State of Florida

Public Service Commission

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TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: May 6, 2004

TO: Director, Division of the Commission Clerk & Administrative Services (Bayó)

FROM: Division of Economic Regulation (Merta, Baxter, Biggins, Draper, Gardner, Hewitt, Kenny, Lester, Maurey, Springer, Stallcup, Wheeler, Winters)
Office of the General Counsel (Fleming)
Division of Regulatory Compliance & Consumer Assistance (Fletcher, Witman)
Office of Standards Control & Reporting (Lowery)

RE: Docket No. 030954-GU – Petition for rate increase by Indiantown Gas Company.

AGENDA: 05/18/04 – Regular Agenda – Proposed Agency Action Except Issue 69 - Interested Persons May Participate

CRITICAL DATES: 5-Month Effective Date: waived until 05/18/04 (PAA Rate Case)

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\ECR\WP\030954.RCM.DOC
Attachments 6 & 7 are not electronically submitted
R:\PSC\ECR\123\030954-ATT6.123
R:\PSC\ECR\123\030954-ATT7.123

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CASE 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.

The Commission 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, the Commission 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, the Commission approved initial rates and charges for IGC on a temporary basis. The Commission, 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. 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, the Commission 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, the Commission must enter its 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 the Commission enter its 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 the Commission 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, the Commission granted intervention to Indiantown Cogeneration, L.P. (ICLP).

A customer meeting was held in Indiantown on February 5, 2004. The purpose of the meeting was to allow the public to offer comments concerning IGC's requested permanent rate increase and the quality of service provided. 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 the meeting opposed the increase in their rates.

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

Discussion of Issues

TEST YEAR

Issue 1: Is IGC's projected test period of the 12 months ending December 31, 2004 appropriate?

Recommendation: Yes. With the adjustments recommended by staff in the following issues, the 2002 and 2004 test years are appropriate. (Merta)

Staff Analysis: 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 Commission auditors and analyzed by 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.

In the following issues, staff is recommending that certain adjustments be made to IGC's projected test year. With the inclusion of these adjustments, staff believes that 2002 and the projections of IGC's financial operations for 2004 are sufficient to use as a basis for setting rates.

Issue 2: Are IGC's forecasts of customer growth and therms by rate class for the projected test year appropriate?

Recommendation: Yes. The number of bills and therms by rate class contained in revised MFR Schedule G-2, page 8 of 31 (dated January 16, 2004) are appropriate. (Stallcup, Hewitt)

Staff Analysis: 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 staff 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, staff concludes 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. Staff agrees that these projections for the company's three industrial customers are appropriate.

Subsequent to the company's original filing, the staff 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. 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. Staff therefore recommends that the projected test year customer counts and therms contained in revised MFR Schedule G-2, page 8 of 31 are appropriate.

The revision to the billing determinants in MFR Schedule G-2 results in a minor change in test year revenues as discussed in Issue 23.

QUALITY OF SERVICE

Issue 3: Has Indiantown Gas Company periodically tested customer meters within a ten-year interval as required by Rule 25-7.064 (1) and (2), Florida Administrative Code (F.A.C.), and have customer refunds been made for all meters tested and found to measure more than 2 percent fast, as required by Rule 25-7.087(1), F.A.C.?

Recommendation: No. IGC should be ordered to accelerate its meter test program to have all customer meters with a rated capacity of 2500 cubic feet per hour (cfh) or less be tested within a ten-year period as required by Rule 25-7.064(1) and (2), F.A.C. Meters should be tested at a rate that will assure full compliance by December 31, 2005.

Further, IGC should be ordered to make refunds for each of the meters tested during calendar years 2003 and 2004 that are found to register more than two percent fast. The refunds should 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 test interval cannot be established due to inadequate records, it is recommended that the calculation of the refund should 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 a forwarding address, a reasonable effort should be made to locate the individual. If the refund cannot be completed, a record should be established in accordance with Rule 25-7.091(7)(c), F.A.C., and the Commission informed of all unclaimed refunds and a method of disposal established. (Fletcher)

Staff Analysis: 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, F.A.C., a copy of which is attached. 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.

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, F.A.C., a copy of which is attached. 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 do 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), F.A.C., a copy of which is attached.

The primary factor that must be considered in 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, staff has recommended salaries for additional personnel in Issues 30 and 32 and additional periodic meter and change-out expenses in Issue 31 to aid the company in attaining compliance with the rules. Therefore, staff recommends that the company be ordered to 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, the Commission 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, staff recommends that the refunds be recalculated using a multiplier of 10 times the average consumption to arrive at an equitable refund for the affected customers.

Staff recommends that IGC be ordered to 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 should 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, staff recommends that the calculation of the refund should 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 should be made to locate the individual. If the refund cannot be completed, a record should be established in accordance with Rule 25-7.091(7)(c), F.A.C., a copy of which is attached, and the Commission should be informed of all unclaimed refunds and a method of disposal established.

In light of staff's recommendation to require the company to comply with the requirements by a date certain, staff recommends that the Commission not pursue show cause proceedings at this time.

Issue 4: Is the quality of service provided by IGC adequate?

Recommendation: Yes. The quality of service provided by IGC is satisfactory. (Merta, Lowery, Witman)

Staff Analysis: 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.

Staff 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 in Issue 3, IGC is not in compliance with Commission 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, staff recommends that the Commission find that IGC's quality of service is satisfactory.

RATE BASE

Issue 5: Should an adjustment be made for the transfer of the office building land?

Recommendation: Yes. An adjustment should be made to increase plant and non-utility operations by $1,552 and $524, respectively for the projected test year. (Gardner)

Staff Analysis: The staff engineers 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 staff engineer recalculated IGC's 57.07% allocation factor of the land value. Staff 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. See Issue 11 for a more detailed discussion of the recalculation of the allocation factors.

Issue 6: Should an adjustment be made to IGC's proposed level of plant additions for the projected test year?

Recommendation: Yes. Plant, Accumulated Depreciation, and Depreciation Expense should be increased by a total of $13,060, $646, and $1,040, respectively. (Gardner)

Staff Analysis: During the 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 should be increased by $13,060, $646, and $1,040, respectively, for the 2004 projected test year.

Issue 7: Should an adjustment be made to plant retirements for the projected test year?

Recommendation: Yes. The adjustment to correct the overstated retirements should be to increase Plant, Accumulated Depreciation, and Depreciation Expense for the projected test year by \$2,264, \$2,359, and \$190, respectively. (Gardner)

Staff Analysis: The staff engineers evaluated the monthly plant retirements for the 2004 projected test year. For Account 376, Mains, staff calculated 3,351 feet of new plastic mains would have to be installed to replace the bare steel mains. Staff believes 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.

Issue 8: Should an adjustment be made to Plant, Accumulated Depreciation, and Depreciation Expense for the installation of a gas distribution system that occurred prior to 1970 which was incorrectly booked to IGC's Continuing Property Records in the amount of $182,252?

Recommendation: Yes. Plant, Accumulated Depreciation, and Depreciation Expense should be reduced by $81,347, $81,110 and $3,417, respectively, for the projected test year. (Gardner)

Staff Analysis: During the staff audit, the 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 a 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 Commission 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. The accumulated depreciation and the depreciation expense should be reduced by $81,110 and $3,417, respectively. IGC should record $82,818 as the reduction to accumulated depreciation if it will be booked at 2004 year end.

Issue 9: Should an adjustment be made to Plant, Accumulated Depreciation, and Depreciation Expense for the installation of mains at the New Hope Subdivision in Booker Park in 1980?

Recommendation: Yes. Plant, Accumulated Depreciation, and Depreciation Expense should be increased by $30,536, $21,040 and $1,283, respectively. (Gardner)

Staff Analysis: During the staff audit, an 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 should 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 should be increased by $21,040 and $1,283, respectively. IGC should record $21,681 as an increase to accumulated depreciation if it will be booked at 2004 year end.

Issue 10: Is IGC's requested level of Plant in Service in the amount of $1,341,330 for the projected test year appropriate?

Recommendation: No. The appropriate Plant in Service amount should be $1,307,395 for the projected test year. (Gardner)

Staff Analysis: The recommended $1,307,395 is based upon the recommendations made in the preceding issues. 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.

Issue 11: Should an adjustment be made to non-utility Common Plant, Accumulated Depreciation, and Depreciation Expense for non-utility operations?

Recommendation: Yes. Common Plant Allocated, Accumulated Depreciation-Common Plant Allocated, and Depreciation Expense for non-utility operations should be increased by a total of $110,303, $13,800, and $9,420, respectively. (Biggins, Gardner)

Staff Analysis: 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. The staff auditor believes that using this percentage of net non-utility to total net plant may not be the most reasonable methodology to allocate common plant. Staff believes using this one factor does not allow proper allocation of non-utility plant. The staff auditor proposed 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 33.79%.

The company disagrees with the application of the staff auditor's proposed three factor methodology for allocating plant assets between utility and non-utility operations. The company disagrees with the staff auditor 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 the 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 the staff auditor's 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. The staff auditor received job descriptions for each employee and a specific assessment of the time spent on utility vs. non-utility activities. 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 staff 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 proposed by the staff auditor 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 the staff auditor's gross plant ratio in 2003 as an appropriate method of allocating plant.

Staff has recalculated non-utility plant based on a three factor methodology using number of customers, gross plant, and payroll. Staff believes that this three factor methodology is a more appropriate method for allocating common costs between regulated and non-regulated operations. Staff believes this gives the company a broader based allocation. Staff believes that using the number of customers is more accurate. The number of customers does not change on a constant basis, and would give the company a more accurate based allocation. Staff also proposed using payroll as part of the three factor methodology. Staff believes payroll to be an accurate factor as well. Staff believes 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. Staff believes using payroll as a factor of the three factor allocation is a very reasonable factor, as it shows a description for regulated and non-regulated charges, as well as the amount of time spent on the utility. The payroll factor is discussed in more detail in Issue 27. The third factor staff 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. Staff believes 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%. Staff believes this methodology is more reasonable. Staff believes using these three factors gives the company a broader based allocation. Staff does not propose using revenue as a factor. Staff believes revenue is too variable to be included in the three factor allocation. By 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, the Commission approved the use of a three factor methodology using payroll, plant, and number of customers. Staff believes using the number of customers, the amount for gross plant, and payroll is more reasonable.

The staff auditor 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 staff's recalculation using the three factor methodology of number of customers, gross plant, and payroll, staff recommends increasing the non-utility factor from 6.2% to 33.79%.

Staff recommends non-utility Plant, Accumulated Depreciation, and Depreciation Expense should 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.

Issue 12: Is IGC's requested level of non-utility Common Plant Allocated in the amount of $24,749 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Common Plant Allocated for the projected test year is $135,575 which reflects an increase to non-utility plant by $110,827. (Gardner, Biggins)

Staff Analysis: This is a calculation based upon the recommendations made in preceding issues. Issue 11 provides a detailed explanation of the re-calculation of the allocation factors which changed from 6.2% to 33.39% for non-utility plant.

Issue 13: Is IGC's Total Plant of $1,316,581 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Total Plant for the projected test year is $1,171,820 a total reduction of $144,762 for the projected test year. (Gardner)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues.

