BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Peoples Gas System, Inc.	DOCKET NO. 20230023-GU
In re: Petition for approval of 2022 depreciation study, by Peoples Gas System, Inc.	DOCKET NO. 20220219-GU
In re: Petition for approval of depreciation rate and subaccount for renewable natural gas facilities leased to others, by Peoples Gas System, Inc.	DOCKET NO. 20220212-GU ORDER NO. PSC-2023-0388-FOF-GU ISSUED: December 27, 2023

The following Commissioners participated in the disposition of this matter:

ANDREW GILES FAY, Chairman
ART GRAHAM
GARY F. CLARK
MIKE LA ROSA
GABRIELLA PASSIDOMO

APPEARANCES:

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ORDER GRANTING IN PART AND DENYING IN PART
PEOPLES GAS SYSTEM, INC.'S PETITION FOR A RATE INCREASE

BY THE COMMISSION:

Table of Contents

Background

On April 4, 2023, Peoples Gas System, Inc. (PGS or Company) filed a petition seeking our approval of a rate increase and associated depreciation rates. PGS is a natural gas distribution company providing sales and transportation of natural gas, and is a public utility subject to our regulatory jurisdiction under Chapter 366, Florida Statutes (F.S.). PGS is a wholly-owned subsidiary of TECO Gas Operations, Inc. and provides service to approximately 470,000 customers in 39 of Florida's 67 counties.

PGS requested an increase of approximately $139.3 million in base rates. Of that amount, about $11.6 million is associated with revenue requirements transferred from the Cast Iron/Base Steel Replacement Rider. The remaining $127.6 million is necessary, according to PGS, for the Company to earn a fair return on its investment. PGS based its request on a 13-month average rate base of $2.4 billion for the projected test year ending December 31, 2024. The requested overall rate of return is 7.42 percent based on a mid-point return on equity (ROE) of 11.00 percent. The Company did not request an interim rate increase.

On December 15, 2022, PGS filed its petition in Docket No. 20220212-GU (RNG Depreciation Docket) seeking approval of a new depreciation rate and subaccount for renewable natural gas facilities leased to others. On December 28, 2022, PGS filed its petition seeking approval of the Company's 2022 Depreciation Study in Docket No. 20220219-GU (Depreciation Study Docket). On April 4, 2023, PGS filed a motion seeking to consolidate the RNG Depreciation Docket, the Depreciation Study Docket, and the rate proceeding in Docket No. 20230023-GU. By Order No. PSC-2023-0128-PCO-GU, issued April 12, 2023, the three dockets were consolidated. In Order No. PSC-2023-0157-PCO-GU, we suspended the proposed permanent increase in rates and charges.

PGS stated that even though it made efforts to increase cost savings and efficiency, PGS is expected to earn a return on equity of less than 8 percent in 2023, which places the Company at the bottom of its approved ROE range. PGS is seeking rate relief because of statewide growth and construction, higher depreciation expenses, changing pipeline safety and security regulations, higher inflation, and higher cost of capital in the financial markets.

The Company's last rate case, in Docket No. 20200051-GU, was resolved by our approval of a Stipulation and Settlement Agreement (2020 Agreement).[1] The 2020 Agreement allowed PGS to generate an additional $58 million in revenues for the projected test year ended December 31, 2021. The 2020 Agreement also authorized a return on equity of 9.90 percent. The 2020 Agreement will expire on December 31, 2023. It also authorized PGS to amortize $34 million of depreciation reserve surplus as a depreciation expense from 2020 through 2023.

By Order No. PSC-2023-0082-PCO-GU, we acknowledged intervention by the Office of Public Counsel (OPC). By Order No. PSC-2023-0129-PCO-GU, we granted intervention to the Florida Industrial Power Users Group (FIPUG). The two parties (collectively, "Joint Parties") filed a joint post-hearing brief.

We held two in-person service hearings in Pembroke Pines and Tampa on June 28 and June 29, 2023, respectively, and four virtual service hearings on July 10 and July 11, 2023. Out of the six customer service hearings, two customers expressed concerns over a potential rate increase. We also received letters from ten customers that were placed in correspondence in the docket. All of the customers urged us not to increase their gas rates during these financially challenging times and contended that the proposed rate increases are excessive and unreasonable.

An administrative hearing was held September 12-15, 2023. At the hearing, we approved Type 1 stipulations[2] and Type 2 stipulations[3] for certain issues, which are described throughout this order.[4]

Prior to filing for this rate case, the Company decided to move PGS out as a separate legal entity from Tampa Electric Company (TECO) in what will be discussed as the "2023 Transaction." The 2023 Transaction was effective on January 1, 2023, and restructured the Company so that TECO would no longer be a direct parent company of PGS. Both PGS and TECO are still under the umbrella of the same parent company, Emera Incorporated (Emera).

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[1]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*.
[2]A Type 1 stipulation occurs on an issue where the utility and intervenors agree on the resolution of the issue.
[3]A Type 2 stipulation occurs when the utility and our staff, or the utility and at least one party adversarial to the utility, agree on the resolution of the issue and the remaining parties (including our staff if they do not join in the agreement) do not object to us relying on the agreed language to resolve that issue in a final order.
[4]OPC's position on each Type 2 stipulation is as follows:

> OPC takes no position on these issues, nor does it have the burden of proof related to them. As such, the OPC represents that it will not contest or oppose the Commission taking action approving a proposed stipulation between the Company and another party or staff as a final resolution of the issue. No person is authorized to state that the OPC is a participant in , or party to a stipulation on these issues, either in this docket, in an order of the Commission or in a representation to a Court.

This order addresses the requested permanent rate increase. We have jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.06 and 366.071, F.S.

Decision

I. **Test Period and Forecasting**

A. Projected Test Year

i. Parties' Arguments

PGS witness Parsons stated that the Company selected the 2024 projected test year, comprised of the twelve-month period ending December 31, 2024, as the test year in this proceeding. Witness Parsons argued that utilizing the 2024 calendar year as the test year is appropriate because it is "representative of the Company's projected revenues and projected cost of service, capital structure and rate base required to provide safe, reliable, and cost-effective service to its customers during the period when the Company's new rates will be in effect." PGS also noted that there are "no pending or anticipated merger activities involving Peoples that would cast doubt on the reasonableness of the 2024 test year data or financial forecast." The Company proposed the new base rates become effective for the first billing cycle of January 2024.

The Joint Parties agree that with appropriate adjustments, the 2024 test year may be representative of the period of time in which rates will be in effect.

ii. Analysis

In general, a projected test year methodology is the process whereby a Company uses forecasted data for a twelve-month period to match its average revenues with its average expenses and average rate base investment for the same period. Witness Parsons testified that, with the exception of its accelerated preparation to meet the filing schedule for this rate case, PGS's 2024 projected test year was developed "using the same process used to develop the Company's annual budgets, including capital expenditure and income statement forecasts."

While the Joint Parties proposed adjustments to other issues, the Joint Parties did not cite any objections to the appropriateness of the 2024 test year itself. Further, the Joint Parties did not propose any alternative to the projected test year as proposed in this case for setting customer rates.

PGS's proposed 2024 test year will result in a matching of the Company's revenues to be produced during the first twelve months in which the new rates would be in effect, with average rate base investment and average expenses for the same period. Therefore, we find that the Company's projected test period of the twelve months ending December 31, 2024, is appropriate.

B. Customer and Therm Forecasts

At the hearing, we approved a type 2 stipulation as follows: The Company used linear regression models for both customer counts and average use for the test year. These models are both theoretically and statistically strong as measured by model coefficient and overall model fit statistics. The chosen modeling framework has been adopted by numerous utilities in the United States and Canada for forecasting.

C. Estimated Gas Revenues

At the hearing, we approved a type 2 stipulation as follows: Residential and small commercial customer and sales forecasts were used to estimate the 2024 test year revenues at current rates. These forecasts were prepared using theoretically and statistically strong models that have been adopted by numerous utilities in the United States and Canada for forecasting.

II. Quality of Service

A. Quality of Service

i. Parties' Arguments

In its brief, PGS argued that its quality of service is adequate. The Company highlighted that only two individuals spoke during the six customer service hearings, neither of which expressed a negative view of the Company's gas service. PGS witness Sparkman testified that the Company has an evolving strategy that is focused on customer service and simplified customer experiences, which has led to PGS receiving several industry awards for its customer service. Additionally, witness Sparkman argued that customer complaints filed with this Commission have decreased by approximately 43 percent in 2022 and PGS has not had any Commission infractions over the last seven years. The Company argued it has low complaint levels and PGS witness Wesley testified that the complaint levels of PGS are lower than those presented in the last rate cases of Florida City Gas (FCG) and Florida Public Utilities Company (FPUC).

The Joint Parties argued that the quality of service received by customers does not justify the magnitude of PGS's requested rate increase. In support of their argument, the Joint Parties referenced the testimony received at the customer service hearings, which highlighted the requested rate increase amount of PGS.

ii. Analysis

Pursuant to Section 366.041(1), F.S., in fixing rates we are authorized to give consideration, among other things, to the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered. We held two in-person service hearings in Pembroke Pines and Tampa on June 28 and June 29, 2023, respectively, and four virtual service hearings on July 10 and July 11, 2023. Out of the six customer service hearings, two customers expressed concerns over a potential rate increase. There was no customer testimony that posed any quality of service concerns. In addition, no intervening party witness addressed this matter in their prefiled testimony or during the hearing.

PGS serves approximately 470,000 customers. Staff witness Calhoun testified that from June 1, 2018, through May 31, 2023, 265 complaints were logged with us with 99 of those being transferred to PGS. The average of these complaints, 53 per year, results in an overall complaint rate of 0.01 percent per year. Of the 265 complaints, approximately 49 percent concerned billing issues, while approximately 51 percent involved quality of service issues. Additionally, witness Calhoun testified that of the 265 complaints, none appeared to demonstrate a violation of Commission Rules. To date, there were ten customer comments filed in the docket file, all of which expressed concerns regarding PGS's proposed rate increase.

Pursuant to Rule 25-7.018, Florida Administrative Code (F.A.C.), each utility shall keep a complete record of all interruptions affecting the lesser of 10 percent or 500 or more of its division meters. PGS provided two separate instances where this Rule applied. On June 13, 2022, a contractor failed to confirm the location of the gas main before commencing work. The contractor's directional drill damaged a 4-inch plastic main under Lutz Lake Fern Road and as a result, affected the service of 505 customers. PGS reported that it took approximately three days to restore 95 percent of the customers affected by this interruption. On September 27, 2022, the service of 823 customers was interrupted due to Hurricane Ian across the Sarasota and Ft. Myers divisions. Excluding Ft. Myers Beach (143 accounts), service was restored within 48 hours of the interruption or upon customer return. Both of these interruptions were beyond the control of the Company.

Based on a review of all witness and customer testimony and consideration of the information presented above, we find that the Company's quality of service is adequate.

III. Depreciation Study

A. Renewable Natural Gas (RNG) Subaccount, Depreciation Rate, and Implementation Date

At the hearing, we approved a type 2 stipulation as follows: We shall approve a new subaccount under Account 104 (Gas Plant Leased to Others) to be denominated "Account 336.01 – RNG Plant Leased – 15 Years" and a depreciation rate of 6.7 percent for that subaccount effective January 1, 2023. The proposed new depreciation rate will ensure that the cost recovery period for the Brightmark RNG Project (Section IV.F) will match the period over which the project will generate revenues, that the costs of the project will be removed by the time the customer takes ownership of the RNG plant assets at the end of the contract term and will prevent the Company from experiencing a gain or loss on the sale of the assets at the end of the contract term. The new subaccount will facilitate application of the new depreciation rate.

B. Vehicle Retirements

i. Parties' Arguments

PGS argued that, pertaining to the retirement of vehicles in the test year, no adjustment to the calculation of test year Net Operating Income (NOI) or rate base is needed. PGS explained that the Company did not include vehicle depreciation expense in the depreciation expense component of the 2024 test year NOI. PGS stated that it included the vehicle depreciation expense in a transportation cost allocation that was reflected in the test year Operation & Maintenance (O&M) Expense and capital expenditures. PGS further explained that including expected vehicle retirements in 2023 and 2024 would equally reduce plant in service and accumulated depreciation and would have the effect of slightly increasing test year rate base due to the lower depreciation expense in the test year.

PGS also argued that it has met the burden of proof of demonstrating the level of 2023 and 2024 vehicle expense is necessary for several reasons. These reasons all relate to the size of PGS's territory and the number of miles that must be driven by employees to maintain the safety and reliability of PGS's system.

The Joint Parties argued that the company did not reflect retirements associated with the replacement of older vehicles which has the effect of overstated rate base and depreciation expense over time. Given other compensating adjustments in allocations, this is no longer a contested issue.

ii. Analysis

PGS witness Parsons testified that the Company did not reflect vehicle retirements in Account 392.01 – Auto & Truck Less Than ½ Ton on MFR G-2, pages 23 and 26. She stated that PGS identified $1,706,817 of retirements for 2023 and $1,571,627 of retirements for 2024 that should have been reflected on MFR G-2 for that account. Witness Parsons further stated that reflecting these retirements would have the effect of reducing the 2024 test year depreciation expense (as derived from the depreciation study) by $243,046. However, witness Parsons explained that this reduction in depreciation expense would have had no impact on test year net operating income due to the fact that PGS charges vehicle depreciation expense "through a transportation cost allocation to O&M and capital expenditures and is not included in depreciation expense in determining NOI." We have verified that these retirements were not reflected in the MFRs, as well as the fact that no depreciation expense for Account 392.01 was included in the projected test year depreciation expense calculation.

With regard to NOI, witness Parsons further testified that neither the transportation cost allocation nor the FERC O&M budget were impacted by the potential increase in vehicle depreciation expense. Witness Parsons explained that the Company did not increase the transportation allocation to account for the increased vehicle depreciation expense in O&M, but instead simply trended the existing 2022 vehicle transportation costs forward for inflation and customer growth in areas that utilized the vehicles. Therefore, witness Parsons testified that the calculation of the test year NOI would not have been affected by any adjustment to vehicle retirements in the test year.

Separate from her explanation of the vehicle additions and retirement's effect on NOI, PGS witness Parsons also testified as to the effects of the vehicle retirements on rate base. Witness Parsons clarified that reflecting the vehicle retirements on MFR G-2 would equally reduce PGS's plant and reserve balances, thereby having no impact on rate base. Witness Parsons added that rate base could be slightly increased due to the lower test year depreciation expense that would result from the lower plant balances in Account 392.01. Witness Parsons also stated that since the increased vehicle depreciation expense was not factored into the 2023 and 2024 Capital Expenditures, there would be no rate base impacts due to the lower depreciation expense. Witness Parsons' Exhibit No. RBP-2, Document No. 8 shows the potential rate base and NOI impacts if vehicle retirements had been reflected in the MFRs.

In their position on this issue, the Joint Parties stated that the Company did not properly reflect retirements related to new vehicles. However, the Joint Parties further explained that due to other adjustments being made in this case, this issue is no longer contested.

iii. Conclusion

Both PGS and the Joint Parties took the position that vehicle retirements did not properly match vehicle additions in rate base. However, PGS stated that no adjustments are necessary, while the Joint Parties indicated this is no longer a disputed issue due to other compensating adjustments. Therefore, even though vehicle retirements do not match vehicle additions in rate base, no adjustments to net operating income or rate base are necessary because any corrective adjustments would be immaterial.

C. Depreciation Parameters

i. Parties' Arguments

PGS stated "the Commission should find that Mr. Watson's depreciation rates and parameters as presented in Exhibit 32, Document No. 3 are appropriate." The Company argued that these rates were calculated in accordance with the applicable Commission Rule, based on a Commission-approved methodology, and utilizing the most current data and information available. PGS stated that its witness Watson used the straight-line method, Average Life Group procedure, remaining life technique depreciation system to prepare PGS's instant depreciation study. The Company attested that witness Watson used the same methodology to prepare the study that was used by PGS and approved by us in the Company's last base rate case.

PGS contended that OPC witness Garrett did not perform his own depreciation study, but instead considered PGS's study and proposed extending the average service lives (ASL) of five plant accounts.[5] The Company argued that witness Garrett "only utilized one placement and

[5]Individual plant assets in an account do not normally have identical lives or investment amounts. An account's ASL is the average number of years that the assets in the account are expected to be in-service.

experience band to arrive at his service life recommendations, while depreciation treatises recommend the use of multiple bands."[6]

PGS further asserted that witness Garrett's choice to utilize a short placement band of the years 1983-2021 violates the principles of actuarial analysis by failing to analyze trends in service lives over time. Additionally, the Company argued that witness Garrett relied solely on the output of a statistical model and ignored company-specific experience and operational information, an inaccurate method for setting asset lives. PGS argued that, for each of these reasons, the Joints Parties' approach is unreasonable and we should reject its recommended adjustments to service lives.

The Joint Parties claimed that OPC witness Garrett correctly calculated the depreciation rates. Witness Garrett testified that he used a straight-line method, the average life procedure, the remaining life technique, and the broad group model to analyze the Company's actuarial data. The Joint Parties stated that witness Garrett recommended the adoption of different average service lives for five of the plant accounts based on his analysis of the best Iowa curve to fit the "observed life table" (OLT) curve; and he accomplished this analysis through a combination of visual and mathematical curve-fitting techniques, as well as professional judgement.[7]

Witness Garrett proposed longer lives for Accounts 37600 and 37602, respectively. The Joint Parties stated that witness Garrett focused his statistical analysis on the relatively newer vintages in Account 37600, because "the Company's bare steel replacement program that began around 2013, which focused on retiring assets from vintages spanning from the 1930s through the 1960s." The Joint Parties asserted that witness Garrett's choice of life-curve combination is a mathematically closer fit to the OLT curve than the Company's choice. The Joint Parties provided the same argument with respect to Account 37602, and asserted that witness Garrett's results showed his choice was a mathematically slightly closer fit to the OLT curve than the Company's choice.

For each of Accounts 37900, 38002 and 38200, witness Garrett also proposed a longer ASL than PGS. The Joint Parties argued that witness Garrett's results showed his choice was a mathematically closer fit to the OLT curve of Account 37900. Similarly, the Joint Parties also argued that witness Garrett's choices were a mathematically slightly closer fit to the respective OLT curve of Accounts 38002 and 38200 than the Company's choices.

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[6]A placement band is the vintages (a vintage refers to the year in which an asset was purchased) of plant assets that are being studied, and it is used to show the effects of technological and material changes over a specific era. An experience band means the transactions (such as retirements) that are happening over time to those vintage years of assets, and it is used to show the effects of business and operational changes during a set period.

[7]Iowa Curves, which depict the retirement distributions, published in Bulletin 125, *Statistical Analysis of Industrial Reporting*, published in 1935, by Robley Winfrey of the Iowa State College Engineering Experimental Station, are widely-accepted representations of utility property retirement patterns. These are well established depreciation tools. Each curve is denoted by a letter and number. The letter defines when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL while an R curve implies that retirements tend to occur after the ASL. The number portion of the Iowa Curve designation indicates how steep or flat the curve's shape is. For example, both R1 and R3 indicate that the majority of the retirements of the account are likely to occur after the ASL; and R3 curve indicates more retirements occur closer to the ASL, compared to R1 curve indicated.

While PGS witness Watson argued that witness Garrett only presented one band in his exhibits and work papers, he conceded that witness Garrett said he reviewed multiple placement and experience bands, and also conceded that his own study did not present all of the possible placement and experience bands for the accounts. The Joint Parties further argued that PGS witness Watson took issue with witness Garrett's lack of consideration of the subject matter experts' input, yet witness Watson himself "qualified his reliance on the Company's experts by saying he validates their opinions based on his own engineering experience and from doing theses studies for many years."

The Joint Parties asserted that "[g]iven that witness Watson has only testified on one or two occasions for a non-utility party, and he mostly develops depreciation studies while acknowledging that customer interests generally critique them, his observations may lack objectivity."

The Joint Parties concluded that witness Garrett's recommendations are "better fittings" of the Iowa Curve to the OLT curve both mathematically and also based on considerations of factors impacting the data.

ii. Analysis

In this proceeding, parties proffered various proposals of the depreciation parameters and resulting depreciation rates. Two of the proposals remain unresolved: (1) PGS's revised depreciation study filed July 2023, that is based on the actual and estimated activities and data of plant accounts ending December 31, 2023 (2023 Study), and (2) OPC's proposed adjustments to PGS's 2023 Study.

The remaining life depreciation rate of a plant account is designed to recover the remaining unrecovered plant balance over the remaining life of the associated investment in that account.[8] Rule 25-7.045(1)(e), F.A.C., prescribes the formula for determining this rate.[9]

For each of PGS's plant accounts, the Company's witness Watson proffered a proposal of an ASL with a specific curve (retirement dispersion) to determine the average remaining life (ARL) of the account, which, in turn, is used to calculate the remaining life depreciation rate of the account.[10] OPC witness Garrett also provided an ASL-curve proposal for each of the accounts. Table 1 shows the parameters for the five accounts in dispute between the two proposals:

[8]The remaining life depreciation rate is the type of depreciation rate we use for determining appropriate customer rates.
[9]Remaining Life Rate = (100% - Reserve % - Average Future Net Salvage %) ÷ Average Remaining Life in Years.
[10]An account's curve is a graphical representation of the retirement pattern for the plant assets of the account.

Table 1
Differences in Proposed Depreciation Parameters

Account No.	Account Title	Current		PGS Proposed (Watson)		OPC Proposed (Garrett)	
		ASL (yrs)	Curve Type	ASL (yrs)	Curve Type	ASL (yrs)	Curve Type
37600	Mains Steel	65	R1.5	65	R1.5	70	R1.5
37602	Mains Plastic	75	R2	75	R2	82	R2
37900	Meas & Reg Station Equip City	50	R2.5	52	R2	60	R2
38002	Services Plastic	55	R1.5	55	R2.5	62	R2
38200	Meter Installations	44	R1	45	R1.5	55	R0.5

Average Service Life and Curve

Our natural gas utility depreciation rule requires a gas company to conduct a depreciation study at least once every five years.[11] To determine an account's ASL for the coming five years, historical data as well as the prospective outlook for the account are considered. Actuarial analysis, also known as the Retirement Rate Method, is commonly used in evaluating historical asset retirement experience when vintage data is available and sufficient retirement activity is present. Historical data, including plant additions, retirements, and transfers, is organized by vintage and transaction year[12] to develop an OLT to depict the percentage of the assets surviving at each age interval.

The OLT is plotted as a survivor curve and the area under the curve represents the average life of the plant assets in the account being analyzed. An OLT curve is rarely smooth and typically incomplete due to plant assets in the account not reaching zero percent surviving yet.[13] However, in order to calculate a particular account's ARL, there must be a complete curve as well as an ASL. Standard mortality curves, such as the Iowa Curves, are used to compare with, or fit, the OLT curve for this purpose. The ASL and its associated best fitted Iowa Curve together describes the life estimate of the account. This ASL-curve combination, in turn, is used to calculate the ARL of the account. Data "bands" refer to the period of placement and experience years that are analyzed. They are used in this curve-comparing/fitting process to define what portion of the OLT curve is to be evaluated. The curve-fitting process is a critical step of the service life analysis, and involves a combination of visual and mathematical curve-fitting techniques, as well as professional judgment.

In this proceeding, both witness Watson and Garrett used the Retirement Rate Method in their service life analyses, but the historical data bands analyzed by each witness were different. Witness Watson claimed that he analyzed five or more placement and experience bands for each account at issue in the proceeding where sufficient retirement data exists. He testified that:

[11]Rule 25-7.045(4)(a), F.A.C.
[12]Transaction year is the year in which the asset was retired.
[13]An OLT curve is only ever complete when all assets within the data set being analyzed are retired.

> I ran an overall placement band with two experience bands: the overall experience band, 1983–2021, and 1997–2021 to isolate experience in those transaction years. I also ran the 1983–2021 placement band with the 1983–2018 and 1997–2021 experience bands. If sufficient data existed for life analysis, I also ran an overall band of 1997–2021.

Witness Garrett's life analysis used placement and experience bands with both bands being from 1983-2021. He testified that:

> While I also considered the other banding periods Mr. Watson presented, I focused on OLT curves under the 1983-2021 placement and experience bands because this time period strikes a good balance between considering a sufficient amount of data for analysis and considering relatively newer data. In this particular case, most of the accounts discussed below have been affected by asset replacement programs in which relatively newer assets may have different life characteristics than older assets. Thus, it can be instructive to focus on relatively newer vintage years when conducting analyses.

Witness Watson disagreed with witness Garrett. He asserted that witness Garrett's selection of the data bands supporting his life analysis has the following errors:

- Violates the principles behind actuarial analysis by only using one placement and experience band (thereby not analyzing trends in life through time).
- Discards relevant data in analyzing his single band by using a novel (non-industry standard) approach that cuts off and ignores Company-specific experience.
- Ignores both company-specific operational information and reasonable engineering expectations for the life of assets.

Witness Watson also contested that witness Garrett was not consistent in the placement and experience bands he relied on for his ASL recommendation:

- In the 2017 [PGS rate] case, witness Garrett did not specifically state the placement experience band used for each account, but it appears the placement band is the longest experience available from his Exhibits and workpapers.
- In the 2020 [PGS rate] case, witness Garrett used a non-existent experience band that included 12 or more years with no retirements as his only band.
- In this case, witness Garrett relied on placement and experience bands of 1983-2021 for his recommendations.

Witness Watson further argued against witness Garrett's life analysis and ASL recommendations as witness Garrett did not consider information from the Company's subject matter experts. He stated:

> The lives witness Garrett selected for the five accounts at issue are beyond what would reasonably be expected for the mix and types of assets within these accounts. If the majority of the dollars in a particular account are associated with assets that have projected lives between 20 and 40 years, an overall life for the account of 60 years for that account will not be reasonable. Simply recommending the output of a statistical model without validating against operational realities or reasonable norms is not an accurate way to set asset lives.

In responding to OPC's question whether he would agree that the Company subject matter experts are only giving their estimates with regard to different lives for different equipment, witness Watson expounded that, with their estimates, the experts are also "giving their understanding [of asset lives] based on operating those assets for many years." Witness Watson testified that there were two additional considerations which validated the estimates provided by the Company's experts. One consideration was witness Watson's own understanding as an engineer and his own understanding of the assets and their lives based on the number of depreciation studies he's conducted for many, many companies during his career. The second consideration that he included for validating the experts estimates was that the Company's opinions were in line with his expectations and the industry's expectations, concluding "they supported each other."

OPC also questioned whether witness Watson relied on the subject matter experts, the employees of PGS, for the Company's specific information to develop his curve. Witness Watson testified that he did not solely depend on such information, but instead he relied on the historical books and records of the Company to make his service life selection, and used the information from the experts to support the selection. He further expounds:

> I will look at the actual experience of the company, and I will understand if there are changes that are happening to the assets operationally that would impact what I would project, and also understand what's in the account and expected lives of the account.

Based on the record evidence discussed above, we find that the approach that witness Watson chose to perform his asset life analysis is more comprehensive than witness Garrett's approach. It is consistent with the core concept of the Retirement Rate Method and more comprehensively incorporates the assets' specific operational information which is important in the assets' life analysis.

The account-specific analysis for the five accounts in dispute between PGS and the Joint Parties follows:

Account 37600 – Distribution Mains Steel

The currently-approved ASL for this account is 65 years with a R1.5 curve, also denoted as 65 R1.5. PGS witness Watson proposed to retain these parameters. OPC witness Garrett proposed to increase ASL to 70 years with the same R1.5 curve. Witness Watson disagreed with witness Garrett's life proposal.

PGS personnel indicated that the driving forces of retirements for the account include inadequate capacity of the steel pipes since they were originally built when gas demand was not as prevalent as today's demand; some steel pipes have not been cathodically protected for their full life, and steel will corrode if scratched. Witness Watson asserted that witness Garrett's proposal "does not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]."

Regarding the curve-fitting process which determines the selected ASL-curve combination, witness Watson testified that his proposed combination was based on his evaluation of five different placement and experience bands. He argued that "witness Garrett only examines one band for his proposal," and pointed out that "[a]s stated in NARUC's *Public Utility Depreciation Practices*, it is important to look at different placement bands and experience bands." He further averred that "[b]y selecting only one band (and having the errors discussed earlier), witness Garrett's analysis doesn't fully analyze or accurately represent the Company's historical experience." Witness Watson also asserted that the OLT witness Garrett used in life analysis is not long enough to meet criteria recommended by authoritative texts that witness Garrett quoted himself.

In previous dockets, witness Garrett recommended a 55 R2 life for this account and a 65 R1.5 life for this same account.[14] Witness Watson claimed that "[i]t does not seem logical that three years later, these same assets would last 7.7 percent longer than witness Garrett's recommendation [that] he supported less than three years ago – especially when he does not speak to any operational reason for the change."[15]

We reviewed all the graphical curve-fitting presentations together with all the data and information proffered by both witnesses. We find that witness Watson's life analysis is more persuasive, and a 65 R1.5 life proposal is reasonable for the account at this point in time, because it is derived from an appropriate depreciation asset life analysis and incorporated with the Company-specific assets' operational information, and within the range of other Florida gas utilities. We also note that an ASL of 65 years is within the industry's current ASL range for this account, which is 40 to 65 years with an average of 56 years.[16]

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[14]Docket No. 20160159-GU, *In re: Petition for approval of settlement agreement pertaining to Peoples Gas System's 2016 depreciation study, environmental reserve account, problematic plastic pipe replacement, and authorized ROE;* Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*.
[15](70 – 65) / 65 = 7.7%
[16]The industry's current ASL range is determined based upon Order Nos. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*; PSC-2022-0153-PAA-GU, issued April 22, 2022, in Docket No. 20210183-GU, *In re: Petition for approval of 2021 depreciation study, by Sebring Gas System;* PSC-2023-0103A-FOF-GU, issued April 6, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division*; PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*; and PSC-2023-0215-PAA-GU, issue July 26, 2023, in Docket No. 20230022-GU, *In re: Petition for approval of 2022 Depreciation Study by St. Joe Natural Gas Company, Inc*.

Account 37602 – Distribution Mains Plastic

The currently-approved ASL for this account is 75 R2. Witness Watson proposed to retain the existing parameters. Witness Garrett proposed to extend the ASL to 82 years. Witness Watson disagreed with witness Garrett's life proposal.

Witness Watson testified that this account is more mature with assets that are replaced on an ongoing basis, and Company subject matter experts indicated the retirements of the account would be focusing on pre-1984 pipe, with the newer pipe likely to last 75 years. He claimed that his proposal recognized both the indications in the life analysis, which included examination of 17 different fits across multiple placement and experience bands, and the account-specific information from Company experts. Witness Watson asserted that Witness Garrett's life proposal is excessive. He contested that witness Garrett's proposal seems illogical as it would make PGS have assets in this account that last 17.1 percent longer than witness Garrett recommended for the same assets of another Florida utility without providing an operational reason to explain the difference.[17]

The industry's current ASL range for this account is 40 to 75 years with an average of 62 years. We find that a 75 R2 life proposal is reasonable for the account at this point in time, because it is derived from an appropriate depreciation asset life analysis, incorporated with the Company-specific assets' operational information, and within the range of other Florida gas utilities. It is also in line with our recognized and generally accepted principle of gradualism.[18]

Account 37900 – Distribution Measuring & Regulating Equip – City Gate

The currently-approved life for this account is 50 R2. Witness Watson proposed to moderately increase the ASL from 50 to 52 years. Witness Garrett proposed to increase the life to 60 years, and claimed that he did "not believe Watson's proposed average life of 52 years is long enough given the data presented at this time." Witness Watson disagreed with witness Garrett's proposal.

This account is composed of city gate distribution measuring and regulating station-related piping, regulators, controls, odorizers, and other equipment.[19] Witness Watson testified that PGS is beginning to build new city gates and is doing more capital improvements than in the past, and newer stations are expected to last longer than older ones. He also attested that different assets in the account may have different service lives, and Company subject matter experts indicated that "50 years seems reasonable from an operational perspective."[20] Witness Watson

[17]In Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas*, witness Garrett recommended an ASL of 59 years for this account. In Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*, witness Garrett recommended an ASL of 70 years for this account.

[18]As it pertains to depreciation and rate change, gradualism is the concept of making smaller adjustments over time as opposed to less frequent, large adjustments. *See* Order Nos. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, *In re: Petition for increase in rates by Progress Energy Florida*; and PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.

[19]A city gate is the entry point for gas being taken from a transmission system to a distribution system. PGS has over 90 city gates.

[20]For example, odorizers may last 40-50 years, heaters may last 20-30 years, and regulators may last 30 years or more.

claimed that witness Garrett did not appear to factor in the life expectations for specific assets in this account as communicated by Company experts.

Witness Watson also argued that witness Garrett's proposal was based on examining one placement-experience band which ends at approximately 92.36 percent of the account's OLT data. He contested that the placement-experience band that witness Garrett used "is not statistically valid. It's too short to make any predictions from it."

Witness Watson further stated that witness Garrett's recommended ASL represents an increase of 15.4 percent when compared to existing parameters and contested that "[t]his level of change at one time without an operational justification is unreasonable, is not supported by the evidence, and should be rejected." Witness Watson additionally opined that:

> In Docket No. 20170179-GU for Florida City Gas, witness Garrett recommended a 39 R0.5 life for this account. In Docket No. 20220069-GU for Florida City Gas, witness Garrett recommended a 45 S3 life for this account. It does not seem logical that Peoples would have assets in this account that last 33.3 percent longer than witness Garrett's recommendation for another Florida utility.

After reviewing the account-specific data, information, curve-fitting graphs, and the related testimonies presented by both witnesses, we find that an estimate of 52 R2 life is appropriate for the account at this time. This life estimate is slightly longer than the high end of the industry's current ASL range for the account, which is 32 to 50 years with an average of 41 years, but is still in line with our recognized and generally accepted principle of gradualism.

Account 38002 – Distribution Services Plastic

The currently-approved ASL-curve combination for this account is 55 R1.5. Witness Watson proposed retaining the current ASL with a slight shift in retirement dispersion: 55 R2.5. Witness Garrett proposed to increase the ASL to 62 years with an R2 curve. Witness Watson disagreed with witness Garrett's proposal.

Witness Watson argued that, as with other accounts, witness Garrett's recommendation "[did] not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]" and "only examines one band for his proposal." He further claimed that, with witness Garrett's recommended 1983-2021 placement and experience band, the OLT "is too short a stub to be predictive of the life of the account (only going to 84 percent surviving)." In his rebuttal testimony, witness Watson proffered four graphs, each visually comparing the fit of the curve to the account's actual data for placement-experience bands selected by him versus the bands selected by witness Garrett.[21] It appears to us that the 55 R2.5 life proposal is a better fit of the actual activity in this account.

Witness Watson also argued that witness Garrett's proposal of a 7-year increase to the ASL is excessive. He claimed that this level of change without operational reasons is both

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[21]Respectively, placement and experience bands used by witness Watson are: 1) 1959-2021 and 1983-2021, 2) 1959-2021 and 1997-2021, and 3) 1983-2021 and 1983-2021; by witness Garrett is: 1) 1983-2021 and 1983-2021.

unreasonable and not supported by the evidence. Witness Watson further pointed out that witness Garrett recommended a 54 R2.5 life and a 55 R2.5 life for this account in prior dockets.[22,23] He stated that it did "not seem logical that Peoples would have assets in this account that last 12.7 percent longer than witness Garrett's recommendation for another Florida utility."

Based on the review of the evidence presented, we find that a 55 R2.5 life proposal is appropriate at this point in time for Account 38002. The ASL is within the industry's current ASL range for the account, which is 40 to 60 years with an average of 53 years.

Account 38200 – Distribution Meter Installations

The currently-approved parameters for this account is 44 R1. Witness Watson proposed to increase the current ASL to 45 years with a slight shift in retirement dispersion to R1.5. Witness Garrett proposed to increase the ASL to 55 years with a R0.5 dispersion. Witness Watson disagreed with witness Garrett's proposal.

At the time of preparing the 2023 Study, this account's average age of survivors and average age of retirements is 12.09 years and 13.72 years, respectively. Witness Watson testified that "[t]his information demonstrates that this is an account with newer assets and retirements that have occurred before a full cycle of activity has occurred." He also cited interview notes with Company subject matter experts to show the factors that influence the life of the account and argued that "witness Garrett does not appear to factor in the life expectations for specific assets in this account as communicated by Company [experts]." Witness Watson further presented several graphs, each visually comparing the fit against the account's actual data for placement-experience bands selected by him versus the bands selected by witness Garrett. Witness Watson claimed that his life proposal is a better visual match.[24]

Witness Garrett's proposed ASL represents an increase of 11 years, or a 25 percent change. Witness Watson asserted that this level of change at one time without operational reasons is unreasonable and it is not supported by the evidence. He further emphasized that for the same account, witness Garrett recommended a 34 S3 and a 35 R3 for this account in prior dockets, and claimed that "[i]t does not seem logical that Peoples would have assets in this account that last 57.14 percent longer than witness Garrett's recommendation for another Florida utility."[25,26]

We find that a life proposal of a 45 R1.5 is reasonable for this account at this point in time. It is derived from an appropriate depreciation asset life analysis, incorporated with the Company-specific assets' operational information, and within the industry's current ASL range

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[22]Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas*; Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[23](62 - 55) / 55 = 12.7%
[24]Respective placement and experience bands used by witness Watson are: 1) 1939-2021 and 1983-2021, 2) 1939-2021 and 1997-2021, and 3) 1983-2021 and 1983-2021; used by witness Garrett is: 1) 1983-2021 and 1983-2021.
[25]Dockets No. 20170179, *In re: Petition for rate increase by Florida City Gas*; 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[26](55 - 35) / 35 = 57.14%

which is 34 to 45 years with an average of 41 years.[27] This is also in line with our recognized and generally accepted principle of gradualism regarding the rate increase.

Average Remaining Life

The ARL is the average number of in-service years left for plant currently in service. An account's ARL is determined by the account's age, its ASL, and the associated curve. As such, witnesses Watson and Garrett's ARL proposals are in dispute for the same five aforementioned accounts due to the difference in each account's ASL-curve proposals. Based on our approved ASL and curves for each account, the appropriate ARLs for each account are listed in Table 2.

Net Salvage

The net salvage is gross salvage minus cost of removal. An account's net salvage percentage is based on the account's historical data, but is also prospective in outlook. No intervenor disagreed with PGS's net salvage percentage proposals presented in its 2023 Study. We have reviewed these proposals and find them all to be reasonable based on the evidence in the record, including the data and corresponding analysis.

Reserve Percentage

An account's reserve percentage represents the portion of the account's investment accumulated through depreciation expense to date unless restated to another level.[28] It is calculated by dividing the book reserve by the original cost of plant. PGS proffered the reserve percent, or reserve position, for each of its accounts. The parties had no dispute regarding this parameter as it was calculated directly from the actual data of each respective account.

Depreciation Rates

For each of PGS's accounts, witness Watson calculated the remaining life depreciation rate based on his account-specific parameter proposals. The resulting remaining life depreciation rates, or depreciation rates, were used to determine PGS's proposed test year depreciation expense for the instant proceeding.[29] We have verified witness Watson's calculations and confirmed that they are consistent with the prescribed formula of Rule 25-7.045(1)(e), F.A.C., for determining an account's remaining life depreciation rate.

Witness Garrett also performed the calculation for all the accounts which results in three sets of depreciation rate proposals from OPC. The first one, "Depreciation Rate Development – 2023 Study (With Book Reserve and Adjusted Parameters)," was developed by using witness Garrett's proposed depreciation parameters. It results in an overall depreciation rate of 2.47 percent for all plant accounts studied. The second one, "Depreciation Rate Development – 2023 Study (With Theoretical Reserve and Adjusted Parameters)," was developed also by using witness Garrett's proposed depreciation parameters. It results in an overall depreciation rate of 2.64 percent for all plant accounts studied. The third depreciation rate proposal, "Depreciation Rate Development – 2023 Study (Unadjusted Parameters)," was developed by using witness

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[27]*Id.*
[28]Rule 25-7.045, F.A.C.
[29]Rule 25-7.045(1)(e) and (m), F.A.C., prescribes the respective formulas for calculating an account's whole life depreciation rate and remaining life depreciation rate. Conventionally, we use the remaining life depreciation rate for the purpose of customer rate setting.

Watson's proposed depreciation parameters. It results in an overall depreciation rate of 2.69 percent for all plant accounts studied.

We have also verified witness Garrett's depreciation rate calculations. The aforementioned second depreciation rate proposal from witness Garrett leads to the amount of the depreciation theoretical reserve imbalance of $221 million that is the Joint Parties' primary recommendation for Section III.E. We note that Garrett's rate proposal was developed by using a calculation method that deviates from what is prescribed by our depreciation rule pertaining to gas service by gas public utilities, Rule 25-7.045, F.A.C.[30]

We agree with the depreciation rates proposed by witness Watson. These rates are derived from the depreciation parameters (ASLs, ARLs, net salvage, and reserve percentages) which are best supported by the record in this case, and the associated calculations are in accordance with Rule 25-7.045, F.A.C.

iii. Conclusion

Based on the record evidence, we approve the depreciation parameters and resulting depreciation rates for each plant account as shown in Table 2. The resultant test year depreciation expense, based on the approved depreciation rates in this issue, is addressed in Section VI.N, *infra*.

[30]Rule 25-7.045, F.A.C., prescribes the formula to determine a plant account's remaining life depreciation rate: Depreciation base percent (or plant minus future net salvage percentages) less book reserve percent, divided by the average remaining life of the account. However, witness Garrett's proposal was determined for all accounts' depreciation rates by subtracting the theoretical reserve from the depreciation base, rather than subtracting the book reserve from the depreciation base. This substitution impacted his calculation of the remaining life rate, and is in violation of the rule.

Table 2
Commission-Approved Depreciation Parameters and Resulting Remaining Life Depreciation Rates

Comparison of Depreciation Rates and Parameters												
		Existing				Commission Approved						
Account No.	Account Number	Curve Type	Average Service Life (yrs)	Future Net Salvage (%)	Remaining Life Rate (%)	Curve Type	Average Service Life (yrs)	Average Remaining Life (yrs)	Reserve (%)	Future Net Salvage (%)	Remaining Life Rate (%)
DISTRIBUTION PLANT											
37402	Land Rights	SQ	75	0	1.3	SQ	75	57	25.3	0	1.3
37500	Structures & Improvements	L0	33	0	2.8	L0	33	26	26.7	0	2.8
37600	Mains Steel	R1.5	65	(50)	2.1	R1.5	65	55	28.5	(60)	2.4
37602	Mains Plastic	R2	75	(33)	1.6	R2	75	67	20.4	(40)	1.8
37700	Compressor Equipment	R2	35	(5)	3.0	R2	35	33	6.9	(5)	3.0
37800	Meas & Reg Station Eqp Gen	R1.5	40	(10)	2.7	R1.5	40	31	26.2	(20)	3.0
37900	Meas & Reg Station Eqp City	R2.5	50	(10)	2.1	R2	52	46	16.0	(20)	2.2
38000	Services Steel	R0.5	52	(125)	4.0	R0.5	52	39	60.9	(130)	4.3
38002	Services Plastic	R1.5	55	(68)	2.7	R2.5	55	46	33.3	(75)	3.1
38100	Meters	R2	19	3	5.0	R2	20	12.4	41.4	0	4.7
38200	Meter Installations	R1	44	(25)	2.2	R1.5	45	37	33.1	(30)	2.6
38300	House Regulators	S1	42	0	1.8	S1.5	42	28	42.4	0	2.0
38400	House Regulator Installs	R1	47	(25)	1.9	R1.5	47	38	38.1	(30)	2.4
38500	Meas & Reg Station Eqp Ind	R3	37	(2)	2.3	R2.5	39	24	45.9	0	2.2
38700	Other Equipment	L2	24	0	3.0	L1.5	27	20	39.6	0	3.0
TRANSPORTATION EQUIPMENT											
39201	Vehicles up to 1/2 Tons	L2.5	9	11	7.0	L2.5	8	5.2	39.4	11	9.5
39202	Vehicles from 1/2 - 1 Tons	L3	10	11	5.6	L3	10	5.6	46.9	11	7.5
39204	Trailers & Other	R2	27	15	2.9	R1.5	30	26	17.8	20	2.4
39205	Vehicles over 1 Ton	L2	12	4	6.6	L2	13	7.5	49.4	7	5.8
OTHER GENERAL PLANT											
30300	Mis Intangible Plant	SQ	25	0	4.0	SQ	25	0	100.0	0	0.0
30301	Custom Intangible Plant	SQ	15	0	6.6	SQ	15	11.0	27.3	0	6.6
39000	Structures & Improvements	L0	25	0	2.4	L0	25	24	2.8	0	4.1
39100	Office Furniture	SQ	17	0	5.9	SQ	17	9.4	51.8	0	5.1
39101	Computer Equipment	SQ	9	0	11.1	SQ	9	5.4	57.8	0	7.8
39102	Office Equipment	SQ	15	0	6.7	SQ	15	5.9	63.1	0	6.3
39300	Stores Equipment	SQ	24	0	4.2	SQ	24	12.5	46.1	0	4.3
39400	Tools, Shop & Garage Equip	SQ	18	0	5.6	SQ	18	10.2	51.5	0	4.8
39401	CNC Station Equipment	SQ	20	0	5.0	SQ	20	14.9	24.5	0	5.1
39600	Power Operated Equipment	L1.5	18	10	2.7	L1.5	18	10.7	59.5	10	2.9
39700	Communication Equipment	SQ	13	0	7.7	SQ	13	2.3	97.4	0	7.7
39800	Miscellaneous Equipment	SQ	20	0	5.0	SQ	20	16.6	28.3	0	4.3
GATHERING AND LNG PLANT											
33600	RNG Plant	R2	30	(5)	3.5	R2	30	30	3.2	(5)	3.4
33601	RNG Plant Leased - 15 Years					SQ	15	13.5	5.5	0	6.7
36400	LNG Plant	R2	30	(5)	3.5	R2	30	30	1.7	(5)	3.5

D. Depreciation Study Date

At the hearing, we approved a type 2 stipulation as follows: Although the terms of the 2020 Agreement we approved in Order No. PSC-2020-0485-FOF-GU, suggests otherwise, the Company agrees with OPC that the depreciation rates that become effective on January 1, 2024 shall be calculated using a depreciation study date of December 31, 2023.

E. Theoretical Reserve Imbalance

i. Parties' Arguments

PGS stated that the appropriate theoretical reserve imbalance is a surplus of $160.4 million as of December 31, 2023, based on the recommended life and net salvage parameters as reflected in Exhibit 32, Document No. 3.

PGS argued that OPC presented an alternative calculation of the theoretical reserve surplus as of December 31, 2023, based on its proposed adjustments to PGS's depreciation parameters. The Company contended that OPC's recommended adjustments are unreasonable, do not follow sound depreciation practice, and those adjustments and OPC's resulting theoretical reserve surplus should be rejected.

The Joint Parties stated that OPC witness Garrett identified four options regarding the depreciation reserve surplus amount in his testimony. The Joint Parties' primary recommendation is to use OPC witness Garrett's proposed ASLs, which results in a depreciation reserve surplus of $221,024,192. The Joint Parties asserted that, should we adopt all of PGS witness Watson's depreciation lives, the depreciation reserve surplus would be $159,474,313.

ii. Analysis

Our natural gas utility depreciation Rule 25-7.045(4)(k), F.A.C., provides that an account's theoretical reserve amount is determined by the account's book investment minus the account's future accruals and future net salvage. The reserve imbalance of an account is the difference between the account's calculated theoretical reserve and its book reserve. If the book reserve amount is larger than the theoretical reserve amount, this account presents a reserve surplus at a specific point in time.

PGS witness Watson calculated a $160.392 million reserve surplus for PGS's plant accounts based on his proposed depreciation parameters. OPC witness Garrett calculated a $221.024 million reserve surplus by applying his proposed adjusted depreciation parameters. This amount is the Joint Parties' primary recommendation regarding the reserve imbalance. Witness Garrett also calculated a $159.474 million reserve surplus by adopting PGS witness Watson's proposed depreciation parameters.

Pursuant to Rule 25-7.045(4)(k), F.A.C., and the prescribed formula along with the depreciation parameters that we approved in Section III.C, *supra*, the calculated theoretical reserve imbalance for each category of PGS's plant accounts is as shown in Table 3:

Table 3
Theoretical Reserve Imbalance

Account Type	Reserve Imbalance (as of 12/31/2023)
Distribution	$152,368,138
Transportation	$3,216,382
General	$3,772,298
Gathering and LNG Plant	$1,035,3413
Total Plant	$160,392,158

iii. Conclusion

Based on the application of the depreciation parameters that we approved in Section III.C and application of the formula prescribed in Rule 25-7.045, F.A.C., the resulting imbalance is a surplus of $160.4 million.

F. Corrective Depreciation Reserve Measures

i. Parties' Arguments

PGS stated that its witness Watson designed his proposed depreciation rates to eliminate the theoretical depreciation reserve surplus over the remaining life of the depreciable assets and the average remaining life for the accounts where the Company proposed general plant amortization.

PGS argued that OPC's recommendation to amortize the reserve surplus over ten years is a departure from the remaining life technique, and as such, it does not follow normal depreciation study practice. PGS also contested that OPC's recommendation is also inconsistent with OPC's position in the recent FCG case, which was to follow the remaining life technique.

PGS recommended that we follow standard depreciation study practice and amortize the surplus using the remaining life technique.

The Joint Parties proposed that "a relatively conservative return" of the theoretical depreciation reserve surplus should be implemented over 10 years "or a little less than half the time proposed by PGS." The Joint Parties argued that the reserve surplus reflects an overpayment from PGS's customers, and that current customers have overpaid due to excessive depreciation rates. The Joint Parties further argued that their proposed conservative return should occur for the benefit of the customers who overpaid in rates for depreciation expense and to implement a more moderate treatment of "PGS's enormous rate increase request." The Joint Parties stated, "These customers can and should receive the benefits of lower depreciation rates and base revenues in the near future through a shorter amortization period of the reserve surplus, rather than pushing those overpayment-driven benefits into the next several decades for the benefit of future generations of customers." The Joint Parties claimed that if OPC witness Kollen's proposed $221.024 million reserve surplus, calculated using OPC witness Garrett's proposed depreciation parameters and depreciation rates, is amortized in 10 years, the depreciation expense will be reduced by $17.625 million and revenue requirement will be reduced by $16.980 million.

