BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Peoples Gas System.	DOCKET NO. 080318-GU ORDER NO. PSC-09-0411-FOF-GU ISSUED: June 9, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
KATRINA J. McMURRIAN
NANCY ARGENZIANO
NATHAN A. SKOP

APPEARANCES:

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On behalf of the Florida Public Service Commission (Staff)

FINAL ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR RATE INCREASE

BY THE COMMISSION:

BACKGROUND

This proceeding commenced on August 11, 2008, with the filing of a petition for a permanent rate increase by Peoples Gas System (Peoples, PGS, Utility or Company). The Company is engaged in business as a public utility providing gas service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to the jurisdiction of the Commission. Peoples provides gas service to 338,790 customers in the following counties: Bay, Broward, Charlotte, Clay, Collier, Dade, Duval, Gilchrist, Hernando, Highlands, Hillsborough, Lafayette, Lake Lee, Levy, Liberty, Manatee, Marion, Martin, Orange, Osceola, Palm Beach, Pasco, Pinellas, Polk, Sarasota, Seminole, St. Johns, Sumter, Volusia, Wakulla, and Union. Since the last rate case, Peoples added approximately 100,000 residential and commercial customers.

Peoples requested an increase in its retail rates and charges to generate $26,488,091 in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 8.88 percent or an 11.50 percent return on equity (range 10.50 percent to 12.50 percent). The Company based its request on a projected test year ending December 31, 2009. Peoples stated that this test year is the appropriate period to be utilized because it represents the conditions to be faced by the Company, and is representative of the customer base, investment requirements, throughput levels, and overall cost of service to be realized for the period when the new rates will be in effect.

In Peoples last rate case, it was granted a final revenue increase of $12,050,000 by Order No. PSC-03-0038-FOF-GU.[1] In that order, the Company's jurisdictional rate base was found to be $505,441,206 for the projected test year ended December 31, 2003. The allowed rate of return was found to be 8.83 percent for the test year using an 11.25 percent return on equity.

In the instant docket, Peoples was granted an interim revenue increase of $2,380,000 by Order No. PSC-08-0696-PCO-GU.[2] In that order, the Company's Jurisdictional Adjusted Rate Base was found to be $515,212,000 for the 2008 interim test year. The allowed overall rate of return was found to be 8.31 percent for the test year using a return on equity (ROE) of 10.25 percent, which is the minimum of the authorized range for an ROE of 11.25 percent from the last rate case.

The Office of Public Counsel (OPC)[3] and Florida Industrial Gas Users (FIGU)[4] intervened in this proceeding.

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[1] Issued January 6, 2003, in Docket No. 020384-GU, In re: Petition for rate increase by Peoples Gas System.
[2] Issued October 20, 2008, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.
[3] See Order No. PSC-08-0532-PCO-GU, issued August 18, 2008, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.

Customer service hearings were held in Panama City on November 7, 2008, and in Jacksonville on November 14, 2008, and no customers attended either service hearing. Customer service hearings were also held in Orlando on January 13, 2009, Tampa and Charlotte County on January 14, 2009, and Hollywood on February 2, 2009. Ten customers presented testimony. There were no complaints related to Peoples' gas service. This order addresses Peoples' requested permanent rate increase. We have jurisdiction pursuant to Sections 366.06(2) and (4), and 366.071, F.S.

DECISION

I. APPROVED STIPULATIONS

We have previously approved several stipulated issues, stipulated adjustments, and partially stipulated issues. The stipulated issues are reflected below, as well as in a consolidated list attached as Appendix 1.

II. TEST PERIOD

At the hearing, witness Cantrell read from PGS's test year letter dated June 12, 2008, that, "[t]he proposed 2009 test year will most accurately reflect the economic conditions during the first 12 months the new rate will be in effect." Witness Cantrell testified that the test year was based on the best projections at that time and not on the current economic conditions. In extensive cross examination, witness Cantrell agreed that the ratepayers throughout the PGS service area were hurting because of the downturn in economic conditions, as a result of job losses and the decline in the real estate market. Witness Cantrell explained that if the Utility filed its MFRs in the current economic climate, the Utility's requested revenue increase would be greater because of a decrease in the projected revenues from the future customers.

The test year letter stated that since the last historical base year, the Consumer Price Index (CPI) has increased more that 17 percent. During cross examination, witness Cantrell emphasized that PGS is receiving more requests for service, for example, the opportunity to extend lines to serve six or seven asphalt plants around PGS's service territory. Witness Cantrell also noted that PGS will provide gas to a steel plant that is coming online south of Ocala. Even though usage per customer has decreased in many segments, PGS sees no drop-off in the commercial sector because of the increase in customers that want natural gas service. OPC pointed out that commercial customers were using less therms of gas because of the slow down in the economic conditions for BPB Celotex, National Gypsum Co., and United States Gypsum Company-D.I.P. At the hearing, witness Cantrell stated that even though United States Gypsum Company used 3.2 million less therms, this would equate only to a $116,000 decrease in revenues at 3.5 cents per therm.

Witness Cantrell further explained that even though the initial revenue requirement increase was $15-20 million in the 2008 Business Plan, PGS requested $26 million because of the economic slow down, the decrease in therm usage, and PGS's revenue forecast. Witness

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[4] See Order No. PSC-08-0532-PCO-GU, issued August 18, 2008, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.

Cantrell further explained that if the case were filed today, the requested revenue increase would be even higher than the $26 million currently requested.

FIGU asserted that we should exercise caution when using a projected test year that is 18 months from the filing of the test year letter. Section 366.06, F.S., states that we shall only approve rates using the depreciated investment in utility plant that is actually in use and useful in providing service. When the time lag for a projected, test year is too far in the future from the base year, it becomes more difficult to verify the used and useful plant in service that is necessary to comply with Section 366.06, F.S.

The real estate market has deteriorated and unemployment has risen in the PGS service area since the test year letter was filed on June 12, 2008. The current economic climate may improve because of the federal economic stimulus package that will be effective in 2009 and future years.

FIGU asserted that the Florida Administrative Procedures Act requires regulatory agencies to express their governing policies by adopting rules.[5] FIGU further stated that the Commission has rules but their applicability is developed using common law principles on a case by case basis. The current rulings and findings set precedents for future cases with similar issues. Staff believes that the regulatory process, which includes auditing the company, issuing discovery requests, conducting depositions and holding a hearing, would uncover any consequential financial and account excesses that would be represented in the projected 2009 test year.

Based on the above, we find that the historical base year ended December 31, 2007, and the projected test year ending December 31, 2009, as adjusted, reflect the appropriate rate base, cost of capital, and net operating income. Therefore, the historical base year ended December 31, 2007, and the projected test year ending December 31, 2009, are the appropriate test years.

[5]Section 120.52(16), F.S., provides that "rule" means each agency's statement of general applicability that implements, interprets, or prescribes law or policy.

III. RATE BASE

A. Adjustments to Projected Plant, Accumulated Depreciation, and Depreciation Expense

The Company's MFRs indicated a 13-month average for Plant in Service and Accumulated Depreciation for the 2009 projected test year of $989,149,922 and $426,364,359, respectively. PGS asserted that the 2009, 13-month average net Plant in Service, should include approximately $6.4 million in actual expenditures for 2008.

PGS witness Higgins testified that the factors which contributed to the over six years of growth in rate base included: 1) the increase of about 100,000 new residential and commercial customers, 2) the addition of over 1,500 miles of main to support growth, 3) increased need for maintenance capital expenditures, and 4) significant relocation of facilities due to the rapid expansion of highways and roads throughout the State of Florida.

1. System Expansion

PGS witness Binswanger testified that PGS uses a multi-step decision process to serve new developments. He stated that the Company must first identify the development of gas load potential; secondly, design the distribution main, and finally, design the supply main. He further stated that by establishing the gas load potential, the Company is able to establish the residential and commercial mix, and the timeline for build-out. He contended that the distribution main and service lines size are based on hourly demand for gas. In addition, witness Binswanger testified that the gas load information enables the PGS engineers to properly size the distribution mains and service lines to properly transport gas to customers anytime. He also stated that the size of typical distribution mains range from two inches to four inches, and service lines range in size from three-quarters of an inch to two inches. Furthermore, he stated that the completion of the design of the distribution mains and service lines to serve a development, results in the design criteria for a natural gas distribution system and estimates of construction cost. Additionally, he stated that the natural gas supply main and associated appurtenances connects the development distribution system to the interstate transmission pipeline system or an existing Peoples supply main. In the final step, witness Binswanger further asserted that the supply main design requirements include the length of the main, hourly customer demand, and available gas pressure.

2. Government-Mandated Line Relocation

Witness Binswanger testified that the Company used different government-owned public rights-of-way, including those owned or controlled by the Florida Department of Transportation. He stated that the provisions for public utilities to use the rights-of-way were established by statute, regulation, ordinance, or franchise agreements. He further stated that the Company is required to move any installed mains or service lines under or along public rights-of-way when they are ordered by a governmental entity. He contended that in "most instances" it is at the Company's expense, without reimbursement, to meet its service obligations. In addition, the Company's right to install supply and distribution mains in public rights-of-way is subject to PGS relocating any facilities if conflict develops when work is done by or for governmental entities. He further contended that once PGS receives a relocation order, it means that the

Company has been put on notice that at some point in the near future, road construction work will begin, and facilities must be relocated. He asserted that contractors/governmental entities could impose fees on the Company if it fails to relocate facilities as required, and the entity/entities miss established deadlines.

According to witness Binswanger, the Company's capital expenditures for government-mandated relocations were $17.6 million during the period of 2004 through 2007. He contended that PGS did not receive any revenues to recover the associated depreciation and ad valorem tax expense or a return on its investment. He further contended that PGS was granted depreciation expense and a return on government-mandated relocations in its 2003 rate case. He stated the Company is proposing capital expenditures for the 2008 and 2009 projected test year for government-mandated relocations in the amount of $6.3 million and $3.8 million, respectively.

3. Capital Budget and Expenditures

PGS witness Narzissenfeld testified that the annual capital budget is determined by normal expenditures and capital projects. He stated that normal expenditures are composed of recurring costs required to provide service to new customers, and routine costs associated with the replacement and/or relocation of existing facilities and equipment. He further stated that major projects consist of expansions with cost in excess of $500,000. He asserted that in the quantification of the annual capital budget, PGS detailed the existing revenue-producing projects that have activity in the current year. He further asserted that the information was then used in the establishment of the capital expenditures by budget category for the next fiscal year. Finally, he contended that the information obtained from the analysis enabled PGS to: 1) forecast new customers; 2) calculate blanket expenditures, such as meter sets and service lines; and 3) main expansion within a development, city, or projected new area. He stated that maintenance capital was forecasted by budget category, which consisted of known projects and historical experience.

According to witness Narzissenfeld, the capital expenditures for 2008 and 2009 are projected to be $62 and $60 million, respectively. He stated that for 2008, of the budgeted $62 million, PGS would use: 1) $39 million to construct revenue producing facilities for new and existing customers; 2) $15 million for the replacement or removal of mains and services, improvements to the distribution systems and relocations and replacements to accommodate municipal, state and federal road construction; and 3) $8 million for improvements to structures, replacement of vehicles, office equipment and communication systems, and other tools and equipment. He described revenue producing facilities as the construction of mains and services, together with installation of metering and pressure regulation stations, control equipment, corrosion prevention systems, and other appurtenances. He further stated that of the budgeted $60 million for 2009, PGS would use: 1) $42 million for facilities to serve new and existing customers; 2) $13 million spent for replacement or removal of mains and services, improvement of the distribution systems, and relocations and replacements to accommodate municipal, state and federal road construction; and 3) $5 million for improvements to structures, replacement of vehicles, office equipment and communication systems, and other tools and equipment.

According to OPC witness Schultz, the Company overstated its 2008 and 2009 capital expenditures by 33 percent in comparison to its historical spending. He also stated that the Company's past five years' average capital expenditures were $44,784,558. Witness Schultz acknowledged that the adjustments he proposed in his direct testimony are no longer applicable as they were based on erroneous information provided by the Company. However, he believed that the cost of spending was primarily for mains and services without showing a complementary increase in customer growth. Witness Schultz believes that when rates are set they are based on plant and operating costs that are associated with a specific level of customers. He stated that according to Company witness Richards, the average use per customer has declined. He contended that witness Richards' statement is in direct contradiction with witness Narzissenfeld's argument that the increase in plant is attributable, in part, to accommodating increased use by existing customers.

Witness Schultz stated that PGS witness William Cantrell testified that the cost of steel pipe has more than doubled and the cost of plastic pipe has increased by 45 percent. Witness Schultz used historical data provided by the Company in OPC's Exhibit 64 to confirm the figures regarding the cost of pipe. He stated that the information showed the fluctuation of cost per foot for both steel and plastic pipe for mains and services. He stated that the provided data showed the projected cost per foot for the size of mains and service lines installed more than doubled the actual cost. Witness Schultz's adjustments show a reduction to average projected plant in the amount of $2,356,919 for steel mains, $15,883,458 for plastic mains, and an increase to the average projected plant for plastic mains by $2,912,691. He further stated that the adjustment for accumulated depreciation and depreciation expense should be $369,404 and $404,900, respectively.

OPC witness Shultz stated that the errors in the Company-provided documents caused an initial wrong turn, but it has not caused OPC to retreat from the recommendation that rate base should be reduced for excessive and unjustified capital spending. OPC believes that the customer growth does not explain nor justify the 2008 and 2009 spike in capital expenditures. OPC's post-hearing brief states that:

> Regardless of whether it is by design or not, it appears that PGS is asking current customers to unfairly bear the cost of the downturn in the economy. Additionally, they are asking the current customers to shoulder the cost of extending facilities to position the company to meet or serve future demands regardless of the cost effectiveness or viability of the facilities extensions.

OPC argued that PGS Vice President of Operations, Bruce Narzissenfeld, testified on January 30, 2009, that "nothing occurred which caused the Company to believe that its 2009 projections should be changed." OPC argued that: 1) 12 projects were delayed, or cancelled between the time of filing and the hearing which caused a 43 percent or $6,973,735 reduction in the original budgeted revenue producing category, 2) Witness Narzissenfeld testified that delays were due primarily to the real estate market, and 3) for 2009, over $8 million of revenue-producing projects were reduced or eliminated from the initial budget included in the MFRs. OPC believes that when new last minute dollars appear in order to plug the budget so that it does not change by one single dollar, then the reliability of those new additions should be questioned. OPC asserted that in the last rate case, which was stipulated, an adjustment in the amount of

$15,377,000 was made for cancelled, delayed, or under-budgeted additions. OPC recommends that we should reduce the projected rate base by $15 million. OPC believes it would be consistent with the adjustment made in the last rate case, and would insure that revenues, and costs are appropriately matched while providing a check on excessive spending to pursue ever elusive customer growth.

In his rebuttal testimony, witness Narzissenfeld stated that OPC witness Schultz's adjustments were based on a re-estimate of the 2008 capital expenditures which were based on erroneous data received from PGS. He contended that in the process of calculating the "estimated" projected footage, the Company divided the projected spending by what it believed to be the 2007 actual costs per foot. He further contended that PGS estimated the footage because the budget system could not capture that type of data. He stated that this type of information is prepared by personnel at the project level and only the financial projections are captured in the budget system. He further stated that the Company provided OPC and staff with the corrected answers. He concluded that the information needed by witness Schultz for his adjustment methodology is not available, and the estimated footage used was inaccurate for his adjustments to capital expenditures.

PGS witness Narzissenfeld argued that there is no relationship between use per customer and capital expenditures. In addition, the use per customer can decrease while the overall system usage would increase due to an increase in the total number of customers or changes in customer mix. He further asserted that economic conditions have reduced near-term customer growth estimates, but PGS's planning cycle is much longer. Furthermore, he argued that PGS's evaluation of expansion capital is based on a four-year payback period which is reflected in PGS's 2009 budget. He believes that short-term economic conditions should not automatically reduce the Company's expansion plans and delay providing gas to areas not currently served. According to witness Narzissenfeld, the 2008 final capital expenditures are now known, validated, and exceed the level of capital spending included in the Company's filing.

We examined the Company's plant data filed in this rate proceeding. Our staff's audit of the historical test year revealed no adjustments to plant, construction work in progress (CWIP), retirements, and accumulated depreciation. We further reviewed the responses to interrogatories provided by the Company for the historical base year plus one and the projected test year. Staff received a copy of the Company's responses to OPC's interrogatories and request for documents (PODs). The Company's response to OPC POD No. 72 and its backup documentation mirrored MFR Schedule G-1, Construction Budget for the Historic Base Year Plus One and Construction Budget for the Projected Test Year, pages 23 through 28. This information was used by staff to correlate the data provided by the Company to OPC Interrogatories 70, 72, and 73, which later were revised. Accordingly, we agree with OPC that the documentation received was flawed. Also, the initial adjustments to plant were based on this information.

We reviewed the corrected data provided by the Company in response to OPC POD No. 72, and Interrogatories 70, 72, and 73. The Company's response included a breakdown of several projects listed as revenue-producing – new, ongoing, and other, and maintenance expenditures. The updated information included actual expenditures for 2008 totaling $68.4 million. This is a $6.4 million increase over the projected historical base year. The actual capital expenditures for 2008 validates the Company's 2008 projection. But, there existed in the revised documentation for OPC POD No. 72 cancelled, delayed, cost over-runs, and new projects completed in 2008. We removed government-mandated projects totaling $3,803,800 for 2009 since the majority of the projects were completed in 2008. Because the Company added new government-mandated projects for 2009, we believe that the projects listed in Exhibit 94 should be completed in 2009. Also, the Company projected $3,200,042 for cost of removal for 2008, but the actual expenditure was $1,552,481. This created an overstatement of accumulated depreciation in the amount of $1,647,561.

Peoples is currently involved in a territorial dispute in Martin County with Florida Public Utilities Company.[6] This dispute is over an area located immediately west of the Florida Turnpike on SW Martin Hwy (State Hwy 714) near Stuart, Florida. Peoples extended a supply main into this area which prompted this dispute. That supply main is estimated to cost $114,816 when complete. Peoples' witness Binswanger testified that Peoples does not serve any customers located within the disputed area, nor does the Utility have any contracts or agreements to provide service in the area. We find that while this dispute is as yet undecided by the Commission, it would be discriminatory and inappropriate to allow the cost of this supply main in rate base.