Issue 14: Is IGC's requested level of Accumulated Depreciation and Accumulated Amortization of Gas Plant in Service in the amount of $685,574 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Accumulated Depreciation and Amortization of Plant in Service for the projected test year is $614,709. (Gardner)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues. The prior recommendations that impacted accumulated depreciation creating a reduction of $70,865 included: (1) Issue 6, understated additions created an increase of $646, (2) Issue 7, overstated retirements created an increase of $2,359, (3) Issues 8 and 9, overstated plant since 1969 created a reduction of $81,110, and mains installed but not capitalized created an increase of $21,040, (4) Issue 11 reflects the recalculation of the allocation factor and created an increase of $13,800 to non-utility operations.

Issue 15: Should an adjustment be made to the amount of cash in working capital for the 2004 projected test year?

Recommendation: Yes. Cash for the 2004 projected test year should be decreased by $96,081 to reflect cash based on the three year average. (Biggins)

Staff Analysis: 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. Staff recommends adjusting cash based on a three year average. The three year average from 2001 through 2003 was $56,659. Staff believes 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. Staff believes using a three year average would be more indicative of the trend, since there was no negative cash balance. Staff recommends 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).

Issue 16: Should an adjustment be made to allocate working capital to reflect non-utility operations allocations?

Recommendation: Yes. Working Capital should be decreased by $10,400 to reflect the non-utility operations allocations. (Biggins)

Staff Analysis: The company projected cash in the amount of $152,740. Per Audit Exception 5, the cash balances were not reduced for non-utility operations. Staff is recommending cash based on a three-year average from 2001 through 2003. 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 discussed in Issue 11.

Per Audit Exception 4, Working Capital's plant and operating material and supplies are company Account 154, Inventory, and Account 156, Capital Inventory. Staff 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 should 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. As discussed in Issue 11, staff is recommending using a three factor method to calculate the non-utility allocation factor of 33.79%. Staff recommends decreasing accounts payable by $20,737 (75,160 x 33.79%-$4,660), to reflect staff's three factor method of allocation.

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

Issue 17: Should an adjustment be made to Deferred Debits?

Recommendation: Yes. Deferred Debits should be increased by $8,137. (Biggins)

Staff Analysis: Per Audit Exception 3, in the working capital calculation starting October 2003, 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, the Commission 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. Staff has made adjustments to reflect these changes. Staff has increased the 2004, 13-month average by $8,137 ($4,911 to $13,048). The year end December 31, 2004, should be changed from zero to $7,510. Staff recommends an increase to Deferred Debits in the amount of $8,137 to reflect the changes in this calculation.

Issue 18: Should an adjustment be made to Accrued Taxes Payable in Working Capital?

Recommendation: Yes. Accrued Taxes Payable should be increased by $2,609. This adjustment results in a $2,609 decrease to Working Capital Allowance. (Winters, Biggins)

Staff Analysis: Per 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.

Staff determined, based on the company's response to a staff data request, that the company did not include any accrued property taxes in Taxes Accrued – General. Using the property taxes calculated by staff in Issue 51, the correct 13-month average for accrued property taxes is $2,609. Therefore, Taxes Accrued – General should be increased by $2,609 to reflect the correct balance of the accrued property taxes payable account.

Issue 19: Is IGC's requested level of Working Capital Allowance in the amount of $124,804 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Working Capital Allowance for the projected test year is $31,814. (Biggins)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues. Working Capital is shown on Attachment 1A.

Issue 20: Is IGC's requested level of Rate Base in the amount of $755,812 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Rate Base for the projected test year is $588,925. (Biggins, Gardner)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues. Rate Base is shown on Attachment 1.

COST OF CAPITAL

Issue 21: What is the appropriate cost rate for common equity to use in establishing IGC's revenue requirement for the projected test year?

Recommendation: The appropriate return on equity for IGC for the projected test year is 11.50% with a range of plus or minus 100 basis points. (Maurey)

Staff Analysis: 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, the Commission 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, the Commission has 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, the Commission 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, the Commission 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, the Commission 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, staff recommends the Commission approve an authorized ROE of 11.50% with a range of plus or minus 100 basis points for purposes of this proceeding.

Issue 22: What is the appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with the capital structure for the projected test year?

Recommendation: The appropriate weighted average cost of capital for the projected test year is 9.53%. (Maurey)

Staff Analysis: Based upon the proper components, amounts, and cost rates associated with the capital structure for the projected test year ending December 31, 2004, staff recommends a weighted average cost of capital of 9.53%. Attachment 2 details staff's recommendation.

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's true that the Commission established an equity ratio cap of 60% in Order No. PSC-02-1666-PAA-GU, the intent of the Commission's 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 made by staff 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, the Commission waived this adjustment to avoid the same outcome.

The third adjustment made by staff 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. Staff made an adjustment consistent with the auditor's finding which reflects a more accurate balance of long-term debt outstanding for the projected 2004 test year.

Staff used the respective cost rates supplied by the company with one exception. Staff 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. Staff agreed with the cost rate for customer deposits of 6.22% and the return on equity (ROE) of 11.50%. The determination of the appropriate ROE for IGC is discussed in more detail in Issue 21.

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, staff made a pro rata adjustment over all sources of capital to reconcile rate base and capital structure.

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

The capital structure is shown on Attachment 2.

NET OPERATING INCOME

Issue 23: Are IGC's estimated revenues from sales of gas by rate class at present rates for the projected test year appropriate?

Recommendation: No. Revenues should be increased by $392 to correct estimated sales of gas by rate class for the projected test year. (Springer, Baxter, Merta)

Staff Analysis: Per MFR Schedule H-3, Page 2, IGC shows present revenue from sales of gas for the projected test year of $338,798. Staff's 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 should be increased by $719 to reflect a correction to the bills and therms. The TS-2 revenues should be decreased by $503 to reflect a correction to the bills and therms. The TS-3 revenues should be increased by $104 to reflect a correction to the therms. Finally, the TPS revenues should be increased by $72 to reflect a correction to the bills.

Based on the above, staff recommends that revenues be increased by $392.

<u>Issue 24</u>: Is IGC's projected level of Total Operating Revenues in the amount of $342,918 for the projected test year appropriate?

<u>Recommendation</u>: No. The appropriate amount of Total Operating Revenues for the projected test year is $343,310. (Merta, Springer)

<u>Staff Analysis</u>: This is a calculation based upon the recommendations made in Issue 23.

Issue 25: Has IGC made the appropriate adjustment to Account 921, Office Supplies, Account 930, General Advertising and Miscellaneous General Expense, and Account 932, Maintenance of General Plant, to remove non-utility expenses?

Recommendation: No. Account 921, Office Supplies, Account 930, General Advertising and Miscellaneous General Expense, and Account 932, Maintenance of General Plant Expenses, should be reduced by $2,042, $118, and $393, respectively, for a total adjustment of $2,553 to remove non-utility expenses. (Merta)

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

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. Staff believes the $2,920 in charges for cleaning the homes are non-utility expenses, and consistent with prior Commission decisions, should be disallowed. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on staff's allocation factor, trended to 2004, using staff's trend rates. This calculation does not include the impact of the adjustments in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors. Therefore, staff recommends that Account 921, Office Supplies, be reduced by $2,042 ($2,920 x .6621 x 1.019 x 1.0363). The company agrees with this adjustment.

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. Staff believes these are non-utility expenses, and should not have been allocated to the utility. Consistent with prior Commission practice, these costs should be disallowed. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on staff's allocation factor, trended to 2004, using staff's trend rates. This calculation does not include the impact of the adjustments in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors. Therefore staff recommends that Account 930 be reduced by $118 ($171 x .6621 x 1.019 x 1.021). The company agrees with this adjustment.

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. Staff believes these are non-utility expenses and should not have been allocated to the utility. The amount to be disallowed is the portion of these expenses that is allocated to regulated operations, based on staff's allocation factor, trended to 2004, using staff's trend rates. This calculation does not include the impact of the adjustments in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors. Therefore, staff recommends reducing Account No. 932 by $393 ($571 x .6621 x 1.019 x 1.021).

Issue 26: Has IGC properly allocated expenses between regulated and non-regulated operations?

Recommendation: No. Expenses should be increased by $10,341 to properly allocate expenses between regulated and non-regulated operations. (Merta)

Staff Analysis: 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. Staff believes the three factor method described in Issue 11 is a more reasonable approach because most costs are not directly related to revenue. Therefore, staff allocated 66.21% of common expenses to the regulated utility based on staff's recommendation of the three factor percentage in Issue 11.

Staff 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 staff's factor ($126,509) and trended each account by the appropriate trend factor to 2004. Therefore, staff recommends increasing expenses by $10,341.

Issue 27: Should an adjustment be made to IGC's requested level of Administrative & General (A&G) salaries for the projected test year?

Recommendation: Yes. A&G salaries should be reduced by $44,459 for non-utility allocations. (Merta)

Staff Analysis: 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, the staff's 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. 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.

Staff agrees with the 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. Staff believes 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, staff used the same method the auditor used, as described above, except that staff 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, staff included the impact of the new employees and the increase for the CFO in its calculation of the payroll factor. This calculation resulted in a payroll allocation factor of 62.91% regulated and 37.09% non-regulated. Staff believes 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, staff 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, staff reduced A&G

salaries 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 in Issue 48 to reduce expenses for the effect of the change in trend factors. An adjustment was made in Issue 51 to reduce Taxes Other Than Income to remove the related withholding taxes.

Issue 28: Should an adjustment be made to Account 932, Maintenance of General Plant, and Account 926, Employee Pensions and Benefits, to remove certain memberships and dues?

Recommendation: Yes. Account 932, Maintenance of General Plant, should be reduced by $169 and Account 926, Employee Pensions and Benefits, Expenses should be reduced by $290 for a total adjustment of $459 to remove certain memberships and dues. (Merta)

Staff Analysis: 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.

Staff believes the cost of these memberships should be 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 staff's allocation factor, trended to 2004, using staff's inflation trend rates. This calculation does not include the impact of the adjustments in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors.

Therefore, staff recommends that Account 932, Maintenance of General Plant, and Account 926, Employee Pensions and Benefits, 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.

Issue 29: Should an adjustment be made to Account 880, Other Expenses, Account 921, Office Supplies, and Account 923, Outside Services, to remove nonrecurring expenses?

Recommendation: Yes, Account 880, Other Expenses, Account 921, Office Supplies, and Account 923, Outside Services, should be reduced by $456, $527, and $5,878, respectively, for a total adjustment of $6,861 to remove nonrecurring expenses. (Merta)

Staff Analysis: 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, staff recommends that Account 880 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 in Issue 48 to reduce expenses for the effect of the change in trend factors. The company agrees with this adjustment.

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. Staff believes 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 staff's allocation factor, trended to 2004, using staff's customer growth times inflation trend rates. This calculation does not include the impact of the adjustments in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors. Therefore, staff recommends that Account 921, Office Supplies, be reduced by $527 ($754 x .6621 x 1.019 x 1.0363).

