BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Indiantown Gas Company.	DOCKET NO. 030954-GU ORDER NO. PSC-04-0565-PAA-GU ISSUED: June 2, 2004

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

NOTICE OF PROPOSED AGENCY ACTION
ORDER GRANTING REQUEST FOR RATE INCREASE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

I. BACKGROUND

This proceeding commenced on December 15, 2003, with the filing of a petition for a permanent rate increase by Indiantown Gas Company, Inc. (IGC or company). Indiantown requested an increase of $306,751 in additional annual revenues. The company based its request on a 13-month average rate base of $755,812 for a projected test year ending December 31, 2004. The requested overall rate of return is 10.09% based on an 11.50% return on equity.

We granted an interim increase of $137,014 by Order No. PSC-04-0180-PCO-GU, issued February 24, 2004, in this docket. In that Order, we found the company's jurisdictional rate base to be $572,394 for the interim test year ended December 31, 2002, and its allowed rate of return to be 9.10%, using a return on equity of 10.50%.

By Order No. 4933, issued August 27, 1970, in Docket No. 70377-GU, In Re: Application of Indiantown Gas Company, Inc. for approval of rate schedules for the sale of natural gas, p.1, we approved initial rates and charges for IGC on a temporary basis. We, in Order No. 5578, issued November 9, 1972, in Docket No. 70377, In Re: Application of Indiantown Gas Company, Inc., for approval of rate schedules for the sale of natural gas, p. 1, made the previously authorized temporary rates permanent. IGC has never had a rate case. However, by Order No. PSC-02-1666-PAA-GU, issued November 26, 2002, in Docket No.

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020470-GU, In Re: Request for limited proceeding by Indiantown Gas Company for approval of Natural Gas Tariff, Original Volume No. 2, implementing restructured rates, p. 7, we approved a revenue-neutral restructuring of the company's rates based on the 2001 test year billing determinants. The restructured rates became effective December 5, 2002. In addition, the Order established an authorized return on equity of 11.50% with a range of plus or minus 100 basis points, limited IGC's common equity ratio to not more than 60%, and ordered a refund for over collection of regulatory assessment fees.

Pursuant to Section 366.06(4), Florida Statutes, IGC requested to proceed under the rules governing Proposed Agency Action (PAA). Under that section, we must enter a vote on the PAA within five months of the date on which a complete set of minimum filing requirements (MFRs) are filed with the Commission. By letter dated April 8, 2004, the company waived its right pursuant to Section 366.06(4), Florida Statutes, to have us enter our vote on its petition for a rate increase using the PAA procedure within five months following the filing of the company's petition. Specifically, the company waived its rights to the extent of agreeing to have us vote on the company's request at the May 18, 2004 Agenda Conference. Although this rate case is being processed under the PAA procedures, by Order No. PSC-04-0269-PCO-GU, issued March 9, 2004, we granted intervention to Indiantown Cogeneration, L.P. (ICLP). A customer meeting was held in Indiantown on February 5, 2004.

We have jurisdiction over this request for a rate increase and interim rate increase under Sections 366.06(2) and (4), and 366.071, Florida Statutes.

II. TEST YEAR

A. Projected Test Year

The company used actual data for the 2002 test year rate base, net operating income, and capital structure. The 2004 projected test year balances were prepared using a combination of 2002 data trended for expected inflation, customer growth, and payroll growth, and specific budgeted increases. The 2002 data and certain plant additions and expenses in 2003 have been audited by our auditors and analyzed by our staff.

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. New rates for IGC will go into effect 30 days after the May 18, 2004 agenda, or about June 17, 2004. IGC's 2004 fiscal year begins January 1, 2004 and ends December 31, 2004. Therefore, calendar year 2004 is an appropriate test year.

B. Forecasts of Customer and Therms

In its original filing, the company provided MFR Schedule G-2 containing the projected number of bills and therms by rate class. As discussed in the direct testimony of company witness Householder, these projections extend the historical pattern of negligible customer and therm growth for the residential and small commercial rate classes into the projected test year. The only material change contained in these projections is the addition of 10 new residential accounts associated with the renovation of low-income rental-housing units. The projections for therm usage by the three industrial customers served by the company were derived from historical usage patterns and conversations with the industrial customers. These projections show negligible change in therm usage from the prior year.

In response to a request for a production of documents, the company provided historical customer counts and therm usage data by rate class for the period 1998 to 2003. An analysis of this data confirms that over this six year period, customer growth and therm usage for the residential and small commercial rate classes has been negligible. Therefore, we conclude that extending this trend into the 2004 test year is reasonable. The historical data for the three industrial customers served by the company (a roofing tile manufacturer, a citrus processor, and a coal-fired cogeneration facility) has shown a declining pattern of usage that has leveled off in the last two years. The company's projections for these three customers continues this levelized therm usage into the test year. We agree that these projections for the company's three industrial customers are appropriate.

Subsequent to the company's original filing, the audit report documented several minor errors in MFR Schedule G-2 (Audit Exception No. 7). In response to the audit report, the company corrected the errors and submitted a revised MFR Schedule G-2, dated January 16, 2004. Our staff compared these revised customer counts and therms by rate class to the historical data described above. The revised data conformed to the historical patterns observed over the last six years and did not materially differ from the data originally filed by the company. As such, we find that the projected test year customer counts and therms contained in revised MFR Schedule G-2, page 8 of 31 are appropriate.

III. QUALITY OF SERVICE

A. Periodic Meter Testing and Refunds

On March 21, 2003, an evaluation was conducted of the periodic meter test program of IGC. The purpose of this evaluation was to determine if the program is in compliance with the rule requirements of Rule 25-7.064, Florida Administrative Code (F.A.C.). The rule states, in part:

> (1)(a) Each gas utility may formulate a statistical sampling plan for the purpose of periodically testing installed diaphragm type positive displacement gas service meters having a capacity rating of 250 cfh or less measured at the manufacturer's specification for one-half (1/2) inch pressure differential. Such sampling plan shall be subject to approval by the Commission's Division of Auditing and Safety prior to implementation.

> (b) All meters installed of the above type and size not included in an approved Random Sampling Plan shall be periodically removed, inspected and tested at least once every one hundred twenty (120) months.
>
> (2) Meters having a capacity rating of 250 cfh through 2500 cfh measured at the manufacturer's specifications for one half (1/2) inch pressure differential shall be field tested or shop tested in accordance with American Gas Association's Gas Measurement Manual: Meter Proving Part No. Twelve, 1978 edition at least once every one hundred twenty (120) months.

Our staff's evaluation revealed that IGC was not performing periodic meter tests in accordance with Rule 25-7.064 (1) and (2), F.A.C. IGC indicated that the meters tested in the past years were not chosen based on the period of time in service, but based on apparent inaccurate measurement, inactivity, or possible damage. The ten-year limitation for a meter to remain in service was not a factor in the testing of customer meters.

A review of company records determined data was not available to document either the date of installation or the date of the last test for the 687 natural gas meters installed at the customers' premises. At the time of the evaluation, it was not possible to determine the number of meters not in compliance with the periodic test requirements due to the lack of meter history data. IGC has since developed a computer program to input and maintain the meter history information required by Rule 25-7.021, Florida Administrative Code. This new computer program has made it possible for company personnel to determine the actual number of meters not in compliance with Commission rule requirements. As part of its rate case MFRs, the company submitted Schedule I-3 that indicates there are 340 meters not in compliance with Commission periodic meter test requirements.

With the information provided in Schedule I-3 of the MFRs, the exact number of meters not in compliance with the Commission's periodic meter test requirements has been established, and company personnel have increased the number of meters being tested. During calendar year 2003, a total of 111 meters with a rated capacity of 2500 cfh or less were removed from service for testing. Of the 111 meters tested, only 70 of the meters were determined to be those meters identified in Schedule I-3 as not being in compliance with the periodic test requirement. The remaining 41 meters were removed for various causes, such as possible inaccuracies, meters that did not register, or meters removed at the customer's request.

On January 15, 2004, an evaluation was conducted to determine the status of the company's meter test program and refund records. The evaluation revealed that approximately 42 percent, or 270, of the company's 687 meters were not in compliance with Commission rules. It was further determined that customer refunds were not made in accordance with Rule 25-7.087(1), Florida Administrative Code.

The primary factor that must be considered in the development of an accelerated meter test program for IGC is the limited manpower that will be available to perform the actual meter change-out function. According to IGC, there are two employees that are qualified to perform the meter change-out task. These individuals are also responsible for all other routine field operations and maintenance activities for the natural gas system. Considering the limited manpower factor, it is estimated that approximately 20 months will be necessary to complete the change-out and test the 270 meters that are not in compliance with Commission rule requirements. However, we have allowed salaries for additional personnel and additional periodic meter and change-out expenses to aid the company in attaining compliance with the rules. Therefore, the company shall have all customer meters in compliance with Rule 25-7.064 (1) and (2), F.A.C., by December 31, 2005.

The March 21, 2003, evaluation of IGC's meter test program also noted one additional deficiency that results from the company's failure to make proper adjustments to customers' bills due to meter error. It was determined that 24 of the 64 meters tested during calendar year 2002 were found to have measurement inaccuracies in excess of two percent fast. Rule 25-7.087 (1), F.A.C., requires a utility to make adjustments to the bill of any customer whose meter was tested and found to measure in excess of two percent fast. This refund is to be calculated based on the amount billed in error for one half the period since the last test. This refund period should not exceed 12 months, unless the meter has not been tested in accordance with Rule 25-7.064, F.A.C. If the meter is not in compliance with the periodic meter test requirement, then the period of time for which the meter has been in service beyond the regular ten-year test period shall be added to the 12 months in computing the refund. By letter dated May 16, 2003, our staff directed IGC to initiate prompt action and make the appropriate refunds by July 31, 2003, for the 24 customers' bills whose meters were tested and found to measure in excess of two percent fast. Those refunds were to be made pursuant to Rule 25-7.087 (1), F.A.C.

The evaluation of January 15, 2004, determined that the company made partial refunds for 19 of the 24 customer meters which were not in compliance during the initial evaluation. A review of the method of calculation determined that these refunds were based on only calendar year 2002 consumption. No attempt was made to determine if the meters in question were beyond the ten-year periodic test limit. In the event that the company's meter history records cannot establish a date of the last test for a meter, we order that the refunds be recalculated using a multiplier of 10 times the average consumption to arrive at an equitable refund for the affected customers.

Accordingly, IGC shall make refunds for each of the meters tested during calendar years 2003 and 2004 and found to register more than two percent fast by July 31, 2004. The refunds shall be calculated based on the time the meter has remained in service beyond the ten-year test interval required by Rule 25-7.064, F.A.C. If the exact period of time beyond the ten-year interval cannot be established due to inadequate records, the calculation of the refund shall be based on ten times the customer's average annual therm usage obtained from available company records. If a customer moves from the service area without providing an address, a reasonable effort shall be made to locate the individual. If the refund cannot be completed, a record shall be established in accordance with Rule 25-7.091(7)(c), F.A.C., and we shall be informed of all unclaimed refunds and a method of disposal established.

In light of our decision to require the company to comply with the requirements by a date certain, we will not pursue show cause proceedings at this time. However, the company is put on notice that if the company is not in full compliance with Chapter 25-7, Florida Administrative, Code, by December 31, 2005, show cause proceedings shall be initiated.

B. Quality of Service

A customer meeting was held at Indiantown, Florida on February 5, 2004, to gather information from customers regarding the company's quality of service and its request for a permanent rate increase. One industrial customer and five Spanish speaking residential customers attended. A comparison of actual and proposed rates was translated into Spanish and handed out at the meeting to the Spanish customers. The presentation and questions and answers were also translated into Spanish. There were no quality of service complaints. The residential customers who attended opposed the increase in rates.

We reviewed the consumer complaints logged by the Division of Consumer Affairs. There have been no consumer complaints filed against IGC with the Commission for the period July 1, 1999 through February 29, 2004. There are no safety concerns at this time as well. However, as discussed previously, IGC is not in compliance with our rules regarding periodic meter testing and refunds. The company has committed to attain compliance by December 31, 2005, and is actively pursuing that end. Therefore, we find that IGC's quality of service is satisfactory.

IV. RATE BASE

A. Transfer of Office Building to Land

Our staff engineer reviewed and evaluated Account 389, Land and Land Rights, and determined that the value of the land purchased in 1967 should be $4,500 ($12,500 x 36%) rather than $2,948, for non-utility operations. The documentary stamp rate of 30 cents per $100 established a value of $12,500 for lot 6. The engineer recalculated IGC's 57.07% allocation factor of the land value. We calculated the total cost of the land to be allocated as 36% of the land used for utility and 64% used for non-utility operations. The recalculation of the allocation factor from 57.07% to 36% allocated to utility operations increased Account 389, Land and Land Rights, by $1,552.

After determining the cost of the land distributed between utility and non-utility operations, the company's non-utility plant allocation factor was recalculated from 6.2% to 33.79% reflecting an increase of $524.

B. Plant Additions

During our staff engineer's review and evaluation of IGC's construction budget, it was discovered that the construction budget was understated for the historic base year +1 and the projected test year. For the historic base year +1, IGC increased the expenditures for Accounts 376, Mains; 380, Service Lines (Plastic); and 382, Meter Installations, by $ 4,407. The projected test year additions show projected expenditures for the bare steel main replacement program, installation of new service lines, meter testing/replacement program, and power operated equipment during 2004. The increase in expenditures totaled $13,977 for the 2004 projected test year for Accounts 376, Mains; 380, Service Lines (Plastic); 381, Meters; 382, Meter Installations; 383, Regulators; 394, Tools/Work Equipment; and 396, Power Operated Equipment.

The total increase in additions due to changes in the construction budget is $18,024. To correct this understatement of the construction budget, Plant, Accumulated Depreciation, and Depreciation Expense shall be increased by $13,060, $646, and $1,040, respectively, for the 2004 projected test year.

C. Plant Retirements

Our staff engineer evaluated the monthly plant retirements for the 2004 projected test year. For Account 376, Mains, our staff calculated that 3,351 feet of new plastic mains would have to be installed to replace the bare steel mains. We believe that if 3,351 feet of new plastic mains were installed, then the same amount should be retired. The Handy-Whitman Index cost of $2.47/foot was used to calculate the average cost of ¾" main from 1964-1970. Therefore, the retirement would be $8,277 ($2.47 x 3,351 ft.). The 2004 retirements were projected to be $12,804, a difference of $4,527. To reflect the 13-month average, the $4,527 was re-calculated to be $2,264, with the applicable accumulated depreciation and depreciation expense.

D. Distribution System Recorded Prior to 1970

During the audit, our auditors discovered that IGC recorded $182,252 on the Continuing Property Record (CPR) and in Account 376, Mains, for a gas distribution system. There was no documentation supporting the installation of the distribution main. IGC performed aerial mapping and determined that 11,689 linear feet of mains were installed from 1964 though 1969. Also, there are 239 service lines (¾ inch) related to the mains installation.

An original cost estimate for the IGC Distribution System was prepared by our staff engineer using the Handy-Whitman Index of Public Utility Cost Trends. This resulted in an estimated cost of approximately $28,923 for the 11,689 linear feet of main. The installation of 239 ¾ inch services lines would be approximately $71,982. Therefore, the total original cost of the distribution system is approximately $100,905. The company recorded the costs on the CPR at $182,252, an overstatement of $81,347 to plant.