In summary, based on reductions discussed in this issue, we find that the 2009 projected test year 13-month average Projected Plant, and Depreciation Expense shall be reduced by $1,959,308 and $113,640, respectively, and Accumulated Depreciation shall be increased by $795,371, resulting from 2008 and 2009 activities.

B. Adjustments to Reduce Plant, Accumulated Depreciation, Depreciation Expense, and Other Expenses to Reflect Non-Utility Operations

PGS stated that all required adjustments to remove non-utility items have been made for the 2009 test year. Moreover, the parties did not propose any adjustments to reduce plant, accumulated depreciation expense, or other expenses to reflect non-utility operations.

We find that no adjustments are necessary to Plant, Accumulated Depreciation, Depreciation Expense or other expenses to reflect non-utility operations.

C. Construction Work in Progress (CWIP)

PGS stated that the appropriate amount of CWIP for the 2009 projected test year is $18,249,444. OPC argued that the Company's CWIP balances for 2008 and 2009 appear to be as excessive as plant. OPC argued that there were no specific adjustments to recommend to any particular CWIP project. According to OPC, the MFRs showed $25,028,580 for the 2008 projected base year CWIP amount, but the final amount for 2008 was $26,863,863. OPC asserted that it compares unfavorably to the 2003-2006 average CWIP balance in the amount of $14,771,750. OPC further argued that although the 2003 final CWIP balance was $16,685,000, the amount used for setting rates in the 2003 test year was $21,277,545.[7] OPC asserted that the

[6] See Docket No. 080642-GU, In re: Petition of Florida Public Utilities Company to resolve a territorial dispute with Peoples Gas System.
[7] Order No. PSC-03-0038-GU, issued January 6, 2003, in Docket No. 020384-GU, In Re: Petition for rate increase by Peoples Gas System.

projected CWIP for 2009 represents another opportunity for the Company to curtail costs and reduce the impact of the economy on its customers. OPC further stated that 2008 and 2009 CWIP mirror the 2008 capital budget during dire economic conditions, no growth, and a stagnant real estate market. OPC further argued that the Company failed to meet its burden of showing the projected rate base is reasonable.

During PGS witness Higgins' telephonic deposition where several questions were proposed by OPC, witness Higgins testified in the affirmative that the average CWIP for the unadjusted projected test year was lower than the originally projected 2008 average. He agreed that the actual average CWIP for 2008 was greater than the historic base year plus one average CWIP. He further stated that the amount was $26.6 million.

In the following chart, our staff analyzed the data provided in the parties' testimonies concerning the average CWIP costs in the MFRs for 2003-2006, the 2008 base year plus one and the 2009 projected test year.

Comparison of Construction Work in Progress (CWIP)

2003-2006 Average CWIP Balance	$14,771,750	
2003 Final CWIP Balance	16,685,000	12.9 percent increase over 2003-2006 average CWIP
2003 CWIP used for Setting rates	21,277,545	27.5 percent increase over 2003 Balance and a 17 percent increase over 2009 projected test year.
2008 Projected Base Year	25,028,580	17.6 percent increase over 2003 for rate setting.
2008 Final CWIP	26,863,863	7 percent increase over 2008 projected base year and 47 percent increase over 2009 Projected Test Year
2009 Projected Test Year	$18,249,444	32 percent decrease over 2008 Final CWIP and a 14.2 percent decrease over 2003 CWIP used for setting rates 9 percent increase over 2003 final CWIP balance

As shown in the chart, the 2003 final CWIP balance increased by 12.9 percent over the 2003-2006 average. But, the 2003 CWIP used for setting rates was 27.5 percent over the 2003 final CWIP balance. PGS's last rate case included a $15.377 million decrease to plant. Furthermore, the 2008 projected base year plus one CWIP was 17.6 percent over the 2003 CWIP used for setting rates, which entails a five-year span of time. Finally, the 2009 projected test year CWIP is 9 percent more than the 2003 final CWIP balance, but 32 percent less than the 2008 final CWIP. The balance in CWIP continually fluctuates depending on when projects are completed during the year and transferred to plant in service.

We believe that the data provided by OPC in the comparison of CWIP from 2003 through 2009 does not support its position of excessive CWIP for the projected test year. Accordingly, we find that the $18,249,444 is appropriate for the 2009 projected test year.

D. <u>2009 Projected Test Year Total Plant</u>

In determining the appropriate 2009 projected test year to plant, we reviewed Plant in Service documentation provided by the Company for 2008 to determine the proper 2009 projected test year amount. For this issue, we used the 13-month average Plant in Service balance as contained in the MFRs of $1,009,374,293 minus Construction Work in Progress, which totaled $991,124,849. We also made an adjustment to decrease Total Plant of $991,124,849 by $1,959,308 for the 13-month average to $989,165,541. Therefore, the appropriate level of Total Plant in Service shall be $989,165,541.

E. 2009 Projected Test Year Depreciation Reserve

In determining the 2009 projected test year total amount we examined accumulated depreciation data for 2008. Moreover, we used the 13-month average for Accumulated Provision-Depreciation and Amortization and Customer Advances For Construction contained in the MFRs of $426,364,359 and $7,916,127, respectively, totaling $434,280,486. We also incorporated the adjustments made to Projected Plant, Accumulated Depreciation, and Depreciation Expense. The effect of the adjustments increases the depreciation reserve of $434,280,486 by $795,371 to $435,075,857.

F. Projected Test Year Rate Base

The appropriate amount of rate base for the 2009 projected test year is $560,844,757, as stated in the table below.

Comparative Rate Base
Projected Test Year Ending December 31, 2009

	Per Company	OPC[8]	Commission
Utility Plant in Service	$991,124,849	$983,624,849	$989,165,541
Accumulated Depreciation	(434,280,486)	(434,171,736)	(435,075,857)
Net Plant-In-Service	556,844,363	549,453,113	554,089,684
CWIP	18,249,444	18,249,444	18,249,444
Net Utility Plant	575,093,807	567,702,557	572,339,128
Working Capital	(11,494,371)	(11,494,371)	(11,494,371)
Total Rate Base	$563,599,436	$556,208,186	$560,844,757

IV. COST OF CAPITAL

A. Return on Common Equity

Two witnesses testified in this proceeding regarding the appropriate return on common equity (ROE) for PGS. PGS witness Murry recommended an ROE of 11.50 percent. OPC witness Woolridge recommended an ROE of 9.25 percent. PGS's currently authorized ROE of 11.25 percent was set in 2003 in Order No. PSC-03-0415-FOF-GU.[9]

The statutory principles for determining the appropriate rate of return for a regulated utility were set forth by the U.S. Supreme Court in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Waterworks & Improvement Company v.

[8] The calculation of OPC's position is based on the amounts contained in OPC's Brief.
[9] Issued March 25, 2003, in Docket No. 020384-GU, In re: Petition for rate increase by Peoples Gas System.

Public Service Commission of West Virginia, 262 U.S. 679 (1923). These decisions define the fair and reasonable standards for determining rate of return for regulated enterprises. Namely, these decisions hold that the authorized return for a public utility should be commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms.

While the logic of the legal and economic concepts of a fair rate of return are fairly straight forward, the actual implementation of these concepts is more controversial. Unlike the cost rate on debt that is fixed and known due to its contractual terms, the cost of equity must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM) are generally recognized as being consistent with the market-based standards of a fair return enunciated in Hope, 320 U.S. 591 and Bluefield, 262 U.S. 679.

1. Discounted Cash Flow Model (DCF)

Both witnesses Murry and Woolridge used the DCF model to estimate the investor-required ROE for PGS. PGS is a division of Tampa Electric Company (TECO), which is a wholly-owned subsidiary of TECO Energy, Inc. (TECO Energy). As such, its common stock is not publicly traded. To apply the DCF model, each witness had to select a group of companies with publicly traded stock to serve as a proxy for PGS.

To select his group of comparable companies, PGS witness Murry started from a group of all publicly traded local distribution companies (LDCs) followed by Value Line Investment Survey (Value Line). From this initial sample, he excluded all companies that did not pay a dividend and companies with a market capitalization greater than $1.7 billion. Based on this selection criteria, witness Murry identified a group of six companies that he testified provided a representative sample of the financial and cost of capital information for a financially healthy gas distribution utility such as Peoples.

Witness Murry relied on stock prices and dividends for a recent two week period prior to the filing of his direct testimony in August 2008 and the high and low stock prices for the preceding 52-week period. While he reviewed dividend growth rates, his DCF analysis relied principally on forecasted earnings growth rates. In lieu of making a specific adjustment for flotation costs, witness Murry recognized the high end of the results of his DCF analysis to compensate for the price impact flotation costs and market pressure from a stock issuance have on the price of that common stock.

The various iterations of witness Murry's DCF analysis produced indicated returns ranging from a low of 6.94 percent to a high of 11.02 percent for his proxy group. Due to the recent turmoil in the debt and equity markets, he testified that the relevant DCF results from his analysis range from 10.04 percent to 11.02 percent.

To select his group of comparable companies, OPC witness Woolridge started with all publicly-held gas distribution companies followed by Value Line and AUS Utility Reports.

From this initial sample, he removed all companies that did not have an investment grade bond rating from Moody's Investors Service (Moody's) and Standard & Poors' (S&P). He further narrowed his proxy group by focusing on companies that generate at least 50 percent of its operating income from regulated natural gas operations. Based on this selection criteria, witness Woolridge identified a group of nine comparable companies for use in his analysis.

Witness Woolridge relied on dividend yields for the six-month period ended December 2008 and for the month of December 2008. He relied on Value Line's historical and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, he used the average EPS growth rate forecasts from Bloomberg and Zacks and the expected growth rate as measured by the earnings retention method. Witness Woolridge's DCF analysis did not include an adjustment for flotation costs. The indicated return from witness Woolridge's DCF analysis is 9.50 percent.

OPC witness Woolridge's direct testimony critiqued the reasonableness of certain aspects of PGS witness Murry's DCF analysis. In turn, witness Murry filed rebuttal testimony challenging the reasonableness of certain aspects of witness Woolridge's analysis. The two witnesses used very similar DCF models, similar estimates of dividend yields, and relatively similar proxy groups. The primary reasons for the difference in the witnesses' indicated DCF returns are their respective estimates of the growth rate to include in the DCF model and witness Murry's decision to rely on the high end of his indicated DCF results to account for flotation costs.

Focusing first on expected growth rates, OPC witness Woolridge used a growth rate of 5.25 percent. This growth rate is the average of the projected growth rates for EPS, DPS, BVPS, and the internal growth rate. In contrast, PGS witness Murry's relevant DCF range is based on growth rates that range from 6.50 percent to 8.06 percent. These growth rates are based exclusively on forecasted EPS growth rates.

This Commission has traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor-required ROE.[10] However, such adjustments have typically been on the order of 25 to 35 basis points. While not making a specific adjustment for flotation costs, by going to the high end of his DCF results witness Murry has effectively incorporated an adjustment to his recommended DCF result far in excess of 25 to 35 basis points.

2. Capital Asset Pricing Model (CAPM)

Both witnesses relied on the CAPM approach to estimate the investor-required ROE for PGS. For the reasons discussed earlier, the witnesses used their respective proxy groups for certain inputs to their CAPM analyses.

PGS witness Murry performed two different, but complimentary, approaches to estimate a CAPM ROE for PGS. The first method compared the historical risk premium between common stocks and long-term government bonds. The second method examined the historical

[10] Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company, p. 37.

risk premium of common stocks over Aaa-rated corporate bonds. In both analyses, he used the average beta for his proxy group.

In PGS witness Murry's first CAPM method, he relied on Ibbotson Associates' data to compare the risk premium between the historical earned returns on common stocks and the earned returns on 20-year Treasury bonds. This method produced a CAPM result of 12.46 percent. This result included a "small size adjustment" of 165 basis points. Witness Murry testified that this adjustment is necessary to account for an empirical bias against smaller companies in the CAPM analysis.

In his second CAPM approach, witness Murry relied on Ibbotson Associates' data to compare the risk premium between the historical earned returns on common stocks and the earned returns on long-term Aaa-rated corporate bonds. This method produced a CAPM result of 13.01 percent. Witness Murry testified that this CAPM method does not require a separate recognition of the size bias because it embodies the historical relationship between common equity and debt.

OPC witness Woolridge performed an ex ante version of the CAPM analysis. As a proxy for the risk free rate, he used a composite yield of long-term U.S. Treasury bonds. He used the average beta for his proxy group. He determined an expected risk premium based on the results of various studies of historical risk premium, ex ante risk premium studies, equity risk premium surveys, and the building block approaches. Witness Woolridge's CAPM analysis indicated an ROE of 7.4 percent.

Both witness Murry and Woolridge challenged the reasonableness of certain aspects of each other's CAPM analysis. The primary reasons for the difference in their indicated CAPM results is the size of the market risk premium assumed in their respective analyses, and PGS witness Murry's decision to include a small size adjustment to the results of one of his CAPM methods. Also contributing to the difference in their respective CAPM results were differences between the risk-free rate and beta each witness used in their respective analyses.

OPC witness Woolridge used a risk premium of 4.78 percent in his CAPM analysis. PGS witness Murry used risk premiums of 7.10 percent and 8.50 percent in his CAPM analyses. Witness Woolridge relied on ex ante or forward-looking risk premiums in his analysis. In contrast, witness Murry relied on ex post or historical risk premiums in his CAPM analysis. Witness Woolridge testified that there is considerable academic research documenting that risk premiums based on historical, earned returns are poor predictors of current market expectations. PGS witness Murry used a risk-free rate of 4.60 percent and a beta of .88. In contrast, OPC witness Woolridge used a risk-free rate of 3.50 percent and a beta of .82.

OPC witness Woolridge testified that the small size adjustment proposed by PGS witness Murry in one of his CAPM approaches is not justified. Witness Murry testified that he calculated the small size adjustment consistent with the method recommended by Ibbotson Associates. However, witness Woolridge countered that the errors in using historical earned returns to measure forward-looking risk premiums also apply to this type of analysis. In addition, witness Woolridge noted that the explicit size premium in the Ibbotson study is for companies with betas much greater than the betas for gas distribution companies. As such, witness Woolridge believes these size adjustments are not associated with companies in the gas distribution industry. Due to regulation, government oversight, performance review, accounting standards, and information disclosure, witness Woolridge testified that utilities are much different than industrial companies. For these reasons, witness Woolridge testified that there is no evidence of a significant size premium for utility stocks.

Based on a review of the results of all the models presented in the testimony in this proceeding, the record supports an authorized ROE within the range of 6.94 percent to 13.01 percent. Based on a more pragmatic review of the testimony, we find that the record more strongly supports an ROE for PGS within the range of 9.25 percent to 11.50 percent.

Each of the witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. Under normal economic circumstances, the relaxation of these assumptions for the practical application of these models is generally understood. However, as each of the ROE witnesses have testified, the economy is not presently in a normal or stable state. This realization does not mean that the models no longer have value, rather, it is particularly important at this point in time to exercise informed judgment in the application of the models.

Due to the reliance on historical earned returns to estimate the current risk premium and the decision to include a questionable small-size adjustment in his CAPM analysis, combined with the decision to recognize the high end of his DCF results, we believe that witness Murry's recommended ROE overstates the current investor-required ROE for PGS. Conversely, recognizing that witness Woolridge's recommended ROE is only marginally greater than the current cost of utility debt, we believe returns in the single digits may understate the investor-required ROE in the current market.

PGS witness Murry testified that recently authorized returns of other natural gas companies are not relevant to this proceeding because these returns do not account for investor expectations following the recent disruption in the credit markets. However, this position is drawn into question by the fact witness Murry's recommended ROE is significantly influenced by the historical earned returns over the period 1926–2007. We do not agree that returns recently authorized in other cases are not relevant to this proceeding, but a return based on historical earned returns over the past 81 years does convey information on current investor expectations that this Commission can rely on for making its decision in this case.

There is little doubt the recent disruption in the credit markets has exerted some degree of upward pressure on the current expectations of the market risk premium. However, we believe that this incremental increase in required return, whatever the appropriate amount may be, should be applied to a contemporary estimate of the current investor-required return, not an authorized return set in 2003. Witness Murry identified a group of companies which he testified are comparable in risk to PGS. These utilities have authorized ROEs ranging from a low of 10.00 percent to a high of 10.51 percent. The average ROE for this group is 10.23 percent. We do not believe that the investor-required return for PGS is 127 basis points greater than the average authorized return for the group of companies witness Murry has identified as comparable in risk to PGS.

We find that an authorized ROE of 10.75 percent is appropriate. We have taken into account PGS's proposed construction program and its need to access the capital markets during this potentially challenging period. In addition, we considered the Company's proposed equity ratio of 54.7 percent. We find that at an equity ratio of approximately 55 percent, and an authorized ROE of 10.75 percent is supported by competent, substantial evidence in the record and satisfies the standards set forth in the Hope, 320 U.S. 591 and Bluefield, 262 U.S. 679 decisions of the U.S. Supreme Court regarding a fair and reasonable return for the provision of regulated service.

B. Capital Structure

PGS's proposed capital structure for the projected 2009 test year reflects an equity ratio as a percentage of investor-supplied capital of 54.7 percent. PGS witness Gillette testified that the proposed 54.7 percent equity ratio is reasonable when compared to the equity ratio of 57.4 percent approved by this Commission in PGS's 2002 base rate proceeding. Witness Gillette also testified that no equity infusions were deemed necessary in 2008, and the 2009 planned equity infusion from TECO Energy to PGS is $25 million.

OPC witness Woolridge agreed that PGS's proposed capital structure is appropriate, but with a caveat. The witness asserted that the average common equity ratio for the Gas Proxy Group in the first eleven months of 2008 was 49.9 percent. Witness Woolridge testified that PGS's proposed capital structure includes a higher common equity ratio than the average equity ratio for the Gas Proxy Group and therefore, represents lower financial risk. The witness explained that he recognized PGS'S lower financial risk in his recommended cost of equity. Witness Woolridge testified that his recommended ROE of 9.25 percent is a fair return given PGS's higher common equity ratio and lower degree of financial risk.

PGS witness Murry identified a group of six natural gas companies that he testified "provide a representative sample of the financial and cost of capital information for a financially healthy gas distribution utility such as Peoples." The regulated utilities associated with the companies in witness Murry's proxy group have equity ratios that range from a low of 38.1 percent to a high of 52.7 percent. The average equity ratio for this group of utilities is 45.4 percent.