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 should be removed from test year expenses. Staff recommends that Account 923 be reduced by $260 ($250 x 1.019 x 1.021). This calculation does not include the impact of the adjustment in Issue 48 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, staff recommends that expenses be reduced by $5,618 ($5,400 x 1.019 x 1.021). This calculation does not include the impact of the adjustment in Issue 48 to reduce expenses for the effect of the change in trend factors. The company agrees with this adjustment.

Based on the above, staff recommends that expenses should be reduced by $6,861.

Issue 30: Should an adjustment be made to Account 874, Mains & Services, for the projected test year?

Recommendation: Yes. Account 874, Mains & Services, should be decreased by $12,666 for the projected test year. (Merta)

Staff Analysis: Per 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 recommended by Commission engineering staff 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 recommended by staff. 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.

Staff believes that the company should receive the cost to employ the Service Technician because the Commission has directed IGC to come into compliance with Rule 25-7.064(1) and (2), F.A.C., as described in Issue 3. However, staff recommends that Account 874 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 in Issue 27 because this employee will charge his time directly. An adjustment has been made in Issue 51 to reduce Taxes Other Than Income to remove the related withholding taxes.

Issue 31: Should an adjustment be made to Account 878, Meter and House Regulator Expenses, to include periodic meter and regulator change-out expense?

Recommendation: Yes. Account 878, Meter and House Regulator Expenses, should be increased by $4,832 and Miscellaneous Deferred Debits should be increased by $7,249 to include periodic meter and regulator change-out expense. (Merta, Fletcher)

Staff Analysis: As discussed in Issue 3, 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. Staff 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), F.A.C., "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." Staff believes 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, staff determined that of the 687 meters, 69 should be tested each year (687/10). Staff divided the 270 meters left to be tested by 69 and the result was approximately four. Therefore, staff believes a reasonable amortization period is four years.

Staff recommends that $19,329 be amortized over four years, that expenses 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) be included as an increase to working capital in Miscellaneous Deferred Debits.

Issue 32: Should an adjustment be made to Accounts 880, Other Expenses, and 889, Measuring and Regulating Station Equipment, to remove non-utility related salary for the projected test year?

Recommendation: Yes. Accounts 880, Other Expenses, and 889, Measuring and Regulating Station Equipment, should be reduced by $3,169 each for a total of $6,338 to remove the non-utility related salary of a Customer Service representative. (Merta)

Staff Analysis: 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, F.A.C., and 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. Staff believes this is a reasonable rate based on the job description of this position.

According to the company, this employee's time should be allocated to non-utility operations consistent with the allocation of the office manager position. Staff used the payroll factor calculated by the auditor to allocate the office manager's salary. Therefore, based on staff's payroll factor calculated in Audit Exception No. 11, 33.79% or $6,338 ($18,760 x .3379) should be allocated to non-utility operations. This calculation does not include the impact of the adjustment in Issue 26 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.

Staff believes the company has justified this position. Staff directed IGC to come into compliance with Commission Rules as discussed in Issue 3. However, staff recommends that Accounts 880 and 889 be decreased by $3,169 each for a total decrease to expenses of $6,338 to remove the non-utility portion of the salary. An adjustment was made in Issue 51 to reduce Taxes Other Than Income to remove the related withholding taxes.

Issue 33: Should an adjustment be made to Account 880, Miscellaneous Distribution Expense, to include odorant costs?

Recommendation: Yes. Account 880, Miscellaneous Distribution Expense, should be increased by $714 for odorant costs for the 2004 projected test year. In addition, an adjustment should be made to increase working capital Prepayments by $715. (Merta)

Staff Analysis: 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, staff believes that the odorant costs should be amortized over three years. Hence, staff recommends that expenses 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).

Issue 34: Should an adjustment be made to Account 902, Meter Reading, for the projected test year?

Recommendation: Yes. Account 902 should be increased by $220. (Merta)

Staff Analysis: 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 in prior issues reducing it by $1,390 for allocations from A&G salaries and for the effect of changing the trend factors. Staff recommends increasing the balance of this account by $220 ($5,218 + $1,390 - $6,388) in order to allow the $5,218 for the meter reading contract.

Issue 35: Should an adjustment be made to Account 920, A&G Salaries, for the projected test year?

Recommendation: Yes. Account 920 should be decreased by $4,731 to allocate the non-utility increase in the Chief Financial Officer's (CFO) salary due to an increase in her work hours. (Merta)

Staff Analysis: 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).

Staff believes 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 staff's payroll factor calculated in Audit Exception No. 11, staff recommends that expenses be decreased by $4,731 ($14,000 x .3379). This adjustment is not impacted by the adjustment in Issue 27 to allocate A&G salaries because this was a pro forma adjustment and not included in 2002 expenses. An adjustment was made in Issue 51 to reduce Taxes Other Than Income to remove the related withholding taxes.

Issue 36: Should an adjustment be made to Account 921, Office Supplies, to remove one-half of the charges for employee activities?

Recommendation: Yes. Account 921, Office Supplies, should be reduced by $614 to remove one-half of the charges for employee activities. (Merta)

Staff Analysis: 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, staff recommends that one-half of the amount 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, staff recommends that Account 921 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 in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors.

Issue 37: Should an adjustment be made to Account 921, Office Supplies and Expenses, to remove non-utility entertainment expenses for the projected test year?

Recommendation: Yes. Account 921, Office Supplies and Expenses, should be reduced by $1,394 to remove non-utility entertainment expenses. (Merta)

Staff Analysis: 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, staff removed the meals and lodging of the spouses and non-employees ($1,250), the personal charges ($180), and the unsupported lodging ($564). Therefore, staff recommends reducing Account 921 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 in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors.

Issue 38: Should an adjustment be made to Account 923, Outside Services?

Recommendation: Yes. Account No. 923, Outside Services, should be reduced by $11,800. (Merta)

Staff Analysis: 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 should be reduced by $11,047 ($12,029 - $982). Staff 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 in Issue 48 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). Staff trended this amount by inflation and reduced this account by $307. This calculation does not include the impact of the adjustment in Issue 48 for the change in trend factors.

Based on the above, staff recommends that Account 923 be decreased by $11,800.

Issue 39: Should an adjustment be made to Account 926, Employee Pensions and Benefits, to remove non-utility life insurance expenses for the projected test year?

Recommendation: Yes. Account 926, Employee Pensions and Benefits, should be reduced by $475 to remove non-utility life insurance expenses. (Merta)

Staff Analysis: 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. Therefore, staff believes this is a non-utility expense and should not be included in operating expenses. Staff recommends that Account 926 be reduced by $475. ($690 x .6621 x 1.019 x 1.021).

Issue 40: Should an adjustment be made to Account No. 923, Outside Services, and Account No. 926, Employee Pensions and Benefits, to remove out of period expenses?

Recommendation: Yes. Account No. 923, Outside Services, and Account No. 926, Employee Pensions and Benefits, should be reduced by $1,966 and $3,445, respectively, for a total adjustment of $5,411 to remove out of period expenses. (Merta)

Staff Analysis:

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. Staff 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 in Issue 48 for the change in trend factors. The company agrees with this adjustment.

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, staff recommends that Account 926 be reduced by $3,445 ($5,000 x .6621 x 1.019 x 1.021).

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

Issue 41: Should an adjustment be made to Account 928, Regulatory Commission Expense, for rate case expense for the projected test year and what is the appropriate amortization period?

Recommendation: Yes. Account 928, Regulatory Commission Expense, should be decreased by $13,888 for rate case expense for the projected test year. The appropriate amortization period is four years. (Merta)

Staff Analysis: 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 for rate case expense.

On March 26, 2004, the company provided staff with an updated estimate of rate case expense based on actual expense to date and an estimate to complete the case. The documentation has been reviewed. IGC projected $35,000 for consulting fees, however the updated estimate is now $30,000, provided there is no protest. Therefore, expenses for consulting should be reduced by $5,000. In addition, IGC projected $55,050 for legal fees. The updated estimate for legal expenses, provided there is no protest, is $10,000, therefore legal expenses should be reduced by $45,050. 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 should be reduced by $55,550. The remaining $44,500 of expenses incurred by the company appear to be reasonable and prudent.

As presented in the MFRs, 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. Therefore, staff believes that four years is a reasonable time period over which to recover rate case expense.

Based on the above, staff recommends that the appropriate amount of rate case expense is $44,500 to be amortized over four years. The appropriate amount to be included in rate case expense is $11,125 ($44,500/4), therefore expenses should be reduced by $13,888.

Issue 42: Should an adjustment be made to Account 930, Miscellaneous General Expense, to remove a portion of American Gas Association (AGA) dues?

Recommendation: Yes, Account 930, Miscellaneous General Expense, should be reduced by $208 to remove a portion of AGA dues related to lobbying and advertising that is not informational or educational in nature. (Merta)

Staff Analysis: In 2002, the company included $500 for its annual AGA dues. The Commission has traditionally removed that portion of AGA dues that is attributable to lobbying, charitable contributions, and advertising that did 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, the Commission 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, the Commission removed 40% of AGA dues. In that case, staff reviewed the NARUC Audit Report dated June, 2001, for the twelve month period ended December 31, 1999, the most recent report that staff could locate. 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, staff recommends that Account 930, Miscellaneous General Expense, be reduced by 40% of AGA dues, or $208 ($500 x .4 trended to 2004) to remove lobbying and advertising that is not informational or educational in nature.

Issue 43: Should an adjustment be made to Account 930, Miscellaneous General Expense, to remove image building or other inappropriate advertising expenses?

Recommendation: Yes, Account No. 930, Miscellaneous General Expense, should be reduced by $1,487 for non-utility advertising. (Merta)

Staff Analysis: 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 should be included in expenses.

Therefore, staff recommends that expenses 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 in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors.

Issue 44: Should an adjustment be made to Account 930, Miscellaneous General Expense, to remove charitable contributions?

Recommendation: Yes. Account 930, Miscellaneous General Expense, should be reduced by $1,536 to remove charitable contributions. (Merta)

Staff Analysis: Per Audit Exception No. 12, in 2002, the company made a $250 donation to the Indiantown Neighbor for the 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.

The Commission has consistently held that charitable contributions should not be included in operating expense. The Commission 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, staff recommends that Account No. 930, General Advertising and Miscellaneous General Expenses, 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.

Issue 45: Should an adjustment be made to Account 930, Miscellaneous General Expense, for director fees?

Recommendation: Yes, Account 930, Miscellaneous General Expense, should be reduced by $12,000 for director fees. (Merta)

Staff Analysis: The company requested $18,000 in director fees for three non-employee directors in 2004. Staff does 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. Staff believes that $2,000 each for one meeting is reasonable for this company. Therefore, staff recommends that Account 930 be reduced by $12,000 for director fees.

Issue 46: Should an adjustment be made to Account 930, Miscellaneous General Expenses, to remove interest expense for the projected test year?

Recommendation: Yes, Account 930, Miscellaneous General Expenses, should be reduced by $490 to remove interest expense. (Merta)

Staff Analysis: 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. Hence, interest expense should be reclassified to Account 431, a below-the-line account.