Supporting the shorter amortization period, the Joint Parties stated that, with Order No. PSC-2010-0153-FOF-EI, we ordered Florida Power & Light Company (FPL) to amortize its reserve surplus over a four-year period, and "[t]his policy is consistent with any number of prior orders dealing with imbalances that are deficits involving amortization periods between one and seven years."

The Joint Parties concluded that, "[g]iven the Company's position that they will defer to Commission policy and will not be financially harmed by the return of the overpayment of depreciation expense," the theoretical reserve surplus should be amortized over a 10 year period.

ii. Analysis

This section addresses whether any corrective measures should be taken with regard to the theoretical reserve imbalances identified in Section III.E. The remaining life technique is the most common method we use to address reserve imbalances (surplus or deficit). As indicated in Rule 25-7.045(1)(e), F.A.C., this method self-corrects the imbalances over the remaining life of the plant assets. We have also approved some other corrective measures. In some cases, we have approved an amortization of a certain portion of the surplus over a period of time that is shorter than the remaining life.[31] In other cases, we have approved the amortization of the entire surplus over a specific period (years) shorter than the remaining life.[32]

In PGS's 2018 case, we approved a reserve surplus correction using the remaining life technique. In the Company's 2020 case, we approved a Settlement Agreement which permitted the amortization of a $34 million portion of the reserve surplus, which was approximately 12.6 percent of the total surplus amount.[33] Table 4 shows the details:

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[31]*See* Order Nos. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company*; PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*; PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 1600621, *In re: Petition for rate increase by Florida Power & Light Company*; PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket 20200051-GU, *In re: Petition for rate increase by Peoples Gas System;* and PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for increase in rates by Florida Power & Light Company*.
[32]Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*.
[33]Order Nos. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System*; and PSC-2018-0501-S-GU, issued October 18, 2018, in Docket No. 20180044-GU, *In re: Consideration of the tax impacts associated with Tax Cuts and Jobs Act of 2017 for Peoples Gas System*.

Table 4
PGS's Identified Theoretical Reserve Surplus and the Correction Measures

	Overall Plant Balance	Overall Reserve Balance	Theoretical Reserve	Theoretical Reserve Surplus	Surplus/Overall Plant Balance	Surplus/Overall Reserve Balance	Surplus/ Theoretical Reserve	Corrective Measure	Portion of the Reserve Surplus Corrected	
	($)	($)	($)	($)	(%)	(%)	(%)		($)	(%)
	(1)	(2)	(3)	(4) = (2) - (3)	(5) = (4) / (1)	(6) = (4) / (2)	(7) = (4) / (3)	(8)	(9)	(10) = (9) / (4)
Instant Case	3,186,513,154	889,076,505	728,684,347	160,392,158	5.0%	18.04%	22.0%	Decision Pending		
2020 Case[1]										
As filed	2,221,452,580	800,111,427	531,219,857	268,891,570	12.1%	33.61%	50.6%			
Per the SA[2]				268,891,570				4 yrs Amortization	34,000,000	12.6%
				268,891,570				Remaining life	234,891,570	87.4%
2018 Case[3]	1,378,109,097	664,335,975	515,783,674	148,552,301	10.8%	22.36%	28.8%	Remaining life	148,552,301	100.0%

The Joint Parties contested that the surplus, when measured against the entire theoretical depreciation reserve, is between 22 percent and 33 percent. As shown in Table 4, based on our finding in Section III.E, the surplus amount of $160,392,158 is 22 percent when measured against the entire theoretical depreciation reserve. We note that as shown in Table 4, in PGS's 2020 case, the surplus was 50.6 percent (or 44.2 percent after taking into account the $34 million amortization) when measured against the theoretical depreciation reserve.[34] Also shown in Table 4, in PGS's 2018 case, the surplus was 28.8 percent when measured against the theoretical depreciation reserve.[35] In essence, we approved PGS to use the remaining life technique to correct its reserve surplus when the surplus amount was respectively 28.8 percent and 44.2 percent and measured against the entire theoretical depreciation reserve.

For the theoretical reserve surplus identified in the instant case, PGS proposed to amortize the entire amount over the remaining life of the plant assets. OPC proposed to amortize the entire amount over 10 years.

PGS witness Watson asserted that OPC's proposal "contradicts sound depreciation theory." He further explained that:

> Reserve imbalances change in each depreciation study (as evidenced by the decrease in surplus since the last study). Depreciation theory and the use of the remaining life technique in calculating depreciation rates will spread any surplus (or deficit) over the remaining life of the asset group.

In responding to OPC's question, "apart from your recommendation [. . .] what amortization period should be used if it's shorter than the remaining life," witness Watson answered "I don't believe there is another option that would be appropriate other than the remaining life approach." He further argued that the exact amount of surplus at one point in time can vary based on the different ways by which an analyst chooses to look at the plant assets. Witness Watson pointed out that the reserve surplus declined between PGS's last case and this case, and "it will drop further as moving further forward."

We note that within the three years since our approval of the 2020 Settlement Agreement, applying the remaining life technique resulted in PGS's reserve surplus decreasing from $234.9

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[34] Order No. PSC-2020-0485-FOF-GU, p. 217.
[35] Order No. PSC-2018-0501-S-GU, p. 39, 42.

million (after amortizing $34 million from the original $268.9 million) to $160.4 million, as shown in Table 4. This decrease indicates that the remaining life technique worked to significantly reduce the surplus.

Regarding the use of a method other than the remaining life technique to correct the reserve imbalance, witness Watson opined that "[it] is a policy decision, not a depreciation theory decision." He further testified that he believed "it is not a valid depreciation theory, that if we were to do that, it would be a policy decision, not a[n . . .] appropriate depreciation theory decision."

OPC witness Kollen recommended that "the Commission remove the theoretical depreciation reserve surplus from the calculation of the depreciation rates and separately amortize the reserve surplus over ten years." He argued that a ten year amortization of the surplus will mitigate the customer rate increase requested by the Company in the current proceeding, and return the excessive depreciation expense that was recovered from customers in prior years to the customers who paid that expense through their base rates. Specifically, the Joint Parties claimed that if OPC witness Kollen's proposed $221.024 million reserve surplus, calculated using OPC witness Garrett's proposed depreciation parameters and depreciation rates, is amortized in 10 years, the depreciation expense will be reduced by $17.625 million and revenue requirement will be reduced by $16.980 million.

We do not agree with the first portion of witness Kollen's recommendation. His proposal to "remove the theoretical depreciation reserve surplus from the calculation of the depreciation rates" does not comport with Rule 25-7.045(1)(e), F.A.C., Depreciation, as explained in Section III.C of this order.

We agree with witness Kollen's argument that amortization of the reserve surplus can mitigate the Company's currently requested customer rate increase, and would return the excessive depreciation expense to the current customers. When responding to a question about whether he was aware that our prior policy decisions involving accelerated surplus amortization resulted in monies returned to ratepayers sooner rather than later, due in part, to concerns about intergenerational unfairness, witness Watson testified, "I think you are going to create intergenerational unfairness by returning it as well [. . .] returning it is not going to solve any problems. It's actually going to cost your customers more in the long-term."

The existence of a reserve surplus means that, under present estimations, a theoretical excess recovery of plant investment has occurred to date, so there is a smaller amount of investment left to be recovered over the remaining life of the asset. As a result, current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates (all other things equal) and a lower return on rate base. However, if the identified reserve surplus is amortized, the depreciation rates set in future proceedings would be higher, plus the Company would have an increased rate base on which to earn a return, all of which would drive up costs to ratepayers.

More specifically, any amortized amount of the reserve surplus represents a reduction to the accumulated depreciation, or depreciation reserve, previously recovered by the Company from customers through rates. The identified $160.4 million reserve surplus, as of December 31, 2023, is an indication that customers, at that point in time, have excessively reimbursed PGS its investment by $160.4 million theoretically; plus they have paid the Company its cost of capital of this investment. By statute, a public utility is allowed the opportunity to recover its cost of, and earn a fair return on, plant investment that is used and useful in providing service to customers. If this $160.4 million of reserve surplus is amortized, such as what is proposed by the Joint Parties, customers can expect to pay increased depreciation expense resulting from future rate setting proceedings in order to allow that returned surplus to be collected again. In addition, customers have to pay for the Company's cost of capital on the $160.4 million from now until the associated plant investment is completely recovered again. This would impose an extra financial burden on customers.

Given the above, it is clear that, while amortizing the reserve surplus can reduce customer rates in this proceeding, higher customer rates will likely have to be imposed on customers in future rate case proceedings. Additionally, OPC provided no details as to how the amortization of the $160.4 million reserve surplus would be implemented.

Therefore, the appropriate method to correct the reserve surplus, from the standpoint of depreciation theory, is the remaining life technique. As shown in Table 4, the ratios of surplus to plant balance, to reserve balance, and to theoretical reserve do not provide a compelling reason to abandon the utilization of the remaining life technique for reserve surplus correction in this case. The remaining life technique is the appropriate corrective measure to address the $160.4 million depreciation theoretical reserve surplus identified in the current case. It is consistent with our decisions in a majority of prior depreciation studies and rate case proceedings, fair to customers as a whole, and supported by sound depreciation theory.

iii. Conclusion

Based on the record evidence and our analysis, we approve the use of the remaining life technique for correcting the theoretical reserve imbalance identified in Section III.E.

G. Implementation Date for Revised Depreciation Rates and Other Schedules

At the hearing, we approved a type 2 stipulation as follows: The implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules shall be January 1, 2024.

IV. Rate Base

A. Adjustments for Non-Utility Activities

At the hearing, we approved a type 2 stipulation as follows: All required adjustments to remove non-utility items have been included in the 2024 projected test year, as shown on MFR Schedule G-1, page 4.

B. Removal of Costs Attributable to Operations of Seacoast Gas Transmission

i. Parties' Arguments

PGS has proposed adjustments to its original petition related to the operating costs of Seacoast Gas Transmission (SGT). More specifically, the adjustments are related to the amount of corporate overhead costs attributable to SGT. The effect of the proposed adjustment in this issue is a revenue requirement reduction of $189,347. The Company also states it is willing to conduct a comprehensive study of the services and costs that SGT receives from PGS.

Throughout the proceeding and in their brief, the Joint Parties raised a number of concerns regarding the methodology by which PGS attributes costs to SGT. In general, the Joint Parties are concerned that ratepayers now, and in the future, could potentially be subsidizing the Company's non-regulated activities such as the operations of SGT. This concern is heightened given the additional staffing/hiring proposals being made in this case. The Joint Parties recognize the Company, in response to OPC discovery, proposed a "good faith" adjustment to account for additional costs attributable to SGT operations. However, due to the issues raised in this proceeding, the Joint Parties' request that we direct PGS to conduct a comprehensive review of its relationship to SGT, and revise its procedures to accurately describe the circumstances when SGT imposes direct and indirect demands on PGS resources, including the need to maintain the availability of resources to service the needs of SGT.

ii. Analysis

The primary purpose of this issue is to identify and ensure an appropriate amount of costs attributable to the operations of SGT is removed from PGS's 2024 projected test year. SGT is an affiliated limited liability company that conducts business in the areas of natural gas pipeline design, construction, and operation. SGT is a "sister company" to PGS, while both SGT and PGS are wholly-owned subsidiaries of TECO.

Valuing and accounting for the labor and other cost support provided by PGS to its affiliates is being performed in the following three ways. The first is by directly charging the labor cost to the affiliate. The second method is through a standard labor distribution where a PGS employee allocates a fixed portion of their worktime to the affiliate. While the third method is through an overhead allocation method, namely and in this instance, the Modified Massachusetts Method (MMM).

The contention is that the MMM understates the allocation of corporate overhead costs. This is a result of how the MMM functions relative to the operating profile of SGT. More specifically, the MMM allocates corporate overhead costs based on the ratios of net revenues, payroll and benefits costs, and property, plant, and equipment between PGS, TECO Partners Inc., and SGT. Since SGT does not have any employees, the MMM - without further modification - will likely under-allocate corporate overhead costs from PGS to SGT. We note the initial or as-filed 2024 test year overhead costs allocated by PGS to SGT are $1,595,205.

In recognition of this matter, PGS proposed to include the directly-allocated or charged 2022 historical test year payroll and benefits amount of $1,150,287 in the MMM calculation. By doing so, the costs assigned to SGT increases by $180,225. After accounting for assumed inflation in 2023 and 2024 of 2.8 percent and 2.2 percent respectively, the adjusted cost amount equals $189,347. After grossing-up for the regulatory assessment fee and bad debt expense, this figure increases (revenue requirement reduction) to $190,837. We find that using the directly-allocated labor cost for computing an allocation for associated corporate overhead costs is a reasonable approach as it appears to be a fair representation of the actual labor support/cost provided to SGT.

There was an additional proposed SGT-related O&M adjustment of $8,359 contained within PGS witness Parson's rebuttal testimony. This adjustment is with respect to the "agreed upon [O&M] reductions with [OPC]." We note that this adjustment is related to the 2022 base recoverable O&M expense which the 2024 projected test year is partially predicated on. After grossing-up for the regulatory assessment fee and bad debt expense, this figure increases (revenue requirement reduction) to $8,425. This adjustment is addressed in Section VI.M.

A portion of the OPC's cross-examination of witness Parsons centered around PGS's willingness to file a comprehensive cost study of the services and support it provides to SGT as part of its next base rate proceeding if we so direct. To that end, the Joint Parties do recommend that we direct PGS to conduct a comprehensive review of its relationship to SGT, and revise its procedures to accurately describe the circumstances when SGT imposes direct and indirect demands on PGS resources, including the need to maintain the availability of resources to service the needs of SGT. When asked if the Company was willing to conduct and produce such a study, witness Parsons replied "of course." Given the matters raised with respect to accurately and fully valuing the support PGS provides to SGT, a comprehensive procedural review and associated cost study would benefit us in our analysis of the Company's next base rate case.

With the previously-allocated $1,595,205, and the additional adjustments of $8,359 and $189,347 discussed above, the total amount of overhead costs (before gross-up) removed from the 2024 projected test year attributable to SGT is $1,792,911. Further, the Joint Parties' recommendation to have PGS file a cost study of the support it provides SGT as part of its next base rate case has merit.

iii. Conclusion

An additional $189,347, before gross-up, shall be removed from the Company's as-filed proposed revenue requirement to account for additional costs attributable to the operations of SGT. We also direct PGS to file a comprehensive procedural review and associated cost study of the support it provides to SGT contemporaneously with its next base rate proceeding.

C. Cast Iron/Bare Steel Rider (CI/BSR) Adjustments

At the hearing, we approved a type 2 stipulation as follows: The appropriate CI/BSR investment amounts as of December 31, 2023 to be transferred into rate base are $91,733,660 for plant in service, $2,808,776 for Construction Work in Progress and $1,273,990 for accumulated depreciation, as shown on Exhibit No. RBP-1, Document No. 2, lines 2-4.

D. Advanced Metering Infrastructure (AMI) Pilot

i. Parties' Arguments

PGS argued that the AMI Pilot should be approved because it will allow PGS to assess the benefits to gas customers of a technology widely used in the electric utility industry. The potential benefits PGS identified include cost reductions, remote disconnection and leak and outage detection, and improved billing accuracy and customer information on individual usage. PGS contended that the Pilot was sized such that the Pilot cost was balanced with the need to provide a large enough sample to test the benefits of the Pilot. PGS asserted that the Hillsborough County area was selected as the location for the Pilot due to the ability to connect to TECO's existing AMI infrastructure. PGS averred that its AMI Pilot is similar to the pilot we approved for FCG.

The Joint Parties argued that the costs associated with PGS's AMI Pilot should be disallowed because PGS has not demonstrated the prudence of the Pilot. The Joint Parties asserted that PGS has not satisfied its burden of proof because it admitted that only a small number of gas utilities have deployed AMI technology to date, and stated that it was still evaluating opportunities to connect to TECO's existing AMI technology. The Joint Parties contended that PGS should be required to further evaluate the experimental AMI technology before customers cover the costs of the Pilot.

ii. Analysis

PGS is requesting a research and development pilot to evaluate AMI infrastructure with two-way communication capability. As part of the pilot, PGS would collect data on the durability of the proposed smart meters, especially with regard to corrosion, and usage of two-way communications for central control of meter functions, such as remote connects and disconnects, and improved customer information on usage. The proposed pilot would be over a four-year period, with one year of installation and three years of operation, and consist of 5,000 smart devices with related back-office technology support installed in the Hillsborough County area where PGS can connect to TECO's existing AMI network. The estimated total cost of the AMI Pilot is $2.2 million in capital expenditures, with annual O&M expenses estimated at $100,000. PGS's AMI Pilot is largely similar to FCG's AMI Pilot, approved in its most recent base rate proceeding.[36]

PGS witness O'Connor testified that although AMI technology is widely used by electric utilities, only a small number of gas utilities have deployed this technology. We note that the recent approval of FCG's AMI Pilot would make PGS the second gas utility in Florida to implement AMI technology. As such, the feasibility of AMI technology usage by gas utilities in

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[36]Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas.*

Florida is still being determined. Under the AMI Pilot, PGS intends to determine whether deploying AMI technology could result in cost reductions through remote meter reading, leak and outage detection, and disconnection capabilities. The AMI Pilot would also allow PGS to evaluate improvements regarding billing accuracy and customer information on usage. Witness O'Connor contended that replacing 5,000 meters under the AMI Pilot would provide a large enough sample to test the benefits of smart meters with AMI technology on PGS's system without creating excessive costs, as this represents approximately seven percent of PGS's customer meters in the Hillsborough County area. Hillsborough County was selected due to it being in PGS's Tampa service area, which would allow PGS to pay TECO to connect to its existing AMI network and avoid costs associated with PGS having to create its own standalone AMI network.

No intervenor addressed this matter in their prefiled testimony or during the hearing. However, in their brief, the Joint Parties argued that the costs associated with PGS's AMI Pilot should be disallowed because PGS has not satisfied its burden of proof regarding the prudence of the Pilot. As discussed above, PGS witness O'Connor acknowledged that, while common in the electric industry, AMI technology has only been deployed by a limited number of gas utilities. We note that, traditionally, it has been our practice that pilot programs serve as vehicles for utilities to explore new technologies or processes, and assess the benefits using a sample prior to permanent implementation.[37] As such, the newness of AMI technology to the gas industry, specifically in Florida, lends credibility to PGS's proposal for a pilot program to allow this technology to be further evaluated prior to full scale implementation. Regarding PGS evaluating whether it could connect to TECO's existing AMI technology, PGS indicated in response to discovery that it has confirmed that it can connect to TECO's existing AMI network for the Pilot.

We have reviewed PGS's AMI Pilot request and agree with PGS that customers and the Utility could potentially benefit from implementation of AMI technology due to the potential for reduced costs for the Utility, and, as a result, the customers. As no gas utility in Florida has implemented system-wide deployment of AMI technology, the benefits of such implementation need to first be assessed and a pilot program provides the means to do so. As such, we approve PGS's proposed AMI Pilot. In addition, PGS shall provide a final report with a summary of the findings to us within 90 days of completion of the AMI Pilot. This summary should include the findings with regard to the project cost, meter installation, maintenance, and corrosion performance, as well as sample reports including information such as customer daily usage, remote meter communication performance, and billing accuracy impacts.

iii. Conclusion

The AMI Pilot is hereby approved and PGS shall provide a final report with a summary of the findings to us within 90 days of completion of the AMI Pilot. No adjustments are necessary.

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[37] Order No. PSC-2021-0237-PAA-EI, issued June 30, 2021, in Docket No. 20200234-EI, *In re: Petition for approval of direct current microgrid pilot program and for variance from or waiver of Rule 25-6.065, F.A.C., by Tampa Electric Company.*

E. New River RNG Project

At the hearing, we approved a type 1 stipulation as follows: The New River RNG Project (interconnection) was planned and executed based on and in reliance on the Company's Rate Schedule RNGS and will be included above the line in the calculation of the Company's 2024 revenue requirement, with whether to use deferral accounting for the project as proposed by OPC to be decided under subsequent issues. Subject to our approval in this docket of the Company's new Renewable Natural Gas Interconnection Service tariff (RNGIS) to be effective January 1, 2024 as agreed to with OPC, the Company will close its RNGS tariff to new projects effective August 29, 2023, so New River and Brightmark will be the only two projects it undertakes under that rate schedule.

F. Brightmark RNG Project

At the hearing, we approved a type 1 stipulation as follows: The Brightmark RNG Project (bio conditioning and interconnection) was planned and executed based on and in reliance on the Company's Rate Schedule RNGS and will be included above the line in the calculation of the Company's 2024 revenue requirement, with whether to use deferral accounting for the project as proposed by OPC to be decided under subsequent issues. Subject to our approval in this docket of the Company's new Renewable Natural Gas Interconnection Service tariff (RNGIS) to be effective January 1, 2024 as agreed to with OPC, the Company will close its RNGS tariff to new projects effective August 29, 2023, so New River and Brightmark will be the only two projects it undertakes under that rate schedule.

G. Alliance Dairies RNG Project

At the hearing, we approved a type 1 stipulation as follows: The Alliance Dairies RNG Project shall be accounted for on an unregulated, below-the-line basis and the Company's proposed revenue requirement shall be increased by approximately $220,000 to reflect the movement of this project below the line.

H. Work and Asset Management (WAM) Program

i. Parties' Arguments

PGS asserted that WAM is used by most utilities and will allow the Company to use capital and O&M resources more effectively through better planning and work management. PGS witness Richard testified there were no cost savings benefits associated with WAM in its initial filing, but later identified $750,000 in cost savings by reducing O&M costs in its revised revenue requirement for the 2024 test year. PGS proposed a reduction of $750,000 to O&M expense in an effort to combine the 2024 and 2025 expected O&M cost-saving benefits in the 2024 test year to recognize the WAM benefits. PGS argued that the adjustment made by the Company to reflect WAM cost savings for ratemaking purposes is reasonable.

The Joint Parties stated that they are not seeking disallowance of the cost of WAM or denying the efficiency provided by WAM. The Joint Parties argued that PGS is requesting full cost recovery for WAM initially filed its case without reflecting any savings in the test year. The Joint Parties further argued that WAM should be a basis for limiting hiring.

ii. Analysis

The WAM system is a centralized asset management program that would consolidate the management of new construction, system reliability, maintenance and compliance into a single interconnected system. Additionally, this program would allow PGS to track all planning, design, construction, use, and retirement of PGS's assets throughout the life of each asset. WAM was initially deployed in two phases, with Phase 1 implemented in November 2022 and Phase 2 implemented in May 2023. Phase 1 was intended to address the needs of the Engineering, Construction and Technology team and Phase 2 was intended to address the needs of the Gas and Safety Operations teams. The initial implementation cost of the WAM project was $34.3 million. PGS determined that WAM required additional functionality beyond the initial implementation, which will be integrated by the end of September 2023. PGS required an additional $4.4 million in capital associated with the additional functionality, which PGS has not included for rate recovery in this proceeding.

PGS's Gas and Safety Operations teams formerly utilized five independent legacy systems, some of which are no longer supported by their respective vendors, in completing their work. The legacy systems handled compliance activities, service and emergency orders, work tracking for distribution services, leak remediation tracking, and locate responses ticketing whose functions would be incorporated within WAM into a single program.

WAM Efficiency Savings

PGS witness Richard testified that the implementation of WAM would facilitate PGS's ability to more efficiently execute work planning, enhance customer service, enhance system safety and provide centralized asset management. WAM would also reduce the risk associated with PGS's reliance on independent legacy systems, allow for the digitization and standardization of processes that are currently manually completed, and allow for integration with existing financial and customer systems. PGS witness O'Connor claimed that WAM would enable PGS to more easily coordinate work activities, better manage the scheduling and dispatch of work, increase optimization of work, and improve data collection that allows for more informed decision making. The witness also claims that once WAM is fully implemented the length of time required for jobs would be quantifiable which would allow PGS to optimize employee work duties. PGS anticipates that cost-savings would be realized as WAM provides efficiency improvements by more effective use of capital and O&M resources. Cost-savings would come in the form of PGS avoiding hiring new team members and contractor services.

Witness Richard indicated in direct testimony that there were minimal cost-savings in the 2024 test year associated with the project. In agreeance, witness O'Connor asserted in direct testimony that as WAM is intended to streamline PGS's future productivity and efficiency, and has only been implemented since 2023, immediate cost savings were not expected. The witness further asserted that the first one to two years of WAM's implementation would include team members becoming more familiar with the system, PGS obtaining data that would be utilized to facilitate software optimization, and fully integrating WAM's features and functions into existing systems. However, in the late filed exhibit to witness Richard's first deposition, "WAM Benefits Realization Metrics 2022 Update," PGS indicated WAM was projected to provide O&M and capital benefits starting in 2023. Witness Richard testified that the document was created in November 2020 while seeking approval for the original business plan and updated in March 2022 after PGS became more familiar with the WAM technology. The witness clarified that due to project delays, the first full year of operation was delayed from 2023 to 2024 along with all subsequent benefits.

The evidence shows that PGS expected a total O&M savings of $363,000 and $726,000, in 2024 and 2025 respectively. The record additionally indicates that PGS expected a capital savings of $144,750 and $289,500 in 2024 and 2025, respectively. At the hearing, witness Parsons provided an exhibit updating the Company's revenue requirement to reflect revisions from her rebuttal testimony and positions updated prior to the hearing. In the revised revenue requirement, PGS revised its estimate to reflect $750,000 of cost-savings in the 2024 test year associated with the WAM implementation. The Company indicated that it intended to bring forward the 2025 O&M cost-savings into the test year as a proxy for anticipated offset labor costs due to WAM and would achieve these cost savings via reducing O&M costs, which would likely come from reducing internal and external labor costs. Witness O'Connor testified that achieving the $750,000 reduction in O&M expense for 2024 would be difficult for PGS to achieve.

We note that the proffered amount of $750,000 in reduced O&M expense exceeds the expected test year O&M WAM savings by approximately $386,786 and the expected year two savings by $23,571. Bringing forward year two savings into the test year will provide immediate savings for PGS customers that would otherwise go unrealized due to the lag expected with PGS gathering data and optimizing its processes. Because of these facts, we find the proffered $750,000 amount to be an adequate proxy for savings expected from WAM. The adjustment of $750,000 to O&M expense is reflected in Section VI.M, which addresses projected test year O&M expenses.

No party disputed the efficiencies gained by WAM. In fact, in their brief, the Joint Parties stated that it was not seeking disallowance of the cost related to WAM. However, the Joint Parties argued that the cost-savings that WAM is projected to provide are not being fully realized in the projected test year, such as curtailing the need for additional employee hiring. We find that the evidence in the record shows that the Company is adequately recognizing those savings by bringing forward year two savings into the 2024 test year. The Company's need for additional employees is discussed in Section VI.F.

iii. Conclusion

PGS has properly reflected the cost saving benefits of $750,000 in reduced O&M expenses to be gained from implementation of the WAM system as a proxy for anticipated offset labor costs due to WAM is appropriate and no further adjustments shall be made.

I. Acquisition Adjustment and Accumulated Amortization of Acquisition Adjustment

At the hearing, we approved a type 1 stipulation as follows: As shown on MFR Schedule B-6, page 1, as of December 31, 2022, the Company has fully amortized the $5,031,897 of acquisition adjustments and the related net rate base amount is $0.

J. Plant in Service

i. Parties' Arguments

PGS stated that the appropriate amount of plant in service for the projected test year of 2024 is $3,298,318,785, which includes reductions due to the removal of the Alliance Dairies RNG project. PGS projected over $1 billion in capital expenditures to support customer growth, enhance customer service, and enhance the safety and reliability of its system. PGS witness Richard asserted that PGS's capital investments are made to serve increasing customer demand in the areas of growth projects; reliability, resiliency, and efficiency projects; and legacy pipe replacement projects, and not just to grow rate base.

PGS explained that the Company determines its capital costs based on the scale of the customer or project in order to develop a capital budget that reflects a reasonable total amount of capital spending. However, PGS stated that construction distribution system projects' costs have increased over the recent years and are projected to continue to rise due to higher materials costs; strong industry demand for external contractors; governmental, regulatory, and compliance requirements, including permitting and maintenance of traffic requirements; higher costs to retire, remove, and restore existing plant; and new construction safety protocols and enhanced construction management, inspection, and quality control activities.

PGS explained that the Joint Parties' use of 5-year averages, in their recommended reduction to projected test year plant in service, fails to recognize the Company's capital governance changes that have improved the capital budgeting process and capital spending controls, including building a new budgeting tool for distribution work to better predict a division's work. PGS asserted that these improvements allow the Company to improve its budgeting process and reduce variances between budgeted and actual capital costs. PGS argued that the Joint Parties' claim that the Company will not spend its 2023 and 2024 capital budget should be rejected, as well as any proposed capital adjustments, as the Company spent more than budgeted on capital in 2022 and projects to spend its 2023 capital budget.

The Joint Parties stated that we should make adjustments to PGS's request for 100 percent of its projected rate base for 2023 and 2024 due to concerns with the Company's ability to spend up to its projected levels. Furthermore, the Joint Parties claimed that PGS is having difficulty closing construction work-in-progress (CWIP) despite proposing an ambitious 2023 budget. The Joint Parties argued that PGS's "Capital Management Improvement Plan" would be effective in 2024 at the earliest, and these tools are still a work in progress.

The Joint Parties stated that PGS has failed to fully spend its capital budget in each of the most recent five years, with an average weighted underspending of 6.5 percent. The Joint Parties stated that in 2021, the last rate case test year, PGS appeared to go under budget by 2.6 percent, but the Joint Parties pointed out this fails to account for major additions to the rate base. In 2021, $48 million was added to the rate base for a liquid natural gas (LNG) and RNG project, with PGS using its Integrated Resource Process as reason that we should approve the projects; however, the Joint Parties pointed out that the LNG project was never completed and the RNG project was completed two years late, which goes against the idea that PGS met the 2021 capital budget. The Joint Parties also cited PGS's delayed Summerville-Dade City Connector and the FGT to JEF projects.

The Joint Parties acknowledged that delays are expected, but claimed that the problem with delays relative to the rate base are that they lead to customers being overcharged and shareholders benefitting if actual capital spending comes in under budget. Witness Kollen argued that the Company's track record gives precedence for us to be cautious in approving all of the requested projected base rate. The Joint Parties cited further evidence regarding PGS's development of projected plant in service additions, claiming that it is a false foundation for the 2023 capital budget. The Joint Parties stated that witness Parsons testified that in 2023, year-to-date closures of CWIP fell short of plant in service to the amount of over $220 million, which the Joint Parties used to question the Company's ability to meet 2024 budgets, as actual plant closure in 2022 also fell short of projections and carried over to 2023. The Joint Parties further posited that the 2022 and 2023 budgets, where PGS had or is expected to have underrun CWIP closures to plant in service, should be considered the best evidence and suggests that 2024 capital expenditures will not be met. The Joint Parties acknowledged that the Company argued against the Joint Parties' conclusions, citing its new budgeting, governance, and asset management process improvement measures. While the Joint Parties accepts the implementation of these programs as useful for the future, they claimed that because the measures are untimely and cannot influence the accuracy of the capital budget, that they should not be used to justify the approval of the rate base in this case. The Joint Parties based this assessment on the fact that the 2023 and 2024 budgets were established in the summer of 2022. At that time, the Company's new measures were still under development or not yet developed, and therefore can't provide cost controls for the test year. The Joint Parties used this line of reasoning to recommend a disallowance of $33.331 million of purely projected rate base from the test year, which yields an adjusted revenue requirement of $2.963 million in return on rate base and $905,000 in depreciation expense after gross-up.

ii. Analysis

In its initial filing, PGS requested $3,308,320,402 for projected test year plant in service.[38] PGS witness Parsons stated in her direct testimony that PGS applied the same accounting principles, methods, and practices that the Company employed for its historical data and the forecasted data for the 2024 projected test year to create the budget for 2024. OPC witness Kollen declared in his testimony that the capital budget was created outside of the Company's normal course of business and is excessive considering the Company does not use all budgeted funds it has had approved in prior years for capital projects. In her rebuttal testimony,

[38]The projected test year balance of plant in service, less the Company's adjustment to reflect Common Plant allocations.

witness Parsons stated that the timing of the budget was different than previous years in order to meet the schedule of this rate case and to account for use of a forecasted test year. Witness Parsons also noted that PGS has not used budgeted funds in prior years due to the impact of the COVID-19 pandemic, which created unique and unprecedented operational changes.

PGS maintained its stance that the budget is reasonable and prudent, and is needed to support customer growth, enhance customer service, and enhance the safety and reliability of its system. Contrary to PGS, the Joint Parties maintained in their brief that PGS failed to capture all circumstances that might impact an underspend and failed to meet its burden of demonstrating that its projections are fully reliable.

The Company has requested test year cost-recovery for $362 million associated with capital projects. For all capital projects, our staff requested detailed information that included the project need, project capital, and how the Company determined the project was the least-cost alternative. For the major expansion projects, such as the Sumterville-Dade City Connector, our staff additionally requested the Company provide all alternatives considered and a detailed cost breakdown. Upon reviewing the Company's responses, we have determined that PGS selected projects that were reasonable and the least-cost alternative when possible. We therefore approve of PGS's capital projects reflected in the projected test year.

However, fallout adjustments from other issues have been made to reduce projected test year plant in service. The stipulation in Section IV.G addresses the removal of the Alliance Dairies RNG project from the Company's request, but it only cites the total corresponding adjustment to revenue requirement. Based on a detailed breakdown of the cost components for the Alliance Dairies RNG project, the fallout adjustment to projected test year plant in service shall be a reduction of $11,530,336. Further, based on our ruling in Section VI.F to disallow recovery of the new Real Estate employee positions, the balance shall be decreased by $314,216 to remove the capitalized salaries and benefits associated with the three positions. As in Section VI.F, the total adjustment reflects the payroll and benefits data for each specific position. In total, projected test year plant shall be decreased by $11,844,552. As such, the appropriate level of projected test year plant in service shall be $3,296,475,850.

iii. <u>Conclusion</u>

Based on the stipulation in Section IV.G and our ruling in Section VI.F, we find that projected test year plant in service shall be reduced by $11,844,552. As such, the appropriate level of projected test year plant in service shall be $3,296,475,850.

K. <u>Accumulated Depreciation and Amortization</u>

i. <u>Parties' Arguments</u>

PGS stated that it has made five adjustments to accumulated depreciation that are reflected in its revised net revenue requirement increase, but the level of projected test year plant accumulated depreciation and amortization depends on the outcome of the other rate base and depreciation issues.

The Joint Parties stated that the resolution of this issue is dependent upon our decision in Section IV.J.

ii. Analysis

This is a fallout issue. Based on a detailed breakdown of the cost components for the Brightmark and Alliance Dairies RNG projects, the fallout adjustments to the stipulations in Sections III.A and IV.G shall be an increase of $477,092 for the accelerated depreciation of Brightmark assets and a reduction of $507,203 for the removal of Alliance. Based on our findings in Section III.C and VI.N regarding the Company's updated Depreciation Study and corrections to the New River RNG project depreciation, fallout adjustments shall be made to decrease the projected test year balance by $127,147 and $101,319, respectively. In total, projected test year accumulated depreciation and amortization shall be decreased by $258,577. As such, the appropriate level of projected test year accumulated depreciation and amortization in service shall be $922,567,707.

iii. Conclusion

Based on the stipulations in Sections III.A and IV.G and our findings in Sections III.C and VI.N, projected test year accumulated depreciation and amortization shall be decreased by $258,577. As such, the appropriate level of projected test year accumulated depreciation and amortization shall be $922,567,707.

L. Construction Work in Progress

i. Parties' Arguments

PGS stated that, as shown in Section IV.J, the Company budgeting process is reliable and CWIP should not be adjusted according to the Joint Parties' proposal. PGS claimed that due to the Company updating its 2023 budget and reflecting this in its 2024 budget, the Joint Parties' use of budgeted amounts of CWIP for 2021 is misplaced. PGS acknowledged that actual CWIP for 2022 varied from the budget primarily due to large projects that accrued allowance for funds used during construction; however, the Company explained that the CWIP variances created by these projects would not affect rate base or CWIP. Furthermore, the Company asserted that it exceeded its 2022 budget and expects to spend its capital budget for 2023, and believes the test year CWIP balance should not be adjusted.

The Joint Parties stated that the resolution of this issue is dependent upon our decision regarding Section IV.J.

ii. Analysis

This is a fallout issue. In Section IV.J, no adjustments to the projected test year associated with the budgeted level of capital expenditures are necessary. As such, no related adjustments to CWIP are necessary.

As discussed in Section VI.M, we approve an adjustment to decrease O&M expenses by $2,125,283 to increase the amount of A&G expense being capitalized. OPC witness Kollen proposed the A&G expense adjustment in his testimony, but he did not recognize the corresponding increase in rate base that would result in the capitalization of additional expense. PGS witness Parsons testified that if we made an adjustment to increase the capitalization of A&G, it should also increase rate base. Further, OPC witness Kollen testified that once the A&G credit is then capitalized to relevant construction projects, it is included in CWIP before being included in plant in service. As such, an adjustment to CWIP is an appropriate method to reflect the corresponding increase to rate base. Therefore, based on our finding in Section VI.M to increase the transfer of A&G expense, projected test year CWIP shall be increased by $2,125,283. The appropriate level of projected test year CWIP shall be $26,434,732.

iii. Conclusion

Based on our finding in Section VI.M, projected test year CWIP shall be increased by $2,125,283. As such, the appropriate level of projected test year CWIP shall be $26,434,732.

M. Working Capital Allowance Adjustments for Under- and Over-Recoveries

At the hearing, we approved a type 2 stipulation as follows: The Company has made the proper adjustments to the Working Capital Allowance to reflect under recoveries and over recoveries in the projected test year related to the Purchased Gas Adjustment, Energy Conservation Cost Recovery, and CI/BSR as shown in MFR Schedule G-1, pages 2 and 3.

N. Unamortized Rate Case Expense

At the hearing, we approved a type 1 stipulation as follows: The Company did not include unamortized rate case expense in working capital for the 2024 projected test year.

O. Working Capital

At the hearing, we approved a type 2 stipulation as follows: The appropriate amount of projected test year working capital is a negative $28,047,011 as shown on MFR Schedule G-1, page 1, line 11.

P. Rate Base

i. Parties' Arguments

PGS argued that the Joint Parties' proposal to increase the allocation of administrative and general (A&G) expenses to rate base should be rejected, as PGS has shown its allocation of A&G expenses are reasonable. PGS recommended using the Company's revised proposed rate base of $2,355,546,414, unless we accept the Joint Parties' proposal on Section VI.M, in which case a corresponding increase to rate base should be made to reflect the increase of allocated A&G expense.

The Joint Parties stated that the resolution of this issue is dependent upon our decision regarding Sections IV.J, VI.M, and VII.B.

ii. Analysis

This is a fallout issue of Section IV, which addresses the projected test year balance of each rate base component. Based on the stipulation of Working Capital in Section IV.O and the adjustments we approved to the projected test year balances of plant in service, accumulated depreciation and amortization, and CWIP in Sections IV.J, IV.K, and IV.L, respectively, the appropriate level of rate base for the projected test year shall be $2,357,327,760.

iii. Conclusion

The appropriate level of projected test year rate base shall be $2,357,327,760.

V. Cost of Capital

A. Accumulated Deferred Taxes

i. Parties' Arguments

PGS witness Parsons argued the amount of accumulated deferred income taxes (ADITs) to include in the capital structure is $279,720,428. This reflects three adjustments to the $280,240,209 amount shown on MFR Schedule G-3, page 2. The first adjustment ($4,486 decrease) was related to changes in accumulated depreciation, as discussed in Section IV.K. The second adjustment was to remove the deferred taxes associated with the Alliance Dairies RNG project, as discussed in Section IV.G ($489,300 decrease). The third adjustment was for the decrease in rate base discussed in Section IV.P, allocated pro rata over all sources of capital ($25,995 decrease).

OPC witness Kollen argued that the correct amount of ADITs to include in the capital structure is $286,705,000. This is the result of witness Kollen's recommendation of $904,439,158 for accumulated depreciation and amortization (see Section IV.K), which corresponds to an increase of $6,464,791 in ADITs when reconciled to the capital structure pro rata over all sources of capital.

ii. Analysis

PGS's and the Joint Parties' recommended amount of ADITs in the projected test year capital structure differs slightly. PGS requested a total ADITs balance of $280,240,209 to include in the projected test year capital structure, which is presented on MFR Schedule G-3, page 2. PGS witness Parsons subsequently made three adjustments to PGS's as-filed request. The first adjustment was a $4,486 decrease of deferred taxes related to the Company's proposed net adjustment in accumulated depreciation (see Section IV.K). The second adjustment is to remove the deferred taxes associated with Alliance Dairies RNG project, a $489,300 decrease (see Section IV.G). The third adjustment was a $25,995 decrease to deferred taxes related to the removal of the Alliance Dairies RNG project plant in service (see Section IV.P). The end result is a final requested ADITs balance of $279,720,428. OPC witness Kollen recommended a total ADITs balance of $286,705,000. The difference in the Joint Parties' recommended amount arises from witness Kollen's recommendation to change depreciation expenses. This results in a $6,464,791 increase in ADIT's as well as a $532,000 decrease to the base revenue requirement.

There is no difference in opinion between PGS and the Joint Parties with regard to the effects of the stipulation on Section IV.G regarding the Alliance Dairies RNG project, which resulted in a $489,300 decrease in ADITs. In Section IV.P, we approve a total rate base amount of $2,357,327,760. When this amount is reconciled pro rata over all sources, excluding customer deposits, to our approved capital structure, the corresponding amount of ADITs based on a ratio of 11.77 percent (see Section V.I) shall be $277,551,630.

iii. Conclusion

For the aforementioned reasons, the appropriate amount of ADITs to include in the projected test year capital structure shall be $277,551,630.

B. Cost Rate of Unamortized Investment Tax Credits

i. Parties' Arguments

PGS witness Parsons argued that because the Alliance Dairies RNG project will be moved below the line (see Section IV.G) that there will be no unamortized investment tax credits (ITCs) in the projected test year capital structure, and therefore the issue is essentially moot.

OPC witness Kollen stated that all the applicable Joint Parties adjustments that affect the cost rate of unamortized ITCs are appropriate, and result in cost rate for the test year of 6.73 percent.

ii. Analysis

This is a fallout issue. The appropriate cost rate for unamortized ITCs is determined by the jurisdictional capital structure and associated cost rates of long-term debt, short-term debt, and common equity. Based on our findings in Section V, the cost rate of the unamortized ITCs is calculated using the sum of the weighted average cost of the appropriate jurisdictional capital structure and cost rates of long-term debt, short-term debt, and common equity, as shown in Table 5.

Table 5
Projected Test Year Investment Tax Credits Component Cost

Capital Component	Jurisdictional Adjusted Capital	Capital Ratio	Component Costs	Weighted Average Cost
Long-Term Debt	$830,722,209	40.48%	5.54%	2.24%
Short-Term Debt	$99,496,189	4.85%	4.85%	0.24%
Common Equity	$1,122,029,733	54.67%	10.15%	5.55%
Total	$2,052,248,131			8.03%

We note that when PGS filed its petition, the ITCs for the projected test year capital structure included the Alliance Dairies RNG project. Due to fallout from Section IV.G, that project has been moved outside of rate base, meaning that the basis for including the associated ITCs in the projected test year capital structure is no longer applicable. This means that the dollar amount of the ITCs shall be zero for the projected test year capital structure.

iii. Conclusion

Due to fallout from Section IV.G, there shall not be any unamortized ITCs included in the projected test year capital structure. However, the appropriate cost rate for unamortized ITCs for the projected test year capital structure shall be 8.03 percent.

C. Amount and Cost Rate of Customer Deposits

At the hearing, we approved a type 1 stipulation as follows: The amount of customer deposits for the 2024 projected test year is $27,528,000. The cost rate of the customer deposits to include in the projected test year capital structure is 2.53 percent, as shown on MFR Schedule G-3, page 2, line 4.

D. Cost Rate of Short-Term Debt

i. Parties' Arguments

PGS argued the appropriate cost rate for short-term debt for inclusion in the projected test year capital structure is 4.85 percent as shown on MFR G-3, page 4. PGS witness McOnie argued that the cost rate reflects PGS's forecasted short-term interest expense on a stand-alone basis on its credit quality and that the short-term debt cost rate is based upon on the Secured Overnight Financing Rate (SOFR) plus credit spreads and program fees. Witness McOnie contended that the short-term debt cost rate in PGS's 2020 rate case, approved by us in the 2020 Agreement, was 1.15 percent.[39] Witness McOnie argued that since 2020, the underlying overnight borrowing rate increased by approximately 425 basis points. This is a result of the U.S. Federal Reserve increasing the overnight borrowing rate. This is the main cause for the rise in short-term borrowing costs. Witness McOnie further argued that we have consistently allowed utilities to recover the short-term debt costs for the projected test year through base rates, and

[39]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System.*

should not reverse this precedent. Witness McOnie claimed that a departure from past precedents by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and the Company's ability to generate cash flow.

OPC witness Kollen argued that PGS is not entitled to recover its predicted market-based cost rate of 4.85 percent for short-term debt. Witness Kollen further argued that we should set PGS's cost of short-term debt at 3.81 percent to retain the lower cost debt previously allocated to the Company when it was a subsidiary of TECO and to shift new costs resulting from the 2023 Transaction away from customer rates, as further discussed in Section IX.B. Additionally referring to PGS's requested Private Letter Ruling (PLR)[40] from the Internal Revenue Service (IRS) regarding the 2023 Transaction, witness Kollen argued we are not required to recognize the higher cost of the new debt for ratemaking purposes, regardless of the structure of the 2023 Transaction and the PLR from the IRS. Witness Kollen argued that the IRS has no statutory authority - nor does the PLR itself direct this Commission - to provide recovery of the Company's requested cost of debt. The Joint Parties noted that the last forecasted earnings surveillance report (ESR) for the consolidated PGS and TECO operations ending December 31, 2022 (submitted February 28, 2022) showed a 0.39 percent cost for short-term debt.

ii. Analysis

OPC witness Kollen did not provide any specific arguments regarding the appropriateness of PGS's proposed cost rate for short-term debt of 4.85 percent. Rather, witness Kollen argued that because the separation of PGS from TECO will result in higher costs to PGS customers, we should approve a lower cost of debt to shift the effects from the 2023 Transaction away from customer rates. The amount witness Kollen used to quantify the additional costs to customers from the 2023 Transaction was about $8.9 million, and was determined from PGS's response to discovery. The Joint Parties argued that we should set the Company's cost of short-term debt below the market-based cost for PGS's projected test year. Witness Kollen recommended a cost rate for short-term debt of 3.81 percent, combined with his recommended cost rate for long-term debt, which together would reduce the revenue requirement by $8.895 million and nullify the increased costs to customers resulting from the 2023 Transaction.

PGS witness McOnie explained, and we agree, that we have consistently accepted that short-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. We note that in rate cases with a projected test year, as is the case here, it is common practice for a utility to estimate debt cost rates for prospective debt issuances and calculate the cost of short-term and long-term debt accordingly.[41] Witness McOnie contended that a departure from past precedent by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability.

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[40]A PLR is a statement by the IRS that interprets tax law at the request of a taxpayer .

[41]Order Nos. PSC-10-0153-FOF-EI, issued March 17, 2020, *In re: Petition for increase in rates by Florida Power & Light Company*, p. 109-110, and PSC-10-0029-PAA-GU, issued January 14, 2010, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation*, p. 10.

We reviewed the Joint Parties' reference to PGS's ESR short-term debt cost rate of 0.39 percent, and note that the referenced ESR is a forecast for the 2022 year that was submitted February 28, 2022. This was before the U.S. Federal Reserve increased the overnight borrowing rate, and thus the cited ESR could not take this factor into consideration. Further, PGS's historic base year cost rate for short-term debt (ending December 31, 2023) is 4.22 percent (as seen in MFR Schedule G-3, page 1 of 11) and reflects the changes to overnight borrowing rates not reflected in the Joint Parties' cited source. We further note that short-term debt is, by definition, for a period of one year or less. Therefore, using a cost rate from previous years is inappropriate.

We note that most of the Joint Parties' arguments in this issue relate to the 2023 Transaction's effect on PGS's projected cost rate for its short-term debt which are mostly identical to their arguments in Section V.E for PGS's projected cost rate for long-term debt. Therefore, we address the Joint Parties' arguments related to the 2023 Transaction in Sections V.E. and IX.B.

iii. <u>Conclusion</u>

We reviewed PGS's estimate for the projected test year short-term debt cost rate, which is based on the SOFR plus credit spreads and program fees, and find PGS's estimate to be reasonable. With this in mind, and additionally taking into consideration that the Joint Parties did not provide any specific arguments as to the market-based appropriateness of PGS's proposed short-term debt cost rate, we agree with PGS. We therefore approve a cost rate for short-term debt of 4.85 percent for the projected test year capital structure.

E. <u>Cost Rate of Long-Term Debt</u>

i. <u>Parties' Arguments</u>

PGS argued that OPC did not present testimony contesting the Company's forecasted long-term debt cost rate, but proposed that the incremental borrowing expenses attributable to the 2023 Transaction be disallowed. PGS addressed that proposal in Section IX.B. PGS argued its proposed 5.54 percent long-term debt rate reflects the Company's forecasted long-term debt borrowing costs on a stand-alone basis, reflecting forecasted market conditions and the Company's credit quality. PGS explained the Company plans to issue $825 million of long-term debt in three tranches with differing terms to mitigate the long-term costs of debt and refinancing risks. PGS estimated its cost rates based on underlying U.S. Treasury rates sourced by Bloomberg, plus a forecasted spread for a typical gas distribution company with a BBB+ credit rating. PGS argued that the increase in long-term interest rates since the Company's last base rate proceeding is attributable to the efforts of the Federal Reserve to combat inflation by increasing its overnight borrowing rate. PGS asserted that we have consistently concluded that utilities should recover their projected debt costs through base rates and a departure from this practice would negatively impact rating agency assessments of the Company's regulatory environment and cash flow generating ability. PGS confirmed the Company is in the process of obtaining an independent, standalone credit rating and is making progress toward that goal. PGS argued the Company's proposed amount of long-term debt for the test year reflects the $832,185,531 of long-term debt on MFR G-3, page 2, adjusted for the decrease in rate base in Section IV.P, and increased for a pro-rata allocation over investor sources of capital offset for change in accumulated deferred income taxes in Section V.A.