Based on the record, we find that the capital structure proposed by PGS is appropriate for rate setting purposes. This capital structure reflects an equity ratio of 54.7 percent as a percentage of investor-supplied sources of capital. While this level of equity is less than the equity ratio approved for PGS in its last rate case, it is above the range of equity ratios of the regulated utilities in witness Murry's proxy group. Neither OPC nor FIGU objected to PGS's proposed capital structure and equity ratio other than contending that this level of equity should be considered in the setting of the Company's ROE.

While the equity ratio and authorized ROE are two separate matters, we believe that equity ratio and ROE are inextricably related. Thus, the ROE of 10.75 percent discussed above is implicitly linked to the equity ratio recommended herein.

We find that the appropriate capital structure for purposes of setting rates in this proceeding is the Company's 2009 projected test year capital structure. This capital structure reflects a projected equity ratio of 54.7 percent as a percentage of investor-supplied capital. The appropriate capital structure for the 2009 test year is shown on Schedule 2.

C. Short Term Debt

PGS's capital structure for the projected test year reflects a short-term debt cost rate of 4.50 percent. PGS witness Higgins testified that the Company utilized an average historical London Interbank Offered Rate (LIBOR) rate in developing its proposed short-term interest rate. Witness Higgins asserted that current LIBOR rates are at historical lows due to the financial crisis and believes that rates have been extremely volatile and will continue to be volatile in the foreseeable future. Witness Higgins testified it is therefore prudent to use a historical average LIBOR rate as proposed by PGS as opposed to a rate at a particular point in time as recommended by OPC witness Woolridge.

OPC witness Woolridge recommended a short-term debt cost rate of 1.76 percent. Witness Woolridge contended that PGS's recommended rate is based on the historical LIBOR rate between 1991-2008 of 4.73 percent, plus a program financing fee. The witness asserted that the historic rate has little to do with current LIBOR rates. Witness Woolridge testified that as of December 17, 2008, the three-month LIBOR rate was 1.58 percent. Witness Woolridge explained that his recommended short-term debt cost rate consisted of the 1.58 percent LIBOR rate, plus a financing program fee of 18 basis points (1.59% + 0.18% = 1.76%).

FIGU adopted no position on the appropriate cost rate of short term debt for the projected test year.

PGS witness Gillette testified that PGS is a division of TECO and does not issue its own debt securities. Any debt is issued in TECO's name and is then allocated to PGS and Tampa Electric on an as-needed basis. The Company utilized average historical LIBOR rates, plus a program financing fee, to develop its proposed short-term interest rate of 4.50 percent. For the period 1991 through 2008, the three-month average LIBOR rate was 4.37 percent. This was the number on which PGS based its proposed short-term debt cost rate. Witness Higgins argued that OPC witness Woolridge's use of the December 17, 2008, LIBOR rate of 1.76 percent is not appropriate due to the volatility in the market.

One year ago, TECO was paying approximately 5.34 percent for its short-term credit facility due to a higher three-month LIBOR rate, which averaged about 4.5 percent over the last three years. In December 2008, PGS renewed its LIBOR-based credit facility. This credit facility included a fixed cost fee of 125 basis points, plus a fee for use of the facility of 50 basis points. Therefore, the effective cost of this credit facility is the current three-month LIBOR rate plus 175 basis points. On March 4, 2008, the three-month LIBOR rate closed at 1.27 percent.

Accordingly, witness Gillette confirmed that if the Company were to draw on its credit facility today, its rate would be approximately 3.02 percent.

We find that a cost rate of 3.02 percent is appropriate for short-term debt. This cost rate is based on the three-month LIBOR rate at the close of the record plus 175 basis points to account for financing fees. This is the same methodology used to determine the cost rate of short-term debt recently approved by this Commission in the TECO rate case in Docket No. 080317-EI.[11] Based on the record in the TECO case, the Commission approved a short-term debt cost rate of 2.75 percent.

Based on the record, we find that the appropriate cost rate for short-term debt for the 2009 projected test year is 3.02 percent as shown on Schedule 2.

D. Accumulated Deferred Taxes

In its MFRs, PGS recorded a balance of accumulated deferred income taxes (ADITs) in the Company's capital structure for the projected test year of $27,670,682. PGS witness Higgins testified that in order to comply with specific rules under the Internal Revenue Code (IRC), an adjustment was made to reduce the balance of ADITs to compensate for using a projected test year. The offset to this reduction was applied to investor-supplied sources of capital on a pro rata basis.

PGS witness Felsenthal testified that the projected 2009 MFR income tax amounts have been properly stated in accordance with Generally Accepted Accounting Principles (GAAP), and with the adjustment included in Exhibit 40, have been calculated in accordance with the requirements of the IRC and Regulations applicable to the use of a projected test period. The methodology used by witness Felsenthal to calculate the balance of ADITs for purposes of this case represents a change from the Company's prior practice. The witness, however, cited several private letter rulings (PLRs) to support his proposed adjustment to ADITs of $205,000 that results from the Company's revised methodology. The witness stated that the methodology used to calculate the adjustment in the instant case is the same methodology used in the TECO rate case in Docket No. 080317-EI.[12]

OPC recognized that this issue may follow the decision in the TECO case since the two companies are part of a wholly owned subsidiary of TECO Energy. OPC questioned why PGS cannot seek a private letter ruling with the facts presented with input from Commission staff. OPC reasoned that if the Internal Revenue Service (IRS) ruled that PGS is in compliance with IRS code with respect to normalization, the associated revenue requirement benefit could be flowed through the Purchased Gas Adjustment (PGA) clause. OPC asserted that if the Commission allows the Company's proposal, it should at least follow Commission precedent and adjust the deferred tax balance by reconciling the capital structure to rate base for these dollars over investor-supplied sources of capital.

[11] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.
[12] Id.

FIGU adopted no position on the appropriate amount of accumulated deferred taxes to be included in the capital structure for the projected test year.

ADITs represent taxes that are expected to be paid in the future based on transactions recorded in the financial statements in the current period. These amounts are sometimes referred to as "interest free loans" from the U.S. Treasury. Accelerated depreciation is the major component of deferred taxes and is intended to lower the cost of financing assets by providing a utility an interest free loan. When Congress changed the IRC to permit the use of accelerated depreciation, it intended that, by being allowed to accelerate depreciation deductions (and thereby reduce current income tax payments), companies would lower the financing costs of their investment in capital assets and would be incented to incur such expenditures. The ADIT balance is a zero cost source of capital in the cost of capital computation thereby sharing the benefit of the reduced financing costs with ratepayers.

ADITs are recognized as a liability for future taxes due when the book depreciation of an asset exceeds the tax depreciation of the asset. This is referred to as a temporary book/tax difference. In the regulatory environment, the process of recording deferred income taxes on temporary differences is often referred to as normalization. Witness Felsenthal testified the pro rata adjustment of $205,000 is required for accumulated deferred income taxes recorded in Account 282, net of the Financial Accounting Standard 109 component, because this account includes the deferred taxes governed by the IRS normalization rules. In this case, the future portion of the test period subject to the pro rata adjustment necessary to comply with the normalization requirement is the period from May 2009 (the expected effective date of the rate change) to December 31, 2009. The IRC rules are set forth in Treasury Regulation Section 1.167(1)-1(h)(6) which addresses forecast net periods and the appropriate amount of ADIT used to be treated as a zero cost of capital in the determination of cost of capital for a forecast test period. The penalty for violating the normalization requirements is the loss of the ability to claim accelerated depreciation on public utility property.

We find that PGS has reasonably relied on PLRs which, while not binding on the IRS, are indicative of the IRS's position on this issue. In reconciling rate base and capital structure, PGS followed Commission precedent and made a pro rata adjustment over investor-supplied sources of capital. Further, PGS used the same methodology to calculate the required normalization adjustment of the ADITs that was approved by this Commission in the TECO rate case. PGS is a division of TECO, and as a matter of consistency, we believe that the same methodology should be utilized. Therefore, we find that the Company's change in methodology is appropriate. Moreover, we find that the appropriate amount of accumulated deferred taxes to include in PGS's capital structure for the 2009 projected test year is $27,670,682 as shown on Schedule 2.

E. Weighted Average Cost of Capital

Based upon the decisions in preceding issues and the proper components, amounts, and cost rates associated with the capital structure, we calculated a weighted average cost of capital of 8.50 percent.

As discussed previously, we find that 10.75 percent is the appropriate mid-point return on common equity. Moreover, as stipulated to by the parties, the appropriate cost rate for long-term debt is 7.20 percent. As discussed above, we find that 3.02 percent is the appropriate cost rate for short-term debt. Further, the appropriate balance of accumulated deferred income taxes (ADIT) is $27,670,682. As stipulated to by the parties, the appropriate amount and cost rate of unamortized investment tax credits (ITCs) are $7,862 and 0 percent, respectively.

In reconciling rate base and capital structure, PGS made a pro rata adjustment over investor-supplied sources of capital only. This treatment is consistent with past Commission practice.[13]

The net effect of these adjustments is a decrease in the overall cost of capital from the 8.88 percent return requested by PGS to a return of 8.50 percent approved herein. Schedule 2 shows the approved test year capital structure. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2009, we find that the appropriate weighted average cost of capital for PGS for purposes of setting rates in this proceeding is 8.50 percent.

V. REVENUES

A. Off-System Sales

PGS witness Higgins testified that the Commission ruled in PGS's last rate case[14] that, "for the purpose of setting rates in this docket, operating revenues should be increased by $500,000 in the projected test year" for off-system sales ("OSS"). According to witness Higgins, the Company did not include any amount for OSS in the last rate case, and the $500,000 was set as an annual base level for the purpose of setting rates. He further testified that we changed the sharing mechanism where the Company would retain 25 percent of all net revenues and 75 percent of the net revenues were to be used to reduce the Company's cost of gas recovered through the Purchased Gas Adjustment Clause (PGA). For this proceeding, the Company only included the base level of $500,000 of OSS net revenues. He further testified that the Company intends to maintain the current sharing mechanism on a going-forward basis.

Witness Higgins argued that the Company has been successful in generating net revenues for OSS in excess of $500,000 annually. He further asserted that we were clear in the last order that the base level of sales was "for purposes of setting rates." Witness Higgins testified that this was not presented as the Company's expected level of future OSS revenues. He believes that the $500,000 represents a significant reduction to revenue requirements in this proceeding without excessively burdening the Company with an unreasonably high "hurdle" in future years. He stated that "sales are sporadic, opportunistic transactions that are highly dependent on market conditions, sale agreements which are short-term, or spot market type transactions that are non-recurring in nature." In addition, market conditions drive the opportunities for OSS, and PGS has noticed a decline in the market, as 2007 sales are below the 2006 level. Finally, he stated that the Company expects continuing decline in the market.

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[13] 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.
[14] Id.

OPC witness Schultz stated that the Company wants to keep OSS shared and to continue the sharing based on any sales in excess of $500,000. He also stated "there is no reason that the Company will not earn in excess of the $500,000 revenue base currently used to trigger the sharing mechanism." He argued that the Company has averaged $2,258,556 a year from 2003 through 2007. He stated that if the 2008 actual to date was annualized it would be $2,170,781. He believes the sharing should continue but should be on revenue in excess of $2,000,000. He further believes that the Company's shareholders receive the benefit, especially when the trigger point is lower, the earlier the revenue sharing takes place.

OPC argued that PGS tracks and budgets OSS at the very highest levels of the Company. OPC further added that this was admitted by PGS President William Cantrell while on the stand at the hearing, and that he regularly reports on OSS sales at the TECO Energy Board of Director's meeting and has described them in glowing terms: "strong" and "ahead of plan." OPC believes that recent history has shown that the $2 million sales level is achievable, measurable, and known. OPC argued that PGS made significant capital expenditures in 2008 which are included in rate base to serve affiliate TECO's Bayside Power Station and for facilitating OSS.

We agree with OPC witness Schultz's adjustments to increase OSS by $1,500,000. In response to Staff's Interrogatory No. 129, the Company provided actual OSS for 2003 through 2008. The 2008 OSS Gross Margin was $8,255,652. The PGA portion was $6,191,739, and the OSS net revenue was $2,063,913. In its response to Interrogatory No. 129c, the Company stated that:

> PGS did not use the $500,000 in the calculation of the sharing amount for the 2009 projected test year. The $500,000 amount included in revenues for the projected test year is, in part, the result of PGS's applying the 75/25 percent sharing mechanism to reasonably attainable OSS Gross Margins for 2009 of $2 million to obtain the amounts which would be credited to the PGA ($1.5 Million) and included in revenues for this case. The $500,000 is also, the amount of OSS that was included in the last base rate proceeding.

Although the Company used $2 million as its OSS gross margin to apply the 75/25 sharing mechanism for 2009, the amount has never been below $3 million since 2003.

Therefore, we find that OSS shall be increased by $1,500,000 for the projected test year and taxes other than income shall be increased by $7,500 for the related regulatory assessment fee.

B. Projected Test Year Total Operating Revenues

Based on our finding above, the requested Operating Revenues of $169,906,126 shall be increased by $1,500,000 resulting in an adjusted total of $171,406,126 for the 2009 projected test year. See Schedule 3.

VI. EXPENSES

A. Trend Rates Used to Calculate Projected Operation & Maintenance Expenses

In its filing, the Company utilized three different projection factors in its calculation of the projected test year ending December 31, 2009. The three factors that the Company used were a payroll factor, inflation factor, and customer growth factor. For items that the Company expected to increase at a greater rate than the projection factors, the Company projected the expenses based on estimated expenses for the twelve-month period ending December 31, 2009.

The Company separated operating and maintenance (O&M) expenses into payroll expenses and other expenses in each account. The Company applied the payroll factor to six payroll accounts, as of December 31, 2007, and payroll times the customer growth factor to the remaining payroll accounts. The 2008 and 2009 payroll factor is 3.5 and 4.0 percent, respectively. These payroll increase percentages were taken from the WorldatWork Annual Salary Budget Survey and were appropriately used by Peoples.

PGS witness Higgins used Moody's Economy.com forecasts for the inflation trend factor for 2008 and 2009. The estimates of the Consumer Price Index – All Urban (CPI-U) inflation for 2008 and 2009 were 2.9 percent and 2.1 percent, respectively. OPC asserted that a more recent forecast for the 2009 inflation factor was -1.1 percent, and asked witness Higgins why PGS does not feel it's appropriate to use a lower inflation factor for 2009. Witness Higgins testified that looking at 2008, the forecast was for a 2.9 percent increase with an actual 3.8 percent increase. Witness Higgins also testified that the forecast data can change dramatically, decreasing from 2.4 percent in September, four months before the testimony, to 1.2 percent in November, two months before the testimony. Witness Higgins further testified "that it is somewhat of a crap shoot in terms of what you pick in 2009 . . . there's a lot of stimulus dollars placed in the economy. I don't know how fast that's going to factor in, but I think the longer term expectation is that that could have inflationary pressures on the economy." In addition, page 2 of witness Higgins Late Filed Deposition Exhibit No. 9 contains Moody's Economy.com January 2009 CPI-U forecasts, which has a 2.1 percent inflation rate for the out years.

We find that the appropriate trend factors to be used in deriving projected expenses in the projected test year are as follows:

Trend Factors	**Historic Base Year +1 12/31/2008**	**Projected Test Year 12/31/2009**
Payroll Only	3.50%	4.00%
Customer Growth & Payroll	4.37%	4.51%
Customer Growth & Inflation	3.76%	2.60%
Inflation Only	2.90%	2.10%
Customer Growth	0.84%	0.49%

These are the same factors that were used by the Company in its filing.

Peoples' payroll increases were based on actual merit increases for 2008 of 3.5 percent overall and a projected increase of 4.0 percent for 2009 provided by compensation professional in the TECO Human Resources department.

OPC is correct that the CPI has fallen since 2008. However, during periods of recession this decline is but with the economy in a recession that is not typical. The State's National Economic Estimating Conference in February 2009 forecast that the CPI will reach 2.6 percent in 2010, and afterwards will not fall below 2.7 percent going out to 2019. Therefore, PGS's trend factor of 2.1 percent is reasonable for use in this docket.

B. Adjustments to the Projected Test Year O&M Expense

Based on OPC's analysis of the trend factors, OPC stated that expenses should be reduced by $245,164. In determining the $245,164, OPC included the impact of modifying the trend factors that were applied to each expense account.

OPC witness Schultz testified that 19 payroll accounts should not be increased by using the customer growth factor of 0.84 percent for 2008 and 0.49 percent for 2009. The customer growth factors were used to increase payroll expense for additional customers from 2007-2008 and 2008-2009. These customer growth factors were addressed below. The total customer growth expense is $210,199. Witness Schultz believed the current employees should be able to perform the required work for the small growth in customers. In rebuttal testimony, PGS witness Higgins explained in a few isolated instances, new positions were included in the 2009 payroll budget. Witness Higgins stated that these additional new positions are limited and do not reflect a significant increase in expense.

While OPC pointed out in its brief that PGS actually lost 580 customers in 2008, the number of bills and therms for the test year ending December 21, 2009, was stipulated by the parties. As the stipulated number of bills is based on the number of customers, we find that the number of customers and customer growth factors used in this filing are appropriate. For several accounts, the amount of expense is dependent on the level of customer growth. Therefore, the customer growth factor, discussed above, shall be applied to the 19 payroll accounts identified by OPC witness Schultz.

Based on the above analysis, the payroll factor, customer growth factors and inflation factors were not changed, so no adjustments are necessary to the 2009 O&M expenses. Also, no adjustment is needed to remove the customer growth factors in the determination of the 2009 payroll expense. Therefore, we find that no adjustments are necessary to the 2009 O&M expenses.

C. Adjustments to Account 920, Administrative and General Salaries

Witness Higgins testified that PGS has an incentive program for all employees which includes a fixed base pay and a variable incentive pay mechanism which equals the market average salary. The variable pay incentive mechanism is based on the achievements of each individual against the criteria established by PGS. An incentive pay increase is based on the performance of safety goals, customer favorability goals, operational unit financial goals, and individually-determined goals. At the hearing, witness Higgins agreed that employees work harder to achieve the goals when there is incentive pay. Witness Higgins emphasized that base pay and any additional pay based on meeting the various goals does not change with downturns in the economy. Meeting the goals based on certain criteria are still necessary to earn a portion of the employees' salaries which would bring his/her salary to the average market salary. The average market salary may change because of the economic conditions, but the process to determine the pay of an individual does not change when the economic conditions changes.

