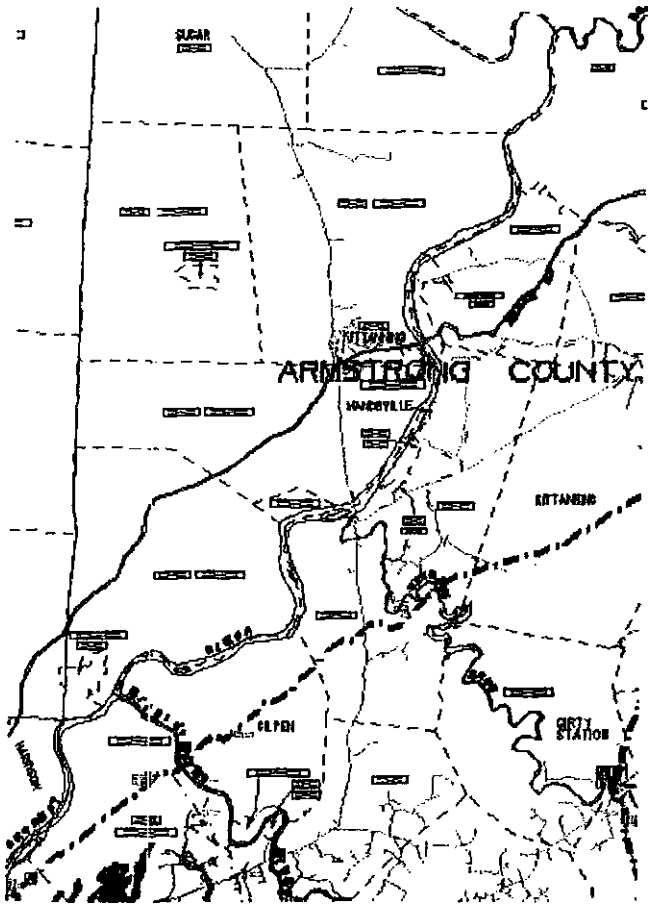
Laurel Ridge



- Laurel Ridge
- Install new Compressor to move 12-16 mmcfd into storage during summer months
- Reduces the need for Interstate Supply to fill storage pool
- All producers impacted

Dominion

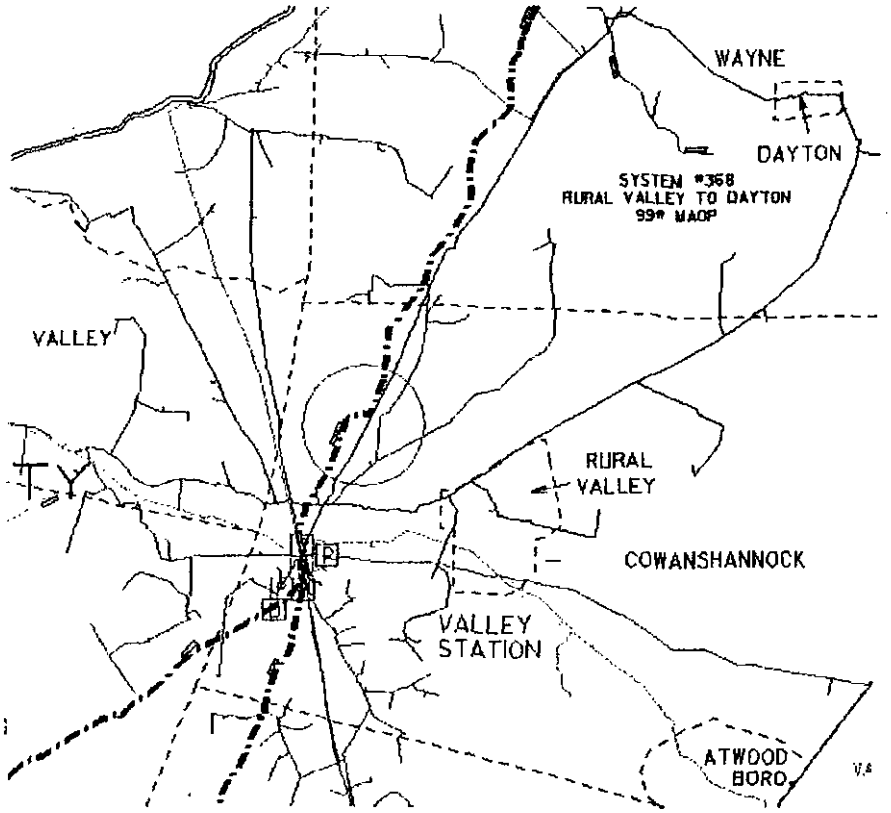
Kittaning/Ford City System



- Performing Load Study to confirm Eljer volume
- Winter Production as high as 1.7mmcfd & Summer Production as low as .9 mmcfd
- 38 producers impacted

Dominion

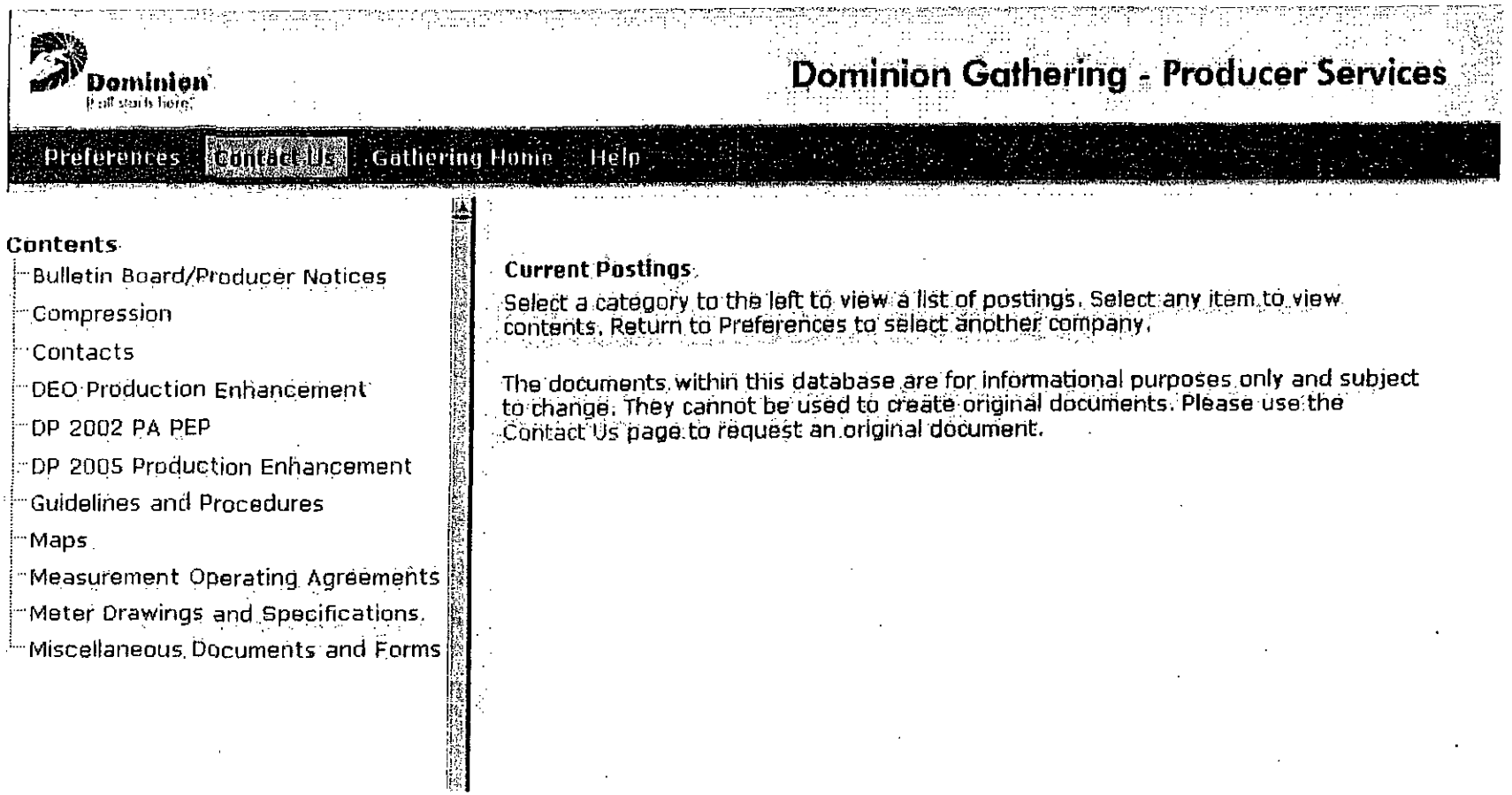
DTI Project North of Valley



- Deliver 25mmcfd to DTI
- All producers impacted

Dominion

Dominion Gathering – Producer Services Website



Dominion

Dominion Gathering – Producer Services Website

DOMINION PEOPLES PRODUCTION STATION STATUS

AS OF: 5/1/08

STATION	RUNNING	COMMENTS:
Armbrust	YES	
Arnold	#2 ON	#1 Not Needed.
Belknap	YES	Unit #2 is back on-line.
Creekside	YES	
Egry	YES	
Girty	#1, #2, #3, #4	All units are operating.
Latrobe	YES	
Mendon	YES	
Merwin	YES	
Roaring Run	YES	
Shady Plain	YES	
T'Burg Field	YES	
T'Burg Storage	OFF	Not Needed
Valley	#3, #4, #5	Unit #1 is down as of 4:30 for exhaust leak repairs. Estimated 5 – 7 days.

OTHER NOTES:

UPCOMING MAINTENANCE:

1). Merwin will be shut down for 5 – 7 days in late May for a routine compressor inspection and repairs.

2). Valley #1 was shut down on Wednesday April 30th to repair some exhaust leaks. Power heads were removed for proper alignment with the header.

3). Valley #5 will be down in late-May for carbon cleaning. Estimated 3 – 5 days.

Dominion

Tap Requests & Market Inquiries

- Please Contact Dave Fritz Business Development Representative for any new tap requests or market inquiries @ (724) 292-3413.