The calculation of depreciation expense and accumulated depreciation is for the period of 1969 through 2004. This is the first rate case for IGC, but it has filed five depreciation studies and received approved depreciation rates. The depreciation rates for 1969-1987 (2.8%), 1988-1992 (3.2%), 1998-2002 (2.3%), and 2003-2007 (4.2%) were applied to the overstated plant amount of $81,347. Accordingly, the accumulated depreciation and the depreciation expense shall be reduced by $81,110 and $3,417, respectively. IGC shall record $82,818 as the reduction to accumulated depreciation if it will be booked at 2004 year end.

E. Installation of Mains in New Hope Subdivision

During the audit, a staff engineer discovered that IGC did not capitalize 4,435 linear feet of mains and 34 service lines installed in the New Hope Subdivision in Booker Park in 1980. An estimated original cost was prepared by a staff engineer using the Handy-Whitman Index of Public Utility Cost Trends for the Booker Park Distribution System. The estimated cost for the installation of the mains for the system is approximately $30,536. Since the installed mains were not capitalized, the adjustment for the projected test year should be an increase to plant for the $30,536. The accumulated depreciation and depreciation expense shall be calculated based upon the Commission approved depreciation rate for Account 376, Mains, from 1980 through 2004. The Commission approved depreciation rates for 1980-1987 are (2.8%), 1988-1992 (3.2%), 1993-1997 (3.1%), 1998-2002 (2.3%), and 2003-2007 (4.2%). The resulting accumulated depreciation and depreciation expense for the installed mains at Booker Park shall be increased by $21,040 and $1,283, respectively. IGC shall record $21,681 as an increase to accumulated depreciation if it will be booked at 2004 year end.

F. Total Gas Plant in Service

The approved $1,307,395 is based upon the preceding adjustments. The total adjustment for the reduction to Plant in Service is $33,935 for the projected test year. This amount includes: (1) an increase of $13,060 for understated additions, (2) an increase of $2,264 for overstated retirements, (3) a reduction of $81,347 for plant overstated since 1969, (4) a $30,536 increase for mains installed but not capitalized, and (5) a $1,552 increase to Plant in Service for the recalculation of the land value for non-utility operations.

G. Common Plant – Non-Utility Operations

The company allocated non-utility plant for 2004, using a non-utility factor of 6.2%. The 6.2% was calculated using net non-utility plant to total net plant. We believe that using this percentage of net non-utility to total net plant may not be the most reasonable methodology to allocate common plant. Our auditor believes using this one factor does not allow proper allocation of non-utility plant. Instead, we propose to use a three factor methodology allocation based on regulated revenues, gross plant, and payroll. Using this three factor method would increase the non-utility factor from 6.2% to 42.93%.

The company disagrees with the application of the proposed three factor methodology for allocating plant assets between utility and non-utility operations. The company disagrees with using the company's 2003 margin revenue compared against gross revenue for non-utility operations. The relative costs to operate the company's business units have not substantively changed subsequent to its unbundling of the utility. The company believes applying the revenue factor proposed in our staff audit would have a dramatic and inappropriate effect on the historic cost allocations. The company believes such an allocation would over allocate common plant cost to the non-regulated business.

The company also disagrees with the use of regulated payroll to unregulated payroll as a factor in our three factor allocation. The company directly charges field staff payroll costs to the appropriate business unit based on the actual work performed. The cost of the Officers and Office Manager are allocated. Our auditor received job descriptions for each employee and a specific assessment of the time spent on utility vs. non-utility activities. Our staff indicates that the company's time allocations do not appear reasonable when looking at direct labor charged to total labor or the amount of revenues generated from non-utility operations. The company believes our auditors made the assumption that the time spent by the Officers in managing the utility and the non-utility business follows the direct labor charged to the respective units by field employees. The company believes that this assumption is not accurate. The third factor our auditor proposed is based on a comparison of gross plant between the utility and non-utility units. The company originally proposed the use of a ratio of net regulated plant to net non-regulated plant in the historic base year as its plant allocation method. The company agrees with the use of our auditor's gross plant ratio in 2003 as an appropriate method of allocating plant.

We have recalculated non-utility plant based on a three factor methodology using number of customers, gross plant, and payroll. We believe that this three factor methodology is a more appropriate method for allocating common costs between regulated and non-regulated operations. This method gives the company a broader based allocation. Using the number of customers is more accurate because the number of customers does not change on a constant basis. We also believe payroll to be an accurate factor as well. Some of the office staff perform duties that are specific to regulation and are not directly related to supervising the field employees. Per Audit Exception 11, detailed job descriptions from the office employees with hours spent each month was reviewed. These employees put an allocation between regulated and non-regulated on the job descriptions. Using payroll as a factor is reasonable because it shows a description for regulated and non-regulated charges, as well as the amount of time spent on the utility. The third factor proposed was gross plant. Gross plant is all property and plant used to produce the company's primary service function. Gross plant is established by its original cost, and is the summary account appearing in the balance sheet. The costs of utility plant is functionally allocated to utility plant in service, which includes facilities for production, transmission, and distribution. We believe gross plant will give the company a more accurately based amount to be included in the calculation of the three factor methodology. The company agrees with the use of gross plant as a factor to be used in the three factor allocation. Based on the company's actual number for each of the three factors, the overall non-utility percentage increases from 6.2% to 33.79%. We find that this three factor methodology is more reasonable because this methodology provides a broader based allocation. We do not propose using revenue as a factor because revenue is too variable to be included. We have previously approved the use of a three factor methodology using payroll, plant, and number of customers. See Order No. PSC-O1-0316-PAA-GU, issued February 5, 2001, in Docket 000768-GU, In Re: Request for rate increase by City Gas Company of Florida. Accordingly, we find that using the number of customers, the amount for gross plant, and payroll is more reasonable.

We did not include Account 394 for tools and Account 396 for power operated equipment in the allocation because they were determined to be 100% utility related. Based on the recalculation using the three factor methodology of number of customers, gross plant, and payroll, we increase the non-utility factor from 6.2% to 33.79%.

We find that non-utility Plant, Accumulated Depreciation, and Depreciation Expense shall be increased for the December 2004 projected year, by $110,303, $13,800, $9,420, respectively, to reflect the re-calculation of the allocation factors for non-utility plant.

H. Total Common Plant Allocated

Based on the above adjustments, the appropriate amount of Total Common Plant Allocated is $135,575. Section IV, G provides a detailed explanation of the recalculation of the allocation factors which changed from 6.2% to 33.79% for non-utility plant.

I. Total Plant

Based on the above, we find the appropriate amount of Total Plant for projected test year to be $1,171,820.

J. Accumulated Depreciation and Amortization of Plant in Service

Based on our adjustments above, the appropriate amount of Accumulated Depreciation and Amortization of Plant in Service for the projected test year is $614,709.

K. Cash in Working Capital

Per Audit Exception 5, the cash included in working capital in the last three months of 2003, and for the projected test year 2004, are the remaining amounts after all the balance sheet accounts are forecast. The company projected cash in the amount of $152,740. The company projected cash as a function of projected revenue. We adjusted cash based on a three year average. The three year average from 2001 through 2003 was $56,659. Using a three year average gives the company a more accurate amount to work with. In other cases a five year average has been used due to a negative cash balance. We believe using a three year average would be more indicative of the trend, since there was no negative cash balance. As such, we find that an adjustment be made decreasing cash in working capital to reflect the three year average in the amount of $96,081 ($152,740-$56,659).

L. Non-Utility Allocation of Working Capital

The company projected cash in the amount of $152,740. Per Audit Exception 5, the cash balances were not reduced for non-utility operations. An adjustment should be made decreasing cash by $19,145 ($56,659 x 33.79%) to reflect the non-utility allocation based on the three factor method previously discussed.

Per Audit Exception 4, Working Capital's plant and operating material and supplies are company Account 154, Inventory, and Account 156, Capital Inventory. We determined the invoices in Account 154 indicated that this account was for the purchase of appliances and supplies for resale; therefore, it should be removed from working capital. These items do not relate to the regulated natural gas utility and are disallowed by statute. The company projected $18,001 for the 2004, projected test year. The 2004 13-month average utility related balance for Account 156 is $6,009. The 13-month average plant and operating materials and supplies shall be decreased by $11,992 ($18,001-$6,009), to reflect the removal of Account 154, Inventory.

For accounts payable the company removed 6.2% for non-utility payables for 2004, in the amount of $4,660. Using a three factor method to calculate the non-utility allocation factor of 33.79%, we decreased accounts payable by $20,737 (75,160 x 33.79%-$4,660), to reflect our staff's three factor method of allocation.

The net adjustment to the company's working capital shall be a decrease of $10,400 (-$19,145 - $11,992+$20,737).

M. Transition Cost Recovery Deferred Debits

Per Audit Exception 3, in the working capital calculation starting October 2003, there are deferred debits in the amount of $12,243. The 13 month average for 2003 is $2,612. The deferred debits are in the amounts that the company will collect over 24 months from one transportation customer for the Transition Cost Recovery (TCR) amounts. The TCR is comprised of costs incurred to transition its customers to transportation services. By Order No. PSC-03-1109-PAA-GU, issued October 3, 2003, in Docket 030462-GU, In Re: Petition of Indiantown Gas Company for approval of transition cost recovery charge and for approval of final purchased gas adjustment true-up credit, we approved $22,158, to be billed over 24 months ($923). Per Audit Exception 3, the company should have forecasted $20,432 for October 31, 2003. The company, at the end of October, already billed this customer for two months. In its MFRs, the company projected the deferred debits at year end December 31, 2004, at zero and the 13-month average as $4,911. We have made adjustments to reflect these changes. We have increased the 2004, 13-month average by $8,137 ($4,911 to $13,048). The year end December 31, 2004, shall be changed from zero to $7,510. Accordingly, we find that Deferred Debits shall be increased by $8,137 to reflect the changes in this calculation.

N. Accrued Taxes Payable

According to MFR Schedule G-1, Page 8 of 28, the company proposed a credit amount of $3,850 for Taxes Accrued - General for the projected test year.

We determined, based on the company's response to a data request, that the company did not include any accrued property taxes in Taxes Accrued – General. Using the property taxes calculated, the correct 13-month average for accrued property taxes is $2,609. Therefore, Taxes Accrued – General shall be increased by $2,609 to reflect the correct balance of the accrued property taxes payable account.

O. Total Working Capital

Based on the adjustments above, the appropriate amount of Working Capital Allowance for the projected test year is $31,814. Working Capital is shown on Attachment 1A, attached hereto and incorporated herein by reference.

P. Total Rate Base

Based on the adjustments above, we calculate the Rate Base to be $588,925 for the projected test year. Our calculation of Rate Base is shown on Attachment 1, attached hereto and incorporated herein by reference.

V. COST OF CAPITAL

A. Cost Rate for Common Equity

In Order No. PSC-02-1666-PAA-GU, issued November 26, 2002, in Docket No. 020470-GU, In Re: Request for Limited Proceeding by Indiantown Gas Company for Approval of Natural Gas Tariff, Original Volume No. 2, Implementing Restructured Rates, we established an authorized return on equity (ROE) for IGC of 11.50% with a range of plus or minus 100 basis points. In the instant docket, the company is requesting that its authorized ROE remain at 11.50%.

In the past year and a half, we have conducted cost of equity reviews in the disposition of rate cases involving two other natural gas distribution companies and one small electric utility. In Order No. PSC-03-0038-FOF-GU, issued January 6, 2003, in Docket No. 020384-GU, In Re: Petition for Rate Increase by Peoples Gas System, we approved a stipulation that included an ROE of 11.25%. In Order No. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 030569-GU, In Re: Application for Rate Increase by City Gas Company of Florida, we approved an ROE of 11.25%. Finally, in Order No. PSC-04-0369-AS-EI, issued April 6, 2004, in Docket No. 030438-EI, In Re: Petition for Rate Increase by Florida Public Utilities Company, we approved a settlement reached between the parties that included an ROE of 11.50%.

IGC is significantly smaller, both in terms of net plant and total revenues, than any of the aforementioned companies. In addition, IGC's risk profile and general character of service indicates greater risk thereby warranting an authorized ROE greater than the return approved for either Peoples Gas System or City Gas Company. For these reasons, we approve an authorized ROE of 11.50% with a range of plus or minus 100 basis points for purposes of this proceeding.

B. Weighted Average Cost of Capital

Based upon the proper components, amounts, and cost rates associated with the capital structure for the projected test year ending December 31, 2004, the appropriate weighted average cost of capital is 9.53%. The capital structure is shown on Attachment 2, attached hereto and incorporated herein by reference.

The company per book amounts were taken directly from IGC's MFR filing, Schedule G-3. Three specific adjustments were made to the company's filing. First, the company's adjustment to simultaneously increase common equity and reduce long-term debt to target a 60% equity ratio was reversed. While it is true that we established an equity ratio cap of 60% in Order No. PSC-02-1666-PAA-GU, the intent of our Order was to limit the equity ratio to 60% of investor capital for purposes of earnings surveillance. As noted in Audit Disclosure No. 2, the Order did not authorize the company to make adjustments to target a 60% equity ratio for purposes of setting rates in future proceedings.

The second adjustment reversed the company's adjustment to remove non-utility investment directly from common equity. Historically, it has been Commission practice to remove non-utility investments from equity when reconciling rate base and capital structure. This treatment discourages companies from subsidizing higher risk, non-utility investments with the lower cost of capital associated with less risky utility operations. However, removal of non-utility investments solely from common equity in the instant case would produce an unreasonably low equity ratio (less than 30%). In similar cases, most recently in Order No. PSC-

04-0128-PAA-GU involving City Gas Company, we waived this adjustment to avoid the same outcome.

The third adjustment reduced the company's long-term debt balance. As noted in Audit Disclosure No. 3, the company projected a significant increase in its long-term debt balance over actual levels maintained in 2002 and 2003. Per discussions with the company, IGC acknowledged that the forecasted debt had not been issued. Moreover, IGC stated that it is extremely unlikely that the forecasted level of debt would be achieved during the 2004 projected test year. Our staff made an adjustment consistent with the auditor's finding that reflects a more accurate balance of long-term debt outstanding for the projected 2004 test year.

We used the respective cost rates supplied by the company with one exception. We used a cost rate for long-term debt of 7.74% rather than the 8.10% shown in the company's filing. Because of the adjustment to the long-term debt balance, it was necessary to recalculate the cost rate to be consistent with the revised debt balance for the projected test year. We agreed with the cost rate for customer deposits of 6.22% and the return on equity (ROE) of 11.50%.

Due to various factors, most notably the relatively small size of the company and past operating losses, IGC's capital structure does not contain preferred stock, short-term debt, deferred taxes, or investment tax credits. After all specific adjustments were made, we made a pro rata adjustment over all sources of capital to reconcile rate base and capital structure.

Finally, although the equity ratio implicit for purposes of this proceeding is well under the 60% cap established in Order No. 02-1666-PAA-GU, we find that the 60% equity ratio cap shall remain in effect going forward. In addition, while we find that the adjustment to remove non-utility investment directly from equity shall not be made in this proceeding for the reasons discussed above, such action shall not be interpreted to mean this adjustment will not be ordered in future proceedings if the situation warrants.

VI. NET OPERATING INCOME

A. Projected Operating Revenues

Per MFR Schedule H-3, Page 2, IGC shows present revenue from sales of gas for the projected test year of $338,798. Our calculation of projected revenues based on the projected billing determinants results in a total of $339,190, an increase of $392.