PGS routinely evaluates salary levels for all jobs in the Company using data from various outside expert resources such as Towers Perrin, WorldatWork, Mercer Inc., Hewitt Associates, Watson Wyatt Worldwide, and Gartner, Inc. Therefore, compensation levels, including targeted incentive compensation, reflect a market-based average necessary to attract and retain qualified employees. Witness Higgins pointed out the World at Work 2008/2009 Annual Salary Budget Survey stated that over 80 percent of the 2,375 companies surveyed use an incentive pay program. In rebuttal testimony, witness Higgins pointed out that witness Schultz's proposed adjustment to incentive compensation was not based on any studies and no alternatives were proposed to compensate PGS employees.

At the hearing, witness Higgins agreed that a downturn in the economic conditions could affect the market average and would lower salaries. In fact, witness Higgins agreed that the Mercer Study reflects that executives are less likely to get an increase than the rank and file employees. Further, PGS made an adjustment to delete the executives' 2009 salary increase and reduce the other employees' salaries for the projected test year as reflected in Higgins' Late-filed Deposition Exhibit No. 7. A World at Work article pointed out that the employers are committed to rewarding employees. Further, the survey indicates that 77 percent of employees expect a pay raise especially for high performance.

OPC Interrogatory No. 42 asked PGS to provide for each of the years 2003-2007, the respective Company and team goals and the respective actual results for each of the goals. Witness Schultz stated that PGS's response to OPC's Interrogatory No. 42 was incomplete for 2003-2007 in relation to Company and team goals and actual results for each of the goals. The specific customer service and safety goals for 2005-2008 were missing. In response to OPC POD No. 35, the Company provided a document for 2005-2008 customer service and safety goals, but this information was not given in response to OPC's Interrogatory No. 42.

In rebuttal testimony, witness Higgins testified that if the response was insufficient for Mr. Schultz's needs, OPC had another two and a half months between the date of the Company's responses to discovery and the date on which witness Schultz's direct testimony was filed to seek additional information. Witness Higgins did not know of witness Schultz's alleged incompleteness of PGS responses until the reading of the direct testimony of witness Schultz.

OPC witness Schultz believes that the incentive program is not justified because the goals are not realistic. Witness Schultz pointed out that the 2003 goal to answer a phone call within 30 seconds, 85 percent – 90 percent of the time, was not met in 1 percent of the calls. In 2004, PGS changed the goal to require that a call must be answered within 60 seconds, 80 percent of the time. The calls were answered within this new criterion 96 percent of the time. Witness Schultz stated that a goal should be set to achieve or exceed target goals to incent the employee to work at a higher level of efficiency.

Lastly, witness Schultz's explained that there was insufficient evidence to determine whether the goals were achieved or required a higher level of performance to earn the incentive compensation pay. Therefore, it is impossible to determine if the incentive compensation plan benefits the ratepayers.

In rebuttal testimony, PGS witness Higgins testified that OPC witness Shultz's proposed adjustment to eliminate 100 percent of the Company's targeted 2009 incentive compensation as inappropriate. Witness Higgins argued that OPC witness Schultz's recommendation removing incentive compensation based on his opinion that PGS did not provide sufficient evidence is inappropriate. Witness Higgins testified that PGS has provided at least 100,000 pages of documents of which a number of the documents related to incentive compensation, especially those produced in response to OPC's First and Second Sets of Requests for Production of Documents (Nos. 35, 59, and 60) and OPC's First and Second Sets of Interrogatories (Nos. 22, 28, 41, 42, 43, 61, and 79). Witness Higgins further testified that if this data was not sufficient for Mr. Schultz's needs, he could have asked for additional detail. There was enough time for further discovery between the date of PGS's last response to OPC's Discovery and the date Witness Schultz's testimony was filed.

Further, witness Higgins explained that all employees' compensation has two parts: a base salary, which is the fixed portion of total compensation, and a short term incentive, which is the cash portion of compensation that is "at risk." In addition, officers and key employees have a third component of compensation, long-term incentive, which is the equity portion of total compensation. Witness Higgins testified that Peoples includes health care and life insurance benefits in its total rewards plan.

Witness Higgins explained that there is a separate short-term incentive plan for an officer, a key employee, and a general employee. The short-term incentive plan for the general employee is know as "RSVP" or Rewarding Service Valuing Performance. The officer's short-term incentive plan provides a consistent framework of financial and operation goals. Each participant has a business plan goal which reflects the participant's contribution to achieving initiatives and enhancing profitability through effective management initiatives beyond the business plan. The key employees' short-term incentive plan works virtually identically to the incentive plan for officers. As with officers, key employees have both financial and operational goals.

In all incentive compensation plans for officers, key employees and general employees, the actual amount of the award depends upon the achieved results. All of the incentive plans are designed to emphasize key operational and financial goals and link pay with business performance results. Incentive plans such as these encourage cost control and resource optimization both of which will benefit customers.

In rebuttal testimony, witness Higgins asserted that we did not challenge the appropriateness of the incentive compensation plan in Peoples' last rate case.[15] Also, in the Gulf Power Company rate case, in Docket No. 010949-EI, we approved an incentive compensation plan that consisted of a base salary and incentive compensation to pay the Gulf employees at the 75th percentile while Peoples is targeted at the market average.[16]

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[15] Order No. PSC-03-0038-FOF-GU, issued January 6, 2003, in Docket No. 020304-GU, In Re: Petition of Florida Power & Light Company for authority to increase its rates and charges.

[16] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In Re: Request for rate increase by Gulf Power Company.

Witness Higgins stated that if the incentive compensation portion was eliminated, the base pay package would need to be redesigned because payment of base pay alone would be below the market average and would not be competitive in attracting and retaining a high quality and skilled workforce. Witness Higgins further pointed out that elimination of the incentive compensation portion of the pay package would increase the salary expense for the ratepayers because there would be no deduction when the financial and operational goals are not met by the individual employees.

In response to witness Schultz's claim that the goals set are not realistic goals, witness Higgins explained that witness Schultz does not understand "incentive compensation." Witness Higgins explains the goal-setting process includes a review of historical results and achievements, the challenges of the goal, and the applicability to the upcoming year's operational and financial objectives. Also, the goals are set to have a reasonable chance of achievement, while requiring efforts that challenge the organization's employees and balance the cost to provide targeted levels of service. PGS does not take the goal-setting process lightly and there are numerous factors that go into setting goals and targets each year, including consideration of past achievements, reorganizational changes and system enhancements.

According to OPC, payroll expense should be reduced by $697,861 for the difference between the payroll amounts calculated from Interrogatory No. 61 and the amount shown on MFR Schedule G-2. OPC argues that this payroll expense reduction should be made for lack of justification.

PGS witness Higgins testified that Peoples prepared two O&M expense projections. The first methodology was based on the Company's annual budget process and the second methodology utilized the trend factor study contained in the MFRs. He further testified that the O&M expense in the MFRs was lower than the amount calculated through the budget process. The difference between these two amounts was approximately $72,000, a difference of 0.1 percent. Witness Higgins pointed out that PGS was able to reconcile total O&M expenses using the two methods to within an immaterial difference.

PGS Witness Higgins testified that the Securities and Exchange Commission, Form 8K, Section 5, Item 5.02E stated that "On February 4th, 2009, the board and the compensation committee for TECO Energy, with respect to the chief executive officer's salary, decided to keep the salaries of the executive officers the same as in 2008 . . . " Witness Higgins agreed that this adjustment should be reflected in the PGS rate case by keeping the 2009 projected year test year officers' salary expense the same as the 2008 salary expense:

Table 1

	2009 Original Guidelines	Revised Guidelines
Officers	4.0%	0.0%
Exempt	4.0%	2.0%
Non-Exempt	4.0%	3.5%

The revised guidelines reduced PGS's projected test year salary expense by an estimated impact of $253,300. The TECO Electric salary allocation was reduced by $26,500.

1. Incentive Compensation

An employee's salary is made up of their base pay and the incentive compensation pay. It is up to the employees to earn the incentive portion of their salary. If the employees do not meet their work goals, the employees will not be paid the additional incentive compensation. Even though the customer response goals were slightly lower in 2004, the goals were achieved at a higher percentage of responsiveness. We find that the incentive compensation has been earned not only because of the response time of calls to ratepayers is appropriate, but also because no ratepayers testified at the four customer service hearings throughout the State of Florida about any complaints about the gas service or the cost of PGS's gas service.

We believe that an incentive compensation plan is an appropriate tool to motivate employees to work efficiently and effectively. The incentive portion of salary gives the employee the opportunity to earn the market average salary. As the base pay is below the average market salary, the incentive is provided that allows the employee the opportunity to achieve a market based salary.

This Commission approved PGS's incentive program in its last rate case in 2003. The incentive program allows PGS to maintain and attract a quality workforce that provides quality gas service demonstrated by the lack of customer complaints at the service hearings. We find that an adjustment is not necessary to the incentive compensation plan. The reduction in the merit increases, as discussed above, compensates for the lowering of the 2009 average market salaries.

2. Other Payroll

This filing is based on a 2009 projected test year. PGS witness Higgins testified that PGS's 2009 O&M expenses included in the MFRs were lower when compared to PGS's 2009 budgeted O&M expenses. An adjustment could be made to update the O&M expenses in the MFRs to reflect the budgeted expenses in OPC's Interrogatory No. 61. We believe that PGS did not request an adjustment in this issue to update its 2009 O&M expenses because the budgeted expenses were only $72,000 more than the expenses in the MFRs. In addition, this adjustment would have been additional expense borne by the ratepayer. Thus, we find that OPC's suggested $697,861 payroll expense reduction is not warranted.

3. Merit Increase Guidelines

Witness Higgins agreed that the $253,300 adjustment should be reflected in the PGS rate case by keeping the 2009 projected test year officers' salary expense the same as the 2008 salary expense. We find that this adjustment shall be made.

In summary, we find that an adjustment to Account 920, Administrative and General Salaries, in the amount of $253,300 to reduce the officers' payroll increases to zero and reduce the merit increase of the other employees, is warranted in this case.

C. Rate Case Expense and Amortization Period for Rate Case Expense

OPC witness Schultz testified that PGS projected a total expenditure of $750,000 to be amortized over a three year period at a cost to rate payers of $250,000 per year. He testified that using the average CPI index and the inflation rates proposed on MFR Schedule G-2, page 19, the benchmark costs for rate case expense should have increased by only 18.4 percent instead of 212 percent. Thus, witness Schultz concluded that the costs are excessive.

According to witness Schultz, the Company stated that its accounting staff was not capable of handling the additional workload associated with a rate proceeding. Furthermore, the Company hired seven consultants to handle the rate case. He asserted that the Company included amounts that were not supported by the contract information provided in response to OPC Interrogatory No. 65. He contended that in the filing; 1) C.H. Guernsey payment is $3,000 less than what is in the contract, 2) AUS Consultant amount is $6,500 higher than the contract, 3) Huron Consulting amount is $37,000 more than what is in the contract, and 4) C. Holden's contract is on an "as required" contract basis with a fixed hourly rate without any cap. Witness Schultz believes that an adjustment should be made for the consultants' contracts in the amount of $65,500. He further asserted that the three-year amortization period is not reasonable based on the Company's history of five years between rate cases. The Company's last rate case was in 2002. He believes that a five-year contract is more appropriate. Witness Schultz believes that the Company's amortization expense should be reduced by $113,100, the unamortized balance in rate base should be reduced by $8,950, and the working capital allowance should be increased by $8,950.

In his rebuttal testimony, PGS witness Higgins testified that the Company is staffed to handle ongoing day-to-day responsibilities but additional workload of the rate filing required supplementing the existing team. He stated that the consultants were hired to assist in case preparation and to serve as expert witnesses. He argued that the adjustments proposed by witness Schultz are based on "bid" amounts in the contracts. He further argued that the $37,000 reduction made to the Huron Consulting Group by witness Schultz was not reflective of the contract bid, "which was for professional services only, and did not reflect out of pocket expenses that are reimbursable by the Company." He testified that C. Holden was retained as a contractor on an "as needed" basis to supplement the Company's accounting staff. In addition, the related fees were paid on an hourly basis and the Company was required to estimate the total expenses expected for his work. Witness Higgins, argued that witness Schultz's reduction of C. Holden's contract by 50 percent was totally unsubstantiated. He further argued that witness Schultz's statement is not based on the understanding of the Company's size, workload, any studies of the same, or any information other than his arbitrary and conclusory statement. According to witness Higgins, to provide the detailed information required by the Company for a rate case proceeding requires quality professionals to supplement Peoples' existing staff. He asserted that C. Holden is familiar with the Company and its accounting system and also provides quality services. Witness Higgins testified that it is difficult to predict when Peoples will file its next base rate case, but he is certain it will be sooner than five years. He testified that three years is an appropriate amortization period for rate case expense, and no adjustment should be made.

We examined PGS's contracts for the rate case consultants and agrees with OPC witness Schultz's findings. A review of Huron's Consulting contract shows that the "Scope of Service" had defined costs, stated as "fixed price and budget limit." Pursuant to our analysis of this information, we believe that the burden of proof for the reasonableness of Mr. Holden's work and payment is on the Company. Also, the scope of work and directions to the consultant was to account for and maintain records as documentation, which is stated in Section 2 of the agreement between the Company and Mr. Holden. Therefore, we believe that the information was readily available and should have been supplied to validate Mr. Holden's performance as it related to PGS rate case.

With respect to the amortization of rate case expense, we find that a four-year period is appropriate. We have previously approved four-year amortization periods for St. Joe Natural Gas Company, Inc. and Sebring Gas System, Inc.[17]

In summary, we find that rate case expense is $684,500 and shall be amortized over 4 years. In PGS's last rate case, we approved a 4-year amortization period. In addition, we find that a reduction to amortization expense in the amount of $78,875 is appropriate. The $78,875 represents the difference between the Company's proposed annual amortization of $250,000 ($750,000/3 years) and our calculations with respect to the annual amortization of $171,125 ($684,500/4 years).

D. Recovery of the Gas Cost Portion of Bad Debt Expense Through the Purchased Gas Adjustment Clause

PGS witness Higgins testified that PGS made a pro forma adjustment in its filing to remove the gas cost portion (46 percent, or $723,580) of bad debt expense and proposed to recover this cost through the Purchased Gas Adjustment Clause (PGA) instead of base rates. OPC witness Schultz argued that PGS's proposal will not benefit customers. He also testified that as a type of uncollectible expense, the gas cost portion of bad debt showed no strong correlation with the volatility of natural gas prices. This point was not contested by PGS. However, PGS contested OPC's claim that recovery through the PGA will reduce scrutiny and Company incentive to pursue collection.

PGS and OPC agreed that PGS's proposal would be a change in our practice of not using the PGA to separately recover the gas cost portion of bad debt expense. PGS has not presented any basis in the record to justify a change in our practice. Therefore, we find that the appropriate recovery mechanism for the gas cost portion of bad debt expense shall be base rates, not the PGA. Moreover, PGS's adjustment to transfer $723,580 of the bad debt expense to the Purchased Gas Adjustment Clause shall be reversed.

E. Adjustments to Bad Debt Expense

PGS witness Higgins testified that the Company proposed to recover a portion of the Company's uncollectible accounts or bad debt expense through the PGA instead of base rates. As discussed subsequently, the Company made a pro forma adjustment in the amount of $723,580, as reflected on MFR Schedule G-2, page 2, of bad expense from the PGA. Witness Higgins testified that to arrive at the estimate to apply to the projected test year, PGS performed

[17] See Order No. PSC-08-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In re: Petition for rate increase by St. Joe Natural Gas Company, Inc. Consummating Order No. PSC-08-0489-CO-GU, issued August 8, 2008, made Order No. PSC-08-0436-PAA-GU final and effective; and Order No. PSC-04-1260-PAA-GU, issued December 20, 2004, in Docket No. 040270-GU, In re: Application for rate increase by Sebring Gas System, Inc. Consummating Order No. PSC-05-0039-CO-GU, issued January 12, 2005, made Order No. PSC-04-1260-PAA-GU final and effective.

an analysis of the historical write-offs for 2005, 2006, and 2007. The resulting fuel portion of the bad debt expense for each year was 40, 49, and 47 percent, respectively, was used to develop the weighted average percentage of 46 percent. Finally, the 46 percent was applied to the total calculated bad debt expense of $1,573,000, (which was based on a four-year average factor), resulting in a $723,580 adjustment to be used for the PGA.

OPC witness Schultz testified that the shifting of a substantial portion of the uncollectible cost to the PGA would provide the Company an automatic pass-through. He further testified that without an automatic pass-through, the Company is required to provide the effort to minimize the level of write-offs between rate cases. Witness Schultz believes that the adjustment to remove the $723,580 from O&M expense shall be reversed.

We find that bad debt expense shall be increased by $723,580 and shall be based on a four-year average. PGS's calculation of the total bad debt expense in the amount of $1,573,000 was based upon a four-year average before applying the 46 percent weighted average. Therefore, we find that the bad debt expense should be increased by $723,580, based upon a four-year average.

F. Adjustments to Account 926, Employee Pensions and Benefits

In its response to OPC Interrogatory No. 6, PGS stated that its test year amounts for pensions and post retirement benefits were $1,735,700 and $1,203,600, respectively. These amounts are, in combination, lower than the base year amounts provided in the same response by $271,966, or 8.47 percent. In direct testimony, PGS witness Higgins testified that the projected test year amounts were calculated by the outside actuary firm of Towers Perrin. No other party filed testimony regarding pension and post retirement benefits. Staff has reviewed the evidence in the record and believes that pension and post retirement benefit expense are reasonable, and that no adjustment is appropriate.

In its response to OPC Interrogatory No. 6, the Company stated that its test year amounts for executive stock grants and stock option expense were $564,200 and $5,300 respectively for a total of $569,500. OPC witness Schultz testified that these costs should not be paid for with ratepayer funds. Witness Schultz stated that "the addition of restricted stock grants and stock options only increases the disparity between the general employee population and the executive levels." Witness Schultz also averred that "the cost of this perk is especially excessive given the current economy and taking into consideration the fact that very few of the Company ratepayers have a similar benefit available to them."

In rebuttal testimony, PGS witness Higgins testified that OPC witness Schultz provided no analysis, benchmarks, or other data to support his recommended adjustment. Witness Higgins stated his belief that witness Schultz's general characterization of the amounts as excessive was not sufficient to remove them from the Company's O&M expense, which he noted was already below this Commission's benchmark. In response to staff Interrogatory No. 118, PGS stated that, according to the 2008 Towers Perrin General Industry and Energy Services Industry Long-Term Incentive Plan Reports, 57 percent of Energy Services Industries offer restricted stock. The Company stated that "the prevalence and utilization of these plans makes these incentives necessary to attract and retain talent."