The Joint Parties argued that PGS's customers will have to pay a higher rate for long-term debt than they otherwise would have if the 2023 Transaction had not occurred. The Joint Parties argued the 2023 Transaction requires PGS to issue new and significantly higher cost of debt to "repay" the entirety of its share of long-term debt acquired by TECO. PGS's requirement to "repay" the debt is due to the Intracompany Debt Agreement (IDA) that needs to be paid back by December 31, 2023, to avoid a potential tax liability of $150 million. The Joint Parties argued this harms PGS's customers for the foreseeable future and will permanently increase PGS's cost structure until all new debt fully matures 30 years from now. In addition, the Joint Parties argued the effect of paying off the IDA at a blended cost rate of 5.57 percent results in an increase in the overall weighted cost of debt by 29 basis points and an increase in revenue requirement of approximately $7.1 million. The Joint Parties argued that the reallocation of lower-cost legacy debt from PGS to TECO for ratemaking purposes, which is replaced with higher cost debt, is a subsidization by PGS customers for the benefit of TECO customers. The Joint Parties argued that PGS will incur additional costs, i.e., independent audit fees and credit rating agency fees, associated with issuing its own debt that it did not incur while a division of TECO. The Joint Parties argued that the consolidated surveillance report for PGS and TECO for December 2022 shows a 3.81 percent cost rate for long-term debt.

In its brief for Section V.I, the Joint Parties argued that although PGS witness McOnie asserted that PGS's capital structure and ROE are two of the key variables that rating agencies consider when reviewing a utility's debt level and cash flow as part of the rating agencies' process to assign a credit rating, he ignored the impact the 2023 Transaction would have on PGS's financial strength and access to capital. The Joint Parties argued that PGS would have a credit rating of BBB+ if it was still a division of TECO, but the 2023 Transaction will likely cause a one notch lower credit rating for PGS. The Joint Parties also argued that all three credit rating agencies have reduced TECO's credit rating outlook from stable to negative as a result of the spin-off of PGS. Further, the Joint Parties argued PGS's plans to use the private placement market to purchase its debt capital will cost more than accessing debt capital in the public market through TECO. The Joint Parties argued the impact of the Company's decision to undertake the 2023 Transaction is to increase financing costs to customers. The Joint Parties recommended that we should approve a cost rate of 4.61 percent to retain the savings from the lower-cost debt previously allocated to it, regardless of the Company's actual cost of the new debt issued to replace the former allocation.

ii. Analysis

According to PGS, as a result of the 2023 Transaction, PGS must begin securing its own debt capital by borrowing from lenders and pay off the IDA with TECO by December 31, 2023, so the PGS restructuring will be considered a non-taxable asset transfer for Federal income tax purposes. Failure by PGS to pay off the IDA would potentially create a Federal income tax liability of $150 million for PGS and its customers. The Joint Parties did not refute PGS's position on the potential tax liability, but rather argued that PGS should not have structured the 2023 Transaction in the manner it did. The 2023 Transaction requires PGS to issue its own debt by December 31, 2023, pursuant to the terms of the IDA between TECO and PGS. Prior to the 2023 Transaction, TECO issued all long-term debt and short-term debt sufficient to meet the debt financing requirements for both its electric business and its PGS gas division. The debt then was allocated between the electric business and the PGS division based on the respective financing requirements for each year. The 2023 Transaction ended this relationship and prospectively reallocates the existing long-term debt originally issued by TECO on behalf of PGS back to TECO.

Both the Joint Parties and PGS agree that the 2023 Transaction increased PGS's long-term debt cost for the 2024 projected test year. PGS estimated the impact of the 2023 Transaction will increase the cost of long-term debt from 3.97 percent in 2022 to 5.54 percent in 2024. PGS has not quantified any short-term financial benefits from the 2023 Transaction. However, PGS witness Wesley explained the 2023 Transaction provides long-term benefits by isolating PGS from potential incidents (natural disasters or detrimental business issues not related to PGS) that could impair TECO's ability to provide capital to PGS.

The Joint Parties did not contest PGS's forecasted long-term debt cost rate of 5.54 percent. OPC witness Garrett did not specifically address the long-term debt cost rate in his testimony, and he used PGS's proposed cost of long-term debt of 5.54 percent in his recommended authorized rate of return for PGS. Instead, the Joint Parties argued that we should set PGS long-term debt rate at 4.61 to recognize the historical debt that was allocated from TECO when PGS was a division of TECO. Witness Kollen asserted the effect of the Joint Parties' recommendation is a $8.895 million reduction in revenue requirement for long-term and short-term debt combined.

In their brief, the Joint Parties cited to an ESR for the consolidated PGS and TECO operations for December 31, 2022, and argued it showed a long-term debt cost rate of 3.81 percent. We reviewed the document and note that the referenced ESR is a forecasted ESR that was submitted on February 28, 2022. We note that this was before the U.S. Federal Reserve Board increased interest rates, and thus, the cited forecast, at that time, could not have taken this factor into consideration. We further note that PGS's historic base year cost rate for long-term debt (ending December 31, 2023) is 4.58 percent (as seen in MFR Schedule G-3, page 1 of 11) and reflects the changes to interest rates not reflected in the Joint Parties' cited source.

As shown on MFR Schedule G-3, page 8, the long-term debt cost rate of 5.54 percent is based on forecasted debt issuances of $825 million during 2023 and $100 million in 2024. PGS witness McOnie testified the $825 million inaugural debt issuance during 2023 is forecasted to occur using three tranches of differing terms; $325 million of 5-year notes at 5.40 percent, $300 million of 10-year notes at 5.47 percent, and $200 million of 30-year notes at 6.00 percent. Witness McOnie explained the Company cannot predict the specific time of year this will occur, but the Company budgeted the 2023 issuance to occur on September 30, 2023. Evidently, the issuance date will be later than September 30, 2023, as explained by witness McOnie, possibly in late October, November or December. However, the 2024 issuance still assumes a June 30, 2024, financing date for $100 million of 10-year notes at 5.37 percent. The embedded cost of long-term debt as a result of combining the four tranches of debt issuances is 5.54 percent as shown on MFR Schedule G-3, page 3.

PGS intends to engage credit rating agencies in 2023 to assess the stand-alone credit rating of PGS and assign an indicative credit rating[42] as part of the rating evaluation service provided by the rating agencies. Witness McOnie explained the rating agencies will assess the outcome of the instant rate case in addition to other business and financial risk assessments and provide a final credit rating. PGS is targeting a credit rating of BBB+, which is two notches above the minimum investment grade rating of BBB-.

In their brief for Section V.I, the Joint Parties argued that as a result of the 2023 Transaction, TECO's credit rating outlook from all three rating agencies changed from stable to negative. In their brief, the Joint Parties asserted that in September 30, 2022, TECO had a BBB+ credit rating from S&P, A3 from Moody's, and A from Fitch, with a stable outlook. In the December 31, 2022 TECO 10-K, the potential business risk related to the $150 million potential tax liability as of January 1, 2023, related to the legal separation of PGS was addressed. TECO's credit rating outlook changed to negative in December 2022 for all three rating agencies. The credit agencies' outlook continued to remain negative for TECO as of June 30, 2023. However, witness McOnie explained the negative outlook will continue to be the case for a twelve-to-eighteen-month period. Witness McOnie also explained the reason for the negative outlook:

> Tampa Electric is part of the Emera family of companies. Emera was placed on negative outlook due to the legislative action in Nova Scotia that pertained to Bill 212, I believe, that capped Nova Scotia Power rates rate increase at 1.8 percent per filed document. Each of the rating agencies viewed the political interference extremely negative to the regulatory process. In addition to that, the credit metrics were down from the higher gas prices at Tampa Electric, and there was an under-recovery period during -- leading into the end of 2022. So, these two factors combined, along with the delay in cash flows from the Labrador Island link, caused each of the rating agencies to place Emera on negative outlook. Because Tampa Electric is one of our group of families, its rating agency practice is to put the entire group on negative outlook.

According to witness McOnie, the main drivers for the increase in the long-term cost of debt in the 2024 test year is the increase in the U.S. Treasury Bond rates. PGS's requested cost rate for its newly issued long-term debt is based on the prevailing yield on U.S. Treasury Bonds plus an additional credit risk spread associated with a BBB+ credit rating. Witness McOnie's direct testimony filed on April 2, 2023, indicated the forecasted rate for 30-year U.S. Treasury Bonds was 3.89 percent and 3.76 percent for the third and fourth quarters of 2023, respectively. During cross examination, OPC witness Garrett confirmed that as of September 13, 2023, the yield on 30-year U.S. Treasury Bonds was 4.34 percent. Witness McOnie explained the Federal Reserve's decision to increase interest rates to mitigate inflation caused short-term interest rates to increase more than long-term interest rates which is commonly referred to as an inverted yield curve. That is, short-term debt is more costly than long-term debt. However, the interest rates for 30-year U.S. Treasury Bonds have remained anchored to approximately 4.00 percent due to expectations that the economy will slow down in the future.

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[42]An indicative credit rating is one that is unpublished and confidential which reflects the analysis of one or more hypothetical scenarios for a company.

We agree with witness McOnie that issuing three tranches of debt for terms of five, ten and thirty years would be prudent and mitigate refinancing risk. Issuing a 30-year note would mitigate the risk of continued rising interest rates because the prevailing rate on 30-year U.S. Treasury Bonds is in line with its long-term average yield of 4.46 percent. The 5-year and 10-year notes should afford PGS the opportunity to refinance at short-term interest rates that are more reflective of their 30-year averages of 3.38 percent and 3.90 percent, respectively. Currently, short-term debt cost rates are much higher than their historical averages.

PGS proposed an additional adjustment to ensure the accuracy of its long-term debt cost rate. Because the long-term debt cost rate is prospective and based on assumed debt issuances by PGS that have yet occurred, PGS proposed a long-term debt true-up mechanism that is discussed in Section IX.A. PGS believes the long-term debt true-up mechanism will provide a fair one-time adjustment to base rates reflecting the actual long-term debt cost achieved in 2023.

OPC witness Kollen recommended that we should approve a long-term debt cost rate of 4.61 percent. Witness Kollen obtained his recommended long-term debt cost rate from PGS's discovery response to OPC's First Set of Interrogatories, No. 100, wherein the Company quantified the effect of the legal separation of PGS from TECO. The long-term debt cost rate of 4.61 percent was derived from a blended rate of 4.04 percent for the historical debt issued by TECO on behalf of PGS and a forecasted cost rate of 5.64 percent and 5.54 percent for two new issuances of long-term debt.

OPC witness Kollen asserted that Emera structured the 2023 Transaction, including the Intercompany Debt Agreement, for its benefit and that it will harm PGS customers. The Joint Parties argued that the structure of the 2023 Transaction and the consequences of its implementation will deny PGS of the benefits of the lower-cost, historical debt that had been issued specifically to PGS to meet its financing requirements. Witness Kollen contended the reallocation of the historical lower-cost, long-term debt from PGS back to TECO benefits TECO's customers and, is in essence, a subsidy from PGS to TECO in the amount of $7.1 million annually until TECO's base rates are reset in its next rate case sometime in 2025. Further, witness Kollen asserted PGS failed to explain why it did not consider a separate intercompany loan from TECO to PGS that would preserve the historical lower-cost debt beyond 2023.

Witness McOnie disagreed with witness Kollen's assertion and explained the Company evaluated whether to continue the historical borrowing arrangement between the two utilities or preserve the allocation of lower-cost, long-term debt to PGS as part of the 2023 Transaction, but decided that entering into an IDA along with PGS issuing its own short-term and long-term debt to repay the IDA in 2023 and fund future capital needs was the best long-term solution for PGS and its customers. PGS argued that the objective of the 2023 Transaction was to insulate PGS from TECO from the contagion risk[43] of the other respective affiliates through legal, operating, and financial structures. Witness McOnie explained that PGS has implemented organizational changes to structurally isolate itself from its TECO affiliate through its own separate management team, separate accounting records, and adheres to arm's length transaction

[43]Contagion risk is the spread of financial difficulties or economic crisis between affiliates.

protocols when doing business with affiliates. Further, Emera decided that PGS establishing its own borrowing arrangement and ceasing its reliance on TECO as a creditor and source of capital was the best way to achieve bankruptcy remoteness.[44]

On rebuttal, witness McOnie testified we have a long history of allowing utilities to recover their projected long-term and short-term borrowing costs through customer rates, and that we should not depart from this practice in this case. Witness McOnie explained that we have consistently accepted that long-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. We note that in rate cases with projected test years, as is the case here, it is common practice for the utility to estimate debt cost rates for prospective debt issuances and calculate the cost of long-term debt accordingly.[45] Witness McOnie contended that a departure from past precedent by not allowing the recovery of market-based interest rates would impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability respectively. As pointed out by witness McOnie, since the forecasted long-term borrowing costs are market-based, and reflect actual interest obligations, a disallowance of the recovery of the full interest expense amount could potentially be considered unconstructive by rating agencies.

PGS witness McOnie rebutted the Joint Parties' argument that the 2023 Transaction results in a subsidy in favor of TECO and its customers and asserted that to the extent that the 2023 Transaction benefits TECO and its customers in the short term, the Joint Parties should also recognize that TECO's historical practice of borrowing on behalf of PGS benefitted PGS's customers through lower interest rates and avoided stand-alone expenses such as independent audit and credit rating agency fees. Witness McOnie asserted that except for interest rate differences associated with different credit ratings, PGS and TECO will over time borrow at approximately the same interest rates, because the long-term debt issued at historically low interest rates and enjoyed by the customers of both utilities will over time be replaced with new debt at the then current market rates.

We do not find the Joint Parties' argument for us to set PGS's cost of long-term debt below its actual forecasted market-based cost to be persuasive and there is no evidence in the record that Emera's decision to legally separate PGS involved malfeasance or was a deliberate plan to benefit TECO at the expense of PGS's customers (see Section IX.B). Emera made a business decision to spin PGS off into a new company for which we have no authority to approve or deny. The Joint Parties' argument that PGS customers are entitled to past debt cost rates that were obtained by TECO under the previous divisional organizational relationship was not based on any Commission precedent or legal argument, nor was it convincing. If Emera sold PGS to another entity as opposed to the restructuring, PGS would not be entitled to the historical long-term debt cost from TECO. In this case, PGS demonstrated that its 2023 Transaction meets

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[44]Bankruptcy remoteness is a company within a corporate group whose bankruptcy has as little impact as possible on other entities within the group.

[45]Order Nos. PSC-10-0153-FOF-EI, issued March 17, 2020, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company*, p. 109-110, and PSC-10-0029-PAA-GU, issued January 14, 2010, in Docket No. 20090125-GU, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation*, p. 10.

IRS requirements for a tax-free transaction which includes PGS divesting from TECO and issuing its own debt. Otherwise, PGS could be liable for $150 million of capital gains tax. The Joint Parties' recommendation to not allow PGS to recover its actual market-based cost of long-term debt in the Company's allowed overall rate of return will reduce PGS revenue below a level necessary to recover its interest expense. This revenue reduction would consequently not allow PGS to earn its authorized return on equity and could be considered non-compensatory.

iii. Conclusion

Based on the aforementioned, we approve a forecasted long-term debt cost rate of 5.54 percent for the projected test year ending December 31, 2024.

F. Adjustments for Non-Utility Investments

i. Parties' Arguments

PGS asserted it made the proper adjustments to remove all non-utility investments from the projected test year common equity balance as shown on MFR G-3, page 2, and Exhibit RBP-1, Document No. 9, attached to witness Parsons' direct testimony and Exhibit 218 (revised revenue increase).

The Joint Parties took no position on this issue in their brief.

ii. Analysis

In its initial filing, PGS presented its projected test year capital structure based on a 13-month average as of December 31, 2024, consisting of common equity in the amount of $1,124,006,187 (adjusted) on MFR Schedule G-3, page 2, line 1. Exhibit RBP-1, Document No. 9, attached to PGS witness Parsons' direct testimony, detailed the Company's projected test year reconciliation of capital structure to rate base that showed its specific adjustments to remove non-utility investments from common equity. The reconciled items with specific adjustments to the projected test year common equity balance reflected within Exhibit RBP-1, Document No. 9, included a total of three adjustments to the following: (1) Property Held for Future Use; (2) Investments in Subsidiaries; and (3) Non-utility Adjustments to Rate Base. In addition, a type 2 stipulation was approved for Section IV.A that all required adjustments to remove non-utility items from Plant in Service, Accumulated Depreciation, and Working Capital have been included in the projected test year, as shown on MFR Schedule G-1, page 4. Typically, if all non-utility activities have been removed from rate base, corresponding adjustments are made to remove non-utility activities from the capital structure. We reviewed the Company's adjustments and concur with PGS that the non-utility items have properly been removed from common equity.

Further, no argument was proffered on behalf of the Joint Parties concerning whether PGS has made the proper adjustments to remove all non-utility investments from the projected test year common equity balance.

iii. Conclusion

PGS has made the proper adjustments to remove all non-utility investments from the projected test year common equity balance and no additional adjustments are necessary.

G. Equity Ratio

i. Parties' Arguments

PGS argued its requested equity ratio of 54.7 percent from investor sources is the same equity ratio we previously approved in the 2020 Settlement Agreement by Order No. PSC-2020-0485-FOF-GU[46] and is consistent with the equity ratios that have been maintained by the Company since 1998. PGS contended that an equity ratio of 54.7 percent is entirely consistent with two Florida-based peers given the 55.1 percent equity ratio approved by us for FPUC and the 59.6 percent equity ratio approved for FCG. PGS also argued the Company's 54.7 percent equity ratio compares favorably to the equity ratios maintained by the gas companies in witness D'Ascendis's proxy group that he used to develop his recommended return on equity for PGS. PGS argued the maintenance of the requested equity ratio, coupled with an appropriate ROE, should lead to adequate coverage ratios, and provide the financial strength and credit parameters necessary to achieve the Company's targeted credit rating of BBB+ and assure access to capital. PGS argued Joint Parties' proposed equity ratio of 49 percent would not be sufficient to maintain the Company's financial integrity. PGS contended that financial integrity refers to a relatively stable condition of liquidity and profitability in which the Company can meet its financial obligations to investors while maintaining the ability to attract investor capital as needed on reasonable terms, conditions, and costs. PGS argued a more highly leveraged capital structure with a lower overall authorized return will render it more difficult for PGS to achieve credit metrics sufficient to support its targeted rating of BBB+.

The Joint Parties argued that PGS's equity ratio should be set to equal the average equity ratio of the gas utilities in witness Garrett's proxy group which equates to 49.2 percent. The Joint Parties contended that PGS witness D'Ascendis's conclusion that PGS's proposed equity ratio is reasonable because it is within the range of the equity ratios of his gas proxy group is flawed. The Joint Parties argued that every company in the gas utility proxy group has an equity ratio of less than 49 percent, with the exception of Atmos Energy Corp. which has an equity ratio of 62 percent. The Joint Parties contended that since PGS's equity ratio is higher than the proxy group average, it has less financial risk than the gas utility proxy group.[47] The Joint Parties argued that OPC witness Garrett demonstrated that PGS's proposed equity ratio is clearly too high and results in excessively high capital costs and utility rates. In addition, witness Garrett contended that competitive firms maximize their value by minimizing their weighted average cost of capital (WACC) by recapitalizing and increasing their debt financing. Witness Garrett opined that because utilities have low levels of risk and operate a stable business, they can afford to operate

[46]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In Re: Petition for rate increase by Peoples Gas System.*
[47]Both PGS witness D'Ascendis and OPC witness Garrett used the same gas utility proxy group in their equity ratio analysis.

with relatively higher levels of debt (lower equity ratio) to achieve their optimal capital structure. The Joint Parties also argued that because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation. The Joint Parties argued that under a rate base, rate of return model, a higher WACC results in higher rates, all else held constant. The Joint Parties contended the rate base, rate of return model does not incentivize utilities to operate at the optimal capital structure, and consequently, utilities can increase their revenue requirement by increasing their WACC, not by minimizing it. Thus, the Joint Parties argued, there is no incentive for a regulated utility to minimize its WACC by lowering its equity ratio, and therefore, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

ii. Analysis

In its filing, PGS requested a projected test year capital structure consisting of an equity ratio of 54.7 percent based on investor-supplied capital for rate setting purposes. We approved PGS's current equity ratio of 54.7 percent as part of the 2020 Settlement Agreement in the Company's last rate case by Order No. PSC-2020-0485-FOF-GU.[48] PGS witness D'Ascendis testified that PGS requested equity ratio of 54.7 percent is consistent with the range of common equity ratios maintained by the gas utility proxy group, and therefore, is appropriate for ratemaking. For 2022, the range of the equity ratios of the six gas utilities in the proxy group was 34.43 percent to 62.61 percent with an average equity ratio of 48.83 percent. Witness D'Ascendis testified that in order to continue to provide safe and reliable service to its customers, PGS must meet the needs and serve the interests of its various stakeholders, including its customers, shareholders, and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment, so that the Company has access to capital on reasonable terms in order to make necessary investments.

OPC witness Garrett contended that regulated utilities can generally afford to have higher debt levels than other industries because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (lower equity ratios). Further, OPC witness Garrett contended that under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The Joint Parties asserted that because there is no incentive for a regulated utility to minimize its WACC a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC. OPC witness Garrett's arguments are based on basic financial theory and are misapplied to ratemaking and not persuasive. Simply setting PGS equity ratio to the average of the gas utility proxy group for the sole purpose of lowering rates without analyzing the effect on the Company's individual financial metrics is not a convincing argument.

To assess a reasonable equity ratio for PGS, witness Garrett examined the capital structures of the gas utility proxy group and the debt ratios in other industries. Based on his analysis, witness Garrett concluded the average equity ratio of the gas utility proxy group is 49 percent, which he noted is lower than PGS's proposed equity ratio of 54.7 percent. In addition,

[48]Order No. PSC-2020-0485-FOF-GU.

witness Garrett testified that there are nearly 2,000 companies in the U.S. with debt ratios higher than 50 percent and equity ratios lower than 50 percent. Witness Garrett compared the equity and debt ratios of Cable Television, Power and Telecom (other utilities) which are all below 50 percent. Witness Garrett concluded PGS's proposed debt ratio is clearly too low (and its equity ratio is too high). Witness Garrett asserted PGS's high equity ratio results in excessively high capital costs and utility rates and recommended that PGS's equity ratio should be no more than 49 percent.

PGS witness McOnie disagreed with OPC's proposal to reduce PGS equity ratio. In rebuttal, witness McOnie asserted that in credit rating agencies' view the regulatory environment is a key consideration in determining the creditworthiness of an energy utility. The regulator determines an appropriate capital structure and establishes the allowed return on equity, and these are two of the key variables that go into determining a utility's revenue requirement, and by extension, the debt level and cash flow generating capability of the company. Witness McOnie contended a change to either or both will have an impact on the company's financial metrics and creditworthiness. PGS's obligation to serve its customers and the significant capital expenditure requirements needed to maintain and grow its system is better served by stronger financial integrity. Witness McOnie concluded that the maintenance of the requested capital structure, coupled with an appropriate return on equity, should lead to adequate coverage ratios, and provide the financial strength and credit parameters necessary to achieve the Company's targeted credit rating and assure access to capital.

Witness Garrett admitted that he did not perform any quantitative analysis on what affect his recommendation to reduce PGS's equity ratio and allowed ROE would have on PGS's financial metrics, or financial integrity. While this line of questioning was regarding witness Garrett's ROE testimony and not specifically about the equity ratio, witness Garrett testified that "There is no analysis that I performed that I did not present in my testimony and work papers." Therefore, it is a reasonable presumption that witness Garrett did not consider the effect of his recommended equity ratio of 49.0 percent in combination with his recommended ROE of 9.0 percent on PGS forecasted credit metrics and financial integrity. It is a widely accepted paradigm in the financial community that the equity ratio and allowed return on equity are inextricably related. As explained by witness Garrett:

> The cost of equity of any particular company is necessarily connected with its capital structure. This is because there is a direct relationship between risk and return. That is, the higher (lower) risk, the higher (lower) expected return. All else held constant, companies with higher amounts of leverage have higher levels of financial risk. Since we are using a proxy group of companies to assess a fair cost of equity estimate for PGS, we must also factor in the capital structures of those companies into the analysis – failing to do so is an analytical error. Since PGS's debt ratio is lower and the equity ratio is higher than the proxy group average, it has less financial risk than the proxy group. This discrepancy in debt ratio and equity ratio must be accounted for.

Based on the risk-return paradigm, a company with a higher equity ratio in its capital structure, all else being equal, will have less financial risk and should have a comparatively lower return on equity. We agree with PGS that witness Garrett's recommendation to reduce the equity ratio and the ROE at the same time would result in a significant reduction to the revenue requirement of PGS and could possibly have a negative affect on the quality of PGS's credit metrics and financial integrity.

iii. Conclusion

Based on record evidence, and in conformity with our past practice of using a capital structure that approximates the Company's actual sources of capital,[49] PGS's projected equity ratio of 54.7 percent for the projected test year is reasonable and appropriate. Accordingly, we find the appropriate equity ratio is 54.7 percent as a percentage of investor-supplied capital.

H. Return on Equity (ROE)

i. Parties' Arguments

PGS argued that competent, substantial evidence in the record supports an ROE of 11.0 percent with a range of plus or minus 100 basis points. PGS cited the order in our decision regarding the 2022 FCG rate case and argued that we explained:

> Neither case law nor statute mandates that the awarded ROE be tied to the result of a particular financial model. Instead, the Commission will establish a reasonable ROE that is consistent with *Hope* and *Bluefield* and supported by competent, substantial evidence in the record. The Commission has a long history of establishing an ROE midpoint and a range of 100 basis points on either side to create a range of reasonableness and ensure rate stability.

PGS argued that witness D'Ascendis's approach to estimating PGS's required return on equity by applying multiple generally accepted cost of common equity models to a proxy group consisting of six comparable publicly traded companies is reasonable and appropriate. PGS asserted that witness D'Ascendis and OPC witness Garrett agree that an ROE analysis should be based on the use of multiple models and both witnesses used two of the same cost of equity models (the discounted cash flow, or DCF Model, and the capital asset pricing model, or CAPM)[50] and shared the same proxy group of companies. PGS argued that witness D'Ascendis's ROE analysis constitutes competent, substantial evidence that we may rely on in establishing a reasonable ROE that is consistent with *Hope* and *Bluefield*.[51] PGS argued that while OPC witness Garrett followed the same general approach to estimating an ROE as witness D'Ascendis, the results of his analysis are unreasonable and lack credibility. In its brief, PGS

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[49]Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division*, p. 57.
[50]DCF Model and CAPM refer to the Discounted Cash Flow Model and the Capital Asset Pricing Model. These cost of equity models are discussed in greater detail, *infra*.
[51] *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). These cases are discussed in greater detail, *infra*.

pointed out that in PGS's last rate case in 2020, witness Garrett recommended that we adopt an ROE of 9.5 percent. PGS argued that although witness Garrett agreed that capital costs have increased since 2020, he nonetheless recommended that we reduce PGS's authorized ROE by 90 basis points to 9.0 percent. Hence, PGS argued that witness Garrett's recommended ROE is simply irreconcilable with the now higher cost of capital and should be rejected.

Finally, PGS argued that we recently approved effective equity returns or weighted cost of equity (equity ratio times equity return) of approximately 5.65 percent and 5.66 percent for FPUC and FCG, respectively. PGS argued that given PGS's proposed equity ratio of 54.7 percent, to obtain a comparable weighted cost of equity of 5.65 percent, the ROE would work out to be approximately 10.33 percent (5.65% ÷ 54.7% = 10.33%). PGS concluded that although FPUC and FCG may be different than PGS, we should consider its recent decisions and the upward trend in interest rates when setting the Company's mid-point return on equity.

The Joint Parties argued we should reject PGS's exorbitant proposed ROE of 11.0 percent and adopt witness Garrett's more reasonable ROE of 9.0 percent, or in the alternative, award PGS the most current annual national average for natural gas local distribution companies of 9.4 percent. The Joint Parties argued an ROE of 9.0 percent gradually moves PGS's current authorized ROE of 9.9 percent, which is excessive based on current market conditions, toward the actual, current market-based ROE of 8.5 percent based on witness Garrett's application of the CAPM.

The Joint Parties argued the DCF Model and CAPM used by witness Garrett are consistent with the legal standards set forth in the *Hope* and *Bluefield* decisions.[52] The Joint Parties argued witness Garrett's recommended ROE of 9.0 percent complies with the *Hope* and *Bluefield* standards and allows PGS to maintain its financial integrity and satisfy the claims of its investors. The Joint Parties argued that the results from witness Garrett's cost of equity models closely estimate PGS's true cost of equity which comports with the U.S. Supreme Court's decision in the *Hope* case. The Joint Parties argued that witness Garrett correctly stated that the legal standards do not mandate that awarded ROEs must exactly match the cost of capital, but instead must reflect the true cost of capital. The Joint Parties contended that ROEs awarded through the regulatory process may be influenced by outside factors such as settlements and other political factors, not true market conditions, and relying on awarded ROEs from other jurisdictions bears little relation to market-based cost of equity. The Joint Parties argued since 1990, utilities have been awarded ROEs above the market return. The Joint Parties argued witness Garrett's estimated market cost of equity is 9.3 percent, and because utility stocks are less risky than the market, they should be below the market cost of equity. The Joint Parties further argued the failure to closely track the actual market-based cost of capital is detrimental to customers and Florida's economy because these much higher returns result in an inappropriate transfer of wealth from Florida ratepayers to shareholders. The Joint Parties argued that because witness Garrett is an attorney who has practiced law at a regulatory commission, his legal interpretation that the *Hope* and *Bluefield* cases allows for gradualism and supports his true

[52] *Bluefield Water Works and Improvement Co. v. Public Service Commission,* 262 U.S. 679, 692 (1923)*; Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944). These cases are discussed in greater detail, *infra.*

market-based cost of equity is appropriate. Whereas, witness D'Ascendis, who is not an attorney, failed to recognize the main issue that awarded ROEs generally have been greater than the actual market-based cost of equity. The Joint Parties also disagreed with witness D'Ascendis's interpretation of *Hope* and *Bluefield* that the investor-required ROE should equal the allowed ROE, and that the *Hope* and *Bluefield* standards are not as rigid as he contended. The Joint Parties' argument supporting witness Garrett's gradualism theory was best explained in witness Garrett's summary of his testimony:

> Despite the fact that the indicated cost of equity for PGS under my CAPM analysis is only 8.5 percent, it is my opinion that a nine-percent awarded ROE for PGS is reasonable under the circumstances. This is primarily due to the fact that PGS's current awarded ROE of 9.9 percent is significantly higher than a reasonable estimate of the company's market-based cost of equity. One could argue that it is preferable for awarded ROEs to gradually change rather than abruptly. An awarded ROE of 9.0 percent would partially mitigate the excess wealth from Florida customers to shareholders, while gradually moving the company toward [the] actual market-based cost of equity.

ii. Analysis

The ROE is the allowed cost of common equity included in a utility's regulatory capital structure to determine the overall rate of return used to establish a revenue requirement. PGS's common equity is not publicly traded, and as such, a market-based cost rate for the Company cannot be directly observed. Consequently, both PGS witness D'Ascendis and OPC witness Garrett applied cost of equity financial models to a proxy group of publicly traded gas distribution companies (gas proxy group) with similar risk to PGS to derive estimates of the investor required ROE. OPC witness Garrett used the same gas proxy group as that of witness D'Ascendis. Both OPC and PGS witnesses used the DCF Model and the CAPM to estimate the cost of equity. Witness Garrett applied the Hamada Formula to his CAPM to account for the difference between his recommended equity ratio of 49.0 percent and PGS's requested equity ratio of 54.7 percent. In addition, witness D'Ascendis employed two risk premium models (RPM): a predictive risk premium model and a risk premium using an adjusted total market approach. Witness D'Ascendis also applied the DCF Model, CAPM and RPM to a non-price regulated group of companies he argued were similar in total risk to the gas proxy group and obtained a result of 12.3 percent. Witness D'Ascendis did not consider the results from his non-price regulated proxy group in his determination of his recommended range of indicated ROEs for PGS. Consequently, in the interest of brevity, this order will not include an analysis of witness D'Ascendis's non-price regulated proxy group testimony.

In his rebuttal testimony, witness D'Ascendis updated the results of the cost of equity models used in his direct testimony. Therefore, we find it is more appropriate to evaluate witness D'Ascendis's ROE model results used in his rebuttal testimony than his direct testimony because the market-based data is more recent and reflects recent interest rates. Witness D'Ascendis used the same ROE models and methodology in his rebuttal testimony as he did in his direct testimony.

In general, witness D'Ascendis employed assumptions and methods that produced a high ROE estimate, while OPC witness Garrett used assumptions and methods that produced a low ROE estimate. As a result of their respective assumptions used in the cost of equity models, our approved ROE is greater than OPC's recommended ROE of 9.0 percent and lower than PGS's requested ROE of 11.0 percent. The range of results of the witnesses' cost of equity models is 7.50 percent to 11.74 percent. The witnesses' cost of equity model results are summarized in Table 6.

Table 6
Summary of Cost of Equity Model Results

ROE Model	PGS witness D'Ascendis	OPC witness Garrett
DCF – with analyst growth estimates	9.60%	8.30%
DCF – with sustainable growth estimates		7.50%
CAPM	11.74%	8.50%
CAPM with Hamada Formula		8.10%
Risk Premium	11.42%	
Range of Results	9.60% - 11.74%	7.50% - 8.50%
Average of Results	10.92%	8.10%
Recommended ROE	11.00%	9.00%

Legal Standard

The landmark *Hope* and *Bluefield* U.S. Supreme Court cases established standards for setting a fair rate of return for equity investment in utilities providing service to the public. Under the *Hope* and *Bluefield* decisions, the U.S. Supreme Court established that a fair rate of return should be commensurate with the returns on investments in other enterprises having corresponding risks, should be sufficient to assure confidence in the financial integrity of the utility, support reasonable credit quality, and allow a company to raise capital at reasonable costs and terms. Therefore, PGS witness D'Ascendis asserted, it is important that the authorized ROE reflect the risks and prospects of PGS's operations and supports the Company's financial integrity from a stand-alone perspective as measured by its combined business and financial risks.

Witness D'Ascendis acknowledged that in prior rate cases for PGS, we have approved the use of multiple cost of equity models that satisfy the terms for determining a fair rate of return as laid out by *Hope* and *Bluefield*. In particular, he contended that we recognized the market-based approaches such as the DCF model and the CAPM as being consistent with the market-based standards of a fair return enunciated in *Hope* and *Bluefield*. In its brief, PGS made the following statement regarding our decision in Order No. PSC-10-0153-FOF-EI for FPL's rate case:

> The Commission has previously stated that the models used by Mr. D'Ascendis "are generally recognized as being consistent with the market-based standards of a fair return enunciated in the *Hope* and *Bluefield* decisions."

PGS's statement is in need of clarification. First witness D'Ascendis did not testify in the 2009 FPL rate case. Second, upon review of this order, we actually stated:

> 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, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the *Hope* and *Bluefield* decisions.[53]

To be clear, in the order cited by PGS, we did not approve witness D'Ascendis's models as he presented them in this case. Further, witness D'Ascendis's Predictive Risk Premium Method (PRPM) using the Generalized Autoregressive Conditional Heteroscedasticity (GARCH) approach was developed in 2011 and was not used by any witnesses in the 2009 FPL rate case.

Witness Garrett opined that the *Hope* standard makes it clear that the allowed return should be based on the actual cost of capital. Witness Garrett contended that his ROE of 9.0 percent will comply with the U.S. Supreme Court's standards established in *Hope* and *Bluefield* and allow PGS to maintain its financial integrity and satisfy the claims of its investors. Witness Garrett further opined that an allowed ROE that is set far above the actual cost of equity is contrary to the *Hope* and *Bluefield* standards and results in an excess transfer of wealth from the customers to the utility. Witness Garrett's gradualism theory is based on his narrow interpretation of the *Hope* and *Bluefield* standards which he opined supports his argument that the "actual market-based cost of equity" is equal to the results of his estimated cost of equity and would support the financial integrity of the Company simply because his recommended ROE gradually reduces the Company's ROE, but is still higher than the results of his cost of equity analysis or the Company's actual cost of equity. Witness D'Ascendis testified that the national average of awarded ROEs for natural gas companies in 2022 ranged from 9.0 percent to 10.2 percent, with an average of around 9.6 percent. Based on the comparable awarded ROEs for other natural gas companies in the U.S., witness Garrett's recommended ROE may not be commensurate with returns on investments in other enterprises having corresponding risks, and it is certainly at the bottom of the range of awarded ROEs.

Witness Garrett failed to demonstrate that his recommended ROE of 9.0 percent would satisfy the *Hope* and *Bluefield* requirement that the awarded ROE would support PGS's financial integrity so as to maintain its credit quality and attract capital on reasonable terms. Witness Garrett admitted that he did not perform any separate analysis to determine if his recommended adjustments to reduce PGS's current allowed ROE by 90 basis points and equity ratio from 54.7 percent to 49 percent would "maintain" PGS's credit quality. OPC witness Kollen calculated that the impact of witness Garrett's recommended ROE and equity ratio would be a reduction to revenue requirement of $38.5 million. As explained by PGS witness McOnie, credit rating agencies evaluate business risk, financial risk, and regulatory risk to determine a company's credit rating. Financial risk is based on financial ratios covering cash flow and leverage (debt ratio) analysis. The primary business risk credit rating agencies focus on is regulatory risk.

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[53]Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light*, p. 121.

Regulatory risk is based upon transparency, predictability, and stability of the regulatory environment, timeliness of operating and capital cost recovery, regulatory independence, and financial stability. Regulation in Florida has historically been supportive of maintaining the credit quality of the state's utilities, and that has benefited customers by allowing utilities to provide for their customers' needs consistently and at a reasonable cost. Witness McOnie testified that a more highly leveraged capital structure with a lower overall authorized ROE will render it more difficult for the Company to achieve credit metrics sufficient to support its targeted rating of BBB+. Hence, the record makes it clear that any substantial change to reduce PGS's cash flow could lower its credit rating.

Proxy Group Gas Companies

Because PGS is not publicly traded and does not issue publicly traded equity securities, a group of publicly traded companies that have comparable risk characteristics to PGS must be used as a proxy that the cost of equity models may be applied to determine the required ROE. Witness D'Ascendis selected six companies from the Value Line Investment Survey's Natural Gas Utility Group. The gas proxy group includes Atmos Energy Corp.; New Jersey Resources Corp.; NiSource, Inc.; Northwest Natural Holding Co.; ONE Gas, Inc.; and Spire, Inc. Witness D'Ascendis testified that the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards.

OPC witness Garrett did not take issue with witness D'Ascendis's proxy group and opined, "There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups."

We find that the proxy group of gas companies used by both PGS witness D'Ascendis and OPC witness Garrett is reasonable and comparable to PGS for the reasons explained by witness D'Ascendis.

Cost of Equity Models

Discounted Cash Flow Model

The DCF model is based on the theory that a stock's current price represents the present value of all expected future cash flows in the form of dividends discounted at the appropriate risk-adjusted rate of return. In its basic form, the DCF model is expressed as the dividend yield of a stock, plus the expected long-term growth rate: ROE = (dividend ÷ stock price) + growth rate. This is known as the single-stage constant growth DCF model. Both witnesses used an adjusted version of the single-stage constant growth DCF model by adjusting the annual dividend for expected growth expressed as: ROE = [(dividend (1 + growth rate)) ÷ stock price] + growth rate. Witness Garrett used the full value of the growth rate in his DCF calculation to adjust the dividend upwards, whereas witness D'Ascendis used ½ of the growth rate. Although witness D'Ascendis testified that DCF theory calls for using the full growth rate, he used one-half the growth rate in his DCF calculations because the utilities in the gas proxy group increase their quarterly dividends at various times of the year which we agree is a reasonable assumption. We find that the witnesses' use of an adjusted DCF model to account for growth in dividend payments from the utilities is appropriate.

Witness D'Ascendis's DCF model results for the six proxy group gas companies in his rebuttal testimony ranged from 8.81 percent to 11.44 percent with an average of 9.72 percent. Witness Garrett's DCF model results using a sustainable growth rate ranged from 6.6 percent to 8.3 percent with an average of 7.5 percent. Witness Garrett also calculated a DCF result using analysts' estimated dividend growth rate published by Value Line and obtained a range from 4.7 percent to 10.3 percent with an average of 8.3 percent.

The difference between witness Garrett's and witness D'Ascendis's DCF model results are primarily caused by differences in their estimated growth rates. Witness Garrett's average growth rate for the proxy group is 4.7 percent using analysts' growth rate estimates of the dividends declared and 3.9 percent using a sustainable growth rate based on the Gross Domestic Product (GDP) of the U.S. economy. Witness D'Ascendis's average growth rate for the proxy group is 6.12 percent based on an average of three sources of published analysts' estimates from Value Line, Zacks, and Yahoo! Finance. Witness D'Ascendis relied on analysts' five-year forecasts of earnings per share growth in his DCF analysis. Witness D'Ascendis explained that over the long run there can be no growth in dividends per share without growth in earnings per share. Witness D'Ascendis asserted that analysts' earnings expectations have a more significant influence on market prices than dividend expectations, and therefore, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component in the DCF model.

Witness Garrett argued that witness D'Ascendis incorrectly used short-term growth rate estimates from third-party analysts in the DCF model analysis which should use long-term growth estimates. Witness Garrett argued that analysts' earnings forecasts are short-term growth rate projections which are unreasonably high and are not sustainable in the long term. Witness Garrett asserted that a fundamental concept in finance is that no firm can grow forever at a rate higher than the growth of the economy in which it operates as measured by the GDP. Witness Garrett testified that the Congressional Budget Office's 2022 long-term budget outlook forecast for the U.S. GDP is 3.90 percent, and thus, the growth rate in the constant growth DCF model should be no more than 3.90 percent. Witness Garrett opined that theoretically the stable growth DCF model should consider only sustainable growth rates which are appropriate for estimating the growth for utilities, because they are in the sustainable growth stage of the industry life cycle. Witness Garrett contended that once a company is in the maturity stage of the industry life cycle it is not necessary to consider higher short-term growth rates in the DCF model, but rather it is preferable to analyze the cost of capital using a stable growth DCF model with a sustainable growth rate. Witness Garrett opined it is reasonable to assume that a regulated utility would grow at a rate that is less than GDP. On cross-examination, witness Garrett agreed that quantitatively utilities earnings can grow by more than the GDP for an extended period of time, but asserted that when choosing a growth rate one has to be careful that it is not too high.

Witness D'Ascendis took issue with witness Garrett's growth rate of 3.90 percent based on the forecasted GDP. Witness D'Ascendis asserted that witness Garrett's growth rate is not based on any measure of company-specific growth, or growth in the utility industry in general. Further, GDP is a measure of the total output of goods and services in an economy and is not a market-based measure. Witness Garrett's dividend yield is calculated using the proxy group utilities' individual market price and expected dividends, but his growth rate is the same for all companies. Witness D'Ascendis contended that under the DCF model's strict assumptions, expected growth and dividend yields are inextricably linked, and assuming the same growth rate for all companies has no basis in theory or practice.

Witness Garrett's argument to use the GDP growth rate in his DCF model is not supported by persuasive evidence. We agree with witness D'Ascendis that the growth rate should reflect a measure of the utilities' individual growth, and not a generic measure of the output of the entire economy. However, we agree with witness Garrett that witness D'Ascendis use of earnings per share growth rates overestimated the growth of cash flows from the companies. Earnings per share are not actual cash flows realized by the investor, whereas dividends declared is a more accurate measure of the cash flow provided to the investor. Both witnesses' models using analyst forecasts from well-established and recognized sources are comparable and reasonable. Therefore, we find that equal weight should be given to the witnesses' DCF model results using analyst forecasts. The average of both witnesses' DCF model results is 9.0 percent.

Capital Asset Pricing Model

The CAPM is a market-based model that estimates the cost of equity for a stock as a function of a risk-free return plus a market risk premium. The market risk premium is defined as the incremental return of the stock market as a whole, less the risk-free rate multiplied by the beta for the individual security. The beta is expressed as the volatility of an individual security compared against the stock market as a whole. A beta value of 1.0 indicates the individual security has the same volatility as the stock market. A beta value of less than 1.0 is considered less risky than the stock market as a whole and a beta value greater than 1.0 is considered more risky. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the market equity risk premium expressed in this equation: ROE = risk-free rate + Beta × (market return – risk-free rate). Witness D'Ascendis used two variations of the CAPM, the traditional CAPM and the Empirical CAPM (ECAPM). The average of the mean and median of the results of his application of the CAPM and ECAPM in his rebuttal testimony is 11.74 percent. Witness Garrett used the traditional form of the CAPM to calculate a cost of equity of 8.5 percent.

Risk Free Rate

Although witness D'Ascendis and Garrett used different methods to estimate the risk-free rate, both witnesses used the same risk-free rate of 3.8 percent based on the 30-year U.S. Treasury Bonds. Witness D'Ascendis based his estimate on the average of the forecasted expected yields for the six quarters ending in the third quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033. Witness Garrett based his estimate on the 30-day average of the then current 30-year U.S. Treasury Bond yields from April 14, 2023, through May 25, 2023.

Beta Coefficient

Witness D'Ascendis used a slightly lower beta coefficient in his application of the CAPM than witness Garrett. Witness Garrett used the average beta coefficient of 0.84 for the gas proxy group as published by Value Line. Witness D'Ascendis also used the beta coefficient of 0.84 from Value Line, but he also included the average beta coefficient of 0.685 for the gas proxy group as published by Bloomberg and averaged the Value Line beta with the Bloomberg beta to derive a final average beta of 0.76.

Market Equity Risk Premium

The most significant difference between the witnesses' application of the CAPM is their respective estimates of the market equity risk premium (MRP). The MRP is an estimate of the expected return on the stock market less the estimated risk-free rate. Witness D'Ascendis derived a MRP of 10.0 percent as compared to witness Garrett's estimated MRP of 5.6 percent. To derive his MRP, witness D'Ascendis used six different measures from three sources. Three of witness D'Ascendis measures used historical market data from Kroll that averaged 8.85 percent. The other three used projected returns on the market, two using market-based data from Value Line and a third using market-based data from Bloomberg. The projected MRP using the projected market data averaged 11.17 percent. Witness D'Ascendis estimated MRP of 11.17 percent using projected data indicates the total return on the stock market is expected to average 15 percent per year.

However, for Measure 6[54] in witness D'Ascendis's MRP derivation, there is a discrepancy between his market-based MRP using Bloomberg data as presented in his direct testimony versus his rebuttal testimony. In his direct testimony witness D'Ascendis presented a total return on the market of 11.06 percent and an MRP of 7.15 percent based on Bloomberg data for the S&P 500 Index. In his rebuttal testimony, witness D'Ascendis presented a total market return of 15.68 percent and an MRP of 11.88 percent for the Bloomberg data. This result is suspect as all the other MRP measures in Document No. 5, page 2, in witness D'Ascendis's rebuttal analyses decreased from his direct testimony to his rebuttal testimony. Therefore, it is reasonable to assume that it is unlikely the total return on the market based on the S&P 500 using Bloomberg data would increase by 42 percent (11.06 percent to 15.68 percent) when all the other market-data based measures used by witness D'Ascendis decreased. Consequently, we find that the 11.06 percent total return on the market in his direct testimony shall be used in place of 15.68 percent used in his rebuttal testimony, which would result in a revised MRP of 7.26 percent for Measure 6.

As pointed out by witness Garrett, an MRP based on historical data is convenient and easy to calculate; however, there are disadvantages to relying on a historical MRP for the application of the CAPM. Because the CAPM application in this case should be forward-looking, using historical data is not ideal. Therefore, witness Garrett relied on MRPs reported in expert surveys and his application of the implied MRP which witness Garrett contended is the best method to use. Witness Garrett applied a variation of the DCF model to the current value of the S&P 500 to calculate an expected return on the entire market of 9.3 percent. Witness Garrett's ERP was developed using the average of four estimates. The first ERP of 5.7 percent was obtained from a 2023 survey published by the IESE Business School. Witness Garrett explained the survey involves conducting a survey of experts including professors, analysts, chief financial officers and other executives around the country about what they believe the MRP is. A second MRP estimate published by Kroll (formerly Duff & Phelps) was 6.0 percent. A third

[54]Measure 6 is the Bloomberg Projected MRP based on the total return on the market using the S&P 500 index.

estimate using an implied MRP methodology from Dr. Aswath Damodaran[55] indicated a MRP of 5.1 percent. The average of all four estimates used by witness Garrett was 5.6 percent.

In addition to the traditional CAPM, witness D'Ascendis also applied the ECAPM to the gas proxy group and derived an average indicated ROE of 12.0 percent. Witness D'Ascendis asserted that the traditional CAPM underestimates the ROE for companies with low betas as is the case with the gas proxy group and the ECAPM accounts for this tendency. The average results from witness D'Ascendis's application of the ECAPM in his rebuttal testimony was 60 basis points higher than his traditional CAPM results (12.0 percent as compared to 11.4 percent) Witness Garrett disagreed with witness D'Ascendis and asserted there are three problems with witness D'Ascendis's use of the ECAPM. First, the Value Line betas for the gas proxy group have already been adjusted upward to account for the low-beta bias. Second, there is empirical evidence that Value Line betas overstate betas from low-beta industries like utilities. Third, witness Garrett contended that witness D'Ascendis's ECAPM and CAPM applications include overestimates of the MRP. When compared with other independent sources for the MRP which range from 5.6 percent to 6.0 percent, witness D'Ascendis's MRP is nearly twice as high as the average MRP from reputable sources, and as a result, is overstated and less reliable. Further, witness D'Ascendis's estimated projected market return of 15 percent that he used in his MRP calculation is unreasonably high.

Witness D'Ascendis contended that witness Garrett's use of surveys to estimate the MRP in the CAPM are not widely used by practitioners. Witness D'Ascendis cited to Dr. Damodaran, who was also cited and relied upon by witness Garrett, that few practitioners are inclined to use surveys because they are too sensitive to recent stock price movements, not objective based on to whom the surveys are presented and the questions asked, and they are more reflective of the recent past than forecasts into the future. Further, witness D'Ascendis asserted the determination of the MRP as calculated by Kroll is not transparent, although witness D'Ascendis uses Kroll information in his own derivation of the MRP. Lastly, witness D'Ascendis contended that witness Garrett's implied MRP is based on a series of questionable assumptions and followed the approach described by Dr. Damodaran's method to calculate an implied MRP. Witness D'Ascendis's main concern with witness Garrett's implied MRP calculation was the growth rate of 6.64 percent used in his DCF application. Witness D'Ascendis recalculated witness Garrett's implied MRP using an updated growth rate of 9.79 percent and obtained a required return on the market of 10.0 percent and a MRP of 6.2 percent, but asserted that the revised results still produce ROE estimates far below any reasonable measure. Using the traditional CAPM, witness Garrett's revised CAPM using a MRP of 6.2 percent produced a result of 9.0 percent. ($9.0\% = 3.8\% + 0.84(10\% - 3.8\%)$) Witness Garrett agreed that since the time he filed his direct testimony the risk-free rate he used in his CAPM has increased, and as a result, the results of his CAPM using analyst growth forecasts would be closer to 9.0 percent rather than 8.5 percent.