Therefore, staff recommends that Account 930 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 in Issue 26 to allocate expenses or in Issue 48 to reduce expenses for the effect of the change in trend factors.

Issue 47: Are the trend rates used by IGC to calculate projected O&M expenses appropriate

Recommendation: No. The appropriate trend rates are:

	2003	2004
Inflation	1.9%	2.1%
Customer Growth	0.0%	1.5%
Customer Growth x Inflation	1.9%	3.63%
Payroll	2.5%	2.5%

(Lester, Stallcup, Merta)

Staff Analysis: 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. Staff notes 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. Staff recommends that the inflation rate be 1.9% for 2003 and 2.1% for 2004.

As discussed in Issue 2, 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%. Staff recommends that IGC's customer growth trend factors of 0% for 2003 and 1.5% for 2004 are appropriate.

The customer growth times inflation rate is a calculation that falls out of staff's recommendation for those rates. For the customer growth times inflation rates, staff recommends 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 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), the Commission limited wage increases to the inflation rate. As stated above, staff is recommending 1.9% and 2.1% for the inflation rate. Staff believes that a 2.5% payroll trend rate for 2003 and 2004 is not unreasonable. This is a conservative approach which falls somewhere between the staff's inflation rate and the company's payroll rate for 2004.

Issue 48: Should the projected test year expense be adjusted for the effect of any changes to trend rates or bases?

Recommendation: Yes. Projected test year expenses should be reduced by $5,954 for the effect of changing the trend rates. (Merta)

Staff Analysis: In its MFRs, the company applied trend rates that were different than staff. Therefore, an adjustment is recommended as a result of a calculation of the differences in trend rates.

Staff recommends that expenses be decreased by $5,954 as a result of lowering the inflation rate, the customer growth times inflation rate, and the payroll rate as discussed in Issue 47. This dollar amount represents the difference in the company's filed 2004 O&M expense and staff's recommended O&M expense after taking into account the change in trend rates. Staff made no changes to the trend basis of any account. Therefore, staff recommends that projected test year expenses be decreased by $5,954.

Issue 49: Is IGC's O&M Expense of $447,301 for the projected test year appropriate?

Recommendation: No. The appropriate amount of O&M Expense for the projected test year is $330,083. (Merta)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues.

Issue 50: Is IGC's Depreciation and Amortization Expense of $68,248 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Depreciation and Amortization Expense for the projected test year is $57,924. (Gardner)

Staff Analysis: This is a calculation based upon the recommendations made in preceding issues which created a decrease in the amount of $10,324 for the projected test year. The issues that impacted the Depreciation and Amortization Expense of $68,248 included: (1) Issue 6, $1,040 due to increase of plant additions, (2) Issue 7, $190 due to overstated retirements, (3) Issue 8, $3,417 reduction due to overstated 1969 plant addition, (4) Issue 9, 1980 mains for Booker Park installed but not capitalized in the amount of $1,283; and (5) Issue 11, $9,420 increase for non-utility operations due to recalculation of the non-utility operations allocation factors.

Issue 51: Is IGC's Taxes Other Than Income of $24,924 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Taxes Other Than Income is $17,677, a decrease of $7,247. (Winters)

Staff Analysis: 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	Staff Adjustment	As Adjusted By Staff
Payroll Taxes	**15,719**	0	**15,719**	**-7,164**	9,888
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**	-8,580-8,580	**17,677**

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. In Issues 27, 30, 32 and 35, staff reduced payroll for the projected test year by a total of $68,194, resulting in a revised payroll basis of $115,651. Payroll taxes were then calculated by staff on the revised payroll basis. This results in staff recommended Payroll Taxes of $9,888, a $5,831 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. Staff 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 in Issue 23. The impact of this adjustment to revenue is to increase RAFs by $2; therefore, staff recommends decreasing RAFs by a total amount of $8.

The company projected 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 staff data request, the company provided copies of actual 2003 property tax bills. Staff's review indicated property taxes of $6,635, if paid during the November 4% discount period. To this, staff 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. Staff calculated the percentage to remove as 10.37% by dividing $135,576 of gross non-utility plant determined in Issues 5 and 11 by $1,307,395 of plant in service determined in Issues 5, 6, 7, 8, and 9. Staff 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 staff recommended 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 should be decreased by $5,831 for payroll taxes, decreased by $8 for RAFs, and decreased by $1,408 for property taxes, resulting in a net decrease of $7,247, and a net amount of Taxes Other Than Income of $17,677.

Issue 52: Is IGC's Income Tax Expense of ($83,452) for the projected test year appropriate?

Recommendation: No. The appropriate income tax expense for the December 2004 projected test year is ($16,826). (Kenny)

Staff Analysis: The company proposes to include ($83,452) of income tax expense for its 2004 projected test year. Staff's adjustments to the company's revenues and expenses increases income tax expense by $50,869. Additionally, staff's 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 $51,270 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 $15,356. Therefore, the appropriate amount of income tax expense for the December 2004 projected test year is ($16,826).

Issue 53: Is IGC's Total Operating Expenses of $457,022 for the projected test year appropriate?

Recommendation: No. The appropriate amount of Total Operating Expenses for the projected test year is $388,857. (Merta)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues.

Issue 54: Is IGC's Net Operating Income of ($114,103) for the projected test year appropriate?

Recommendation: No. The appropriate amount of Net Operating Income for the projected test year is ($45,547). (Merta)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues. Net Operating Income is shown on Attachment 3.

REVENUE REQUIREMENTS

Issue 55: What is the appropriate projected test year revenue expansion factor and the appropriate net operating income multiplier, including the appropriate elements and rates for IGC?

Recommendation: The appropriate revenue expansion factor is 1.2512. (Merta, Kenny)

Staff Analysis: Staff reviewed the company's calculations and determined that the company calculated the revenue expansion factor using a 34% federal income tax rate. Staff has 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, the appropriate revenue expansion factor to use in calculating the revenue deficiency is 1.2512.

The revenue expansion factor is shown on Attachment 4.

Issue 56: Is IGC's requested annual operating revenue increase of $306,751 for the projected test year appropriate?

Recommendation: No. The appropriate annual operating revenue increase for the projected test year is $127,211. (Merta)

Staff Analysis: This is a calculation based upon the recommendations made in the preceding issues. The revenue requirement is shown on Attachment 5.

COST OF SERVICE AND RATE DESIGN

Issue 57: What is the appropriate cost of service methodology to be used in allocating costs to the rate classes?

Recommendation: The appropriate methodology is contained in Attachment 6. (Wheeler, Springer)

Staff Analysis: 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.

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 the 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. Staff's recommended study differs in several respects from the company's filed study. Staff's study reflects the recommended adjustments to rate base, expenses, net operating income, billing determinants, and projected test year base rate revenues. In addition, staff's 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.

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 staff's study were developed based on the projected 2004 test year billing determinants. Staff believes 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.

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 staff agrees that the preparation of a cost of service study often requires the exercise of judgment, staff believes that any rate impact and other concerns in this case can be addressed through the allocation of the rate increase granted by the Commission, rather than through the somewhat arbitrary reallocation of costs. Therefore, staff's recommended study does not include the reallocation of $77,000 in O&M costs.

Issue 58: Is IGC's proposal to bill certain of its customers a demand charge based on their Maximum Daily Transportation Quantity appropriate?

Recommendation: No. The Commission should not approve IGC's demand charge as proposed. Instead, the Commission should approve a demand charge of $.53, applicable only to the TS-4 rate schedule. (Draper)

Staff Analysis:

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 by the Commission 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.

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 the Commission 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.

Staff Recommended Demand Charge

The Commission 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. The Commission found that the concept of a demand charge is appropriate for the gas industry; however, great consideration must be given to customer acceptance. The Commission further found that the applicability of the demand charge should be limited to customers that have automatic meter reading (AMR) devices.

Given the Commission's findings in the prior docket and ICLP's concerns, staff recommends that IGC's proposal to apply a demand charge of $2.51 to customers taking service under rate schedules TS-3 and TS-4 be 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, staff recommends a demand charge of $0.53 per MDTQ for customers taking service under the TS-4 rate schedule only. As discussed below, staff agrees with the company's proposed billing determinant. Staff 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 staff recommended charge will recover $70,369 in total annual capacity costs, which represents 15 percent of the staff recommended total target revenues.

Staff notes that the recommended demand charge does not modify the total base rate revenues IGC is projected to receive from the TS-4 rate class. By recommending a lower demand charge, staff has increased the transportation charge accordingly. Staff's recommended 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. Staff's recommended demand charge, when coupled with the staff's allocation of the recommended rate increase, results in a 59 percent increase in ICLP's annual bill (excluding fuel and taxes), and an 18 percent increase in Citrus's annual bill.

Consistent with the Commission's 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, staff does not believe it is appropriate to apply a demand charge to customers taking service under the TS-3 rate. Therefore, the demand charge should only apply to customers taking service under rate schedule TS-4.

Staff agrees 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. Staff notes 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, staff believes that it is appropriate to utilize this level in applying the demand charge.

Issue 59: Should IGC's proposal to change the applicability provisions of its TS-2 and TS-3 rate schedules be approved?

Recommendation: Yes. (Springer)

Staff Analysis: 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.

These 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. Staff recommends that the revisions be approved.

Issue 60: Should IGC's proposal to eliminate the TS-5 rate schedule and to remove the upper annual therm consumption limit for the TS-4 rate schedule be approved?

Recommendation: Yes. (Springer)

Staff Analysis: 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. Staff therefore recommends that the TS-5 rate class 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. Staff therefore recommends 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.

Issue 61: Is IGC's proposed new Third Party Supplier (TPS) rate schedule appropriate?

Recommendation: No. The appropriate TPS charge is $2.09. (Draper, Baxter)

Staff Analysis: 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 (See Issue 35).

As discussed in Issue 2, IGC has provided corrections to its billing determinants, resulting in 8,073 projected transportation service bills. As discussed in Issue 34, staff recommends a downward adjustment of $1,170 to account 902 - Meter Reading. Adjustments recommended by staff in Issues 27, 35, and 48 result in a downward adjustment of $12,689 to Account 903. Finally, as discussed in Issue 35, staff recommends that a portion of the Chief Financial Officer's salary be allocated to non-utility operations. Accordingly, staff recommends that the proposed TPS charge be adjusted to $2.09 per monthly transportation service bill to reflect staff's recommended adjustments. Staff's recommended TPS charge is designed to recover $16,903 in TPS-related costs. The charge is subject to change based on the Commission's vote in the above referenced issues.

Issue 62: If the Commission grants a revenue increase to IGC, how should the increase be allocated to the rate classes?

Recommendation: Staff's recommended allocation of the revenue increase to the rate classes is contained in Attachment 6, page 16 of 16. (Wheeler, Springer)

Staff Analysis: This issue addresses the manner in which staff's recommended revenue increase of $127,211 is apportioned among the various rate classes. Once this allocation is determined, rates are designed for each rate class that recover the total revenue target for the class. Staff's recommended allocation of the revenue increase is contained in Attachment 6, page 16 of 16. Staff's recommended allocation and the resulting per-therm charges will be adjusted subsequent to the agenda conference to reflect any change to the revenue requirement that results from the Commission's votes on the issues.