After examining the evidence in the record, we find that the Company's testimony is persuasive, and we agree that OPC has not provided specific data to support its position that the stock grants and associated expense are excessive. Accordingly, we find that no adjustments to these amounts are appropriate.

In direct testimony, witness Schultz testified the 2007 Employee welfare/activity expense was $211,374. In response to OPC Interrogatory No. 13, PGS identified an additional $122,720 in expenses that needed to be removed as part of the ratemaking process and Witness Schultz identified a corresponding $8,361 inflation factor that needed to be removed. In rebuttal testimony, witness Higgins agreed with the adjustment to remove $8,361 for the approximate inflation factor. Also, witness Schultz identified $164,600 in unjustified costs.

PGS Witness Higgins pointed out that OPC witness Schultz provided no explanation as to why he believes that the $164,500 costs were unjustified other than the fact these expenses are new. Witness Higgins explained the $164,500 costs were derived from the Company's budget process that requested that field and corporate managers to include any new prudent expenses anticipated in 2009. In this case, PGS's Human Resource experts provided detailed information for the additional employee costs.

We find that a portion of the $164,500 expense shall be removed. The $10,000 for interviews and $37,500 for job postings expenses are self explanatory in the budget process. However, PGS has not put forth sufficient justification for the $27,000 in wellness expenses or the $90,000 in crucial conversation expenses to be allowed even though the expenses were requested and documented in the budget process. The budget process is a guide for future expenses, not a guarantee that the dollars will be spent for the original requested purpose. This Commission would need additional facts in order to allow the wellness and crucial conversation expenses. Therefore, we find that and adjustment shall be made to reduce Account 926, Employee Pensions and Benefits by $125,361, which removes the $117,000 in unjustified employee benefit expenses and the $8,361 inflation factor that was agreed to by OPC and PGS.

G. <u>Appropriate Amount of Pipeline Integrity Expense</u>

PGS included $751,500 in operations and maintenance (O&M) expense (Account 887 – Maintenance of Mains) for the projected test year for transmission and distribution pipeline integrity costs. A portion of the expense was included in anticipation of a new federal rule which is expected to be adopted in 2009, as well as for additional required distribution system reliability. OPC believes that the increase is not justified and recommends that PGS's request be reduced by $250,000.

PGS's witness Higgins testified that a proposed new rule related to distribution pipeline integrity activities will require a significantly large level of expenses in 2009 and beyond. The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (Public Law 109-468, the PIPES Act) was passed by Congress and signed into law by President Bush. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has been studying the issue of distribution integrity management programs (DIMP) with the intention of promulgating new regulatory requirements in this area. PHMSA published a notice of proposed rulemaking in the Federal Register for June 25, 2008. PGS's witness Binswanger testified that the federal Pipeline Safety Act of 2002 (the 2002 Act) required the implementation of integrity management activities with respect to "transmission" pipeline, and the PIPES Act required similar measures with respect to "distribution" pipelines. He stated that the 2002 Act and the resulting PHMSA's regulations were limited because of the relatively small proportion of pipelines within PGS's system that are classified as transmission pipelines. However, the PIPES Act and PHMSA's implementing regulations will much more directly affect PGS and other natural gas local distribution companies, and PGS simply has no control over the incurrence of the costs. PHMSA's proposed rule for distribution integrity, expected to be finalized in about a year, outlines seven steps that distribution companies must take, including develop and implement a written integrity management plan, know your infrastructure, identify threats, both existing and of potential future importance, assess and prioritize risks, identify and implement appropriate measures to mitigate the risks, measure performance, monitor results, and evaluate effectiveness of programs while making changes where needed, and periodically report a limited set of performance measures to regulators.

Witness Higgins indicated that the full impact of costs related to the proposed DIMP rule is not known with certainty. It is anticipated that the costs of developing a plan, preparing required documentation, and performing required risk assessments will represent approximately $250, 000 in the 2009 projected test year. This estimate, to be added to Account 887, was based on industry data included in a study completed by the American Gas Association. PGS anticipates that most, or all of this work, will be accomplished by the employment of outside contractors. According to the Utility, the 2009 projected test year expenses included in Account 887 are approximately $250,000 more than the 2008 and 2010 through 2013 projected expenses. The increased amount for 2009 reflected a boost in transmission and distribution integrity management.

OPC argues that PGS's proposal to recover the speculative pipeline integrity expense from customers is unwarranted and unjustified. The expense level is based largely on guesswork and not even on existing rules or regulations. OPC witness Schultz testified that it is important to note that the steps required above are steps that a prudently operated distribution company should already have had in existence. Because of the unknown nature of the new distribution pipeline integrity costs that PGS proposes to include in Account 887 for 2009, witness Schultz recommended that they should not be allowed at the level requested. He points out that an adjustment of $250,000 reduces PGS's unknown cost estimate to $501,500. This amount is similar to the 2008 amount and slightly below the estimated costs for each of the years 2010 through 2013. It is also $241,930 more than the 2007 base year cost, an increase of 100 percent.

In his rebuttal testimony, PGS witness Binswanger testified that pipeline integrity costs are very difficult to estimate, and disagrees with OPC's adjustments as they ignore the integrity management mandates. The witness does not believe that the federal government would have spent the last four years crafting these requirements, in addition to the time the gas industry has spent in addressing the requirements of DIMP, if prudently operated distribution companies already had them in existence as OPC witness Schultz indicated. Witness Binswanger indicated that in this case, the fact that history does not support estimates for future DIMP costs is quite understandable because the industry would not have historical expenses to justify future expenses. PGS believes that while not every item of expense is expected to occur in every year, the inclusion of $750,000 for this category of expense for the projected test year is reasonable for ratemaking purposes, and should be approved by the Commission.

We find that the Utility failed to prove that the proposed costs for system reliability are warranted. PGS's request for the inclusion of an estimated $250,000 in Account 887 for system reliability costs relating to the proposed DIMP rule may be premature since a rule has not yet been adopted. We also note that the 2009 projected expense constitutes approximately $250,000 in increases over the projected expenses for 2008 and the four years following 2009. We question the validity of this amount without sufficient documentation to warrant such an increase. We have concerns with the estimated costs and the lack of detailed information justifying those costs, such as supporting documentation including actual historical costs, bids or contracts. Accordingly, we find that the proposed costs are too wide-ranging in nature and the amount requested by the Utility shall not be allowed. Therefore, we find that the projected test year pipeline integrity expense shall be reduced by $250,000.

H. Storm Damage Reserve

PGS witness Higgins testified that the annual accrual for the storm reserve for the projected test year should be $100,000. He stated that the Company should be allowed to establish a storm reserve so that it would not be forced to incur large, unusual, and unpredictable costs in any particular year. He further stated that Florida Public Utilities Company,[18] a gas distribution Company, had received Commission approval for an unfunded storm damage reserve liability. Witness Higgins stated that the Company proposed to accrue the amount annually to reduce the liability account for storms or significant weather. He stated that PGS proposed to limit the storm reserve liability to $1 million. When the balance is reached, PGS would stop accruing the annual expense.

According to witness Higgins, the Company provided a storm reserve analysis schedule which agreed to Exhibit 50 which was attached to his direct testimony. The storm analysis schedule included columns for the following: 1) employee expense which included employees travel, meals, or hotels; 2) outside contracted services; 3) fringes which follows PGS fringe allocation program including medical benefits, payroll taxes, and pension; 4) bonuses; and 5) other. He stated that the "other" was a catch-all category and was unsure as to the types of expenses included in this category. In addition, the calculated annual storm accrual is based on PGS expenditures for hurricanes and storms from 1998 through 2007 (10-years). He stated that the 10-year expenditures totaled $1,056,000, of which $900,000 were O&M expenses. Witness Higgins further stated that he abided by Commission Rule 25-6.0143, F.A.C., and removed "base pay."

In the calculation to establish a storm damage reserve, the Company used a 10-year simple average for O&M expense resulting in $69,454. Witness Higgins contended that a 5-year average of O&M expenses of approximately $133,000 was calculated. He further contended that this was based on 97 percent of the O&M expenses occurring in the past 5 years. The overall averaged cost for the storms was $101,500 ($69,454+$133,463/2), but the Company proposed

[18] Order No. PSC-05-1040-PAA-GU, issued October 25, 2005, in Docket No. 041441-GU, In Re: Petition for approval of storm cost recovery clause to recover storm damage costs in excess of existing storm damage reserve, by Florida Public Utilities Company.

$100,000. Witness Higgins stated that the bulk of the storm damage expenses incurred in 2004 and 2005. He testified that the Company contemplated filing a petition with the Commission to address storm costs because the expense incurred was relatively large. He further testified that "he did not recall the details", but "was not involved in the decision directly to not come before the Commission." During his deposition, witness Higgins stated the storm damage costs, which were summarized on Exhibit 50, were revised to remove straight time payroll and bonuses because of the storm reserve rule. He then asserted that the proposed annual storm accrual was recalculated and revised from $100,000 to $75,000.

OPC witness Schultz testified that the Company should not be allowed to establish an annual storm reserve in rates:

> First, the company assumes it will incur unusual an unpredictable costs in future in the future from storms even though there is no evidence that a significant level of storm costs will incur and produce damage. Secondly, the company is requesting that the reserve be unfunded.

OPC witness Schultz believes that an unfunded reserve would allow the Company to use it for any purpose. He asserted that the Company reviewed the storms costs, with the exclusion of straight-time payroll, for the last ten years, and averaged the costs to total $69,454; and then averaged the storms for five years to be $133,463. He stated the Company assumed a reasonable level of expense would be derived by averaging the totals of the 10-year and 5-year costs.

OPC argued that the Company's experience with storms does not support the need for a $1 million reserve or an accrual to establish one. OPC argued that the initial accrual was done on guesswork and not based on actuarial or scientific studies. OPC further argued that the estimate included costs that should not have been included causing the initial $100,000 accrual request to be trimmed to $75,000.

We examined the data PGS provided in Exhibit 50 and the storm reserve analysis schedule. For the period of 2004 through 2005, PGS experienced storm expenditures of approximately $961,000. For the 10-year period 1998 to 2007, the Company provided costs totaling $1,056,310 on the storm analysis schedule for payroll, bonuses, supplies, employee expense, outside service/TECO, fringe, other, and capital. The Company excluded straight-time payroll, bonuses, and capital expenditures from its calculations. We included in our calculations the following costs: overtime payroll ($164,674), supplies expense ($43,515), employee expense ($19,281), and outside services/TECO ($155,968). The Company provided a late-filed exhibit for our review. The exhibit contained a detailed breakdown of the expenses. Since the Company could not provide a breakdown of the costs for analysis we excluded fringe and other expenses. Based upon our recalculations and applying the Company's methodology, the storm damage accrual shall be $57,500.

We find that the Company shall be allowed to establish a storm damage reserve and the annual accrual shall be in the amount of $57,500. As a result, the proposed annual storm damage accrual of $100,000 shall be reduced by $42,500. A target level of $1,000,000 shall be established for the storm damage reserve, but no "cap" shall be imposed at this time.

I. Adjustments to Account 912, Demonstrating and Selling Expenses

In his testimony, PGS witness Higgins explained that the marketing expense was needed because PGS was focusing on signings in saturated areas on existing mains. A signing is when a customer signs a letter of intent to use PGS's gas service. This type of one-on-one marketing is more labor intensive and costly than signing customers in large developments as was done in the past. In rebuttal testimony, witness Higgins explained that the contract is not simply one that reflects new sales efforts that add customers, but also a contract that supports customer retention.

PGS's marketing services are provided by its affiliate, TECO Partners, Inc. ("TPI") Witness Higgins stated that the cost of services received under the current marketing contract has declined significantly since the Company's last rate case. The marketing contract expense in the filing for 2009 is $6.126 million, which includes variable expenses of $2.144 million attributed to the number of signings.

Witness Higgins further testified that the benchmark analysis calculated the historical 2007 sales expense as $12,785,270, compared to the 2007 historical sales expense of $5,419,540 in this filing. The benchmark analysis tool determines the appropriateness of O&M expenses, because O&M expenses should generally grow at a rate similar to customer growth and inflation. The benchmark analysis shows that the 2009 sales expense of $6,126,000 is a 52 percent reduction from the 2007 base year benchmark expense level of $12,785,270.

Witness Schultz testified that the marketing contract with TPI was effective January 1, 2008, and consisted of a fixed amount and a variable amount that is escalated annually by CPI. Witness Schultz questioned the total cost of the contract and, in particular, the monthly installments of $216,666 for a total of $2.6 million per year. The total amount paid each year is adjusted to reflect the number of "New Signings" that is greater or less than the target level of 12,000. Witness Higgins agreed that this contract was not competitively bid, but testified that if the targeted goal of 12,000 signings was not reached, the payment amount would be decreased as it was in 2008.

Witness Schultz asserted that even with PGS's marketing contracts, there was only an increase of 593 customers based on a year end count or 1,298 customers based on an average basis for the year. Witness Schultz concluded that, based on the customer growth in this filing, there is no justification to compensate TPI for the unachieved 2009 increase in new customer signings. Witness Schultz also concluded that it appears that the affiliate, TPI, is being compensated based on gross additions, and not net additions, which would include customer losses. Therefore, PGS is paying TPI for keeping Peoples at a gross level of customers, and not taking into account customer losses.

In rebuttal testimony, witness Higgins explained a customer may not start using the gas service the same year of the signing. For example, the signing of a development of a housing project may happen a few years before the construction is completed or homeowners take occupancy. Therefore, a "New Signing" is not a reflection of the gross number of customers or net number of customers added, but rather the intent of the customers to use PGS's gas service

In cross-examination, Witness Higgins agreed that the definition of "New Signings" means executed Gas Service Agreements, executed Builder or Developer Agreements, or any other form of agreements as required by Peoples to establish natural gas service. Witness Higgins stated that this definition does not identify whether the "New Signings" are gross or net customer additions, just that it relates to customers signings.

Witness Higgins explained that the 1,298 customers on an average basis for the year could have included the customer losses because the Utility usually loses 10,000 customers per year. Witness Higgins agreed that the average in new signings for 2003-2007 was 9,720.

We believe that it is necessary for the Utility to market the use of natural gas in order to inform the public and bring in additional revenues to maintain the cost of service at a reasonable level. The signing document is a useful tool to motivate customers, developers and organizations to commit to PGS gas service. In addition, a target goal of 12,000 signings is unrealistic in today's economy.

Therefore, we find that an adjustment to the target goal is warranted even if the payment to TPI can be adjusted for the number of actual signings. We find that the target goal shall be the average number of signings for 2003-2007, which is 9,720 or 81 percent of the target goal of 12,000. This average number is more realistic because of the downturn in the real estate market.

Witness Higgins stated that there were $2.144 million in variable expenses. We find that an adjustment shall be made to reflect the reduction in signings to the five-year average. As the five-year average of signings is 81 percent of the target goal of 12,000 signings, the variable expenses shall be reduced by 19 percent or $407,360. Therefore, we find that an adjustment to reduce Account 912, Demonstrating and Selling expenses by $407,360 to reflect a five-year average of customer signings shall be made.

J. Directors and Officers Liability Insurance

In his direct testimony, OPC witness Schultz testified that Directors and Officers Liability Insurance (DOL) protects the directors and officers from personal liability for bad and/or questionable decisions, and ultimately protects the shareholders. Witness Schultz explained that in the event that litigation occurred the shareholders could make a claim against the insurance company and receive the benefit of the insurance policy. Witness Schultz explained the officers and directors are compensated for their time and their traditionally generous compensation benefit packages are considered sufficient compensation for directors, and officers. Therefore, witness Schultz states that the officers compensated should pay for the DOL Insurance, because the DOL provides no benefit and/or protection to the ratepayers. Further, witness Schultz testified that ratepayers have no say in the choice of officers and directors and insurance company.

Witness Schultz asserted that $342,000 should be excluded from the rates. He testified that if we want to allow some of the DOL Insurance, the expense should be limited to the 2003 level of expense of $167,955 because the cost of insurance doubles to $386,684 in 2007. Lastly, witness Schultz stated that unless it is shown that DOL Insurance does benefit ratepayers, the escalation in costs due to general corporate misdeed should not be borne by the ratepayers

PGS witness Higgins testified that witness Schultz did not have any studies or information to support his claim that the compensation packages are sufficient compensation for directors and officers for their services absent DOL Insurance expense. Witness Higgins explained that DOL Insurance expense is required to attract and retain qualified individuals in these valuable roles. Witness Higgins stated that corporate surveys indicate that virtually all publicly traded entities maintain DOL Insurance. Lastly, witness Higgins explained that DOL Insurance provides a significant source of balance sheet protection from losses and from lawsuits and preserves the capital for the efficient and continuous delivery of gas service to customers.

Witness Higgins explained that the DOL Insurance premiums fluctuate because of the same market forces that impact the premiums for property, liability, worker's compensation, and other insurance policies. The significant changes that influenced the price of DOL insurance premiums from 2002 to 2007 were the negative claims from the "dot com" stock market bubble, the September 11 terrorist attacks, the Enron collapse, and the Sarbanes-Oxley legislation. Witness Higgins anticipates that the premiums will increase in the future because of the negative market influences from the current financial market distress. Also, witness Higgins stated that the 2009 projected DOL Insurance expense is reasonable and prudent because this type of insurance is based on expected market conditions.

Lastly, witness Higgins stated that no DOL Insurance expense needed to be removed because all of the DOL Insurance expense of $337,000 is included in the TECO Energy allocated expenses to Peoples. In its response to OPC's Interrogatory No. 44, Peoples submitted a schedule of Peoples' insurance premiums, not a schedule of Peoples' expenses on its books and records. In this schedule, the 2009 DOL Insurance was listed as $342,000. Therefore, there is no direct DOL Insurance expense in the MFR filing to remove from Peoples and there is no double dipping for this expense.

DOL Insurance is a part of doing business for any company or organization. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain DOL Insurance including investor owned gas utilities. We do not agree with OPC that the ratepayers do not benefit from DOL Insurance. Without DOL Insurance, it is unrealistic that the Company could operate effectively. Moreover, being served by a large Company helps ratepayers in a number of ways including easier access to the capital markets for their service provider. Lastly, even though the increase more than doubled between $167,955 in 2003 to $386,684 in 2007, we believe that the negative claims from the "dot com" stock market bubble, the September 11 terrorist attacks, the Enron collapse, and the Sarbanes-Oxley legislation justified the increase in premiums. We find that to apply the expense incurred in 2003 for setting rates in today's market would be inappropriate. The projected DOL Insurance of $342,000 will be difficult to maintain at the 2009 level of DOL Insurance expense because of the negative insurance market influence due to today's economic conditions.