Dominion

Questions/Concerns

Dominion

Dominion Peoples

Production Enhancement Agreement

PA PES/Project Review Committee Update

Project Review Committee

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- Charter
  - Three IOGA representatives
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Dominion

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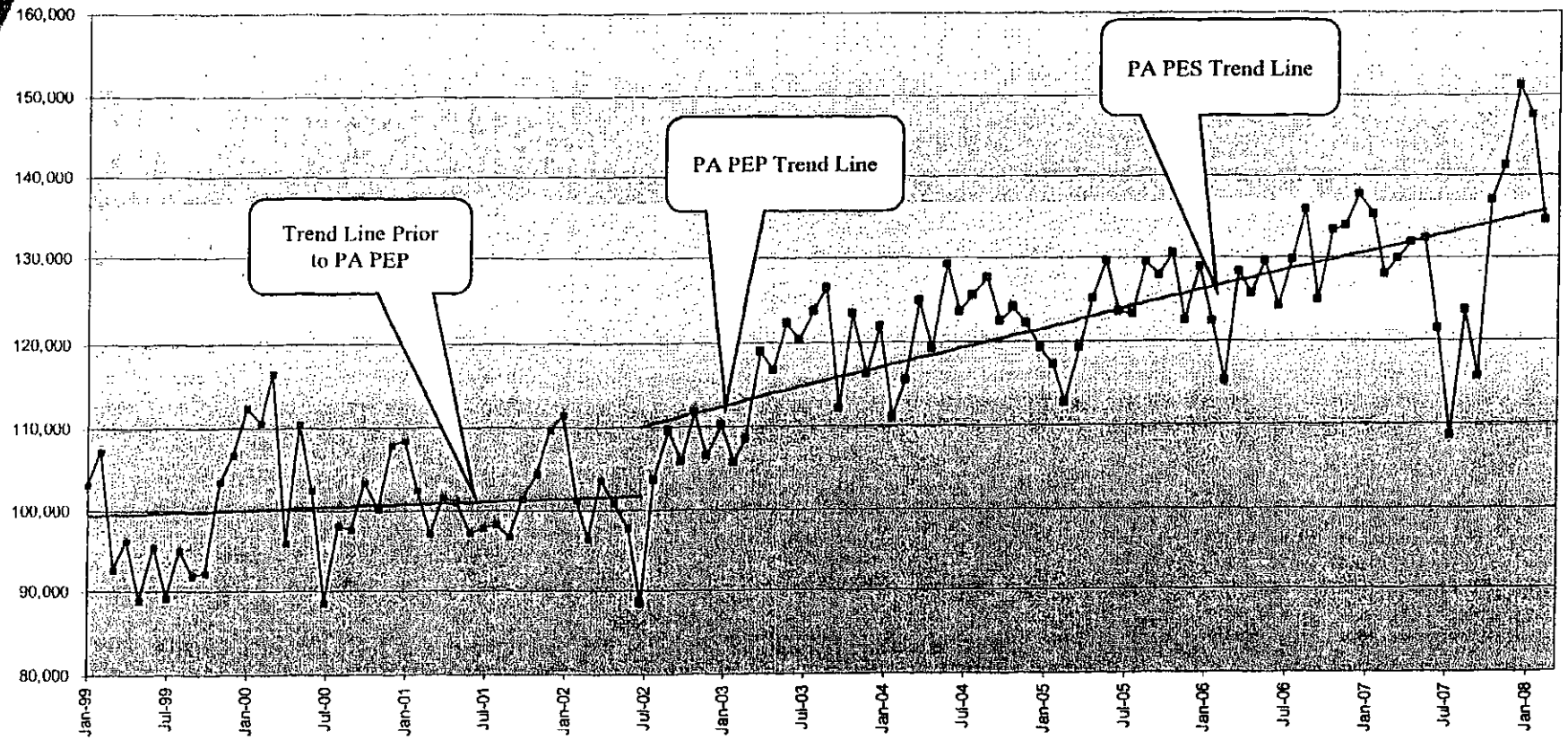
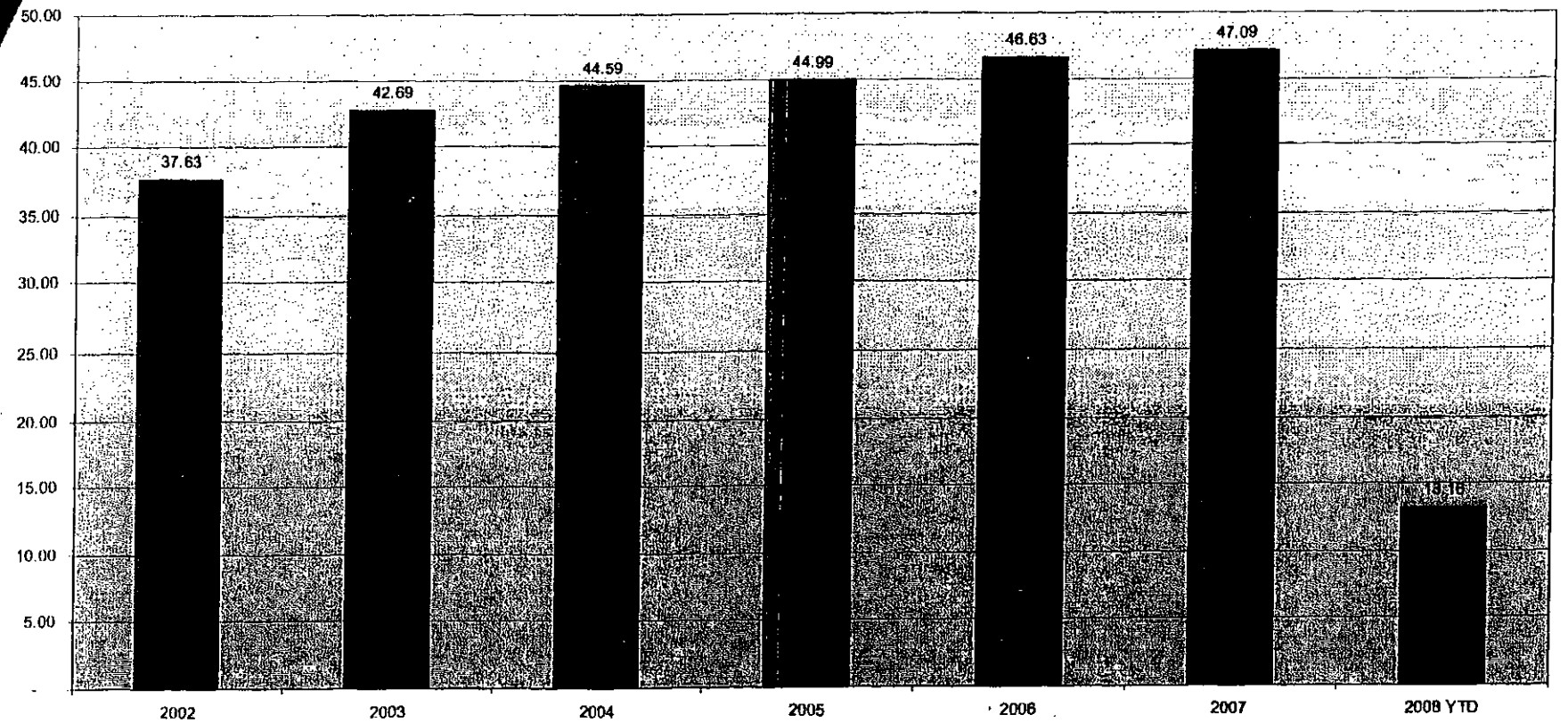
Dominion

Dominion Peoples Production Volumes



Dominion

Dominion Peoples Production Volumes BCF/Year



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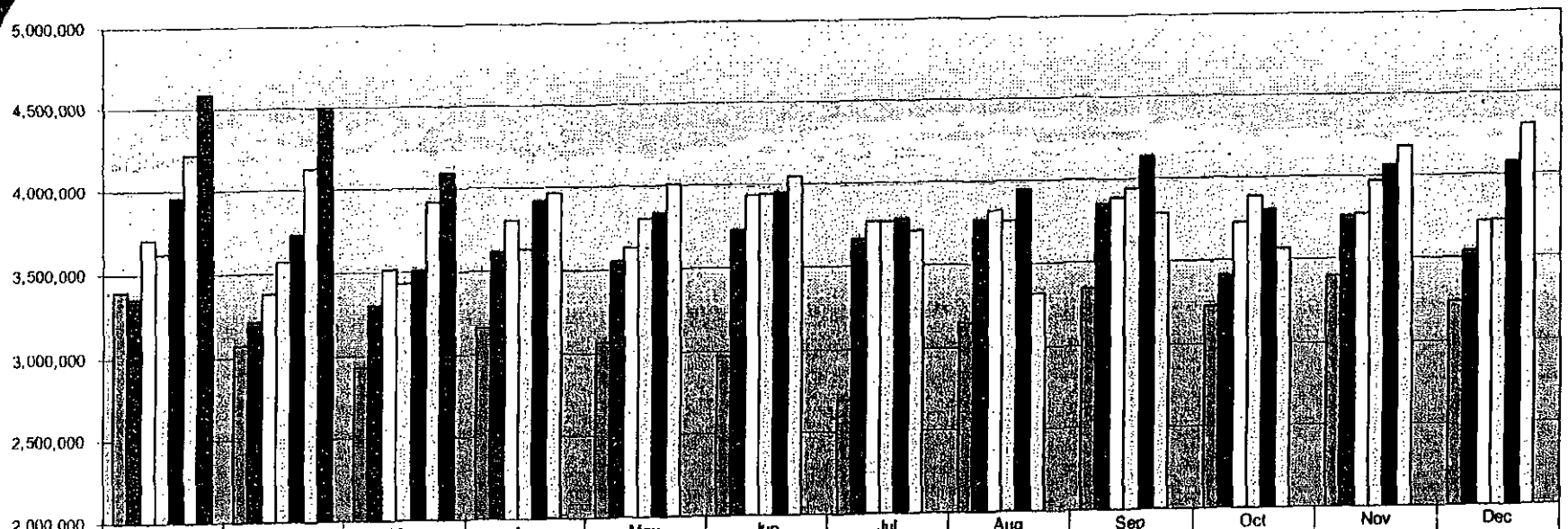

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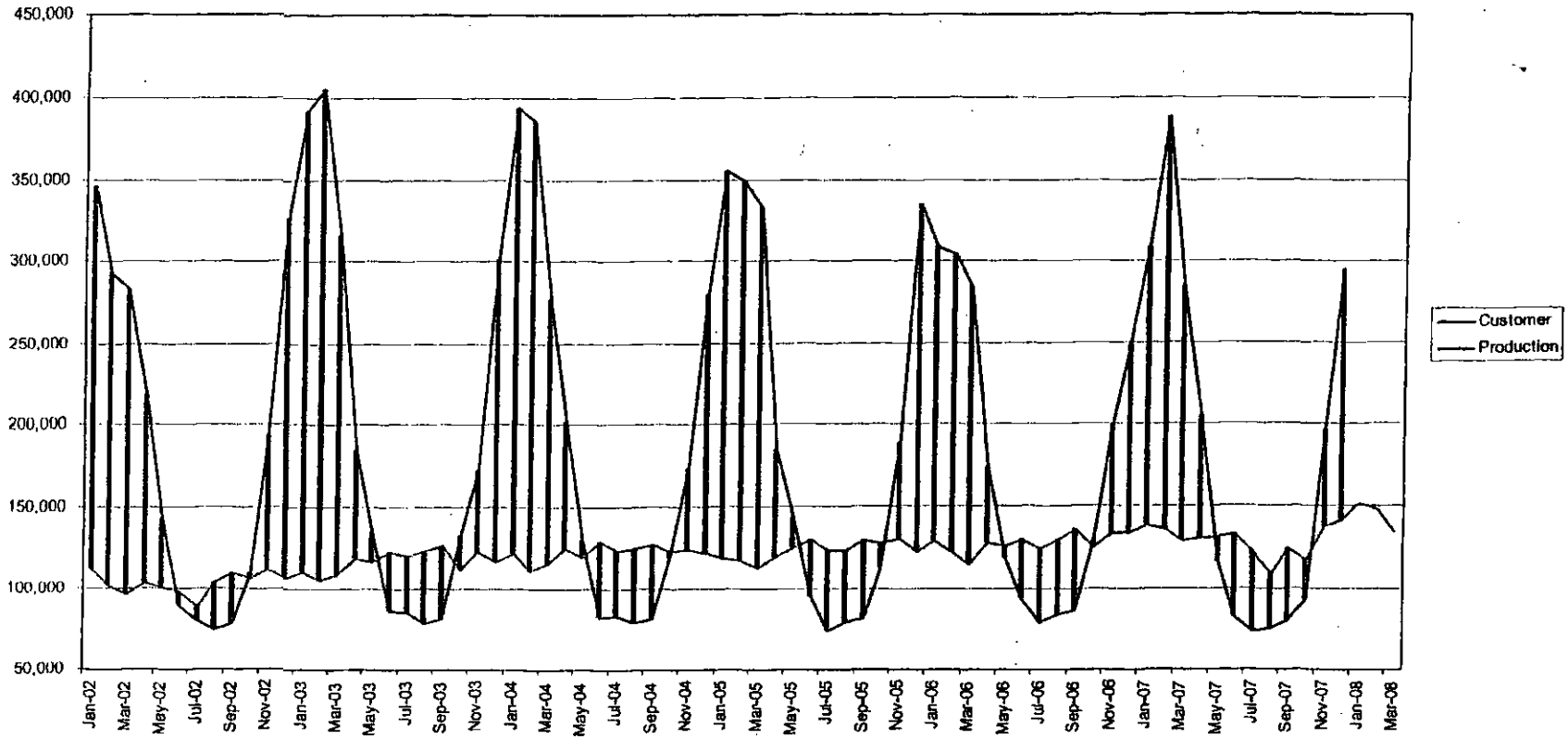