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 should be allocated. Traditionally, the Commission has 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 77.5% revenue increase, which is over two times the system average rate increase of 37%. The TS-4 rate class would receive a 23.5% increase, and the TS-2 and TS-3 classes would receive a slight rate decrease.

Staff does not believe that such an allocation is 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 the Commission in Docket No. 020470-GU. In that same proceeding, the TS-4 rate class received an approximate 11% rate decrease. Staff believes that 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.

Staff's recommended allocation of the revenue increase to the rate classes is contained in Attachment 6, page 16 of 16. As shown in Column 10 of the table, staff's recommended allocation results in a revenue increase to the TS-1 rate class of 40%. The TS-4 rate class also receives a 40% increase. The TS-2 and TS-3 rate classes receive slight increases of approximately five percent. Although staff's recommended allocation of the increase does not result in parity for the rate classes, staff believes that it is appropriate and equitable in this case, give other considerations.

The impact of staff's proposed allocation on customer bills is shown in Attachment 7, pages 2 through 6. These schedules show the monthly bills for various therm usage levels at both present and staff recommended rates.

Issue 63: What are the appropriate Customer Charges?

Recommendation: Staff's recommended customer charges are as follows:

Rate Class	Staff Recommended Customer Charge
TS-1	$9.00
TS-2	$25.00
TS-3	$60.00
TS-4	$2,000.00

(Baxter)

Staff Analysis: 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.

Staff's recommended customer charges are contained in the table below. The table also shows the present customer charges and the company-proposed charges.

Rate Class	Present Customer Charge	Company Proposed Customer Charge	Staff Recommended 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, staff is recommending the same customer charges as the company has proposed, with the exception of the TS-1 and TS-2 rate classes. Staff is recommending lower charges than what the company proposed for these classes due to staff's 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. Staff notes that the TS-1 customer charge, which is recommended 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. Staff believes that the recommended charges are reasonable, and should be approved.

Issue 64: What are the appropriate per therm Transportation Charges?

Recommendation: Staff's recommended per therm Transportation Charges are contained in Attachment 7, page 1. (Wheeler, Springer)

Staff Analysis: Staff's recommended per therm Transportation Charges are contained in Attachment 7, page 1. These charges are subject to change based on the Commission's vote in other issues.

Issue 65: What is the appropriate Demand Charge?

Recommendation: The appropriate demand charge is $.53 per Maximum Daily Transportation Quantity (MDTQ). (Draper)

Staff Analysis: The appropriate demand charge is $.53 per MDTQ. See Issue 58 for a discussion on the development of the recommended demand charge. The charge is subject to change based on the Commission's vote on other issues.

Issue 66: What is the appropriate effective date for IGC's revised rates and charges?

Recommendation: The revised rates and charges should become effective for meter readings on or after 30 days following the date of the Commission vote approving the rates and charges. (Wheeler)

Staff Analysis: All new rates and charges should become effective for meter readings on or after 30 days from the date of the Commission vote approving them. This will insure that customers are aware of the new rates before they are billed for usage under the new rates.

OTHER ISSUES

Issue 67: Should any portion of the $137,014 interim increase granted by Order No. PSC-04-0180-PCO-GU, issued on February 24, 2004, be refunded to the customers?

Recommendation: No portion of the $137,014 interim revenue increase should be refunded. (Merta)

Staff Analysis: In this docket, the requested interim test year was the twelve months ended December 31, 2002. The Commission 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 should 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.

Staff reviewed the company's 2004 financial projections for purposes of recommending final revenue requirements and made an adjustment to remove rate case expense. Staff believes that no refund of interim is required because the revenue requirement recommended for the projected test year, less rate case expense, exceeds the revenue requirement awarded.

Issue 68: Should IGC be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records that will be required as a result of the Commission's findings in this rate case?

Recommendation: Yes. The company should be required to fully describe the entries and adjustments that will be either recorded or used in preparing reports submitted to the Commission within 90 days after the final order in this docket. (Merta)

Staff Analysis: Various adjustments will be made to the company's records as a result of findings in this case. IGC should be required to fully describe the entries and adjustments that will be made in preparing reports submitted to the Commission within 90 days after the final order in this docket.

Issue 69: Should this docket be closed?

Recommendation: Yes, if no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order. (K. Fleming)

Staff Analysis: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order.

Docket No. 030954-GU
Date: May 6, 2004

COMPARATIVE RATE BASES

INDIANTOWN GAS COMPANY — ATTACHMENT 1
PTY 12/31/04

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	STAFF ADJS.	STAFF ADJUSTED
	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			STAFF	
ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	STAFF ADJS.	STAFF ADJUSTED
	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

Docket No. 030954-GU
Date: May 6, 2004

ATTACHMENT 2

CAPITAL STRUCTURE

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

		COMPANY ADJUSTMENTS			RATE BASE ADJUSTMENTS					
	PER BOOKS	SPECIFIC	PRO RATA	ADJUSTED PER BOOKS	SPECIFIC	PRO RATA	STAFF 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

			COMPANY		STAFF	
ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	STAFF ADJS.	STAFF ADJUSTED
	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 utililty				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)				(6,338)	
33	Include odorant costs (880)				714	
34	Reduce meter reading costs (902)				220	
35	Remove portion of CFO's increase (920)				(4,731)	
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)				(13,888)	
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	(117,218)	330,083

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	STAFF ADJS.	STAFF ADJUSTED
	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				(5,831)	
	TOTAL TAXES OTHER THAN INCOME	24,924	0	24,924	(7,247)	17,677
	INCOME TAX EXPENSE	(94,204)				
	Income taxes - current & deferred		0			
52	Tax effect of adjustments		795		50,869	
52	Interest Synch/Rec. Adj.		9,957		401	
52	Adjust to Calculated Amount				15,356	
	TOTAL INCOME TAXES	(94,204)	10,752	(83,452)	66,626	(16,826)
	TOTAL OPERATING EXPENSES	448,383	8,638	457,021	(68,164)	388,857
	NET OPERATING INCOME	(105,465)	(8,638)	(114,103)	68,556	(45,547)

NET OPERATING INCOME MULTIPLIER

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

ATTACHMENT 4

DESCRIPTION	COMPANY PER FILING	STAFF
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		STAFF
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		330,083
Depreciation & Amortization		68,248		57,924
Amortization of Environ. Costs		0		0
Taxes Other than Income Taxes		24,924		17,677
Income Taxes		(83,452)		(16,826)
Total Operating Expenses		457,021		388,857
ACHIEVED NOI		(114,103)		(45,547)
NET NOI DEFICIENCY		190,364		101,671
REVENUE TAX FACTOR		1.6114		1.2512
REVENUE DEFICIENCY		$306,751		$127,211

DOCKET NO. 030954-GU
DATE: May 6, 2004

ATTACHMENT 6
PAGE 1 OF 16

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	**20,815**	**10,999**	**0**	oper. and maint. exp.
equals: TOTAL RATE BASE	**588,925**	**218,526**	**370,399**	**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.	37,574	21,759	15,815	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	13,226	1,809	11,417	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	21,995	10,707	11,289	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	9,469	0	9,469	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	99,328	48,351	50,978	0	
CUSTOMER ACCOUNTS:					
901 Supervision		0			
902 Meter-Reading Expense	5,218	5,218			
903 Records and Collection Exp.	25,316	25,316			
904 Uncollectible Accounts				0	100% commodity
905 Misc. Expenses	14,264	14,264			
Total Customer Accounts	44,798	44,798	0	0	
(907-910) CUSTOMER SERV.& INFO. EXP.	8,253	8,253			
(911-916) SALES EXPENSE		0			100% CUSTOMER
(932) MAINT. OF GEN. PLANT	11,035	5,518	5,518	0	
(920-931) ADMINISTRATION AND GENERAL	166,669	109,049	57,621	0	O&M excl. A&G
TOTAL O&M EXPENSE	330,083	215,969	114,117	0	

DOCKET NO. 030954-GU
DATE: May 6, 2004

ATTACHMENT 6
PAGE 4 OF 16

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	16,596	5,890	10,706	0		Net plant
Total Taxes other than Income Taxes	**18,313**	**5,890**	**10,706**	**0**	**1,717**	
REV.CRDT TO COS (NEG.OF OTHR OPR.REV)	**(4,120)**	**(4,120)**				100% customer
RETURN (REQUIRED NOI)	**56,124**	**20,825**	**35,299**	**0**		Rate base
INCOME TAXES	8,077	**2,997**	**5,080**	**0**	**0**	Return (noi)
TOTAL OVERALL COST OF SERVICE	466,401	262,117	202,569	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	330,083	215,969	114,117	0	
LESS O&M DIRECT ASSIGNMENTS	(28,980)	(15,886)	(13,094)	0	
NET O&M	301,106	200,083	101,022	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	18,313	5,890	10,706	0	1,717
RETURN	56,124	20,825	35,299	0	0
INCOME TAXES	8,077	2,997	5,080	0	0
REV.CRD. TO COS	(4,120)	(4,120)	0	0	0
TOTAL COST OF SERVICE	**466,401**	**262,117**	**202,569**	**0**	**1,717**
RATE BASE	**588,925**	**218,526**	**370,399**	**0**	**0**
less: Rate Base direct assignments	**(333,828)**	**(96,859)**	**(236,969)**	**0**	**0**
NET RATE BASE	**255,097**	**121,667**	**133,430**	**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	13,226	1,809	11,417	0	
887 MAINT. OF MAINS	1,677	0	1,677	0	
Total O&M Direct Assignments	**28,980**	**15,886**	**13,094**	**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.	2,248	845	52	11	1,340	0
Allocation Factors	**100.0000%**	**37.5751%**	**2.3161%**	**0.4809%**	**59.6279%**	**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	20,815	14,504	636	137	5,539	0
Total Customer	218,526	152,264	6,679	1,439	58,145	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	32,579	606	359	64	31,549	0
Total Capacity	370,399	6,894	4,085	732	358,688	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	159,158	10,764	2,171	416,833	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	236,525	147,902	7,229	1,557	62,934	16,903
Capacity	151,484	2,820	1,671	299	146,695	0
Commodity	0	0	0	0	0	0
Revenue	0	0	0	0	0	0
Total	388,010	150,722	8,900	1,857	209,629	16,903
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	1,809	1,260	55	12	481	0
892 Maint. of Services	8	6	0	0	2	0
All Other	200,083	122,510	6,115	1,317	53,238	16,903
Total	215,969	133,579	6,601	1,422	57,464	16,903
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	11,417	213	126	23	11,056	0
887 Maint. of Mains	1,677	31	18	3	1,624	0
All Other	101,022	1,880	1,114	200	97,828	0
Total	114,117	2,124	1,259	226	110,508	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	330,086	135,703	7,859	1,648	167,973	16,903
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	5,890	4,104	180	39	1,567	0
Capacity	10,706	199	118	21	10,368	0
Subtotal	16,596	4,303	298	60	11,935	0
Revenue	1,717	645	40	8	1,024	0
Total	**18,313**	**4,948**	**338**	**68**	**12,959**	**0**
RETURN (NOI)						
Customer	20,825	14,511	636	137	5,541	0
Capacity	35,299	657	389	70	34,183	0
Commodity	0	0	0	0	0	0
Total	**56,124**	**15,168**	**1,026**	**207**	**39,724**	**0**
INCOME TAXES						
Customer	2,997	2,088	92	20	797	0
Capacity	5,080	95	56	10	4,919	0
Commodity	0	0	0	0	0	0
Total	**8,077**	**2,183**	**148**	**30**	**5,717**	**0**
REVENUE CREDITED TO COS:						
Customer	**(4,120)**	**(4,120)**	0	0	0	0
TOTAL COST OF SERVICE:						
Customer	262,117	164,485	8,137	1,753	70,840	16,903
Capacity	202,569	3,770	2,234	400	196,164	0
Commodity	0	0	0	0	0	0
Subtotal	464,687	168,255	10,371	2,153	267,004	16,903
Revenue	1,717	645	40	8	1,024	0
Total	**466,404**	**168,900**	**10,411**	**2,162**	**268,028**	**16,903**