DOL Insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers without it. Moreover, ratepayers receive benefits from being part of a large public company, including, among other things, access to capital. In addition, DOL Insurance is necessary to protect the ratepayers from allegations of corporate misdeeds. We also believe that it would be difficult for PGS to obtain DOL Insurance at the 2003 expense level and maybe even at that the requested 2009 expense level because of the current market conditions. Therefore, DOL insurance shall be included in the projected test year and no adjustment shall be made to reduce or remove DOL Insurance. Furthermore, the DOL Insurance recovered through the TECO allocated expenses to Peoples is also appropriate.

K. Adjustments to Costs Allocated by TECO to PGS

In his direct testimony, OPC witness Schultz stated that Account 921 included $6,722,093 of charges from TECO Electric and $4,671927 of charges from TECO Energy. Witness Schultz explained that TECO Energy allocated costs to Peoples including costs for incentive compensation, restricted stock grants and stock options, and DOL insurance, for an estimated total of $1,261,437. This estimated total of $1,261,437 was calculated by multiplying 89.75 percent (ratio of 2007 allocated costs to the 2009 allocated costs) times total costs of $1,495,546 for incentive compensation, restricted stock grants and stock options, and DOL insurance. Witness Schultz explained that all of these costs should be removed based on OPC's recommended adjustments in the individual issues.

In rebuttal testimony, PGS witness Higgins acknowledged that OPC witness Schultz recognized that the expenses allocated from TECO Energy to PGS were lower in the 2009 projected test year than in the 2007 historical base year. Based on his recognition, witness Schultz's proposed adjustment was reduced by the percentage decrease from 2007 to 2009. An adjustment was made by PGS in Exhibit 8 to decrease TECO's allocated compensation expense by $26,500. This decrease is necessary to reflect the appropriate 2009 merit increases.

On the basis of the foregoing, an adjustment shall be made to reduce TECO Electric's allocated payroll expense by $26,500 to reflect the change in 2009 merit increase guidelines.

L. Taxes Other Than Income Taxes

Based on our findings above, the requested Taxes Other Than Income Taxes expense of $10,823,933 shall be increased by $7,500 resulting in an adjusted total of $10,831,433 for the 2009 projected test year. See Schedule 3.

M. Parent Debt Adjustment

Rule 25-14.004, F.A.C., provides that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." Further, Rule 25-14.004(3), F.A.C., states that "it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure." Rule 25-14.004(4), F.A.C., provides that:

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

In MFR Schedule C-26, PGS provided some of the information required to calculate the parent debt adjustment, but did not include an adjustment to income tax expense to reflect the parent debt in the calculation of its requested revenue requirement. In Interrogatory No. 18, Commission staff requested that the Company provide the financial information necessary to make a parent debt adjustment in accordance with Rule 25-14.004, F.A.C. The Company provided the following information:

Debt Ratio of the parent	19.01%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	$167,473,246

In its response, the Company also provided an alternative set of data, which it labeled "Company Position," as follows:

Debt Ratio of the parent	0%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	$0 - $108,843,000

In its response, PGS reiterated its objection to the application of the parent debt adjustment in this case, as expressed in the testimony of PGS witness Gillette.

Witness Gillette testified that TECO Energy has $400 million of long term debt on its books. Witness Gillette also stated that this debt is related to TECO Energy's investment in its failed TPS merchant power projects, and that TECO Energy did not raise debt to invest in PGS. In its response to Interrogatory No. 18, the Company stated that between 1998 and 2003, TECO Energy raised approximately $3.4 billion dollars of external capital, including approximately $2.1 billion in debt. PGS asserted that the bulk of this capital was invested in TPS and other unregulated subsidiaries; however, PGS also stated that $119 million ($109 million if adjusted to reflect the external dividends of TECO Energy) was invested in PGS during this timeframe.

In direct testimony, OPC witness Schultz stated that the Company failed to include a detailed analysis to show how all parent debt was specifically used. Further, witness Schultz stated that, absent such a detailed analysis, the Company's statement that none of the existing debt was used to fund any equity infusions to PGS does not meet the Company's burden to rebut the presumption that a parent debt adjustment should be made, pursuant to Rule 25-14.004(3), F.A.C.

We agree with OPC that the Company has not effectively rebutted the presumption that the parent debt adjustment should be applied in this case. In ruling that a parent debt adjustment was required in a case involving Indiantown Company, Inc., this Commission stated:

> Based on our analysis, the rule requires that a parent debt adjustment be made in this proceeding. Further, the rule does not allow for specific identification of debt from the parent to the subsidiary utility. Since the utility is included in the consolidated income tax returns of the parent, we believe that it would be very difficult to prove specific identification to only the utility. Rule 25-14.004(3), Florida Administrative Code, states that it shall be a rebuttable presumption that a

> parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.[19]

Rule 25-14.004, F.A.C., is based on the premise that debt at the parent level supports a portion of the parent's equity investment in the utility. Since the interest expense on such debt is deductible by the parent for income tax purposes, the income tax expense of the regulated subsidiary is reduced by the tax effect. Further, we find that the Company has not demonstrated that the interest on the debt on TECO Energy's books can be attributed to any source other than the general funds of the parent.

Accordingly, we find that the parent debt adjustment shall be applied in this case and that the elements of the computation shall be based on the projected test year capital structures of TECO Energy and PGS. Our calculation of the system income tax expense reduction is as follows:

Debt Ratio of parent		.1901
Debt Cost Rate of parent	x	.069
	=	.0131169
Consolidated Tax Rate	x	.38575
	=	.005059844
Subsidiary Equity	x	$167,473,246
Parent Debt Adjustment	=	$847,389

Therefore, we find that the Company has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 14.004, F.A.C. Further, the appropriate subsidiary equity amount to be used in the calculation is the projected test year equity of $167,473,246. Accordingly, the appropriate jurisdictional adjustment is a reduction of income tax expense in the amount of $847,389.

N. Income Tax Expense, ITC Amortization, and Interest Synchronization

Based on our findings above, the requested total income tax expense of $9,204,185 (current, deferred, and ITC) should be increased by $15,901 resulting in an adjusted total of $9,220,086 for the 2009 projected test year. (See Schedule 3).

Amount Requested	$9,204,185
Commission Adjustments:	
Issue 39 – Parent Debt	(847,389)
Effect of Other Adjustments	809,233
Interest Synchronization	54,057

[19] See Order No. PSC-00-2054-PAA-WS, issued October 27, 2000, in Docket No. 990939-WS, In re: Application for rate increase in Martin County by Indiantown Company, Inc.

Total Commission Adjustments	15,901
Commission Adjusted Amount	$9,220,086

O. Projected Test Year O&M Expense

Based on our findings above, the appropriate level of O&M expense for the 2009 projected test year is $72,124,723. See Schedule 3.

P. Projected Test Year Depreciation and Amortization Expense

We examined the depreciation and amortization expense of the Company for 2009 to determine the appropriate projected test year amount. We made several adjustments thereto. The effect of the adjustments is to reduce the projected depreciation and amortization expense of $43,804,733 by $113,640 to $43,691,093 for the 2009 projected test year.

Q. Total Operating Expenses

The appropriate level of Total Operating Expenses for the 2009 projected test year is $135,387,014. (See Schedule 3).

R. Net Operating Income

Based onour findings above, the appropriate Net Operating Income for the 2009 projected test year is $36,019,112. (See Schedule 3).

VI. REVENUE REQUIREMENTS

The appropriate annual operating revenue increase for the 2009 projected test year is $19,152,365. The following schedule shows the calculation of the revenue requirements.

Calculation of Revenue Requirements December 31, 2009 Test Year		
	PGS	**COMMISSION**
Rate Base Rate of Return	$563,599,436 x 8.88%	$560,844,757 x 8.50%
Required NOI Adjusted Achieved NOI	$50,060,255 (33,944,697)	$47,671,804 (36,019,112)
NOI Deficiency Revenue Expansion Factor	$16,115,558 x 1.6436	$11,652,692 x 1.6436
Total Revenue Increase	$26,488,091	$19,152,365

VII. RATES

A. Customer Charges

The appropriate customer charges are shown in Schedule 6. The current residential customer charge is $10. The cost of service study indicates that the customer unit cost for the residential class is $15. Pursuant to an approved stipulation, Peoples received approval to stratify the current single residential service class into three classes (RS-1, RS-2, RS-3) depending on annual usage. For small users, such as RS-1 customers, the customer charge is a large percentage of the monthly bill. Our approved RS-1 customer charge is $12, thus mitigating the bill impact on those small users. Our approved customer charge for the RS-2 class is $15. The RS-3 class is available for large residential gas users, with multiple gas appliances, and the approved $20 customer charge is a small percentage of the monthly bill. The aforementioned customer charges, in conjunction with the proposed distribution charges, result in reasonable bill impacts across the entire residential class.

The customer charge for the residential standby generator (RS-GS) rate is $20, which is equal to the RS-3 customer charge. The RS-GS customer charge includes usage up to 20 therms. Usage above 20 therms is billed at the RS distribution charge. Similarly, the customer charge for the commercial standby generator (CS-GS) rate is set at the at the GS-1 customer charge of $35. The $35 customer charge includes therm usage up to 40 therms per month; usage above 40 therms is billed at the GS-1 therm charge. In addition, we grant our staff authority to administratively approve the tariffs filed to implement all Commission-approved rates and charges in this docket.

B. Per Therm Distribution Charges

The appropriate per therm distribution charges are shown in Schedule 6. The distribution charges are set at a level which, in combination with the customer charge, will result in the recovery of the total base revenues allocated to each rate class.

C. Gas System Reliability Rider (GSR Rider)

PGS proposed a new GSR Rider that would allows PGS to recover from its customers, through a surcharge, certain relocation and safety related costs, beginning in January 2010. Specifically, the GSR Rider is designed to recover two types of costs: revenue requirements associated with certain eligible infrastructure system replacements, and incremental O&M expenses incurred to comply with federal transmission and distribution pipeline integrity requirements.

The proposed GSR Rider tariff defines "eligible replacements" as:

1. mains, service lines, regulator stations, and other pipeline components installed to comply with state or federal safety requirements as replacements for existing facilities;

> 2. main and service line projects extending the useful life or enhancing the integrity of the pipeline components, undertaken to comply with state or federal safety requirements; and
>
> 3. facility relocations due to construction or improvement of a highway, road, street, public way or other public work by or on behalf of a government or other entity having the power of eminent domain, to the extent costs of the project are not reimbursed to PGS.

In addition to the eligible replacements listed above, PGS witness Binswanger testified that PGS anticipates being faced with incremental O&M expenses incurred to comply with federal transmission and distribution pipeline integrity requirements. Witness Binswanger referred to two new federal acts that could impact PGS: the Pipeline Safety Act of 2002, and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act). The Pipeline Safety Act addresses transmission lines, and the PIPES Act addresses distribution systems. Witness Binswanger explained during the hearing that PGS is currently doing an assessment for transmission facilities in place; however, the guidelines on distribution systems have not been fully implemented yet.

In its brief, PGS asserted that a GSR Rider would be an appropriate mechanism for the recovery of revenue requirements associated with government-mandated investments for relocation of its facilities and O&M expenditures, neither of which the Company has any control over. The Company also would have no ability to recover these costs absent the filing of a petition for new base rates or for a limited proceeding. Currently, relocation costs are only recovered during a base rate proceeding. Witness Binswanger testified that for the years 2004 through 2007, there were total capital expenditures of $17.6 million for government-mandated relocations, for which PGS received no revenues through which to recover the associated depreciation, ad valorem tax expenses, or a return on its investment in the replacement facilities.

PGS explained that it is standard practice for the Company to install facilities at the edge of public rights-of-way, which are substantially less expensive than the installation of facilities on private property. Installing in public rights-of-ways, however, subjects the Company to the requirements of federal, state, and local governmental statutes and regulations requiring the relocation of facilities when ordered to do so. For example, an entity may be re-routing or widening a road, installing water or wastewater lines, or reconfiguring an intersection, thereby necessitating the relocation of PGS facilities. PGS stated that in most instances, the Company must replace or relocate its facilities as part of the agreement to use the right-of-way without reimbursement in order to continue to meet its obligations.

PGS Witness Binswanger testified in his direct testimony that since the Company proposed that certain costs are included in the 2009 projected test year, no item would constitute an eligible replacement unless installed on or after January 1, 2010. Specifically, PGS has proposed to include in the test year $750,000 of O&M expenses for pipeline integrity costs, which were addressed previously in this order. Witness Binswanger testified that any reduction in O&M expense for transmission and distribution pipeline integrity below what is allowed in the projected test year in this case would reduce the revenue requirement to be required through the GSR Rider. PGS also proposed to include $3.8 million of relocation costs in the projected test year. In his deposition, witness Binswanger clarified that there would be a similar reduction in the revenue requirement to be recovered through the GSR Rider if capital expenditures for relocations are less than what was allowed in the projected test year.

Witness Binswanger explained that if we approve the GSR Rider, PGS's first petition for GSR Rider factors would be filed late in 2009, and would be based on eligible investments projected to be placed in service and incremental expenses to be incurred by the Company during 2010. The charges resulting from the 2009 filing would be included on customers' bills commencing in January 2010. PGS would again file petitions in 2010, which would recalculate the charges to recover the revenue requirement based on eligible costs for both 2010 and 2011, as adjusted by projected true-ups of the initially projected 2010 revenue requirements.

OPC objects to the formation of the GSR Rider for several reasons. In its brief, OPC stated that it has grave concerns about whether we possess the authority from the legislature to establish a mechanism to recover non-volatile, non-fuel, base rate costs. OPC stated that at the present time there are two true capital cost recovery mechanisms that the Commission administers: the Environmental Cost Recovery Clause and the Nuclear and IGCC Cost Recovery Clause. Both those clauses were authorized and established by the Florida Legislature. OPC further stated that the other clause mechanism that we have established on our own are almost exclusively expense-related.

OPC stated that PGS has acknowledged that no other company in Florida has a rider like the GSR Rider. OPC argued in its brief that the two electric cases PGS cites as precedent were resolved by the Commission approving a stipulated settlement and thus the cases cited by PGS do not establish a precedent for the creation of the GSR Rider in the instant case.

Apart from the legal concerns, OPC also stated in its brief that there are strong policy and factual reasons not to grant the requested relief regarding the GSR Rider. OPC Witness Schultz testified in his direct testimony that he disagrees with PGS' contention that it will not recover those costs outside of base rate relief unless it receives this annual rate increase. Witness Schultz stated that as long as the Company earns sufficient net income to keep its overall rate of return within its authorized range, the Company will recover its investment in these costs.

Furthermore, OPC witness Schultz disagreed with PGS's assertion that the government-mandated relocation costs incurred by the Company have been substantial. The average capital costs for relocation projects for the years 2003-2007 was $4.28 million, which is less than 10 percent of the Company's $44.8 million capital cost over the same time period. With respect to the pipeline integrity costs, witness Schultz stated that PGS already petitioned to include $750,000 in the test year, and that there is uncertainty about whether the Company would ever spend over the $750,000. Finally, witness Schultz testified that the GSR Rider will have no positive impact on the management of the investments associated with the relocation of facilities and safety expenses. Witness Schultz expressed concern that an annual recovery mechanism will not provide management incentive to reduce costs or seek proper reimbursement of these costs because it will allow for the automatic pass-through of costs.

While FIGU did not sponsor a witness on this issue, FIGU objects to the GSR Rider in its brief. FIGU stated that line relocations have been going on since PGS began to locate its lines in public rights-of-way at no cost. FIGU argued that line relocations do not trigger rate cases because the cost of relocations is more than offset by the money customers pay each year to cover depreciation.

We find that the adoption of a GSR Rider is not appropriate in this matter. However, we recognize that PGS may petition this Commission pursuant to 366.076, F.S., for a limited proceeding for the recovery of revenue requirements associated with government-mandated investments for relocation of PGS's facilities and O&M expenditures. Limited proceedings are narrow in scope and are designed to avoid the greater expenditure of time and resources typically associated with a full base rate proceeding. A limited proceeding is normally processed as a PAA in which a point of entry will be afforded to substantially interested persons to address concerns they may have regarding the petition. Historically, relocation costs have been recovered during full base rate proceedings. In order to mitigate regulatory lag and to ensure the timely recovery of those corporate expenditures for government-mandated relocations, in the absence of the adoption of a the GSR Rider discussed herein, we recognize that PGS may seek to recover costs expended pursuant to its compliance with government-mandated relocations via limited proceedings under 366.076, F.S.

D. Carbon Reduction Rider (CRR)

PGS has proposed a new cost recovery mechanism to collect, on a more timely basis, costs associated with extending supply mains to facilitate use of natural gas in new residential subdivisions. Extending gas lines consists of two basic operations: the extension of the supply main from the pipeline to a point close to the service location, and the installation of distribution mains and service lines necessary to provide gas to end users. The costs for distribution mains and service lines are collected through base rates, from developers, or through a Main Extension Program surcharge on bills of end users. The costs of supply mains currently is recovered only during a base rate proceeding.

The CRR "is designed to address, manage, and encourage the expansion of natural to new [residential] developments that are not located near interstate pipelines or existing Company supply mains." In determining whether serving a new area is cost effective, PGS stated that it evaluates several factors. PGS obtains information on potential load by meeting with developers, and reviewing land use maps and zoning criteria. The approximate time of build-out is also important in determining the time frame over which PGS can expect to recover the costs of extending facilities. One significant cost consideration is whether the potential end users are located near an interstate pipeline or a PGS supply main. If not, PGS must build a supply main to reach the area. PGS asserts that, unlike a distribution main and services, a supply main produces no direct revenue, but without it, potential revenue-producing customers cannot access natural gas.

PGS maintains that economically extending natural gas facilities to more areas in Florida accomplishes several goals. Witness Binswanger noted that natural gas is an extremely important source of energy for Florida because it is environmentally friendly, efficient, domestically produced, and more reliable during hurricanes. Witness Binswanger further stated that expanding natural gas availability in the state is consistent with Executive Order 07-127, and the Omnibus energy legislation contained in House Bill 7135. PGS has identified over 25 areas in the state which it believes could be served by natural gas, if the supply mains were in place. However, financial constraints discourage extension of facilities because the recovery of those costs may be delayed over long periods due to build-out of new developments, or until the Company's next rate case.