IGC submitted a revised MFR Schedule G-2, page 8, to correct errors to the billing determinants for the TS-1, TS-2, TS-3, and Third Party Supplier (TPS) rate schedules. Based upon these revised billing determinants, the TS-1 revenues shall be increased by $719 to reflect a correction to the bills and therms. The TS-2 revenues shall be decreased by $503 to reflect a correction to the bills and therms. The TS-3 revenues shall be increased by $104 to reflect a correction to the therms. Finally, the TPS revenues shall be increased by $72 to reflect a correction to the bills.

Based on the adjustments above, we find that revenues shall be increased by $392.

B. Total Operating Revenues

Based on the above adjustments, we calculate Total Operating Revenues for the projected test year to be $343,310.

C. Non-Utility Expenses

The company records certain expenses in clearing accounts and allocates them between regulated and non-regulated operations.

1. Account 921, Office Supplies

Per Audit Exception No. 12, the company pays an individual $40.00 per week to clean the office. However, the $4,720 charged to a clearing account included the cleaning charges for the residences of one employee and three family members. We find that the $2,920 in charges for cleaning the homes are non-utility expenses, and consistent with prior Commission decisions, shall be disallowed. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on the allocation factor, trended to 2004, using our staff's trend rates. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors. Therefore, we find that Account 921, Office Supplies, shall be reduced by $2,042 ($2,920 x .6621 x 1.019 x 1.0363). The company agrees with this adjustment.

2. Account 930, General Advertising and Miscellaneous General Expense

Per Audit Exception No. 12, in 2002, the company included $171 in a clearing account for clothing purchased for employees. The company logo was not on the clothes nor did the clothing show any indication that they were uniforms for utility business use. We find that these are non-utility expenses, and should not have been allocated to the utility. Consistent with prior Commission practice, these costs are disallowed. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on the allocation factor, trended to 2004, using our staff's trend rates. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors. Therefore, we find that Account 930 shall be reduced by $118 ($171 x .6621 x 1.019 x 1.021). The company agrees with this adjustment.

3. Account 932, Maintenance of General Plant

In 2002, the company included $571 in a clearing account for car repairs on the Chief Executive Officer's (CEO) Lexus. The Lexus is not in rate base and is not a utility vehicle. We find that these are non-utility expenses and shall not be allocated to the utility. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on the allocation factor, trended to 2004, using our staff's trend rates. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors. Therefore, we find that Account No. 932 shall be reduced by $393 ($571 x .6621 x 1.019 x 1.021).

Based on the above adjustments, we find that expenses shall be reduced by $2,553.

D. Non-Utility Allocations

Per Audit Exception 12, the company charges common expenses to clearing accounts and allocates them between regulated and non-regulated operations. In 2002, the company used revenue factors to allocate the common expenses each month. The average percentage allocated to utility operations was 62.28% of the common expenses, or $116,678.

Using revenue alone may not be the most reasonable allocation method to allocate common expenses. We find that the three factor method is a more reasonable approach because most costs are not directly related to revenue. Therefore, we allocated 66.21% of common expenses to the regulated utility based on the three factor percentage.

We calculated the difference between the amount of expenses allocated to the utility by the company ($116,678) and the expenses allocated to the utility using our staff's factor ($126,509) and trended each account by the appropriate trend factor to 2004. Therefore, we find that expenses shall be increased by $10,341.

E. Non-Utility Allocation of Administrative & General (A&G) Salaries

Per Audit Exception 11, field employees prepare time sheets and charge their payroll directly to regulated or non-regulated operations. The company allocates A&G payroll between regulated and non-regulated operations. The company allocated salaries for the CEO, the President, the Chief Financial Officer (CFO), and the office manager using fixed allocation percentages which allocated 87.61% of these salaries to regulated operations.

The field staff charges 23.70% of its payroll directly to regulated operations, 55.04% to non-regulated operations, and 21.25% is capitalized. Because the A&G payroll charged to regulated operations was so much higher than the direct labor charged by the field staff and because the auditor believes some of the office staff performs duties that are specific to regulation and are not directly related to supervising the field employees, our auditor calculated a payroll allocation factor.

To determine the appropriate payroll allocation factor, the auditor asked the company to provide detailed descriptions of the duties of the CEO, the President, the CFO, and the office manager, and the amount of time spent on each task. The company determined the amount of time they spent on regulated vs. non-regulated duties. Our audit staff separated the time based on the descriptions into five categories: 1) regulated duties specific, 2) non-regulated duties specific, 3) indirect general, 4) indirect employee related, and 5) indirect financial related. The payroll was then allocated to the above categories based on the percentages provided by the officers and office manager. Next, the auditor allocated the indirect general and the indirect financial categories by an average of the percent of regulated gross plant to total gross plant and regulated revenue to total revenue (57.10% regulated). The indirect employee related category was allocated based on the percent of total payroll except this category (57.02% regulated). The amounts allocated to regulated and non-regulated were then totaled and the percent of total payroll was calculated to be 57.02% regulated and 42.98% non-regulated.

We agree with our auditor's calculation except for the use of revenue as a component of the two factor allocator for allocating the indirect general and indirect financial categories. We believe that the ratio of natural gas customers to total customers is a better allocator because revenue is variable depending on weather, usage by industrial customers, etc. Therefore, we used the same method the auditor used, as described above, except that we used a two factor method consisting of regulated gross plant to total plant and number of natural gas customers to total customers for allocating the indirect general and indirect financial categories. In addition, we included the impact of the new employees and the increase for the CFO in our calculation of the payroll factor. This calculation resulted in a payroll allocation factor of 62.91% regulated and 37.09% non-regulated. We believe this payroll factor is a more accurate and reasonable method to allocate A&G salaries.

Per audit workpapers, the total A&G salaries to be allocated is $172,457. Using the 62.91%, the regulated office salaries came to $108,492. To that amount, we added the direct regulated payroll of $20,011 for a total regulated payroll of $128,503. In its trend schedule, IGC included $170,820 of regulated direct and allocated payroll. Therefore, we find that A&G salaries shall be reduced by $44,459 ($170,820 - $128,503 = $42,317 trended by the payroll trend factor to 2004). This calculation does not include the impact of the adjustment to reduce expenses for the effect of the change in trend factors. An adjustment was made to reduce Taxes Other Than Income to remove the related withholding taxes.

F. Membership and Dues

Per Audit Exception 12, the company included $245 in a clearing account for AAA membership dues for two employees and three family members and allocated it to Account 932.

In addition, the company also included $422 in a clearing account for YMCA dues for five employees and two family members and allocated it to Account 926. The AAA and YMCA memberships are not part of the company's overall benefits package.

We find that the cost of these memberships are disallowed because they are non-utility in nature and do not provide a benefit to ratepayers. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on the allocation factor, trended to 2004, using inflation trend rates. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors.

Therefore, we find that Account 932, Maintenance of General Plant, and Account 926, Employee Pensions and Benefits, shall be reduced by $169 ($245 x .6621 x 1.019 x 1.021) and $290 ($422 x .6621 x 1.019 x 1.021), respectively, for a total of $459.

G. Nonrecurring Expenses

1. Account 880, Other Expenses

Per Audit Exception No. 8, Account 880 contains $438 in direct charges for a telephone line that was no longer in use as of July, 2002. The company inadvertently failed to cancel the line. IGC does not plan to replace this line, therefore this is a nonrecurring cost. Hence, we find that Account 880 shall be reduced by $456 ($438 x 1.019 x 1.021) for a telephone line that is no longer in use and will not be replaced. This calculation does not include the impact of the adjustment to reduce expenses for the effect of the change in trend factors. The company agrees with this adjustment.

2. Account 921, Office Supplies

The company recorded $754 in a clearing account for meals and entertainment expense related to Docket No. 020470-GU, In Re: Request for a limited proceeding by Indiantown Gas Company for approval of Natural Gas Tariff, Original Volume No. 2, implementing restructured rates. These are nonrecurring expenses and should be removed from the test year. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on the allocation factor, trended to 2004, using customer growth times inflation trend rates. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors. Therefore, we find that Account 921, Office Supplies, shall be reduced by $527 ($754 x .6621 x 1.019 x 1.0363).

3. Account 923, Outside Services

In addition, the company recorded $250 in direct charges for Lester Construction in Account 923, Outside Services. According to IGC, this was a one-time charge. Therefore, it shall be removed from test year expenses. We find that Account 923 shall be reduced by $260

($250 x 1.019 x 1.021). This calculation does not include the impact of the adjustment to reduce expenses for the effect of the change in trend factors. The company agrees with this adjustment.

Further, the company recorded $5,400 in direct charges in Account 923 for accounting services related to Purchased Gas Adjustment (PGA) filings. This expense was disallowed by Order No. PSC-04-0180-PCO-GU, in this docket because IGC will no longer participate in the PGA and filings will not be required. Therefore, expenses shall be reduced by $5,618 ($5,400 x 1.019 x 1.021). This calculation does not include the impact of the adjustment to reduce expenses for the effect of the change in trend factors. The company agrees with this adjustment.

Based on the above adjustments, we find that expenses shall be reduced by $6,861.

H. <u>Service Technician Salary</u>

According to Audit Disclosure No. 4, the company requested $13,498 for 50% of the salary for a Service Technician. The other 50% will be capitalized because half of this position involves the bare steel replacement program. IGC included a pro forma adjustment to 2004 expenses to include the entire $13,498 in expenses. The company should have made an incremental adjustment to include only the portion of the salary not already included in expenses, as discussed below.

The bare steel program has been approved by this Commission for the past few years and requires this position, at a minimum of part-time, to complete this task. The remainder of the time allocated to this position primarily includes the accelerated meter change-out program approved by us. Secondary functions will include valve maintenance and damage prevention/line location.

The company compared compensation for this position by job description to other jobs as listed by the local workforce development board and U.S. Department of Labor statistics. The proposed salary falls within the range of the hourly rates for similar positions.

This employee worked part-time for the company in 2002 and received $10,129 in salary or $10,642 trended to 2004. Thus, $10,642 is already included in 2004 expenses. In addition, the company estimates that this employee will spend 15% of his time on non-utility work. Therefore, an adjustment is necessary to remove the non-utility portion of the salary.

The company should receive the cost to employ the Service Technician because we have directed IGC to come into compliance with Rule 25-7.064(1) and (2), Florida Administrative Code. However, we find that Account 874 shall be decreased by $10,642 to remove the Service Technician's salary already included in 2004 expenses plus 15% of $13,498 ($2,025) for non-utility tasks for a total decrease of $12,666. This adjustment is not impacted by the A&G salary adjustment because this employee will charge his time directly. An adjustment has been made to reduce Taxes Other Than Income to remove the related withholding taxes.

I. Periodic Meter and Regulator Change-Out Expense

As discussed previously, the company is involved in a meter change-out program to bring it into compliance with Commission rules. Two hundred seventy meters remain to be changed out by December 31, 2005. We calculated the following expenses related to this program: $8,000 for labor to change-out and replace the meter and regulator with a new meter and regulator; $7,360 for shipping and handling to send meters to Georgia for testing; plus $3,969 for the cost of testing in Georgia. Total expenses are $19,329.

Pursuant to Rule 25.7-0461(8), Florida Administrative Code, "All maintenance costs, whether the work is done by the utility or under contract, should be expensed. Unusual or extraordinary expenses can be amortized over a reasonable period of time as determined by the Commission." We believe that these are extraordinary expenses because IGC has neglected to change-out meters for many years.

To amortize the expense over the two years to complete the project would allow excessive expense in the projected test year. Rule 25-7.064(1) and (2), F.A.C., sets a ten-year limitation for a meter to remain in service. However, data was not available to document either the date of installation or the date of the last test for all 687 meters. Therefore, we determined that of the 687 meters, 69 should be tested each year (687/10). We divided the 270 meters left to be tested by 69 and the result was approximately four. Therefore, we find that a reasonable amortization period is four years.

We find that $19,329 shall be amortized over four years, that expenses shall be increased by $4,832 ($19,329/4), and that the 13-month average of the unamortized portion of the meter change-out costs, or $7,249 ($19,329 - $4,832/2) shall be included as an increase to working capital in Miscellaneous Deferred Debits.

J. Customer Service Representative Salary

Per Audit Disclosure No. 4, the company requested $9,380 each in Accounts 880 and 889 for a total of $18,760 for a Customer Services Representative. Fifty percent of this position is being charged to Account 889 due to the increased record keeping required for compliance with Rule 25-7.064, Florida Administrative Code, and our staff's request which was contained in a May 16, 2003 letter. According to the letter, IGC committed to changing-out almost half of its existing meters over a three-year period. The company is confident this task can be accomplished; however, it cannot meet the recordkeeping requirements with existing staff. In addition, the Customer Service Representative would assist with other Operation and Maintenance (O&M) functions, such as Operator Qualification recordkeeping, Public Awareness and Contractor Notification.

The company provided information from the U.S. Works – Development Board of the Treasure Coast web site, that shows that the salary is based on the median salary of $9.00 per hour. We find that this is a reasonable rate based on the job description of this position.

Based on the company's response to our data request, 20% of the Customer Service Representative's time will be spent on non-utility work. Therefore, 20% or $3,752 ($18,760 x .2) shall be allocated to non-utility operations. This calculation does not include the impact of the adjustment to reduce A&G salaries because this expense is a pro forma expense, was not included in 2002 expenses, and thus was not trended to 2004.

We believe the company has justified this position. However, we find that that Accounts 880 and 889 shall be decreased by $1,876 each for a total decrease to expenses of $3,752 to remove the non-utility portion of the salary. An adjustment was also made to reduce Taxes Other Than Income to remove the related withholding taxes.

K. Odorant Costs

IGC purchases odorant based on field monitoring of tank levels and purchasing lead time. Therefore, the company did not purchase odorant in 2002 and did not include odorant costs in the 2002 operating expenses.

In January 2004, IGC purchased odorant at a cost of $2,143. The quantity purchased will last the company approximately three years. Therefore, odorant costs should be amortized over three years. Hence, we find that expenses shall be increased by $714 for odorant costs ($2,143 / 3). In addition, a corresponding adjustment of $715, increasing working capital prepayments is appropriate to include the unamortized 13-month average of the remaining balance ($2,143 - $714/2).

L. Meter Reading Expense

The company included $6,388 in this account for 2004. Per Audit Exception 9, in 2002, IGC employed a meter reader; however, this employee left in October 2003. The company could not find a dependable person to fill the position. Thus, it entered into a contract with a meter reading company to read each meter for 65 cents each, or $5,218 annually. Adjustments were made to this account reducing it by $1,390 for allocations from A&G salaries and for the effect of changing the trend factors. We find that the balance of this account be increased by $220 ($5,218 + $1,390 - $6,388) in order to allow the $5,218 for the meter reading contract.

M. Chief Financial Officer's Salary Increase

Per Audit Disclosure No. 4, the company requested $14,000 in this account to increase the CFO's work schedule from one-half to three-quarter time. The CFO is principally responsible for administering the company's Aggregated Transportation Service (ATS) Program.