In his CAPM MRP calculation, witness D'Ascendis included a MRP result of 10.88 percent by applying a predictive risk premium model to the Kroll Historical Data and we find that it should be disregarded as discussed in the remainder of this section. As discussed above,

[55]Aswath Damodaran is a Professor of Finance at the Stern School of Business at New York University and is renowned for his work in the field of investment valuation and has written several books on the subject.

witness D'Ascendis's Measure 6 MRP should be revised from 11.88 percent to 7.26 percent. With those two adjustments, witness D'Ascendis CAPM MRP would be 8.91 percent instead of 10.01 percent. With the adjusted MRP of 8.91 percent, witness D'Ascendis CAPM would be 10.66 percent (10.66% = 0.77(8.91%) + 3.8%)

Risk Premium Model (RPM)

The RPM recognizes that common equity capital has a greater investment risk than debt capital, and as a result, investors require higher returns on common stocks than bonds to compensate them for bearing the additional risk. Witness D'Ascendis derived an estimated ROE of 11.42 percent using the average of two different RPMs: a RPM using his adjusted total market approach (TMARPM), and a predictive RPM (PRPM) developed by his firm. The TMARPM result was 11.0 percent and the PRPM result was 11.82 percent. Witness Garrett did not include an additional risk premium analysis in his testimony citing that the CAPM is a risk premium model.

Total Market Approach RPM

In his TMARPM, witness D'Ascendis estimated a projected yield on A2-rated public utility bonds of 5.47 percent, which is equivalent to the average bond rating of the gas proxy group, and added an equity risk premium (ERP) of 5.54 percent to the A2-rated public utility bond yield for a result of 11.0 percent. To estimate a projected A2-rated bond yield, witness D'Ascendis added a 0.71 percent yield spread to the forecasted Aaa-rated corporate bond yield of 4.76 percent as published by Blue Chip Financial Forecasts. Witness D'Ascendis estimated a yield spread of 0.71 percent by calculating the difference between an Aaa-rated corporate bond and an A2-rated corporate bond as published by Bloomberg Professional Service. The projected A2-rated public utility bond yield as estimated by witness D'Ascendis was 5.47 percent.

To estimate the ERP in his TMARPM, witness D'Ascendis used the average of three different derivations: a beta-adjusted total market ERP, an ERP based on the S&P Utilities Index, and an ERP based on a regression analysis of the awarded authorized ROEs for natural gas distribution utilities.

For his beta-adjusted total market approach, witness D'Ascendis relied on six different ERP measures reflecting the ERP for the stock market as compared to Moody's average Aaa and Aa rated corporate bond yields. His total market ERP results ranged from 5.82 percent to 10.92 percent with and average of 8.95 percent. Witness D'Ascendis multiplied the average beta of the gas proxy group to his average total market ERP to obtain a beta-adjusted forecasted ERP of 6.89 percent. As discussed in the following PRPM section, we find that all of witness D'Ascendis's analyses using the PRPM shall be disregarded. Consequently, witness D'Ascendis ERP of 9.77 percent derived from Kroll Equity Risk Premium based on the PRPM on Line 3 in Document No. 4 shall be disregarded. With this adjustment, his average equity risk premium would have been 6.76 percent as opposed to 6.89 percent.

For his S&P Utilities Index ERP, witness D'Ascendis calculated three ERP estimates based on long-term historical holding period returns for large company common stocks less the average historical yield on Moody's A2-rated public utility bonds for the period 1928 to 2021, and two ERP estimates based on the expected returns of the S&P Utilities Index. His results ranged from 4.2 percent to 5.44 percent with an average of 4.83 percent. As discussed in the following PRPM section, we find that all of witness D'Ascendis's analyses using the PRPM shall be disregarded. Consequently, witness D'Ascendis's forecasted ERP of 5.44 percent based on the PRPM in Document No. 4, Line No. 3, shall be disregarded. With this adjustment, his average equity risk premium would have been 4.63 percent as opposed to 4.83 percent.

For his third ERP estimate, witness D'Ascendis used a regression analysis to estimate the difference between regulatory awarded ROEs and the yields on Moody's A2-rated public utility bonds for 818 rate cases during the period from January 1, 1980, through July 20, 2023, and obtained a result of 4.90 percent. This was in increase of 19 basis points from his direct testimony.

As a result of our adjustments to remove witness D'Ascendis's ERP estimates using his PRPM, witness D'Ascendis's ERP would be 5.43 percent and his TMARPM result would be 10.9 percent.

OPC witness Garrett disagreed with witness D'Ascendis's use of risk premium models in addition to the CAPM, which witness Garrett asserted is itself a risk premium model that has been utilized by companies for decades for the purpose of estimating the cost of equity. In particular, witness Garrett contended that witness D'Ascendis's risk premium models rely in part on utility bond yields dating back to 1928, which is of questionable relevance because a cost of equity estimation is a forward-looking process. Further witness Garrett asserted that witness D'Ascendis's ERP regression analysis model that compared regulatory awarded ROEs dating back to 1980 to then-current bond yields effectively perpetuate the discrepancy between awarded ROEs that are consistently higher than the market-based cost of equity.

Predictive RPM (PRPM)

Witness D'Ascendis utilized a risk premium method that estimates a risk-return relationship by analyzing the volatility of past economic time series data and using that result to predict future levels of risk and risk premiums. This method was developed from the work of Robert F. Engle who shared the Nobel Prize in Economics in 2003 for his ARCH model. ARCH is an acronym for Autoregressive Conditional Heteroscedasticity. Witness D'Ascendis, along with other colleagues, applied a generalized form of the ARCH model, or GARCH, to develop the PRPM. Witness D'Ascendis explained that the inputs to his GARCH model are the historical returns on the common shares of each of the gas proxy group's companies, minus the historical monthly yield on long-term U.S. Treasury securities through July 2023. Using GARCH, he calculated each of the gas proxy group companies' projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produced a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it produces the predicted annual equity risk premium. He then added the forecasted 30-year U.S. Treasury bond yield of 3.80 percent to each company's PRPM-derived equity risk premium to arrive at an indicated ROE for each company. Witness D'Ascendis's PRPM produced a range of results of 8.66 percent to 19.1 percent for the gas proxy group, with an average of 11.61 percent. Witness D'Ascendis eliminated the highest result of 19.1 percent for ONE Gas, Inc. because it was too high and the GARCH coefficient was not statistically significant. In comparison, the DCF Model and CAPM results for ONE Gas, Inc. were 8.84 percent and 10.91 percent, respectively.

In April 2013, witness D'Ascendis co-authored an article published in The Electricity Journal that compared the results of his PRPM with the results of the DCF Model and the CAPM for estimating the cost of equity. Witness D'Ascendis agreed that in the article it states that "[F]or the most part, the PRPM produces a higher average indicated ROE than both the DCF and CAPM." The authors concluded that in their opinion, "the PRPM benefits ratemaking with an additional model to estimate ROE." To that end, the authors have been including the PRPM in their rate-of-return testimonies and the model has been presented publicly in several venues. Witness D'Ascendis also agreed that the PRPM he utilized in his testimony in the instant case produced higher results than his CAPM and DCF Model.

As pointed out by the Joint Parties in their brief, witness D'Ascendis testified on behalf of utility companies in over 130 rate cases and his testimony that included his PRPM was partly accepted only twice. Witness D'Ascendis alluded to two water rate cases, one each in South Carolina and North Carolina, in which he testified and included his PRPM method. In the South Carolina rate case for Carolina Water Service, Inc., witness D'Ascendis testified the ROE should fall within a range of 10.45 percent to 10.95 percent and the South Carolina Commission ultimately found a ROE of 10.50 percent, at the low end of witness D'Ascendis's range, was supported by the evidence. The South Carolina Commission did not specifically discuss or approve witness D'Ascendis's PRPM method but found his arguments persuasive and apparently used the average of the results of all his cost of equity models, including the PRPM, of 10.51 percent as a basis for its decision. In the North Carolina case for Carolina Water Service, Inc., the North Carolina Commission found witness D'Ascendis's RPM using his total market approach, not his PRPM, to be credible. The North Carolina Commission found that analyses using interest rate forecasts rely unnecessarily on projections and approved the use of current interest rates rather than projected near-term or long-term interest rates.

Witness D'Ascendis admitted that his PRPM produces a ROE which is forward-looking and not associated with a definite time period. Further, witness D'Ascendis agreed that while other utility witnesses use the PRPM method, no other practitioners use the PRPM and combine it within their testimony the way he does. Witness D'Ascendis also confirmed that his PRPM is not easily verified by using simple algebra which is possible for the DCF Model and CAPM and requires the use of statistical software to derive and test.

As discussed above, witness D'Ascendis's PRPM suffers from a lack of transparency, is used only by a few ROE witnesses testifying on behalf of utilities, has not been widely relied upon by other regulatory jurisdictions, and routinely produces ROE results that are higher than both the DCF Model and CAPM which are widely accepted and relied upon by the regulatory community. We find that there is persuasive evidence in the record that the PRPM method developed and used by witness D'Ascendis in all his cost of equity analyses produces an unreasonably excessive ROE and shall be disregarded.

Flotation Costs

OPC witness Garrett contended that PGS is asking us to award PGS a cost of equity that is more than 150 basis points above its market-based cost of equity and it is especially inappropriate to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal. Therefore, the Joint Parties argued that flotation costs should be disallowed from a technical and policy standpoint. OPC witness Garrett disagreed with the inclusion of flotation costs in the cost of equity for PGS. Witness Garrett also opined that when an underwriter markets a firm's securities to investors, the investors are well aware of the underwriter's fees and have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price. As a result, witness Garrett opined, there is no need for PGS's shareholders to receive additional compensation to account for costs they have already considered and to which they agreed. Witness Garrett contended that investors of competitive firms do not expect additional compensation for flotation costs, and therefore it would not be appropriate for this Commission to stand in place of competition to award a utility's investors with additional compensation. Witness Garrett's argument is not persuasive and we agree with witness D'Ascendis that it is appropriate to include a flotation cost adjustment when using ROE models to estimate the cost of equity.

In PGS's last rate case in 2008, we did not make a specific adjustment for flotation costs, but in our order we stated that we have traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor required return. Witness D'Ascendis asserted it is important to recognize flotation costs in the allowed ROE because there is no other mechanism in ratemaking paradigm through which such costs can be recovered. Historical flotation costs are a permanent loss of investment income to the utility and should be accounted for. Witness D'Ascendis explained that for each dollar that is issued at market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Because these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10.00 percent is for the net investment, $0.95, to earn more than 10.00 percent to net back to the investor a fair return on that dollar. Witness D'Ascendis contended that all of the cost of equity models assume no transaction costs and an adjustment to the cost of equity needs to be made to account for the flotation costs and make the utility whole. Consequently, it is appropriate to include a flotation cost adjustment when using ROE models to estimate the cost of equity. Witness D'Ascendis calculated the flotation cost adjustment based on the actual flotation costs of Emera and adjusted the dividend yield in his DCF Model to estimate the effect of the flotation cost on the DCF cost rate. We find witness D'Ascendis's method to determine the flotation cost is credible and provided persuasive evidence for his recommendation to include a flotation cost of 9 basis points.

Business Risk Adjustment

To reflect PGS's specific business risks, witness D'Ascendis made an upward adjustment of 20 basis points to reflect PGS smaller relative size, high level of customer growth, overall performance, and capital investment plans. Witness Garrett argued that firm-specific business risk factors are not rewarded by the market and systemic risk (i.e., interest rate risk, inflation risk, and other risks that affect all stock market listed companies) is the only type of risk for which investors expect a return. Witness Garrett asserted that investors do not require additional compensation for assuming these firm-specific risks. Witness Garrett opined that investors eliminate firm-specific risk through diversification and do not expect a higher return for assuming the firm-specific risk in any one company. For the reasons cited herein, we agree with witness Garrett that business risk is reflected in the stock price investors pay for a stock and a specific adjustment to the cost of equity for business risk is not necessary.

Small Size Premia

Witness D'Ascendis asserted that because PGS is smaller in size relative to the gas proxy group, PGS is less able to cope with significant events that affect sales, revenues, and earnings. Therefore, since smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Witness D'Ascendis cited to three sources supporting his assertion that investors require higher returns on stocks of small firms than on otherwise similar stocks of large firms. Witness D'Ascendis contended that consistent with the financial principle of risk and return, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore witness D'Ascendis argued, our authorized ROE in this proceeding must appropriately reflect the unique risks of PGS, including its smaller relative size, which is justified and supported by evidence in the financial literature. Witness D'Ascendis quantified a small size risk adjustment for PGS based on its estimated market capitalization as compared to the market capitalization of the gas proxy group. Witness D'Ascendis estimated that the average market capitalization of the gas proxy group is 3.7 times that of PGS. Based on Kroll Associates Size Premia Decile Portfolio, the applicable premium for PGS would be 79 basis points.

OPC witness Garrett disagreed with witness D'Ascendis's size adjustment and recommended we should reject PGS's proposed size premium. Witness Garrett explained the size premium arose from a study in 1981 conducted by Banz, which indicated that during the period of 1936 through 1975 common stock of small firms had on average higher risk-adjusted returns that larger firms. Witness Garrett cited from the book, *Triumph of the Optimists*, published in 2002, that there were subsequent empirical studies that found the size effect phenomenon disappeared within a few years and the authors of the study concluded it is inappropriate to automatically expect there to be a small-cap premium on every stock. Further, witness Garrett cited an article by Kalesnik and Beck that stated in part:

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.

OPC witness Garrett made a persuasive argument that small company stocks do not necessarily outperform large company stocks, and therefore, an upward size adjustment to the market-based ROE is not warranted.

Capital Investment and Customer Growth

Witness D'Ascendis asserted that as addressed in PGS witness Fox's direct testimony, PGS has experienced strong customer growth over the last five years and projects it will continue to experience relatively strong growth over the next five years. PGS plans to invest over $1 billion of capital from January 1, 2022 to December 31, 2024, to support its growth. Witness D'Ascendis asserted that the allowed ROE should enable PGS to finance capital expenditure requirements at reasonable rates, and maintain its financial integrity. Witness D'Ascendis contended that credit rating agencies recognize risks associated with increased capital expenditures, and from a credit perspective the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. Witness D'Ascendis asserted that PGS has the highest ratio of projected capital expenditures to net plant as compared to the gas proxy group which indicates an increased business risk. In his direct testimony, witness D'Ascendis calculated PGS's ratio of forecasted capital expenditures to net plant at 60 percent as compared to 39.5 percent for the median ratio of the gas proxy group based on 2021 information; a difference of 20.5 percentage points. In his rebuttal testimony, witness D'Ascendis updated his calculation and derived a capital expenditure to net plant ratio of 33 percent for PGS as compared to a median of 26.5 percent for the gas proxy group based on 2022 information; a difference of 6.5 percent. On cross examination, witness D'Ascendis agreed that the decrease in the difference from 20.5 percent to 6.5 percent indicated the relative risk for PGS on this measure decreased:

> I would say, yeah, based on -- based on these numbers, but I don't know whether or not they -- well, I guess, yeah, I mean, I would agree with that, but the debt would still be outstanding, like, the capital would still be outstanding. But, yes, I would agree that going forward, the company is less risky than when they were when they filed based on this measure.

Witness D'Ascendis's projected capital expenditures to net plant business risk measure suffers from a lack of credible evidentiary support and should be given little weight. Witness D'Ascendis agreed that the gas proxy group consists primarily of holding companies which are larger than PGS and have a significantly higher amount of net plant. By operation of math, a higher amount of net plant would reduce the ratio of projected capital expenditures to net plant. Further, witness D'Ascendis agreed that a better comparison would have been to use the operating gas companies owned by the holding companies, but the projected net plant for operating companies are not available. Finally, by witness D'Ascendis's own admission PGS's business risk by this measure has decreased from 2021 to 2022.

Financial Risk

Financial risk is created by the introduction of debt into the capital structure. The higher proportion of debt in the capital structure, the greater the financial risk. Consistent with the basic principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk. PGS requested an equity ratio of 54.7 percent which is higher than the average equity ratio of the gas proxy group of 48.83. Based on the risk-return relationship, PGS has lower financial risk than the gas proxy group. However, witness D'Ascendis did not consider a downward adjustment to his recommended ROE to reflect the lower financial risk. He explained that the operating utilities under the publicly traded holding companies have a more comparable equity ratio and if taken together (holding company and operating company equity ratios). In his opinion, there is not a difference in risk to the capital structure. Witness D'Ascendis agreed that the operating subsidiary companies do not issue stock, so he relied on the holding companies market data in his cost of equity analyses to derive his recommended ROE. Witness D'Ascendis agreed he could not perform a ROE analysis on the operating companies because they are not publicly traded and do not have market data. According to financial theory, it is most appropriate to use the equity ratio of the publicly traded company proxy group to assess financial risk because the stock prices used in witness D'Ascendis's ROE analysis are based on the equity ratios of the holding companies. Using the subsidiary operating companies to assess financial risk would be meaningless. OPC witness Garrett recommended an equity ratio of 49 percent for PGS based on the average of the gas proxy group. Witness Garrett did not make a specific adjustment for financial risk to his ROE analysis because there is not a difference between his recommended equity ratio and that of the average of the proxy group. However, witness Garrett did quantify the effect of using a higher equity ratio of the gas proxy group in his CAPM analysis by using the Hamada Model. His calculation demonstrated that the difference in equity ratios of 54.7 percent to 49 percent, or financial risk, equated to a reduction of 40 basis points to the ROE.

iii. Conclusion

After making the adjustments to the witnesses' ROE models discussed herein, the adjusted range of results for the gas proxy group is 9.0 percent to 10.9 percent. Record evidence supports the risk-return concept that utilities with lower financial risk should be allowed lower returns. The record evidence demonstrates PGS has a higher equity ratio than the average of the gas proxy group, and as such, it has less financial risk. Therefore, a downward adjustment to PGS's ROE shall be recognized to reflect PGS's lower financial risk as compared to the gas proxy group. In addition, the record evidence is clear that capital costs have increased since PGS's last rate case in 2020 in which we authorized an ROE of 9.9 percent, and interest rates have increased during the course of this proceeding which may not be fully recognized in the financial cost of equity models presented by the witnesses. Therefore, on balance, we find the record evidence supports an ROE of 10.15 percent for PGS. This return is above the recent national average of awarded ROEs of approximately 9.5 percent and should enable PGS to generate the cash flow needed to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, maintain sufficient levels of liquidity to fund unexpected events, and sustain confidence in Florida's regulatory environment among credit rating agencies and investors. Accordingly, we find the appropriate ROE for establishing PGS's projected test year revenue requirement is 10.15 percent with a range of plus or minus 100 basis points.

I. Capital Structure and Weighted Average Cost of Capital

i. Parties' Arguments

PGS witness Parsons testified that the appropriate capital structure consists of 54.7 percent common equity, 40.5 percent long-term debt, and 4.8 percent short-term debt from investor sources. This is presented in Table 7. PGS witness McOnie contended the capital structure containing an equity ratio of 54.7 percent as proposed by PGS is consistent with the capital structure previously approved for PGS by us and is entirely consistent with the capital structures and equity ratios approved by us for FPUC (55.1 percent) and FCG (56.9 percent). Witness McOnie asserted that PGS's proposed capital structure is appropriate for ratemaking purposes as it is both typical and important to have significant proportions of common equity in its capital structure. PGS argued Section V.I is a fallout issue that depends on the decisions made on other capital structure issues. Table 8 reflects PGS's requested overall weighted average cost of capital and reflects the Company's positions in Section V. In its brief for Section V.E, PGS argued the Company's proposed amount of long-term debt for the test year reflects the $832,185,531 of long-term debt on MFR G-3, page 2, adjusted for the decrease in rate base in Section IV.P, and increased for a pro-rata allocation over investor sources of capital to offset for the change in accumulated deferred income taxes in Section V.A.

The Joint Parties argued OPC witness Kollen testified that the WACC is 5.87 based on witness Garrett's 49 percent equity ratio and 9.0 percent ROE. The Joint Parties argued that witness Garrett's combined ROE and capital structure recommendation is a combined $38.515 million reduction to PGS's requested base rate increase. The Joint Parties argued the Company's decision to undertake the 2023 Transaction with all its potential risks was executed solely at the discretion of the Company and its impact is an increase of financing costs to customers. The Joint Parties argued that PGS would have a credit rating of BBB+ if it was still a division of TECO, but the 2023 Transaction will likely cause a one notch lower rating for PGS. Joint Parties argued that we should take every opportunity to minimize the impacts of the 2023 Transaction to PGS's customers by adopting the WACC proposed by OPC witnesses Kollen and Garrett. We note that most of the Joint Parties' arguments in this issue relate to the 2023 Transaction's effect on credit ratings, the cost rate for long-term debt, and the expectation by PGS for it's customers to pay a higher-than market cost of capital to support the Company's preferred credit ratings. Therefore, we address the Joint Parties' arguments related to those subjects in Section V.E.

ii. Analysis

The capital structure and WACC is a fall-out issue that incorporates the amounts and cost rates of the capital sources into a final WACC. The cost rates and amounts of the capital components were determined in Section V. In MFR Schedule G-3, page 2 of 11, PGS presented its requested projected test year capital structure based on a 13-month average as of December 31, 2024, consisting of common equity in the amount of $1,124,006,187 (54.7 percent), long-term debt in the amount of $832,185,531 (40.5 percent) and short-term debt in the amount of $99,671,451 (4.8 percent) as a percentage of investor-supplied capital. The initial capital structure submitted by PGS is summarized in Table 7.

Table 7
PGS Initial Adjusted Capital Structure and WACC

Capital Component	Amount (Adjusted)	Ratio	Cost Rate	Weighted Cost
Common Equity	$1,124,006,187	47.49%	11.00%	5.22%
Long-Term Debt	$832,185,531	35.16%	5.54%	1.95%
Short-Term Debt	$99,671,451	4.21%	4.85%	0.20%
Customer Deposits	$27,528,183	1.16%	2.53%	0.03%
Deferred Taxes	$280,240,209	11.84%	0.00%	0.00%
Investment Tax Credits	$3,156,892	0.13%	8.49%	0.01%
Total	$2,366,788,452	100%		7.42%

In her rebuttal testimony, PGS witness Parsons included adjustments to rate base and the amount of ADITs related to depreciation adjustments. Based on those adjustments, PGS's adjusted proposed capital structure for the 2024 test year as presented in its brief is summarized in Table 8.

Table 8
PGS Revised Adjusted Capital Structure and WACC

Capital Component	Amount (Adjusted)	Ratio	Cost Rate	Weighted Cost
Common Equity	$1,118,145,545	47.47%	11.00%	5.22%
Long-Term Debt	$827,335,811	35.12%	5.54%	1.94%
Short-Term Debt	$99,662,408	4.23%	4.85%	0.21%
Customer Deposits	$27,525,625	1.17%	2.53%	0.03%
Deferred Taxes	$279,720,428	11.87%	0.00%	0.00%
Investment Tax Credits	$3,156,598	0.13%	8.49%	0.00%
Total	$2,355,546,414	100%		7.41%

The Joint Parties recommended we set PGS's equity ratio at 49 percent with an ROE of 9.0 percent. The Joint Parties also recommended we set PGS's long-term and short-term debt cost rates at 4.61 percent and 3.81 percent, respectively. OPC witness Kollen also made adjustments that increased the ADIT balance in the capital structure. The Joint Parties' recommended adjusted capital structure and WACC are summarized in Table 9.

Table 9
Joint Parties' Recommended Adjusted Capital Structure and WACC

Capital Component	Amount (Adjusted)	Ratio	Cost Rate	Weighted Cost
Common Equity	$1,008,304,000	42.60%	9.00%	3.83%
Long-Term Debt	$941,736,000	39.79%	3.81%	1.83%
Short-Term Debt	$99,358,000	4.24%	4.85%	0.16%
Customer Deposits	$27,525,625	1.17%	1.16%	0.03%
Deferred Taxes	$286,705,000	12.11%	0.00%	0.00%
Investment Tax Credits	$3,157,000	0.13%	6.73%	0.01%
Total	$2,366,788,000	100%		5.87%

In Section V.G, we approved an equity ratio of 54.7 percent. In Section V.H, we approved a cost of equity of 10.15 percent. We agree with PGS's proposed capital structure as presented in MFR Schedule G-3, page 2 of 11, with the adjusted capital component amounts described in PGS witness Parson's rebuttal testimony. In her rebuttal testimony, PGS witness Parsons included adjustments to rate base and the amount of ADITs related to depreciation adjustments as discussed in Section V.A. We also approved a stipulation in Section IV.G to remove the Alliance Dairies RNG project from rate base that resulted in an adjustment to remove the associated ADITs and ITCs from the capital structure. Because all of the ITCs were realized through the investment in the Alliance Dairies RNG project, the ITC balance was decreased to zero. PGS noted in its brief that the capital structure and WACC would have to be updated to reflect that adjustment and our decisions regarding other capital structure issues. In addition, we approved a stipulation to the amount and cost rate for customer deposits of $27,528,000 at 2.53 percent. The capital structure shall be reconciled with the rate base adjustments over investor sources and deferred taxes after the proper adjustments to the ADIT balance are included. Our approved capital structure is summarized in Table 10.

Table 10
Commission-Approved Adjusted Capital Structure and WACC

Capital Component	Amount (Adjusted)	Ratio	Cost Rate	Weighted Cost
Common Equity	$1,122,029,733	47.604%	10.15%	4.83%
Long-Term Debt	$830,722,209	35.24%	5.54%	1.95%
Short-Term Debt	$99,496,189	4.22%	4.85%	0.20%
Customer Deposits	$27,528,000	1.17%	2.53%	0.03%
Deferred Taxes	$277,551,630	11.77%	0.00%	0.00%
Investment Tax Credits	$0		8.03%	0.00%
Total	$2,357,327,760	100%		7.02%*

iii. Conclusion

A capital structure consisting of 54.7 percent common equity, 40.5 percent long-term debt, and 4.8 percent short-term debt as a percentage of investor sources shall be approved for the 13-month average test year ending December 31, 2024. A weighted average cost of capital of 7.016 percent shall be approved for establishing PGS's projected test year revenue requirement and setting rates in this proceeding.

VI. Net Operating Income

A. Removal of Purchased Gas Adjustment, Natural Gas Conservation Cost Recovery Clause, and CI/BSR Revenues and Expenses

At the hearing, we approved a type 2 stipulation as follows: PGS made the proper adjustments to remove the Purchased Gas Adjustment, Natural Gas Conservation Cost Recovery Clause, and CI/BSR Revenues and Expenses from the projected test year, as shown on MFR Schedule G-2, pages 2-3.

B. Removal of Non-Utility Activities Including Depreciation and Amortization Expense

i. Parties' Arguments

The Company testified that all appropriate adjustments have been made to remove all non-utility activities from operation expenses as shown in MFR Schedule G-2, pages 2-3 and in Exhibit 218, the revised revenue increase.

The Joint Parties have concerns about PGS's basis for attributing costs associated with SGT. The Joint Parties argued that the current standard is based on an impermissibly narrow basis and allows for engineering-related costs to be attributed to SGT when the Company is actively working on a Seacoast project. The Joint Parties argued that this standard does not consider the workload put onto the Engineering, Construction, and Technology (ECT) department for potential SGT projects. The Joint Parties stated that there is evidence in 2022 where there were non-work order projects underway or being evaluated, but those activities did not have any cost allocated to SGT.

The Joint Parties emphasized their concern for the current standard of PGS executing tasks for an unregulated affiliate company and moreso that PGS is requesting to increase its employee headcount by a seven member team that would work within the Company's business development organization on projects that could be affiliated with SGT. The Joint Parties are concerned the hiring needs proposed for the projected test year could be driven by the needs of SGT because SGT projects have the potential to redirect resources of PGS's ECT team at any given time. The Joint Parties concluded that due to these factors the Company should mitigate the authorization of funding needed to hire the capital management team.

The Joint Parties argued that the Company could leverage its regulated operations funded by its customers to subsidize its unregulated ventures of SGT. The Company was understanding of the concerns and acted in good faith by making a reduction in the revenue requirement of $190,000. The Joint Parties agreed with the Company's reduction and understood that the Company utilized a method that has not been challenged. Therefore, the Joint Parties recommended that we instruct the Company to redefine its method of attributing costs to SGT. The Joint Parties ascertained that the cost allocation manual (CAM) by TECO was not designed to determine the separation of costs between PGS and SGT. In the CAM it states, "Periodically, PGS may provide a service to its affiliates. When this occurs, PGS will direct charge that affiliate for these services. Direct charges are expenses directly tied back to service provided to an affiliate." The Joint Parties deduced from the Company's CAM that the approach is informal and does not provide an efficient approach of attributing the costs from PGS to SGT.

The Joint Parties urge us to instruct the Company to complete a comprehensive review of the relationship with SGT, with a focus on the procedures when SGT requires direct and indirect support from PGS, including the Company's need to maintain open availability of resources to service SGT needs. The Joint Parties also requested that we direct the study to be filed in the next rate case and applied in any projected test year revenue.

ii. Analysis

As addressed in Section IV.B, PGS agreed to reduce O&M expense by $189,347 to increase PGS's overhead cost allocation to SGT as shown in Exhibit 218. The Joint Parties agreed with the methodology of this adjustment and, in lieu of seeking an additional adjustment, requested that we direct the Company to revisit its method of attributing costs to SGT. As discussed in Section IV.B, we find that a comprehensive procedural review and associated cost study would benefit us in our analysis of the Company's next base rate case.

As reflected in the stipulation in Section VI.H and PGS witness Parsons' testimony, the Company agreed upon an adjustment to reduce projected test year O&M expense by $500,000 to remove expenses associated with lobbying, charitable contributions, sponsorships, and institutional and image advertising. This adjustment is comprised of several adjustments including audit findings identified by staff witness Brown. Witness Brown's testimony identified several adjustments that reduced PGS's 2022 base rate recoverable O&M, including the reclassification of expenses related to the Tampa Bay Buccaneers as non-utility. The adjustment presented by witness Parsons reflects the inflationary factors applied to the projected test year. No further adjustments are necessary.

iii. Conclusion

Although not completely removed in PGS's original filing, adjustments for non-utility activities are addressed by our finding in Section IV.B and the stipulation in Section VI.H. As such, no further adjustments are necessary.

C. Uncollectible Accounts and Bad Debt

At the hearing, we approved a type 1 stipulation as follows: The Bad Debt Expense is $1,611,232, as shown on MFR Schedule G-2, page 19b, line 7, and the bad debt rate of 0.2805 percent was incorporated into the Revenue Expansion Factor, as shown on MFR Schedule G-4.

D. Non-Labor Trend Factors

At the hearing, we approved a type 2 stipulation as follows: The appropriate non-labor trend factor for inflation is 2.80 percent and 2.20 percent for 2023 and 2024, respectively. The appropriate non-labor trend factor for customer growth is 3.81 percent and 3.23 percent for 2023 and 2024, respectively.

E. Contractor and Contract Services

i. Parties' Arguments

PGS argues that the appropriate amount of projected test year contractor and contract services cost is $24,989,844 which reflects an adjustment of $190,000 for the decrease in the projected test year standalone audit fees. PGS asserts that contractors allow the Company to quickly adjust the size of its workforce to meet operational, performance, and geographic needs.

PGS also asserts that the Company works to balance internal labor and contract labor costs, has already taken steps to reduce contractor expenses and that the proposed mix of labor and contracted services is necessary to properly maintain adequate levels of safety, reliability, and customer service.

The Joint Parties assert that PGS did not reduce contractor expenses by an amount that justified the increase in employees. The Joint Parties also assert that the Company filled 22 pipeline locator positions and two administrative support positions which displaced outside contract services. The Joint Parties argue that total cost savings provided by these replaced positions is approximately $206,000 and should be removed from the contractor and contract services cost.

ii. Analysis

In PGS's original filing, it stated that the appropriate amount of projected test year contractor and contract services costs that should be approved is $25,179,844. PGS later updated this total to $24,989,844 to account for a $190,000 adjustment based on standalone audit fees.

PGS witness Wesley testified that due to customer growth and increased work activity the Company has become more reliant on outside contractors. Witness Wesley asserted that from 2022 to 2024 PGS is expected to add approximately 28,000 new residential customers and 1,200 new commercial customers. PGS has experienced an increase in total work orders, attributed to customer growth, for all 14 of PGS's service territories which is anticipated to continue into 2024. The evidence in the record shows that for all service areas from 2020 to 2024 there is a projected 18 percent increase in total work orders. Specifically, PGS witness O'Connor projected that work volumes in the Company's Jacksonville service area for service, compliance, locates and meter readings are forecasted to experience double digit percentage growth in 2024. No parties disputed that customer growth has led to increased work activities. Witness O'Connor maintained that the use of contractors allows the Company to meet immediate needs related to operations, compliance, safety, maintenance, customer service and emergency response activities associated with the increase in work orders.

Witness O'Connor testified that in order to meet the higher workload and reduce the Gas Operation team's dependence on contractors, 38 new apprentices were trained in 2022. The witness further testified that as internal labor headcount increases, PGS evaluates contractor expenses in an effort to reduce contractor costs. During cross-examination, the witness stated that when a new employee is hired a contractor cannot be immediately replaced. The witness explained that because it takes approximately 18 months to train a new employee, the Company would maintain an outside contractor while the employee is trained. The witness further explained that because of this overlap, there is no immediate cost savings between internal and external costs associated with new positions. The witness argued that the overlap of internal and external labor is necessary to manage the transition to internal labor while simultaneously maintaining safety, reliability and customer service levels. Additionally, PGS has to make considerations regarding future contractor availability and contractual terms that may disallow contracts to be immediately terminated. Due to the newly trained Gas Operations team employees, PGS reduced contractor expenses in the test year by $1.1 million by eliminating contractors for locates, leak surveys, and other work activities. The witness clarified that this reduction was primarily driven by financial considerations and reductions of contractor expenses is not sustainable long-term because continued balancing of employees and contractors is necessary to meet workload requirements.

OPC witness Kollen testified that PGS is already staffed for continued growth and that the Company did not reduce contractor expenses to match PGS's requested increase in employees. In response to witness Kollen, witness O'Connor rebutted that there is no equivalent exchange between internal and external labor and the Company manages external labor to align with the required workload. The witness further rebutted that outside service expenses have decreased from previous years which is attributed to the increase in headcount. The evidence in the record shows that from 2020 to 2022, total outside service costs increased by $2,622,425 but from 2022 to 2024 are projected to decrease by $1,037,859. Furthermore, the evidence in the record also shows that as internal labor headcount increased in 2023, Gas Operations reflected a $1.6 million reduction in contractor costs.

We agree with the Company that the extended time required to train new employees may require an overlap of new internal labor with external labor in order to address the increase in work activities. We find that the Company's $1.1 million reduction in test year contractor expenses, to account for new employees, serves as an example of PGS appropriately reducing contractor expenses once employees are available. In addition, PGS witness Bluestone testified that in 2023, PGS hired 118 positions and 24 of these positions would displace the use of outside services. The witness affirmed that of the 24 positions filled, 22 positions were pipeline locators and two were administrative specialists who have or will displace the use of outside services. Witness Bluestone further affirmed that there is a cost-savings of approximately $200,000 associated with the 22 displaced contracted pipeline locators and $6,000 associated with the two displaced contracted administrative specialists. We note that the Company did not remove these costs from its requested contractor and contract services cost. We find that the requested test year contractor expenses are necessary to maintain current and future system reliability, due to the increased work activities in PGS's service areas. However, we agree with the Joint Parties and approve an adjustment of $206,000 associated with the displaced outside services. In their brief, the Joint Parties agreed with the removal of $206,000 in contractor and contract services due to positions being filed that displaced outside services.

Lastly, PGS stated that $3.9 million of contractor costs in the projected test year were attributed to the Alliance Dairies RNG project. The stipulation in Section IV.G addresses the removal of the Alliance Dairies RNG project from the Company's request and a corresponding adjustment removing the $3.9 million of O&M expense associated with Alliance is reflected in Section VI.M. Therefore, we approve a reduction of $3.9 million to the appropriate projected test year contractor and contract services cost.

These adjustments shall be made to the projected test year contractor and contract services cost of $24,989,844, as reflected in PGS's updated filing. Therefore, the appropriate projected test year contractor and contract services cost shall be $20,827,232.

iii. Conclusion

We approve the $20,827,232 in projected test year contractor and contract services cost. This amount reflects an adjustment of $206,000 associated with displaced outside services and approximately $3.9 million associated with the stipulation in Section IV.G.

F. Employees

i. Parties' Arguments

PGS stated in its brief that the number of employees for the projected test year should be an average of 837 after vacancy allowances, including its revised plans to forgo cost recovery for one Business Development Manager for RNG. The 837 average the Company proposed is comprised of an additional 90 employees in 2023 and 64 employees in 2024. Of the additional 90 employees, 63 were replacement positions at the end of December 2022. PGS witness Bluestone argued that the increase in team members is to strengthen the workforce to provide safe and reliable service to the growing Company's system. Bluestone maintained that each budgeted position is carefully considered, with justifications identified by a functional team leader for each position.

PGS contended that the Joint Parties' recommendation to remove all of the proposed new employees does not consider the current market challenges, nor the reasonable projection of additional needed employees to operate the system safely and reliably. PGS argued that through its combined testimony and discovery responses it has provided sufficient justifications for each proposed position, while the Joint Parties only made a generalized argument on the proposed additional positions. PGS concluded that we should reject the Joint Parties' recommended adjustments of $9.762 million for staffing increases and $1.162 million for office supplies, and expenses for additional employees.

PGS witness O'Connor testified that Gas Operations are increasing due to customer growth, and the Company's projections show that service-related work will grow by 6 percent annually, locate requests will increase 6 percent annually, and meter reading activities will increase 4 percent annually. Witness O'Connor stated that to keep up the growth in the industry, PGS will need more trained team members, because currently PGS in unable to keep up with industry standard of responding to 98.5 percent of damage calls within 60 minutes.

PGS witness Richard rationalized the need for new team members in the ECT area in 2023 and 2024 due to the growth in size and complexity of the Company. Witness Richard affirmed that the Company plans to hire 41 employees in the ECT area in 2023 and 2024, with 17 being replacements and 24 being new positions. Witness Richard justified each new position and explained the breakdown of the positions to be five in the Supply Chain; four in the Gas Control and Measurement and Regulation; seven in the support of the Capital Management; and the remaining eight positions will support the Design, Engineering, and Construction area.

PGS witness Bluestone addressed the need of 18 additional team members in support positions including three team members in Human Resources; six team members in Strategy, Marketing, and Communications; three team members in Regulatory and Pipeline Safety; three team members in Process Improvements and Analytics; and three team members in Real Estate. PGS witness Parsons attested to the need of the eight Finance positions.

The Joint Parties presented several arguments on why PGS should have to reduce the number of employees in the projected test year. Among those arguments made are: PGS had eliminated 21 vacant positions in the Gas Operations and Pipeline Safety fields, PGS did not reduce contractor expenses adequately to justify the increase of new employees, PGS's actual employees reflected significant vacancies compared to employees budgeted, additional employees are discretionary, the Company already has sufficient team members for the continued customer growth and related infrastructure, and the requested positions do not include efficiencies from WAM. The Joint Parties also argued that all 65 requested positions for the 2024 projected test year should be removed due to being discretionary by the Company. The Joint Parties concluded that we should find the projected test year employees to be 746, the headcount at the time of the hearing, or a maximum amount of 777, to reflect the 30 additional positions that witness Bluestone attested were unfilled in 2023.

Witness Kollen testified that the additional employees are discretionary and the Company already has sufficient team members for the continued customer growth and related infrastructure. Witness Kollen also noted that the forecasted 2023 and 2024 employee counts were significantly greater compared to the actual employee count from 2019 through March 2023.

The Joint Parties stated that the Company forecasted 798 team members by December 31, 2023, and as of August 15, 2023, there are 746 team members, with 61 positions filled and 30 unfilled positions. The Joint Parties asserted that witness Bluestone's testimony confirmed most new team members filled existing positions reflected by the fact that of the 61 positions filled, 46 were backfilled and/or replacements, while 15 were new positions. The Joint Parties affirmed that the Company must provide sufficient evidence for the requested increase in team members to be reasonable and prudent. The Joint Parties asserted that PGS has failed to provide justification considering the comparison of the base year and prior years.

The Joint Parties also provided an alternative approach to adjusting the test year level of employees, should we prefer a more targeted approach. The Joint Parties cited insufficient blanket statements as to the proposed staffing, impending WAM transformation, questionable hiring of contractor forces, and the lack of metrics to determine the need for new hires.

The Joint Parties provided targeted arguments on the new team members specifically in the ECT and Gas Operations areas. The Joint Parties argued that we should prohibit the cost of the 2024 component of the Capital Management Team because it is part of a project that is considered to bring benefits in the budgeting and cost control beyond the test year. The Joint Parties argued that due to the hiring not projected to occur before the second half of 2024 that the matching principle needs to be applied to ensure that costs and revenues are within the same period. The Joint Parties contended that under the current timeline, the ECT hires will not have any impact on the 2025 budget will most likely impact projects and capital budgeting for 2026.

The Joint Parties also contended that PGS failed to demonstrate the need for the 29 proposed new hires in Gas Operations.

The Joint Parties used testimony from PGS witness O'Connor to highlight their concerns with insufficient justification and the lack of metrics related to hiring. The Joint Parties cited the identical justification provided by witness O'Connor for 61 positions regardless of the type of position. The Joint Parties continued that no objective metrics were utilized to determine geographical distribution of the proposed new hires. The Joint Parties reasoned that the amount of new employees is not appropriate due to witness O'Connor's testimony that PGS was rated the highest in a national survey for its service and that it does not have any safety compliance issues. The Joint Parties contested that by hiring more employees in an area where tasks per employee is considerably higher than the Company's average, as stated by witness O'Connor, it could lower efficiency. The Joint Parties also questioned hiring new employees in areas where tasks per employee are below the Company's average because the Company has not provided a sufficient metric on its proposed hiring locations. The Joint Parties argued that PGS's explanation provided in response to OPC Interrogatory No. 13 was generic and that the data pulled from Exhibits 27 and 188 does not provide a legitimate reason for the geographical locations of the proposed new hires.

The Joint Parties agreed that WAM will be beneficial to the Company by providing metrics that the Company can utilize in hiring both team members and contractors and will produce a reduction in costs overall. The Joint Parties disputed the 15 apprentices projected to be hired for the 2024 test year because of the lengthy time to train in order for them to work independently. The Joint Parties further disputed whether the apprentices would be needed with the implementation of WAM.

The Joint Parties claimed that by hiring individuals from its contracted services, the Company may have reduced its need to hire backfills or apprentices because they already have experience and knowledge of the industry. The Joint Parties raised concerns that the cost of contracted services could be lower in the projected test year because of the loss of workers now hired at PGS coupled with a difficult hiring environment. The Joint Parties attested to not being able to acquire sufficient data on this topic due to information coming out at the hearing and the Joint Parties continued that this should be considered a failure on the Company to meet its burden of proof.

ii. Analysis

PGS requested recovery of 154 new employees in the projected test year. Ninety of the employees were to be added in 2023 and the remaining 64 employees in 2024. To explain the need for these new employees, PGS witnesses Rutkin, Parsons, Richard, O'Connor and Bluestone provided direct and rebuttal testimony to explain why the additional employee count is necessary and prudent for PGS.

Witness Rutkin stated that PGS intends to add new Gas Supply and Development positions in the next couple of years, equivalent to six replacement positions in 2023 and two replacement positions and three new positions in 2024. Witness Rutkin said that these additional positions are needed so that the Gas Supply and Development team can continue to support PGS's efforts to provide safe and reliable gas systems to its growing customer base.

Witness O'Connor stated that additional team members are required in Gas Operations to meet future work requirements and to maintain safe and reliable operations to serve customers. For 2023, 38 additional employees are needed and 36 additional employees are needed for 2024. The new positions are needed to perform the incremental level of work activities driven by Florida's growth, to comply with increasingly stringent compliance requirements and evolving risks across pipeline safety, damage prevention, and emergency management.

Witness Richard stated that the ECT team will have 33 new employees added in 2023 and eight new employees added in 2024, for a total of 41 additional employees. These additional employees will support customer growth, capital management, support services, a growing natural gas system through 24 hours monitoring of the natural gas system, and deliver greater value to customers through strategic materials and supplies contract management.

Witness Bluestone stated in her direct testimony that in order for PGS to strengthen its Human Resources (HR) function, the Company will need three new employees in HR to review internal processes and systems to ensure they appropriately support the Company's growth, assist the Company's team members with career advancement goals, and provide Company leaders with tools to keep PGS's team members engaged. Witness Bluestone did not address the additional employees for the Strategy, Marking, and Communications, Real Estate, or Regulatory teams in her direct testimony, although she sponsored them on MFR Schedule G-2 page 19e.

Despite the many justifications for the additional employees provided by PGS witnesses in its direct testimony and throughout discovery, OPC witness Kollen proposed that we reject all new employee positions. Witness Kollen argued that the additional employees should be rejected because the additions are discretionary, PGS is already staffed for continued growth in customers and the related infrastructure, the Company's actual employees reflected significant vacancies compared to budgeted, PGS did not reduce contractor costs by an amount that justifies the increase in new employees, and the additional employees do not reflect efficiencies in WAM.

In his rebuttal testimony, witness O'Connor disagreed with OPC witness Kollen's assertion that the addition of employees is discretionary and that PGS is already sufficiently staffed for future work needs. Witness O'Connor asserted that if PGS does not increase headcount, locators will be required to perform more locates each day which could sacrifice quality and safety. As a result, higher compliance work volumes would be completed by team members working overtime and potentially cause burn-out or poor performance. Witness O'Connor also asserted in his rebuttal testimony that each service area must be considered to evaluate its ability to meet projected workload requirements, and he maintained that witness Kollen did not perform that evaluation. Witness O'Connor also disagreed with witness Kollen's assertion that PGS has not reduced contractor expense by an amount that justifies the increase in new employees by noting that the outside services expenses for Gas Operations has decreased from past years. Witness O'Connor asserted that high work activity and inflation are driving an increase in O&M costs, but regardless of that, PGS found a balance between internal and external labor. To further rebut witness Kollen's assertion on contractor costs, witness O'Connor pointed out that there is not an immediate one-for-one offset with an outside contractor as PGS's headcount increases.

In her rebuttal testimony, witness Parsons addressed eight new employees in the Finance department, three of which were replacement positions. Witness Parsons stated that these eight employees are needed to support the new requirements related to PGS's independent financings associated with the 2023 Transaction and replace the support being provided by TECO, provide financial and project evaluation support to the Gas Supply and Development team, and support enhanced financial profitability analysis to ensure appropriate revenue projections and rate analysis. In addition to the justification provided for the additional Finance positions in her rebuttal testimony, witness Parsons also asserted that the Company has proven its need for its forecasted new team members based on the growth of its system and increased work activity, the majority of which is non-discretionary; based on her rebuttal and direct testimony; responses to OPC Interrogatories; and the direct testimony of witnesses Wesley, O'Connor, Richard, and Bluestone, as well as the rebuttal testimonies of witnesses O'Connor, Richard, and Bluestone.

In his rebuttal testimony, witness Richard maintained that the gas system is growing in size and complexity and requires additional resources to ensure safe and reliable service. To further his point, witness Richard explained why each additional employee is needed by justifying all positions for each team and employee he sponsored in MFR schedule G-2.

The Joint Parties updated their position from witness Kollen's recommendation in their post-hearing brief and proposed that the number of employees should remain at 746, the 2023 level as of the hearing, or a maximum of 777. The Joint Parties stated that customers should only fund positions that are filled as of the hearing or likely to be filled by the end of 2023, as we should only approve the revenue requirement for which PGS had satisfied its burden of proof. The Joint Parties also included an alternative method of removing employee positions and honed in on positions sponsored by witness O'Connor within Gas Operations. The Joint Parties argued that witness O'Connor provided contradictory evidence that fell short of the burden of proof for the 61 positions he sponsored, disputed his testimony regarding the metrics used for geographic hiring, and raised an issue with the employment of contractual labor.

In regards to the issues the Joint Parties raised with witness O'Connor at the hearing, we find that he adequately covered the issues raised. Witness O'Connor explained that the job descriptions are intentionally broad to cover all possible tasks that would be expected of a team member over the course of training. In terms of the geographic hiring, he explained that the process is quite dynamic and specific to each service area, including the projected workload, existing workforce, and level of experience within the workforce. The significant arguments presented in the Joint Parties' brief regarding the employment of contractual labor are solely based on the witness affirming that some of the new hires may have come from the contractor workforce. Witness O'Connor added that the Company maintains a constructive relationship with its contractors in the instances when the contracted workforce finds and takes interest in posted PGS positions.

We have reviewed all information provided by PGS and agree that the additional employees sponsored by witnesses Richard, O'Connor, and Parsons were fully supported in their testimony and throughout the record. We also agree that the three HR positions sponsored by witness Bluestone were fully supported in her testimony and throughout the record. We approved additional O&M adjustments to reflect efficiencies from WAM and an additional reduction in contractual services in Sections IV.H and VI.E, respectively, based on the record evidence available, and no further adjustments related to these issues are necessary.

However, the Company did not provide adequate justification for the 15 positions in Strategy, Marketing, and Communications; Real Estate; Process Improvement and Analytics; and Regulatory and Pipeline Safety positions. In witness Bluestone's rebuttal testimony, she disputed OPC witness Kollen's assertion that the addition of employees was discretionary by referring to the testimonies of witnesses O'Connor, Richard, and Parsons. When asked about the positions she sponsored, witness Bluestone referenced the Company's response to OPC Interrogatory 13. In the response to Interrogatory 13, witness Bluestone did not provide an explanation for the positions, but instead provided a brief description of each position. Witness Bluestone further described the functions of the team members in her rebuttal testimony and in response to discovery, but did not provide detail on why the additional positions are necessary for the Company. At the hearing, witness Bluestone stated that although she felt she could provide some knowledge on the needs and challenges in those functional areas, she is not the functional expert for those teams and does not have the personal knowledge to explain why the positions she sponsored in her rebuttal testimony are necessary and prudent for business. We do not approve these positions to be recovered for ratemaking purposes, because these positions were not adequately supported in testimony or record evidence.