The CRR would recover the revenue requirements[20] associated with supply mains installed to reach one or more new developments. Recovery under the CRR would be limited to installations of mains greater that four inches in diameter, or which are certified to operate at 60 pounds per square (psi) or greater, and which serve company distribution systems serving primarily residential customers.

CRR factors would be filed with, and approved at the same time as, other cost recovery factors each year. The costs would be allocated to rate classes consistent with the cost of service methodology approved in PGS's last rate case. Collection of the CRR for each project would continue for five years, or until PGS's next base rate case. The five year period is consistent with how costs are recovered under the existing Main Extension Program (MEP) surcharge for distribution facilities.

OPC objects to the CRR because it believes expansion revenue should be sufficient to pay for all of the facilities necessary to achieve new load. The new customers will be paying the same rates as the old customers and that, in theory, should be sufficient to cover the cost of new plant and operating expenses. The fact that Florida is not seeing the aggressive growth of prior years, plus the fact that PGS has not been in for a general rate increase since 2002, indicates that PGS is currently recovering such costs. OPC witness Schultz further stated that the average capital cost under the rider for year 2005 through 2007 cited by PGS is $436,943, which is not significant enough to justify a new clause. In addition, OPC noted that PGS has been earning within its approved rate of return range for prior years in which PGS said it incurred similar costs of supply mains.

OPC Witness Schultz noted several drawbacks to the CRR. He believes implementation of this rider (and the GSR) constitutes single issue ratemaking without appropriate oversight. He asserted that the more certain costs are subject to recovery through some form of recovery mechanism, the less the Company is required to establish control over costs and the risk of managing costs is reduced. He also maintained that the addition of two new clauses, on top of the six existing cost recovery clauses, will create additional workload for this Commission and its staff in what was designed to be a streamlined, expedited process. In addition, Witness Schultz noted PGS has not included a reduction in ROE to recognize the reduction in risk of recovering capital costs between rate cases. Shareholder risk should be reduced because of the automatic pass-through; therefore a similar reduction would need to be made in the allowed rate of return to account for the reduced risk. OPC noted that Exhibit 92 demonstrates that PGS has been able to achieve a more favorable regulatory rating than every other member of the proxy group - many of which have cost recovery clauses.

[20] Revenue requirements are defined by PGS as the Company's weighted average cost of capital, depreciation expense, and ad valorem taxes, grossed up for federal and state income taxes.

OPC also questions our authority to create new clauses, such as the GSR and CCR, to recover non-volatile, non-fuel, base rate costs. Other than statutorily-created environmental cost recovery mechanisms in Florida, and a statutorily created rider in Missouri, PGS has not cited any authority or precedent to support the adoption of such clauses. In addition, OPC noted that other clauses are industry specific, not utility specific, and are almost exclusively expense-related. Only after experience and familiarity have certain ad hoc capital costs been allowed for clause recovery.

FIGU took no position on the CRR in its prehearing statement because it did not believe it would be subject to the CRR. It modified its position in its post-hearing brief to oppose the CRR. Although FIGU still does not think its members are affected by the CRR, it believes adoption of such a clause is bad regulatory policy. FIGU argued that PGS competes with it parent, TECO for revenues from new subdivisions. By shifting the cost of expanding the PGS system from PGS to its existing customers, the revenue loss experienced by PGS and its parent, TECO, is mitigated at the expense of PGS customers. FIGU also noted that PGS's arguments on regulatory lag are overstated. Regulatory lag exists not only in recovery of capital expenditures, but also in recognition of depreciation, which reduces rate base and thus costs to be recovered from customers.

PGS currently has mechanisms in place to recover a portion of costs incurred as a result of requests from customers seeking service. The costs of extending distribution facilities is either recovered in base rates, or, if costs exceed estimated revenues, through a surcharge to the customers directly benefitting from the extension. The MEP provides for the collection of costs associated with dedicated residential and commercial infrastructure that exceed the amount included in base rates.[21] PGS maintains, however that these cost recovery mechanisms only recover distribution lines to a specific customer or development. The proposed CRR is designed to recover the cost of supply mains which may be extended to serve multiple developments within a common geographical area. The CRR would only recover costs associated with mains in excess of four inches in diameter or which are certified to operate at a maximum of sixty pounds psi. Further, the revenue for any one project would only be collected for the first five years following installation.

Absent the CRR, PGS does not directly collect any of the cost of supply mains until customers begin taking service. Witness Binswanger testified that PGS has identified over 25 projects representing over 100,000 new customers which would require extension of supply mains. PGS estimated that, had the CRR been available in 2008, approximately $609,805 would have been eligible for collection under the CRR mechanism. Specifically, PGS cited two major projects, Ave Maria University and Town Center (total cost $4.3 million), and Nocatee St. Johns County planned community ($420,000), which did not go forward because of the costs. However, OPC noted in its brief that PGS filed a revised capital budget just prior to hearing, noting that Nocatee is shown as a new 2009 development project. OPC said this revision casts doubts on the Company's judgment relative to the extension of viable development, as well as demonstrating that the lack of the CCR may not be the true reason the Nocatee development did not go forward as planned.

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[21] See Tariff Sheets 5.601 through 5.601-2 Mains and Service Extensions, and Tariff Sheets 7.101-7 through 7.101-9, Main Extension Program.

Our primary concern is that PGS would be encouraged to extend facilities with only speculative prospects of customers, if it could immediately recover the revenue requirements associated with supply mains through a cost recovery clause. In discovery, OPC asked if projects recoverable through the CRR would be subject to our pre-approval. PGS's response did not answer the question directly. Instead, it said that PGS would file a petition requesting approval of the billing factors to be installed in the upcoming year. According to PGS, "the Commission would have the opportunity to thoroughly review and audit the company's filings and make necessary adjustments." This implies that this Commission could check the calculations, but that the Utility would not specifically seek Commission approval of the projects, per se. This lack of review of the prudence of the projects gives us pause in passing these costs on the ratepayers through a clause. It is also unclear whether we would have any opportunity for review and possible disallowance of projects in future rate cases, once such projects were included for cost recovery through the clause.

We do not take issue with the benefits associated with the use of natural gas cited by witness Binswanger. Nor do we disagree that expansion of natural gas availability may be consistent with state efforts to reduce green house gas emissions. However, we find that too few safeguards have been included to ensure that supply main extensions recovered through the CRR are viable, revenue-producing assets. We agree with OPC's assessment that expansion of facilities should be cost-effective at current rates. Extension of supply mains under the CRR does not require that there be any actual customers asking for gas service. Facilities may be extended to make gas available to encourage developers to install gas facilities in new developments in the future. PGS argued that developers will not even consider natural gas, if no supply main is in place.

If the expected pay-back period for a project is not sufficient for PGS to commit its internal funds, we question whether it is prudent to commit ratepayer funds to such projects. If PGS can recover the revenue requirements associated with any such investment, it has little incentive to either minimize costs, or ensure that the expansion is prudent and will generate revenue in a reasonable time frame. If there are no upfront costs to PGS for extending facilities where there are currently no customers, it might also encourage PGS to extend supply main facilities simply to claim territory for future growth, without reasonable expectations of revenue producing customers in the shorter term. The ability to claim territory by extending service mains without concern for concurrent revenue may create more territorial disputes, and disadvantage utilities which do not have the ability to immediately pass on such costs. The ability to avoid the upfront costs (and delay) of installing supply mains to serve a development makes it more attractive for developers to seek service from PGS over an adjacent utility, who does not have the ability to pass on such costs on an annual basis, even when other costs may indicate a different choice.

We also agree with OPC and FIGU that approval of the CCR may constitute imprudent regulatory policy. The purpose for all existing cost recovery clauses is to allow utilities to recover costs which are volatile and which are outside the control of the utility. Decisions on when and where to expand facilities are entirely under the control of the utility. PGS's management, not ratepayers, should bear the cost and responsibility for decision on expansion of the Utility. We also agree with OPC that we should move cautiously in approving collection of capital costs outside a rate case. OPC notes that the Legislature has already seen fit to explicitly address other areas where capital costs have been approved for recovery outside a rate case. If expansion of gas infrastructure is necessary or desirable to meet state goals as noted by witness Binswanger, it may be more appropriate for PGS to seek legislative approval first.

For the foregoing reasons, we find that PGS has not demonstrated the need for treatment of these costs outside a rate proceeding. Further, we find that there are insufficient safeguards built into the Carbon Reduction Rider, as proposed, to adequately protect ratepayers from imprudent expenditures. PGS's request if therefore denied.

VIII. OTHER ISSUES

A. Refund of Interim Rate Increase Granted by Order No. PSC-08-0696-PCO-GU to Ratepayers

By Order No. PSC-08-0696-PCO-GU, issued October 20, 2008, we authorized the collection of interim rates, subject to refund, pursuant to Section 366.071, F.S. The approved interim revenue requirement was $171,383,000, which represents an increase of $2,380,000 or 1.54 percent. The interim collection period is November 2008 through June 2009.

According to Section 366.071, F.S., any refund shall be calculated to reduce the rate of return of the utility during the pendency of the proceeding to the same level within the range of the newly authorized rate of return. Adjustments made in the rate case test period that do not relate to the period interim rates are in effect shall be removed. Rate case expense is an example of an adjustment which is recovered only after final rates are established.

In this proceeding, the test period for establishment of interim is the 12-month period ending April 30, 2008. PGS's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of actual interest costs, and the lower limit of the last authorized range for return on equity.

To establish the proper refund amount, we calculated a revised interim revenue requirement utilizing the same data used to establish final rates for the 2009 projected test year. Items, such as rate case expense and the storm damage accrual, were excluded because these items are prospective in nature and did not occur during the interim collection period. Using the principles discussed above, because the $171,383,000 revenue requirement, granted in Order No. PSC-08-0696-PCO-GU, for the April 2008 interim test year, is less than the revenue requirement for the interim collection period of $190,176,226, we find that no refund is required. Further, upon the expiration of the period for appeal, the corporate undertaking shall be released.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Peoples Gas System's Petition for Rate Increase is granted in part and denied in part as set forth herein. It is further

ORDERED that each of the findings made in the body of this Order are hereby approved in every respect. It is further

ORDERED that Peoples Gas System is authorized to charge the new rates and charges as set forth in the body of this Order and the attachments and schedules attached hereto. It is further

ORDERED that all matters contained in the appendix, attachments, and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that Peoples Gas System's request for the establishment of a Gas System Reliability Rider is hereby denied. It is further

ORDERED that Peoples Gas System's request for the establishment of a Carbon Reduction Rider is hereby denied. It is further

ORDERED that no refund of the interim increase approved by Order No. PSC-08-0696-PCO-GU, issued October 20, 2008, shall be required. It is further

ORDERED that the rates and charges approved in this Order shall become effective for meter readings made on or after June 18, 2009, which is 30 days from the date of the final Commission vote approving the rates and charges. It is further

ORDERED that Peoples Gas System shall submit, within 90 days of the issuance date of this Order, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. It is further

ORDERED that upon expiration of the period for appeal this docket shall be closed.

By ORDER of the Florida Public Service Commission this 9th day of June, 2009.

Ann Cole

ANN COLE
Commission Clerk

(S E A L)

CMK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

APPENDIX 1: STIPULATED ISSUES AND PARTIALLY STIPULATED ISSUES

The approved stipulations fall within one of two categories, as listed below. "Category 1" stipulations reflect the agreement of PGS, Staff, and at least one of the intervenors in this docket. Intervenors who have not affirmatively agreed with a particular Category 1 stipulation but otherwise take no position on the issue are identified in the proposed stipulation. "Category 2" stipulations reflect the agreement of PGS and Staff where no other party has taken a position on the issue.

CATEGORY 1 STIPULATIONS:

ISSUE 12: What is the appropriate 2009 projected test year Working Capital Allowance?

Stipulation: The appropriate 2009 projected test year Working Capital Allowance is ($11,494,371). (FIGU does not affirmatively stipulate this issue but takes no position on the issue.)

ISSUE 16: What is the appropriate cost rate of long-term debt for the projected test year?

Stipulation: The appropriate cost rate of long-term debt for the projected test year is 7.20%.

ISSUE 19: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the projected test year?

Stipulation: The appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the projected test year are $7,862 and 0%, respectively, as shown on MFR Schedule G-3, page 2. (FIGU does not affirmatively stipulate this issue but takes no position on the issue.)

ISSUE 45: What is the appropriate projected test year revenue expansion factor to be used in calculating the revenue deficiency?

Stipulation: The appropriate projected test year revenue expansion factor to be used in calculating the revenue deficiency is 1.6436. (FIGU does not affirmatively stipulate this issue but takes no position on the issue.)

ISSUE 48: What is the appropriate cost of service methodology to be used in allocating costs to the rate classes?

Stipulation: The appropriate methodology is contained in revised MFR Schedule H, and should reflect the Commission-approved adjustments to rate base, expenses, rate of return, and net operating income. (OPC does not affirmatively stipulate this issue but takes no position on the issue.)

ISSUE 58: Should PGS 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, earnings surveillance reports, and books and records which will be required as a result of the Commission's findings in this docket?

Stipulation: Yes. PGS should 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 which will be required as a result of the Commission's findings in this rate case. (FIGU does not affirmatively stipulate this issue but takes no position on the issue.)

ISSUE 59: Should this docket be closed?

Stipulation: Yes. This docket should be closed after the Commission has issued its final order and the time for filing an appeal has expired.

CATEGORY 2 STIPULATIONS:

ISSUE 2: Are the projected bills and therms for the test year ending December 31, 2009, appropriate for use in this case?

Stipulation: Yes. The projected bills and therms for the test year ending December 31, 2009 are appropriate for use in this case.

ISSUE 3: Is the quality of gas service provided by PGS adequate?

Stipulation: Yes.

ISSUE 21: Has PGS made the appropriate test year adjustments to remove revenues and expenses recoverable through the Purchased Gas Adjustment Clause?

Stipulation: Yes.

ISSUE 22: Has PGS made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause?

Stipulation: Yes.

ISSUE 27: Should any adjustments be made to the 2007 O&M expenses for staff Audit Finding Nos. 1 and 2, to address out-of-period expenses, reclassifications, and non-utility expenditures?

Stipulation: Yes. Adjustments should be made to the 2007 O&M expenses to remove out-of-period, reclassifications, and non-utility expenses. Based on these trended adjustments, 2009 Office Supplies and Expenses, Account 921, should be reduced by $18,853 and Miscellaneous General Expenses, Account No. 930.2 should be reduced by $5,007.

ISSUE 47: Are PGS's estimated revenues by rate class at present rates for the projected test year appropriate?

Stipulation: Yes. PGS's estimated revenues by rate class at present rates for the projected test year are appropriate.

ISSUE 51: What are the appropriate Miscellaneous Service Charges?

Stipulation: The appropriate revised miscellaneous service charges are as follows:

Service Charge	Commission Approved
Account Opening Charge	$28
Service Initiation Charge - Residential	$50 for initial meter
Service Initiation Charge - Other	$30 for each additional meter
Reconnection Charge - Residential	$70 for initial meter
Reconnection Charge - Other	$20 for each additional meter
Temporary Meter Turn-off Charge	$20
Failed Trip Charge	$25

ISSUE 52: Is PGS's proposal to stratify its current single residential service class into three individual classes appropriate?

Stipulation: Yes. The proposal allows the Company to recover a greater proportion of fixed customer-related costs indicated by the allocated cost of service study through customer charges, while at the same time managing the potential bill impacts for individual customers to reasonable levels. Absent establishing the three billing classes, the bill impacts associated with increasing fixed cost recoveries through the customer charge would be too large for smaller residential customers that use natural gas for fewer appliances. (Yardley)

ISSUE 53: Is PGS's proposal to reclassify certain customers appropriate?

Stipulation: Yes. Redefining the GS-1 class (presently 1,000-17,500 annual therms) by moving the smallest GS-1 customers (up to 1,999 annual therms) into an expanded SGS rate class and moving the largest GS-1 customers (above 10,000 annual therms) into an expanded GS-2 rate class is appropriate to provide greater homogeneity and reduce the potential for intra-class subsidies.

At present all residential customers take service under the RS rate. The reclassification of a limited number of large residential customers addresses a separate issue, which relates to common areas of condominiums. Such use is considered residential even though the characteristics of the load are similar to use by larger GS customers. By expanding the eligibility of the GS-1 through GS-5 rate schedules to include residential use, the largest residential customers are included with similarly-situated non-residential customers for pricing purposes. An additional benefit of this approach is that it clarifies the rights of condominium units to purchase their gas supply from a third-party pursuant to the Company's transportation service program. The deposit terms and conditions associated with residential service would continue to apply to condominium customers that are reclassified to a GS rate schedule.

ISSUE 56: What is the appropriate effective date for PGS's revised rates and charges?

Stipulation: 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 which, under the current schedule, would mean for meter readings taken on or after June 18, 2009.

PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
13-MONTH AVERAGE RATE BASE
DECEMBER 2009 TEST YEAR

SCHEDULE 1

Issue No.		Plant in Service & Acquisition Adjustment	Accumulated Deprec., Amort. & Customer Adv.	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	991,124,849	(434,280,486)	556,844,363	18,249,444	0	575,093,807	(11,494,371)	563,599,436
	Commission Adjustments								
5	Plant & Accumulated Depreciation	(1,959,308)	(795,371)	(2,754,679)	0	0	(2,754,679)	0	(2,754,679)
7	Non-Utility Operations	0	0	0	0	0	0	0	0
8	CWIP Amount	0	0	0	0	0	0	0	0
9	Total Plant	0	0	0	0	0	0	0	0
10	Accumulated Depreciation	0	0	0	0	0	0	0	0
12-S	Total Working Capital Allowance	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
				0			0		0
				0			0		0
				0			0		0
				0			0		0
				0			0		0
---	Total Commission Adjustments	(1,959,308)	(795,371)	(2,754,679)	0	0	(2,754,679)	0	(2,754,679)
13	Commission Adjusted Rate Base	989,165,541	(435,075,857)	554,089,684	18,249,444	0	572,339,128	(11,494,371)	560,844,757

SCHEDULE 2

PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2009 TEST YEAR

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	273,561,565	48.54%	11.50%	5.58%
Long-term Debt	222,773,987	39.53%	7.20%	2.85%
Short-term Debt	3,456,397	0.61%	4.50%	0.03%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	36,128,943	6.41%	6.65%	0.43%
Deferred Income Taxes	27,670,682	4.91%	0.00%	0.00%
Tax Credits - Zero Cost	7,862	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	0	0.00%	0.00%	0.00%
Total	563,599,436	100.00%		8.88%
Equity Ratio	54.74%			

Staff Adjusted	($) Amount	($) Specific Adjustments	($) Pro Rata Adjustments	($) Commission Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	273,561,565	0	(1,507,776)	272,053,789	48.51%	10.75%	5.21%
Long-term Debt	222,773,987	0	(1,227,853)	221,546,134	39.50%	7.20%	2.84%
Short-term Debt	3,456,397	0	(19,050)	3,437,347	0.61%	3.02%	0.02%
Preferred Stock	0	0	0	0	0.00%	0.00%	0.00%
Customer Deposits	36,128,943	0	0	36,128,943	6.44%	6.65%	0.43%
Deferred Income Taxes	27,670,682	0	0	27,670,682	4.93%	0.00%	0.00%
Tax Credits - Zero Cost	7,862	0	0	7,862	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	0	0	0	0	0.00%	9.11%	0.00%
Total	563,599,436	0	(2,754,679)	560,844,757	100.00%		8.50%
Equity Ratio	54.74%			54.74%			

Interest Synchronization	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Dollar Amount Change					
Long-term Debt	(1,227,853)	7.20%	(88,405)	38.575%	34,102
Short-term Debt	(19,050)	3.02%	(575)	38.575%	222
Customer Deposits	0	6.65%	0	38.575%	0
					34,324
Cost Rate Change					
Short-term Debt	3,456,397	-1.48%	(51,155)	38.575%	19,733
Tax Credits - Weighted Cost	0	9.11%	0	38.575%	0
					19,733
TOTAL					54,057

PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
NET OPERATING INCOME
DECEMBER 2009 TEST YEAR

SCHEDULE 3

		Operating Revenues	O&M Gas Cost	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	169,906,126	0	72,608,899	43,804,733	10,823,933	9,204,185	(480,321)	135,961,429	33,944,697
	Commission Adjustments:									
2-S	Projected Bills and Therms	0	0	0	0	0	0	0	0	0
5	Depreciation	0	0	0	(113,640)	0	43,837	0	(69,803)	69,803
7	Non-Utility Operations	0	0	0	0	0	0	0	0	0
21-S	PGA Revenues & Expenses	0	0	0	0	0	0	0	0	0
22-S	ECCR Revenues & Expenses	0	0	0	0	0	0	0	0	0
23	Off-System Sales Revenues	1,500,000	0	0	0	7,500	578,625	0	586,125	913,875
24	Total Operating Revenues	0	0	0	0	0	0	0	0	0
25	Appropriate O&M Trend Rates	0	0	0	0	0	0	0	0	0
26	O&M Trend Rate Adjustments	0	0	0	0	0	0	0	0	0
27-S	Audit Findings Nos. 1 and 2	0	0	(23,860)	0	0	9,204	0	(14,656)	14,656
28	A&G Salaries (920)	0	0	(253,300)	0	0	97,710	0	(155,590)	155,590
29	Rate Case Expense	0	0	(78,875)	0	0	30,426	0	(48,449)	48,449
30	Bad Debt Expense - Gas Cost	0	0	0	0	0	0	0	0	0
31	Bad Debt Expense	0	0	723,580	0	0	(279,121)	0	444,459	(444,459)
32	Employee Pensions & Benefits (926)	0	0	(125,361)	0	0	48,358	0	(77,003)	77,003
33	Pipeline Integrity Expense	0	0	(250,000)	0	0	96,438	0	(153,563)	153,563
34	Storm Damage Accrual	0	0	(42,500)	0	0	16,394	0	(26,106)	26,106
35	Demonstrating & Selling Exp. (912)	0	0	(407,360)	0	0	157,139	0	(250,221)	250,221
36	Directors and Officers Liability Ins.	0	0	0	0	0	0	0	0	0
37	Allocation of TECO Costs	0	0	(26,500)	0	0	10,222	0	(16,278)	16,278
38	Taxes Other Than Income	0	0	0	0	0	0	0	0	0
39	Parent Debt Adjustment	0	0	0	0	0	(847,389)	0	(847,389)	847,389
40	Total Income Tax Expense	0	0	0	0	0	0	0	0	0
41	Total O&M Expense	0	0	0	0	0	0	0	0	0
42	Total Depreciation & Amortization Exp.	0	0	0	0	0	0	0	0	0
43	Total Operating Expenses	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	54,057	0	54,057	(54,057)
	Total Commission Adjustments	1,500,000	0	(484,176)	(113,640)	7,500	15,901	0	(574,415)	2,074,415
44	Commission Adjusted NOI	171,406,126	0	72,124,723	43,691,093	10,831,433	9,220,086	(480,321)	135,387,014	36,019,112

SCHEDULE 4

PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
DECEMBER 2009 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) Commission Adjusted
1	Revenue Requirement	100.0000	100.0000
2	Gross Receipts Tax	0.0000	0.0000
3	Regulatory Assessment Fee	(0.5000)	(0.5000)
4	Bad Debt Rate	(0.4511)	(0.4511)
5	Net Before Income Taxes	99.0489	99.0489
6	Income Taxes (Line 5 x 38.575%)	(38.2081)	(38.2081)
7	Revenue Expansion Factor	60.8408	60.8410
8	Net Operating Income Multiplier (100%/Line 7)	1.6436	1.6436

SCHEDULE 5

PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
DECEMBER 2009 PROJECTED TEST YEAR
REVENUE REQUIREMENTS CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$563,599,436	$560,844,757
2.	Overall Rate of Return	8.88%	8.50%
3.	Required Net Operating Income (1)x(2)	50,060,255	47,671,804
4.	Achieved Net Operating Income	33,944,697	36,019,112
5.	Net Operating Income Deficiency (3)-(4)	16,115,558	11,652,692
6.	Net Operating Income Multiplier	1.64360	1.64360
7.	Operating Revenue Increase (5)x(6)	$26,488,091	$19,152,365

SCHEDULE 6
Page 1 of 4

PEOPLES GAS SYSTEM
PRIOR TO INTERIM, APPROVED INTERIM, AND APPROVED RATES
DOCKET NO. 080318-GU

RATE CODE	RATE SCHEDULE	PRIOR TO INTERIM	APPROVED INTERIM RATES effective 10/29/08	APPROVED RATES effective 5/18/09
RS-1	RESIDENTIAL			
	CUSTOMER CHARGE	$10	$10	$12
	DISTRIBUTION CHARGE (cents/therm)	37.667	39.034	26.782
RS-2	RESIDENTIAL			
	CUSTOMER CHARGE	$10	$10	$15.00
	DISTRIBUTION CHARGE (cents/therm)	37.667	39.034	26.782
RS-3	RESIDENTIAL			
	CUSTOMER CHARGE	$10	$10	$20
	DISTRIBUTION CHARGE (cents/therm)	37.667	39.034	26.782
SGS	SMALL GENERAL SERVICE			
	CUSTOMER CHARGE	$20	$20	$25
	DISTRIBUTION CHARGE (cents/therm)	26.955	28.099	33.894
GS-1	GENERAL SERVICE - 1			
	CUSTOMER CHARGE	$30	$30	$35
	DISTRIBUTION CHARGE (cents/therm)	23.045	23.497	26.800
GS-2	GENERAL SERVICE - 2			
	CUSTOMER CHARGE	$35	$35	$50
	DISTRIBUTION CHARGE (cents/therm)	22.267	22.636	22.746
GS-3	GENERAL SERVICE - 3			
	CUSTOMER CHARGE	$45.00	$45.00	$150.00
	DISTRIBUTION CHARGE (cents/therm)	19.533	19.843	19.670
GS-4	GENERAL SERVICE - 4			
	CUSTOMER CHARGE	$85	$85	$250
	DISTRIBUTION CHARGE (cents/therm)	17.828	18.107	15.215
GS-5	GENERAL SERVICE - 5			
	CUSTOMER CHARGE	$150	$150	$300
	DISTRIBUTION CHARGE (cents/therm)	10.041	10.199	11.321
CSLS	COMMERCIAL STREET LIGHTING SERVICE			
	CUSTOMER CHARGE	n/a	n/a	n/a
	DISTRIBUTION CHARGE (cents/therm)	12.829	13.026	18.859
NGVS	NATURAL GAS VEHICLE SERVICE			
	CUSTOMER CHARGE	$35	$35	$45
	DISTRIBUTION CHARGE (cents/therm)	14.013	14.250	18.392
RS-SG	RESIDENTIAL STANDBY GENERATOR SERVICE			
	CUSTOMER CHARGE	$17.82	$17.82	$20
	DISTRIBUTION CHARGE (cents/therm)	37.667 (>20.8 therms)	37.667	26.782 (>20 therms)
CS-SG	COMMERCIAL STANDBY GENERATOR SERVICE			
	CUSTOMER CHARGE	$27.67	$27.67	$35
	DISTRIBUTION CHARGE (cents/therm)	26.955 (>28.6 therms)	26.955	33.894 (>40 therms)
WHS	WHOLESALE SERVICE - FIRM			
	CUSTOMER CHARGE	$100	$100	$150
	ENERGY CHARGE (cents/therm)	13.622	13.840	14.934
SIS	SMALL INTERRUPTIBLE SERVICE			
	CUSTOMER CHARGE	$150	$150	$300
	DISTRIBUTION CHARGE (cents/therm)	7.227	7.340	7.131
IS	INTERRUPTIBLE SERVICE			
	CUSTOMER CHARGE	$225	$225	$475
	DISTRIBUTION CHARGE (cents/therm)	3.522	3.576	3.491
ISLV	INTERRUPTIBLE SERVICE - LARGE VOLUME			
	CUSTOMER CHARGE	$225	$225	$475
	DISTRIBUTION CHARGE (cents/therm)	1.002	1.021	0.996

PEOPLES GAS SYSTEM

DOCKET NO. 080318-GU
BILL COMPARISONS - PRESENT & APPROVED RATES
RS-1
Annual Consumption 0-99 Therms

PRESENT RATES	APPROVED RATES
Customer Charge $10.00	Customer Charge $12.00
Distribution Charge (Cents per therm) 37.667	Distribution Charge (Cents per therm) 26.782
Purchased Gas Costs 2009 (Cents per therm) 95.533	Purchased Gas Costs 2009 (Cents per therm) 95.533
Conservation (Cents per therm) 2.438	Conservation (Cents per therm) 2.438

Therm Usage Increment: 1

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Approved Monthly Bill w/o Gas Cost	Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
1	$10.40	$11.36	$12.29	$13.25	18.2%	16.6%	$1.89
2	$10.80	$12.71	$12.58	$14.50	16.5%	14.1%	$1.78
3	$11.20	$14.07	$12.88	$15.74	15.0%	11.9%	$1.68
4	$11.60	$15.43	$13.17	$16.99	13.5%	10.1%	$1.57
5	$12.01	$16.78	$13.46	$18.24	12.1%	8.7%	$1.45
6	$12.41	$18.14	$13.75	$19.49	10.8%	7.4%	$1.34
7	$12.81	$19.49	$14.05	$20.73	9.7%	6.4%	$1.24
8	$13.21	$20.85	$14.34	$21.98	8.6%	5.4%	$1.13
9	$13.61	$22.21	$14.63	$23.23	7.5%	4.6%	$1.02

Purchased Gas Costs effective May 2009.
Bills do not include local taxes, franchise fees, or gross receipts taxes.

PEOPLES GAS SYSTEM

DOCKET NO. 080318-GU
BILL COMPARISONS - PRESENT & APPROVED RATES
RS-2
Annual Consumption 100-249 Therms

PRESENT RATES	APPROVED RATES
Customer Charge $10.00	**Customer Charge** $15.00
Distribution Charge (Cents per therm) 37.667	**Distribution Charge** (Cents per therm) 26.782
Purchased Gas Costs 2009 (Cents per therm) 95.533	**Purchased Gas Costs 2009** (Cents per therm) 95.533
Conservation (Cents per therm) 2.438	**Conservation** (Cents per therm) 2.438

Therm Usage Increment: 2

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Staff Approved Monthly Bill w/o Gas Cost	Staff Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
10	$14.01	$23.56	$17.92	$27.48	27.9%	16.6%	$3.91
12	$14.81	$26.28	$18.51	$29.97	25.0%	14.0%	$3.70
14	$15.61	$28.99	$19.09	$32.47	22.3%	12.0%	$3.48
16	$16.42	$31.70	$19.68	$34.96	19.9%	10.3%	$3.26
18	$17.22	$34.41	$20.26	$37.46	17.7%	8.9%	$3.04
20	**$18.02**	**$37.13**	**$20.84**	**$39.95**	**15.6%**	**7.6%**	**$2.82**
22	$18.82	$39.84	$21.43	$42.45	13.9%	6.6%	$2.61

Purchased Gas Costs effective May 2009.
Bills do not include local taxes, franchise fees, or gross receipts taxes.

SCHEDULE 6
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PEOPLES GAS SYSTEM
DOCKET NO. 080318-GU
BILL COMPARISONS - PRESENT & APPROVED RATES
RS-3
Annual Consumption 250-1,999 Therms

PRESENT RATES	APPROVED RATES
Customer Charge $10.00	Customer Charge $20.00
Distribution Charge (Cents per therm) 37.667	Distribution Charge (Cents per therm) 26.782
Purchased Gas Costs 2009 (Cents per therm) 95.533	Purchased Gas Costs 2009 (Cents per therm) 95.533
Conservation (Cents per therm) 2.438	Conservation (Cents per therm) 2.438

Therm Usage Increment: 20

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Approved Monthly Bill w/o Gas Cost	Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
20	$18.02	$37.13	$25.84	$44.95	43.4%	21.1%	$7.82
40	$26.04	$64.26	$31.69	$69.90	21.7%	8.8%	$5.65
60	$34.06	$91.38	$37.53	$94.85	10.2%	3.8%	$3.47
80	$42.08	$118.51	$43.38	$119.80	3.1%	1.1%	$1.30
100	$50.11	$145.64	$49.22	$144.75	-1.8%	-0.6%	-$0.89
120	$58.13	$172.77	$55.06	$169.70	-5.3%	-1.8%	-$3.07
140	$66.15	$199.89	$60.91	$194.65	-7.9%	-2.6%	-$5.24
160	$74.17	$227.02	$66.75	$219.60	-10.0%	-3.3%	-$7.42

Purchased Gas Costs effective May 2009
Bills do not include local taxes, franchise fees, or gross receipts taxes.

	TOTAL	RESIDENTIAL SERVICE	RESIDENTIAL GENERATOR	COMMERCIAL STREET LIGHTING	COMMERCIAL GENERATOR	(1 - 1,999) SMALL GENERAL SERVICE	(2,000 - 9,999) GENERAL SERVICE 1	(10,000 - 49,999) GENERAL SERVICE 2	(50,000 - 249,999) GENERAL SERVICE 3
PRESENT RATES (Projected Test Year)									
GAS SALES (due to growth)	162,561,427	59,391,044	153,109	115,660	262,976	5,046,880	20,534,619	30,498,072	15,303,329
OTHER OPERATING REVENUE	8,844,698	7,115,713	16,635	1,890	23,766	312,860	399,935	181,954	24,837
TOTAL	171,406,125	66,506,757	169,744	117,551	286,742	5,359,740	20,934,554	30,680,026	15,328,166
RATE OF RETURN	6.42%	3.18%	18.86%	0.81%	2.25%	4.52%	6.44%	8.79%	8.47%
INDEX	1.00	0.50	2.94	0.13	0.35	0.70	1.00	1.37	1.32
PROPOSED RATES									
GAS SALES	180,777,977	71,788,774	171,840	170,027	332,640	5,900,693	22,946,884	31,842,979	16,191,879
OTHER OPERATING REVENUE	9,780,513	8,031,862	18,777	1,925	24,202	318,605	407,279	185,295	25,293
TOTAL	190,558,490	79,820,635	190,617	171,953	356,842	6,219,298	23,354,163	32,028,275	16,217,172
TOTAL REVENUE INCREASE	**19,152,365**	**13,313,878**	**20,872**	**54,402**	**70,101**	**859,558**	**2,419,609**	**1,348,249**	**889,006**
PERCENT INCREASE	11.17%	20.02%	12.30%	46.28%	24.45%	16.04%	11.56%	4.39%	5.80%
RATE OF RETURN	**8.50%**	**8.48%**	**24.13%**	**8.50%**	**9.99%**	**8.50%**	**8.50%**	**8.75%**	**8.75%**
INDEX	1.00	1.00	2.84	1.00	1.18	1.00	1.00	1.03	1.03

	(250,000 - 499,999) GENERAL SERVICE 4	(500,000 +) GENERAL SERVICE 5	(1,000,000 - 3,999,999) SMALL INTERRUPTIBLE SERVICE	(4,000,000 - 50,000,000) INTERRUPTIBLE SERVICE	(50,000,000 +) INTERRUPTIBLE LARGE VOLUME	NATURAL GAS VEHICLE SALES	WHOLESALE SERVICE	SPECIAL CONTRACTS
PRESENT RATES (Projected Test Year)								
GAS SALES (due to growth)	7,839,571	6,691,956	3,568,425	4,773,640	1,531,163	66,369	228,759	6,555,855
OTHER OPERATING REVENUE	3,691	343,416	113,991	86,486	56,119	450	330	162,623
TOTAL	7,843,262	7,035,372	3,682,416	4,860,127	1,587,282	66,819	229,089	6,718,478
RATE OF RETURN	8.69%	6.18%	9.85%	12.53%	14.94%	-1.93%	6.87%	10.67%
INDEX	1.35	0.96	1.53	1.95	2.33	-0.30	1.07	1.66
APPROVED RATES								
GAS SALES	6,952,475	7,707,654	3,568,414	4,773,637	1,531,163	86,941	256,125	6,555,851
OTHER OPERATING REVENUE	3,759	343,473	114,006	86,494	56,120	458	336	162,628
TOTAL	6,956,234	8,051,127	3,682,420	4,860,132	1,587,283	87,400	256,462	6,718,478
TOTAL REVENUE INCREASE	**(887,028)**	**1,015,755**	**4**	**5**	**2**	**20,580**	**27,373**	**0**
PERCENT INCREASE	-11.31%	14.44%	0.00%	0.00%	0.00%	30.80%	11.95%	0.00%
RATE OF RETURN	**4.25%**	**8.50%**	**8.51%**	**11.19%**	**13.60%**	**2.62%**	**8.50%**	**9.33%**
INDEX	0.50	1.00	1.00	1.32	1.60	0.31	1.00	1.10