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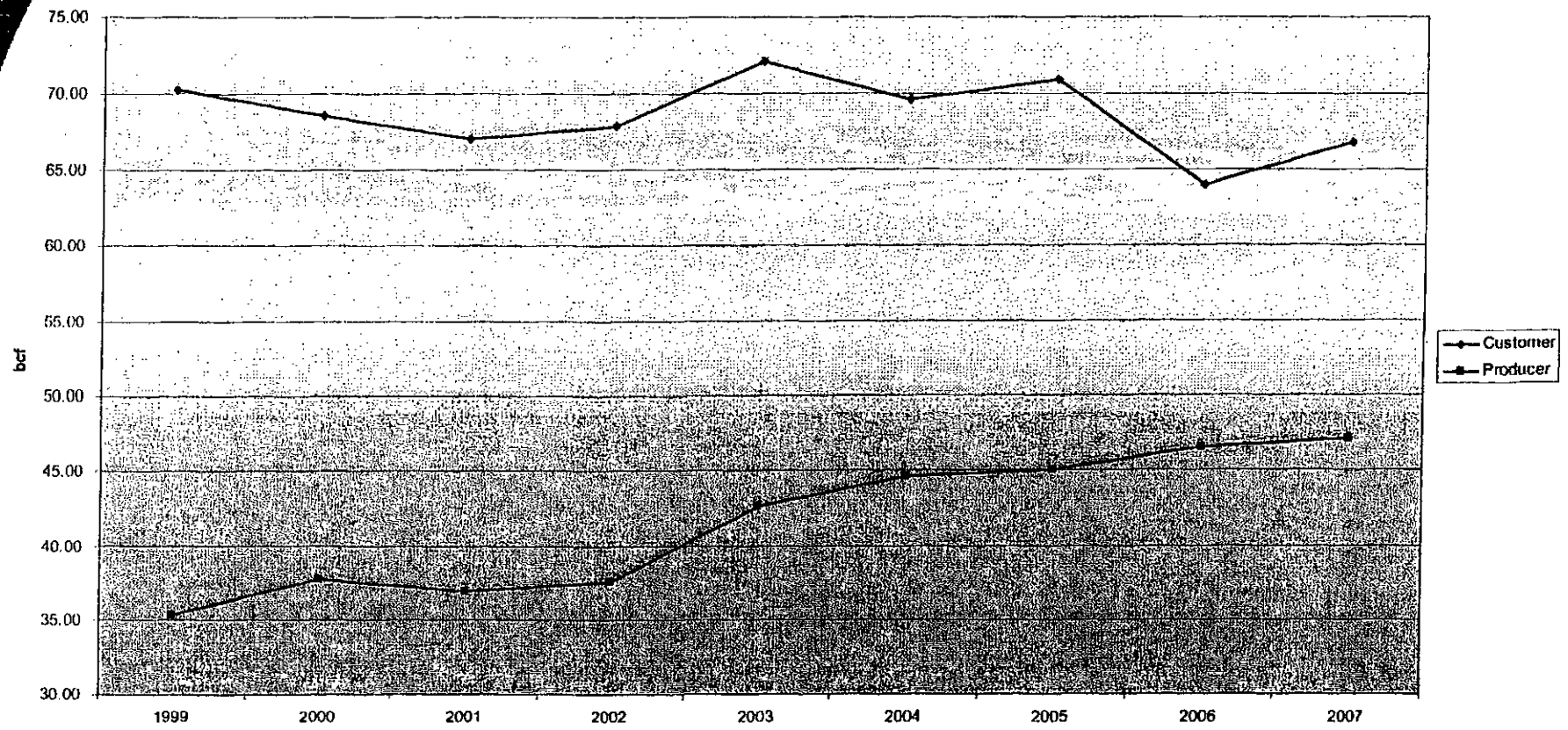
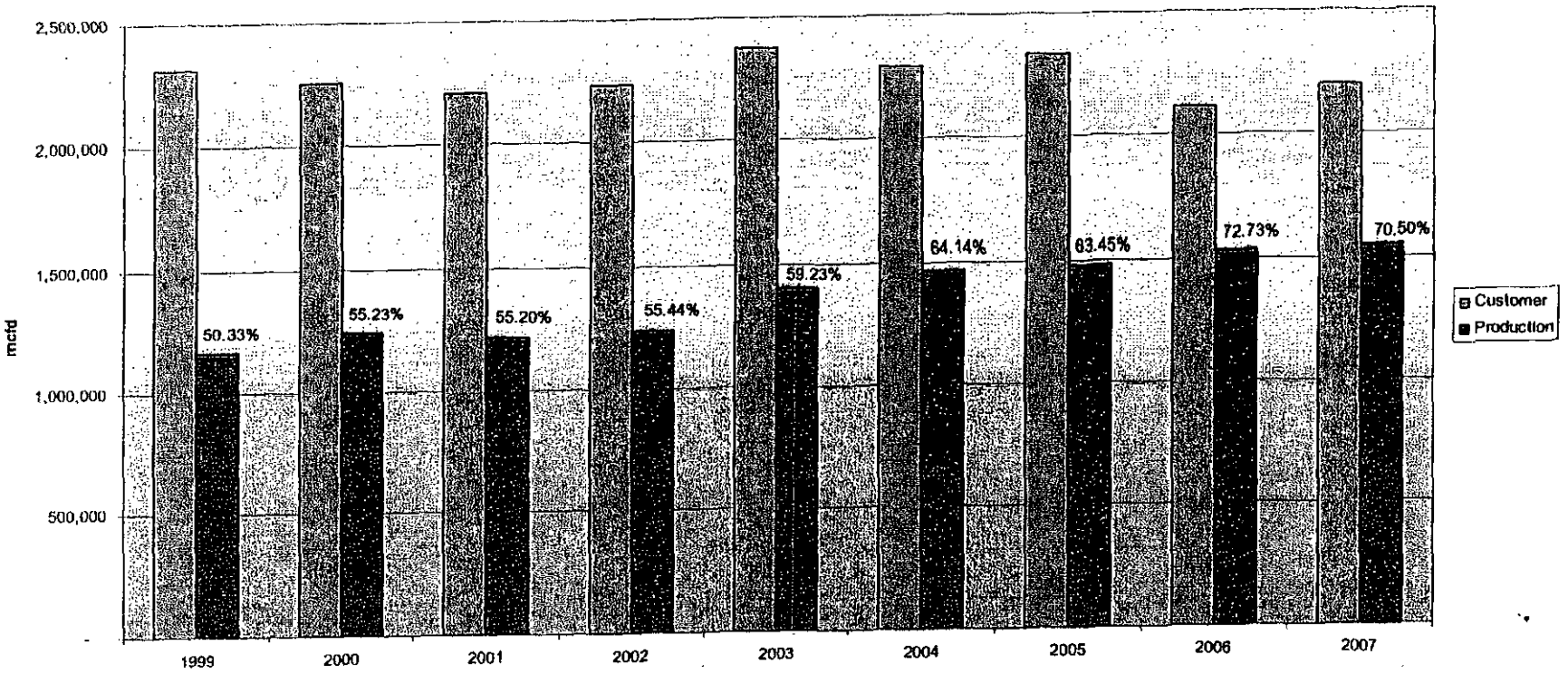