Considering all information provided from all parties, we find that all Strategy, Marketing, and Communications; Real Estate; Process Improvement and Analytics; and Regulatory and Pipeline Safety team members shall be disallowed from the projected test year number of employees for ratemaking purposes. As such, projected test year salaries and benefits shall be reduced by $1,245,959 to reflect the removal of these positions. The total adjustment reflects the payroll and benefits data for each specific position. In addition to the removal of these 15 positions sponsored by witness Bluestone, we also disallow the Business Development Manager for RNG position as proposed by PGS, resulting in an additional reduction of $37,882. We also removed the Company's corresponding increase in A&G expense associated with the additional employees in the projected test year, as addressed in Section VI.M.

In total, projected test year salaries and benefits shall be reduced by $1,283,841 to reflect our removal of the 16 employees. We find that PGS has provided sufficient record evidence to support 824 employees in the projected test year for ratemaking purposes.

iii. Conclusion

The number of projected test year employees that shall be approved for ratemaking purposes is 824. As such, projected test year salaries and benefits shall be decreased by $1,283,841.

G. Salaries and Benefits

i. Parties' Arguments

PGS testified that the appropriate amount of the projected test year salaries expense is $56,832,906, which reflects a reduction of $25,137 due to the salary of one Business Development Manager for RNG that is discussed further in Section VI.F. PGS contended the appropriate amount of the projected test year short-term incentive compensation included in FERC Account 920 is $8,046,556, and reflected in that amount is a reduction of $3,444 due to the mitigation of short-term incentive of one Business Development Manager for RNG as discussed in Section VI.F. The Company testified that the appropriate amount of projected test year employee pension and benefits included in FERC Account 926 is $12,255,566, which included a reduction of $9,301 of the benefits and loading of one Business Development Manager for RNG as discussed in Section VI.F.

PGS witness Bluestone testified that in order for the Company to attract and retain skilled and experienced team members it is crucial for the Company to offer a fair and market-based compensation and benefits package. Witness Bluestone continued that PGS's total compensation and benefits package includes base salary, short-term incentive, long-term incentive, pension or 401K, paid time off, employee common share purchase plan, and medical, dental, and vision insurance plans. Witness Bluestone described the Company's practice of benchmarking its total compensation against applicable markets for compensation. She contended that this provided evidence that the compensation practice and amounts are reasonable and appropriate for the 2024 projected test year. Witness Bluestone continued that the Company utilized an independent consultant, Mercer, to evaluate its healthcare plan and its pension and retirement savings plans. Based on a recent study, the Company ascertained that its healthcare plan and its pension and retirement savings plans are consistent with the median of the Company's peer groups.

The Company argued that its budgeted 5 percent annual merit increase for non-union employees for 2023 and 2024 is justified because the actual wage increases of 2.2 percent for both 2020 and 2021 were lower than the overall level of inflation of 4.7 percent and 8 percent, respectively. Witness Bluestone emphasized the importance of having a budgeted merit increase of 5 percent in order to attract and retain team members but insisted that it does not mean that the actual merit raises for 2023 and 2024 will reach the budgeted 5 percent.

As the Joint Parties previously argued in Section VI.F, we should only fund 746 positions that were filled at the time of the hearing, or at most 777 positions to include approximately 30 positions that remain unfilled in 2023. This recommendation by the Joint Parties resulted in a proposed annual reduction in payroll and payroll related costs for staffing reductions, after being grossed up to $5.997 million. The Joint Parties also recommended that the requested 64 employees in the 2024 projected test year be removed, resulting in an annual reduction in payroll and payroll related costs for staffing reductions in the amount of $3.844 million, after being grossed-up.

OPC witness Kollen testified that a 5 percent escalation factor for the trended payroll expenses in 2023 and 2024 is unreasonable based on the Company's historic factors and general inflation assumptions. Witness Kollen noted that the 5 percent trended factor was greater than any contractual union increase for 2023 and 2024 and exceeded inflation for 2023 and 2024 of 2.8 percent and 2.2 percent, respectively. Witness Kollen recommended utilizing escalation factors of 4 percent and 3 percent for the trended payroll in 2023 and 2024, respectively. Witness Kollen's recommendation resulted in an adjustment of $1.918 million after being grossed-up for regulatory assessment fees and bad debt expense.

The Joint Parties emphasized that the Company's pay is nearly at the national market average with a compensation ratio of 0.97 as of January 23, 2023, with the national market average being 1.0. Therefore, they argued that the 5 percent merit raises for 2023 and 2024 are not necessary in order for the Company to catch up to CPI as stated by PGS witness Bluestone. The Joint Parties contested that a 5 percent escalation factor was necessary in order for the Company to achieve competitive contracting, signing bonuses, moving expenses, and raises of existing employees and added that witness Bluestone testified that the Company's merit increases would most likely be under 5 percent. The Joint Parties also noted that a 5 percent wage differential is included in the test year for the areas of Miami, Ft. Myers, Jupiter, and Ft. Lauderdale due to the increased cost of living and labor cost, as presented by witness Bluestone's testimony.

The Joint Parties claimed the Company does not have justification for such a high increase considering that it is almost 2 percent higher than PGS's merit increases from 2018 through 2021 and 1.25 percent higher than 2022. The Joint Parties continued the argument on the fact that PGS has given merit raises every year the last five years, in an amount greater than the CPI; therefore, the Company does not need to catch up. Witness Kollen's recommended merit increases of 4 percent and 3 percent for 2023 and 2024, respectively, are greater than the projected CPI of 2.8 percent and 2.2 percent for 2023 and 2024, respectively.

The Joint Parties recommended three adjustments to the projected test year salaries and benefits, including a reduction of $5.997 million due to eliminate 29 requested positions in 2023; a reduction of $3.844 million to eliminate 64 requested positions in 2024, and a reduction of $1.918 million to reflect escalation factors of 4 percent and 3 percent for 2023 and 2024, respectively.

ii. Analysis

Witness Bluestone stated in her direct testimony that PGS benchmarks its total compensation and benefits against applicable markets using relevant Company benchmarks for both compensation and benefits. She testified that the Company's costs come in at the median of the market. To align total direct compensation (TDC) with the market, PGS first benchmarked positions against the labor market using data from the U.S. Mercer Benchmark database and the Willis Tower Watson MMPS Survey. With the information provided from these sources, PGS determined the compensation range, calculated the TDC and measured it against the market to determine where the team members' compensation fell.

PGS formed a TDC package that consists of base pay, a short-term incentive plan (STIP), and a long-term incentive plan (LTIP). The STIP links PGS's success to financial incentives for

PGS's team members for achieving the Company's annual goals and objectives, allowing eligible team members to receive STIP payments based on the balanced scorecard and the particular team member's performance multiplier. LTIP is administered through the Emera Performance Share plan that gives a grant of a performance share unit that has value tied to the value of Emera's common stock.

Witness Bluestone declared that PGS has salaries that are at the median of the market and in support of PGS's compensation philosophy that attracts, retains, and develops and incentives talent. PGS used the compensation ratio, which is a measurement of pay that compares a team member's base compensation to the median compensation for similar positions within the target market. To have a compensation ratio of 1.0 would indicate that the team member's base compensation would be at market. The Company's team members were at an average .97 compensation ratio, which meant that the Company was paying just below the market median.

PGS benefits are administered as a shared service through TECO and the benefit plans are held at the TECO Energy Incorporated level. PGS used the Mercer Benefits Valuation Analysis study to compare the relative value a company's overall benefit plan and its various components with other companies' plans contained within the Benefits Data Source United States database. PGS has an index score that is slightly above the market for retirement, medical, dental, and short-term and long-term disability. Because of that, witness Bluestone stated in her direct testimony that this is what allows PGS to be competitive and attract skilled team members in the marketplace.

PGS retained Mercer Health Benefits to project future plan costs for the self-funded plans to evaluate the design and cost of its health care programs. To ensure its healthcare costs are reasonable, PGS partnered with industry experts such as Mercer, Blue Cross Blue Shield, and others, and has implemented a customized, comprehensive, best-in-market clinical care management program, directed members to high quality doctors and hospitals, improved member engagement, purchased stop-loss coverage through a coalition, implemented wellness initiatives, and implemented a pharmacy program that includes utilization oversight.

PGS has multiple pension and retirement savings plans that are evaluated by an independent consultant, Mercer, to provide actuarial assumptions and methods used for the pension valuation. Witness Bluestone declared that the actuarial assumptions and methods are reasonable and consistent with Financial Accounting Standards Board standard and industry practice and provide a reasonable basis for determining the level of pension costs included in PGS's cost of service studies.

The Joint Parties did not provide an objection to PGS's compensation or benefits plan, nor did they propose alternative options for compensation and benefits, including incentive compensation. We have reviewed all documentation provided by PGS related to its compensation and benefits plans and agree with the Company that these costs are reasonable and prudent. However, the Joint Parties did take issue with the escalation factors used to trend payroll expenses in the projected test year.

PGS asserted in its brief that the appropriate amount of projected test year salaries and benefits, including incentive compensation, should be $77,135,028. The Joint Parties asserted in their brief that based on the recommended adjustments laid out in Section VI.F regarding the limited number of employees they recommend and the alternative number of employees recommended, the annual reduction in payroll and payroll related expenses should be reduced by $5.997 million or $3.844 million, respectively. Further, the Joint Parties recommended a reduction of $1.918 million to adjust for the requested merit increase rates of 4 percent and 3 percent for 2023 and 2024, respectively.

Witness Bluestone stated in her direct testimony that the Company is projecting a 5 percent merit increase for 2023 and 2024. In response, OPC witness Kollen stated that the 5 percent merit increase requested by PGS is significantly greater than increases PGS has given in past years. OPC witness Kollen also pointed out the 5 percent merit increase is greater than the 2.8 percent and 2.2 percent trended inflation escalation factors for 2023 and 2024, respectively. Because of this, OPC witness Kollen recommended that the merit increases be lowered to 4 percent and 3 percent in 2023 and 2024, respectively, to be consistent with PGS's historic practice of tracking general inflation for employees. Witness Bluestone maintained in her rebuttal testimony that the 5 percent merit increases are reasonable because PGS's actual wage rate increases for 2020 and 2021 were lower than the overall level of inflation for those years and PGS needs to "catch up" with inflation.

We approve a merit increase of 4 percent for 2023 and 2024. According to the "PGS Average Salary Increase Compared to Market" in witness Bluestone's direct testimony, PGS has been just below the market in salary increases for prior years and raising the salary increase to 5 percent for 2023 would place PGS above the market salary budget by almost 1 percent. Witness Bluestone argued that the actual merit increases for 2023 and 2024 would likely be less than 5 percent, but the Company must have the budgeted dollars to be competitive when contracting new hires, meet growing compensation demands due to market demands, and adjust compensation of existing employees who are at risk of being recruited away. We agree with witness Kollen's recommendation to limit the merit increase to 4 percent for 2023. As shown in witness Bluestone's direct testimony, the market salary increase for 2023 is about 4 percent, and witness Bluestone stated in her direct and rebuttal testimony that PGS used the market median to make projections for salaries. We agree that PGS should have the budgeted dollars for the reasons witness Bluestone provided in her testimony, and to be consistent with the projected market growth, we approve a 4 percent merit increase for 2024.

Based on the adjustments approved in Section IV.B to increase the allocation of labor to SGT and to decrease the number of employees in Section VI.F, projected test year salaries and benefits, shall be reduced by $189,347 and $1,283,841, respectively. Salaries and benefits in the projected test year shall also be reduced by $1,057,084 to account for the 1 percent decrease in merit increases for 2023 and 2024, resulting in a total decrease of $2,530,272. As such, projected test year salaries and benefits shall be $74,642,638.

iii. Conclusion

The amount of projected test year salaries and benefits, including incentive compensation, shall be $74,642,638.

H. Adjustments for Lobbying, Charitable Contributions, Sponsorships, and Advertising

At the hearing, we approved a type 1 stipulation as follows: In its initial filing, PGS did not make the proper adjustments to remove lobbying, charitable contributions, sponsorships, and institutional and image advertising from the projected test year. However, as reflected in Witness Parsons' rebuttal testimony, the Company has agreed to make an adjustment to the projected test year O&M expense of $500,000 to remove lobbying, charitable contributions, sponsorships, and institutional and image advertising. These adjustments arise from Commission Staff Audit findings, agreed upon reductions during a review of these items by OPC, and PGS self-disclosed reductions related to review of these items.

I. Economic Development Expense

At the hearing, we approved a type 2 stipulation as follows: The appropriate amount of added Economic Development expense in the 2024 test year is $265,498. This amount reflects the $367,920 stated in the direct testimony of witness O'Connor, pages 60-61, less a reduction of $102,422 for the adjustments described in Section VI.H related to economic development.

J. Storm Damage Accrual and Reserve Cap

At the hearing, we approved a type 1 stipulation as follows: The Company agrees to maintain its existing annual storm damage accrual of $380,000 and its existing storm reserve target of $3.8 million without prejudice to its ability to seek relief pursuant to Rule 25-7.0143(1)(j), F.A.C.

K. Adjustments for Merger & Acquisition Development

i. Parties' Arguments

PGS witness Parsons stated in her rebuttal testimony that there are no merger and acquisition costs included in the Company's 2024 test year O&M expenses. PGS witness Wesley confirmed on cross examination and confidential discovery responses that there is not an anticipated merger or acquisition to affect the 2024 projected test year. Therefore, the Company contended that it does not need to make an adjustment for merger and acquisition activity in the projected test year.

The Joint Parties stated that this issue is moot.

ii. Analysis

PGS witness Parsons affirmed in her rebuttal testimony that the Company did not incur any outside services costs associated with merger and acquisition activity, nor did it receive any allocated costs from Emera or any affiliate associated with such activity. She further testified that since 2022 actual costs are the basis for the 2024 budget, there are no costs associated with merger and acquisition activity in the projected test year. The Joint Parties declared the issue moot in its post-hearing brief. As such, no adjustments are necessary to projected test year expenses related to merger and acquisition development or pursuit activity.

iii. Conclusion

No adjustments are necessary to projected test year expenses related to merger and acquisition development or pursuit activity.

L. Rate Case Expense

At the hearing, we approved a type 2 stipulation as follows: The appropriate rate case expense is $2,778,647 and the amortization period shall be three years. This amount is a reduction from the $3,247,810 shown on MFR Schedule C-13.

M. O&M Expenses

i. Parties' Arguments

PGS's proposed amount of O&M expense is $144,856,712, which reflects the adjusted amount of O&M expense of $150,817,212 listed on MFR Schedule G-2, page 1, line 5. The adjustments are discussed by PGS witness Parsons in her rebuttal testimony and are as follows: a reduction of $500,000 discussed in Section VI.H, a reduction of $189,347 for increased overhead cost allocation to SGT discussed in Section IV.B, a reduction of $190,000 for the decrease in standalone audit fees discussed in Section VI.E, A reduction of $60,234 for updated treasury analyst costs, a reduction of $37,882 for removal of RNG business development manager discussed in Section VI.F, a reduction of $750,000 for WAM costs discussed in IV.H, a reduction of $3,956,653 for removal of Alliance as discussed in Section IV.G, a reduction of $120,000 for storm reserve adjustment as discussed in Section VI.J, and a reduction of $156,384 for a revised rate case expense amortization as discussed in Section VI.L.

PGS ascertained that the O&M expense in the 2024 projected test year is reasonable and necessary and is about $13 million below the $158.3 million benchmark. PGS argued that we should not approve the Joint Parties' recommendation of reducing O&M expense and should not accept the $2.125 million reduction to A&G expense presented by the Joint Parties. PGS asserted that its proposed A&G allocation of $11 million in the 2024 test year is $3 million more than the allocation of 2020 and $2 million more than the allocation in 2021, it is consistent with the actual amount allocated in 2022, and it is reasonable due to the number of employees who charge time to A&G accounts and work on the Company's capital program. PGS continued that if we decide to reduce A&G expenses, then a corresponding adjustment to increase rate base in Section IV.P will need to be made.

The Joint Parties asserted that the O&M expense for the 2024 projected test should be reduced by at least $46,595,000. The Joint Parties argued that the Company's under-allocation of A&G expense to construction will be addressed in this issue due to it being a bottom-line O&M issue.

OPC witness Kollen noted that the $11 million transferred in 2022 for A&G allocations and proposed by the Company to be held constant for both 2023 and 2024 is an error. Witness Kollen proposed increasing this allocation by either 34.9 percent, if the proposed new hires are approved, or 19.3 percent, if the proposed new hires are excluded. The Joint Parties argued that this is a conservative percentage used by witness Kollen in his adjustment of the A&G transfer.

The Joint Parties contended that the Company's proposed accounting treatment overstates the revenue requirements. The Joint Parties continued their contention that the most problematic issue with this is that a post-rate case increase in the transfer from the last rate case test year, 2021, provided an immediate increase in the Company's earnings, while the customers' rates stayed as established in the last rate case.

The Joint Parties recommended that even though the Company testified the amount to transfer is at its discretion, PGS did not demonstrate the reasonableness or prudence of the cost due to not performing any necessary studies or analysis required by the Uniform System of Accounts (USOA). Therefore, the Company did not meet its burden of proof. The Joint Parties asserted that we should reject the fixed amount of the A&G transfer based on the lack evidence provided alone.

The Joint Parties urged us to consider the effects of allowing the Company to make its own subjective assessment of this type of transfer. In the scenario that we set the rates based on the $11 million transfer and then the Company revised the test year income statement to transfer additional expenses to capital, it would result in rates that are excessive and would force customers to pay certain costs twice. The Joint Parties stated that this scenario happened after the 2020 rate case, when amounts approved for recovery as O&M expense were transferred to capital.

The Joint Parties testified that no evidence was provided by the Company to determine if the major project, FGT to Jacksonville Export Facility, would be ongoing in the test year. Therefore, the Company's recommendation to remove this project from proposed test year recovery should be disregarded. Furthermore, the Joint Parties stated that the project does not need to be included in any test year rate base or even plant in service to draw an allocation of A&G expenses.

The Joint Parties also asserted that by the USOA standards it is required to base allocations on direct timecard distributions, or a special study provided by the Company. The Joint Parties noted that the Company did not complete either of those necessities. The Joint

Parties cited Rule 25-7.014(1), F.A.C., that sets requirements and prohibitions on the ratemaking process based on the test year accounting and in any post-test year revision of the A&G transfer.

Witness Kollen observed the lack of consistency in the relationship between the capital spent and the A&G expense. The Joint Parties noted that the Company stated the allocation should correspond to the capital spent but evidence provided by the Company does not support that standard. The Joint Parties concluded that due to the Company not meeting its burden of proof or providing a justification on the fixed A&G transfer, the A&G transfer should be increased by $2.1423 million, before gross-up.

ii. Analysis

Although this issue is a fallout issue of stipulations and our findings on other NOI issues, as listed in Tables 11 and 12, additional expenses included in projected test year O&M expenses will also be addressed.

A&G Transfer

OPC witness Kollen proposed that an adjustment be made to reduce O&M expense by $2.125 million to increase the amount of A&G expense that should be capitalized to construction work. The basis of this adjustment is that there is an $11 million credit included in Account 922 in the projected test year 2024, which is used to allocate A&G expense in Accounts 920 and 921 to capital expenditures. Witness Kollen testified that the Company significantly increased the capital expenditures and the A&G expenses compared to the historic base year 2022. Yet the Company held the Account 922 credit for A&G allocation to capital constant from 2022 to 2024.

PGS witness Parsons testified in her rebuttal that the Company deemed it reasonable to keep the A&G allocation to capital at $11 million in the 2023 and 2024 budgets as it had already increased the allocation from $8 million in 2020. Additionally, witness Parsons testified that the 2024 capital budget, excluding the FGT to JEF project, would be $314.2 million, which is lower than the capital expenditures in 2020 and 2022, which were $339 million and $325.2 million, respectively.

In their brief, the Joint Parties argued that the relationship between the A&G transfer to capital and capital expenditures are not consistent. From 2019 to 2020, capital expenditures increased by 68 percent but the A&G transfer remained constant at $8 million. From 2020 to 2021, capital expenditures decreased by 9 percent but the A&G transfer increased from $8 million to $9 million. Then, from 2021 to 2022, capital expenditures gradually increased by 2.6 percent but the A&G transfer increased from $9 million to $11 million.

Additionally, the Joint Parties argued that the USOA states that expenses allocated to direct construction costs are not permitted to be added arbitrarily, but that allocation should be based on direct time card distribution or a special study. PGS witness Parsons testified that the Company has not been able to refresh past studies given resource constraints. The Joint Parties argued that the Company failed to meet its burden of proof by performing any type of study to justify holding the A&G transfer to capital steady while A&G increased significantly from the historic base year 2022 to the projected test year 2024.

Witness Kollen based his proposed adjustment on the increase in A&G expenses from the historical base year 2022 to the projected test year 2024. Witness Kollen testified that the Company forecasted an increase in A&G Accounts 920 and 921 expense of 34.9 percent from 2022 to 2024. However, without including the increase in payroll to these accounts related to new employees the Company forecasted an increase of 19.3 percent for these accounts. Witness Kollen conservatively proposed using the 19.3 percent to increase the $11 million A&G allocation to capital, resulting in his proposed adjustment to reduce O&M expenses by $2.125 million.

We agree with the Joint Parties' argument that, without an up-to-date study to justify the amount of A&G expense being allocated to capital projects, the Company did not meet its burden of proof to justify keeping the A&G transfer constant from 2022 to 2024. We agree with witness Kollen's methodology for keeping the A&G transfer consistent with the growth in A&G from 2022 to 2024. Therefore, O&M expense shall be reduced by $2,125,283.

Audit Fees & Treasury Support

In her rebuttal testimony, witness Parsons testified that PGS was able to negotiate down audit fees from its 2024 standalone audit by $190,000, after the MFRs were filed. Witness Parsons also testified that the Company was able to update its 2024 budgeted Treasury support costs. The Company was able to add a treasury analyst position with a cost allocation to PGS of $50,000 and trustee costs of $40,000 in order to remove the 2024 budgeted TECO Treasury team cost allocation of $150,234 to PGS. The Joint Parties did not dispute these adjustments. Therefore, projected test year O&M expenses shall be reduced by $190,000 to reflect the Company's adjustment to reduce the one time audit fee for 2024, and $60,234 ($150,234 - $40,000 - $50,000) to reflect the net reduction of costs for treasury support.

Fallout

Projected test year O&M expense shall reflect the fallout of stipulations and our findings in other issues, as reflected in the following tables.

Table 11
Fallout Adjustments from Stipulated Issues

Issue No.	Description	Amount
18	Remove Alliance O&M	($3,956,653)
44	Lobbying, Contributions, Sponsorships, & Advertising	(500,000)
46	Reduce Storm Reserve Accrual	(120,000
48	Reduce Rate Case Expense Forecast	(156,384)
	Total	($4,733,037)

Table 12
Fallout Adjustments from Other Findings

Issue No.	Description	Amount
13	Increase Allocation to Seacoast	($189,347)
19	WAM Efficiency O&M Reductions	(750,000)
41	Reduce Redundant Outside Service	(206,000)
42	Remove Unsupported New Employees	(1,245,959)
42	Remove BDM Position	(37,882)
42	Remove Employee Expense Related To Unsupported Employees	(92,919)
43	Reduce Annual Increase to 4 Percent	(1,057,084)
	Total	($3,579,191)

iii. Conclusion

The appropriate amount of projected test year O&M expenses for PGS shall be $140,129,467.

N. Depreciation and Amortization Expense

i. Parties' Arguments

PGS claimed the appropriate approved amount of Depreciation and Amortization Expense for the 2024 projected test year to calculate NOI is $87,271,966. PGS derived this figure from taking the total Depreciation and Amortization Expense of $87,613,968 then reducing expenses by $252,303 based on an updated depreciation study and rates, $359,701 due to the removal of the Alliance Dairies RNG Project, and $51,505 to reflect the reclassification of the New River RNG Project assets to different accounts. PGS also noted that if we decide on a 15 year depreciation period for the Brightmark RNG Project pipeline extension, then depreciation expense will increase by $321,507. PGS recognized that OPC witness Garrett proposed extending the service lives of five accounts based on People's study; however, PGS argued that for similar reasons as stated in Section III.B, the Joint Parties' recommendations are unreasonable and no adjustments should be made based on witness Garrett's testimony.

The Joint Parties recommended that we should reduce test year Depreciation and Amortization Expense by at least $26,404,000. The Joint Parties based their position on OPC witness Garrett's recommendation that we accept the application of the December 31, 2023 depreciation study date as well as longer lives for the five accounts listed in Section III.C. The Joint Parties explained that witness Garrett made these recommendations based on the Iowa Curve that was found to best fit the OLT curve as well as other previously discussed factors, in Section III.C, affecting the data. OPC witness Kollen testified that this reduction results in a $7.257 million reduction in depreciation expense and a $6.991 million reduction in the base revenue requirement. Witness Kollen also testified that the stipulated study date of December 31, 2023 would result in a net reduction in base revenue requirement of $16.980 million, offset in part by witness Garrett's changes to depreciation expense. The Joint Parties proposed that we adopt these changes, which would lead to a reduction of at least $26,404,000 to the projected test year Depreciation and Amortization Expense.

ii. Analysis

This is a fallout issue. Based on the depreciation rates and the projected test year plant in service approved in Section III.C and IV.J, respectively, the implementation date of the depreciation rates stipulated in Section III.G, the accelerated depreciation period for RNG plant leased to others stipulated in Section III.A, as well as the outcome of the stipulations in Sections III.D and IV.G, we find several adjustments to the amount of projected test year depreciation and amortization expense that PGS proposed in MFR Schedule G-2.

First, depreciation expense shall be reduced by $252,303 to reflect our findings in Sections III.C and III.D. This adjustment is a result of PGS's update to its originally-filed depreciation study and the calculation of depreciation rates as of December 31, 2023, rather than December 31, 2024. Second, depreciation expense shall also be reduced by $359,701 to reflect the removal of the Alliance Dairies RNG Project, as addressed by the stipulation in Section IV.G. Third, depreciation expense shall be reduced by $51,505 based on PGS's proposed reclassification of certain New River RNG Project assets to different plant accounts. Finally, an increase to depreciation expense in the amount of $321,507 shall be approved to recognize the accelerated depreciation of the Brightmark RNG Project-associated pipeline extension over 15 years, per the stipulation in Section III.A. As such, projected test year depreciation and Amortization Expense shall be decreased by $342,002. The appropriate level of projected test year Depreciation and Amortization Expense shall be $87,271,967

iii. Conclusion

Based on the stipulations in Sections III.D and IV.G and our findings in Sections III.C, III.D, and VI.N, projected test year Depreciation and Amortization Expense shall be decreased by $342,002. As such, the appropriate amount of projected test year Depreciation and Amortization Expense shall be $87,271,967.

O. Taxes Other Than Income (TOTI)

i. Parties' Arguments

PGS stated that the appropriate level of TOTI in the projected 2024 test year is $29,604,654. The Company initially proposed a total of $31,701,341 in TOTI. PGS noted an error in the property tax forecast work papers and recommended that property tax be adjusted downward by $2,008,000 to correct this error. PGS further noted that property tax should be reduced by $88,687 for the removal of the Alliance Diaries RNG project. PGS argued that the use of the experience trend factor is reasonable and consistent with the Company's experience and presented historical data, including a 5-year average, demonstrating the higher taxable values derived by taxing authorities than that proposed by PGS.

The Joint Parties stated that since PGS corrected an error by reducing the property tax by $2.008 million, they have dropped their objection to the use of the five-year trending analysis.

ii. Analysis

In MFR Schedule G-2, page 1, PGS showed a total TOTI for the projected test year of $31,701,341. Through OPC discovery, PGS witness Parsons stated the Company estimated a property tax expense of $24,462,000 in 2024. However, PGS acknowledged an error in the calculation of its 2024 tangible personal property and property tax expense experience trend factor. The experience trend factor is used to account for the difference between estimated taxes and actual tax payed. As filed, the trend factor was 13.7 percent corresponding to a property tax expense of $24,462,000. After correcting the error, the trend factor became 3.7 percent corresponding to a property tax expense of $22,454,000. This results in a decrease of $2,008,000.

In direct testimony, OPC witness Kollen argued that an experience trend factor based on 2021 valuation was unjustified and unreasonable, due to being much greater than the 2022 factor, 0.8 percent. In rebuttal testimony, PGS witness Parsons argued that a 3.7 percent experience trend factor was within reason and supported this notion with the historical average of the past five years, 2018 - 2022. The 5-year average experience trend factor was 3.9 percent. During the hearing, witness Parsons stated that the 0.8 percent factor in 2022 was anomalous and stated that using one point in time is not the best practice in some cases. PGS witness Parsons restated that a 3.7 percent factor is conservative, being lower than the historical 5-year average of 3.9 percent including the anomalous 0.8 percent. We agree with the assessment of witness Parsons and find that an experience trend factor of 3.7 percent is reasonable.

Furthermore, based on stipulations and our findings in previous sections, additional corresponding adjustments to TOTI are necessary. Per the stipulation in Section IV.G, property tax shall be decreased by $88,687 for the removal of Alliance Dairies RNG. A reduction to salaries and benefits in Sections VI.F and VI.G, results in a corresponding reduction of $179,692 to payroll taxes. Therefore, we find that TOTI shall be reduced by a total of $2,276,379. As such, the appropriate amount of TOTI for the projected test year shall be $29,424,962.

iii. Conclusion

Based on the stipulation in Section IV.G and our findings in Sections VI.F and VI.G, projected test year TOTI shall be decreased by $2,276,379. As such, the appropriate amount of TOTI for the projected test year shall be $29,424,962.

P. Parent Debt Adjustment

i. Parties' Arguments

The Company's proposed Parent Debt Adjustment amount of $3,084,000 is based on the Company's proposed 54.7 percent equity ratio and complies with the current parent debt adjustment rule as explained in the direct testimony of PGS witness Parsons. There is no difference between the adjustment methodology used by PGS and the one used by the Joint

Parties. The difference in amounts arises from the Joint Parties' use of a lower equity ratio, which PGS argues we should not adopt for the reasons explained in Section V.G.

The Joint Parties argued the Parent Debt Adjustment required by the rule is $2,762,000 based on the level of common equity recommended by the Joint Parties. To the extent we approve a greater amount of equity in the Company's capital structure, there should be a concomitant increase in the adjustment.

ii. Analysis

PGS included a Parent Debt Adjustment of $3,084,000 pursuant to Rule 25-14.004, F.A.C., Effect of Parent Debt on Federal Corporate Income Tax, as shown in MFR Schedule C-26. The Company proposed to follow the same methodology in the 2024 projected test year as it did in its last rate case in Docket No. 20200051-GU.[56] The methodology used by PGS comports with Rule 25-14.004(4), F.A.C., as described herein:

> 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.

The Joint Parties did not oppose a Parent Debt Adjustment in this case. In its response to Staff's 2nd Set of Interrogatories, No. 20, OPC stated that if we adopt OPC's recommendation regarding the capital structure, the Parent Debt Adjustment reduction to income tax expense would be $2,762,000, a reduction of $322,000 from PGS's Parent Debt Adjustment of $3,084,000. The parent debt adjustment would be based on an equity balance of $965,336,000 instead of PGS requested equity balance of $1,119,871,358. Joint Parties' recommended adjustment to lower the common equity balance would result in an increase of $435,000 to their recommended revenue requirement for PGS. Both PGS and Joint Parties agreed that a Parent Debt Adjustment pursuant to Rule 25-14.004, F.A.C., is applicable in this case.

Based on our adjustments to the capital structure and common equity balance in Section V.I, the common equity balance for PGS shall be $1,122,029,733. The parent debt adjustment based on the adjusted common equity balance is $3,213,476 (1.13% × 25.345% × $1,122,029,733 = $3,213,476). This results in an increase to the Company's proposed parent debt adjustment of $129,476. Consequently, the amount of projected test year income tax expense in Section VI.Q shall be decreased by $129,476. This decreases revenue requirement by $174,793 ($129,476 × 1.35 = $174,793)

[56]Order No. PSC-2020-0485-FOF-GU, issued December 10, 2020, in Docket No. 20200051-GU, *In re: Petition for rate increase by Peoples Gas System.*

iii. Conclusion

We find that the appropriate amount of a Parent Debt Adjustment required by Rule 25-14.004, F.A.C., is $3,213,476.

Q. Income Tax Expense

i. Parties' Arguments

PGS acknowledged that Income Tax Expense is dependent on the results of any adjustments that we approve. Based on PGS's revised revenue requirement, the Company proposed a 2024 test year Income Tax Expense of $3,770,671, which is the net test year Income Tax Expense of $3,093,175 including an income tax offset of $677,496.

The Joint Parties stated that this is a fallout issue, which depends on the adjustments made to revenue requirement.

ii. Analysis

This is a fallout issue. Based on the stipulation in Section IV.G and our findings in Sections VI.M, VI.N, VI.O, and VI.P, projected test year Income Tax Expense shall be increased by $1,814,368. As such, the appropriate amount of Income Tax Expense for the projected test year, including current and deferred income taxes and interest synchronization, shall be $4,907,543.

Table 13
Commission-Approved Income Tax Expense

MFR Amount Requested	$3,093,175
Fallout Adjustments:	
Parent Debt Adjustment	($129,476)
Interest Synchronization	22,684
Other Issues—Federal Income Tax	1,504,258
Other Issues—State Income Tax	416,902
Total Adjustments	$1,814,368
Adjusted Amount	$4,907,543

iii. Conclusion

Based on the stipulation in Section IV.G and our findings in Sections VI.M, VI.N, VI.O, and VI.P, projected test year Income Tax Expense shall be increased by $1,814,368. As such, the appropriate amount of Income Tax Expense for the projected test year, including current and deferred income taxes and interest synchronization, shall be $4,907,543.

R. Total Operating Expenses

i. Parties' Arguments

PGS proposed total operating expenses of $266,008,087, which is a decrease in Total Operating Expenses of $7,721,692.

The Joint Parties stated that this is a fallout issue, which depends on the adjustments made to revenue requirement.

ii. Analysis

This is a fallout issue of Sections VI.M, VI.N, VI.O, and VI.Q, which address the projected test year amount of each component of Total Operating Expenses. Based on our adjustments to the projected test year amounts of O&M Expense, Depreciation and Amortization Expense, TOTI, and Income Tax Expense in Sections VI.M, VI.N, VI.O, and VI.Q, respectively, the appropriate amount of projected test year Total Operating Expenses shall be $262,238,021.

iii. Conclusion

The appropriate amount of projected test year Total Operating Expenses shall be $262,238,021.

S. Net Operating Income (NOI)

i. Parties' Arguments

PGS stated that this is a fallout issue, and the NOI will need to be calculated to reflect adjustments approved by us on other issues. The Company's proposed NOI of $74,332,841 reflects two adjustments made to the initial proposed NOI of $72,337,240 as shown on MFR Schedule G-2, page 1, line 17. PGS stated the first adjustment is a decrease of $7,721,692 in total operating expenses as determined in Section VI.R and the second adjustment of $5,726,092 is for the removal of the Alliance project revenue, also reflected in the Company's revised revenue requirement.

The Joint Parties stated that this is a fallout issue and maintained that PGS has not quantified the amount of the appropriate NOI that would remain after the revenue requirement adjustments.

ii. Analysis

This is a fallout issue of projected test year revenues and Total Operating Expense in Section VI.R. Projected test year revenues shall be decreased by $5,726,092 to reflect the stipulation to remove the Alliance Dairies RNG project in Section IV.G. Based on the stipulation in Section IV.G and our finding in Section VI.R, the appropriate amount of projected test year NOI shall be $78,102,907.

iii. Conclusion

Based on the stipulation in Section IV.G and our finding in Section VI.R, the appropriate amount of projected test year NOI shall be $78,102,907.

VII. Revenue Requirements

A. Revenue Expansion Factor and NOI Multiplier

At the hearing, we approved a type 1 stipulation as follows: The appropriate revenue expansion factor in this case is 74.0723 percent and the NOI multiplier proposed in this case is 1.3500, as shown on MFR Schedule G-4, page 1.

B. Annual Operating Revenue Increase

i. Parties' Arguments

PGS stated this is a fallout issue, and the annual operating revenue increase will need to be calculated to reflect any adjustments that we approve on all other issues. The Company's proposed annual operating revenue increase of approximately $135.3 million reflects a net decrease of approximately $3.9 million from the Company's original request as discussed in the testimony of PGS witness Parsons.

PGS argued that we should not approve the Joint Parties' proposed use of deferral accounting for the New River and Brightmark RNG projects. PGS attested that the annual contract revenues will not recover the annual revenue requirement in the early years and surpass the revenue requirement in the later years, as typical with all fixed-rate, long-term customer contracts. The Company affirmed that there is nothing improper about its accounting method which is a function of the depreciation expense reducing the net book value of an asset over the course of the asset's useful life. The Company argued that the Joint Parties' proposal of deferral accounting for the two RNG projects that were developed with the Company's approved RNG tariff is inconsistent with our practice on the treatment of contract revenues and revenue requirement of other long term customer projects. Additionally, PGS argued that the application of deferral accounting would create an administrative burden to the Company.

The Joint Parties stated that we should approve a base revenue increase of no more than $42,903,000, including the transfer of CI/BSR revenues. The Joint Parties also discussed whether we should approve a revenue neutral revenue requirement related to RNG projects, Brightmark and New River. The Joint Parties stated that if the projects remain in the test year revenue requirement, it will inflict a revenue requirement increase of $1.5 million onto the customers. The Joint Parties noted the two main concerns with allowing the $1.5 million increase of the revenue requirement are that customers in 2024 and for the next several years will have to endure most of the costs, and there is no assurance that the customers will remain with the Company long enough to receive any benefit.

OPC witness Kollen supported creating a deferred asset as a solution to align costs to match with the customer contract revenue and shield the rest of the customers from taking on the cost. The Joint Parties noted that the Company reasoned the administrative burden and expense associated with creating a deferred asset would not be favorable, but if we approved a deferral then the Company could achieve the neutral revenue requirement as proposed by the Joint Parties. However, the Joint Parties contested that the cost tracking and accounting for this process is provided in the regulated cost of the test year revenue requirement and the administrative burden is not an adequate argument to reject the deferred asset. The Joint Parties affirmed that the Company did not present sufficient evidence that the revenue requirement including the RNG projects is reasonable or prudent, and therefore witness Kollen's recommendation to neutralize the $1.533 million revenue requirement with a deferred asset should be accepted.

ii. Analysis

Although this issue is a fallout of stipulations and our findings in previous issues, the remaining point of contention regarding the renewable natural gas projects stipulated in Sections IV.E and IV.F will also be addressed, as stipulated by the parties at the hearing.

New River and Brightmark RNG Projects

The costs associated with PGS's New River and Brightmark RNG projects are included in rate base per the stipulations in Sections IV.E and IV.F. RNG is biogas extracted from above ground decomposing waste, such as animal and food waste, which has been upgraded to a pipeline quality similar to natural gas. Both of the RNG projects were developed under PGS's Commission-approved RNG Service Tariff, which is now closed to new participants and being replaced with PGS's new RNG Interconnection Service Tariff per the stipulations in Sections IV.E and IV.F.

The New River and Brightmark RNG projects involve production and transportation of RNG, with capital investments of $8.2 million and $42.7 million, respectively. The projects' respective counterparties, Opal Fuels and Brightmark, are responsible for the payments over the 20 and 15 year project terms. The counterparties are required to pay levelized rates designed to recover the revenue requirements for the projects over the life of the contracts pursuant to each project's RNG Service Agreement.

As explained by OPC witness Kollen, although project revenues offset project costs over the terms of the contracts, there is a difference between the revenues and project costs in the test year, which increases the revenue requirement for all customers in the test year. As reflected in the Company's original petition, there are revenue requirement deficiencies in the test year of approximately $144,104 for New River, and approximately $1,389,000 for Brightmark. Because rates are established using only test year values, customers would be responsible for the test year deficiencies until we reset PGS's rates.

OPC witness Kollen's testimony initially only recommended the removal of the revenue requirement associated with the mismatch of RNG revenues and costs, so that all customers are neither harmed nor benefited from the RNG projects. His recommendation did not include any specific basis or method for adjusting the costs in excess of revenues in the test year. He further testified that he did not oppose the use of deferral accounting to address the mismatch, so long as the deferrals were not included in rate base since the levelized revenues associated with the projects already embed a return on rate base. At the hearing, witness Kollen provided additional support for reflecting the project as "revenue neutral" through the deferral of the costs. He explained that the test year would reflect the deferral of the mismatch in the first year of the contract, when costs exceed revenues, and over time, when revenues are greater than costs, the deferrals would start to reduce the balance to zero by the end of the contracts.

PGS witness Parsons testified that although the annual contract revenues from the customers will not recover the annual revenue requirement in the early years, they will exceed the annual revenue requirement in the latter years. She further argued that there is nothing improper about this situation, as it is a function of how depreciation expense reduces the net book value of assets subject to a fixed-rate, long term customer contract over the useful life of the assets. PGS witness Parsons compared the Company's proposed treatment of contract revenues and the revenue requirement as being consistent with our treatment of other long-term customer projects, specifically pipeline extensions. PGS affirmed that this standard rate development is not unique to PGS's RNG Tariff and maintained that most utilities formulate rates on this Commission-approved fundamental regulated principle. The Company explained that this approach provides rate certainty over the contract term, which is important to customers committing to long-term agreements.

Witness Parsons emphasized the administrative burden of deferral accounting for the two projects, which she characterized as being no different than most of the Company's other projects. She contended that they weren't any different than many of the Company's other projects that don't meet their revenue requirement in the early years, so it wasn't ideal to expend the additional resources to treat them differently. In response to discovery, PGS stated that it had no precedent to base a request for deferral accounting on a customer contract.

As proposed by PGS, net benefits would not begin to accrue for the New River and Brightmark RNG projects until 2034 and 2037, respectively, based on each project's cumulative present value revenue requirement analysis. Based on the Company's analysis, the New River and Brightmark RNG projects would start showing revenue sufficiency in 2027 and 2029, respectively. However, this analysis and the calculation of the revenue deficiency in the test year does not reflect the adjusted capital structure components, accumulated depreciation, or depreciation expense as set out in this order.

The cost of service-based rate was developed in compliance with the tariff applicable to both RNG projects and recovered revenue requirement is comprised of the capital investment, a return on the investment, depreciation, O&M costs, and property taxes. Using the Company's work papers, we recalculated the revenue requirement impact associated with each project based on the capital structure approved in Section V.I, and adjustments to accumulated depreciation and depreciation expense for both projects in Sections IV.K and VI.N, respectively. With contract revenues held constant, the New River RNG project revenues exceed costs in the allowed revenue requirement by approximately $32,000 and the Brightmark revenue deficiency is reduced to approximately $921,000, resulting in a net revenue deficiency of less than

$900,000. In total, this represents approximately 0.20 percent of the total revenue requirement. Unadjusted for our findings, the revenue deficiency is approximately 0.33 percent.

We have previously cited Financial Accounting Standards Board's Accounting Standards Codification 980 Regulated Operations (FASB ASC 980) in previous decisions regarding the approval of regulatory assets.[57] The recognition and establishment of regulatory assets are addressed in ASC 980, which allows a regulated entity to capitalize all or part of an incurred cost that would otherwise be charged to expense, provided that: 1) it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes; and 2) based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

What witness Kollen proposed is an open-ended authorization to record the deferrals of costs in excess of revenue requirement until the revenues exceed costs, at which point the deferrals would start to reduce until the end of the contracts when they would be zero. In the projected test year, he describes it as a negative expense of $1.6 million to record as a deferral. As previously described, the total RNG project costs include several components, but only three of the components are incurred expenses—depreciation, property taxes, and O&M. They comprise less than half of the revenue requirement associated with each project combined, yet those would be the only costs eligible for deferral. The Joint Parties had no support or suggestion for a specific method of assigning costs to be deferred. The process would also require tracking the excess costs or revenues for each project annually, and it is not as simplistic as authorizing a regulatory asset in a lump sum to be amortized over a prescribed period.

The relative size of the total excess in the current test year (0.20 percent), which will ultimately benefit customers with its continued inclusion in rates, in conjunction with the administrative burden cited by the Company, does not support treating these projects differently in the projected test year with the imposition of deferral accounting. As such, we will not make an adjustment to address the revenues and costs associated with the New River and Brightmark RNG projects.

Fallout

Based on our findings in previous sections, the appropriate total annual operating revenue increase for the projected test year is $117,839,527, as reflected in the following table. The revenue increase reflects the revenues associated with the transfer of CI/BSR investments, as stipulated in Section IV.C. Based on the Company’s original request, the amount of CI/BSR transferred revenues was $11.6 million. We used the Company’s work papers to recalculate the revenues associated with the CI/BSR transfer using the approved capital structure. Based on our findings, the amount of CI/BSR transferred revenues is $11.2 million.

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[57]Order Nos. PSC-14-0698-PAA-GU, issued December 18, 2014, in Docket No. 20140016, *In re: 2014 depreciation study by Florida Public Utilities Company*; and PSC-13-1093-PAA-EI, issued May 6, 2013, in Docket No. 20120303, *In re: Petition for approval for an accounting order to record in a regulatory asset or liability the unrealized and realized gains and losses resulting from financial accounting requirements related to interest rate derivative agreements, Progress Energy Florida, Inc*.

Table 14
Commission-Approved Annual Operating Revenue Increase

Operating Revenue Increase	$117,839,527
CI/BSR Revenue	(11,156,958)
Incremental Revenue Increase	$106,682,569

iii. Conclusion

The appropriate annual operating revenue increase for the projected test year shall be $117,839,527. This amount includes a base rate increase of $11.2 million for revenue associated with the rate base transfer of CI/BSR investment.

VIII. Cost of Service and Rate Design

A. Cost-of-Service Study

At the hearing, we approved a type 2 stipulation as follows: The Company's cost of service study appropriately reflects cost causation, and each allocation factor is consistent with the factors that drive the underlying costs of providing service to customers.

B. Allocation of Rate Increase

At the hearing, we approved a type 2 stipulation as follows: The revenue increase granted shall be allocated to the rate classes to achieve an equalized rate of return for the Residential and Commercial rate classes and as shown for the Company's proposed increase and rates on Document Nos. 6, 9, 10, 11, and 12 of Exhibit No. GT-1.

C. Customer Charges

i. Parties' Arguments

PGS argued that this is a fallout issue based on the approved revenue requirement and our decisions on issues that impact the inputs to the Company's stipulated cost of service methodology.

The Joint Parties did not provide an argument.

ii. Analysis

The customer charges, in combination with the per therm distribution charges shown in Section VIII.D, are designed to allow the Company to recover the total approved revenue requirement. Further, we approved the Company's proposed cost of service methodology in Section VIII.A and the allocation of the revenue increase to rate classes in Section VIII.B. The proposed customer charges reflect the approved revenue requirements and cost of service methodology; therefore, the proposed charges provided in the tariffs in Attachment 6 to the order, attached hereto, are approved.

iii. Conclusion

The proposed customer charges as provided in the tariffs in Attachment 6 to this order are approved.

D. Distribution Charges

i. Parties' Arguments

PGS argued that this is a fallout issue based on the approved revenue requirement and our decisions on issues that impact the inputs to the Company's stipulated cost of service methodology.

The Joint Parties did not provide an argument.

ii. Analysis

We have reviewed the Company's revised cost of service filing and it reflects the approved total Company revenue requirement. Further, we approved the Company's proposed cost of service methodology in Section VIII.A and the allocation of the revenue increase to rate classes in Section VIII.B. The proposed customer charges reflect the approved revenue requirements and cost of service methodology; therefore, the proposed per therm charges provided in the tariffs in Attachment 6, attached to this order, are approved.

iii. Conclusion

The proposed per therm distribution charges as provided in the tariffs in Attachment 6 to this order are approved.

E. Miscellaneous Service Charges

At the hearing, we approved a type 2 stipulation as follows: We shall approve the Company's proposed miscellaneous service charges as shown on Document No. 3 of Exhibit No. KLB-1. They are fair, just, and reasonable.

F. Revised Annual Residential Reclassification Review

At the hearing, we approved a type 2 stipulation as follows: The proposed revisions to the annual residential reclassification are reasonable and shall be approved.

G. Residential and Commercial Generator Rate Design Revision

At the hearing, we approved a type 2 stipulation as follows: The proposed revisions to the Company's termination fee for the Natural Choice Transportation Program are reasonable and shall be approved.

H. Revised Termination Fee for Natural Choice Transportation Program

At the hearing, we approved a type 2 stipulation as follows: The proposed revisions to the termination fee for the Natural Choice Transportation Program are reasonable and shall be approved.

I. Revised Individual Transportation Administration Fee

At the hearing, we approved a type 2 stipulation as follows: The Company's existing Individual Transportation Fee shall remain in effect.

J. Minimum Volume Commitment Provision and Agreement

At the hearing, we approved a type 2 stipulation as follows: The proposed revisions to the Company's minimum volume commitment provision and agreement are reasonable and shall be approved.

K. Non-Rate Related Tariff Modifications

At the hearing, we approved a type 2 stipulation as follows: The proposed revisions to the Company's non-rate related tariff modifications are reasonable and shall be approved.

L. Revised Tariffs

i. Parties' Arguments

PGS argued that once we approve the Company's customer and per therm charges, the Company should submit updated tariff sheets reflecting the new rates and charges, including those approved by stipulation, and our staff should be given administrative authority to approve the updated tariff pages.

The Joint Parties did not provide an argument.

ii. Analysis

We have reviewed the revised cost of service study and associated tariffs, which were revised to reflect the final approved revenue requirement.[58] Reviewing the documentation provided by PGS, we find that the revised cost of service study and associated tariffs are in accordance with our rulings contained in this order. We approve the proposed tariffs as provided in Attachment 6 to this order.

iii. Conclusion

We approve PGS's proposed tariffs reflecting the approved target revenues, as provided in Attachment 6 to this order.

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[58] Document No. 06067-2023.