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	159,158	10,764	2,171	416,833	0
ATTRITION	0	0	0	0	0	0
OPERATION AND MAINTENANCE	330,086	135,703	7,859	1,648	167,973	16,903
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)	16,596	4,303	298	60	11,935	0
TAXES OTHER THAN INCOME TAX (REVENUE)	1,717	645	40	8	1,024	0
INCOME TAX (TOTAL)	8,077	2,183	148	30	5,717	0
REVENUE CREDITED TO COST OF SERVICE	(4,120)	(4,120)	0	0	0	0
TOTAL COST OF SERVICE (CUSTOMER)	262,117	164,485	8,137	1,753	70,840	16,903
TOTAL COST OF SERVICE (CAPACITY)	202,569	3,770	2,234	400	196,164	0
TOTAL COST OF SERVICE (COMMODITY)	0	0	0	0	0	0
TOTAL COST OF SERVICE (REVENUE)	1,717	645	40	8	1,024	0
TOTAL COST OF SERVICE	466,404	168,900	10,411	2,162	268,028	16,903
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	262,117	164,485	8,137	1,753	70,840	16,903
CAPACITY COSTS	202,569	3,770	2,234	400	196,164	0
COMMODITY COSTS	0	0	0	0	0	0
REVENUE COSTS	1,717	645	40	8	1,024	0
TOTAL - (Includes rev. credit for other inc.)	466,404	168,900	10,411	2,162	268,028	16,903
less: REVENUE AT PRESENT RATES	339,191	$93,352	$10,547	$2,203	$216,943	$16,146
equals: GAS SALES REVENUE DEFICIENCY	127,213	75,548	(136)	(41)	51,085	757
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	127,213	75,548	(136)	(41)	51,085	757
UNIT COSTS:						
Customer	32.468	21.096	35.688	73.042	2,951.658	N/A
Capacity	0.138	0.138	0.138	0.138	0.138	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	330,086	135,703	7,859	1,648	167,973	16,903
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	16,596	4,303	298	60	11,935	0
Taxes Other Than Income--Revenue	1,717	645	40	8	1,024	0
Total Expses excl. Income Taxes	**406,323**	**155,670**	**9,237**	**1,925**	**222,587**	**16,903**
INCOME TAXES:	**8,077**	**2,183**	**148**	**30**	**5,717**	**0**
NET OPERATING INCOME:	**(71,089)**	**(60,381)**	**1,162**	**248**	**(11,361)**	**(757)**
RATE BASE:	**588,925**	**159,158**	**10,764**	**2,171**	**416,833**	**0**
RATE OF RETURN	**-12.07%**	**-37.94%**	**10.80%**	**11.43%**	**-2.73%**	**N/A**

DOCKET NO. 030954-GU
DATE: May 6, 2004

ATTACHMENT 6
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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	466,404	132,300	11,047	2,303	303,851	16,903
Other Operating Revenue	4,120	4,120	0	0	0	0
Total	470,524	136,420	11,047	2,303	303,851	16,903
EXPENSES:						
Purchased Gas Cost	0	0	0	0	0	0
O&M Expenses	330,086	135,703	7,859	1,648	167,973	16,903
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	16,596	4,303	298	60	11,935	0
Taxes Other Than Income--Revenue	1,717	645	40	8	1,024	0
Total Expses excl. Income Taxes	406,323	155,670	9,237	1,925	222,587	16,903
PRE TAX NOI:	64,201	(19,250)	1,810	378	81,263	0
INCOME TAXES:	8,077	2,183	148	30	5,717	0
NET OPERATING INCOME:	56,124	(21,433)	1,662	348	75,547	0
RATE BASE:	588,925	159,158	10,764	2,171	416,833	0
RATE OF RETURN	9.53%	-13.47%	15.44%	16.03%	18.12%	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	**-12.07%**	**-37.94%**	**10.80%**	**11.43%**	**-2.73%**	**N/A**
INDEX	**1.00**	**3.14**	**-0.89**	**-0.95**	**0.23**	**0.00**
PROPOSED RATES						
GAS SALES	466,404	132,300	11,047	2,303	303,851	16,903
OTHER OPERATING REVENUE	4,120	4,120	0	0	0	0
TOTAL	**470,524**	**136,420**	**11,047**	**2,303**	**303,851**	**16,903**
TOTAL REVENUE INCREASE	**127,213**	**38,948**	**500**	**100**	**86,908**	**757**
PERCENT INCREASE	**37.05%**	**39.96%**	**4.74%**	**4.54%**	**40.06%**	**4.69%**
RATE OF RETURN	**9.53%**	**-13.47%**	**15.44%**	**16.03%**	**18.12%**	**N/A**
INDEX	**1.00**	**-1.41**	**1.62**	**1.68**	**1.90**	**0.00%**

COST OF SERVICE SUMMARY
CALCULATION OF STAFF RECOMMENDED 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	**$470,524**	**$136,420**	**$11,047**	**$2,303**	**$303,851**	**$16,903**
LESS: OTHER OPERATING REVENUE	4,120	4,120	0	0	0	0
NET TARGET REVENUE	$466,404	$132,300	$11,047	$2,303	$303,851	$16,903
LESS: CUSTOMER CHARGE REVENUES						
PROPOSED CUSTOMER CHARGES		$9.00	$25.00	$60.00	$2,000.00	$2.09
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	$16,873
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	$270,418	$62,127	$5,347	$863	$185,178	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)		$0.369079	$0.057620	$0.047855	$0.038419	N/A
PER-THERM RATES (ROUNDED)		$0.36908	$0.05762	$0.04785	$0.03842	N/A
PER-THERM-RATE REVENUES (ROUNDED RATES)	$253,521	$62,127	$5,347	$863	$185,184	N/A
SUMMARY: PROPOSED TARIFF RATES						
CUSTOMER CHARGES		$9.00	$25.00	$60.00	$2,000.00	$2.09
DEMAND CHARGES					$0.53	
NON-GAS ENERGY CHARGES (CENTS PER THERM)		**36.908**	**5.762**	**4.785**	**3.842**	N/A
PURCHASED GAS ADJUSTMENT (CENTS PER THERM)		76.000	76.000	76.000	N/A	N/A
TOTAL (INCLUDING PGA)		112.908	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**

INDIANTOWN GAS COMPANY

DOCKET NO. 030954-GU

STAFF-RECOMMENDED ALLOCATION OF REVENUE INCREASE

(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)	(9)		(10)
			PRESENT		INCREASE FROM SERVICE	INCREASE FROM SALES OF	TOTAL INCREASE	REQUIRED	RECOMMENDED		REVENUE PERCENTAGE
RATE	RATE BASE	PRESENT NOI	ROR	INDEX	CHARGES	GAS	IN REVENUE	NOI	ROR	INDEX	INCREASE
TS-1	$159,158	($60,381)	-37.9%	3.14	$0	$38,948	$38,948	($21,433)	-13.47%	-1.41	40.0%
TS-2	$10,764	$1,162	10.8%	-0.89	$0	$500	$500	$1,662	15.44%	1.62	4.7%
TS-3	$2,171	$248	11.4%	-0.95	$0	$100	$100	$348	16.03%	1.68	4.5%
TS-4	$416,833	($11,361)	-2.7%	0.23	$0	$86,908	$86,908	$75,547	18.12%	1.90	40.1%
TPS	$0	($757)	N/A	N/A	$0	$757	$757	$0	N/A	N/A	4.7%
TOTAL	**$588,925**	**($71,089)**	**-12.1%**	**1.00**	**$0**	**$127,213**	**$127,213**	**$56,124**	**9.53%**	**1.00**	**37.1%**

INDIANTOWN GAS COMPANY
STAFF RECOMMENDED RATES
DOCKET NO. 030954-GU

RATE SCHEDULE	PRESENT RATE	STAFF RECOMMENDED RATES
TRANSPORTATION SERVICE - 1		
CUSTOMER CHARGE	$9.00	$9.00
TRANSPORTATION CHARGE (cents/therm)	13.770	36.908
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	$2,000.00
TRANSPORTATION CHARGE (cents/therm)	3.754	3.842
DEMAND CHARGE ($ per MDTQ)	N/A	$0.53
THIRD PARTY SUPPLIER		
MONTHLY CHARGE PER CUSTOMER	$2.00	$2.09

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INDIANTOWN GAS COMPANY
BILL COMPARISONS - PRESENT VS. STAFF RECOMMENDED RATES *
DOCKET NO. 030954-GU

ATTACHMENT 7
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TRANSPORTATION SERVICE - 1
(0 - 1,000 therms per year)
Average Usage: 22 therms per month

PRESENT RATES	STAFF RECOMMENDED RATES
Customer Charge $9.00	Customer Charge $9.00
Transportation Charge (Cents per Therm) 13.770	Transportation Charge (Cents per Therm) 36.908

Gas Cost (Cents/Therm)** : 76.000

Therm Usage Increment: 4

Therm Usage	Present Monthly Bill w/o Fuel	Present Monthly Bill with Fuel	Staff Recommended Monthly Bill w/o Fuel	Staff Recommended Monthly Bill with Fuel	Percent Increase w/o Fuel	Percent Increase with Fuel	Dollar Increase
2	$9.28	$10.80	$9.74	$11.26	5.0%	4.3%	$0.46
6	$9.83	$14.39	$11.21	$15.77	14.1%	9.7%	$1.39
10	$10.38	$17.98	$12.69	$20.29	22.3%	12.9%	$2.31
14	$10.93	$21.57	$14.17	$24.81	29.6%	15.0%	$3.24
18	$11.48	$25.16	$15.64	$29.32	36.3%	16.6%	$4.16
22	**$12.03**	**$28.75**	**$17.12**	**$33.84**	**42.3%**	**17.7%**	**$5.09**
26	$12.58	$32.34	$18.60	$38.36	47.8%	18.6%	$6.02
30	$13.13	$35.93	$20.07	$42.87	52.9%	19.3%	$6.94
34	$13.68	$39.52	$21.55	$47.39	57.5%	19.9%	$7.87
38	$14.23	$43.11	$23.03	$51.91	61.8%	20.4%	$8.79
42	$14.78	$46.70	$24.50	$56.42	65.7%	20.8%	$9.72
46	$15.33	$50.29	$25.98	$60.94	69.4%	21.2%	$10.64
50	$15.89	$53.89	$27.45	$65.45	72.8%	21.5%	$11.57
54	$16.44	$57.48	$28.93	$69.97	76.0%	21.7%	$12.49
58	$16.99	$61.07	$30.41	$74.49	79.0%	22.0%	$13.42
62	$17.54	$64.66	$31.88	$79.00	81.8%	22.2%	$14.35
66	$18.09	$68.25	$33.36	$83.52	84.4%	22.4%	$15.27
70	$18.64	$71.84	$34.84	$88.04	86.9%	22.5%	$16.20
74	$19.19	$75.43	$36.31	$92.55	89.2%	22.7%	$17.12
78	$19.74	$79.02	$37.79	$97.07	91.4%	22.8%	$18.05
82	$20.29	$82.61	$39.26	$101.58	93.5%	23.0%	$18.97

* Bills do not include local taxes, franchise fees, or gross receipts taxes.