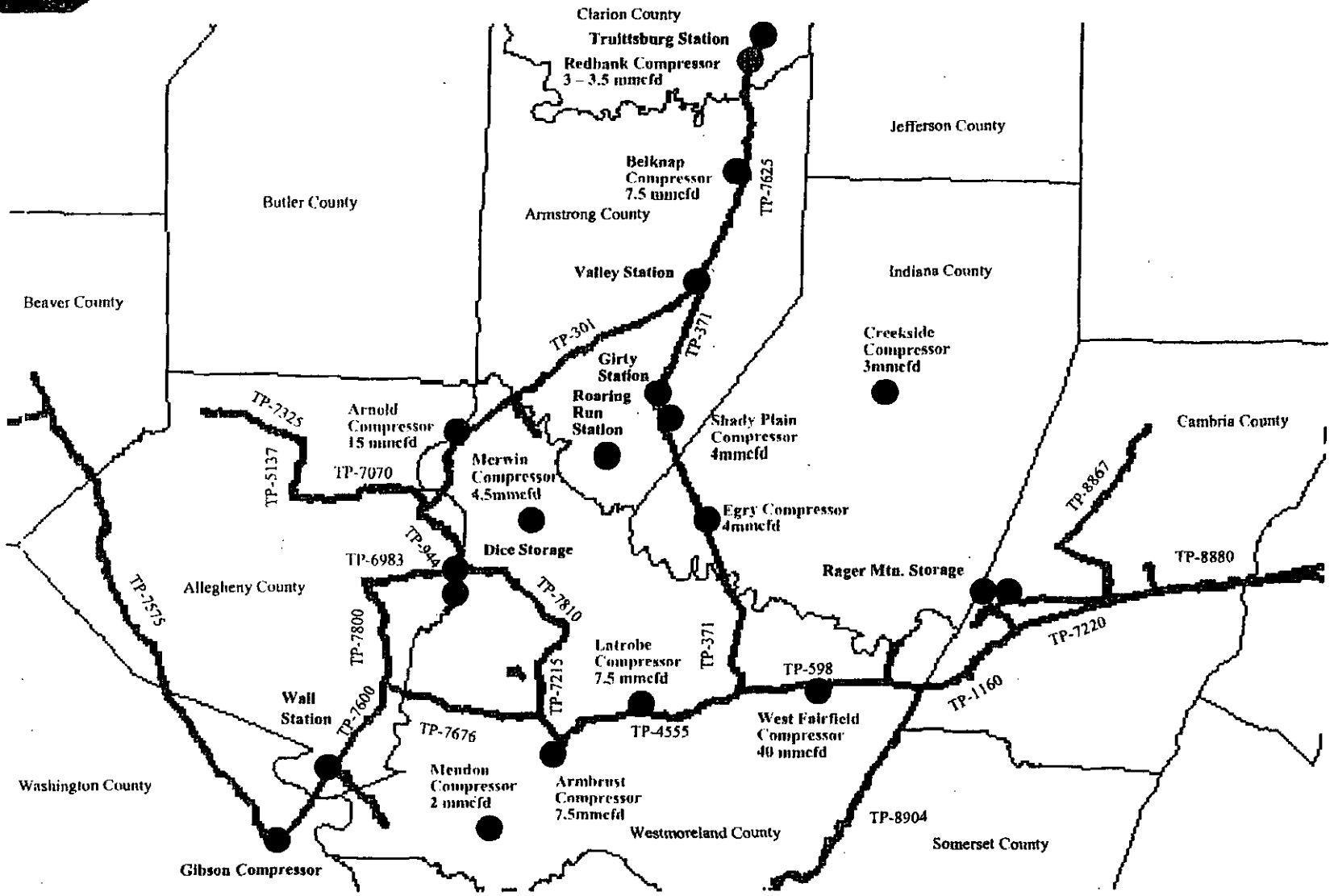
Dominion

Percentage of Production Volumes vs. Customer Load



Dominion

Dominion Peoples Map



Dominion

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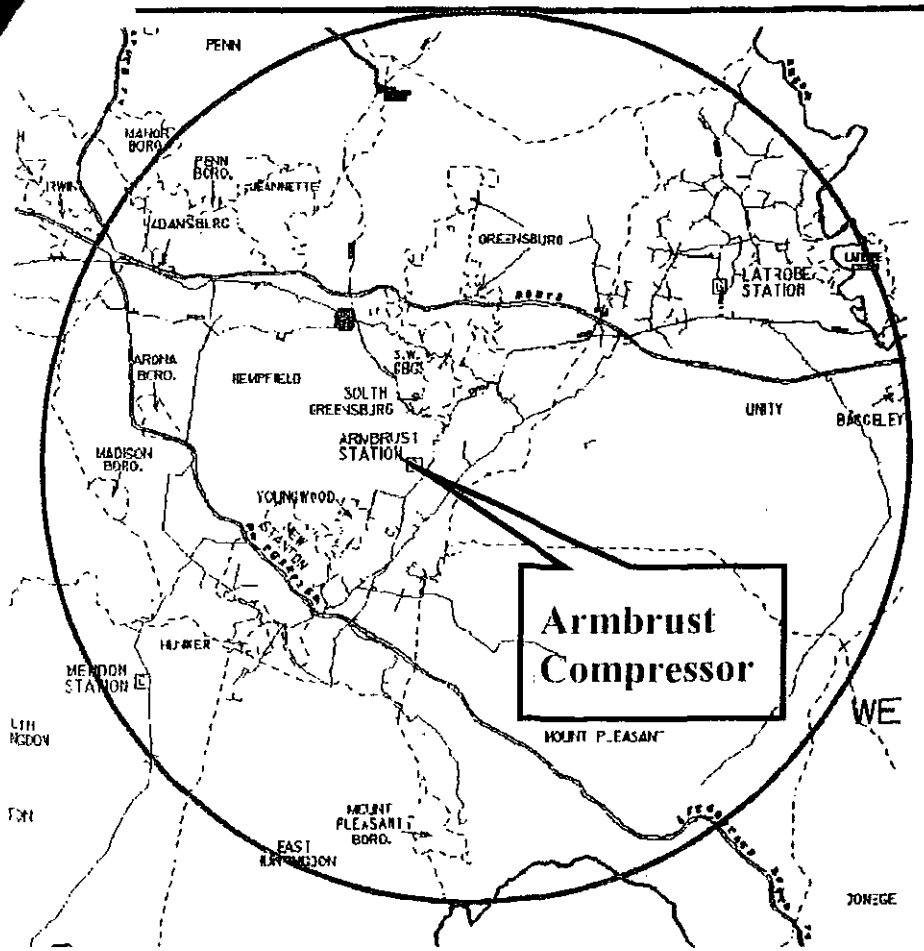
Dominion

Dominion

PA PES Projects Completed or in Progress

Ambrust Compressor Upgrade



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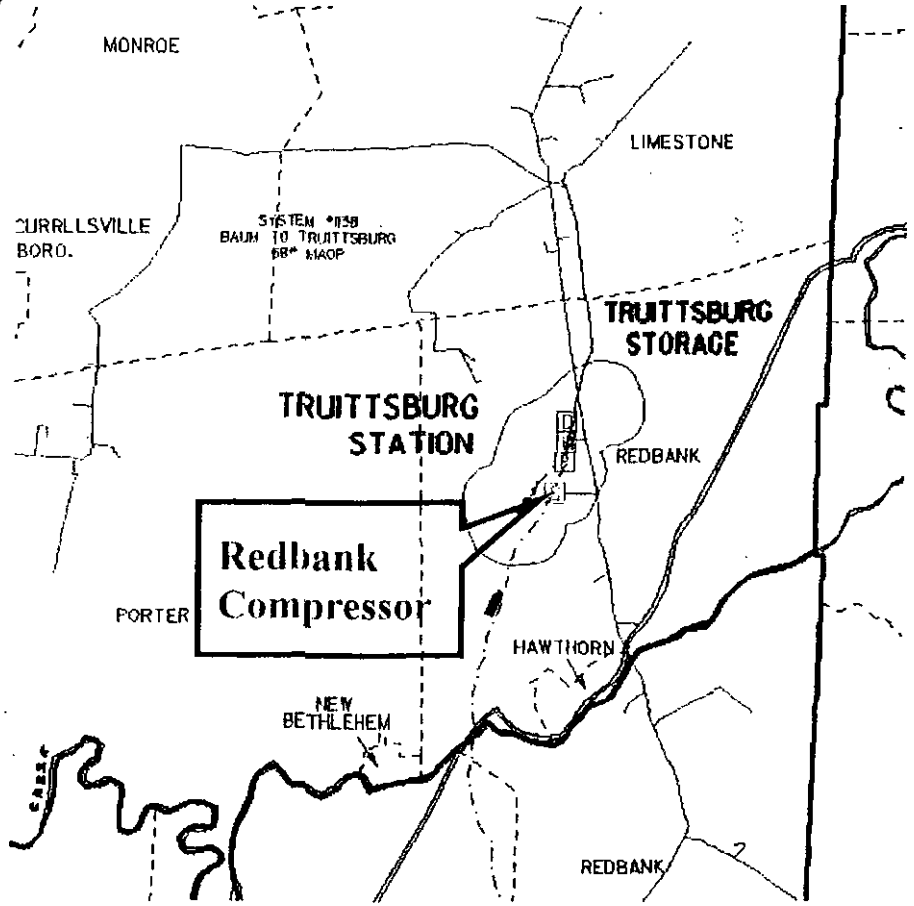
- Cylinders replaced to buck higher discharge pressures. Completed June 2007.

Dominion

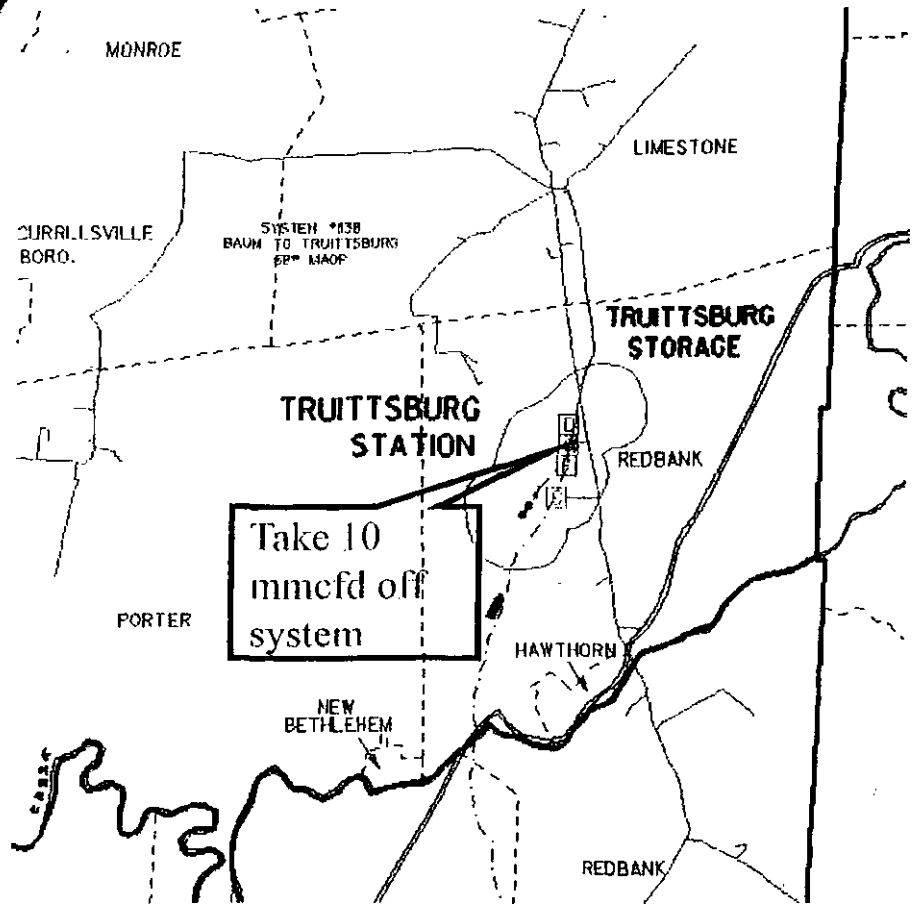
Redbank Compressor



- Install new compressor station utilizing old Armbrust unit to move up to 3.5 mmcf/d of gas out of 48# system into TP-7625
- 60 producers impacted
- $1.2 million proposed budget
- Project is currently under construction
- Projected completion date is late Spring of 2008