M. Effective Date of Rates and Charges

i. Parties' Arguments

PGS argued that the appropriate effective date for the Company's revised rates and charges should be the first billing cycle in January 2024.

The Joint Parties did not provide an argument.

ii. Analysis

PGS provided a notification of the proposed rate increase to its customers during the month of June 2023 and also posted notice of the rate increase on its website. The notification included a comparison between current and proposed rates, and that the rates ultimately approved by us will not exceed those identified in the notice. PGS will also provide a direct notice to customers during December 2023 and January 2024, which will identify the final, Commission-approved rates and charges.

Our staff reviewed the direct notice to ensure the notice reflects the rates and charges we approved. We therefore authorize the approved rates and charges to be effective as of the first billing cycle in January 2024.

iii. Conclusion

The approved rates and charges shall become effective the first billing cycle in January 2024.

IX. Other Issues

A. Long-Term Debt Cost Rate True-Up Mechanism

i. Parties' Arguments

PGS argued the Company's one-time long-term debt cost rate (LTDR) true-up mechanism is described in the direct testimony of witness Parsons and should be approved for the reasons she explains therein. PGS will be seeking its own financing based on its own business profile and credit rating in late 2023. PGS argued that although the Company's forecasted long-term debt interest rates are reasonable, there is uncertainty about the actual cost rates when the long-term debt is eventually issued. PGS asserted its LTDR true-up mechanism will ensure that the Company's 2024 base rates will reflect the Company's actual cost of long-term debt which is fair to both the customers and the Company. PGS argued its true-up mechanism would likely be viewed as credit positive by rating agencies.

The Joint Parties argued that we should not find that the 2023 Transaction is prudent in Section IX.B. However, the Joint Parties agreed that if we find otherwise, we should require PGS to true-up the long term debt cost rate after the Company's first long-term debt issuance. The Joint Parties argued that if we disallow the incremental costs of long-term debt that would not have occurred but for the 2023 Transaction, we should only require the Company to true-up the LTDR after the first debt issuance on a one-time basis limited to the specific facts of TECO spinning off PGS.

ii. Analysis

PGS proposed to use a one-time LTDR true-up mechanism adjustment to the base rates reflecting its actual cost for its inaugural long-term debt issuance in determining the projected test year revenue requirements. PGS witness Parsons testified that the Company is seeking its own financing based on the business risk profile and credit rating of PGS as a stand-alone entity. The purpose for the true-up mechanism is to reflect the actual market-based cost rates for PGS's debt issuances in its capital structure and rates. Because PGS's inaugural long-term debt issuance will occur after the final hearing, a new 13-month average LTDR should be calculated as shown in MFR Schedule G-3, page 3. PGS projected that its inaugural debt issuance will be approximately $825 million. A new calculation of the forecasted long-term debt cost rate for the projected test year would be updated to reflect the actual debt issuance principal amount and components of annual cost.

Witness Parsons explained that any change in the projected inaugural debt issuance principal amount of $825 million assumed in our approved cost of long-term debt would be offset by a specific adjustment so that the projected test year 13-month average principal amount of long-term debt does not change. Second, an adjustment would be made to replace our approved LTDR used in determining the Company's approved WACC with the trued-up weighted average cost of long-term debt (Section V.I). The resulting adjusted WACC would be carried over to update our approved NOI (Section VI.S), and if there is an increase or decrease in revenue requirement, the difference would be passed on to customers through a limited proceeding to adjust base rates. PGS proposed that it would quantify the LTDR true-up impact to the revenue requirement through a one-time adjustment to base rates within 120 days after the Company completes its inaugural debt issuance. PGS proposed that the change to base rates would be applied to all customer classes consistent with the method approved by us in Order No. PSC-2018-0501-S-GU, which changed PGS's base rates as a result of the Tax Cuts and Jobs Act of 2017.[59] The method approved in that order was for the Company to submit the proposed tariff sheets reflecting the approved revenue requirement increase or decrease for administrative approval by our staff.

PGS proposed that for the time period between when the new approved base rates go into effect (first billing cycle in January 2024) and the implementation date of the LTDR true-up adjusted base rates, the Company will defer the rate impact of the LTDR true-up to its balance sheet for refund or collection through the CI/BSR[60] in the subsequent year. If the amount of the LTDR true-up is less than $500,000, PGS proposed to defer the impact of the LTDR true-up to

[59]Order No. PSC-2018-0501-S-GU, issued October 18, 2018, in Docket No. 20180044-GU, *In re: Consideration of the tax impacts associated with Tax Cuts and Jobs Act of 2017 for Peoples Gas System*, p. 8.
[60]PGS's Cast Iron/Bare Steel Replacement Rider was approved by Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 20110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

its balance sheet for collection or refund through the CI/BSR in the subsequent year, and will continue that process annually until the Company's next base rate proceeding or other base rate adjustment being made through a limited proceeding.

The Joint Parties did not object to the one-time LTDR true-up mechanism for new debt that is issued unrelated to that required to replace the TECO debt allocated to PGS prior to the 2023 Transaction. OPC witness Kollen agreed that PGS's proposed LTDR true-up would allow for a one-time adjustment to base rates to reflect the actual costs of long-term debt compared to the projected costs included in the Company's application, whether the actual debt rates are higher or lower than projected. Witness Kollen contended that only the new long-term debt incremental to his recommended allocation of the former embedded long-term debt from TECO should be subject to the LTDR true-up. Witness Kollen asserted that the amount of long-term debt that was originally issued for PGS by TECO should be maintained in PGS's embedded cost of debt and should not be subject to the LTDR true-up mechanism. Witness Kollen explained that if we accepted his recommendation, there would be approximately $500 to $600 million of existing debt that was issued by TECO for PGS that would not be subject to the LTDR true-up. As discussed in Section V.E, we do not accept the Joint Parties' argument to maintain the portion of long-term debt originally issued by TECO on behalf of PGS and approve PGS's forecasted long-term debt cost rate of 5.54 percent. Because PGS's proposed long-term debt cost rate was unknown at the time the record in this proceeding closed, the Company's proposed LTDR true-up mechanism is a prudent method to ultimately set the cost of long-term debt to reflect PGS's actual market-based cost.

Further, as explained in Section V.E, we have consistently accepted that long-term debt costs included in the capital structure should reflect the actual and forecasted cost of debt for ratemaking purposes. In rate cases with projected test years, as is the case here, it is common practice for the utility to estimate debt cost rates for prospective debt issuances and calculate the cost of long-term debt accordingly.[61] We agree with PGS witness McOnie that a departure from past precedent by not allowing the recovery of market-based interest rates could impact rating agency assessments of the regulatory environment and PGS's cash flow generating ability respectively. As pointed out by witness McOnie, since the forecasted long-term borrowing costs are market-based, and reflect actual interest obligations, a disallowance of the recovery of the full interest expense amount could potentially be considered unconstructive by rating agencies. The recovery of interest expense for PGS is accounted for through the rate of return (WACC) applied to the rate base to determine the revenue requirement. If the WACC and subsequent revenue requirement do not include the actual cost of debt, the Company would experience either an under or over recovery of its interest expense. Therefore, a LTDR true-up mechanism will benefit both PGS and its customers by adjusting the approved long-term debt cost rate in Section V.E to match the PGS's actual cost in its inaugural long-term debt issuance and ensure PGS is recovering its actual cost of debt through rates.

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[61]Order Nos. PSC-10-0153-FOF-EI, issued March 17, 2020, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company*, p. 109-110; and PSC-10-0029-PAA-GU, issued January 14, 2010, in Docket No. 20090125-GU, *In re: Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation*, p. 10.

iii. Conclusion

Based on the aforementioned, we approve PGS's proposed long-term debt cost rate true-up mechanism.

B. Legal Entity Separation of PGS

i. Parties' Arguments

PGS ascertained that there is no adjustment to be made to the 2024 projected test year due to the legal entity separation of PGS from TECO. PGS argued that the 2023 Transaction was a well thought out decision by the Company that put the long-term best interest of the customers first. PGS witness Wesley stated that the 2023 Transaction will help protect PGS against risks associated with being attached to an electric company and this transaction was completed on a tax free basis so that none of the involved parties incur a tax burden. The Company continued that the 2023 Transaction was completed to adopt a legal structure similar to many other regulated and unregulated utilities. PGS disagreed with the Joint Parties argument that PGS has disingenuous motives for the timing of the 2023 Transaction and asserted that it has a history of ensuring that its customers are taken care of and there is no documentation of PGS making any decisions to bring harm to its customers.

Regarding PGS's new supply chain, PGS asserted that the new supply chain was planned and created separate from the 2023 Transaction and the costs that were associated with the implementation of the new supply chain team should not be included in the incremental costs of the 2023 Transaction. The Company stated the new supply chain positions are a reduction to the allocations from TECO, decreasing from $839,000 in 2022 to $382,000 in 2024. Regarding interest expense, the Company testified it only requested to recover projected costs of market-based, long-term and short-term debt, through its base rates. PGS contends that this is a practice we have regularly allowed.

The Company testified that it considered multiple interests when deciding on moving forward with the 2023 Transaction, including the consequence to its customers and us. The 2023 Transaction was designed to protect customers from the risk of harm in the long-term and for customers to benefit from the hard to quantify benefits of the spin-off. PGS testified that the new structure of the Company will allow it to be in control of the metrics of new market debt issuances and to optimize the amount of short-term and long-term debt based on only the needs of the Company. This new structure also gives the Company the ability to manage its own affairs in order to maintain its credit rating and reflect its own risk profile associated with the cost of debt. PGS argued it serves a different territory than TECO, PGS is growing differently than TECO, and the risks that both companies encounter are different which is why it was time for PGS to become a separate legal entity.

PGS testified that when the Company first came to be under TECO in 1997 it was relatively small compared to TECO, but now it has extended its service territory around the state well beyond the territory that TECO serves. PGS now serves more than half the number of customers served by TECO. The Company admittedly currently has the same board as TECO, but over time it will be able to fill the board of directors with different members that can solely focus on gas and the Company's statewide service area. PGS asserted that by becoming its own entity in the 2023 Transaction it has protected its customers in the event of a catastrophic event at TECO which could cause financing and operating disruptions at PGS.

The Joint Parties recommended that we not allow $9.693 million in incremental costs associated with the 2023 Transaction, which would cause a reduction of $9.699 million in the revenue requirement. The incremental costs that the Joint Parties included are additional interest expense, cost of audited stand-alone statements, additional rating agency fees, and the additional treasury analyst position. The bulk of the incremental costs associated with the 2023 Transaction noted by the Joint Parties is the approximately $8.9 million associated with incremental interest expense. $7.1 million corresponds to the $570 million long-term debt to be exchanged under the intercompany loan agreement and $1.8 million is related to the rating differentials and short-term debt changes. The Joint Parties asserted the Company has failed to meet its burden of proof to demonstrate why customers should be responsible for the cost of the Company's one-sided decision to spin PGS off from TECO. The Joint Parties contended that the only evidence provided by the Company referencing the 2023 Transaction is intangible, unquantified, and represents only proposed potential benefits. Since its 2016 purchase of TECO (and consequently PGS), Emera has considered spinning PGS off from TECO. In 2019, Emera began its due diligence and analyzed the risks and benefits of completing the transaction. The analysis performed by Emera contained a low-end and high-end estimate of the one-time cost Emera would endure, however the analysis did not include data on costs or benefits to the customers. According to the Joint Parties, the Company chose to carry out the 2023 Transaction at a time and in a manner that saved Emera shareholders $150 million in tax liability. The Joint Parties stated the timing of the 2023 Transaction created an approximate $9.69 million annual cost which PGS has requested to be recovered for the foreseeable future. The Joint Parties asserted that Emera had total control of when the spin-off would take place and it chose a time that was costly to customers due to the higher interest rates and the current credit rating issues faced by Emera and TECO that will trickle down to PGS's credit rating and financing costs in the future.

The Joint Parties stated that there is scarce evidence to support any benefits to the customers resulting from the 2023 Transaction. The Joint Parties asserted PGS witness Wesley admitted that there would be higher financing costs short-term due to the 2023 Transaction but included two benefits to the customers. The Joint Parties stated the first benefit noted by the Company is that it has the option to create its own board of directors separate from TECO. However, the Joint Parties argued, that since the 2023 Transaction, PGS has only added one member to the board of directors and that member was also added to the board of TECO. The Joint Parties ascertained that this is only a potential benefit, and it seems the Company is not actively changing the board.

The Joint Parties indicated the second benefit to customers of the 2023 Transaction noted by witness Wesley is the claimed risk mitigation of having the assets and liabilities of TECO and PGS in separate legal entities. The Joint Parties contested that this benefit may ever occur due to the fact no one is able to predict a catastrophic event. The Joint Parties contended that the customers are already paying for risk mitigation through the recoverable insurance premiums and fees, and that the Company has proposed an increase to $7.9 million in insurance premiums and fees for the 2024 test year.

The Joint Parties asserted that we should deem the decisions made by PGS associated with the 2023 Transaction imprudent due to the lack of evidence provided by the Company showing quantifiable benefits to the customers. The Joint Parties argued the evidence shows that the structure and timing of the 2023 Transaction will save Emera shareholders $150 million in tax liability but cost PGS customers almost $10 million annually for the foreseeable future. The Joint Parties maintained that we should adjust PGS's requested revenue requirement to reflect a reduction of $9,699,000.

ii. Analysis

The Joint Parties argued PGS has failed to meet its burden of proof and that we should disallow all costs associated with the 2023 Transaction and reduce the requested revenue requirement by at least $9,699,000. Witness Wesley, in her direct testimony, presented the Company's rationale for the 2023 Transaction including the benefits to customers. Witness Wesley testified that the 2023 Transaction: 1) provides a better platform for PGS as it grows and changes with evolving natural gas markets; 2) enables PGS to populate its board with board members more familiar with the natural gas industry; 3) allows PGS to manage the timing and amount of market debt issuances enabling more flexibility; and, 4) benefits customers by placing the assets and liabilities of the electric and gas operations in separate legal entities, thereby insulating customers from the effects of catastrophic events. Further, witness Wesley indicated PGS will continue to benefit from the provision of shared services from TECO. Witness Wesley stated, "For instance, we will continue to receive support from TECO's legal, information technology, and customer experience team members. Our shared billing platform and online systems enable high quality customer contact at a more affordable cost-to-quality ratio than PGS might be able to afford on its own."

The Joint Parties further argued PGS, in its 2019 due diligence review, did not include or even attempt to quantify any costs or benefits to customers. However, the 2019 due diligence report and both witness Wesley's direct and rebuttal testimonies addressed the consequences of a catastrophic event. In her testimonies, witness Wesley stated:

> Our customers also benefit from the risk mitigation effect that placing the assets and liabilities of gas and electric operations in separate legal entities will provide. Tampa Electric and Peoples will work diligently to be safe and avoid catastrophic accidents. However, events like the 2010 San Bruno explosion and the deadly 2020 Zogg Wildfire – on the gas and electric systems of Pacific Gas and Electric Company in California – show how accidents on one side of a dual system utility can threaten the other side. The new corporate structure and governance of Peoples, as Peoples Gas System, Inc., helps insulate Peoples' customers from the impact of events that may occur in the future at Tampa Electric, and vice versa.
>
> Of course, one of the significant, potential long-term benefits of the 2023 Transaction to customers will only be realized if Tampa Electric – our former

> debt capital provider – experiences a catastrophic natural disaster (e.g., a major hurricane hitting Tampa) or a different type of incident that (a) impairs its ability to provide debt capital to Peoples or (b) otherwise implicates Peoples' customers in a business issue not directly related to the provision of service to Peoples customers. We hope that these kinds of events never occur but hope by itself is usually not a good strategy.

It is generally accepted that a catastrophic event involving a mid-size or large utility, such as those cited by witness Wesley, could result in billions of dollars of damage and liability. The types and sizes of catastrophic events that could occur to an electric or gas utility are only limited by one's imagination. Making a list of all of them and their associated costs is neither useful nor necessary to determine it is beneficial to customers to legally separate TECO and PGS. In addition to the direct costs associated with a catastrophic event, a utility could have its bond rating lowered and have its ability to attract capital impaired. Both of which can be costly to a utility and its customers both in terms of dollars and quality of service. Consequently, we find that even though PGS did not explicitly quantify the dollar benefit of legally separating from TECO, it nonetheless has carried its burden of proof regarding the benefits to customers.

Finally, in its brief, the Joint Parties argued that, "Instead of deciding to undertake the 2023 Transaction at a time and in a manner that would mitigate and minimize the rate impact on customers, the Company chose to carry out the transaction at a time and in a manner that will save Emera shareholders $150 million in tax liability." In her rebuttal testimony, witness Wesley stated, "The PLR TECO requested and received does not 'require' TECO and PGS to do anything, but it does assure them that the 2023 Transaction will not create a taxable capital gain or otherwise be considered a taxable event if the 2023 Transaction is executed as described in the PLR request."

It is important to note that Emera shareholders will not receive a $150 million gain from the 2023 Transaction. As pointed out by witness Wesley, by executing the 2023 Transaction as described in the PLR request, a $150 million tax liability will be avoided. The 2023 Transaction can reasonably be described as a reorganization. As such, TECO and PGS reorganized and did so in a way that did not incur a tax liability – which is good business practice. It would be inappropriate to conclude that 2023 Transaction was executed to achieve a $150 million gain for Emera's shareholders at the expense of PGS's customers.

iii. <u>Conclusion</u>

Based on the above analysis, we find no adjustments shall be made to the projected test year related to the legal entity separation of PGS.

C. <u>Description of Adjustments</u>

i. <u>Parties' Arguments</u>

PGS stated that it did not object to the requirement 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 our findings in this rate case.

The Joint Parties agreed that the Company 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 our findings in this rate case.

ii. Analysis

Consistent with our practice, PGS shall 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 our findings in this rate case.

iii. Conclusion

PGS shall 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.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Peoples Gas System, Inc.'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 is hereby approved in every respect. It is further

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

ORDERED that the revised tariffs submitted by Peoples Gas System, Inc. and the final rates and charges contained therein, as incorporated and attached to this order, are hereby approved. It is further

ORDERED that the approved rates and charges for Peoples Gas System, Inc. shall be effective for the first billing cycle in January 2024. It is further

ORDERED that Peoples Gas System, Inc. shall file, within 90 days after the issuance 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 our findings in this rate case. It is further

ORDERED that Peoples Gas System, Inc. shall file a comprehensive procedural review and associated cost study of the support it provides to Seacoast Gas Transmission contemporaneously with its next base rate proceeding. It is further

ORDERED that after this final order is issued, Dockets 20230023-GU, 20220219-GU and 20220212-GU shall be closed.

By ORDER of the Florida Public Service Commission this 27th day of December, 2023.

ADAM J. TEITZMAN
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

MRT

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.

COMPARATIVE AVERAGE RATE BASE

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24

ATTACHMENT 1

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
	UTILITY PLANT					
	PLANT IN SERVICE	$3,319,121,612				
	Adjust for Non-Utility Common Plant		(1,528,719)			
	2024 CI/BS Rider		(9,272,491)			
18	Removal of Alliance RNG Project				(11,530,336)	
21	Removal of Capitalized Salaries & Benefits				(314,216)	
	TOTAL PLANT IN SERVICE	$3,319,121,612	($10,801,210)	$3,308,320,402	($11,844,552)	$3,296,475,850
	ACQUISITION ADJUSTMENT	$5,031,897				
	TOTAL ACQUISITION ADJUSTMENT	$5,031,897	$0	$5,031,897	$0	$5,031,897
	CONSTRUCTION WORK IN PROGRESS	$135,611,359				
	2024 CI/BS Rider		(1,178,306)			
	Remove AFUDC - Eligible CWIP		(110,123,605)			
23	Increased A&G Transfer				2,125,283	
	TOTAL CONSTRUCTION WORK IN PROGRESS	$135,611,359	($111,301,911)	$24,309,448	$2,125,283	$26,434,732
	TOTAL UTILITY PLANT	$3,459,764,868	($122,103,121)	$3,337,661,747	($9,719,269)	$3,327,942,478
	DEDUCTIONS					
	ACCUM. DEP. & AMORT. - PLANT & ACQ. ADJ.	($923,335,229)				
	Adjust for Non-Utility Common Plant		468,554			
	2024 CI/BS Rider		40,391			
18	Removal of Alliance RNG Project				507,203	
22	Updated Depreciation Study				127,147	
22	New River RNG - Depreciaton Corrections				101,319	
22	Brightmark RNG - Updated Pipeline Depreciation Rate				(477,092)	
	TOTAL ACCUM. DEP. & AMORT. - PLANT & ACQ. ADJ.	($923,335,229)	$508,945	($922,826,284)	$258,577	($922,567,707)
	CUSTOMER ADVANCES FOR CONSTRUCTION	($20,000,000)				
	TOTAL CUSTOMER ADVANCES FOR CONSTRUCTION	($20,000,000)	$0	($20,000,000)	$0	($20,000,000)
	TOTAL DEDUCTIONS	($943,335,229)	$508,945	($942,826,284)	$258,577	($942,567,707)
	NET UTILITY PLANT	$2,516,429,639	($121,594,176)	$2,394,835,463	($9,460,691)	$2,385,374,771
	WORKING CAPITAL ALLOWANCE	($9,101,011)				
	Projected Test Year Adjustments		(18,946,000)			
	TOTAL WORKING CAPITAL ALLOWANCE	($9,101,011)	($18,946,000)	($28,047,011)	$0	($28,047,011)
	TOTAL RATE BASE	$2,507,328,628	($140,540,176)	$2,366,788,452	($9,460,691)	$2,357,327,760

CAPITAL STRUCTURE

PEOPLES GAS SYSTEMS ATTACHMENT 2
DOCKET NO. 20230023-GU
PTY 12/31/24
13 Month Average

COMPANY POSITION	PGS PER BOOKS	SPECIFIC	PRO RATA	PGS ADJUSTED	RATIO	COST RATE	WEIGHTED COST
COMMON EQUITY	$1,191,009,138	($3,979,951)	($63,023,001)	$1,124,006,187	47.49%	11.00%	5.22%
LONG TERM DEBT	878,846,154	0	(46,660,623)	832,185,531	35.16%	5.54%	1.95%
SHORT TERM DEBT	106,020,088	(760,062)	(5,588,575)	99,671,451	4.21%	4.85%	0.20%
CUSTOMER DEPOSITS	28,892,062	0	(1,363,878)	27,528,183	1.16%	2.53%	0.03%
DEFERRED TAXES	301,187,438	(7,062,782)	(13,884,447)	280,240,209	11.84%	0.00%	0.00%
TAX CREDIT - WEIGHTED	3,313,300	0	(156,408)	3,156,892	0.13%	8.49%	0.01%
TOTAL	$2,509,268,180	($11,802,795)	($130,676,933)	$2,366,788,452	100.00%		7.42%

COMMISSION APPROVED	ADJUSTED PER BOOKS	SPECIFIC	PRO RATA	COMMISSION ADJUSTED	RATIO	COST RATE	WEIGHTED COST
COMMON EQUITY	$1,191,009,138	($3,977,495)	($65,001,910)	$1,122,029,733	47.60%	10.15%	4.83%
LONG TERM DEBT	878,846,154	1,812	(48,125,757)	830,722,209	35.24%	5.54%	1.95%
SHORT TERM DEBT	106,020,088	(759,843)	(5,764,056)	99,496,189	4.22%	4.85%	0.20%
CUSTOMER DEPOSITS	28,892,062	(1,364,062)	0	27,528,000	1.17%	2.53%	0.03%
DEFERRED TAXES	301,187,438	(7,556,568)	(16,079,241)	277,551,630	11.77%	0.00%	0.00%
TAX CREDIT - WEIGHTED	3,313,300	(3,313,300)	0	0	0.00%	8.03%	0.00%
TOTAL	$2,505,954,880	($13,656,157)	($134,970,963)	$2,357,327,760	100%		7.02%

Attachment 3

COMPARATIVE NET OPERATING INCOME

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24

ATTACHMENT 3
Page 1 of 2

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
	OPERATING REVENUES					
	Operating Revenues	$576,955,550				
	Fuel Revenue Adjustment		($229,472,342)			
	2024 CI/BS Rider		(1,298,393)			
	Lease of Plant Held for Future Use		(117,796)			
57	Removal of Alliance RNG Project				(5,726,092)	
	TOTAL REVENUES	$576,955,550	($230,888,531)	$346,067,020	($5,726,092)	$340,340,928
	OPERATING EXPENSES:					
	COST OF GAS	$228,428,641				
	Eliminate Fuel Expense		(228,428,641)			
	TOTAL COST OF GAS	$228,428,641	($228,428,641)	$0	$0	$0
	OPERATION & MAINTENANCE EXPENSE	$151,258,200				
	2024 CI/BS Rider		(299,014)			
	Employee Activities		(79,176)			
	Economic Development		(18,420)			
	Maintenance of General Plant		(38,449)			
	Maintenance of Structures & Improvements		(5,930)			
13	Increased SeaCoast Allocation				(189,347)	
18	Removal of Alliance RNG Project				(3,956,653)	
19	WAM O&M Efficiency Reductions				(750,000)	
41	Reduction to Outside Services				(206,000)	
42	Reduction to Projected Number of Test Year Employees				(1,245,959)	
42	Removal of BDM Position				(37,882)	
43	Reduction of Annual Merit Increases				(1,057,084)	
44	Lobbying, Contributions, Sponsorships, & Advertising				(500,000)	
46	Reduction to Storm Reserve Accrual				(120,000)	
48	Rate Case Expense Reduction				(156,384)	
49	Corresponding Employee Expense Reduction				(92,919)	
49	Reduction to Standalone Audit Fees				(190,000)	
49	Reduction to Treasury Support Costs				(60,234)	
49	Increased A&G Expense Allocation to Capital				(2,125,283)	
	TOTAL O & M EXPENSE	$151,258,200	($440,988)	$150,817,212	($10,687,745)	$140,129,467
	DEP. & AMORT. EXP. - PLANT	$87,776,676				
	Adjust for Non-Utility Common Plant		(43,270)			
	2024 CI/BS Rider		(119,438)			
18	Removal of Alliance RNG Project				(359,701)	
50	Updated Depreciation Study				(252,303)	
50	New River RNG - Depreciaton Corrections				(51,505)	
50	Brightmark RNG - Updated Pipeline Depreciation Rate				321,507	
	TOTAL DEPRECIATION & AMORTIZATION	$87,776,676	($162,708)	$87,613,968	($342,002)	$87,271,967

PEOPLES GAS SYSTEMS
DOCKET NO. 20230023-GU
PTY 12/31/24

ATTACHMENT 3
Page 2 of 2

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
	AMORTIZATION EXP. - OTHER	$1,000,000				
	TOTAL AMORTIZATION EXP. - OTHER	$1,000,000	$0	$1,000,000	$0	$1,000,000
	TAXES OTHER THAN INCOME	$32,748,644				
	TOTI Corresponding to Fuel Revenues		(1,043,800)			
	2024 CI/BS Rider		(3,504)			
18	Removal of Alliance RNG Project				(88,687)	
51	Fallout Adj. - Payroll Tax				(179,692)	
51	Property Tax Correction				(2,008,000)	
	TOTAL TAXES OTHER THAN INCOME	$32,748,644	($1,047,304)	$31,701,341	($2,276,379)	$29,424,962
	INCOME TAX EXPENSE					
	Income Taxes	($16,432,949)				
	Income Taxes - Deferred	22,489,825				
	Taxes Corresponding to Test Year Adjustments		(3,289,038)			
	Interest Synchronization		325,338			
52	Fallout Adj. - Parent Debt				(129,476)	
53	Fallout Adj. - Interest Synchronization				22,684	
53	Fallout Adj. - Federal Income Taxes				1,504,258	
53	Fallout Adj. - State Income Taxes				416,902	
	TOTAL INCOME TAXES	$6,056,876	($2,963,701)	$3,093,175	$1,814,368	$4,907,543
	GAIN ON SALE OF PROPERTY	($495,917)				
	TOTAL GAIN ON SALE OF PROPERTY	($495,917)	$0	($495,917)	$0	($495,917)
	TOTAL OPERATING EXPENSES	$506,773,120	($233,043,341)	$273,729,779	($11,491,758)	$262,238,021
	NET OPERATING INCOME	($166,432,192)	$2,154,811	$72,337,240	$5,765,666	$78,102,907

NET OPERATING INCOME MULTIPLIER

PEOPLES GAS SYSTEMS ATTACHMENT 4
DOCKET NO. 20230023-GU
PTY 12/31/24

DESCRIPTION	COMPANY PER FILING	STIPULATION
REVENUE REQUIREMENT	100.0000%	100.0000%
REGULATORY ASSESSMENT RATE	0.5000%	0.5000%
BAD DEBT RATE	0.2805%	0.2805%
NET BEFORE INCOME TAXES	99.2195%	99.2195%
STATE INCOME TAX RATE	5.5000%	5.5000%
STATE INCOME TAX	5.4571%	5.4571%
NET BEFORE FEDERAL INCOME TAXES	93.7624%	93.7624%
FEDERAL INCOME TAX RATE	21.0000%	21.0000%
FEDERAL INCOME TAX	19.6901%	19.6901%
REVENUE EXPANSION FACTOR	74.0723%	74.0723%
NET OPERATING INCOME MULTIPLIER	1.3500	1.3500

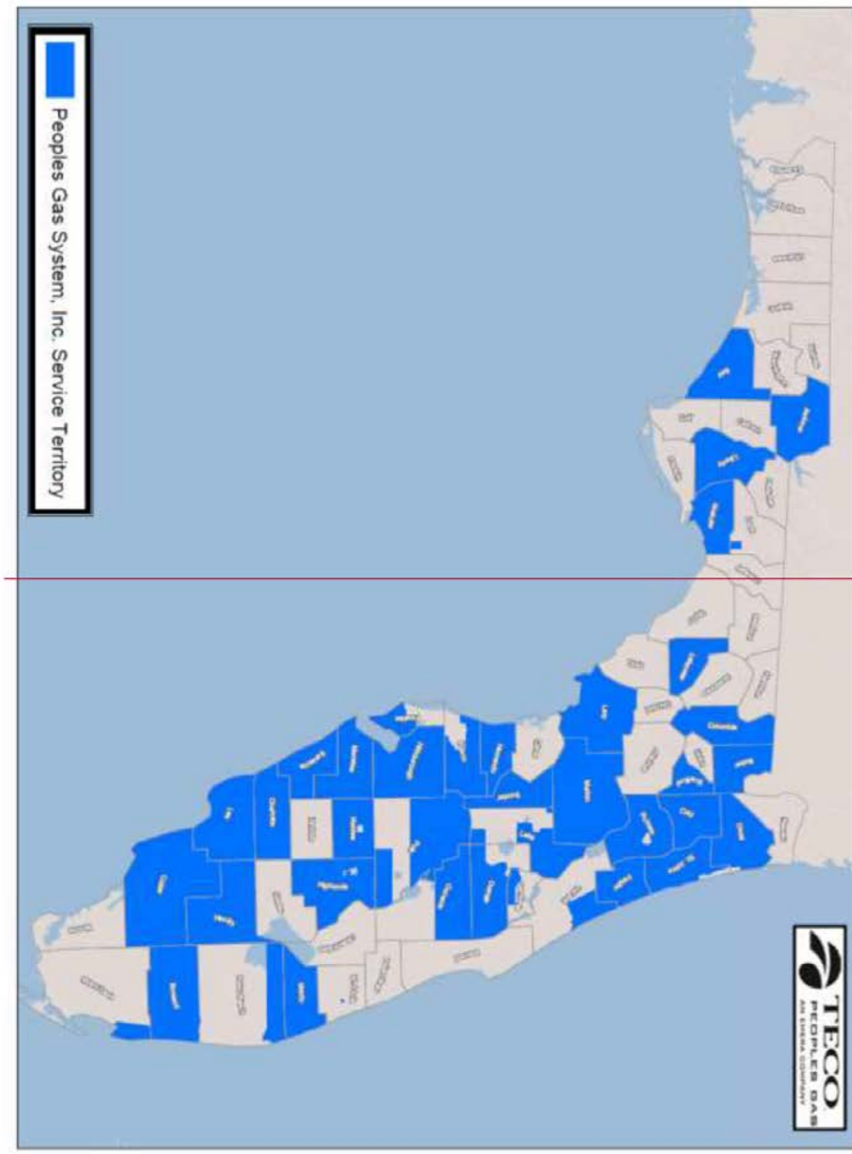
Attachment 5

COMPARATIVE REVENUE DEFICIENCY CALCULATIONS

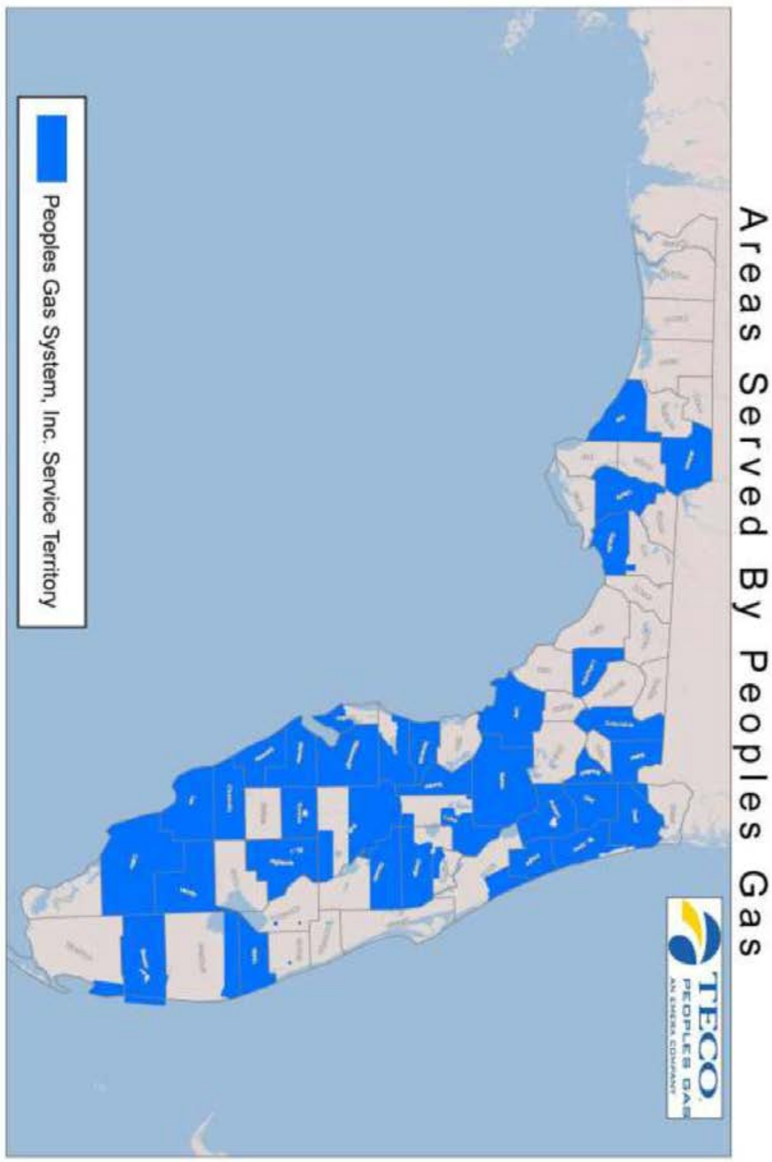
PEOPLES GAS SYSTEMS ATTACHMENT 5
DOCKET NO. 20230023-GU
PTY 12/31/24

		COMPANY ADJUSTED		COMMISSION APPROVED
RATE BASE (AVERAGE)		$2,366,788,452		$2,357,327,760
RATE OF RETURN	X	7.42%	X	7.02%
REQUIRED NOI		$175,542,307		$165,389,334
Operating Revenues		$64,585,444		$64,724,868
Total Operating Expenses		51,316,841		50,592,224
ACHIEVED NOI		72,337,240		78,102,907
NET REVENUE DEFICIENCY		$103,205,067		$87,286,427
REVENUE EXPANSION FACTOR		1.3500		1.3500
REVENUE DEFICIENCY		$139,330,211		$117,839,527
Cast Iron/Bare Steel Rider Revenues		(11,693,817)		(11,156,958)
INCREMENTAL REVENUE INCREASE		$127,636,394		$106,682,569

Peoples Gas System, Inc.



Areas Served By Peoples Gas



Service Territory

This map depicts the general service territory as it stands today. For more details, see the list of counties and communities served in Section 6.

TECHNICAL TERMS AND ABBREVIATIONS

ABSOLUTE PRESSURE. Atmospheric pressure of 14.73 p.s.i.a. plus gauge.

APPLICATION FOR GAS SERVICE. A request for Gas Service made to the Company by a prospective Customer. Applications for residential Gas Service may be made by telephone or in person at the office of the Company. An application for any other class of Gas Service offered by Company shall be submitted to the Company in writing on the Company's standard form of Application For Gas Service.

AUTHORIZED PAYMENT AGENT. A legal entity designated by the Company as authorized to receive, on behalf of the Company, payment of bills for Gas Service rendered by Company to Customers. A third party with which a Customer may enter into a payment processing arrangement (or to which a Customer may direct that bills for Gas Service be mailed or otherwise delivered) is not an Authorized Payment Agent unless the Company has entered into an agreement with such third party to act as an Authorized Payment Agent of the Company.

BILLING PERIOD. Bills are rendered each month, based on regularly scheduled Meter readings which are approximately 30 days apart.

BIOGAS. Untreated gas produced from agricultural, animal, or municipal waste.

BRITISH THERMAL UNIT. The quantity of heat required to raise the temperature of one pound of water from 59°F. to 60°F. at a constant pressure of 14.73 p.s.i.a.

BTU. British Thermal Unit.

COMMISSION. The Florida Public Service Commission.

COMPANY. Peoples Gas System, Inc., a Florida Corporation.

CUBIC FOOT OF GAS. For Gas delivered at the Standard Delivery Pressure, a Cubic Foot of Gas is the volume of Gas which, at the temperature and pressure existing in the Meter, occupies one cubic foot. For Gas delivered at other than the Standard Delivery Pressure, a Cubic Foot of Gas is that volume of Gas which, at a temperature of 60°F. and at Absolute Pressure of 15.09 pounds per square inch for Panama City Operating Area and 14.98 pounds per square inch for the remainder of PGS's service territory, occupies one cubic foot.

CUSTOMER. Any person, other legal entity, ~~or~~ prospective user or third-party beneficiary (not limited to account holder or payor) of the Company's Gas Service, his authorized representative (builder, architect, engineer, electrical contractor, plumber, independent contractor, etc.), or others for whose benefit such Gas Service is or is proposed to be supplied (property owner, landlord, tenant, occupant, renter, etc.). When Gas Service is desired at more than one location, the Point of Delivery at each such location shall be considered as a separate Customer.

CUSTOMER'S INSTALLATION. All pipinge~~e~~, fittings, fixtures, valves, appliances and apparatus of every type (except metering, regulating and other similar equipment which remains the property of the Company) located on the Customer's side of the Point of Delivery and used in connection with or forming a part of an installation for utilizing Gas for any purpose.

~~**FORCE MAJEURE.** Any cause, whether of the kind herein enumerated or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or~~

~~any other person or concern, not reasonably within the control of the Company and which by the exercise of due diligence the Company is unable to prevent or overcome, and such causes shall include but not be limited to:~~

~~(1) (a) in those instances where the Company, Customer or a third party is required to obtain servitudes, rights-of-way grants, permits or licenses to enable the Company to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and~~
~~(b) in those instances where the Company, Customer or a third party is required to furnish~~

TECHNICAL TERMS AND ABBREVIATIONS (Continued)

FORCE MAJEURE. Any cause, whether of the kind herein enumerated or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or any other person or concern, not reasonably within the control of the Company and which by the exercise of due diligence the Company is unable to prevent or overcome, and such causes shall include but not be limited to:

(1) (a) in those instances where the Company, Customer or a third party is required to obtain servitudes, rights-of-way grants, permits or licenses to enable the Company to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and

(b) in those instances where the Company, Customer or a third party is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure grants or permissions from any governmental agency to enable such part to fulfill its obligations hereunder, the inability of the party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions;

(2) a hurricane, storm, heat wave, lightning, freeze, severe weather event, earthquake or other act of God; or

(3) fire, explosion, war, riot, labor strike, terrorism, acts of the public enemy, lockout, embargo, civil disturbance, interference or regulation by federal, state or municipal governments, injunction or other legal process or requirement.

It is understood and agreed that the settlement of strikes, lockouts or other labor difficulties shall be entirely within the discretion of the party having the difficulty.

GAS. Natural Gas or a mixture of gases suitable for fuel, delivered through the Company's distribution system, having a heating value of not less than 1,000 BTU's per cubic foot.

GAS SERVICE. The supplying of Gas (or the transportation of Gas) by the Company to a Customer.

GAS SERVICE FACILITIES. The service line, Meter, and all appurtenances thereto necessary to convey Gas from the Company's Main to the Point of Delivery and which are owned by Company.

HIGH PRESSURE. Gas delivered at any pressure above the Standard Delivery Pressure.

LNG. Liquified Natural Gas or LNG is processed natural gas that has been condensed into a liquid form by reducing its temperature to approximately minus 260° F (minus 162° C) at ambient pressure.

MAIN. The pipe and appurtenances installed in an area to convey Gas to other Mains or to service lines.

METER. Any device or instrument used to measure and indicate volumes of Gas which flow through it.

METER READING DATE. The date upon which an employee of the Company reads the Meter of a Customer for billing purposes.

~~**NORMAL BUSINESS HOURS.** 8 a.m. to 5 p.m. Monday through Friday, excluding Federal holidays.~~

~~**PANAMA CITY OPERATING AREA.** The Panama City Operating Area consists of those Counties and Communities identified in Section 6.~~

~~**POINT OF DELIVERY.** The point at which Company's Gas Service facilities are connected to the Customer's Installation, and at which the Customer assumes responsibility for further delivery and use of the Gas. In all cases, the Point of Delivery for Gas to a Customer shall be at the outlet side of the meter or regulator, if any, whichever is farther downstream. The Point of Delivery shall be determined by Company.~~

~~**RESIDENTIAL.** When used to modify the term "Customer," means a Customer whose use of Gas is for residential purposes, regardless of the rate schedule pursuant to which such Customer receives Gas Service provided by Company.~~

~~**RNG.** Renewable Natural Gas, or gas produced from agricultural, animal, or municipal or other waste that, with or without further processing, (a) has characteristics consistent with the Company's compositional and quality standards for Gas, and (b) in the sole view of the Company does not otherwise pose a hazard to inclusion in the Company's distribution lines when co-mingled with Gas.~~

TECHNICAL TERMS AND ABBREVIATIONS (Continued)

NORMAL BUSINESS HOURS. 8 a.m. to 5 p.m. Monday through Friday, excluding Federal holidays.

PANAMA CITY OPERATING AREA. The Panama City Operating Area consists of those Counties and Communities identified in Section 6.

POINT OF DELIVERY. The point at which Company's Gas Service facilities are connected to the Customer's Installation, and at which the Customer assumes responsibility for further delivery and use of the Gas. In all cases, the Point of Delivery for Gas to a Customer shall be at the outlet side of the meter or regulator, if any, whichever is farther downstream. The Point of Delivery shall be determined by Company.

RESIDENTIAL. When used to modify the term “Customer,” means a Customer whose use of Gas is for residential purposes, regardless of the rate schedule pursuant to which such Customer receives Gas Service provided by Company.

RNG. Renewable Natural Gas, or gas produced from agricultural, animal, or municipal or other waste that, with or without further processing, (a) has characteristics consistent with the Company’s compositional and quality standards for Gas, and (b) in the sole view of the Company does not otherwise pose a hazard to inclusion in the Company’s distribution lines when co-mingled with Gas.

STANDARD DELIVERY PRESSURE. The Standard Delivery Pressure for Panama City Operating Area shall be 10 inches of water column (.36 p.s.i.g.). The Standard Delivery Pressure for the remainder of PGS service territory shall be 7 inches of water column (.25 p.s.i.g). No adjustment will be made for variations from the normal atmospheric pressure at the Customer's Meter. Gas delivered at Standard Delivery Pressure may vary from three inches to 15 inches of water column.

THERM. A unit of heat equal to one hundred thousand (100,000) BTUs.

THIRD PARTY GAS SUPPLIER. Any legal entity, other than the Company, providing Gas for transportation and delivery to a Customer on the Company’s distribution system.

YEAR ROUND CUSTOMER. A Customer who receives (or who it is estimated will receive) Gas Service from Company during each month of a year, and who pays a Customer charge for each such month.

RULES AND REGULATIONS

I

INITIATION OF SERVICE

A. REQUEST FOR GAS SERVICE

Gas Service may be requested by a prospective Customer by:

1. Verbal, telephonic or electronic request to a business office of the Company (in the case of residential Gas Service), or

2. By submission to Company of a completed Gas Service Agreement (in the case of Gas Service other than residential Gas Service).

B. ACCEPTANCE OF REQUEST FOR GAS SERVICE

A Gas Service Agreement shall be deemed to be accepted by the Company when Gas Service pursuant thereto is initiated.

C. OBLIGATION OF CUSTOMER AND COMPANY

The terms and conditions of the Customer's Gas Service Agreement, these Rules and Regulations, and the applicable ~~R~~rate ~~S~~schedules shall become binding upon the Customer and Company upon acceptance by the Company of the Customer's Gas Service Agreement.

D. MISCELLANEOUS SERVICE CHARGES

Whenever Gas Service is established or re-established at any location, the charges set forth below will be made:

	RESIDENTIAL	OTHER
ACCOUNT OPENING CHARGE (applies only where a change of Customer occurs and Gas Service is not shut off at the premises)	**$33~~24~~.00**	**$33~~24~~.00**
METER TURN ON / SERVICE INITIATION CHARGE (applies where service is inactive)	**$78~~63~~.00 for initial unit or meter $34~~29~~.00 for each additional unit or meter**	**$107~~00~~.00 for initial unit or meter $46~~34~~.00 for each additional unit or meter**

Attachment 6

Peoples Gas System, Inc.
Original Volume No. 3

Eighth ~~Seventh~~ Revised Sheet No. 5.101-1
Cancels Seventh ~~Sixth~~ Revised Sheet No. 5.101-1

RULES AND REGULATIONS (Continued)

	RESIDENTIAL	OTHER
METER RECONNECTION/ SERVICE RESTORATION CHARGE (applies where service has been turned off for cause and includes cost of turn-off)	**$104~~87~~.00 for initial unit or meter $33~~28~~.00 for each additional unit or meter**	**$114~~00~~.00 for initial unit or meter $42~~32~~.00 for each additional unit or meter**
TRIP CHARGE/COLLECTION AT CUSTOMER PREMISES (applies when Company's employee, agent, or representative makes a trip to Customer's premises for the purpose of terminating Gas Service or providing final notice of termination for nonpayment of bills)	**$29~~25~~.00**	**$29~~25~~.00**
FAILED TRIP CHARGE AT CUSTOMER PREMISES (applies when the Customer fails to keep a scheduled appointment with the Company's employee, agent or representative)	**$25.00**	**$25.00**
TEMPORARY METER TURN-OFF CHARGE (applies when Company's employee, agent or representative, turns off Customers' meter temporarily at Customer's request)	**$33~~30~~.00 per meter**	**$33~~30~~.00 per meter**

Where Gas Service is established outside of normal business hours, by special appointment, or same day service the charges set forth above multiplied by 1.5.

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

RULES AND REGULATIONS (Continued)

F. LIMITATION OF USE

Gas delivered to a Customer shall be for such Customer's own use and shall not be resold by such Customer, either by submetering or otherwise, unless such resale has been authorized by the Commission.

In case of any unauthorized submetering, sale, or disposition of Gas by a Customer, Gas Service to such Customer may be discontinued and, if discontinued, such Gas Service will not be restored until such unauthorized activities have ceased and all bills outstanding have been paid in full. Billings for Gas sold or disposed of by the Customer may be recalculated under appropriate rate schedules and, in addition, a bill may be rendered to the Customer for all expenses incurred by the Company including but not limited to, clerical work, testing, and inspections in connection with such recalculation.

G. PRESSURE

Company shall make reasonable efforts to maintain its Standard Delivery Pressure at the point of delivery. Where delivery pressure higher than Standard Delivery Pressure is supplied, Company will make reasonable efforts to maintain that delivery pressure.

Prospective industrial and large commercial Customers who desire to utilize Gas at pressures higher than the Standard Delivery Pressure should inquire of the Company to determine the pressure that the Company can make available at any given location in its service territory before obtaining any equipment requiring pressures higher than the Standard Delivery Pressure.

H. SPECIAL CONTRACTS

At the sole option of the Company, service may be provided by entering into an agreement with a Customer memorializing a special contract pursuant to Commission Rule 25-9.034, FAC, where the rates, terms, and conditions for service may be different from those set forth in the Company's approved Tariff. Such agreement is subject to the approval of the Commission. Billing Adjustments and Taxes and Fees, as set forth in Sheet Nos. 7.101- 7.101-10, may also apply to any such agreement.

II

CUSTOMER'S INSTALLATION

A. GENERAL

Customer's Installation shall be constructed, installed and maintained in accordance with standard practice as determined by local codes and ordinances applicable thereto, these Rules and Regulations and other applicable governmental requirements; provided, however, that Company shall have no responsibility whatsoever for determining whether any local code or ordinance or any other governmental requirement is applicable to Customer's Installation, or for enforcing or determining whether Customer's Installation is in compliance with any local code or ordinance or any other governmental requirement. A Customer installing a Gas fired electric generator shall also ensure that the installation and operation of such equipment complies with the ~~t~~Tariff and the ~~-~~requirements of the Customer's electric provider.

The Customer's piping, appliances, equipment and apparatus shall be installed and maintained in accordance with standard practice, and in full compliance with all applicable laws, codes and governmental and Company regulations. The Customer expressly agrees to utilize no apparatus or device which is not properly constructed, controlled, and protected, or which may adversely affect service to others, and the Company reserves the right to discontinue or withhold service for such apparatus or device.

Customer shall give immediate notice to the Company when any leakage of Gas is detected, discovered, or suspected. Whenever a leakage of Gas is suspected, detected, or discovered, Customer agrees not to use any potential source of ignition, such as flame, electrical source, or other igniting medium in the proximity of escaping Gas, which could ignite such Gas.

B. INSPECTION OF CUSTOMER'S INSTALLATION

Where governmental inspection of a Customer's Installation is required, Company will not supply Gas Service to such installation until the necessary inspections have been made and Company has been authorized to provide Gas Service.