According to the company, the increased reporting, customer information, and accounting functions directly related to the program have necessitated the increase in work hours. The result of these activities has been to add approximately forty hours per month in staff time to account for these items. The company provided the following breakdown of these activities and approximate time required to complete each:

> Reconcile Third Party Supplier (TPS) bill (scheduled volumes) with actual throughput (8 hours);
> Reconcile TPS fuel balances (8 hours);
> Validate customer payment records by month (8 hours);
> True-up TPS collection of taxes (5 hours);
> Partial payment reconciliation (4 hours);
> Prepare statement of charges for marketer (2 hours);
> Administration of Fixed Price Program (2 hours); and
> TPS annual audit (1 hour).

We believe that the company has justified the requested increase for this position. However, the CFO's salary is not directly charged to regulated and nonregulated accounts, but rather it is charged to a clearing account and then allocated to utility and non-utility operations. Therefore, a non-utility adjustment is necessary.

Using the payroll factor, we find that expenses shall be decreased by $5,193 ($14,000 x .3709). This adjustment is not impacted by the adjustment to allocate A&G salaries because this was a pro forma adjustment and not included in 2002 expenses. An adjustment was made to reduce Taxes Other Than Income to remove the related withholding taxes.

N. Employee Activities

In 2002, the company recorded $1,756 in a clearing account for a baseball game and dinner ($568), the employees annual dinner ($821), and the president's award dinner ($367). Consistent with prior Commission Orders, we find that one-half of the amount shall be allowed. See Order No. PSC-92-0580-FOF-GU, issued June 29, 1992, in Docket No. 910778-GU, In Re: Petition for a rate increase by West Florida Natural Gas, p. 35.

Therefore, we find that Account 921 shall be reduced by $614 ($1,756/2 x .6621 x 1.019 x 1.0363). This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors.

O. Entertainment Expense

Per Audit Disclosure No. 6, the company charged $2,064 for meals and lodging which included spouses and non-employees. In addition, $180 in personal meals were charged to the company plus $564 in lodging for which the company provided no support. The $2,808 in total entertainment expenses was charged to a clearing account.

Consistent with prior Commission decisions, we removed the meals and lodging of the spouses and non-employees ($1,250), the personal charges ($180), and the unsupported lodging ($564). Accordingly, we find that Account 921 shall be reduced by $1,394 ($1,994 x .6621 x 1.019 x 1.0363) for non-utility entertainment expenses. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors.

P. Costs for Prior Unbundling Docket

The company included $24,988 in 2002 expenses in this account. IGC reduced this account by $982 for costs removed in the unbundling docket and then trended the account for inflation. A total of $25,221 was included in 2004 expenses.

Per Audit Exception No. 13, IGC included $12,902 of costs for the prior unbundling docket (Docket No. 020471-GU), $12,029 of which was recovered in the last purchased gas recovery docket. (Order No. PSC-03-1109-PAA-GU, issued October 6, 2003, in Docket No. 030462-GU, In re: Petition of Indiantown Gas Company for approval of transition cost recovery charge and for approval of final purchased gas adjustment true-up credit). The company attempted to remove these costs by reducing the account by $982. However, the $982 was associated with computer costs not related to the unbundling and should have been left in the account instead of being removed. Therefore, this account shall be reduced by $11,047 ($12,029 - $982). We trended this amount by inflation and reduced this account by $11,493 for unbundling costs recovered in a prior docket. This calculation does not include the impact of the adjustment for the change in trend factors.

Further, costs related to computer repairs of $873 charged directly to Account 923 should be allocated to non-regulated operations because the computers are used for regulated and non-regulated operations. Using the three factor methodology, this allocation would be $295 ($873 x .3379). We trended this amount by inflation and reduced this account by $307. This calculation does not include the impact of the adjustment for the change in trend factors.

Based on the above adjustments, we find that Account 923 shall be decreased by $11,800.

Q. Life Insurance Expenses

Per audit workpapers, IGC included the cost of three life insurance policies on its President in expenses. Two of these policies relate to a life insurance component of the company's pension plan. This provision provides a fully funded pension for the beneficiary if the employee dies before retirement. In 2002, the company included $690 in a clearing account for the cost of a Northwestern life insurance policy on its President.

The Northwestern policy is of a personal nature and not a part of the Glades Gas group life insurance provided by IGC to its employees as part of the benefits package or part of the pension plan requirement. This is a non-utility expense and should not be included in operating expenses. Accordingly, we find that Account 926 shall be reduced by $475. ($690 x .6621 x 1.019 x 1.021).

R. Out of Period Expense

1. Account No. 923, Outside Services

Per Audit Exception No. 13, the company directly charged $1,890 to Account 923, Outside Services, for expenses related to its 2000 tax return. We trended this amount by inflation and reduced this account in 2004 by $1,966 to remove this out of period expense. This calculation does not include the impact of the adjustment for the change in trend factors. The company agrees with this adjustment.

2. Account No. 926, Employee Pensions and Benefits

The company recorded $5,000 in a clearing account for the 2000 contribution to its 401K Plan. This is an out of period expense and consistent with prior Commission practice should be removed. Therefore, we find that Account 926 shall be reduced by $3,445 ($5,000 x .6621 x 1.019 x 1.021).

Based on the adjustments above, we find that Account No. 923, Outside Services, and Account No. 926, Employee Pensions and Benefits, shall be reduced by $1,966 and $3,445, respectively, for a total adjustment of $5,411 to remove out of period expenses.

S. Rate Case Expense

According to the company's MFRs, IGC projected rate case expense of $100,050 for this proceeding. The company amortized this amount over four years and included $25,013 in Account 928, Regulatory Commission Expense, for rate case expense. The company provided an updated rate case expense based on actual expense to date and an estimate to complete the case. IGC projected $35,000 for consulting fees; however, the updated actual amount is now $36,000, provided there is no protest. Therefore, expenses for consulting should be increased by $1,000. In addition, IGC projected $55,050 for legal fees. The updated estimate for legal expenses, provided there is no protest, is $12,000, therefore legal expenses should be reduced by $43,050. Further, miscellaneous expenses were projected to be $10,000. The updated estimate is $4,500, thus miscellaneous expenses should be reduced by $5,500. Based on the foregoing, rate case expense shall be reduced by $47,550. The remaining $52,500 of expenses incurred by the company are reasonable and prudent. The company requested that rate case expense be amortized over a period of four years. In prior cases, the Commission has amortized rate case expense over the length of time between the company's last rate case. However, this is IGC's first rate case. As such, we find that four years is a reasonable time period over which to recover rate case expense.

Based on the above, the appropriate amount of rate case expense is $52,500 to be amortized over four years. The appropriate amount to be included in rate case expense is $13,125 ($52,500/4). Accordingly, expenses shall be reduced by $11,888

T. American Gas Association Membership Dues

In 2002, the company included $500 for its annual AGA dues. We have traditionally removed that portion of AGA dues that is attributable to lobbying, charitable contributions, and advertising that do not meet the criteria of being informational or educational. By Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, in Docket No. 000108-GU, In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, we removed 45.10% of AGA dues. By Order No. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 030569-GU, In Re: Application for rate increase by City Gas Company of Florida, we removed 40% of AGA dues. In that case, we reviewed the NARUC Audit Report dated June, 2001, for the twelve month period ended December 31, 1999, the most recent report that could be located. By a review of the Summary of Expenses, it appeared that 41.65% of 1999 AGA expenditures were for lobbying and advertising.

Consistent with these cases, we find that Account 930, Miscellaneous General Expense, shall be reduced by 40% for AGA dues, or $208 ($500 x .4 trended to 2004) to remove lobbying and advertising that is not informational or educational in nature.

U. Advertising Expenses

In 2002, the company included $2,239 in a clearing account for the annual cost of four advertisements. Two of the ads related to the repair of appliances and air conditioning, one ad related to air conditioner service and repairs and the fourth was a gas safety ad. The cost of the safety ad was $40 and was run twice in 2002.

Consistent with prior Commission decisions, only advertising that is utility related and informational or educational in nature is included in rates. Hence, only $80 for the gas safety ad shall be included.

Therefore, we find that advertising expenses shall be reduced by $1,487 ($2,239 - $80 x .6621 x 1.019 x 1.021) to remove the non-utility advertising. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors.

V. Charitable Contributions

Per Audit Exception No. 12, in 2002, the company made a $250 donation to the Indiantown Neighbor for Fourth of July fireworks. It also donated two water heaters to the YMCA building, at a cost of $1,980. These costs were recorded in a clearing account.

We have consistently held that charitable contributions are not included in operating expense. We have found that ratepayers should not have their choices of contribution to a charity usurped by the utility. Order No. 24049, issued January 31, 1991, in Docket No. 891231-TL, In Re: Petition of the Citizens of the State of Florida to permanently reduce the authorized ROE of United Telephone Company of Florida, and Docket No. 891239-TL, In Re: Investigation into United Telephone Company of Florida's authorized ROE and earnings, p. 22.

Therefore, we find that Account No. 930, General Advertising and Miscellaneous General Expenses, shall be reduced by $1,536 ($250 + $1,980 x .6621 x 1.019 x 1.021) to remove charitable contributions. The company agrees with this adjustment.

W. Director Fees

The company requested $18,000 in director fees for three non-employee directors in 2004. We do not believe that the company has justified this request.

The company had three employee directors in 2002 who did not receive a fee. In 2003, the company increased the number of directors to six; three are employees and three are non-employee family members. The three non-employee directors were paid $2,000 each according to the company's 2003 General Ledger. According to the company, each director has an in depth understanding of IGC because all have been IGC employees at some point in their careers. The company also stated that each director works in different employment sectors but all own or work for small businesses.

A much larger gas company pays its non-employee directors $9,000 per year for 12 meetings, which is $750 per meeting. IGC has one meeting per year. However, no minutes from the meetings were provided to show what contributions were made by the directors. The company provided an agenda from the 2002 directors meeting. It should be noted that in Order No. 18551, issued December 15, 1987, in Docket No. 860960-WS, In Re: Application of St. Johns Service Company for increased water and sewer rates in St. Johns County Florida, directors' fees where minutes were not provided were disallowed.

As stated above, the company paid its directors $2,000 in 2003. We find that $2,000 each for one meeting is reasonable for this company. Therefore, we find that Account 930 shall be reduced by $12,000 for director fees.

X. Interest Expense

Per Audit Exception No. 12, in 2002, the company recorded $712 in interest expense in a clearing account and allocated to regulated and nonregulated operations.

According to the Uniform System of Accounts (USOA), interest expense should be recorded in Account 431, Interest Expense. As such, interest expense shall be reclassified to Account 431, a below-the-line account.

Therefore, we find that Account 930 shall be reduced by $490 ($712 x .6621 x 1.019 x 1.021). The company agrees with this adjustment. This calculation does not include the impact of the adjustments to allocate expenses or to reduce expenses for the effect of the change in trend factors.

Y. Trend Rates

IGC used 2.5% as the inflation rate for 2003 and 2004, the projected test year. The inflation rate is based on the Consumer Price Index (CPI). The company uses inflation, along with payroll growth and customer growth, to project expenses for the projected test year. We note that the actual change in the CPI was 1.9% for 2003 according to the Bureau of Labor Statistics. Also, the Blue Chip Financial Forecast for March 1, 2004, projects inflation as measured by the CPI to be 2.1% for 2004. We find that the inflation rate shall be 1.9% for 2003 and 2.1% for 2004.

As discussed previously, the company has experienced negligible customer growth over the last several years and is projecting this trend to extend into the test year. The only material change projected for the test year is the addition of ten new residential accounts associated with the renovation of low-income rental housing units. These additional accounts represent a growth rate of approximately 1.5%. As such, we find that IGC's customer growth trend factors of 0% for 2003 and 1.5% for 2004 are appropriate. Additionally, we find that the appropriate customer growth times inflation rates shall be 1.90% and 3.63% for 2003 and 2004, respectively.

The company used 2.50% as the payroll trend rate for 2003 and 5.00% for 2004. The company provided our staff with historical data on payroll increases. It appears that the average pay increase for all employees over the past three years has been approximately 1.6%. In 2000, 2001, and 2002 there were no pay increases. In 2000 and 2002, the increases were the result of promotions and increases in responsibilities. In 2003, the average pay increase was 2.5%. By Order No. 12348, issued August 9, 1983, in Docket No. 820097-EU, In Re: Petition of Florida Power and Light Company to increase its rates and charges and supplemental position for addition of St. Lucie Nuclear Unit No. 2 to rate base, p. 10), we limited wage increases to the inflation rate. As stated above, we find the appropriate inflation rate to be 1.9% and 2.1%. We believe that a 2.5% payroll trend rate for 2003 and 2004 is not unreasonable. This is a conservative approach which falls somewhere between the our staff's inflation rate and the company's payroll rate for 2004.

Z. Effect of Changes to Trend Rates on O&M Expenses

In its MFRs, the company applied trend rates that were different than ours. Therefore, an adjustment is necessary as a result of a calculation of the differences in trend rates.

We find that expenses shall be decreased by $5,954 as a result of lowering the inflation rate, the customer growth times inflation rate, and the payroll rate. This dollar amount represents the difference in the company's filed 2004 O&M expense and the Commission approved O&M expense after taking into account the change in trend rates. We made no changes to the trend basis of any account. Therefore, we find that projected test year expenses shall be decreased by $5,954.

AA. Total O&M Expense

Based on our adjustments above, the appropriate O&M Expense for the projected test year is $334,207.

BB. Total Depreciation and Amortization Expense

Based on the above adjustments, the appropriate amount of Depreciation and Amortization Expense for the projected test year is $57,924.

CC. Taxes Other Than Income

Per MFR Schedule G-2, Page 1 of 31, the company proposes Taxes Other Than Income of $24,924 for year 2004, as follows:

	Per Books	Company Adjustments	Company Adjusted	Commission Adjustment	As Adjusted By Commission
Payroll Taxes	15,719	0	15,719	-5,649	10,070
RAFs	1,725	0	1,725	-8	1,717
Property Tax	7,480	0	7,480	-1,408	6,072
TOTAL	24,924	0	24,924	-7,065	17,859

The company included $15,719 of payroll taxes in Taxes Other Than Income. To calculate this amount, the company used a basis of $183,845 of payroll. We reduced payroll for the projected test year by a total of $66,070, resulting in a revised payroll basis of $117,775. Payroll taxes were then calculated on the revised payroll basis. This results in Payroll Taxes of $10,070, a $5,649 decrease to the company's requested amount of $15,719.

The company projected 2004 Regulatory Assessment Fees (RAFs) of $1,725. To calculate this amount, the company multiplied Total Revenues of $342,918 by .00503. We recalculated the RAFs by applying the RAF rate of .005 to the company's Total Revenue, resulting in RAFs of $1,715, a $10 decrease to the company requested amount of $1,725. In addition, revenues were increased by $392. The impact of this adjustment to revenue is to increase RAFs by $2; therefore, we find that RAFs shall be decreased by a total amount of $8.

The company projected the 2004 property tax by increasing the total company 2002 property tax of $8,790 by 2.5 percent for both 2003 and 2004. The company allocated 19% to non-utility based on the percentage of non-utility revenue to total revenue, which resulted in projected 2004 property tax of $7,480. Per Audit Exception No. 14, included in historical 2002 was a tax bill paid in error that was refunded by the Martin County Tax Assessor in February 2003. Therefore, the company's 2002 base used to forecast total company property tax for 2004 was overstated by $2,141. In response to a data request, the company provided copies of actual 2003 property tax bills. Our review indicated property taxes of $6,635, if paid during the November 4% discount period. To this, we applied the 2.1% general inflation factor, resulting in projected 2004 property taxes of $6,774, prior to adjustments to remove property taxes related to service and propane business assets. We calculated the percentage to remove 10.37% by dividing $135,576 of gross non-utility plant by $1,307,395 of plant in service. We then applied this percentage to the recalculated 2004 property taxes of $6,774, and adjusted out $702 to remove non-utility property tax. The results of these adjustments are property taxes of $6,072, a decrease of $1,408 to the company requested amount of $7,480.