** Natural Gas supplied to customers by Infinite Energy. Rate effective April 2004.

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INDIANTOWN GAS COMPANY
BILL COMPARISONS - PRESENT VS. STAFF RECOMMENDED RATES *
DOCKET NO. 030954-GU

TRANSPORTATION SERVICE - 2
(1,000 - 15,000 therms per year)
Average Usage: 339 therms per month

PRESENT RATES	STAFF RECOMMENDED RATES
Customer Charge	Customer Charge
$21.00	$25.00
Transportation Charge (Cents per Therm)	Transportation Charge (Cents per Therm)
6.206	5.762

Gas Cost (Cents/Therm)** : 76.000

Therm Usage Increment: 50

Therm Usage	Present Monthly Bill w/o Fuel	Present Monthly Bill with Fuel	Staff Recommended Monthly Bill w/o Fuel	Staff Recommended Monthly Bill with Fuel	Percent Increase w/o Fuel	Percent Increase with Fuel	Dollar Increase
80	$25.96	$86.76	$29.61	$90.41	14.04%	4.20%	$3.64
130	$29.07	$127.87	$32.49	$131.29	11.78%	2.68%	$3.42
180	$32.17	$168.97	$35.37	$172.17	9.95%	1.89%	$3.20
230	$35.27	$210.07	$38.25	$213.05	8.44%	1.42%	$2.98
280	$38.38	$251.18	$41.13	$253.93	7.18%	1.10%	$2.76
330	**$41.48**	**$292.28**	**$44.01**	**$294.81**	**6.11%**	**0.87%**	**$2.53**
380	$44.58	$333.38	$46.90	$335.70	5.19%	0.69%	$2.31
430	$47.69	$374.49	$49.78	$376.58	4.38%	0.56%	$2.09
480	$50.79	$415.59	$52.66	$417.46	3.68%	0.45%	$1.87
530	$53.89	$456.69	$55.54	$458.34	3.06%	0.36%	$1.65
580	$56.99	$497.79	$58.42	$499.22	2.50%	0.29%	$1.42
630	$60.10	$538.90	$61.30	$540.10	2.00%	0.22%	$1.20
680	$63.20	$580.00	$64.18	$580.98	1.55%	0.17%	$0.98
730	$66.30	$621.10	$67.06	$621.86	1.14%	0.12%	$0.76
780	$69.41	$662.21	$69.94	$662.74	0.77%	0.08%	$0.54
830	$72.51	$703.31	$72.82	$703.62	0.43%	0.04%	$0.31
880	$75.61	$744.41	$75.71	$744.51	0.12%	0.01%	$0.09
930	$78.72	$785.52	$78.59	$785.39	-0.16%	-0.02%	($0.13)
980	$81.82	$826.62	$81.47	$826.27	-0.43%	-0.04%	($0.35)
1,030	$84.92	$867.72	$84.35	$867.15	-0.67%	-0.07%	($0.57)
1,080	$88.02	$908.82	$87.23	$908.03	-0.90%	-0.09%	($0.80)
1,130	$91.13	$949.93	$90.11	$948.91	-1.12%	-0.11%	($1.02)
1,180	$94.23	$991.03	$92.99	$989.79	-1.32%	-0.13%	($1.24)
1,230	$97.33	$1,032.13	$95.87	$1,030.67	-1.50%	-0.14%	($1.46)
1,280	$100.44	$1,073.24	$98.75	$1,071.55	-1.68%	-0.16%	($1.68)

* Bills do not include local taxes, franchise fees, or gross receipts taxes.

** Natural Gas supplied to customers by Infinite Energy. Rate effective April 2004.

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INDIANTOWN GAS COMPANY
BILL COMPARISONS - PRESENT VS. STAFF RECOMMENDED RATES *
DOCKET NO. 030954-GU

ATTACHMENT 7
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TRANSPORTATION SERVICE - 3
(15,000 - 100,000 therms per year)
Average Usage: 1,268 therms per month

PRESENT RATES

Customer Charge
$50.00

Transportation Charge (Cents per Therm)
5.562

STAFF RECOMMENDED RATES

Customer Charge
$60.00

Transportation Charge (Cents per Therm)
4.785

Gas Cost (Cents/Therm)** : 76.000

Therm usage Increment: 200

Therm Usage	Present Monthly Bill w/o Fuel	Present Monthly Bill with Fuel	Staff Recommended Monthly Bill w/o Fuel	Staff Recommended Monthly Bill with Fuel	Percent Increase w/o Fuel	Percent Increase with Fuel	Dollar Increase
1,000	$105.62	$865.62	$107.85	$867.85	2.11%	0.26%	$2
1,200	**$116.74**	**$1,028.74**	**$117.42**	**$1,029.42**	**0.58%**	**0.07%**	**$1**
1,400	$127.87	$1,191.87	$126.99	$1,190.99	-0.69%	-0.07%	($1)
1,600	$138.99	$1,354.99	$136.56	$1,352.56	-1.75%	-0.18%	($2)
1,800	$150.12	$1,518.12	$146.13	$1,514.13	-2.66%	-0.26%	($4)
2,000	$161.24	$1,681.24	$155.70	$1,675.70	-3.44%	-0.33%	($6)
2,200	$172.36	$1,844.36	$165.27	$1,837.27	-4.12%	-0.38%	($7)
2,400	$183.49	$2,007.49	$174.84	$1,998.84	-4.71%	-0.43%	($9)
2,600	$194.61	$2,170.61	$184.41	$2,160.41	-5.24%	-0.47%	($10)
2,800	$205.74	$2,333.74	$193.98	$2,321.98	-5.71%	-0.50%	($12)
3,000	$216.86	$2,496.86	$203.55	$2,483.55	-6.14%	-0.53%	($13)
3,200	$227.98	$2,659.98	$213.12	$2,645.12	-6.52%	-0.56%	($15)
3,400	$239.11	$2,823.11	$222.69	$2,806.69	-6.87%	-0.58%	($16)
3,600	$250.23	$2,986.23	$232.26	$2,968.26	-7.18%	-0.60%	($18)
3,800	$261.36	$3,149.36	$241.83	$3,129.83	-7.47%	-0.62%	($20)
4,000	$272.48	$3,312.48	$251.40	$3,291.40	-7.74%	-0.64%	($21)
4,200	$283.60	$3,475.60	$260.97	$3,452.97	-7.98%	-0.65%	($23)
4,400	$294.73	$3,638.73	$270.54	$3,614.54	-8.21%	-0.66%	($24)
4,600	$305.85	$3,801.85	$280.11	$3,776.11	-8.42%	-0.68%	($26)
4,800	$316.98	$3,964.98	$289.68	$3,937.68	-8.61%	-0.69%	($27)

* Bills do not include local taxes, franchise fees, or gross receipts taxes.

** Natural Gas supplied to customers by Infinite Energy. Rate effective April 2004.

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INDIANTOWN GAS COMPANY
BILL COMPARISONS - PRESENT VS. STAFF RECOMMENDED RATES *
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TRANSPORTATION SERVICE - 4 - Louis Dreyfus Citrus
(Over 100,000 therms per year)
Average Usage: 185,000 therms per month

PRESENT RATES	STAFF RECOMMENDED RATES
Customer Charge $1,500.00	Customer Charge $2,000.00
Transportation Charge (Cents per Therm) 3.754	Transportation Charge (Cents per Therm) 3.842
Demand Charge ($ per MDTQ) N/A	Demand Charge ($ per MDTQ) $0.53

Gas Cost (Cents/Therm): N/A

Therm usage Increment: 13,000

Therm Usage	Present Monthly Bill w/o Fuel	Present Monthly Bill with Fuel	Staff Recommended Monthly Bill w/o Fuel	Staff Recommended Monthly Bill with Fuel	Percent Increase w/o Fuel	Percent Increase with Fuel	Dollar Increase
7,000	$1,763	N/A	$3,123	N/A	77.18%	N/A	$1,361
20,000	$2,251	N/A	$3,623	N/A	60.95%	N/A	$1,372
33,000	$2,739	N/A	$4,122	N/A	50.51%	N/A	$1,383
46,000	$3,227	N/A	$4,622	N/A	43.23%	N/A	$1,395
59,000	$3,715	N/A	$5,121	N/A	37.86%	N/A	$1,406
72,000	$4,203	N/A	$5,621	N/A	33.73%	N/A	$1,418
85,000	$4,691	N/A	$6,120	N/A	30.47%	N/A	$1,429
98,000	$5,179	N/A	$6,620	N/A	27.82%	N/A	$1,441
111,000	$5,667	N/A	$7,119	N/A	25.62%	N/A	$1,452
124,000	$6,155	N/A	$7,618	N/A	23.78%	N/A	$1,463
137,000	$6,643	N/A	$8,118	N/A	22.20%	N/A	$1,475
150,000	$7,131	N/A	$8,617	N/A	20.84%	N/A	$1,486
163,000	$7,619	N/A	$9,117	N/A	19.66%	N/A	$1,498
176,000	$8,107	N/A	$9,616	N/A	18.62%	N/A	$1,509
189,000	$8,595	N/A	$10,116	N/A	17.69%	N/A	$1,521
202,000	$9,083	N/A	$10,615	N/A	16.87%	N/A	$1,532
215,000	$9,571	N/A	$11,115	N/A	16.13%	N/A	$1,544
228,000	$10,059	N/A	$11,614	N/A	15.46%	N/A	$1,555
241,000	$10,547	N/A	$12,114	N/A	14.85%	N/A	$1,566
254,000	$11,035	N/A	$12,613	N/A	14.30%	N/A	$1,578

* Bills do not include local taxes, franchise fees, or gross receipts taxes.