Company may also inspect Customer's Installation prior to rendering Gas Service, and from time to time thereafter, but assumes no responsibility whatsoever as a result of having made such inspection. Company will not render (and may discontinue) Gas Service to any Customer Installation which Company finds to be hazardous. Customer has sole responsibility to insure that the hazardous condition has been corrected prior to initiation of Gas Service.

~~C. CHANGES IN CUSTOMER'S INSTALLATION~~

~~A Customer shall notify Company of any change in Customer's requirements for Gas Service and receive authorization from Company prior to making any such change so that the Company may be in a position to meet the Customer's requirements. A Customer will be liable for any damage resulting from violation of this rule.~~

~~D. RIGHT OF WAY~~

~~Customer shall grant to Company, without cost to Company, all rights, easements, permits and privileges which in Company's opinion are necessary for the rendering of Gas Service. Customer will furnish to Company, without charge, an acceptable location for Company's Meter.~~

CUSTOMER'S INSTALLATION (Continued)

C. RESIDENTIAL GENERATORS

A Customer shall notify Company of the installation of any gas-fired electric generation at the premises. Gas-fired electric generators and their associated equipment shall not be connected to the Company's system without prior approval.

D. CHANGES IN CUSTOMER'S INSTALLATION

A Customer shall notify Company of any change in Customer's requirements for Gas Service, including the installation of gas-fired electric generation, and receive authorization from Company prior to making any such change so that the Company may be in a position to meet the Customer's requirements. A Customer will be liable for any damage resulting from violation of this rule.

E. RIGHT OF WAY

Customer shall grant to Company, without cost to Company, all rights, easements, permits and privileges which in Company's opinion are necessary for the rendering of Gas Service. Customer will furnish to Company, without charge, an acceptable location for Company's Meter.

~~E~~F. PROTECTION OF COMPANY'S PROPERTY

All property of Company installed in or upon Customer's premises is placed there under Customer's protection. Customer shall exercise all reasonable care to prevent loss of or damage to such property, ordinary wear and tear excepted. Customer will be held liable for any such loss of property or damage thereto and shall pay to Company the cost of necessary repairs or replacements.

Customer will be held responsible for broken seals, tampering or interfering with Company's meter or meters or other equipment of Company installed on Customer's premises, and no one except employees of Company or Company agents will be allowed to make any repairs or adjustments to any meter or other piece of apparatus belonging to Company except in case of emergency.

~~F~~G. ACCESS TO PREMISES

Customer shall give Company's employees and representatives access to Customer's property so that Company may operate, inspect and maintain its facilities on Customer's premises. Installation of the Company's facilities may require that Company be granted an easement.

~~G~~H. OPERATION OF COMPANY'S FACILITIES

No Customer or other person shall tamper with any of the Company's facilities. No Customer or other person shall, unless authorized by the Company to do so, operate or change any of the Company's facilities.

V

MEASUREMENT

A. METERS

Company will own, operate and maintain the Meters and regulating equipment needed to accurately measure Gas Service provided to Customer.

Customer will provide a location, satisfactory to Company, for installation of necessary Meters, regulators, and ancillary equipment.

Customer will safeguard Company's facilities on Customer's property and will not permit unauthorized persons to tamper with such facilities or otherwise operate or alter them in any manner.

All Gas delivered to Customers shall be measured by commercially acceptable measuring devices owned and maintained by the Company, except where it is impractical to Meter loads, such as street lighting, and temporary or special installations, in which case the consumption may be calculated, or billed on a rate or as provided in the Company's filed ~~t~~Tariff.

B. TYPE OF METERING PROVIDED

1. Except as provided in paragraph (2) below, each separate occupancy unit (as defined in Commission Rule 25-7.071) for which construction commenced after January 1, 1987, shall be individually metered.

2. Individual Meters shall not be required, and master metering is permitted, for separate occupancy units where dimensions or physical configurations of the units are subject to alteration; where Gas is used in central heating, water heating, ventilating and air conditioning systems, or Gas back up service to storage heating and cooling systems; in specialized-use housing accommodations such as hospitals and other health care facilities specified in Commission Rule 25-7.071, college dormitories, convents, sorority or fraternity houses, motels, hotels and similar facilities; in specially designated areas for overnight occupancy at trailer, mobile home and recreational vehicle parks where permanent residency is not established; in marinas where living aboard is prohibited by permanent means; or where individual Gas Service would otherwise be required above the second story, in accordance with Commission Rule 25-7.071.

3. When individual metering is not required and master metering is used, submeters may be purchased and installed at Customer's request and expense, for use in allocating solely the cost of Gas billed by Company for Gas Service at the master Meter.

C. METER ACCURACY AT INSTALLATION

All Meters, when installed, shall be not more than 1 percent fast or 1 percent slow and will have been tested not more than twelve (12) months prior to being installed.

VI

MAIN AND SERVICE EXTENSIONS

A. MAIN EXTENSIONS

Whenever a prospective Customer or other person, such as a real estate developer, municipality, township, county, or other authority ("Depositor"), requests Gas Service at a location where the Company does not have a Main, the Company will extend its Mains and Services to serve the prospective Customer or Customers under the following conditions (for provisions governing installation of service lines only, see VI.B):

1. The extension of Gas Service to the prospective Customer will not jeopardize Gas Service to existing Customers.

2. The maximum capital cost to be incurred by the Company for an extension of Main and Service facilities shall be defined as the Maximum Allowable Construction Cost. The Maximum Allowable Construction Cost shall equal ten (10) times the estimated annual revenue to be derived from the facilities less the cost of Gas. Where the Company, in its reasonable discretion, believes that there is significant uncertainty regarding the revenues to be derived from service provided through the requested extension of Main and Service facilities, the Company shall use reasonable efforts to calculate the MACC giving due consideration to such uncertainty.

3. The Company may require a Customer to commit to taking an agreed minimum volume of Gas or pay for Gas not taken below such minimum, depending on factors such as facility cost or service requirements. Such minimum volume commitment will not be set at a level that exceeds the volume used to calculate the MACC for such Customer, nor will the term of such minimum volume commitment exceed ten (10) years.

~~3~~4. Where the facilities to be installed will require an investment by the Company in excess of the Maximum Allowable Construction Cost, the Company will construct the necessary facilities provided the Customer or Depositor deposits with the Company an amount equal to the excess of the estimated construction cost over the Maximum Allowable Construction Cost. In this case, the Company and the Depositor will then enter into a Construction Deposit Agreement which will provide for either a) the receipt of the deposit by the Company and including terms and conditions for refund to the Depositor or b) a mutually agreeable pay arrangement that will provide for the guaranteed throughput/revenue for the prospective Customer or project. In consideration of the Company's having to use the deposit to finance the installation of facilities, the deposit made by the Depositor will be non-interest bearing.

5~~4~~. Refund of Deposits: Deposits shall be refunded to Depositors in accordance with the following procedures.

   a. At the end of the first year following the date on which Gas Service to the Depositor is initiated by the Company, at the Customer's request the Company shall recalculate the Maximum Allowable Construction Cost. A re-estimation of the annual revenue (considering the actual revenue derived during the first year) shall be used in such recalculation. The Company shall refund

MAIN AND SERVICE EXTENSIONS (Continued)

to the Depositor an amount equal to the positive difference (if any) determined by subtracting (i) the Maximum Allowable Construction Cost as determined~~–~~ under section A.(2) above from (ii) the Maximum Allowable Construction Cost as recalculated utilizing actual revenue pursuant to this paragraph.

b. For each additional Customer taking Gas Service from any point on the extended Main or Service facilities within a period of four (4) years from the date of construction, the Company shall refund to the Depositor the amount by which the Maximum Allowable Construction Cost of the new Customer exceeds the cost of connecting such new Customer, provided that an additional Main extension shall not have been necessary to serve such additional Customer. Where the Depositor and the Company agree that new Customers are likely to connect to the extended facilities over a period longer or shorter than four (4) years, the Depositor and the Company may agree, within the Construction Deposit Agreement, to provide for refunds over such longer or shorter period as the parties agree is reasonable and appropriate under the circumstances.

c. The aggregate refund to any Depositor made through the provisions of (a) and (b) above shall not exceed the original deposit of such Depositor.

d. The extension shall at all times be the property of the Company, and any unrefunded portion of said deposit at the end of four (4) years, or such longer or shorter period as may be agreed by the Depositor and Company pursuant to section (~~4~~5)(b) above, shall accrue to the Company.

B. SERVICE EXTENSIONS FROM EXISTING MAINS

The Company will install, at no charge to the Customer, the Gas Service Facilities, commencing from an existing Main, necessary to serve a Customer applying for Gas Service, where the cost of such service extension does not exceed the Maximum Allowable Construction Cost as defined in section VI.A. (2) above. Customers not meeting the above criteria will be required to make a non-refundable contribution in aid of construction based on the difference between the cost of the required service facilities and the Maximum Allowable Construction Cost as calculated for each respective Customer.

C. RELOCATION OR MODIFICATION OF GAS SERVICE FACILITIES

When modifications to structures or improvements on premises to which the Company renders Gas Service necessitate the relocation of Company's Gas Service Facilities, or when such relocation, or modifications to Company's Gas Service Facilities, are requested by the Customer for whatever reason, Customer shall be ~~may be~~ required to reimburse the Company in advance of performance of such work for all or any part of the costs incurred by the Company in the performance of such relocation or modifications.

 Attachment 6

MAIN AND SERVICE EXTENSIONS (Continued)

D. MAIN EXTENSION PROGRAM

In cases where (i) the estimated actual cost of extending necessary Main and Service facilities exceeds the MACC; (ii) the Company, in its reasonable discretion, determines that there is a reasonable likelihood that such extension will produce sufficient revenue to justify the necessary investment in such facilities; and (iii) the Company determines that the credit-worthiness of the party or parties requesting the extension is satisfactory to assure recovery of the additional investment above the MACC, the Company may provide the facilities subject to a Main Extension Program Charge (MEP Charge) as provided on Sheets Nos. 7.101-7 through 7.101-9 of the Company's ~~t~~Tariff. In such cases, in lieu of a Construction Deposit Agreement, the party or parties requesting an extension subject to the MEP Charge may enter into a guaranty agreement with the Company by which said party or parties shall agree to pay to the Company any remaining unamortized balance of the amount subject to the MEP Charge at the end of the Amortization Period.

VII

LIMITS OF COMPANY'S RESPONSIBILITIES

The Company shall not be liable for any property damage, fatality, or personal injury sustained on the Customer's premises resulting from the Customer's Installation or the gas pipe, fittings, appliances and apparatus of any type of others on Customer's premises. The Company will not be responsible for the use, care or handling of Gas once the Gas passes the Point of Delivery. The Company shall not be liable to the Customer for naturally occurring or other impurities, regardless of the source, such as water, sand, black powder, sulfur, butane, or other chemicals or compounds in the Gas delivered to Customer. The Company shall not be liable for any loss or damage caused by variation in Gas pressure, defects in pipes, connections and appliances, escape or leakage of Gas, sticking of valves or regulators, or for any other loss or damage not caused by the Company's negligence arising out of or incident to the furnishing of Gas to any Customer.

Whenever Company deems an emergency or system operating condition warrants interruption, curtailment or other limitation of the Gas Service being rendered, such interruption, curtailment or other limitation shall not constitute a breach of contract and shall not render Company liable for damages suffered as a result of such interruption, curtailment or other limitation of Gas Service, or excuse Customer from continuing to fulfill its obligations to Company.

VIII

CONTINUITY OF SERVICE

The Company will use reasonable diligence at all times to provide regular, uninterrupted Gas Service, and shall not be liable to the Customer for any fatality, injury to person, or loss of or damage to property arising from causes beyond its control or from the ordinary negligence of the Company, its employees, servants or agents, including, but not limited to, damages for Gas leakage, complete or partial failure or interruption of service, for initiation of or re-connection of service, for shutdown for repairs or adjustments, for fluctuations in Gas flow, for delay in providing or restoring Gas Service, for termination of Gas Service, or for failure, as the result of an emergency or a Force Majeure event, to warn of interruption of Gas Service.

IX

LIMITATION ON CONSEQUENTIAL DAMAGES

~~Customer shall not be entitled to recover from Company any consequential, indirect, unforeseen, incidental or special damages, such as loss of use of any property or equipment, loss of profits or income, loss of production, rental expenses for replacement property or equipment, diminution in value of real property, or expenses to restore operations, or loss of goods or products.~~
To the fullest extent permitted by law, neither the Company, nor their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, or their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, shall be liable to the Customer or any other party or their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, for (i) claims, suits, actions or causes of action for incidental, indirect, special, punitive, unforeseen, multiple or consequential damages connected with or resulting from Company's performance or non-performance (such as loss of use of any property or equipment, loss of profits or income, loss of production, rental expenses for replacement property or equipment, diminution in value of real property, or expenses to restore operations, or loss of goods or products), or (ii) any actions undertaken in connection with or

 Attachment 6

related to service under this Tariff, including without limitation, actions which are based upon causes of action for breach of contract, tort (including negligence and misrepresentation), breach of warranty, strict liability, statute, operation of law, under any indemnity provision or any other theory of recovery.

X

INDEMNITY TO COMPANY

A. General. The Customer shall indemnify, hold harmless, and defend the Company from and against any and all liability, proceedings, suits, cost or expense for loss or damage or injury to person or property or for fatality, in any manner directly or indirectly connected with or arising out of the transmission, distribution or use of Gas by the Customer at or on the Customer's side of the Point of Delivery or in any manner directly or indirectly connected with or arising out of the Customer's acts or omissions.

B. Governmental. Notwithstanding anything to the contrary in the Company's Tariff, including these Rules and Regulations, the Rate Schedules, and Standard Forms, any obligation of indemnification therein required of a Customer that is a governmental entity of the State of Florida or political subdivision thereof ("governmental entity"), shall be read to include the condition "to the extent permitted by applicable law."

XI

APPEALS TO THE COMMISSION

Whenever the application of these rules and regulations appear to be unjust or impractical either the Company or the Customer may request permission from the Commission for an exception.

TRANSPORTATION SERVICE (Continued)

D. COMPANY STANDARDS

In operating the Natural Choice Transportation Service Rider, the Company will:

1. Apply its transportation service ~~t~~Tariff provisions uniformly to all similarly situated affiliated and non-affiliated marketers, brokers, agents, and Customers.

2. Make ancillary services provided by the Company available on a non-discriminatory basis to all similarly situated Pool Managers.

3. Process all similar requests for transportation service in the same manner.

4. Provide, if requested by a Customer, a list of all Pool Managers operating on Company's system.

5. Functionally separate operating employees for the Company from the operating employees of any affiliated Pool Manager.

6. Maintain its books of accounts and records separate from the books of accounts and records of any affiliated Pool Manager.

In operating the Natural Choice Transportation Service Rider, the Company will not:

7. Give any similarly situated Pool Manager or Customer preference in matters, rates, information, or charges relating to transportation service including, scheduling, balancing, metering, standby service or curtailment policy.

8. Communicate to any Customer, Pool Manager or third person that any advantage might accrue to such Customer, Pool Manager or third person in the use of the Company's Natural Choice Transportation Service Rider as a result of the Customer's, Pool Manager's or other third person's dealing with a Pool Manager affiliated with the Company.

COUNTIES AND COMMUNITIES SERVED

COUNTIES	COMMUNITIES
Baker County	Glen St. Mary Macclenny Sanderson Unincorporated Baker County
Bay	Callaway Lynn Haven Panama City[1] Panama City Beach Parker Springfield Tyndall Air Force Base Unincorporated Bay County
Bradford	Starke Unincorporated Bradford County
Broward	Coconut Creek Cooper City Coral Springs Dania Dania Beach Davie Deerfield Beach Fort Lauderdale Hallandale Beach Hollywood Lauderdale-By-The-Sea Lauderdale Lakes Lauderhill Lighthouse Point Margate Miramar North Lauderdale Oakland Park Parkland Pembroke Park Pembroke Pines Plantation Pompano Beach Southwest Ranches Tamarac Weston Wilton Manors Unincorporated Broward County

[1]Designates location of Local Operations Center

Peoples Gas System, Inc. may extend service to other areas pursuant to the terms and conditions set forth in this ~~t~~Tariff. For further information regarding service areas, contact customer service at:
(877) TECO-PGS / (877) 932-6747

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Charlotte	Babcock Ranch Englewood North Port Port Charlotte Punta Gorda Unincorporated Charlotte County
Clay	Fleming Island Green Cove Springs Maxville Middleburg Orange Park Unincorporated Clay County
Collier	Marco Island Naples Unincorporated Collier County
Columbia	Lake City Unincorporated Colombia County
Duval	Atlantic Beach Baldwin Jacksonville[1] Jacksonville Beach Neptune Beach Unincorporated Duval County
Flagler	Bunnell Flagler Beach Palm Coast Unincorporated Flagler County
Hardee	Zolfo Springs Unincorporated Hardee County
Hendry	Labelle Unincorporated Hendry County
Hernando	Brooksville Spring Hill Weeki Wachee Unincorporated Hernando County

[1]Designates location of Local Operations Center

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 Attachment 6

Peoples Gas System, Inc.
Original Volume No. 3

Fourth ~~Third~~ Revised Sheet No. 6.101-2
Cancels Third ~~Second~~ Revised Sheet No. 6.101-2

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Highlands	Avon Park[1] ~~Sebring~~ Unincorporated Highlands County
Hillsborough	Apollo Beach Brandon Gibsonton Lithia Lutz Plant City Riverview Rocky Point Ruskin Seffner Sun City Center Tampa[1] Temple Terrace Valrico Wimauma Unincorporated Hillsborough County
Jackson	Alford Cottondale Unincorporated Jackson County
Lafayette	Mayo Unincorporated Lafayette County
Lake	Clermont Dona Vista Eustis[1] Grand Island Howey-in-the-Hills Lady Lake Leesburg Mount Dora Sorrento Tavares The Villages Umatilla Unincorporated Lake County

[1]Designates location of Local Operations Center

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(877) TECO-PGS / (877) 932-6747

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

 Attachment 6

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Lee	Alva Babcock Ranch Bonita Springs Cape Coral Estero Fort Myers[1] Fort Myers Beach Lehigh Acres Miromar Lakes North Fort Myers Unincorporated Lee County
Leon	Unincorporated Leon County
Levy	Morriston Unincorporated Levy County
Liberty	Bristol Unincorporated Liberty County
Manatee	Bradenton Bradenton Beach Ellenton Holmes Beach Lakewood Ranch Longboat Key Palmetto Parrish University Park Unincorporated Manatee County
Marion	Belleview Dunnellon Fort McCoy Ocala[1] Silver Springs Summerfield The Villages ~~Summerfield~~ Unincorporated Marion County
Martin	Hobe Sound Palm City Stuart ~~Tequesta~~ Unincorporated Martin County

[1]Designates location of Local Operations Center

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(877) TECO-PGS / (877) 832-6747

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Miami-Dade	Aventura Bal Harbour Bay Harbor Islands Biscayne Park El Portal Golden Beach Indian Creek Village Miami[1] Miami Beach Miami Shores North Bay Village North Miami North Miami Beach Sunny Isles Beach Surfside Unincorporated Miami-Dade County
Nassau	Bryceville Fernandina Beach Unincorporated Nassau County
Okeechobee	Unincorporated Okeechobee County
Orange	Apopka Belle Isle ~~Casselberry~~ Edgewood ~~Fern Park~~ Golden Oak Lake Buena Vista Maitland Orlando[1] Pine Castle Tangerine Winter Garden Winter Park ~~Tangerine~~ Zellwood Unincorporated Orange County
~~Osceola~~	~~Celebration City~~ ~~Kissimmee~~ ~~Unincorporated Osceola County~~
~~Palm Beach~~	~~Jupiter~~ ~~Lake Park~~ ~~Palm Beach Gardens[1]~~ ~~Juno Beach~~ ~~Unincorporated Palm Beach County~~

[1]Designates location of Local Operations Center

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(877) TECO-PGS / (877) 832-6747

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Osceola	Celebration Kissimmee Poinciana Reunion Saint Cloud Unincorporated Osceola County
Palm Beach	Juno Beach Jupiter Lake Park North Palm Beach Palm Beach Gardens[1] Tequesta Unincorporated Palm Beach County
Pasco	Dade City Hudson Land of Lakes ~~Lutz~~ New Port Richey Odessa Port Richey St. Leo San Antonio Wesley Chapel Zephyrhills Unincorporated Pasco County
Pinellas	Bay Pines Clearwater Gulfport Kenneth City Largo Madeira Beach Pinellas Park St. Pete Beach St. Petersburg[1] Seminole South Pasadena Treasure Island Unincorporated Pinellas County
~~Polk~~	~~Davenport~~ ~~Eaton Park~~ ~~Frostproof~~ ~~Lakeland[1]~~ ~~Mulberry~~ ~~Unincorporated Polk County~~
~~Putnam~~	~~Unincorporated Putnam County~~
~~Sarasota~~	~~Englewood~~ ~~Longboat Key~~

~~Nokomis~~
~~North Port~~
~~Osprey~~
~~Sarasota[1]~~
~~Venice~~
~~Unincorporated Sarasota County~~

[1]Designated location of Local Operations Center

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(877) TECO-PGS / (877) 832-6747

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Polk	Davenport Eaton Park Frostproof Lakeland[1] Mulberry Unincorporated Polk County
Putnam	Unincorporated Putnam County
Sarasota	Englewood Longboat Key Nokomis North Port North Venice Osprey Sarasota[1] Venice Unincorporated Sarasota County
Seminole	Altamonte Springs Casselberry Fern Park Goldernrod ~~Golden Rod~~ Longwood Oviedo Winter Springs Unincorporated Seminole County
St. Johns	Elkton Ponte Vedra Ponte Vedra Beach St. Augustine St. Augustine Beach Unincorporated St. Johns County
St. Lucie	Fort Pierce Unincorporated St. Lucie County
Sumter	Coleman Oxford Sumterville The Villages Wildwood Unincorporated Sumter County
~~Volusia~~	~~Daytona Beach~~ ~~Daytona Beach Shores~~ ~~Holly Hill[1]~~ ~~Ormond Beach~~ ~~Port Orange~~ ~~South Daytona~~ ~~Unincorporated Volusia County~~

~~Wakulla~~	~~Crawfordville~~ ~~Unincorporated Wakulla County~~

[1] Designated location of Local Operations Center

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(877) TECO-PGS / (877) 832-6747

COUNTIES AND COMMUNITIES SERVED (Continued)

COUNTIES	COMMUNITIES
Volusia	Daytona Beach Daytona Beach Shores Holly Hill[1] Ormond Beach Port Orange South Daytona Unincorporated Volusia County
Wakulla	Crawfordville Unincorporated Wakulla County

[1] **Designated location of Local Operations Center**

Peoples Gas System, Inc. may extend service to other areas pursuant to the terms and conditions set forth in this ~~t~~Tariff. For further information regarding service areas, contact customer service at:
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INDEX OF RATE SCHEDULES

RATE SCHEDULES

GENERAL APPLICABILITY PROVISIONS

The following general provisions are applicable to each rate schedule contained in this ~~t~~Tariff.

A. CHARACTER OF SERVICE

1. General Service. Gas, purchased by Customer from Company, having a nominal heating value of not less than 1,000 BTU per cubic foot. The Company will endeavor to provide Gas Service on a continuous basis, but does not guarantee to do so. Detailed procedures for orderly curtailment in the event of a shortage of Gas from the Company's suppliers are set forth in the Company's curtailment plan~~ on file with the Commission~~.

2. Interruptible Service and Contract Interruptible Service. Gas, purchased by Customer from Company, having a nominal heating value of not less than 1,000 BTU per cubic foot, delivered on an interruptible basis. Gas Service rendered under Interruptible and Contract Interruptible ~~R~~rate ~~S~~schedules will be curtailed or fully interrupted at the sole discretion of the Company. The Customer shall hold the Company harmless from any and all liabilities, penalties, alternate fuels subsidies, price adjustments and claims of whatever type, resulting from or arising out of the Company's curtailment or interruption of Gas consumption or deliveries to Customers electing Interruptible Service.

3. Individual Transportation Service. Gas made available to Company by or for the account of Customer (other than as a part of Gas made available to Company by or for the account of an NCTS Customer Pool, as defined in Rider NCTS of this ~~t~~Tariff) for transportation service on Company's system from a designated point of receipt to a designated point of delivery. Company shall have no obligation to re-deliver Gas which Company has not received from or for the account of Customer. If the Gas is delivered for transportation by Company under a firm rate schedule, Company will endeavor to re-deliver the Gas on a continuous basis, but does not guarantee to do so. Detailed procedures for orderly curtailment of deliveries are set forth in the Company's curtailment plan~~ on file with the Commission~~. Transportation service rendered under Interruptible and Contract Interruptible rate schedules will be curtailed or interrupted at the sole discretion of the Company. The Customer shall hold the Company harmless from any and all liabilities, penalties, alternate fuels subsidies, price adjustments and claims of whatever type, resulting from or arising out of the Company's curtailment or interruption of deliveries of Gas transported by Company under an interruptible rate schedule.

4. Natural Choice Transportation Service. Gas made available to Company by or for the account of Customer as part of an NCTS Customer Pool (as defined in Rider NCTS of this ~~t~~Tariff), for transportation on Company's system from a designated point of receipt to a designated point of delivery. Company shall have no obligation to re-deliver Gas which Company has not received from or for the account of an NCTS Customer Pool. If the Gas is to be delivered by Company to Customer under a firm rate schedule, Company will endeavor to re-deliver the Gas on a continuous basis, but does not guarantee to do so. Detailed procedures for orderly curtailment of deliveries are set forth in the Company's curtailment plan~~ on file with the Commission~~. Natural Choice Transportation Service rendered under Interruptible

GENERAL APPLICABILITY PROVISIONS (Continued)

F. TAX AND FEE ADJUSTMENT CLAUSE

The bill for Gas Service computed under the rates in this ~~t~~Tariff shall be increased by the appropriate proportionate part of all taxes, licenses, assessments, or fees imposed by any governmental authority based on the production or consumption of natural Gas or on revenues derived from the consumption of Gas. Should franchise fees be included in the basis for determining the amount of the State Regulatory Trust Fund fees, the franchise fee addition reflected in the bill shall be computed at a factor of 1.00503 of such franchise fee. All of the foregoing additions to the bill will be shown separately from the amount billed for Gas.

G. COMPETITIVE RATE ADJUSTMENT CLAUSE

The Distribution Charge for Gas delivered after September 30, 1989 to Customers other than those served under Company's Rate Schedules ISLV and CIS and those Customers receiving a discount under a Rate Schedule NGVS-2 special contract rate approved by the Commission is subject to adjustment in accordance with the following provisions, for prior shortfalls or surpluses in Company's contract interruptible service revenues.

1. For the purposes of this clause, the following definitions shall apply:

   a. "Actual revenue" means Company's actual non-gas revenue derived from service provided under its Rate Schedule CIS and those Customers receiving a discount under a Rate Schedule NGVS-2 special contract rate approved by the Commission during a determination period.
   b. "Base revenue" means the non-gas revenue which Company would have derived had all Gas delivered under Company's Rate Schedule CIS and any Rate Schedule NGVS-2 special contract rate during a determination period been billed at the distribution charge established for service under applicable interruptible rate schedules in Company's last base rate proceeding.
   c. "Surplus" means the amount, if any, by which Company's actual revenue exceeds its base revenue for a determination period.
   d. "Shortfall" means the amount, if any, by which Company's base revenue exceeds its actual revenue for a determination period.

2. The existence of a shortfall or surplus shall be determined by comparing Company's actual revenue with its base revenue. This determination shall be made each year for the twelve (12) months ending September 30 ("determination period").

3. Adjustments to rates pursuant to this clause shall be implemented during an "adjustment period", which shall be the eleven (11) months ending September 30 in the year following the determination period in the event of a surplus. In the event of a shortfall, any eleven (11) successive months ending on a September 30 within five (5) years following the determination period may be an adjustment period.

GENERAL APPLICABILITY PROVISIONS (Continued)

4. In the event of a surplus, Company shall reduce rates to Customers (other than Customers served under Rate Schedules ISLV and CIS and those Customers receiving a discount under a Rate Schedule NGVS-2 special contract rate approved by the Commission) to credit them with revenues equal to the surplus.

5. In the event of a shortfall, Company may increase rates to Customers (other than Customers served under Rate Schedules ISLV and CIS, and those Customers receiving a discount under a Rate Schedule NGVS-2 special contract rate approved by the Commission) to recover an amount not to exceed the amount of the shortfall.

6. A surplus refund or shortfall recovery shall be implemented during an adjustment period by reducing or increasing the distribution charge prescribed in each rate schedule of this ~~t~~Tariff (except Rate Schedules ISLV and CIS and any Rate Schedule NGVS-2 special contract rate approved by the Commission) by an adjustment factor computed as follows and rounded to the nearest .001 cent per Therm:

   In event of a surplus, subtract: $\dfrac{\text{Surplus Refund to Customers}}{\text{PTS}}$

   In event of a shortfall, add: $\dfrac{\text{Shortfall Recovery}}{\text{PTS}}$

   Where PTS is the projected Therm consumption for Customers (excluding Customers serviced under Rate Schedules ISLV and CIS and those Customers receiving a discount under a Rate Schedule NGVS-2 special contract rate approved by the Commission) during the adjustment period.

   Any variation between the actual refund to Customers and the amount calculated pursuant to the preceding paragraph, or between the actual shortfall recovery and the amount which Company elected to recover in an adjustment period, shall be "trued-up" during the succeeding adjustment period pursuant to methodology approved by the Commission.

7. Company may defer all or any portion of a shortfall recovery to a subsequent adjustment period or portion thereof.

GENERAL APPLICABILITY PROVISIONS (Continued)

H. CONDITIONS FOR TRANSPORTATION OF CUSTOMER-OWNED GAS

Provisions applicable to each Customer which receives individual transportation service provided by Company (regardless of whether such Customer also purchases Gas from Company pursuant to a rate schedule providing for sales service) are found in Rider ITS of this ~~t~~Tariff. Provisions applicable to each Customer which receives aggregated transportation service provided by Company (regardless of whether such Customer also purchases Gas from Company pursuant to a rate schedule providing for sales service) are found in Rider NCTS of this ~~t~~Tariff.

I. MAIN EXTENSION PROGRAM

In cases where the estimated actual cost of extending necessary Main and Service facilities exceeds the Maximum Allowable Construction Cost (MACC); and where the Company determines, in its reasonable discretion and in accord with Section VI of the Company's Rules and Regulations, that there is a reasonable likelihood that an extension of Main or Service facilities will produce sufficient revenues to justify the necessary investment in such facilities; and where the Company determines that the creditworthiness of the party or parties requesting the extension is satisfactory to assure recovery of the additional investment above the MACC, the Company may provide for the recovery of estimated actual extension costs in excess of the MACC via a Main Extension Program (MEP Charge). In such cases, in lieu of a Construction Deposit Agreement, the party or parties requesting an extension subject to the MEP Charge may enter into a guaranty agreement with the Company by which said party or parties shall agree to pay to the Company any remaining unamortized balance of the amount subject to the MEP Charge at the end of the Amortization Period.

Where the MEP Charge is applied, the MEP Charge shall be paid only by Customers in the area served by the extended Main for which the MEP Charge is levied. The MEP Charge applicable to each such Customer shall be expressed in dollars per Premise (as hereinafter defined) per month and shall be calculated according to the following formula.

RESIDENTIAL SERVICE
Rate Schedule RS

Availability:

Throughout the service areas of the Company.

Applicability:

Gas Service for residential purposes in individually metered residences and separately metered apartments. Also, for Gas used in commonly owned facilities of condominium associations, cooperative apartments, and homeowners associations, (excluding any premise at which the only Gas-consuming appliance or equipment is a standby electric generator), subject to the following criteria:

1. 100% of the Gas is used exclusively for the co-owner's benefit.
2. None of the Gas is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each Point of Delivery will be separately metered and billed.
4. A responsible legal entity is established as the Customer to whom the Company can render its bills for said services.
5. RS-GHP refers to any Residential Customer utilizing a gas heat pump ("GHP") for heating and cooling.

Customers receiving service under this schedule will be classified for billing purposes according to annual usage as follows:

Billing Class	Annual Consumption
RS-1	0 – 99 Therms
RS-2	100 – 249 Therms
RS-3	250 – 1,999 Therms
RS-GHP	All Therms

Monthly Rate:

Billing Class	Customer Charge
RS-1	$19.06~~15.10~~ per month
RS-2	$24.36~~18.10~~ per month
RS-3	$31.48~~24.60~~ per month
RS-GHP	$31.47~~24.60~~ per month

Distribution Charge: $0.35096~~27011~~ per Therm for RS-1, RS-2, and RS-3
$0.12374~~09598~~ per Therm for RS-GHP

Minimum Bill: The Customer charge.

RESIDENTIAL SERVICE (Continued)

Note 1 – Company's Budget Billing Plan~~BudgetPay~~ plan is available to eligible Customers receiving Gas Service pursuant to this rate schedule (See Sheet No. 5.401-3).

The bill for the Therms billed under this schedule shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1.

Special Conditions:

1. The rates set forth under this schedule shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

2. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

3. Service under this schedule is subject to annual volume review by the Company and one additional review each year~~or any time~~ at the Customer's request. If reclassification to another billing class is appropriate such classification will be prospective.

   a) Each year, the Company will review active residential Gas Service consumption to determine whether the prior 12 months of consumption was within the consumption band for the assigned Billing Class.

   b) If consumption is 10 percent over or below the consumption parameters for the assigned Billing Class ("10 percent band"), the Company will re-assign the Billing Class to the applicable level of consumption.

   c) If the Customer's consumption is over or below the consumption parameters for the Customer's Billing Class but not more or less than the 10 percent band for the assigned Billing Class for the most recent 12 months of consumption, the Customer will remain on the assigned Billing Class. If the same result occurs in the same direction (over or below) for two consecutive annual volume review cycles, the Company will re-assign the Customer to the appropriate Billing Class for the level of consumption.

~~3.~~4. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

~~4.~~5. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

~~5.~~6. A RS-GHP Customer with an annual consumption in excess of 1,999 Therms shall be eligible for transportation service under Rider NCTS.

~~6.~~7. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

SMALL GENERAL SERVICE
Rate Schedule SGS

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any non-residential Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using 0 through 1,999 Therms per year or less. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS.

Monthly Rate:

Customer Charge:	$42.98~~30.60~~ per month
Distribution Charge:	$0.49196~~38897~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS.

Minimum Bill: The Customer charge.

Special Conditions:

1. When the Customer receives transportation service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth of Sheet No. 7.101-5.

SMALL GENERAL SERVICE (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or any time at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

Note: Company's Budget Billing Plan is available to eligible Customers receiving Gas Service pursuant to this rate schedule (See Sheet No. 5.401-3)

GENERAL SERVICE - 1
Rate Schedule GS-1

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using 2,000 through 9,999 Therms per year. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS.

Monthly Rate:

Customer Charge: $65.91~~45.00~~ per month

Distribution Charge: $0.46334~~31190~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS.

Minimum Bill: The Customer charge.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

 Attachment 6

GENERAL SERVICE – 1 (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or any time at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

GENERAL SERVICE - 2
Rate Schedule GS-2

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using 10,000 through 49,999 Therms per year. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS.

Monthly Rate:

Customer Charge:	$123.22~~82.00~~ per month
Distribution Charge:	$0.39646~~26631~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS.

Minimum Bill: The Customer charge.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

GENERAL SERVICE - 2 (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or anytime at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

GENERAL SERVICE - 3
Rate Schedule GS-3

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using 50,000 through 249,000 Therms per year or RNG delivered into Company's system by any Customer delivering 50,000 through 249,999 Therms per year. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS and may be eligible for transportation service under Rider ITS.

Monthly Rate:

Customer Charge:	$501.48~~420.00~~ per month
Distribution Charge:	$0.3391~~421781~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS or Rider ITS. Company's Purchased Gas Adjustment Clause shall not apply to bills for Therms of RNG delivered into Company's system.

Minimum Bill:	The Customer charge.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. Except in the case of Therms of RNG delivered into the Company's system, the rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

GENERAL SERVICE - 3 (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or anytime at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

 Attachment 6

Peoples Gas System, Inc. **Eighth ~~Seventh~~ Revised Sheet No. 7.303-4**
Original Volume No. 3 **Cancels Seventh ~~Sixth~~ Revised Sheet No. 7.303-4**

GENERAL SERVICE - 4
Rate Schedule GS-4

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using 250,000 through 499,999 Therms per year or RNG delivered into Company's system by any Customer delivering 250,000 through 499,999 Therms per year. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS or Rider ITS.

Monthly Rate:

Customer Charge: $950.43~~670.00~~ per month

Distribution Charge: $0.26271~~17785~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS or Rider ITS. Company's Purchased Gas Adjustment Clause shall not apply to bills for Therms of RNG delivered into Company's system.

Minimum Bill: The Customer charge.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. Except in the case of Therms of RNG delivered into the Company's system, the rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

GENERAL SERVICE - 4 (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or anytime at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

Attachment 6

GENERAL SERVICE - 5
Rate Schedule GS-5

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer (except a Customer whose only Gas-consuming appliance or equipment is a standby electric generator) using a minimum of 500,000 Therms per year or more at one billing location or RNG delivered into Company's system by any Customer delivering a minimum of 500,000 Therms per year or more at one billing location.

A Customer eligible for service under this rate schedule is eligible for transportation service under either Rider NCTS or Rider ITS.

Monthly Rate:

Customer Charge:	$2,096.67~~1,380.00~~ per month
Distribution Charge:	$0.17862~~1188~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under either the Company's Rider NCTS or Rider ITS. Company's Purchased Gas Adjustment Clause shall not apply to bills for Therms of RNG delivered into Company's system.

Minimum Bill: The Customer charge.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. Except in the case of Therms of RNG delivered into the Company's system, the rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

GENERAL SERVICE - 5 (Continued)

5. Service under this schedule (unless otherwise indicated herein) shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule is subject to annual volume review by the Company or anytime at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

COMMERCIAL STREET LIGHTING SERVICE
Rate Schedule CSLS

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered for use in commercial street lighting devices for public or private use in common areas around subdivisions, complexes, streets, highways or roadway lighting. To qualify for this rate, Customer must have at least ten (10) Gas street lights or a total of forty (40) individual mantles installed and separately metered from other gas-using equipment. A Customer eligible for service under this rate schedule is eligible for transportation service under the Company's Rider NCTS.

Monthly Rate:

Distribution Charge: $0.40600~~27513~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under Rider NCTS.

Special Conditions:

1. When the Customer receives service under the Company's Natural Choice Transportation Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

2. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2.

3. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

4. The rates set forth above shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. Service under this schedule will require one street light to be metered per account. The metered volume multiplied by the number of lights will equal total Therm usage per month.

NATURAL GAS VEHICLE SERVICE-2 (continued)

Special Conditions:

1. A separate meter or sub-meter may be requested by the Customer or required by Company; in which case the Customer will pay the cost of the meter (which shall remain the property of the Company) and its installation.

2. The collection and remittance of any federal or state or local tax imposed on CNG or the dispensing thereof for motor fuel shall be the responsibility of the Customer or Retailer, unless otherwise provided in Customer's agreement with Company.

3. Company shall not be responsible in any manner for the use, care or handling of natural gas once it is delivered to a natural gas vehicle.

4. If the Company, alone or together with another entity, responds to a competitive situation of a Customer that will consume quantities greater than 100,000 Therms per year, the Company may provide NGV Service at rates and charges set on an individual Customer basis via a special contract as long as the rate is above incremental cost with a reasonable return. At the Company's discretion it may recover the difference between the otherwise applicable ~~t~~Tariff rate and the approved special contract rate under this provision through Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

5. If a Customer desires to phase in the use of CNG as motor fuel and is acquiring and placing into service vehicles fueled by CNG over a period of years, the Monthly Services Charge may, in the discretion of Company, be phased-in over the term of the agreement between Customer and Company. The terms of any such phase-in shall be included in the agreement between Customer and Company.

6. Service under this schedule shall be subject to the operation of the Company's Tax and Adjustment Clause set forth on Sheet No. 7.101-5.

 Attachment 6

RESIDENTIAL STANDBY GENERATOR SERVICE
Rate Schedule RS-SG

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer otherwise eligible to receive Gas Service under Rate Schedule RS whose only Gas-consuming appliance or equipment is a standby electric generator.

Monthly Rate:

Customer Charge: $31.47~~23.91~~

Distribution Charge: ~~0 – 20.0 therms $0.00000 per Therm~~
~~In excess of 20.0 therms~~ $0.28181~~27011~~ per Therm

Minimum Monthly Bill: The Customer charge

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth ~~the~~ on Sheet No. 7.101-1.

Special Conditions:

1. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2 and will apply to each Therm delivered to Customer during a Billing Period.

2. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5 and will apply to each Therm delivered to Customer during a Billing Period.

3. The rates set forth in this ~~t~~Tariff shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5 and will apply to each Therm delivered to Customer during a Billing Period.

4. Subject to Special Condition 5 below, a Customer receiving Gas Service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month period unless customer terminates Gas Service at the end of any 12-month period.

5. If Customer installs an additional Gas appliance at the premise at which service is provided hereunder, then Customer will be transferred to the otherwise applicable rate schedule.

RESIDENTIAL STANDBY GENERATOR SERVICE (Continued)

6. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

7. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

COMMERCIAL STANDBY GENERATOR SERVICE
Rate Schedule CS-SG

Availability:

Throughout the service areas of the Company.

Applicability:

Gas delivered to any Customer eligible to receive Gas Service under Rate Schedule SGS, GS-1, GS-2, GS-3, GS-4 or GS-5 whose only Gas-consuming appliance or equipment is a standby electric generator.

Monthly Rate:

Customer Charge:	$52.54~~45.00~~	
Distribution Charge:	~~0 – 40.0 Therms~~	~~$0.00000 per Therm~~
	~~In excess of 40.0 Therms~~	$0.28181~~42315~~ per Therm
Minimum Monthly Bill:	The Customer charge	

1. The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set for the on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider NCTS.

Special Conditions:

1. When the Customer receives transportation service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3
2. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth on Sheet No. 7.101-2 and will apply to each Therm delivered to Customer during a Billing Period.
3. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.4 and will apply to each Therm delivered to Customer during a Billing Period.
4. The rates set forth in this ~~t~~Tariff shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5 and will apply to each Therm delivered to Customer during a Billing Period.

COMMERCIAL STANDBY GENERATOR SERVICE
Rate Schedule CS-SG (Continued)

5. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider NCTS.

6. Subject to Special Condition 7 below, a Customer receiving Gas Service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month period unless customer terminates Gas Service at the end of any 12-month period.

7. If Customer installs an additional Gas appliance at the premise at which service is provided hereunder, then Customer will be transferred to the otherwise applicable rate schedule.

8. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

9. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

 Attachment 6

RENEWABLE NATURAL GAS SERVICE
Rate Schedule RNGS

Availability:

Throughout the service areas of the Company.

Applicability:

Renewable Natural Gas Service ("RNG Service") is service to upgrade or condition biogas to RNG or to provide infrastructure for delivery of RNG to a pipeline system. RNG Service is available to any Customer: (1) upgrading/conditioning biogas to RNG to be utilized onsite by Customer; (2) interconnecting to an interstate or intrastate pipeline; or, (3) delivered into Company's distribution system for transportation and delivery. RNG delivering into Company's distribution system shall be subject to the applicable Rate Schedules GS-3, GS-4 or GS-5. The equipment included in the RNG Service as well as the design, location, construction, operation of such equipment under this Schedule is contingent on arrangements mutually satisfactory to the Customer and Company. This rate schedule is closed to new customers as of August 29, 2023.

Monthly Services Charge:

RNG Service is available under the rate schedules referenced under "Applicability" above based on Customer's annual deliveries of RNG into Company's distribution system as determined by Company. The charges, terms and conditions of the applicable rate schedule shall apply unless otherwise provided in this rate schedule. In addition to those charges provided by the rate schedule pursuant to which the Customer delivers RNG to Company, Customer shall pay a Monthly Services Charge, which shall be as mutually agreed. In the case of multiple users of the facility each user will pay a mutually agreed facility fee. If a Customer desires to phase in its deliveries of RNG into Company's system over a period of years, the Monthly Services Charge may be phased in over the term of the agreement between Customer and Company. The Monthly Services Charge will recover the total installed cost of such facilities, as determined by the Company, including a reasonable rate of return on the total installed cost of such facilities, as determined by Company, which facilities may include, but are not limited to, blowers, chillers, condensate removal equipment, compressors, heat exchangers, driers, digesters, gas constituent removal equipment, quality monitoring equipment, storage vessels, controls, piping, metering, propane injection, and any other related appurtenances including any redundancy necessary to provide reliable RNG Service, before any adjustment for accumulated depreciation, a contribution in aid of construction, etc. The agreement between Company and Customer may require a commitment by the Customer to purchase RNG Service for a minimum period of time, to take or pay for a minimum amount of RNG Service, to make a contribution in aid of construction, to furnish a guarantee, such as a surety bond, letter of credit, other means of establishing credit, and/or to comply with other provisions as determined appropriate by the Company.

The Company's provision of RNG Service does not include the provision of electricity, natural gas, or any other fuels required to operate the Company's facilities or to be added to the RNG produced by or transported for Customer.

~~**RESERVED FOR FUTURE USE**~~

RENEWABLE NATURAL GAS INTERCONNECTION SERVICE Rate Schedule RNGIS

Availability:

Throughout the service areas of the Company.

Applicability:

Renewable Natural Gas Interconnection Service ("RNGI Service") is service to provide infrastructure for delivery of RNG to a pipeline system. RNGI Service is available to any Customer: (1) interconnecting to an interstate or intrastate pipeline; or (2) delivered into Company's distribution system for transportation and delivery. The equipment included in the RNGI Service as well as the design, location, construction, operation of such equipment under this Schedule is contingent on arrangements mutually satisfactory to the Customer and Company.

Monthly Services Charge:

RNGI Service is available under "Applicability" above based on the Customer's deliveries of RNG into an interstate or intrastate pipeline or the Company's distribution system as determined by the Company. The charges, terms and conditions of the applicable rate schedule shall apply unless otherwise provided in this rate schedule. In addition to those charges provided by the rate schedule pursuant to which the Customer delivers RNG to an interstate or intrastate pipeline or to the Company, Customer shall pay a Monthly Services Charge, which shall be consistent with this tariff. In the case of multiple users of the facility each user will pay a facility fee consistent with this tariff. If a Customer desires to phase in its deliveries of RNG into Company's system over a period of years, the Monthly Services Charge may be phased in over the term of the agreement between Customer and Company. The Monthly Services Charge will recover (1) the total installed cost of such facilities, as determined by the Company, including a reasonable rate of return on the total installed cost of such facilities, as determined by Company, which facilities may include pipeline, monitoring, regulating, metering, other associated interconnection equipment, and any other related appurtenances including any redundancy necessary to provide reliable RNGI Service, before any adjustment for accumulated depreciation, a contribution in aid of construction, and (2) associated depreciation expenses, taxes, and operations and maintenance expenses for the interconnection facilities, including the cost of electric power to operate the facilities. The agreement between Company and Customer may require a commitment by the Customer to purchase RNGI Service for a minimum period of time, to take or pay for a minimum amount of RNGI Service, to make a contribution in aid of construction, to furnish a guarantee, such as a surety bond, letter of credit, other means of establishing credit, and/or to comply with other provisions as determined appropriate by the Company.

The Company's provision of RNGI Service does not include the provision of electricity, natural gas, or any other fuels required to operate the Customer's facilities or to be added to the RNG produced by or transported for Customer.

Service under this schedule shall be subject to the Rules and Regulations set forth in this tariff.

 Attachment 6

Peoples Gas System, Inc.
Original Volume No. 3

Fourth ~~Third~~ Revised Sheet No. 7.405
Cancels Third ~~Second~~ Revised Sheet No. 7.405

COMMERCIAL GAS HEAT PUMP SERVICE
RATE SCHEDULE CS-GHP

Availability:
Throughout the service areas of the Company.

Applicability:
Gas delivered to any Commercial Customer utilizing a Gas Heat Pump for heating and cooling.

Monthly Rate:

Customer Charge:	$52.54~~45.00~~ per month
Distribution Charge:	$0.26271~~19605~~ per Therm
Minimum Bill:	The Customer charge

Special Conditions:

1. The gas provided for GHP would be separately metered and would appear separately on Customer bills.

2. The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless the customer receives transportation service under the Company's Rider NCTS.

3. The rates set forth above shall be subject to the operation of the Energy Conservation Cost Recovery Adjustment Clause set forth in Sheet No. 7.101-2.

4. When the Customer receives service under the Company's Natural Choice Transportation Service Rider (Rider NCTS), the rates set forth above shall be subject to the operation of the Company's Swing Service Charge set forth on Sheet No. 7.101-3.

5. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

6. A contract for an initial term of one year may be required as a condition precedent to service under this schedule, unless an extension of facilities is involved, in which case the term of the contract shall be the term required under the agreement for the facilities extension.

7. The rates set forth in this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

COMMERCIAL GAS HEAT PUMP SERVICE (Continued)

8. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

9. Service under this schedule is subject to annual volume review by the Company or any time at the Customer's request. If reclassification to another schedule is appropriate such classification will be prospective.

10. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

LIQUIFIED NATURAL GAS SERVICE
Rate Schedule LNG

Availability:

This rate schedule is available to any Customer for the purchase of Liquified Natural Gas ("LNG") service from Peoples Gas System, Inc. throughout the service areas of the Company.

Applicability:

Applicable to Customers requesting liquified natural gas services through storage of LNG, regasification of LNG to natural gas, and/or non-pipeline distribution of LNG ("LNG Service") for customer market segments including, but not limited to: (1) use as a transportation fuel, including marine markets, rail, auto, jet propulsion and other transportation customers, (2) use to increase system reliability, peak shaving and to increase resiliency of their facilities, (3) Customers that cannot be served by pipeline by PGS for any reason, including without limitation, time to construct the pipeline, cost of constructing pipeline, remote location, reliability/resilience and intermittent demand and (4) LNG loaded by ISO containers and exported to foreign markets pursuant to a valid export license. LNG Service under this Schedule is contingent upon arrangements mutually satisfactory to the Customer and Company for the design, location, construction, ownership, and operation of facilities required for the Company's provision of LNG Service. Service under this ~~R~~rate ~~S~~schedule is contingent upon the Company and the Customer entering a mutually satisfactory LNG Service Agreement.