Dominion

Off System @ Truittsburg



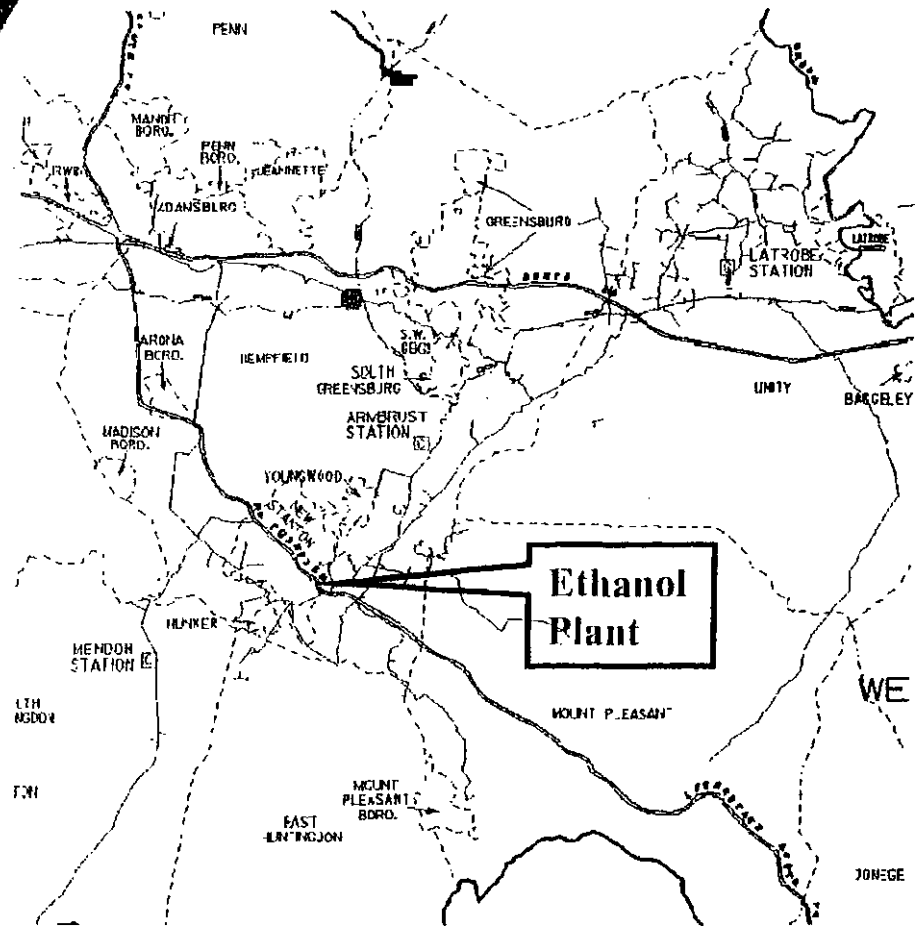
- Take 10 mmcfd off system to DTI
- Offered monthly to marketers as interruptible service for bid
- All producers impacted
- No Cost to PA PES
- Goal is to have Available all year round
- Project completed 4/2006

Dominion

Dominion

Investigating Future Projects

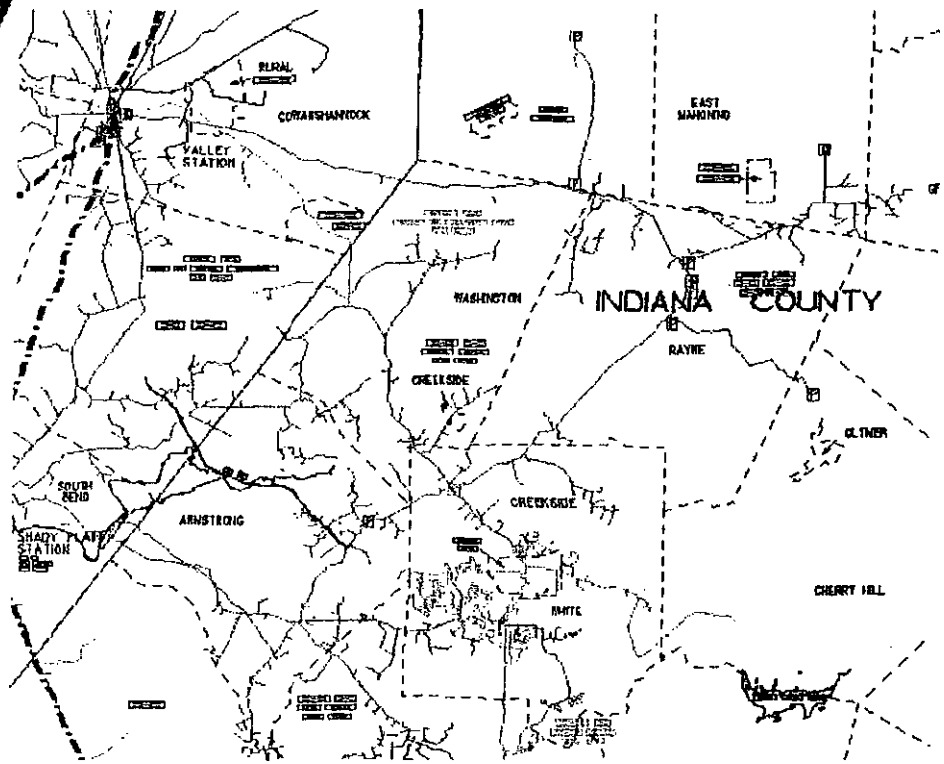
New Load on Dominion Peoples



- Dominion Peoples recently secured the Commonwealth Renewable Energy Ethanol Plant
- Creates an outlet for up to 20 mmcfd
- Third quarter 2009

Dominion

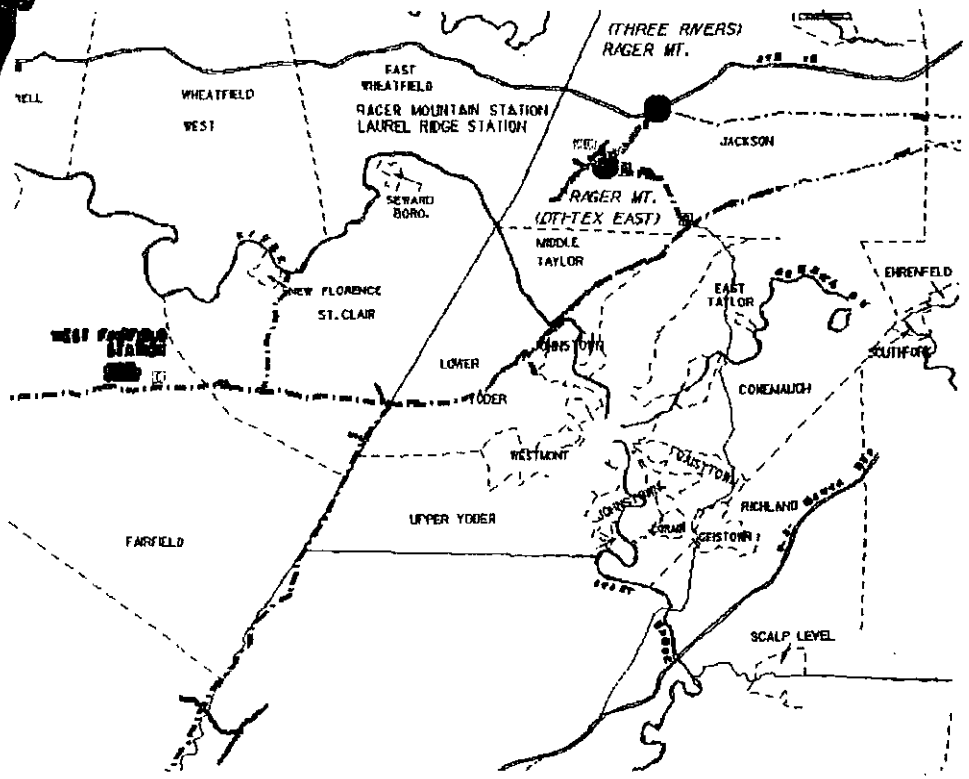
System Enhancements to Girty Indiana Loop



- Install Drips to remove fluids
- Pig lines that currently have Pig Launchers and Receivers to improve gas flow
- 64 producers impacted

Dominion

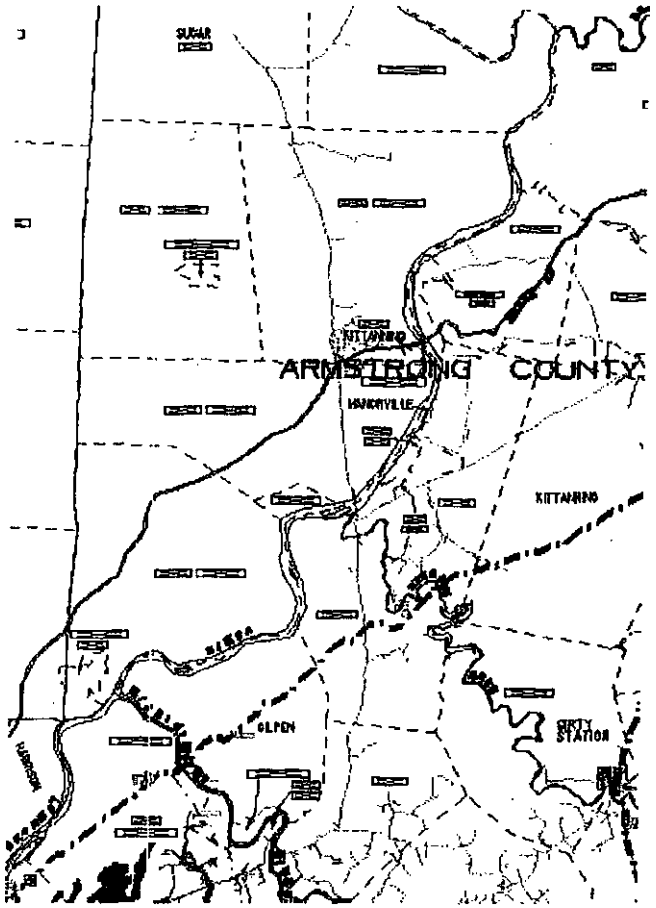
Laurel Ridge



- Laurel Ridge
- Install new Compressor to move 12-16 mmcfd into storage during summer months
- Reduces the need for Interstate Supply to fill storage pool
- All producers impacted

Dominion

Kittaning/Ford City System



- Performing Load Study to confirm Eljer volume
- Winter Production as high as 1.7mmcfd & Summer Production as low as .9 mmcfd
- 38 producers impacted

Dominion

ATTACHMENT – SCR - 11

	Penneco dth	Total Paid	Gathering w/held		Huntley dth	Total Paid	Gathering w/held		Kriebel dth	Total Paid	Gathering w/held	
2000	8,054	$ 25,877.23	$ -	0.00%	306,741	$ 1,419,473.09	$ -	0.00%	45	$ 77.40	$ -	0.00%
2001	82,927	$ 283,169.57	$ -	0.00%	556,969	$ 2,572,128.07	$ -	0.00%	269,566	$ 708,558.75	$ -	0.00%
2002	199,661	$ 688,655.37	$ -	0.00%	624,673	$ 2,315,214.39	$ -	0.00%	461,717	$ 1,646,492.16	$ -	0.00%
2003	212,758	$ 882,298.09	$ -	0.00%	613,362	$ 3,038,652.56	$ -	0.00%	411,372	$ 1,681,191.68	$ 1,360.70	0.08%
2004	351,625	$ 1,925,214.09	$ 55,338.55	2.79%	535,929	$ 3,550,800.34	$ 16,505.58	0.46%	466,244	$ 2,759,998.66	$ 73,751.44	2.60%
2005	416,267	$ 2,975,417.60	$ 81,059.08	2.65%	1,160,691	$ 10,754,249.46	$ 169,641.82	1.55%	923,167	$ 7,480,510.64	$ 275,933.64	3.56%
2006	373,451	$ 2,246,336.22	$ 109,469.06	4.65%	1,448,507	$ 12,813,543.14	$ 316,920.04	2.41%	1,009,135	$ 8,486,366.59	$ 312,907.92	3.56%
2007	410,368	$ 2,631,403.87	$ 142,423.68	5.13%	1,433,901	$ 11,754,007.61	$ 357,536.88	2.95%	975,260	$ 7,178,005.29	$ 329,113.32	4.38%
	2,055,111	$ 11,658,372.04	$ 388,290.37	3.33%	6,680,773	$ 48,218,068.66	$ 860,604.32	1.78%	4,516,506	$ 29,941,201.17	$ 993,067.02	3.32%