In summary, based on the above adjustments, Taxes Other Than Income shall be decreased by $5,649 for payroll taxes, decreased by $8 for RAFs, and decreased by $1,408 for property taxes, resulting in a net decrease of $7,065, and a net amount of Taxes Other Than Income of $17,859.

DD. Income Tax Expense

The company proposes to include ($83,452) of income tax expense for its 2004 projected test year. Our adjustments to the company's revenues and expenses increases income tax expense by $49,249. Additionally, our adjustments to the company's capital structure and rate base increases the interest reconciliation adjustment by $401. The net effect of these adjustments is an increase of $49,650 to the 2004 projected income tax expense.

However, the company used a federal tax rate of 34% to calculate its income tax expense. Even after the rate increase the company's taxable income is less than $50,000. When taxable income is under $50,000, the appropriate federal income tax rate to apply is 15%. After adjusting the federal tax rate from 34% to 15%, income tax expense is increased by an additional $16,129. Therefore, we find that the appropriate amount of income tax expense for the December 2004 projected test year is ($17,674).

EE. Total Operating Expense

Based upon our adjustments set out above, the appropriate amount of Total Operating Expenses for the projected test year is $392,316.

FF. Net Operating Income

Based on the above, the appropriate amount of Net Operating Income for the projected test year is ($49,006). Net Operating Income is shown on Attachment 3, attached hereto and incorporated herein by reference.

VII. REVENUE REQUIREMENTS

A. Revenue Expansion Factor

We reviewed the company's calculations and determined that the company calculated the revenue expansion factor using a 34% federal income tax rate. We determined that the company's taxable income is less than $50,000. Therefore, the appropriate federal income tax rate is 15%. Additionally, the company correctly applied a factor of .5% for regulatory assessment fees. The bad debt rate is zero because the company did not calculate bad debt. Therefore, we find that the appropriate revenue expansion factor to use in calculating the revenue deficiency to be 1.2512. Our calculations of the appropriate Revenue Expansion Factor is shown on Attachment 4, attached hereto and incorporated herein by reference.

B. Annual Operating Revenue

The appropriate annual operating revenue increase for the projected test year is $131,539. Our calculations of the appropriate revenue increase is shown on Attachment 5, attached hereto and incorporated herein by reference.

VIII. COST OF SERVICE AND RATE DESIGN

A. Cost of Service Methodology

The appropriate cost of service methodology to be used in allocating cost to the various rate classes is reflected in the cost of service study contained in Attachment No. 6, pages 1-16, attached hereto and incorporated herein by reference.

The purpose of a cost of service study is to allocate the total costs of the utility system among the various rate classes. The results of the cost of service study are used to determine how any revenue increase granted by this Commission will be allocated to the rate classes. Once this determination is made, rates are designed for each rate class that recover the total revenue requirement attributable to that class.

The company's proposed cost of service study is contained in MFR Schedule H. The Commission approved study differs in several respects from the company's filed study. Our study reflects adjustments to rate base, expenses, net operating income, billing determinants, and projected test year base rate revenues. In addition, our study differs in the manner in which the capacity allocators were developed, and in the manner O&M costs were allocated to the rate classes. These differences are discussed in detail below.

1. Capacity Allocators

In the cost of service study, allocation factors are developed and then applied to total utility system costs to determine each rate class's cost responsibility. Capacity allocators are developed based on the class contributions to the peak and average demands on the gas system. These allocators are then used to allocate capacity related costs.

The company developed capacity allocators using actual historical 1999 billing determinants. The allocators used in our study were developed based on the projected 2004 test year billing determinants. We believe that these test year allocators more accurately reflect current capacity cost responsibility by rate class, and are thus more appropriate for use in the cost of service study.

2. O&M Allocation

As discussed in the testimony of IGC witness Jeff Householder on page 29, the company's study was modified to reallocate $77,000 in O&M costs. These costs were shifted from the TS-1 rate class to the TS-2, TS-3, and TS-4 rate classes. The majority of this shift ($75,000) was to the TS-4 rate class. The reason cited for this shift was to "reflect price competition, and other market concerns."

While we agree that the preparation of a cost of service study often requires the exercise of judgment, we believe that any rate impact and other concerns in this case can be addressed through the allocation of the rate increase granted by us, rather than through the somewhat arbitrary reallocation of costs. Therefore, our study does not include the reallocation of $77,000 in O&M costs.

B. Demand Charge Based on Maximum Daily Transportation Quantity for TS-3 and TS-4

1. The Proposed Demand Charge

IGC has proposed to apply a monthly demand charge of $2.51 per Maximum Daily Transportation Quantity (MDTQ) for customers taking service under rate schedules TS-3 and

TS-4. The MDTQ is based on the customer's maximum daily therm usage over a historic period, and is expressed in Dekatherms. Currently, there is one customer taking service under rate schedule TS-3, at two delivery points. Two customers are served under rate schedule TS-4: Indiantown Cogeneration, L.P. (ICLP) and Louis Dreyfus Citrus (Citrus). The demand charge would apply in addition to the customer and per-therm transportation charges. IGC's proposed demand charge does not affect the revenue requirement for rate schedules TS-3 and TS-4. It affects only how the revenues are collected from the customers within these classes.

IGC has proposed a new billing determinant for the application of the demand charge. IGC has proposed to apply the demand charge to the greater of: (1) the MDTQ established in the customer's transportation service agreement, or (2) the highest daily actual therm consumption over a historical 24-month period. Both ICLP and Citrus take service under IGC's individual transportation service tariff and have an MDTQ established by contract.

The MDTQ will remain the same for a 12-month period. IGC has proposed to reset the MDTQ for each customer annually in January by reviewing the customer's therm consumption history over the previous 24-month period. The proposed tariffs include a provision that IGC will not apply an MDTQ that is lower than the MDTQ established in the customer's transportation service contract. In addition, IGC will not increase a customer's MDTQ unless the customer had at least three occurrences of MDTQ that exceeds their current MDTQ within the 12-month period ending January of the current year.

By Order No. PSC-03-1156-PAA-GU, issued October 20, 2003, in Docket No. 030808-GU, In re: Petition for approval of amended and restated natural gas transportation service agreement between Indiantown Cogeneration, L.P. and Indiantown Gas Company, ICLP's transportation service agreement was approved as a special contract. The special contract specifies an MDTQ of 9,500 Dekatherms for the entire 30-year term of the agreement.

Citrus's transportation service agreement, executed on October 30, 2001, specifies an MDTQ of 800 Dekatherms. However, the actual recorded peak day therm usage for the citrus plant over the past 24-month period was 1,612 Dekatherms. Since Citrus's actual highest daily therm usage was higher than its contracted MDTQ, the demand charge would apply to the 1,612 Dekatherm amount for the initial 12-month period.

Customers on rate schedule TS-4 have automatic meter reading (AMR) devices that record the customer's actual daily therm consumption. For customers such as the TS-3 customer that do not have AMR devices and do not have an MDTQ established by contract, IGC has proposed to estimate the MDTQ based on the highest monthly usage for the most recent 24-month period, divided by the number of days in the month.

The proposed demand charge of $2.51 per MDTQ is designed to recover $334,693 in total annual capacity costs that IGC projects to incur to serve the TS-3 and TS-4 rate classes. The $334,693 represents 51 percent of IGC's proposed total target revenues ($649,675). IGC asserts that the capacity costs represent fixed costs, i.e., costs that are incurred whether the customer uses any gas or not. Capacity costs include the cost of mains and the associated O&M cost, depreciation and return. IGC further asserts that the proposed demand charge will allow the company to differentiate the two customers on the TS-4 rate schedule based on their load factor. IGC projects that ICLP and Citrus will use a similar quantity of annual therms, and therefore both customers qualify for the TS-4 rate. However, ICLP's transportation service contract specifies a MDTQ of 9,500 Dekatherms per day, while Citrus's actual maximum daily therm requirement over the past 24 months was 1,612 Dekatherms. ICLP's high MDTQ represents a large percentage of IGC's total distribution system capacity, and thus IGC asserts that a demand charge allows the company to appropriately recover capacity costs from the customer causing the costs.

2. ICLP's Concerns with the Proposed Demand Charge

ICLP expressed two concerns with the company's proposed demand charge. First, ICLP stated that it opposes a demand charge that is designed to recover 100 percent of the capacity-related costs allocated to the TS-3 and TS-4 rate classes. ICLP noted that in a recent rate case we approved a demand charge for City Gas Company that only recovers a portion of the capacity costs. Since the demand charge is a new concept for IGC, ICLP states that the demand charge should be introduced gradually.

Second, ICLP expressed concern about the company's proposal to apply the demand charge to the greater of the MDTQ established in the customer's transportation service agreement, or the highest daily actual therm consumption over a historical 24-month period. ICLP states that when it entered into a transportation services contract with the company in 2003, it had no knowledge that the 9,500 MDTQ established in the contract would be used in the future as a billing determinant. ICLP asserts that the billing determinant should be based on the *lesser* of actual peak usage or the MDTQ established in the transportation service agreement.

3. Commission Approved Demand Charge

We approved a demand charge for City Gas in Order No. PSC-04-0128-PAA-GU, issued February 29, 2004, in Docket No. 030569-EI, In re: Application for Rate Increase by City Gas Company, p. 61. We found that the concept of a demand charge is appropriate for the gas industry; however, great consideration must be given to customer acceptance. We further found that the applicability of the demand charge should be limited to customers that have automatic meter reading (AMR) devices.

Given our findings in the prior docket and ICLP's concerns, we find that IGC's proposal to apply a demand charge of $2.51 to customers taking service under rate schedules TS-3 and TS-4 is denied. First, IGC's proposed demand charge has a severe rate impact on ICLP. Under IGC's proposal, Citrus would experience a 21 percent increase in its annual base rate bill (excluding fuel and taxes), while ICLP would experience a 219 percent increase. The significant increase in ICLP's bill is primarily a result of applying the proposed demand charge of $2.51 to ICLP's MDTQ of 9,500 Dekatherms. Second, customers on the TS-3 rate do not have automatic meter reading devices installed.

In lieu of the company's proposal, we approve a demand charge of $0.53 per MDTQ for customers taking service under the TS-4 rate schedule only. As discussed below, we agree with the company's proposed billing determinant. We included only the return and depreciation components of the capacity costs to be recovered through the demand charge. This methodology lowers the total dollar amount the demand charge is designed to recover, and in turn lowers the demand charge. The approved charge will recover $70,369 in total annual capacity costs, which represents 15 percent of the total target revenues.

We note that the Commission approved demand charge does not modify the total base rate revenues IGC is projected to receive from the TS-4 rate class. By approving a lower demand charge, we have increased the transportation charge accordingly. The Commission approved demand charge is designed to reflect the differing load profiles of ICLP and Citrus, while taking into account the rate impact on ICLP and Citrus. Our approved demand charge, when coupled with the allocation of the approved rate increase, results in a 61 percent increase in ICLP's annual bill (excluding fuel and taxes), and an 19 percent increase in Citrus's annual bill.

Consistent with our decision in the City Gas rate case, the applicability of the demand charge should be limited to customers that have AMR devices. Since the customer currently taking service under the TS-3 rate schedule is not required to have an AMR device, we find that it is not appropriate to apply a demand charge to customers taking service under the TS-3 rate. Therefore, we find that the demand charge shall only apply to customers taking service under rate schedule TS-4.

We agree with the company that it is appropriate to apply the demand charge to the greater of the MDTQ established in the customer's transportation service agreement or the highest daily actual therm consumption over a historical 24-month period. We note that while ICLP's transportation service agreement establishes an MDTQ of 9,500, ICLP's actual highest peak day in 2003 was 8,904 Dekatherms, which is only slightly below the contracted MDTQ. Since the company is contractually bound to provide 9,500 Dekatherms to ICLP on a daily basis, we find that it is appropriate to utilize this level in applying the demand charge.

C. Change in Applicability Provisions of TS-2 and TS-3 Rate Schedules

Currently, IGC's TS-2 rate schedule is applicable to customers who use between 1,000 and 25,000 therms per year. IGC has proposed to modify the upper threshold under this rate to 15,000 therms per year, so that the proposed TS-2 rate will be applicable to those customers who use between 1,000 and 15,000 therms per year.

The TS-3 rate schedule is currently applicable to customers who use between 25,000 and 100,000 therms per year. IGC has proposed to modify the lower threshold under this rate to 15,000 therms per year, so that the proposed TS-3 rate will be applicable to those customers who use between 15,000 and 100,000 therms per year.

We find that the revised therm usage threshold levels are designed to more accurately reflect similar use patterns such as annual volume, load profile, and the assignment of fixed and variable costs, in order to effect a more equitable distribution of the costs of serving the TS-2 and TS-3 rate classes. Accordingly, the revisions are approved.

D. Changes in TS-5 and TS-4 Rate Schedules

The TS-5 rate schedule is applicable to customers who use in excess of 3,000,000 therms per year. There are currently no customers taking service under this rate schedule, and no customers are projected to take service in the test year. As such, we find that the TS-5 rate class shall be eliminated.

Currently, IGC's TS-4 rate schedule is applicable to customers who use between 100,000 and 3,000,000 therms per year. If the TS-5 rate schedule is eliminated, there is no longer a need for an upper annual therm consumption limit for the TS-4 class. Accordingly, we find that the applicability provision for TS-4 be modified to reflect that it is applicable to all customers who use more than 100,000 therms per year.

E. Third Party Supplier (TPS) Rate Schedule

IGC has proposed to increase the TPS charge from $2.00 per monthly transportation bill to $3.11 per monthly transportation bill. The proposed TPS charge is designed to recover $25,098 in administrative and billing service costs that IGC provides to Third Party Suppliers. IGC projects that it will render 8,061 transportation service bills in the projected test year.

Specifically, IGC has proposed to allocate a portion of its meter reading (Account 902) and records and collections expenses (Account 903) to the TPS. In addition, IGC has proposed to recover the proposed incremental increase in salary expense ($14,000) for its Chief Financial Officer through the TPS charge.

As discussed previously, IGC has provided corrections to its billing determinants, resulting in 8,073 projected transportation service bills. We approved a downward adjustment of $1,182 to account 902 - Meter Reading. Additionally, we approved adjustments which resulted in a downward adjustment of $12,800 to Account 903. Finally, we allocated a portion of the Chief Financial Officer's salary to non-utility operations.

Based on the prior adjustments, we find that the proposed TPS charge shall be adjusted to $2.03 per monthly transportation service bill to reflect the approved adjustments. The TPS charge is designed to recover $16,410 in TPS-related costs.

F. Revenue Allocation Across Rate Classes

IGC's rate structure consists of four rate classes: TS-1 through TS-4. The rate schedule applicable to each customer is determined by its annual therm consumption, regardless of end use. Thus, customers who use between 0 and 1,000 therms per year are served under the TS-1 rate schedule, regardless of whether they are residential or small commercial customers. For the projected test year, 650 of IGC's 673 total customers take service under TS-1. This class represents about 3% of the therms transported through IGC's system for the test year. The TS-4 rate class is applicable to those customers who use in excess of 100,000 therms per year, and consists of two large industrial customers: Indiantown Cogeneration, LP and Louis Dreyfus Citrus. These two large industrial customers account for approximately 95% of the therms transported through IGC's system. The remaining 2% of therm sales are attributable to the 21 customers in the TS-2 and TS-3 rate classes.