** Demand charge portion of bill based on 1,612 MDTQs per month.

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INDIANTOWN GAS COMPANY
BILL COMPARISONS - PRESENT VS. STAFF RECOMMENDED RATES *
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ATTACHMENT 7

TRANSPORTATION SERVICE - 4 - Indiantown Cogeneration LP
(Over 100,000 therms per year)
Average Usage: 216,667 therms per month

PRESENT RATES	STAFF RECOMMENDED RATES
Customer Charge $1,500.00	Customer Charge $2,000.00
Transportation Charge (Cents per Therm) 3.754	Transportation Charge (Cents per Therm) 3.842
Demand Charge ($ per MDTQ) N/A	Demand Charge ** ($ per MDTQ) $0.53

Gas Cost (Cents/Therm): N/A

Therm usage Increment: 13,000

Therm Usage	Present Monthly Bill w/o Fuel	Present Monthly Bill with Fuel	Staff Recommended Monthly Bill w/o Fuel	Staff Recommended Monthly Bill with Fuel	Percent Increase w/o Fuel	Percent Increase with Fuel	Dollar Increase
7,000	$1,763	N/A	$7,304	N/A	314.3%	N/A	$5,541
20,000	$2,251	N/A	$7,803	N/A	246.7%	N/A	$5,553
33,000	$2,739	N/A	$8,303	N/A	203.2%	N/A	$5,564
46,000	$3,227	N/A	$8,802	N/A	172.8%	N/A	$5,575
59,000	$3,715	N/A	$9,302	N/A	150.4%	N/A	$5,587
72,000	$4,203	N/A	$9,801	N/A	133.2%	N/A	$5,598
85,000	$4,691	N/A	$10,301	N/A	119.6%	N/A	$5,610
98,000	$5,179	N/A	$10,800	N/A	108.5%	N/A	$5,621
111,000	$5,667	N/A	$11,300	N/A	99.4%	N/A	$5,633
124,000	$6,155	N/A	$11,799	N/A	91.7%	N/A	$5,644
137,000	$6,643	N/A	$12,299	N/A	85.1%	N/A	$5,656
150,000	$7,131	N/A	$12,798	N/A	79.5%	N/A	$5,667
163,000	$7,619	N/A	$13,297	N/A	74.5%	N/A	$5,678
176,000	$8,107	N/A	$13,797	N/A	70.2%	N/A	$5,690
189,000	$8,595	N/A	$14,296	N/A	66.3%	N/A	$5,701
202,000	$9,083	N/A	$14,796	N/A	62.9%	N/A	$5,713
215,000	$9,571	N/A	$15,295	N/A	59.8%	N/A	$5,724
228,000	$10,059	N/A	$15,795	N/A	57.0%	N/A	$5,736
241,000	$10,547	N/A	$16,294	N/A	54.5%	N/A	$5,747
254,000	$11,035	N/A	$16,794	N/A	52.2%	N/A	$5,759

* Bills do not include local taxes, franchise fees, or gross receipts taxes.

** Demand charge portion of bill based on 9,500 MDTQs per month.

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25-7.021 Records of Meters and Meter Tests.

(1) There shall be kept by each utility a permanent meter record, indicating for each meter owned or used by the utility for any purpose, the date of purchase, identification number, size or capacity, date and place of each installation and removal for the last three locations where the meter was installed. These records shall be preserved until the meter is destroyed or permanently removed from service.

(2) The original test data shall be recorded on the utilities' standard forms and preserved at least until superseded by a later test. These records shall indicate (1) sufficient information to identify the meter; (2) the reason for the test; (3) the date of test and reading of the meter; (4) the computed accuracy both "as found" and "as left"; (5) repairs made, if any, and (6) identification of person performing test.

(3) Every gas utility shall, upon request, report a Summary of the "as found" tests in such form as may be designated by the Commission.

(4) Every gas utility shall file a report with the Division of Auditing and Safety on or before February 10 of each year on such forms as may be prescribed. Such reports shall contain complete information regarding number of meters in service according to installation date, number of meters tested, meters past due for tests, refunds and all other information requests.

Specific Authority: 366.05, F.S.
Law Implemented: 366.05(1), F.S.
History: Repromulgated 1/8/75, 5/4/75, Amended 2/13/84, formerly 25-7.21.

25-7.064 Periodic Meter Tests.

(1) 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.

(a) 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 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.

(3) Meters above 2500 cfh capacity rating measured at the manufacturer's specifications for one half(1/2) inch differential shall be field tested or shop tested in accordance with manufacturer's recommendations and American Gas Association's Gas Measurement Manual: Meter Proving Part No. Twelve, 1978 edition at least every sixty (60) months.

(4) An instrument or auxiliary device used in conjunction with any gas meter to correct the metered volume for pressure or temperature shall be adjusted to an accuracy level to assure that the combined accuracy of the instrument or auxiliary device, or both, and the associated meter does not exceed one percent (1%) error fast or two percent (2%) error slow. Each instrument and auxiliary device shallbe checked at least the same test interval as prescribed for the associated meter to insure and verify the performance.

Specific Authority: 366.05(1), F.S.
Law Implemented: 366.05(1), F.S.
History: Repromulgated 1/8/75, 5/4/75, Amended 5/27/76, 2/13/84, formerly 25-7.64.

25-7.087 Adjustment of Bills for Meter Error.

(1) Fast meters. Whenever a meter is found to have an average error of more than two percent (2%) fast, the utility shall refund to the customer the amount billed in error for one half the period since the last test, said one half period not to exceed twelve (12) months except that if it can be shown that the error was due to some cause, the date of which can be fixed, the overcharge shall be computed back to but not beyond such date, based upon available records. If the meter has not been tested in accordance with Rule 25-7.064, the period for which it has been in service beyond the regular test period shall be added to the twelve (12) months in computing the refund. The refund shall not include any part of any minimum charge.

(2) Slow meters.

(a) Except as provided by this subsection, a utility may backbill in the event that a meter is found to be slow, non-registering or partially registering. A utility may not backbill for any period greater than twelve (12) months from the date it removes the meter of a customer, which meter is later found by the utility to be slow, non-registering or partially registering. If it can be ascertained that the meter was slow, non-registering or partially registering for less than twelve (12) months prior to removal, then the utility may backbill only for the lesser period of time. In any event, the customer may extend the payments of the backbill over the same amount of time for which the utility issued the backbill. Nothing in this subsection shall be construed to limit the application of subsection (4) of this rule.

(b) Whenever a meter tested is found to have an average error of more than two-percent (2%) slow, the utility may bill the customer an amount equal to the unbilled error in accordance with this subsection. If the utility has required a deposit as permitted under Rule 25-7.065(2) the customer may be billed only for that portion of the unbilled error which is in excess of the deposit retained by the utility.

(c) In the event of a non-registering or a partially registering meter, unless the provisions of subsection (3) of this rule apply, a customer may be billed on an estimate based on previous bills for similar usage.

(3) It shall be understood that when a meter is found to be in error in excess of the prescribed limits of two percent (2%) fast or slow, the figure to be used for calculating the amount of refund or charge in (1) or (2)(b) above shall be that percentage of error as determined by the test.

(4) In the event of unauthorized use, the customer may be billed on a reasonable estimate of the gas consumed.

Specific Authority: 366.05(1), F.S.
Law Implemented: 366.05(1), F.S.
History: Repromulgated 1/8/75, Amended 5/4/75, 5/3/82, formerly 25-7.87.

25-7.091 Refunds.

(1) Applicability. With the exception of deposit refunds and refunds associated with adjustment factors, all refunds ordered by the Commission shall be made in accordance with the provisions of this rule, unless otherwise ordered by the Commission.

(2) Timing of Refunds. Refunds must be made within ninety (90) days of the Commission's order unless a different time frame is prescribed by the Commission. Unless a stay has been requested in writing and granted by the Commission, a motion for reconsideration of an order requiring a refund will not delay the timing of the refund. In the event that a stay is granted pending reconsideration, the timing of the refund shall commence from the date of the order disposing of any motion for reconsideration. This rule does not authorize any motion for reconsideration not otherwise authorized by Chapter 25-22, Florida Administrative Code.

(3) Basis of Refund. Where the refund is the result of a specific rate change, including interim rate cases and the refund can be computed on a per customer basis, that will be the basis of the refund. However, where the refund is not related to specific rate changes, such as a refund for overearnings, the refund shall be made to customers of record as of a date specified by the Commission. In such case, refunds shall be made on the basis of consumption. Per customer refund refers to a refund to every customer receiving service during the refund period. Customer of record refund refers to a refund to every customer receiving service as of a date specified by the Commission.

(4) Interest.

(a) In the case of refunds which the Commission orders to be made with interest, the average monthly interest rate until the refund is posted to the customer's account shall be based on the thirty (30) day commercial paper rate for high grade, unsecured notes sold through dealers by major corporations in multiples of $1,000 as regularly published in the Wall Street Journal.

(b) This average monthly interest rate shall be calculated for each month of the refund period:

1. By adding the published interest rate in effect for the last business day of the month prior to each month of the refund period and the published rate in effect for the last business day of each month of the refund period divided by twenty four (24) to obtain the average monthly interest rate;

2. The average monthly interest rate for the month prior to distribution shall be the same as the last calculated average monthly interest rate.

(c) The average monthly interest rate shall be applied to the sum of the previous month's ending balance (including monthly interest accruals) and the current month's ending balance divided by two (2) to accomplish a compounding effect.

(d) Interest Multiplier. When the refund is computed for each customer, an interest multiplier may be applied against the amount of each customer's refund in lieu of a monthly calculation of the interest for each customer. The interest 7-46 multiplier shall be calculated by dividing the total amount refundable to all customers, including interest, by the total amount of the refund, excluding interest. For the purpose of calculating the interest multiplier, the utility may, upon approval by the Commission, estimate the monthly refundable amount.

(e) Commission staff shall provide applicable interest rate figures and assistance in calculations under this rule upon request of the affected utility.

(5) Method of Refund Distribution. For those customers still on the system, a credit shall be made on the bill. In the event the refund is for a greater amount than the bill, the remainder of the credit shall be carried forward until the refund is completed. If the customer so requests, a check for any negative balance must be sent to the customer within ten (10) days of the request. For customers entitled to a refund but no longer on the system, the company shall mail a refund check to the last known billing address except that no refund for less than $1.00 will be made to these customers.

(6) Security for Money Collected Subject to Refund. In the case of money being collected subject to refund, the money shall be secured by a bond unless the Commission specifically authorizes some other type of security such as placing the money in escrow, approving a corporate undertaking, or providing a letter of credit. The Commission may require the company to provide a report by the 10^{th} of each month indicating the monthly and total amount of money subject to refund as of the end of the preceding month. The report shall also indicate the status of whatever security is being used to guarantee repayment of the money.

(7) Refund Reports. During the processing of the refund, monthly reports on the status of the refund shall be made by the 10th of the following month. In addition, a preliminary report shall be made within thirty (30) days after the date the refund is completed and again 90 days thereafter. The above reports shall specify the following:

(a) The amount of money to be refunded and how that amount was computed;

(b) The amount of money actually refunded;

(c) The amount of any unclaimed refunds; and

(d) The status of any unclaimed amounts.

(8) With the last report under subsection (7) of this rule, the company shall suggest a method for disposing of any unclaimed amounts. The Commission shall then order a method of disposing of the unclaimed funds.

Specific Authority: 350.127(2), F.S.
Law Implemented: 366.06(3), 366.071(2), F.S.
History: New 8/17/83, formerly 25-7.91.