ATTACHMENT – SCR - 12

Rafferty, Stephen

From: Michael A. Hillebrand [mahillebrand@gmail.com]
Sent: Wednesday, August 15, 2007 4:47 PM
To: Rafferty, Stephen
Cc: Keith Mangini
Subject: RE: follow-up items

Steve:

The trigger was correct. We have not received the confirmation from Terry yet. For the new contract, I would like to sit with you and talk. Appalachian Basis for the last couple of weeks has been up nice. Week of 8/3 the average was $.52/mcf and week of 8/10 the average was $.37/mcf. This is just the interstate average not taking into account the Equitable gate fees. Thus far, in just the last year and a half, at $.25/mcf, we have paid you approximately $280,000 in gathering fees. The problem with us being a large source of gathering income and being the closest with local production to your physical burn is that it actually causes detriment to us for your investment focus upstream from our taps. With monies we are generating for you, you will be upgrading upstream facilities that will be placing us in a competitive disadvantage to that gas. We are currently producing 15 contracts per month on your pipe. The term of the contract we are discussing is five years. At $.40/dth, on 15 contracts per month for five years, your total gathering income is $3,600,000.00 This does not include the growth we plan on continuing within your system for the next five years. It would be my thought that our local gas would be your most valued being so close to burn and non subject to facility interruption. I realize and appreciate the business pressure you are under to show a profit on local production. I would like to brain storm with you on some ways to keep the gas in contract with you in such a way that you and I both look great. Some of my investors tell me you just sent them a deal where basis was $1.70 on their burn end. Our basis net your gathering costs are making it a much more lucrative move to go directly to the end user by becoming a pool operator ourselves.

I have our gas development agreement done with the exception of knowing the acreage you have under lease. Keith and I are studying the title work we had done on Boyce Park to fill in the blanks. I will send you a draft copy of the development agreement without the acreage for your review next. Keith and I plan on developing the acreage with **no profit** margin made on Equitable Gas.

Steve, I think, between the three of us, we can make Equitable and Huntley even more profitable without pinching each other. I think the world of you in the here and now and have bigger thoughts for the future. Let me know if you can meet at Pannera's some morning for coffee to further discuss.

Mike

Michael A. Hillebrand
Vice President
Huntley & Huntley, Inc.
Penn Office Building, Suite 100
4314 Old William Penn Highway
Monroeville, PA 15146
Office : (412) 380-2355 x.25
Cellular : (412) 445-9151

ATTACHMENT – SCR - 13

Rafferty, Stephen

From: Marc Jacobs [dmarcj@penneco.com]
Sent: Monday, December 11, 2006 4:01 PM
To: Rafferty, Stephen
Cc: Terry Jacobs; Jeremy Sampson
Subject: RE: Continued restrictions

Steve,
I hope your holidays are shaping up to be pleasant and stress-free(right...dream on). I was wondering if you might have an update for us on the anticipated flow improvements in the area of Hulton Road. Is it possible that the project is a little behind schedule? Please advise.
Thanks,
Marc

-----Original Message-----
From: SRafferty@eqt.com [mailto:SRafferty@eqt.com]
Sent: Tuesday, November 07, 2006 6:03 PM
To: Marc Jacobs
Cc: Terry Jacobs; JNehr@eqt.com
Subject: RE: Continued restrictions

Marc,
I mentioned to Terry this afternoon that part of the problem is our M-81 line being out of service. (There was train derailment over July 4th).
Currently, contractors are working to get the line back in service. We expect to be completed by 11/30/2006. Hopefully, you will see a noticeable improvement along Hulton Road in Plum Borough. If not, we can discuss alternatives...

-----Original Message-----
From: Marc Jacobs [mailto:dmarcj@penneco.com]
Sent: Tuesday, November 07, 2006 1:24 PM
To: Rafferty, Stephen
Cc: Terry Jacobs; Nehr, Jeffrey S.
Subject: Continued restrictions

Steve,
We have been anxious to realize some of the relief that was speculated year as a result of some of your system improvements and extensions.
Presently we are continuing to experience restrictions in the area of Haskell Industries and Hulton Road Business Center along Hulton Road in Plum Borough. We were hopeful that you or Jeff might be able to research this and get back to us with an answer. Based on our current production potential, we could introduce an additional 300mcf/d if regulation were not an issue.

Thanks much,
Marc

Rafferty, Stephen

From: Marc Jacobs [dmarcj@penneco.com]
Sent: Wednesday, January 03, 2007 1:42 PM
To: Rafferty, Stephen
Cc: Terry Jacobs; Jeremy Sampson
Subject: Hulton Road Capacity

Steve,
Terry asked me to update you on the status of our Hulton Road production. Currently (based on an instant reading this afternoon) we are flowing at the rate of 42mcf/d at the Hulton Road Business Center meter. We have the capacity to produce another 100-130mcf/d at this station. We are also experiencing proportionate restrictions at our Pyle meter (Haskell Industries). We are currently shut in at our Sentesi meter for some well servicing. Please let us know as soon as possible if we can expect some improvements.
Thanks,
Marc

Rafferty, Stephen

From: Vaina, Alan
Sent: Monday, May 14, 2007 3:27 PM
To: Rafferty, Stephen; Yolton, Tanya
Cc: Wiggers, Thomas; Murphy, Andrew; Davis, Jeff
Subject: RE: Penneco wells

The Texas Keystone tap is going to be very costly if they tie into us while it is an interstate pipeline ($40,000 for hot tap and >$100,000 for the meter, they install and we own) if I remember correctly we made a no decision based on the fact it is in the process of being spun down. From the producer standpoint it will be much cheaper to tie in when it is spun down to EGC)

I don't remember the specifics of the other request.
Jeff do you recall?

Alan

From: Rafferty, Stephen
Sent: Monday, May 14, 2007 2:51 PM
To: Yolton, Tanya
Cc: Wiggers, Thomas; Murphy, Andrew; Vaina, Alan
Subject: RE: Penneco wells

the response seems generic...what exactly is the reason for denial? Thanks!

From: Yolton, Tanya
Sent: Monday, May 14, 2007 1:29 PM
To: Rafferty, Stephen
Cc: Wiggers, Thomas; Murphy, Andrew; Vaina, Alan
Subject: RE: Penneco wells

Steve,

Penneco's Braddock site was denied for operational reasons on June 30, 2006.

The Texas Keystone request for the Brett Davenport #1 was denied on November 20, 2006. It was also denied for operational reasons.

I have included copies of both letters sent to the customers.

From: Rafferty, Stephen
Sent: Monday, 05 14, 2007 8:48 AM
To: Yolton, Tanya
Cc: Wiggers, Thomas; Murphy, Andrew
Subject: Penneco wells

Tanya,
I ran into Terry Jacobs (Penneco) and he was "inquiring" as to the status of the meter tap request that was submitted for Greene County. I think this was denied...Do you have the status/reasons for denial?

Also, Texas Keystone submitted a tap request for Indiana County H-156 (3 Rivers)...They called regarding the status of that one as well....Thanks!

ATTACHMENT – SCR - 14

Rafferty, Stephen

From: Rafferty, Stephen
Sent: Thursday, January 25, 2007 7:35 PM
To: 'MBauer@kriebelgas.com'
Subject: Re: Line in Armstrong County

Is this the same gas as fisher?

Sent using BlackBerry

-----Original Message-----
From: Milissa Bauer <MBauer@kriebelgas.com>
To: Rafferty, Stephen <SRafferty@eqt.com>
Sent: Thu Jan 25 13:58:19 2007
Subject: RE: Line in Armstrong County

Steve:
We have gas backed up on the Apollo system in Armstrong County. I would estimate it is about 500 mcfs per day. We may consider going to Equitrans if there is room to move on the retainage percent. Is that possible or are they pretty much etched in stone?

Milissa Bauer
Vice President of Administration
(814) 226-4160, ext. 115

-----Original Message-----
From: SRafferty@eqt.com [mailto:SRafferty@eqt.com]
Sent: Thursday, January 25, 2007 10:23 AM
To: Milissa Bauer
Subject: Re: Line in Armstrong County

Yes.. We have plans to correct this once we close on the dom peoples acquistion

On another note... I understand you are bringing some of ed browns gas into your system... That's a no-no and you jeopardize your own agreement
---
Sent using BlackBerry

-----Original Message-----
From: Milissa Bauer <MBauer@kriebelgas.com>
To: Rafferty, Stephen <SRafferty@eqt.com>
Sent: Thu Jan 25 09:48:43 2007
Subject: RE: Line in Armstrong County

Steve:

We are still feeling restrictions in this line in Armstrong County that comes down from Fisher Station. We have been restricted since July 2006 when the MAOP was set at 40#. Any idea if this pressure is ever expected to go down?

Milissa Bauer
Vice President of Administration
(814) 226-4160, ext. 115

From: SRafferty@eqt.com [mailto:SRafferty@eqt.com]
Sent: Monday, December 04, 2006 9:46 AM

To: Milissa Bauer
Subject: RE: Line in Armstrong County

this week...i believe the tie-in is scheduled for wednesday - thursday....

From: Milissa Bauer [mailto:MBauer@kriebelgas.com]
Sent: Monday, December 04, 2006 9:14 AM
To: Rafferty, Stephen
Subject: Line in Armstrong County

Steve:

Is the line fixed in Armstrong County that was supposed to be completed by Dec. 1st? Let us know.

Milissa Bauer
Vice President of Administration
(814) 226-4160, ext. 115

ATTACHMENT – SCR - 15

Rafferty, Stephen

From: Mike Hillebrand [mhillebrand@huntleyinc.com]
Sent: Thursday, January 25, 2007 9:17 AM
To: Rafferty, Stephen
Subject: Re: Springdale South master meter

Steve:

Will give it a try today and let you know the results. Can you let Danny know?

Mike
----- Original Message -----
From: <SRafferty@eqt.com>
To: <mhillebrand@huntleyinc.com>; <DKuehn@eqt.com>
Sent: Wednesday, January 24, 2007 6:04 PM
Subject: Re: Springdale South master meter

Mike,
We can't back off creighton station - that action would curtail other producers...
Dan-seems like the best option is to get the set point at 25 psig...can you set the primary at 24.5 and eliminate the monitor since a relief is present??