There are several factors that must be considered when determining the appropriate allocation of the revenue increase. The cost of service study is the primary tool used to determine how the increase is to be allocated. Traditionally, we have allocated the increase in a manner that moves the rate of return of each rate class towards the system rate of return, to the extent practicable. However, the rate impact upon the customer classes must also be taken into consideration when deciding upon an allocation of the increase.

In this case, if the increase is allocated so that each class earns the system rate of return (i.e., each class is set at parity), the TS-1 rate class would receive a 78.2% revenue increase, which is over two times the system average rate increase of 38.3%. The TS-4 rate class would receive a 25.4% increase, and the TS-2 and TS-3 classes would receive a slight rate decrease.

We find that such an allocation is not appropriate because it results in such a large increase to the TS-1 rate class. Effective December 5, 2002, IGC's residential ratepayers (who make up the bulk of the TS-1 rate class) received on average an 86% base rate increase as a result of the revenue-neutral rate restructuring approved by us in Docket No. 020470-GU. In that same proceeding, the TS-4 rate class received an approximate 11% rate decrease. Given this recent large increase to the TS-1 class, the class should not be subjected to an additional rate increase that brings its rate of return to parity in this case.

Our allocation of the revenue increase to the rate classes is contained in Attachment 6, page 16 of 16, attached hereto and incorporated herein by reference, and allocates a revenue increase to the TS-1 rate class of 41.6%, as shown in column 10. The TS-4 rate class also receives a 41.6% increase. The TS-2 and TS-3 rate classes receive slight increases of approximately five percent. Although the allocation of the increase does not result in parity for the rate classes, we find that it is appropriate and equitable in this case given other considerations.

G. Customer Charges

The customer charge is a fixed charge that applies to each customer's bill, no matter the quantity of gas used for the month. The customer charge is typically designed to recover costs such as metering and billing that are incurred no matter whether any gas is consumed.

Our approved customer charges are contained in the table below. The table also shows the present customer charges and the company-proposed charges.

Rate Class	Charge	Company Proposed Customer Charge	Commission Approved Customer Charge
TS-1	$9.00	$12.50	$9.00
TS-2	$21.00	$35.00	$25.00
TS-3	$50.00	$60.00	$60.00
TS-4	$1,500.00	$2,000.00	$2,000.00

As shown in the table, we approve the same charges proposed by the company, with the exception of the TS-1 and TS-2 rate classes. We approve lower charges for these classes due to the concern that large increases in these customer charges may result in large percentage increases in some bills, particularly for low-use residential and small commercial customers. We note that the TS-1 customer charge, which is to remain at $9.00, was recently increased to this level from $5.00 for residential customers in December 2002, as part of IGC's rate restructuring. Accordingly, we find that the charges are reasonable and are hereby approved.

H. Distribution Charges

Based on other adjustments, we find that the per therm Transportation Charges as contained in Attachment 7, page 1, attached hereto and incorporated herein, are approved.

I. Demand Charge

Based on other adjustments, we find that the appropriate demand charge is $.53 per Maximum Daily Transportation Quantity (MDTQ).

J. Effective Date for Revised Rates and Charges

All new rates and charges shall become effective for meter readings on or after 30 days from the date of our vote on May 18, 2004. This will insure that customers are aware of the new rates before they are billed for usage under the new rates.

IX. OTHER ISSUES

A. Interim Increase Refund

In this docket, the requested interim test year was the twelve months ended December 31, 2002. We granted the interim increase by Order No. PSC-04-0180-PCO-GU, issued February 24, 2004, in this docket.

An interim increase is reviewed when final rates are derived to determine if any portion shall be returned to the ratepayers. In this case, interim rates went into effect March 4, 2004, three months after the beginning of the 2004 projected test year and will continue for another three months of the projected test year before final rates are scheduled to take effect. Since the period interim rates are in effect is well within the projected test year for determining final rates, the rate case review requirements are appropriate for affirmation of the interim increase.

We reviewed the company's 2004 financial projections for purposes of determining final revenue requirements and made an adjustment to remove rate case expense. We find that no portion of the $137,014 interim revenue increase shall be refunded because the revenue requirement approved for the projected test year, less rate case expense, exceeds the revenue requirement awarded.

B. Required Entries and Adjustments

As a result of our findings in this rate case, IGC shall file, within 90 days from the date our decision becomes final and effective, a full description of all entries and adjustments that will be made in preparing reports which will be submitted to the Commission.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Indiantown Gas Company's request for a rate increase is hereby approved as set forth in the body of this Order. It is further

ORDERED that all findings set forth herein are approved. It is further

ORDERED that all matters contained in the attachments attached hereto are incorporated herein by reference. It is further

ORDERED that Indiantown Gas Company shall have all customer meters in compliance with Rule 25-7.064 (1) and (2), Florida Administrative Code, by December 31, 2005. It is further

ORDERED that Indiantown Gas Company shall make refunds for each of the meters tested during calendar years 2003 and 2004 and found to register more than two percent fast by July 31, 2004. It is further

ORDERED that Indiantown Gas Company is hereby put on notice that if is not in full compliance with Chapter 25-7, Florida Administrative, Code, by December 31, 2005, show cause proceedings shall be initiated. It is further

ORDERED that Indiantown Gas Company is authorized to collect increased revenues of $131,539. It is further

ORDERED that no refund of the interim increase approved by Order No. PSC-04-0180-PCO-GU, issued February 23, 2004, shall be required. It is further

ORDERED that the rate increase shall be effective on billings rendered for all meter readings taken on or after June 17, 2004. It is further

ORDERED that Indiantown Gas Company shall file, within 90 days from the date our decision becomes final and effective, a full description of all entries or adjustments that will be made in preparing reports. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that if no timely protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of issuance of this Order, this docket shall be closed upon the issuance of a Consummating Order.

By ORDER of the Florida Public Service Commission this 2nd day of June, 2004.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on June 23, 2004.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

COMPARATIVE RATE BASES

INDIANTOWN GAS COMPANY — ATTACHMENT 1

PTY 12/31/04

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMM ADJS.	COMM APPROVED
	PLANT IN SERVICE					
	UTILITY PLANT	1,341,330				
5	Increase for value of the land				1,552	
6	Increase for plant additions				13,060	
7	Increase for overstated plant retirements				2,264	
8	Decrease for Mains booked prior to 1970				(81,347)	
9	Increase for Mains in New Hope Subdiv. 1980				30,536	
	Total Plant-In-Service	1,341,330	0	1,341,330	(33,935)	1,307,395
	COMMON PLANT ALLOCATED	0				
	Remove Common Plant		(24,748)			
5	Increase land nonutility allocation				(524)	
11	Increase nonutility allocation				(110,303)	
	Total Common Allocated	0	(24,748)	(24,748)	(110,827)	(135,575)
	CONSTRUCTION WORK IN PROGRESS	0				
	Total Construction Work In Progress	0	0	0	0	0
	TOTAL PLANT	1,341,330	(24,748)	1,316,582	(144,762)	1,171,820
	DEDUCTIONS					
	ACCUM. DEPR.- PLANT IN SERVICE	693,558				
6	Increase for plant additions				$646	
7	Increase for overstated plant retirements				2,359	
8	Decrease for Mains booked prior to 1970				(81,110)	
9	Increase for Mains in New Hope Subdiv. 1980				21,040	
	Total Accum. Depr.- Plant In Service	693,558	0	693,558	(57,065)	636,493
	ACCUM DEPR. - COMMON PLANT	0				0
	Remove Common Plant Reserve Allocated		**(7,984)**			
11	Increase nonutility allocation				(13,800)	
	Total Accum. Depr. - Common Plant		(7,984)	(7,984)	(13,800)	(21,784)
	TOTAL DEDUCTIONS	693,558	(7,984)	685,574	(70,865)	614,709
	NET UTILITY PLANT	647,772	(16,764)	631,008	(73,897)	557,111
	WORKING CAPITAL ALLOWANCE	279,335	(154,531)	124,804	(92,990)	31,814
	TOTAL RATE BASE	927,107	(171,295)	755,812	(166,887)	588,925

INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU
PTY 12/31/04

WORKING CAPITAL

ATTACHMENT 1A

		COMPANY AS FILED			COMMISSION	
ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMM. ADJS.	COMM. APPROVED
	WORKING CAPITAL					
	ASSETS					
15, 16	Cash	152,740	0	152,740	(115,226)	37,514
	Accounts Rec-Propane	73,453	(73,453)	0		0
	Accounts Rec-Gas	28,947	0	28,947		28,947
	Transporter Fuel-Rec	153,737	(153,737)	0		0
	Accounts Rec-Misc	50,120	(50,120)	0		0
16	Materials & Supplies	18,001	0	18,001	(11,992)	6,009
	Propane Inventory	5,395	(5,395)	0		0
	Appliance Inventory	21,322	(21,322)	0		0
33	Prepayments	0	0	0	715	715
	Suspense Account	0	0	0		0
17, 31	Misc. Deferred Debits	4,911	(4,911)	0	15,386	15,386
	Nonutility Property	44,354	(44,354)	0		0
	LIABILITIES					
16	Accounts Payable	75,160	(4,660)	70,500	(20,737)	49,763
	Acct. Pay.-Transporter Fuel	153737	(153,737)	0		0
	Customer Deposits-Propane	23,200	(23,200)	0		0
	Customer Deposits	17,164	(17,164)	0		0
18	Taxes Accrued-General	3,850	0	3,850	2,609	6,459
	Taxes Accrued-Income	0	0	0		0
	Interest Accrued	534	0	534		534
	TOTALS	279,335	(154,531)	124,804	(92,990)	31,814

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PAGE 44

ATTACHMENT 2

CAPITAL STRUCTURE

INDIANTOWN GAS COMPANY
PTY 12/31/04
13 Month Average

		COMPANY ADJUSTMENTS			COMMISSION RATE BASE ADJS.					
	PER BOOKS	SPECIFIC	PRO RATA	ADJUSTED PER BOOKS	SPECIFIC	PRO RATA	COMM. ADJUSTED	RATIO	COST RATE	WEIGHTED COST
COMMON EQUITY	305,224	($194,772)	342,500	452,952	(147,728)	(18,541)	286,683	48.68%	11.50%	5.60%
LONG TERM DEBT	628,196		(342,500)	285,696	18,930	(18,505)	286,121	48.58%	7.74%	3.76%
SHORT TERM DEBT	0		0	0	0	0	0	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	17,164			17,164		(1,043)	16,121	2.74%	6.22%	0.17%
DEFERRED TAXES - ZERO COST	0	0		0			0	0.00%	0.00%	0.00%
TAX CREDIT - ZERO COST	0			0			0	0.00%	0.00%	0.00%
TOTAL	$950,584	($194,772)	$0	$755,812	($128,798)	($38,089)	$588,925	100.0%		**9.53%**

INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU
PTY 12/31/04

COMPARATIVE NOIs

ATTACHMENT 3
Page 1 of 2

			COMPANY		COMMISSION	
ISSUE NO		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMM. ADJS.	COMM. APPROVED
	OPERATING REVENUES	342,918				
	REVENUES DUE TO GROWTH	0				
23	Correct estimated sales				392	
	TOTAL REVENUES	342,918	0	342,918	392	343,310
	OPERATING EXPENSES:					
	COST OF GAS	0				
	TOTAL COST OF GAS	0	0	0	0	0
	OPERATION & MAINTENANCE EXPENSE	447,301				
25	Remove nonutility expenses (930,921,932)				(2,553)	
26	Increase expenses allocated to the utility				10,341	
27	Remove salaries allocated to nonutility				(44,459)	
28	Remove membership dues (932, 926)				(459)	
29	Remove nonrecurring expenses (921, 923)				(6,861)	
30	Remove portion of Service Tech's salary (874)				(12,666)	
31	Include meter & regulator change out (878)				4,832	
32	Remove portion of Cust Ser Rep salary (880, 889)				(3,752)	
33	Include odorant costs (880)				714	
34	Reduce meter reading costs (902)				220	
35	Remove portion of CFO's increase (920)				(5,193)	
36	Remove 1/2 of employee activities (921)				(614)	
37	Remove nonutility entertainment (921)				(1,394)	
38	Remove unbundling costs recovered (923)				(11,800)	
39	Remove nonutility life insurance costs (926)				(475)	
40	Remove out of period expenses (923, 926)				(5,411)	
41	Reduce rate case expense (928)				(11,888)	
42	Remove AGA lobbying costs (930)				(208)	
43	Remove nonutility advertising (930)				(1,487)	
44	Remove charitable contributions (930)				(1,536)	
45	Reduce directors' fees (930)				(12,000)	
46	Remove interest expense (930)				(490)	
48	Reduce O&M due to change in trend factors				(5,954)	
	TOTAL O & M EXPENSE	447,301	0	447,301	(113,094)	334,207

INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU
PTY 12/31/04

COMPARATIVE NOIs

ATTACHMENT 3
Page 2 of 2

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMM. ADJS.	COMM. APPROVED
	DEPRECIATION AND AMORTIZATION	70,362				
	Remove Nonutility Plant Depreciation		(2,114)			
6	Increase for plant additions				1,040	
7	Increase for overstated plant retirements				190	
8	Decrease for Mains booked prior to 1970				(3,417)	
9	Increase for Mains in New Hope Subdiv. 1980				1,283	
11	Increase nonutility allocation				(9,420)	
	TOTAL DEPRECIATION & AMORTIZATION	70,362	(2,114)	68,248	(10,324)	57,924
	TAXES OTHER THAN INCOME	24,924				
	Revenue Related Taxes					
	Property tax					
	Regulatory Assessment Fee					
	Gross receipts, franchise fees					
	Payroll taxes					
51	Reduce RAF				(8)	
51	Remove nonutility property taxes				(1,408)	
51	Reduce payroll taxes				(5,649)	
	TOTAL TAXES OTHER THAN INCOME	24,924	0	24,924	(7,065)	17,859
	INCOME TAX EXPENSE	(94,204)				
	Income taxes - current & deferred		0			
52	Tax effect of adjustments		795		49,249	
52	Interest Synch/Rec. Adj.		9,957		401	
52	Adjust to Calculated Amount				16,129	
	TOTAL INCOME TAXES	(94,204)	10,752	(83,452)	65,778	(17,674)
	TOTAL OPERATING EXPENSES	448,383	8,638	457,021	(64,705)	392,316
	NET OPERATING INCOME	(105,465)	(8,638)	(114,103)	65,097	(49,006)

NET OPERATING INCOME MULTIPLIER

INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU
PTY 12/31/04

ATTACHMENT 4

DESCRIPTION	COMPANY PER FILING	COMMISSION APPROVED
REVENUE REQUIREMENT	100.0000%	100.0000%
GROSS RECEIPTS TAX RATE	0.0000%	0.0000%
REGULATORY ASSESSMENT RATE	0.5000%	0.5000%
BAD DEBT RATE	0.0000%	0.0000%
NET BEFORE INCOME TAXES	99.5000%	99.5000%
STATE INCOME TAX RATE	5.5000%	5.5000%
STATE INCOME TAX	5.4725%	5.4725%
NET BEFORE FEDERAL INCOME TAXES	94.0275%	94.0275%
FEDERAL INCOME TAX RATE	34.0000%	15.0000%
FEDERAL INCOME TAX	31.9694%	14.1041%
REVENUE EXPANSION FACTOR	62.0582%	79.9234%
NET OPERATING INCOME MULTIPLIER	1.6114	1.2512