Sent using BlackBerry

-----Original Message-----
From: Mike Hillebrand <mhillebrand@huntleyinc.com>
To: Kuehn, Dan <DKuehn@eqt.com>
CC: Rafferty, Stephen <SRafferty@eqt.com>
Sent: Wed Jan 24 17:07:56 2007
Subject: Springdale South master meter

Danny:

Been talking to Steve and just found your email address. I don't know if Steve had a chance to talk to you about our Springdale South production. We have capacity to deliver around 2400 mcf.d at this site, just South of Creighton Station. We recently upgraded our meter station from an 11m meter to a 23m meter. We were maxing out the 11m at 1500 mcf.d prior to the switch out. At the 1500 mcf.d, regulation was set at 24.5 psi and 25 psi on our operating and monitoring regulators. Since the meter switch out, regulation has been set at 23.5 psi operating and 25 psi monitoring. As a result we have only been selling around 600 mcf.d. Your line at static flow is operating around 23.1 psi at this station. I inquired with Steve to see if anything could be done to add capacity for us. Moving the sensing points for the regulators is not an option here because your line is on the other side of Freeport road about 60 feet away. Is it possible to bump back Creighton a bit, adjust regulation at our station up a hair or maybe both to allow flow? I am selling the gas to Steve and it would do us both good. Can you give me a heads up? In addition to the two regulators, we also have a 25 psi pop off on our meter run.

Mike

Rafferty, Stephen

From: Mike Hillebrand [mhillebrand@huntleyinc.com]
Sent: Monday, January 22, 2007 11:58 AM
To: Rafferty, Stephen
Subject: Springdale South Master Meter

Steve:

I hate to bother you with stuff like this, but you are my guy that either gets clarification or things done for us. Appreciated the bridge crew and what you did to get us our check this month. Our Murrysville Domionion system will be turned in line this week as a result of the bridge crew showing up. However this note is on a different subject addressing our Springdale South metering station.

As you are aware, we brought all of our Sprindale North (the TW Phillips Exchange meter) into our existing Springdale South station. This along with several new wells drilled South of the mall has our estimated production capability at around 2400 mcf.d at the station. Last Friday, we upgraded the exchange meter station from an 11m meter to a 23m meter to handle the volume. Ahead of the station, we also installed a check meter and a large dehydration and filtering station. Prior to doing this work, we were peaking the 11m capabilities at around 1500 mcf.d with regulation set at 25 psi on the monitoring and 24.5 psi on the operating regulator with your line operating at around 23.5 psi. Last Friday the regulation guys were out to check our install work and set our regulation at 25 psi and 23.5 psi, monitoring and operating respectively and left before we knew there set points. When we turned back in line, we could only sell 1,100 mcf.d. I had one of our guys adjust the operating back up to 24.5 psi as we had been before. Although we did not get our expected 2400 mcf.d, we did get to 1600 mcf.d and became curtailed by regulation at that new set point. The Equitable regulation guys came out today to meet again with our guys. My guys were there working on some small leaks on the Dehy towers found on Saturday. The regulation guys set us back to 23.5 psi and said that is were it needs to stay. We are once again only selling 1100 mcf.d.

Couple of questions result. On the meter stations we own, are we responsible or is Equitable for not breaching the MAOP on your line. The two psi seperation point done by the Equitable regulation guys seems to be there preferred separation from monitoring and operating. FYI, most of Dominion's exchange points only have one regulator and it is set right at MAOP. FYI only Steve. Because most of our production with Dominion comes directly into their city distribution grid, we voluntarily set two regulators and operate them .5 psi apart. They police the MAOP set point very religiously, but do not have any preferance to operating and monitoring ranges. Experiencing this, is the Equitable set points a PUC issue or one of internal preferance. In either case, do you see anything we can do at Creighton Station, that will allow us to sell more gas at this exchange point. Although not tested very long, even if the 24.5 psi operating and 25 psi monitoring is acceptable, we still appear to be up against regulation.

Greatly appreciate your help or input. When are we going to a Pitt game with the boys?

Mike

Rafferty, Stephen

From: Rafferty, Stephen
Sent: Thursday, August 16, 2007 10:22 AM
To: 'mhillebrand@huntleyinc.com'
Cc: Keith Mangini
Subject: RE: follow-up items

Keith, Mike,
I appreciate your thoughts on this and your willingness to keep an open mind....just to give you a better understanding of where I am coming from...we are investing significant capital in our distribution/gathering systems (upwards of $20 MM next year). Although you think this doesn't benefit you directly, it does. The volumes coming in at Creighton/Springdale are creating operational issues for us, as you are aware. rather than curtailing you (and other producers north of you) I have proposed (and it has been approved) to invest $10 MM and move gas north into Dominion. This will minimize the gas that is currently being moved southward. The end result is you will be able to deliver more into our system. I recognize the gathering charges cause some concern, however, without the improvements we have made and without the ongoing investments, your volumes would have remained flat and possibly decreased because other producers would have continued to bring additional gas into the system...I think there are other opportunities to bring value to you, e.g, Boyce Park...look forward to discussing this more...I'm around all next week so pick a day and I can meet you (except Monday morning)...

C:\WINDOWS\Help\webpub.chm::/webpub_sendphoto

To send a photo in e-mail

1. Open My Pictures, and then open the folder containing the photo you want to send in e-mail.
2. Click the photo you want to send.
3. Under **File and Folder Tasks**, click **E-mail this file**.
4. In the **Send Pictures via E-mail** dialog box, click **Make all my pictures smaller**.

   Windows makes a smaller photo file and attaches it to an e-mail message that displays a default subject and text message.

5. In the **To** box, type the e-mail address of the person to receive the picture, change the subject and message text if you want, and then click **Send**.

Notes

- To open My Pictures, click **Start**, and then click **My Pictures**.
- Use this procedure for photos of file size greater than 64 kilobytes (KB). To check the file size of your photo, right-click the file, click **Properties**, and look at **Size**.
- To send the photo without reducing the size of the file, click **Keep the original sizes**.
- To change the settings for the size of the image, click **Show more options**.
- If you have many pictures to share with others, you can publish them to the Web instead of sending them in e-mail. For more information, click **Related Topics**.

Equitable Statement No. 15-R
Docket No. R-2008-2029325
Witness: Thomas P. Wiggers
Date: 11/19/08
RS

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Thomas P. Wiggers

(Prepared October 2008)

PREPARED REBUTTAL TESTIMONY OF THOMAS P. WIGGERS

WITNESS BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas P. Wiggers. My business address is 225 North Shore Drive, Pittsburgh, Pennsylvania 15212.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Equitable Gas Company ("Equitable" or the "Company") as Director, Gas Supply. Pertinent to my rebuttal testimony, as Director, Gas Supply, I am responsible for the administration of Equitable's end-user transportation program.

Q. PLEASE BRIEFLY DESCRIBE YOUR BACKGROUND AND TRAINING.

A. I attended The Ohio State University and earned a Bachelor of Science degree, majoring in Finance, in 1993. I earned a Master of Public Management degree with a concentration in Financial Resources from Carnegie Mellon University in 2001.

Professionally, from July 1993 to June 2003, I was employed by Columbia Energy Group and NiSource, Inc., where I held positions of increasing responsibility in the Rates and Regulatory Services, Sales and Marketing and Finance departments of the local distribution companies and the Financial Planning and Reporting department of Corporate

Services.

In June 2003, I accepted the position of Manager, Pipeline Rates with Equitrans, L.P. ("Equitrans"), an affiliate of Equitable Gas Company. In that position, I served as a witness in Equitrans' general rate case at Docket RP05-164, *et.al,* sponsoring cost of service, cost allocation and rate design testimony. In addition, I had responsibility for the administration of the transportation and exchange function within Equitrans. In September 2007, I assumed my current position with Equitable Gas Company.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes. I submitted testimony before this Commission in Equitable Gas Company's 2008 1307(f) proceeding at Docket R-2008-2021160. As mentioned previously, I submitted testimony on behalf of Equitrans before the Federal Energy Regulatory Commission in a general rate case proceeding at Docket RP05-164, *et.al.* While employed by the Columbia Energy Group, I submitted testimony before this Commission in Columbia Gas of Pennsylvania's 2003 1307(f) proceeding and before the Maryland Public Service Commission in purchase gas recovery proceedings in 2002.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony, I will respond to various recommendations concerning the operational rules and procedures of Equitable's transportation program as presented in the direct testimony of James L. Crist submitted jointly by the Independent Oil and Gas Association ("IOGA") and Hess Corporation ("Hess").

SUMMARY OF MR. CRIST'S RECOMMENDATIONS

Q. PLEASE SUMMARIZE MR. CRIST'S RECOMMENDATIONS.

A. Mr. Crist makes the following recommendations:

- Customer consumption data should be made available during the month, as meters are read.
- The imbalance tolerance level for marketers should be increased.
- The number of days for imbalance trading should be increased.
- Daily market price information should be published on Equitable's website.
- Monthly reporting information should be automated.
- Communication of customer enrollments and drops should be automated.
- Equitable should have an additional contact person to respond to marketer inquiries.

Consumption Data

Q. WHAT IS MR. CRIST'S RECOMMENDATION REGARDING CONSUMPTION DATA?

A. Mr. Crist recommends that Equitable provide customer consumption data to marketers during the month, as meters are read. Mr. Crist claims that this would allow marketers to estimate consumption more accurately and, thus, better manage pool imbalances.

Q. CAN THE COMPANY ACCOMMODATE THIS REQUEST?

A. Yes. The Company will agree to post, to a secure website, each pool administrator's customer consumption information during the month, as meters are read. The Company will commit to implementing this recommendation no later than six months from the issuance of the Commission's Final Order in this proceeding.

Tolerance Level

Q. WHAT IS MR. CRIST'S TOLERANCE LEVEL RECOMMENDATION?

A. Mr. Crist recommends that Equitable either provide a banking option or increase its imbalance tolerance level from 3.5% to 10%.

Q. DOES MR. CRIST SPECIFY THE ASSETS EQUITABLE SHOULD UTILIZE TO PROVIDE A BANKING OPTION FOR IMBALANCES?

A. Yes. Mr. Crist states that Equitable should utilize on-system storage.

Q. DOES EQUITABLE HAVE ON-SYSTEM STORAGE?

A. No. Equitable does not have on-system storage. Equitable contracts for upstream firm base load and firm peaking storage services from Equitrans, L.P. Therefore, a banking option is not practical.

Q. HAS THE COMPANY PREVIOUSLY PROPOSED INCREASING ITS TOLERANCE LEVEL ABOVE 3.5%?

A. Yes. In fact, as part of the Company's 2004 1307(f) proceeding at Docket No. R-00049154, the Company proposed to increase the tolerance level at the time from 2.5% to 5%.

Q WAS THE COMPANY'S PROPOSAL TO INCREASE THE TOLERANCE LEVEL FROM 2.5% TO 5% ACCEPTED?

A. No. The proposal was opposed by the Office of Trial Staff (OTS), the Office of Consumer Advocate (OCA), and the Office of Small Business Advocate (OSBA). As part of the settlement of the 2004 1307(f) proceeding, the tolerance level was increased to the current level of 3.5%.

Imbalance Trading

Q. WHAT IS MR. CRIST'S IMBALANCE TRADING RECOMMENDATION?

A. Mr. Crist recommends that Equitable increase its imbalance trading period to 3 days, with trading commencing on day 15 of the succeeding month.

Q. CAN THE COMPANY ACCOMMODATE MR. CRIST'S IMBALANCE TRADING RECOMMENDATION?

A. In part. The Company will agree to increase its imbalance trading period to 3 days. However, imbalance trading needs to commence on day 11 of the succeeding month to allow the Company time to prepare and issue invoices consistent with the terms of the general transportation pooling agreement.

Cash In / Cash Out Pricing Data

Q. WHAT IS MR. CRIST'S CASH IN / CASH OUT RECOMMENDATION?

A. Mr. Crist states that it is important that a marketer know the cash in / cash out price to which it will be subject and recommends that Equitable publish on its website the daily pricing data.

Q. DO YOU AGREE WITH HIS RECOMMENDATION TO HAVE EQUITABLE PUBLISH DAILY PRICING DATA ITS WEBSITE?

A. No. The Company's cash in / cash out rates are calculated based on a publicly priced market rate, specifically, the midpoint price published in Platt, Gas Daily, under the heading "Appalachia, Dominion South

Point,". Marketers can easily access this pricing information. Therefore, it is not necessary for Equitable to publish daily pricing information on its website.

Automation of Reporting

Q. WHAT IS MR. CRIST'S RECOMMENDATION ON EQUITABLE'S REPORTING OF INFORMATION?

A. Mr. Crist recommends that Equitable develop automated reporting capabilities so marketers can access customer consumption data in a more efficient manner. Additionally, Mr. Crist states that increasing the imbalance trading period would provide marketers more time to review customer usage information, more clearly and accurately identify imbalance positions and finalize imbalance trades.

Q. CAN THE COMPANY ACCOMMODATE MR. CRIST'S RECOMMENDATION?

A. Yes. As I stated previously, the Company will agree to increase the imbalance trade period to 3 days and post customer usage data during the month, as meters are read. In addition, the Company is willing to consider making enhancements to the reporting functionality of its Nomination Online Management System (NOMS).

Customer Enrollments and Drops

Q. WHAT IS MR. CRIST'S RECOMMENDATION REGARDING THE COMMUNICATION OF THE STATUS OF CUSTOMER ENROLLMENTS AND DROPS?

A. Mr. Crist recommends that Equitable automate its communication of enrollments and drops.

Q. CAN THE COMPANY ACCOMMODATE MR. CRIST'S RECOMMENDATION?

A. Yes. The Company will agree to automate the customer enrollment and drop process. The Company will commit to implementing this recommendation no later than six months from the issuance of a Commission Final Order in this proceeding.

Company Contacts

Q. WHAT IS MR. CRIST'S RECOMMENDATION REGARDING THE NUMBER OF COMPANY CONTACTS AVAILABLE TO ADDRESS MARKETER INQUIRIES?

A. Mr. Crist recommends that Equitable make multiple personnel available to address marketer questions regarding customer usage data and the status of customer enrollments and drops.

Q. CAN THE COMPANY ACCOMMODATE MR. CRIST'S RECOMMENDATION?

A. No. As stated previously in my rebuttal testimony, the Company is willing to take steps to automate the reporting of consumption data and the customer enrollment and drop process. Once these enhancements are implemented, the number of marketer questions should be reduced and multiple customer contact personnel should be unnecessary.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Equitable Statement No. 15-SR
Docket No. R-2008-2029325
Witness: Thomas P. Wiggers
Date: 11/19/08
RS

EQUITABLE GAS COMPANY

Prepared Surrebuttal Testimony of

Thomas P. Wiggers

PREPARED SURREBUTTAL TESTIMONY OF

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Thomas P. Wiggers. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company ("Equitable" or "Company") as Director of Gas Supply. It is my responsibility to ensure Equitable has sufficient natural gas supplies and delivery service capacity to meet the needs of the customers on its system, consistent with least cost procurement policy and practices. In addition, I have the responsibility for the administration of Equitable's end-user transportation program.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted rebuttal testimony that has been marked as Equitable Statement No. 15-R.

II. Purpose of Surrebuttal Testimony

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my surrebuttal testimony I will respond to the rebuttal testimony of Diane Meyer Burgraff submitted on behalf of the Independent Oil and Gas Association of Pennsylvania ("IOGA"). My surrebuttal testimony will address the references Ms. Burgraff has presented with respect to previous Equitable 1307(f) proceedings and a PUC Management Efficiency Investigation wherein Equitable witnesses identified benefits that local Pennsylvania production provides to Purchase Gas Cost ("PGC") customers. I should add that I am the same Thomas P. Wiggers who testified on behalf of Equitable in its recent 2008 Section 1307(f) proceeding. A three-page excerpt from my rebuttal testimony in that proceeding was appended to Ms. Burgraff's rebuttal testimony in this proceeding.

III. Pennsylvania Local Production

Q. IN PREVIOUS SECTION 1307(F) PROCEEINGS AND THE PUC'S 2005 MANAGEMENT EFFICIENCY INVESTIGATION, DID EQUITABLE STATE THAT INCREASING THE LEVEL OF LOCAL PENNSYLVANIA PRODUCED NATURAL GAS VOLUMES INTO EQUITABLE'S SYSTEM WOULD BENEFIT PGC CUSTOMERS?

A. Yes.

Q. WHAT DID EQUITABLE IDENTIFY AS THE PRIMARY BENEFITS TO PGC CUSTOMERS?

A. Equitable identified the primary benefits of increasing the level of local Pennsylvania production as being twofold: providing direct access to lower cost gas supplies and reducing Equitable's reliance on more expensive interstate pipeline supplies.

Q. DOES EQUITABLE STILL CONSIDER LOCAL PENNSYLVANIA PRODUCTION TO BE A LOWER COST SOURCE OF GAS SUPPLY WHEN COMPARED TO OTHER SUPPLY ALTERNATIVES?

A. No and this is why we have Section 1307(f) proceedings every year. The world we serve in is not static and what constitutes least cost fuel procurement must be constantly evaluated. If a 1307(f) proceeding were to begin today, my testimony would be different than it was several months ago.

Q. WHY HAS EQUITABLE CHANGED ITS POSITION ON THIS MATTER?

A. Equitable has changed its position on this matter based on new information that has become available since Equitable's 2008 Section 1307(f) proceeding.

First, in the Third Quarter of 2008, Equitable completed a lost and unaccounted for gas study on its gathering system. The results of the study revealed that the lost and unaccounted for gas percentage on Equitable's gathering facilities is in excess of 20%. Attached to my surrebuttal testimony as Exhibit 15A-SR is the response to the IOGA interrogatory requesting the lost and unaccounted for gas study for Equitable's gathering facilities.

Second, IOGA has taken the position in this proceeding that Rate AGS should be eliminated and, therefore, Equitable would no longer have the ability to charge producers and marketers gathering rates. If Rate Schedule AGS were eliminated, the costs currently being charged to producers and marketers for gathering service would need to be assessed to Equitable's end-use customers.

In addition, in his rebuttal testimony, Equitable Witness Dalena demonstrated that local Pennsylvania Production is no longer the low cost supply it was previously thought to be, and does not offer the operational flexibility of interstate deliveries. It is also a supply source that can easily be replaced if producers were to leave the gathering system. I concur with Mr. Dalena's testimony and as the Company's Director of Gas Supply whose responsibility it is to assure compliance with the least cost procurement obligations under the Public Utility Code, I can state without reservation that the level of Pennsylvania produced gas purchases must be re-evaluated.

Q. DOES THIS CONCLUDE YOUR PREPARED SURREBUTTAL TESTIMONY?

A. Yes, it does.

Exhibit 15A-SR

Docket No. C-20066800
Item: IOGA-I-21
Respondent: Thomas P. Wiggers
Position: Director, Gas Supply

EQUITABLE GAS COMPANY
Response to IOGA's
Interrogatories, Set I

Item: IOGA-I-21

Reference Equitable's Answer to Amended Complaint, ¶s 38 and 81.

(a) When did Equitable complete the LUFG study?

(b) Is the moratorium still in effect? If not, when was it lifted?

(c) Please explain why the moratorium was imposed to perform the LUFG study.

(d) Please provide a copy of the LUFG study.

Response:

a) A LUFG study for Equitable's overall system was included in Equitable's 2008 1307(f) filing at Docket No. R-2008-2021160 which was filed April 1, 2008. A LUFG study of Equitable's gathering system was completed in the third quarter of 2008.

b) Yes.

c) Equitable imposed a moratorium on new taps because the Company believed, inter alia, that the gathering system was experiencing elevated levels of unaccounted for gas. Adding incremental gas to this system would exacerbate this issue and ultimately result in higher LUFG volumes.

d) The LUFG study for the overall system was included in the testimony of Thomas P. Wiggers, identified as Equitable Statement No. 3 in Equitable's 2008 1307(f) filing at Docket No. R-2008-2021160. Please see the attached summary of the LUFG study for the gathering system.

EQUITABLE GAS COMPANY
Response to Interrogatories of IOGA

Docket No. C-20066800
Item: IOGA-I-21

	2007 Jan	2007 Feb	2007 Mar	2007 Apr	2007 May	2007 Jun	2007 Jul	2007 Aug	2007 Sep	2007 Oct	2007 Nov	2007 Dec	2008 Jan	2008 Feb	2008 Mar	2008 Apr	2008 May	2008 Jun
Receipts	1,014,695	836,412	971,042	1,036,952	1,072,622	1,068,127	940,077	1,082,456	1,049,863	1,095,490	1,077,923	1,086,065	1,086,371	965,976	1,119,811	926,524	771,485	680,427
Deliveries	852,041	734,176	705,445	655,910	738,149	850,806	688,758	786,372	807,121	811,510	896,229	893,665	983,782	758,241	1,000,709	748,432	517,757	453,956
LUFG	162,654	102,236	265,597	381,042	334,473	217,321	251,319	296,084	242,742	283,980	181,694	192,400	102,589	207,735	119,102	178,092	253,728	226,471
LUFG - %	16.03%	12.22%	27.35%	36.75%	31.18%	20.35%	26.73%	27.35%	23.12%	25.92%	16.86%	17.72%	9.44%	21.51%	10.64%	19.22%	32.89%	33.28%
Rolling %												23.61%	22.99%	23.59%	22.16%	20.74%	20.59%	21.34%

Equitable Exhibit: Testimony Errata

11/20/08
Hearing

Pennsylvania Public Utility Commission
v.
Equitable Gas Company, a Division of Equitable Resources, Inc.
Docket No. R-2008-2029325, et al.

1. EGC Statement 4-R: Carol B. Gras

   Page 6, lines 13-14.

   Reads: Mr. Hubert recommends elimination of Equitable's $13,151,140 claim for post future test year additions for a reason that appears similar to that advanced by Mr. Morgan. That is, Mr. Hubert claims that the plant . . . .

   Should read: Mr. Hubert recommends elimination of Equitable's $13,151,140 claim for post future test year additions for a reason that the plant . . . .

2. EGC Statement 8-R: David W. Ross

   Page 5, lines 16-17.

   Reads: In that proceeding, Equitable agreed to use of 4 billing lag days instead of the 7 billing lag days . . . .

   Should read: Ms. Backer asserts that in that proceeding, Equitable corrected its billing lag days to 4 instead of the 7 billing lag days . . . .

3. EGC Statement 7, Sandra L. Gagorik, Attachment B, Section II

   Reads: This program will be funded through base rates established at $100,000 annually.

   Should read: This program will be funded with unspent LIURP funds provided that Equitable Gas Company is permitted a waiver of the LIRUP regulations by the Pennsylvania Public Utility Commission.