COMPARATIVE REVENUE DEFICIENCY CALCULATIONS

INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU
PTY 12/31/04

ATTACHMENT 5

	COMPANY ADJUSTED	COMMISSION APPROVED
RATE BASE (AVERAGE)	$755,812	$588,925
RATE OF RETURN	X 10.09%	X 9.53%
REQUIRED NOI	$76,261	$56,125
Operating Revenues	$342,918	$343,310
Operating Expenses:		
Operation & Maintenance	447,301	334,207
Depreciation & Amortization	68,248	57,924
Amortization of Environ. Costs	0	0
Taxes Other than Income Taxes	24,924	17,859
Income Taxes	(83,452)	(17,674)
Total Operating Expenses	457,021	392,316
ACHIEVED NOI	(114,103)	(49,006)
NET NOI DEFICIENCY	190,364	105,130
REVENUE TAX FACTOR	1.6114	1.2512
REVENUE DEFICIENCY	$306,751	$131,539

COST OF SERVICE
CLASSIFICATION OF RATE BASE
(Page 1 of 2: PLANT)

COMPANY NAME: **INDIANTOWN GAS COMPANY**
DOCKET NO. **030954-GU**

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
302 FRANCHISES AND CONSENTS	0				
LOCAL STORAGE PLANT	0		0		100% capacity
INTANGIBLE PLANT:	124,511		124,511		100% capacity
PRODUCTION PLANT	0				100% capacity
DISTRIBUTION PLANT:					
374 Land and Land Rights	0				100% capacity
375 Structures and Improvements	0				100% capacity
376 Mains	441,020		441,020		100% capacity
377 Comp.Sta.Eq.	0				100% capacity
378 Meas.& Reg.Sta.Eq.-Gen	47,982		47,982		100% capacity
379 Meas.& Reg.Sta.Eq.-CG	0				100% capacity
380 Services	69,858	69,858			100% customer
381- 382 Meters	64,419	64,419			100% customer
383- 384 House Regulators	13,610	13,610			100% customer
385 Industrial Meas.& Reg.Eq.	98,378		98,378		100% capacity
386 Property on Customer Premises	0				ac 374-385
387 Other Equipment	0	0	0		ac 374-386
Total Distribution Plant	735,267	147,887	587,380	0	
GENERAL PLANT:	312,041	156,021	156,021	0	50% customer,50%, capacit
TOTAL DIST/INTANGIBLE/GENERAL	1,171,819	303,908	867,912	0	
PLANT ACQUISITIONS:	0	0		0	100% capacity
GAS PLANT FOR FUTURE USE:	0	0	0	0	100% capacity
CWIP:		0	0	0	dist.plant
TOTAL PLANT	1,171,819	303,908	867,912	0	

COST OF SERVICE
CLASSIFICATION OF RATE BASE
(PAGE 2 OF 2: ACCUMULATED DEPRECIATION)

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
LOCAL STORAGE PLANT:	0	0	0	0	related plant
INTANGIBLE PLANT	102,931	0	102,931	0	"
DISTRIBUTION PLANT:					
374 Land and Land Rights	0			0	"
375 Structures and Improvements	0			0	
376 Mains	291,940		291,940	0	
377 Comp.Sta.Eq.	0			0	"
378 Meas.& Reg.Sta.Eq.-Gen	10,077		10,077	0	"
379 Meas.& Reg.Sta.Eq.-CG	0			0	
380 Services	24,102	24,102		0	"
381- 382 Meters	21,949	21,949		0	"
383- 384 House Regulators	4,977	4,977		0	"
385 Industrial Meas.& Reg.Eq.	48,394		48,394	0	'
386 Property on Customer Premises	0			0	
387 Other Equipment	0	0	0	0	"
Total Distribution Plant	401,439	51,028	350,411	0	
GENERAL PLANT:	110,338	55,169	55,169	0	general plant
AMORT. ACQ. ADJUSTMENT	0	0		0	plant acquisitions
RETIREMENT WORK IN PROGRESS:		0	0	0	distribution plant
CUST. ADVANCES FOR CONSTRUCTION					50% cust. 50% cap.
TOTAL ACCUMULATED DEPRECIATION	614,708	106,197	508,511	0	
NET PLANT (Plant less Accum. Dep.)	557,111	197,711	359,401	0	
less: CUSTOMER ADVANCES	0	0	0		50% cust. 50% cap.
plus: WORKING CAPITAL	31,814	20,571	11,243	0	oper. and maint. exp.
equals: TOTAL RATE BASE	588,925	218,282	370,643	0	

COST OF SERVICE
CLASSIFICATION OF EXPENSES
(PAGE 1 OF 2)

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
OPERATIONS AND MAINTENANCE EXPENSES					
LOCAL STORAGE PLANT:		0	0	0	ac 301-320
PRODUCTION PLANT		0	0	0	100% capacity
DISTRIBUTION:					
870 Operation Supervision & Eng.	37,423	21,679	15,744	0	ac 871-879
871 Dist.Load Dispatch			0		100% capacity
872 Compr.Sta.Lab. & Ex.			0	0	ac 377
873 Compr.Sta.Fuel & Power				0	100% commodity
874 Mains and Services	13,214	1,807	11,407	0	ac376+ac380
875 Meas.& Reg. Sta.Eq.-Gen	123	0	123	0	ac 378
876 Meas.& Reg. Sta.Eq.-Ind.		0	0	0	ac 385
877 Meas.& Reg. Sta.Eq.-CG		0	0	0	ac 379
878 Meter and House Reg.	14,069	14,069	0	0	ac381+ac383
879 Customer Instal.		0	0	0	ac 386
880 Other Expenses	23,288	11,149	12,140	0	ac 387
881 Rents	1,114		1,114		100% capacity
885 Maintenance Supervision		0	0	0	ac886-894
886 Maint. of Struct. and Improv.		0	0	0	ac375
887 Maintenance of Mains	1,677	0	1,677	0	ac376
888 Maint. of Comp.Sta.Eq.		0	0	0	ac 377
889 Maint. of Meas.& Reg. Sta.Eq.-Gen	10,762	0	10,762	0	ac 378
890 Maint. of Meas.& Reg. Sta.Eq.-Ind.		0	0	0	ac 385
891 Maint. of Meas.& Reg.Sta.Eq.-CG		0	0	0	ac 379
892 Maintenance of Services	8	8	0	0	ac 380
893 Maint. of Meters and House Reg.		0	0	0	ac381-383
894 Maint. of Other Equipment	73	0	74	0	ac387
Total Distribution Expenses	101,751	48,711	53,041	0	
CUSTOMER ACCOUNTS:					
901 Supervision		0			
902 Meter-Reading Expense	5,206	5,206			
903 Records and Collection Exp.	25,205	25,205			
904 Uncollectible Accounts				0	100% commodity
905 Misc. Expenses	14,264	14,264			
Total Customer Accounts	44,675	44,675	0	0	
(907-910) CUSTOMER SERV.& INFO. EXP.	8,241	8,241			
(911-916) SALES EXPENSE		0			100% CUSTOMER
(932) MAINT. OF GEN. PLANT	11,035	5,518	5,518	0	
(920-931) ADMINISTRATION AND GENERAL	168,504	108,956	59,549	0	O&M excl. A&G
TOTAL O&M EXPENSE	334,206	216,101	118,108	0	

COST OF SERVICE
CLASSIFICATION OF EXPENSES
(Page 2 of 2)

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE	CLASSIFIER
DEPRECIATION AND AMORTIZATION EXPENSE:						
Depreciation Expense	57,924	20,556	37,368	0		Net plant
Amort. of Environmental			0			100% capacity
Amort. of Property Loss			0			100% capacity
Amort. of lease improvements/other			0			Intan/dist/gen plant
Amort. of Acquisitiion Adj.		0	0			Intan/dist/gen plant
Amort. of Conversion Costs				0		100% commodity
Total Deprec. and Amort. Expense	**57,924**	**20,556**	**37,368**	**0**	**0**	
TAXES OTHER THAN INCOME TAXES:						
Revenue Related	1,717				1,717	100% revenue
Other	16,800	5,962	10,838	0		Net plant
Total Taxes other than Income Taxes	**18,517**	**5,962**	**10,838**	**0**	**1,717**	
REV.CRDT TO COS (NEG.OF OTHR OPR.REV)	**(4,120)**	**(4,120)**				100% customer
RETURN (REQUIRED NOI)	**56,125**	**20,802**	**35,323**	**0**		Rate base
INCOME TAXES	**8,077**	**2,994**	**5,083**	**0**	**0**	Return (noi)
TOTAL OVERALL COST OF SERVICE	**470,729**	**262,296**	**206,719**	**0**	**1,717**	

**FULLY ALLOCATED EMBEDDED COST
OF SERVICE STUDY (SUMMARY)**

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

SUMMARY	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE
ATTRITION	0	0	0	0	
OPERATION AND MAINTENANCE EXPENSE	334,206	216,101	118,108	0	
LESS O&M DIRECT ASSIGNMENTS	(28,968)	(15,884)	(13,084)	0	
NET O&M	305,241	200,217	105,023	0	0
DEPRECIATION EXPENSE	57,924	20,556	37,368	0	0
AMORT. OF OTHER GAS PLANT	0	0	0	0	0
AMORT. OF PROPERTY LOSS	0	0	0	0	0
AMORT. OF LIMITED-TERM INVESTMENT	0	0	0	0	0
AMORT. OF ACQUISITION ADJUSTMENT	0	0	0	0	0
AMORT. OF CONVERSION COSTS	0	0	0	0	0
TAXES OTHER THAN INCOME TAXES	18,517	5,962	10,838	0	1,717
RETURN	56,125	20,802	35,323	0	0
INCOME TAXES	8,077	2,994	5,083	0	0
REV.CRD. TO COS	(4,120)	(4,120)	0	0	0
TOTAL COST OF SERVICE	**470,729**	**262,296**	**206,719**	**0**	**1,717**
RATE BASE	**588,925**	**218,282**	**370,643**	**0**	**0**
less: Rate Base direct assignments	**(333,828)**	**(96,859)**	**(236,969)**	**0**	**0**
NET RATE BASE	**255,097**	**121,423**	**133,674**	**0**	**0**
KNOWN DIRECT & SPECICAL ASSIGNMENTS:					
RATE BASE ITEMS (PLANT-ACC.DEP):					
381-382 METERS	42,470	42,470	0	0	
383-384 HOUSE REGULATORS	8,633	8,633	0	0	
385 INDUSTRIAL MEAS.& REG.EQ.	49,984	0	49,984	0	
376 MAINS	149,080	0	149,080	0	
380 SERVICES	45,756	45,756	0	0	
378 MEAS.& REG.STA.EQ.-GEN.	37,905	0	37,905	0	
Total Rate Base Direct Assignments	**333,828**	**96,859**	**236,969**	**0**	
O&M ITEMS					
892 Maint. of Services O & M ITEMS	8	8	0	0	
876 MEAS.& REG.STA.EQ.IND.	0	0	0	0	
878 METER & HOUSE REG.	14,069	14,069	0	0	
890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	0	0	0	0	
893 MAINT.OF METERS AND HOUSE REG.	0	0	0	0	
874 MAINS AND SERVICES	13,214	1,807	11,407	0	
887 MAINT. OF MAINS	1,677	0	1.677	0	
Total O&M Direct Assignments	**28,968**	**15,884**	**13,084**	**0**	

COST OF SERVICE
DEVELOPMENT OF ALLOCATION FACTORS

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
CUSTOMER COSTS						
No. of Customers	673	650	19	2	2	0
Weighting	N/A	1.00	1.50	3.07	124.06	0.00
Weighted No. of Customers	933	650	29	6	248	0
Allocation Factors	**100%**	**69.6775%**	**3.0563%**	**0.6584%**	**26.6078%**	**0.0000%**
No. of Customers: Total Annual Bills	8,073	7,797	228	24	24	0
CAPACITY COSTS						
Peak & Avg. Month Sales Vol. (therms)	1,466,364	27,294	16,173	2,898	1,420,000	0
Allocation Factors	**100%**	**1.8613%**	**1.1029%**	**0.1976%**	**96.8381%**	**0.0000%**
COMMODITY COSTS						
Annual Sales Vol.(therms)	5,099,158	168,330	92,799	18,029	4,820,000	0
Allocation Factors	**100%**	**3.3011%**	**1.8199%**	**0.3536%**	**94.5254%**	**0.0000%**
REVENUE-RELATED COSTS						
Tax on Cust., Cap. & Commod.	2,272	848	52	11	1,360	0
Allocation Factors	**100.0000%**	**37.3283%**	**2.3027%**	**0.4778%**	**59.8911%**	**0.0000%**

COST OF SERVICE
ALLOCATION OF RATE BASE TO CUSTOMER CLASSES

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
RATE BASE BY CUSTOMER CLASS						
DIRECT AND SPECIAL ASSIGNMENTS:						
Customer						
Meters	42,470	29,592	1,298	280	11,300	0
House Regulators	8,633	6,015	264	57	2,297	0
Services	45,756	31,882	1,398	301	12,175	0
General Plant	100,852	70,271	3,082	664	26,834	0
All Other	20,571	14,334	629	135	5,474	0
Total Customer	218,282	152,093	6,671	1,437	58,080	0
Capacity						
Industrial Meas. & Reg. Sta. Eq.	49,984	930	551	99	48,404	0
Meas. & Reg. Sta. Eq.-Gen.	37,905	706	418	75	36,706	0
Mains	149,080	2,775	1,644	295	144,366	0
Mains Large Volume	0					
General Plant	100,852	1,877	1,112	199	97,663	0
All Other	32,823	611	362	65	31,785	0
Total Capacity	370,643	6,899	4,088	733	358,924	0
Commodity						
Account #	0	0	0	0	0	0
Account #	0	0	0	0	0	0
Account #	0	0	0	0	0	0
All Other	0	0	0	0	0	0
Total Commodity	0	0	0	0	0	0
TOTAL	588,925	158,992	10,759	2,170	417,004	0

COST OF SERVICE
ALLOCATION OF EXPENSES TO CUSTOMER CLASSES

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
Customer	236,657	148,487	7,233	1,558	62,969	16,410
Capacity	155,475	2,894	1,715	307	150,559	0
Commodity	0	0	0	0	0	0
Revenue	0	0	0	0	0	0
Total	392,133	151,381	8,948	1,866	213,529	16,410
OPERATIONS AND MAINTENANCE EXPENSE:						
DIRECT AND SPECIAL ASSIGNMENTS						
Customer						
878 Meters and House Regulators	14,069	9,803	430	93	3,743	0
893 Maint. of Meters & House Reg.	0	0	0	0	0	0
874 Mains & Services	1,807	1,259	55	12	481	0
892 Maint. of Services	8	6	0	0	2	0
All Other	200,217	123,096	6,119	1,318	53,273	16,410
Total	216,101	134,164	6,605	1,423	57,500	16,410
Capacity						
876 Measuring & Reg. Sta. Eq.- I	0	0	0	0	0	0
890 Maint. of Meas.& Reg.Sta.Eq.-I	0	0	0	0	0	0
874 Mains and Services	11,407	212	126	23	11,046	0
887 Maint. of Mains	1,677	31	18	3	1,624	0
All Other	105,023	1,955	1,158	208	101,703	0
Total	118,108	2,198	1,303	233	114,373	0
Commodity						
Account #	0	0	0	0	0	0
All Other	0	0	0	0	0	0
Total	0	0	0	0	0	0
TOTAL O&M	334,209	136,362	7,907	1,656	171,873	16,410
DEPRECIATION EXPENSE:						
Customer	20,556	14,323	628	135	5,470	0
Capacity	37,368	696	412	74	36,186	0
Total	57,924	15,019	1,040	209	41,656	0
AMORT. OF ENVIRONMENTAL						
Capacity	0	0	0	0	0	0
AMORT. OF PROPERTY LOSS:						
Capacity	0	0	0	0	0	0
AMORT OF LEASEHOLD / OTHER						
Capacity	0	0	0	0	0	0
AMORT. OF ACQUISITION ADJ.:						
Customer	0	0	0	0	0	0
Capacity	0	0	0	0	0	0
Total	0	0	0	0	0	0
AMORT. OF CONVERSION COSTS:						
Commodity	0	0	0	0	0	0

COST OF SERVICE
ALLOCATION OF EXPENSES TO CUSTOMER CLASSES

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO.: 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
TAXES OTHER THAN INCOME TAXES:						
Customer	5,962	4,154	182	39	1,586	0
Capacity	10,838	202	120	21	10,495	0
Subtotal	16,800	4,356	302	61	12,082	0
Revenue	1,717	641	40	8	1,028	0
Total	**18,517**	**4,997**	**341**	**69**	**13,110**	**0**
RETURN (NOI)						
Customer	20,802	14,495	636	137	5,535	0
Capacity	35,323	657	390	70	34,206	0
Commodity	0	0	0	0	0	0
Total	**56,125**	**15,152**	**1,025**	**207**	**39,741**	**0**
INCOME TAXES						
Customer	2,994	2,086	91	20	797	0
Capacity	5,083	95	56	10	4,923	0
Commodity	0	0	0	0	0	0
Total	**8,077**	**2,181**	**148**	**30**	**5,719**	**0**
REVENUE CREDITED TO COS:						
Customer	**(4,120)**	**(4,120)**	**0**	**0**	**0**	**0**
TOTAL COST OF SERVICE:						
Customer	262,296	165,102	8,142	1,754	70,887	16,410
Capacity	206,719	3,848	2,280	409	200,183	0
Commodity	0	0	0	0	0	0
Subtotal	469,015	168,950	10,422	2,163	271,070	16,410
Revenue	1,717	641	40	8	1,028	0
Total	**470,732**	**169,590**	**10,462**	**2,171**	**272,098**	**16,410**

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

SUMMARY	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
RATE BASE	588,925	158,992	10,759	2,170	417,004	0
ATTRITION	0	0	0	0	0	0
OPERATION AND MAINTENANCE	334,209	136,362	7,907	1,656	171,873	16,410
DEPRECIATION	57,924	15,019	1,040	209	41,656	0
AMORTIZATION EXPENSES	0	0	0	0	0	0
TAXES OTHER THAN INCOME TAX (SUB TOTAL)	16,800	4,356	302	61	12,082	0
TAXES OTHER THAN INCOME TAX (REVENUE)	1,717	641	40	8	1,028	0
INCOME TAX (TOTAL)	8,077	2,181	148	30	5,719	0
REVENUE CREDITED TO COST OF SERVICE	(4,120)	(4,120)	0	0	0	0
TOTAL COST OF SERVICE (CUSTOMER)	262,296	165,102	8,142	1,754	70,887	16,410
TOTAL COST OF SERVICE (CAPACITY)	206,719	3,848	2,280	409	200,183	0
TOTAL COST OF SERVICE (COMMODITY)	0	0	0	0	0	0
TOTAL COST OF SERVICE (REVENUE)	1,717	641	40	8	1,028	0
TOTAL COST OF SERVICE	470,732	169,590	10,462	2,171	272,098	16,410
NO. OF CUSTOMERS	673	650	19	2	2	0
PEAK AND AVERAGE MONTH SALES VOL.	1,466,364	27,294	16,173	2,898	1,420,000	0
ANNUAL SALES	5,099,158	168,330	92,799	18,029	4,820,000	0

COST OF SERVICE
DERIVATION OF REVENUE DEFICIENCY

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

COST OF SERVICE BY CUSTOMER CLASS	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
CUSTOMER COSTS	262,296	165,102	8,142	1,754	70,887	16,410
CAPACITY COSTS	206,719	3,848	2,280	409	200,183	0
COMMODITY COSTS	0	0	0	0	0	0
REVENUE COSTS	1,717	641	40	8	1,028	0
TOTAL - (includes rev. credit for other inc.)	470,732	169,590	10,462	2,171	272,098	16,410
less: REVENUE AT PRESENT RATES	339,191	$93,352	$10,547	$2,203	$216,943	$16,146
equals: GAS SALES REVENUE DEFICIENCY	131,541	76,238	(85)	(32)	55,156	264
plus: DEFICIENCY DUE TO REVENUE EXPANSION						
REGULATORY ASSESSMENT	0	0	0	0	0	0
BAD DEBT	0	0	0	0	0	0
STATE INCOME TAX	0	0	0	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	0
plus: DEFICIENCY IN OTHER OPERATING REV.	0	0	0	0	0	0
equals: TOTAL BASE-REVENUE DEFICIENCY	131,541	76,238	(85)	(32)	55,156	264
UNIT COSTS:						
Customer	32.490	21.175	35.712	73.091	2,953.634	N/A
Capacity	0.141	0.141	0.141	0.141	0.141	N/A
Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	N/A

COST OF SERVICE
RATE OF RETURN BY CUSTOMER CLASS
(PAGE 1 OF 2: PRESENT RATES)

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
REVENUES: (projected test year)						
Gas Sales (due to growth)	339,191	93,352	10,547	2,203	216,943	16,146
Other Operating Revenue	4,120	4,120	0	0	0	0
Total	343,311	97,472	10,547	2,203	216,943	16,146
EXPENSES:						
Purchased Gas Cost	N/A	N/A	N/A	N/A	N/A	N/A
O&M Expenses	334,209	136,362	7,907	1,656	171,873	16,410
Depreciation Expenses	57,924	15,019	1,040	209	41,656	0
Amortization Expenses	0	0	0	0	0	0
Taxes Other Than Income--Fixed	16,800	4,356	302	61	12,082	0
Taxes Other Than Income--Revenue	1,717	641	40	8	1,028	0
Total Expses excl. Income Taxes	410,650	156,378	9,289	1,934	226,638	16,410
INCOME TAXES:	8,077	2,181	148	30	5,719	0
NET OPERATING INCOME:	(75,416)	(61,086)	1,111	239	(15,415)	(264)
RATE BASE:	588,925	158,992	10,759	2,170	417,004	0
RATE OF RETURN	-12.81%	-38.42%	10.32%	11.00%	-3.70%	N/A

COST OF SERVICE
RATE OF RETURN BY CUSTOMER CLASS
(Page 2 of 2: PROPOSED RATES)

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
REVENUES:						
Gas Sales	470,732	133,860	11,047	2,303	307,112	16,410
Other Operating Revenue	4,120	4,120	0	0	0	0
Total	474,852	137,980	11,047	2,303	307,112	16,410
EXPENSES:						
Purchased Gas Cost	0	0	0	0	0	0
O&M Expenses	334,209	136,362	7,907	1,656	171,873	16,410
Depreciation Expenses	57,924	15,019	1,040	209	41,656	0
Amortization Expenses	0	0	0	0	0	0
Taxes Other Than Income--Fixed	16,800	4,356	302	61	12,082	0
Taxes Other Than Income--Revenue	1,717	641	40	8	1,028	0
Total Expses excl. Income Taxes	410,650	156,378	9,289	1,934	226,638	16,410
PRE TAX NOI:	64,202	(18,398)	1,758	368	80,473	0
INCOME TAXES:	8,077	2,181	148	30	5,719	0
NET OPERATING INCOME:	56,125	(20,578)	1,611	339	74,754	0
RATE BASE:	588,925	158,992	10,759	2,170	417,004	0
RATE OF RETURN	9.53%	-12.94%	14.97%	15.61%	17.93%	N/A

COST OF SERVICE SUMMARY
PROPOSED RATE DESIGN

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
PRESENT RATES (projected test year)						
GAS SALES (due to growth)	339,191	93,352	10,547	2,203	216,943	16,146
OTHER OPERATING REVENUE	4,120	4,120	0	0	0	0
TOTAL	343,311	97,472	10,547	2,203	216,943	16,146
RATE OF RETURN	-12.81%	-38.42%	10.32%	11.00%	-3.70%	N/A
INDEX	1.00	3.00	-0.81	-0.86	0.29	0.00
PROPOSED RATES						
GAS SALES	470,732	133,860	11,047	2,303	307,112	16,410
OTHER OPERATING REVENUE	4,120	4,120	0	0	0	0
TOTAL	474,852	137,980	11,047	2,303	307,112	16,410
TOTAL REVENUE INCREASE	131,541	40,508	500	100	90,169	264
PERCENT INCREASE	38.32%	41.56%	4.74%	4.54%	41.56%	1.64%
RATE OF RETURN	9.53%	-12.94%	14.97%	15.61%	17.93%	N/A
INDEX	1.00	-1.36	1.57	1.64	1.88	0.00%

COST OF SERVICE SUMMARY
CALCULATION OF COMMISSION APPROVED RATES

COMPANY NAME: INDIANTOWN GAS COMPANY
DOCKET NO. 030954-GU

	TOTAL	TS-1	TS-2	TS-3	TS-4	THIRD PARTY SUPPLIER
PROPOSED TOTAL TARGET REVENUES	$474,852	$137,980	$11,047	$2,303	$307,112	$16,410
LESS: OTHER OPERATING REVENUE	4,120	4,120	0	0	0	0
NET TARGET REVENUE	$470,732	$133,860	$11,047	$2,303	$307,112	$16,410
LESS: CUSTOMER CHARGE REVENUES						
PROPOSED CUSTOMER CHARGES		$9.00	$25.00	$60.00	$2,000.00	$2.03
TIMES: NUMBER OF BILLS	8,073	7,797	228	24	24	8,073
EQUALS: CUSTOMER CHARGE REVENUES	$125,313	$70,173	$5,700	$1,440	$48,000	$16,388
LESS: DEMAND CHARGE REVENUES						
PROPOSED DEMAND CHARGES				N/A	$0.53	
MAXIMUM DEMAND TRANSPORTATION QUANTITY				N/A	133,344	
DEMAND CHARGE REVENUES	$70,672			$0	$70,672	
EQUALS: PER-THERM TARGET REVENUES	$274,746	$63,687	$5,347	$863	$188,439	N/A
DIVIDED BY: NUMBER OF THERMS	5,099,158	168,330	92,799	18,029	4,820,000	N/A
EQUALS: PER-THERM RATES (UNROUNDED)		$0.378346	$0.057620	$0.047855	$0.039095	N/A
PER-THERM RATES (ROUNDED)		$0.37835	$0.05762	$0.04785	$0.03910	N/A
PER-THERM-RATE REVENUES (ROUNDED RATES)	$258,359	$63,688	$5,347	$863	$188,462	N/A
SUMMARY: PROPOSED TARIFF RATES						
CUSTOMER CHARGES		$9.00	$25.00	$60.00	$2,000.00	$2.03
DEMAND CHARGES					$0.53	
NON-GAS ENERGY CHARGES (CENTS PER THERM)		37.835	5.762	4.785	3.910	N/A
PURCHASED GAS ADJUSTMENT (CENTS PER THERM)		76.000	76.000	76.000	N/A	N/A
TOTAL (INCLUDING PGA)		113.835	81.762	80.785	N/A	N/A
SUMMARY: PRESENT TARIFF RATES						
CUSTOMER CHARGES		$9.00	$21.00	$50.00	$1,500.00	$2.00
DEMAND CHARGES						
NON-GAS ENERGY CHARGES (CENTS PER THERM)		13.770	6.206	5.562	3.754	N/A
PURCHASED GAS ADJUSTMENT (CENTS PER THERM)		76.000	76.000	76.000	N/A	N/A
TOTAL (INCLUDING PGA)		89.770	82.206	81.562	N/A	N/A

SUMMARY: OTHER OPERATING REVENUE	PRESENT		PROPOSED	
	CHARGE	REVENUE	CHARGE	REVENUE
CONNECTION CHARGE	$35.00	$1,575	$35.00	$1,575
CONNECTION CHARGE NON-PAY	$35.00	$1,540	$35.00	$1,540
RECONNECTION	$15.00	$465	$15.00	$465
CONNECTION IN LIEU OF DISCONNECT	$10.00	$540	$10.00	$540
TOTAL		$4,120		$4,120

ATTACHMENT 6

INDIANTOWN GAS COMPANY

DOCKET NO. 030954-GU

COMMISSION APPROVED ALLOCATION OF REVENUE INCREASE

(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)	(9)		(10)
RATE	RATE BASE	PRESENT NOI	PRESENT ROR	PRESENT INDEX	INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF GAS	TOTAL INCREASE IN REVENUE	REQUIRED NOI	APPROVED ROR	APPROVED INDEX	REVENUE PERCENTAGE INCREASE
TS-1	$158,992	($61,086)	-38.4%	3.00	$0	$40,508	$40,508	($20,578)	-12.94%	-1.36	41.6%
TS-2	$10,759	$1,111	10.3%	-0.81	$0	$500	$500	$1,611	14.97%	1.57	4.7%
TS-3	$2,170	$239	11.0%	-0.86	$0	$100	$100	$339	15.61%	1.64	4.5%
TS-4	$417,004	($15,415)	-3.7%	0.29	$0	$90,169	$90,169	$74,754	17.93%	1.88	41.6%
TPS	$0	($264)	N/A	N/A	$0	$264	$264	$0	N/A	N/A	1.6%
TOTAL	$588,925	($75,416)	-12.8%	1.00	$0	$131,541	$131,541	$56,125	9.53%	1.00	38.3%

ATTACHMENT 7

INDIANTOWN GAS COMPANY
COMMISSION APPROVED RATES
DOCKET NO. 030954-GU

ATTACHMENT 7

RATE SCHEDULE	PRESENT RATE	COMMISSION APPROVED RATE
TRANSPORTATION SERVICE - 1		
CUSTOMER CHARGE	$9.00	$9.00
TRANSPORTATION CHARGE (cents/therm)	13.770	37.835
TRANSPORTATION SERVICE - 2		
CUSTOMER CHARGE	$21.00	$25.00
TRANSPORTATION CHARGE (cents/therm)	6.206	5.762
TRANSPORTATION SERVICE - 3		
CUSTOMER CHARGE	$50.00	$60.00
TRANSPORTATION CHARGE (cents/therm)	5.562	4.785
TRANSPORTATION SERVICE - 4		
CUSTOMER CHARGE	$1,500.00	$2,000.00
TRANSPORTATION CHARGE (cents/therm)	3.754	3.910
DEMAND CHARGE ($ per MDTQ)	N/A	$0.53
THIRD PARTY SUPPLIER		
MONTHLY CHARGE PER CUSTOMER	$2.00	$2.03