Peoples Gas System, Inc.'s entry into an LNG Service Agreement with a Customer and the provision of LNG services pursuant to the LNG rate schedule with that Customer will not cause any additional costs to the Company's other rate classes.

Rate:

LNG Service facilities installed under the provisions of this schedule shall be owned, operated and maintained by the Company unless otherwise agreed to in an agreement for services between the parties. The rate for LNG Service supplied hereunder shall consist of a Monthly Services Charge and the transportation and delivery of natural gas under the Company's applicable ~~R~~rate ~~S~~schedules for General Service, Interruptible Service or Wholesale Service.

Monthly Services Charge:

The Monthly Services Charge shall be set forth in the agreement between the parties and unless otherwise specified in the agreement shall be billed in monthly installments over the term of this Agreement. The rate structure of the Monthly Services Charge shall be designed to recover the cost of service required to provide LNG Service to Customer. The rate structure includes, but is not limited to depreciation, return on capital, taxes and operational expenses, fuel used to operate facilities and electric costs to operate the facility. ~~As used in this schedule, LNG Service facility costs to be recovered means the total installed cost of such LNG facilities, as determined by Company, which may include but are not limited to compressors, heat exchangers, pumps, aftercoolers, filters, drivers, control valves (JT), vacuum insulated piping, instrumentation, vaporizers, fire protection equipment, safety equipment, monitoring equipment, truck scales, vent and flare systems, waste water disposal systems, instrument air, power, communications, N2 systems, quality monitoring equipment, storage, controls, piping, metering,~~

Continued from Sheet No. 7.406

As used in this schedule, LNG Service facility costs to be recovered means the total installed cost of such LNG facilities, as determined by Company, which may include but are not limited to compressors, heat exchangers, pumps, aftercoolers, filters, drivers, control valves (JT), vacuum insulated piping, instrumentation, vaporizers, fire protection equipment, safety equipment, monitoring equipment, truck scales, vent and flare systems, waste water disposal systems, instrument air, power, communications, N2 systems, quality monitoring equipment, storage, controls, piping, metering, propane injection, and any other related appurtenances, including any redundancy necessary to provide reliable LNG Service, before any adjustment for accumulated depreciation, a contribution in aid of construction, etc. The agreement between Company and Customer may require a commitment by the Customer to purchase LNG Service for a minimum period of time, to take or pay for a minimum amount of LNG Service, to make a contribution in aid of construction, to furnish a guarantee, such as a surety bond, letter of credit, other means of establishing credit, and/or to comply with other provisions as determined appropriate by the Company.

The Customer's monthly minimum charge under this r~~R~~ate s~~S~~chedule shall be the Monthly Services Charge.

Special Conditions:

1. All charges listed above are subject to applicable federal, state, or local taxes.

2. LNG Services provided hereunder shall be available only in connection with LNG that
   a. will be consumed in the State of Florida, or
   b. if not consumed in Florida,
      i. will not be vaporized for further transportation in interstate commerce by pipeline after its delivery to Customer by the Company pursuant to this r~~R~~ate s~~S~~chedule, and
      ii. will not be involved in a gas exchange or gas transportation by displacement transaction that would be deemed to circumvent the Federal Energy Regulatory Commission's jurisdiction, under the Natural Gas Act, over the interstate transportation of gas by pipeline.

3. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

4. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

WHOLESALE SERVICE - FIRM
Rate Schedule WHS

Availability:

For other Gas distribution or electric utility companies throughout service areas of the Company.

Applicability:

Service under this schedule will only be rendered when the Company has sufficient Gas and interstate pipeline capacity to meet all its other needs during the term of the sale under this schedule. Firm Gas Service for other Gas utility's residential or commercial resale or for use by an electric utility for its own consumption. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider ITS.

Monthly Rate:

Customer Charge:	$663.86~~420.00~~ per month
Distribution Charge:	$0.21935~~17054~~ per Therm
Minimum Bill:	The Customer charge

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider ITS.

Special Conditions:

1. An executed contract for a period of at least one year is required as a condition precedent to service hereunder.

2. The rates set forth above shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

3. If any facilities other than metering and regulating equipment are required to render service under this schedule, the Customer shall pay for these facilities prior to the commencement of service.

4. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

5. The rates set forth above shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

6. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

SMALL INTERRUPTIBLE SERVICE
Rate Schedule SIS

Availability:

Throughout the service areas of the Company.

Applicability:

Interruptible Service for non-residential commercial or industrial service under this schedule is subject to interruption or curtailment at the sole discretion of the Company at any time and is available to Customers using 1,000,000 through 3,999,999 Therms per year. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider ITS.

Service will be provided by the Company based on available pipeline capacity and the Customer delivering suitable Gas into the Company's distribution system.

Monthly Rate:

Customer Charge: $2,435.76~~1,380.00~~ per month

Distribution Charge: $0.1005~~407817~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider ITS.

Minimum Bill: The Customer charge.

Special Conditions:

1. A service agreement accepted by the Company is a condition precedent for service under this schedule. The term of the agreement shall be set forth therein but shall not be less than one year.

2. If the Customer's requirements for Gas change, the Customer shall notify the Company so that the daily and annual quantities in the service agreement may be changed. If the Customer's usage indicates that the amounts set forth in the then existing agreement are not applicable, the Company may require that the daily and annual estimates be changed to reflect the existing conditions.

3. The rates set forth above shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

SMALL INTERRUPTIBLE SERVICE (Continued)

4. Interruption and curtailment:
The Company may notify the Customer at any time to reduce or cease using Gas. The Company will endeavor to give as much notice as possible to the Customer.

Any gas taken in excess of the volume allocated to the Customer in an interruption or curtailment order shall be considered to be unauthorized overrun gas. Company may bill and Customer shall pay for such unauthorized overrun gas at the greater of (i) five (5) times the highest Gas Daily mid-point price for gas delivered to a Gulf Coast pipeline plus FGT's FTS-3 reservation, usage, fuel and applicable surcharges or (ii) five (5) times the Gas Daily FGT Florida City gate price for gas for the calendar day on which such unauthorized overrun gas was taken.

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. As a condition for receiving service pursuant to this rate schedule, Customer agrees that it will give notice to Company at least 120 days prior to the effective date of any termination of service under this rate schedule which is to be followed by the Company's establishment of service to Customer under a rate schedule providing for firm service.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

Attachment 6

Peoples Gas System, Inc.
Original Volume No. 3

Tenth ~~Ninth~~ Revised Sheet No. 7.603
Cancels Ninth ~~Eighth~~ Revised Sheet No. 7.603

INTERRUPTIBLE SERVICE
Rate Schedule IS

Availability:

Throughout the service areas of the Company.

Applicability:

Interruptible Gas for non-residential commercial or industrial use. Service under this schedule is subject to interruption or curtailment at the sole discretion of the Company at any time and is available to Customers using 4,000,000 through 49,999,999 Therms per year (see Special Condition 7). A Customer eligible for service pursuant to this rate schedule is also eligible for transportation service under Rider ITS.

Service will be provided by the Company based on available pipeline capacity and the Customer delivering suitable Gas into the Company's distribution system.

Monthly Rate:

Customer Charge:	$2,817.84~~1,580.00~~ per month
Distribution Charge:	$0.05209~~04050~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under the Company's Rider ITS.

Minimum Bill:	The Customer charge.

Special Conditions:

1. A service agreement accepted by the Company is a condition precedent for service under this schedule. The term of the agreement shall be set forth therein but shall not be less than one year.

2. If the Customer's requirements for Gas change, the Customer shall notify the Company so that the daily and annual quantities in the service agreement may be changed. If the Customer's usage indicates that the amounts set forth in the then existing agreement are not applicable, the Company may require that the daily and annual estimates be changed to reflect the existing conditions.

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

INTERRUPTIBLE SERVICE (Continued)

3. Interruption and curtailment:
The Company may notify the Customer at any time to reduce or cease using Gas. The Company will endeavor to give as much notice as possible to the Customer.

   Any Gas taken in excess of the volume allocated to the Customer in an interruption or curtailment order shall be considered to be unauthorized overrun Gas. Company may bill and Customer shall pay for such unauthorized overrun Gas at the greater of (i) five (5) times the highest Gas Daily mid-point price for gas delivered to a Gulf Coast pipeline plus FGT's FTS-3 reservation, usage, fuel and applicable surcharges or (ii) five (5) times the Gas Daily FGT Florida City gate price for gas for the calendar day on which such unauthorized overrun gas was taken.

4. The rates set forth under this schedule shall be subject to the operation of the Company's Competitive Rate Adjustment Clause set forth on Sheet No. 7.101-5.

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. A Customer which qualifies for service under this rate schedule shall continue to qualify for service hereunder if its usage is decreased below 4,000,000 Therms per year due solely to the Customer's taking thermal energy from a cogeneration facility to which the Company sells Gas or provides transportation service.

7. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

8. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

INTERRUPTIBLE SERVICE - LARGE VOLUME
Rate Schedule ISLV

Availability:

Throughout the service areas of the Company.

Applicability:

Interruptible Gas for non-residential commercial or industrial use. Service under this schedule is subject to interruption or curtailment at the sole discretion of the Company at any time and is available to Customers using 50,000,000 Therms per year or more. A Customer eligible for service pursuant to this rate schedule is eligible for transportation service under Rider ITS.

Service will be provided by the Company based on available pipeline capacity and the Customer delivering suitable Gas into the Company's distribution system.

Monthly Rate:

Customer Charge: $3,104.40~~1,720.00~~ per month

Distribution Charge: $0.01351~~01050~~ per Therm

The bill for the Therms billed at the above rates shall be increased in accordance with the provisions of the Company's Purchased Gas Adjustment Clause set forth on Sheet No. 7.101-1, unless Customer receives transportation service under Company's Rider ITS.

Minimum Bill: The Customer charge.

Special Conditions:

1. A service agreement accepted by the Company is a condition precedent for service under this schedule. The term of the agreement shall be set forth therein but not less than one year.

2. If the Customer's requirement for Gas change, the Customer shall notify the Company so that the daily and annual quantities in the service agreement may be changed. If the Customer's usage indicates that the amounts set forth in the then existing agreement are not applicable, the Company may require that the daily and annual estimates be changed to reflect the existing conditions.

INTERRUPTIBLE SERVICE - LARGE VOLUME (Continued)

3. Interruption and Curtailment:
The Company may notify the Customer at any time to reduce or cease using Gas. The Company will endeavor to give as much notice as possible to the Customer. Any Gas taken in excess of the volume allocated to the Customer in an interruption or curtailment order shall be considered to be unauthorized overrun Gas. Company may bill and Customer shall pay for such unauthorized overrun Gas at the greater of (i) five (5) times the highest Gas Daily mid-point price for gas delivered to a Gulf Coast pipeline plus FGT's FTS-3 reservation, usage, fuel and applicable surcharges or (ii) five (5) times the Gas Daily FGT Florida City gate price for gas for the calendar day on which such unauthorized overrun gas was taken.

4. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

5. Service under this schedule is subject to annual volume review by the Company or any time at the Customer's request. If reclassification to another schedule is appropriate, such classification will be prospective.

6. The rates set forth under this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

7. The rates set forth under this schedule shall be subject to the operation of the Cast Iron Bare Steel Replacement Rider Surcharge set forth on Sheet Nos. 7.806 through 7.806-3.

CONTRACT INTERRUPTIBLE SERVICE (Continued)

5. Service under this schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

6. In instances where the Customer is able to demonstrate the ability and intent to bypass the Company's distribution system and purchase Gas or another source of energy from an alternate supplier, the distribution charge shall, in the discretion of the Company, be the rate per Therm necessary to retain the Customer on the Company's distribution system, provided that such rate is demonstrated to be in the long-term best interests of both the Company and its ratepayers.

7. The rates set forth in this schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-5.

OFF-SYSTEM SERVICE
Rate Schedule OSS

Availability:

Throughout the service areas of Company, and of any interstate or intrastate natural gas pipeline serving the Company (collectively, the "Pipelines").

Applicability:

Interruptible Gas delivered by Company through the facilities of a Pipeline, using Company's transportation capacity rights on such Pipeline, to any person not connected to Company's distribution system.

This ~~t~~Tariff is applicable to both bundled and unbundled gas service, i.e. interstate or intrastate Pipeline capacity only that is released by Company pursuant to Transporter's FERC gas tariff as well as interstate or intrastate Pipeline capacity that is bundled with natural gas supply and subsequently delivered by the Company to the Customer.

Monthly Rate:

Customer Charge: None

Transaction Charge: $100.00 per transaction

Distribution Charge:

For all Scheduled Quantities (as such term is defined in Special Condition 5 below), an amount not less than $.000 per Therm nor greater than 90 percent of the currently applicable firm rate, which Distribution Charge shall be established by agreement between Company and Customer prior to each transaction pursuant to this rate schedule.

The "currently applicable firm rate", as used herein, means the distribution charge prescribed in the firm rate schedule which would apply if the daily sales represented by a transaction under this rate schedule were annualized.

The Distribution Charge for service pursuant to this rate schedule shall be determined by Company based upon Company's evaluation of competitive conditions. Such conditions may include, but are not necessarily limited to: the cost of gas which is available to serve Customer; the delivered price and availability of Customer's designated alternate fuel; and the nature of Customer's operations (such as load factor, fuel efficiency, alternate fuel capacity, etc.). Company may from time to time increase or reduce the Distribution Charge as it deems necessary or appropriate to meet competition or remain competitive, but shall have no obligation to do so; provided, however, that the Distribution Charge shall at all times remain within the limits set forth above.

The bill for Therms billed at the above rates shall be increased by the cost per Therm of any Gas delivered to Customer pursuant to this rate schedule, including all variable costs incurred by Company for (or in connection with) Pipeline transportation. ~~Company's~~

OFF-SYSTEM SERVICE (Continued)

Company's Purchased Gas Adjustment Clause, Energy Conservation Cost Recovery Clause and Competitive Rate Adjustment Clause shall not apply to purchases of Gas made by Customer pursuant to this rate schedule.

Special Conditions:

1. Neither Customer nor Company shall have any obligation to the other for any specific minimum quantity of Gas or pipeline capacity on any day or during any month, and deliveries pursuant to this rate schedule shall be subject to curtailment or interruption at any time in the sole discretion of Company.

2. Amounts payable to Company pursuant to this rate schedule shall be subject to the operation of the Company's Tax and Fee Adjustment Clause set forth on Sheet No. 7.101-4.

3. Disposition of Net Revenues and Transaction Charges. For purposes of this paragraph 3, "net revenues" shall mean the total Distribution Charges received by Company for service pursuant to this rate schedule. Twenty-five percent (25%) of all net revenues shall be retained by Company above the line as regulated revenues, and the remaining seventy-five percent (75%) of such net revenues (and all Transaction Charges) shall be used to reduce Company's cost of Gas recovered through the Purchased Gas Adjustment Clause.

4. Interruption and Curtailment. Company may notify Customer at any time to reduce or cease using Gas. Company will endeavor to give as much notice as possible to Customer.

   Any gas taken in excess of the volume allocated to the Customer in an interruption or curtailment order shall be considered unauthorized overrun gas. Company may bill and Customer shall pay for such unauthorized overrun gas at the greater of (i) five (5) times the highest Gas Daily mid-point price for gas delivered to a Gulf Coast pipeline plus FGT's FTS-3 reservation, usage, fuel and applicable surcharges or (ii) five (5) times the Gas Daily FGT Florida City gate price for gas for the calendar day on which such unauthorized overrun gas was taken.

5. For each day on which Customer desires to receive service pursuant to this rate schedule, Customer shall provide a nomination to Company specifying the quantity of Gas it desires to receive at the specified point of delivery pursuant to this Agreement. Following receipt of a timely and complete nomination from Customer, Company will confirm the quantities of Gas to be made available for delivery to Customer at such point of delivery. Quantities confirmed by PGS for delivery shall be "Scheduled Quantities".

6. The point of delivery for all Gas sold pursuant to this rate schedule shall be the delivery point of the delivering Pipeline specified by Customer.

7. Except as modified by the provisions set forth above, service under this rate schedule shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

NATURAL CHOICE TRANSPORTATION SERVICE (Continued)

2. For purposes of this Rider, "Pool Manager" means a person or entity which has:

   a. Entered into agreements to sell Gas to, or procure Gas for, the Customer accounts comprising an NCTS Customer Pool;

   b. Executed and delivered to Company after approval of this Rider by the Commission an unmodified Firm Delivery and Operational Balancing Agreement (in the form set forth on Sheets 8.119 through 8.119-8 of this ~~t~~Tariff) for an initial term of not less than one (1) year, obligating such person or entity to deliver Gas to Company on a firm basis for the accounts comprising an NCTS Customer Pool, resolve directly with the Company imbalances between (i) the quantities of Gas delivered to Company for the accounts in the NCTS Customer Pool and (ii) the quantities of Gas taken by such NCTS Customer Pool, and establish and maintain credit pursuant to the terms of such agreements; and

   c. Executed and delivered to Company after approval of this Rider by the Commission an unmodified Master Capacity Release Agreement providing for such person's or entity's acquisition from Company of primary firm interstate pipeline transportation capacity, at a reservation charge equivalent to the Load Factor Adjusted Release Rate, to be used for the transportation and delivery to Company of Gas purchased by an NCTS Customer Pool receiving service pursuant to this Rider. The Load Factor Adjusted Release Rate may be varied as determined by Company from time to time for purposes of recovering from Customer Pools receiving service under this Rider Company's cost of the capacity acquired by Pool Manager plus an appropriate allocation of Company's costs of upstream pipeline capacity held by the company for peaking and future growth. Additional revenue derived by the Company from the Load Factor Adjusted Release Rate will be used to reduce costs recovered through the Purchased Gas Adjustment Clause.

Subject to the provisions of Special Condition 3, additional Customer accounts may be added to an NCTS Customer Pool administered by a Pool Manager at any time. A Pool Manager may be disqualified by Company from providing service hereunder in accordance with the Firm Delivery and Operational Balancing Agreement.

NATURAL CHOICE TRANSPORTATION SERVICE (Continued)

3. To initiate service pursuant to this Rider, a Customer shall select a Pool Manager from Company's approved Pool Manager list and Pool Manager shall enroll customer electronically via company's website for service under this Rider. The Pool Manager shall obtain a letter of authorization in the form set forth on Sheet 8.118 of this ~~t~~Tariff and have signed by the Customer prior to such electronic enrollment. Pool Manager shall also pay to Company a registration fee of $10.00 for each Customer account to which service is initiated hereunder. Service by Company to a Customer account for which service hereunder has been properly requested by electronic enrollment prior to the sixteenth day of the month pursuant to this Rider will commence on the first day of the Customer's billing period of the next calendar month following receipt by the Company of the aforesaid electronic enrollment. Service under Rider will be delayed until the first day of the Customer's billing period in the second calendar month following enrollment by the Pool Manager for any Customer enrolled after the fifteenth day of the month.

4. A Customer account receiving service under this Rider may terminate service hereunder by its then serving Pool Manager and commence service hereunder (within the time and in the manner provided in Special Condition 3) by a different Pool Manager. The new Pool Manager shall pay to Company a registration fee of $10.00 for each account.

5. If a Pool Manager requests the Company provide the twelve-month consumption history for a Customer account, the Company shall provide to the Pool Manager the history and apply an administrative fee charge equal to $20 per customer account to Pool Manager's monthly invoice.

6. A Customer receiving service under this Rider may discontinue service hereunder by giving Company 30 days written notice. A Customer who elects to terminate transportation service under this Rider in order to return to sales service will be required to remain on sales service for a period not less than twelve successive billing periods. A Customer who returns to sales service due to abandonment by its Pool Manager will not be required to remain on sales service but cannot return to the same Pool Manager, or any affiliated company, for at least twelve successive billing periods.

7. For purposes of curtailment or interruption by Company, each individually billed account receiving service hereunder shall be treated by the Company in accordance with the curtailment provisions found in the applicable rate schedule or Company's c~~C~~urtailment p~~P~~lan ~~as filed with the Florida Public Service Commission~~.

8. Accounts receiving service pursuant to this Rider will be subject to the Swing Service Charge (set forth on Sheet No. 7.101-3).

NATURAL CHOICE TRANSPORTATION SERVICE (Continued)

9. Except as modified by the provisions set forth above, service under this Rider shall be subject to the Rules and Regulations set forth in this ~~t~~Tariff.

10. If a Customer receiving service pursuant to this Rider has annual consumption greater than or equal to 500,000 therms annually, then the Company will install and maintain facilities for remote monitoring of the Customer's hourly gas flow. The Customer will reimburse the Company for the expense incurred for the investment in and installation of these facilities.

11. A Pool Manager may terminate Gas supply to a Customer pursuant to this Rider electronically via Company's website prior to the sixteenth day of the month as of which such termination will commence on the first day of the Customer's billing period of the next calendar month following receipt by the Company of the aforesaid electronic termination. In the event of non-payment by Customer for charges due, a Pool Manager may terminate Gas supply to a Customer by giving five business days written notice to Company prior to the first day of the month as of which such termination is to be effective. Any such notice shall be accompanied by (a) documentary evidence of the Customer' s failure to make payment for a period of at least 60 days, (b) Pool Manager' s affidavit that it has made commercially reasonable and good faith efforts to collect the amount due, and (c) a non-refundable termination fee of $59.00~~52.00~~ per account number. A Customer whose Gas supply is terminated by a Pool Manager pursuant to this special condition will automatically return to sales service provided by Company until such time as the Customer elects, subject to the conditions of this Rider, to receive service hereunder through a different Pool Manager. Additional deposit may be required from the Customer to return to sales service.

12. It is the Customer's obligation to make payments to the Company (or to an Authorized Payment Agent of the Company) of all bills rendered. Payment by a Customer to a third party (including a Third-Party Gas Supplier or Customer's Pool Manager) which has not been designated by Company as an Authorized Payment Agent will not satisfy the Customer's obligation to make payment of Company's bill for Gas Service.

INDIVIDUAL TRANSPORTATION SERVICE Rider ITS (Continued)

is otherwise unable to deliver Gas to Company; and provided further that, after receiving a Company curtailment or interruption notice, unless Company otherwise directs, Customer shall not cause or permit any of its Scheduled Quantities to be curtailed or redirected so as to reduce the quantities delivered at
the PGS Receipt Point(s). For all Gas sold by Customer pursuant to this Special Condition 3(b), Company shall pay Customer an amount per MMBtu equal to, at Customer's election:

(1) the sum of (a) either (i) if the Gas was purchased by Customer pursuant to a contract with an initial term of five (5) or more years providing for firm purchases and sales of Gas, the price at which Customer purchased such Gas, or (ii) the price for spot Gas delivered to Transporter at FGT Zone 2, as reported in the "Daily Price Survey" in *Gas Daily* for the Day in which Company purchased the Gas, and (b) Company's Weighted Average Cost of Capacity for the Month in which Company purchased the Gas plus the FGT FTS-1 usage rate (including any applicable usage surcharges), or

(2) Customer's documented delivered cost of such Gas at the PGS Receipt Point(s).

(c) Excess Gas Taken by Customer During Interruption. Any Gas taken by Customer in excess of the volume of Gas allocated to it by Company during a period of curtailment or interruption under this Special Condition 3 shall be considered to be unauthorized overrun Gas. Company has the right to bill Customer for such unauthorized overrun Gas, in addition to all other charges payable by Customer under its Gas Transportation Agreement or this ~~t~~Tariff, at a price equal to the greater of (i) five (5) times the highest Gas Daily mid-point price for gas delivered to a Gulf Coast pipeline plus FGT's FTS-3 reservation, usage, fuel and applicable surcharges or (ii) five (5) times the Gas Daily FGT Florida City gate price for gas for the calendar day on which such unauthorized overrun gas was taken. Payment of an overrun penalty shall not give Customer the right to take unauthorized overrun Gas, nor shall it preclude or limit any other remedies available to Company for Customer's failure to comply with interruption or curtailment orders issued by Company.

(d) Company agrees to give Customer as much advance notice of a curtailment or interruption of service as is reasonably practicable, which notice shall, in non-emergency circumstances, be at least four (4) hours.

4. Customer's Responsibilities. Company has no responsibility in connection with Customer's arrangements with its supplier(s). Customer shall timely provide to Company (i) good faith estimates of the daily quantities it is likely to nominate for purchase or transportation as far in advance as reasonably practicable and (ii) all information requested by Company in order to comply with Transporter's FERC Tariff and determine Scheduled Quantities. ~~Customer shall designate in writing an individual,~~

INDIVIDUAL TRANSPORTATION SERVICE Rider ITS (Continued)

Customer shall designate in writing an individual, who is duly authorized to act for Customer with respect to all operational matters arising under the Gas Transportation Agreement and accessible to Company at all times each Day during the term of the Gas Transportation Agreement, to act as Customer's "Contact Person". In performing under the Gas Transportation Agreement, Company shall be entitled to rely upon any instruction or consent given by such Contact Person with respect to operational matters arising under the Gas Transportation Agreement or under the Transporter Agreement (as defined in the Gas Transportation Agreement).

5. Warranty of Title. As between Customer and Company, Customer warrants that it will have good title to all Gas delivered to Company for the account of Customer for transportation on Company's system, that such Gas will be free and clear of all liens, encumbrances and claims whatsoever, and that it will indemnify and save Company harmless from any suit, action, debt, account, damage, cost, loss and expense arising from or out of adverse claims of any person to said Gas.

6. Deliveries of Gas. All Gas delivered under the Gas Transportation Agreement shall be delivered at rates of flow as constant as operationally feasible throughout each Day. Company has no obligation on any Day to deliver on other than a uniform hourly basis in relation to the Scheduled Quantities. The point of delivery for all Gas confirmed by Company for delivery under the Gas Transportation Agreement shall be at the outlet side of such billing meter(s) as shall be installed at the PGS Delivery Point(s). Measurement of the Gas delivered shall be in accordance with Section V of Company's Rules and Regulations.

7. Correction of Imbalances. Company intends that gas delivered to a Customer receiving service pursuant to this Rider on a daily basis will equal such Customer's consumption for that day. All Daily Imbalance Amounts arising under a Gas Transportation Agreement shall be resolved as of the end of each Month. The sum of all Daily Imbalance Amounts incurred during a Month (the "Monthly Imbalance Amount") shall be resolved in accordance with this Special Condition 7 each Month. Company will post a list of Monthly Imbalance Amounts on its Internet web site by noon on the 10th calendar day of each Month. If the 10th calendar day of the Month falls on a federal banking holiday or a weekend, then the Company will post a list of Monthly Imbalance Amounts on the next succeeding business day. Customer shall have a "Book-Out Period" (the period from the date of such posting until 5 p.m. Eastern Clock Time on the 4th business day of the Month following the Company's posting of the Monthly Imbalance Amount) within which to utilize the Book-Out provisions in paragraph (a) below; provided, however, that paragraph (a) below may not be utilized for any month by a Customer whose imbalance level under paragraph (b) or (c) below is greater than 40% for such month. Customer and Company shall utilize the provisions in paragraphs (b) and (c) below to resolve in cash all Monthly Imbalance Amounts (or any portions thereof) remaining after the close of the Book-Out Period. Company will use commercially reasonable efforts to post the list of Monthly Imbalance Amounts in accordance with the foregoing provision but, in the event of unavoidable circumstances, such posting will be made as soon as reasonably practicable.

INDIVIDUAL TRANSPORTATION SERVICE Rider ITS (Continued)

(a) Customer may, during the Book-Out Period, net Positive Monthly Imbalance Amounts (as hereinafter defined), or portions thereof, with Negative Monthly Imbalance Amounts (as hereinafter defined), or portions thereof, of other Customers, and may net Negative Monthly Imbalance Amounts, or portions thereof, with Positive Monthly Imbalance Amounts of other Customers.

Customers availing themselves of the provisions of this paragraph (a) shall submit a completed online Imbalance Trading Form via the Company's gas management system website~~Book-Out Agreement via facsimile to Company~~ before the end of the Book-Out Period. ~~Company shall have no responsibility for failure to receive any facsimile transmission. Such agreement shall not be deemed effective unless it bears the signature of an authorized representative of each Customer which is a party thereto.~~Company will provide Customer an online cash-out statement~~mail Customer an invoice or purchase statement~~ for Customer's Monthly Imbalance Amount remaining (if any) ~~after Customer's execution of a Book-Out Agreement~~ pursuant to this paragraph (a) (the "Remaining Imbalance" by the end of the 4th business day following the end of the Book-Out Period, such statement to be calculated in accordance with paragraph (b) or (c) below, as applicable.

(b) If a Remaining Imbalance is Positive (*i.e.*, Scheduled Quantities exceed Actual Takes), Company shall purchase the same from Customer (and Customer shall sell the same to Company) at a price per Therm (the "Unit Price") equal to the lowest weekly average (weeks where Friday is within the calendar Month) of the "Daily price survey" for Gas under the "Midpoint" column for "Florida Gas, zone 1", "Florida Gas zone 2" or "Florida Gas, zone 3", as reported in Platts Gas Daily, ~~of the average of weekly prices for spot Gas delivered to FGT at Mustang Island (Tivoli), Texas, Vermillion Parish, Louisiana, or St. Helena Parish Louisiana, as reported in *Natural Gas Week*,~~ for the Month in which the Monthly Imbalance Amount was incurred, multiplied by the applicable factor set forth below:

Imbalance Level	Factor
0% to 5%	1.00
Greater than 5% to 20%	0.90
Greater than 20% to 40%	0.80
Greater than 40%	0.50

The total amount due Customer pursuant to this paragraph (b) shall be the product of the Unit Price (calculated as set forth herein) and Remaining Imbalance. The Imbalance Level shall be calculated by dividing the Remaining Imbalance by the Scheduled Quantities for the Month in which the Monthly Imbalance Amount accumulated.

 Attachment 6

INDIVIDUAL TRANSPORTATION SERVICE Rider ITS (Continued)

(c) If a Remaining Imbalance is Negative (*i.e.*, Actual Takes exceed Scheduled Quantities), Company shall sell the same to Customer (and Customer shall purchase the same from Company) at a price per Therm (the "Unit Price") equal to the highest weekly average (weeks where Friday is within the calendar Month) of the "Daily price survey" for Gas under the "Midpoint" column for "Florida Gas, zone 1", "Florida Gas zone 2" or "Florida Gas, zone 3", as reported in Platts Gas Daily,~~sum of (i) the highest average of weekly prices for spot Gas delivered to FGT at Mustang Island (Tivoli), Texas, Vermillion Parish, Louisiana, or St. Helena Parish, Louisiana, as reported in *Natural Gas Week*,~~ for the Month in which the Monthly Imbalance Amount accumulated, multiplied by the applicable factor set forth below:

Imbalance Level	Factor
0% to 5%	1.00
Greater than 5% to 20%	1.10
Greater than 20% to 40%	1.20
Greater than 40%	1.50

and (ii) maximum reservation rate for FGT FTS-3 capacity plus the FGT FTS--3 usage rate (including any applicable surcharges). The total amount due Company pursuant to this paragraph (c) shall be the product of the Unit Price (calculated as set forth herein) and the Remaining Imbalance. The Imbalance Level shall be calculated by dividing the Remaining Imbalance by the Scheduled Quantities for the Month in which the Monthly Imbalance Amount accumulated.

(d) Company's statement for a Remaining Imbalance calculated pursuant to paragraph (b) above shall show a credit for the amount payable by Company to Customer pursuant to paragraph (b), such credit to be applied on Company's bill rendered to Customer pursuant to the Gas Transportation Agreement for the Month following the Month in which the amount payable by Company to Customer pursuant to paragraph (b) was incurred. All amounts not so credited by Company shall be considered delinquent.

(e) Company's statement for a Remaining Imbalance calculated pursuant to paragraph (c) above shall be paid by Customer in accordance with the Gas Transportation Agreement. All amounts not so paid by Customer shall be considered delinquent.

7A. Correction of Imbalances at PGS Receipt Points that Are Gulfstream Delivery Points. If Company is the delivery point operator at a PGS Receipt Point that is a Gulfstream delivery point, Customer shall resolve with Company any Monthly Imbalance Amount attributable to Customer in accordance with the provisions of Special Condition 7 above. In addition, Customer shall bear sole responsibility for, and all costs associated with, the resolution with Gulfstream of imbalances (except imbalances caused by the acts or omissions of Company) resulting from Customer's nominations for deliveries of Gas at any such PGS Receipt Point. If Company is not the delivery point operator at a PGS Receipt Point that is a Gulfstream delivery point, the provisions of Special Condition 7 above shall not apply to the resolution of Monthly Imbalance Amounts at such PGS Receipt Point, and Customer shall bear sole responsibility for, and all costs associated with, the resolution with Gulfstream of imbalances (except imbalances caused by the acts or omissions of Company) resulting from Customer's nominations for deliveries of Gas at any such PGS Receipt Point.

INDIVIDUAL TRANSPORTATION SERVICE Rider ITS (Continued)

(a) On an Overage Alert Day, to the extent a Customer's Actual Takes or an ITS Customer Pool's aggregated Actual Takes exceed the Customer's Scheduled Quantities or the ITS Customer Pool's aggregated Scheduled Quantities, respectively, such overages shall be recorded in an Alert Day Account specific to the particular Alert Day and shall be subject to the Alert Day Charges set forth in paragraph (c) below.

(b) On an Underage Alert Day, to the extent a Customer's Actual Takes or an ITS Customer Pool's aggregated Actual Takes are less than the Customer's Scheduled Quantities or the ITS Customer Pool's aggregated Actual Takes, respectively, such underages shall be recorded in an Alert Day Account specific to the particular Alert Day and shall be subject to the Alert Day Charges set forth in paragraph (c) below.

(c) Alert Day Charges. For each Alert Day Account established during the preceding Month, Company shall bill to Customer or ITS Agent, and Customer or ITS Agent shall pay to Company, in addition to any other amounts payable pursuant to Customer's Gas Transportation Agreement or this ~~t~~Tariff, an Alert Day Charge per MMBtu equal to the higher of (i) the highest Daily Midpoint price for Gas in any FGT Zone as published in *Gas Daily* for the Day on which the Alert Day Account was established, plus FGT's FTS-3 100% load factor rate, or (ii) FGT's City Gate Delivered price for Gas as published in *Gas Daily* for the Day on which the Alert Day Account was established.

The Overage/Underage Level for each Customer's or ITS Customer Pool's Alert Day Account shall be calculated by dividing the Customer's overage or underage (as the case may be) or the ITS Customer Pool's aggregated overage or underage (as the case may be) for such Day by the Customer's Scheduled Quantities or ITS Customer Pool's aggregated Scheduled Quantities for the Day on which the Alert Day Account was established. A Customer's or ITS Agent's failure to receive notice pursuant to this Special Condition 12 shall not excuse Customer or ITS Agent from any Alert Day Charges assessed hereunder.

If an ITS Agent fails to pay any undisputed Alert Day charges imposed by the Company on the ITS Customer Pool within sixty (60) Days after the date on which they are imposed, Company will bill each individual Customer in the ITS Customer Pool and each such Customer will be responsible for, and pay to Company, such undisputed Alert Day charges (if any) as would have been payable by such Customer for such Alert Day in the absence of the ITS Agent Agreement.

(d) Revenues derived from Alert Day Charges imposed by Company pursuant to this Special Condition 12 on any Day shall be netted against any FGT penalty charges incurred by Company for the same Day. Any remaining revenue (less Regulatory Assessment Fees attributable thereto) shall be credited to the Purchased Gas Adjustment Clause.

 Attachment 6

Peoples Gas System, Inc.
Original Volume No. 3

Tenth ~~Ninth~~ Revised Sheet No. 8.000
Cancels Ninth ~~Eighth~~ Revised Sheet No. 8.000

INDEX OF STANDARD FORMS

Issued By: Helen J. Wesley, President & CEO **Effective Date:** January 1, 2024~~January 9, 2023~~

Attachment 6

TECO PEOPLES GAS AN EMERA COMPANY

Gas Service Agreement

No.

Business Partner Name (Customer)	Phone	Cell Phone	E-mail
Service Address	City	State	Zip
Doing Business As (DBA)	City Limits (Enter Yes or No)	County Name	
Mailing Address	City	State	Zip
Contact Name	Phone	E-mail	
Federal ID / Tax Exempt (Yes or No)	Date Service Line Requested	Date Gas Service Requested	
Field Contact Name	Phone	E-mail	

SALES INSTRUCTIONS/REMARKS	SERVICE TYPE
	Main (Enter On or Off)
	New (N), Added Load (AL),
	Reactivate (RA) Manifold (MA)
	Residntl (R), Commrl (C) Industrial (I)
	Rate Class
	Map #

QTY.	APPLIANCE TYPE	PEAK HR DEMAND CF/H	ANNUAL THERMS PRESENT	ADDITIONAL	PRESSURE AT EQPT.
TOTAL					

FINANCIAL INFORMATION		OTHER SERVICES
Gas Deposit		WH Billing Prog
Turn-on Charge		Conversion Bill
Aid to Construction		Other
Construction Deposit		Other
Prepayment		Other
Balance Due		Other

DEALER INFORMATION (if applicable)	
Dealer Name	
Dealer Phone	Alt Phone
Services to be provided by Dealer	

TO BE COMPLETED BY PGS ONLY			
Meter Size	Regulator Size	BP#	CA#
System Pressure	Delivery Pressure	Premise#	Install#
Conversion Propane Company		Meter#	Project#

REMARKS

I have read all of the terms and conditions on the second page and agree to them.

Business Partner/Customer Signature | Sales Rep Signature | Sales Rep ID #

Business Partner/Customer Printed Name | Date | Sales Rep Printed Name | Date

PGS CUSTOMER SERVICE CONTACT DURING INSTALLATION OF GAS SERVICE PHONE#: **1-877-832-6747**

 Attachment 6

TECO PEOPLES GAS AN EMERA COMPANY

Gas Service Agreement

No.

Business Partner Name (Customer)	Phone	Cell Phone	E-mail
Service Address	City	State	Zip
Doing Business As (DBA)	City Limits (Enter Yes or No)	County Name	
Mailing Address	City	State	Zip
Contact Name	Phone	E-mail	
Federal ID / Tax Exempt (Yes or No)	Date Service Line Requested	Date Gas Service Requested	
Field Contact Name	Phone	E-mail	

SALES INSTRUCTIONS/REMARKS	SERVICE TYPE
	Main (Enter On or Off)
	New (N), Added Load (AL), Conversion (Co)
	Reactivate (RA) Manifold (MA)
	Residntl (R), Commrl (C) Industrial (I)
	Rate Class
	Map #

QTY.	APPLIANCE TYPE	PEAK HR DEMAND CF/H	ANNUAL THERMS PRESENT	ANNUAL THERMS ADDITIONAL	PRESSURE AT EQPT.
TOTAL					

FINANCIAL INFORMATION		OTHER SERVICES
Gas Deposit		Other
Turn-on Charge		Other
Aid to Construction (Non-Refundable)		Other
Construction Deposit		Other
Prepayment		Other
Balance Due		Other

DEALER INFORMATION (if applicable)	
Dealer Name	
Dealer Phone	Alt Phone
Services to be provided by Dealer	

TO BE COMPLETED BY PGS ONLY			
Meter Size	Regulator Size	BP#	CA#
System Pressure	Delivery Pressure	Premise#	Install#
Conversion Propane Company		Meter#	Project#

REMARKS

I have read all of the terms and conditions on the second page and agree to them.

Business Partner/Customer Signature

Sales Rep Signature

Sales Rep ID #

Business Partner/Customer Printed Name

Date

Sales Rep Printed Name

Date

PGS CUSTOMER SERVICE CONTACT DURING INSTALLATION OF GAS SERVICE PHONE #: **1-877-832-6747**

Gas Service Agreement No. Page 2

NATURAL GAS SERVICE TERMS AND CONDITIONS:

The applicant named on the first page hereof ("Customer") makes application to Peoples Gas System, Inc. ("Company") for natural gas service under the rate classification indicated on the first page hereof according to the following terms and conditions in consideration of the Company's agreement to deliver natural gas to Customer pursuant to the applicable provisions of Company's ~~t~~Tariff approved by the Florida Public Service Commission. In the event of a conflict between this application and the Tariff, the Tariff shall control.

Gas is to be delivered to Customer at the outlet side of the Company's gas meter serving the premises indicated on the first page hereof, such meter and service line there to be installed and operated by the Company, and, if located on Customer's property, the site therefor to be furnished free of charge by Customer.

The Company and its representatives are hereby authorized to enter upon and install on Customer's property any required gas meter or meters and gas pipe for furnishing gas to said address, and to ditch, lay, or otherwise install pipe as is required outside the building(s). The gas pipe from the Company's gas system to and including said meter or meters shall be owned, operated, and maintained by the Company with a perpetual right of ingress and egress thereto, hereby granted to the Company for such purposes. Installation of Company's facilities may require that Company be granted an easement. All gas pipe, from the outlet side of said meter or meters, shall be owned, operated, and maintained by Customer at its sole cost and risk.

Customer shall receive and pay for all gas delivered to Customer according to the applicable provisions of Company's Tariff and the applicable rules and regulations of the Florida Public Service Commission. Any gas delivered to Customer at any other delivery point is also subject to the terms and conditions hereof. No oral statement shall change ~~the~~any term ~~of this~~ or obligation set forth herein.
A customer receiving gas service under the residential or commercial standby generator ~~t~~Tariff rate shall be obligated to remain on that schedule for a minimum of 12 months. This 12-month requirement shall be renewed at the end of each 12-month period unless Customer terminates gas service at the end of any 12-month period.

If Customer fails or refuses to take gas service from the Company, Customer shall pay to the Company the actual cost incurred by the Company in constructing the facilities to have been used in providing service to the Customer. Any deposits currently held by the Company shall be forfeited by Customer in payment or partial payment of these costs.

UNDERGROUND FACILITIES:

Prior to construction of gas pipeline, it is extremely important that the Company be made aware of existing underground obstacles, sprinkler systems, septic tanks, sewer lines, or structures, etc., located on Customer's property which may be damaged as a result of installation of the gas pipeline. Customer shall be responsible for marking and/or locating any underground facilities that may be on Customer's property that do not belong to local utilities (Power, Telephone, Water, Cable TV companies, etc.), and agrees to indemnify and hold Company harmless for any damages arising out of Customer's failure to do so.

GENERAL TERMS AND CONDITIONS APPLICABLE TO NATURAL GAS SERVICE:

This agreement is not assignable or transferable by Customer without prior written consent by the Company.

IN NO EVENT SHALL THE COMPANY OR ITS AFFILIATED COMPANIES, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS OR REPRESENTATIVES BE LIABLE FOR ANY INCIDENTAL, INDIRECT, SPECIAL, CONSEQUENTIAL, EXEMPLARY OR PUNITIVE DAMAGES, INCLUDING, BUT NOT LIMITED TO, LOSS OF USE OF ANY PROPERTY OR EQUIPMENT, LOSS OF PROFITS OR INCOME, LOSS OF PRODUCTION, RENTAL EXPENSES FOR REPLACEMENT PROPERTY OR EQUIPMENT, DIMINUTION IN VALUE OF REAL PROPERTY, EXPENSES TO RESTORE OPERATIONS, OR LOSS OF GOODS OR PRODUCTIONS, EVEN IF THE COMPANY HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

Customer understands and acknowledges that the dealer (if any) identified on the first page of this document ("Dealer") is not affiliated in any way with the Company and has not been engaged by the Company as a contractor or subcontractor. The Company assumes no responsibility whatsoever for any acts or omissions of, or any services or goods provided by, such Dealer.

This agreement may not be amended or modified except by an instrument in writing signed by the Company and Customer.

This agreement shall be governed by the laws of the State of Florida without regard to principles of conflicts of laws.

This agreement contains the entire understanding between the parties hereto and supersedes any written or oral, prior or contemporaneous agreement or understanding between the parties.

NOTE: I acknowledge installation of the ~~required~~ gas line will not be scheduled until the required easement, if needed, is signed by the landowner and received by Peoples Gas System, Inc. ___________ (customer initials)

____
Customer – Authorized Signature

____
Name

____
Title

 Attachment 6

~~Form #349 Rev. 01/2004~~

CONSTRUCTION DEPOSIT AGREEMENT

This CONSTRUCTION DEPOSIT AGREEMENT (the "Agreement"), dated as of _________, 20___, is entered into between PEOPLES GAS SYSTEM, INC., a Florida corporation (hereinafter called "COMPANY"), and ___________________________________(hereinafter called "APPLICANT") of ________________________ County, Florida. Company and Applicant, in consideration of the premises and of other valuable consideration, hereby agree as follows:

(1) That Company will extend its gas main and/or service as follows:

a total distance of ________ feet (hereinafter referred to as the "EXTENSION"). The route of said Extension is shown as Exhibit "A" hereto attached and hereby made a part hereof.

(2) Without any right to refund, except solely as provided in paragraphs (3) and (4) hereof, Applicant will pay to Company $___________________ in advance of actual construction [said amount being the cost of the Extension, less the Maximum Allowable Construction Cost ("MACC") thereof (determined in accordance with Company's ~~t~~Tariff on file with the Florida Public Service Commission), and less an allowance to Applicant of $______________ for ___________ bona fide customer(s) to be connected to said Extension].

(3) At the end of the first year following the date on which gas service to Applicant is initiated by Company, at the Applicant's request the Company shall recalculate the MACC. A re-estimation of the annual revenue (considering the actual revenue derived during the first year) shall be used in such recalculation. If the MACC so re-calculated exceeds the MACC used to determine the amount paid by Applicant to Company pursuant to paragraph (2) hereof, Company shall refund to Applicant an amount equal to such excess.

(4) For each additional customer connected at any point on said Extension within a period of four years after the date of completion of said Extension, Company further agrees to refund to Applicant an amount by which the MACC for such additional customer exceeds the cost of connecting such customer, provided that an additional extension shall not have been necessary to serve such additional customer.

(5) The aggregate refund to Applicant made through the provisions of the foregoing paragraphs (3) and (4) shall at no time exceed the original deposit of Applicant.

(6) The Extension shall at all time be the property of Company. Any unrefunded portion of Applicant's deposit hereunder, at the end of four (4) years from the date of completion of the Extension covered by this Agreement, shall become the property of the Company.

Applicant acknowledges having read and understood the General Terms and Conditions on the reverse side hereof and agrees to said terms and conditions, which are made a part hereof.

~~DATED AND EXECUTED at _________________, Florida, this __________ day of _____________, 20____.~~

APPLICANT ________________________________

By: _______________________________________

Title: _______________________________________

~~COMPLETION~~ DATE: ________________________

G.S.A. NO. __________________________________

Business Partner NO___________________________

Installation NO________________________________

PEOPLES GAS SYSTEM, INC.
By:____

Title: ______________________________________

~~(Front Side)~~

~~(Back Side)~~

GENERAL TERMS AND CONDITIONS

I. It is agreed that no refund or repayment will be made for any customer not connected directly to the Extension covered by this Agreement, and after the expiration of the periods of time provided in paragraphs (3) and (4) no further refunds or repayments shall be made by Company to Applicant.

II. The Company's obligation to construct the Extension provided for herein will be carried out promptly, subject to an adequate supply of gas to serve the customer(s) to be connected to the Extension, and subject to applicable laws, rules and regulations of governmental authorities and to any delay occasioned by Force Majeure or events or conditions of whatsoever nature reasonably beyond the Company's control.

III. In the event the cost of construction contemplated herein is increased or decreased significantly, for any reason, prior to commencement of such construction, the amount of deposit provided for herein shall be increased or decreased by mutual agreement of Company and Applicant, with such agreement to be memorialized in a separate writing, or this Agreement may be canceled by either party if no such agreement is reached.

IV. Applicant understands that Company shall not be obligated or required to construct the Extension contemplated by this Agreement in advance of and prior to the construction of Extensions covered by contracts and authorizations which were entered into by Company prior to the date of this Agreement, or Extensions required to be constructed by the provision of Company's franchise or construction required to maintain existing service.

V. Title to said Extension, including its pipes and appurtenances, connections thereto and extensions thereof, including the right to use, operate and maintain same, shall forever be and remain exclusively and unconditionally vested in Company, its successors and assigns.

PGS Rev 8/02

NOTICE AND AFFIDAVIT[1]

TO: _________________ (Title)
Peoples Gas System, Inc.
P. O. Box 2562
Tampa, Florida 33601-2562

Please take notice that the undersigned Pool Manager will cease supplying gas to the following Customer of Peoples Gas System, Inc. ("Peoples") under Peoples' NaturalChoice Transportation Service Program for such Customer's non-payment of charges due Pool Manager, the termination of gas supply to be effective with respect to the locations listed below on and after___________:[2]
(Date)

______________________________(name of customer)
______________________________(billing address)
______________________________(city, state, zip code)
______________________________(telephone)

Customer locations to which service will be terminated. Include the contract number and account number:

(list all)

In accordance with the requirements of Peoples' Rider NCTS, the undersigned Pool Manager also submits the following affidavit:

STATE OF _______________

COUNTY OF ______________

BEFORE ME, the undersigned authority, this day personally appeared__________________________, who is personally known to me and who, after taking an oath, states as follows: (Name of person signing affidavit)

I am over 18 years of age and of sound mind and the matters set forth herein are personally known to me.

1. I am employed by _______________________________ ("Pool Manager") as _____________.
(Name of Pool Manager) (Title / Position)
2. Pool Manager has made good faith and commercially reasonable efforts to collect amounts due from the above named Customer to Pool Manager, but such Customer has failed to make the payments due Pool Manager for a period of at least sixty (60) days as reflected by the documents/records attached to this Notice and Affidavit. Such documents/records are true and correct.
3. Final notice of Pool Manager's intent to cease supplying gas to the above Customer has been sent to Customer, and a copy of such final notice is attached to this Notice and Affidavit.

FURTHER AFFIANT SAYETH NOT.

____
Name:
Title/Position:

Sworn to and subscribed before
me this ______ day of ____________, ____.

_____________________________ [SEAL]
Notary Public - State of ___________

My commission expires:______________

[1] A non-refundable termination fee in the amount of $59.00~~52.00~~ per account number must accompany this Notice and Affidavit.

[2] This date must be at least five (5) business days after the date on which this Notice and Affidavit is furnished to Peoples Gas System, Inc.

 Attachment 6

ALTERNATE FUEL PRICE CERTIFICATION

TO: PEOPLES GAS SYSTEM, INC.
702 Franklin St
P. O. Box 2562
Tampa, Florida 33601-2562

Attention:

____ has received a firm offer from ____ for our purchase of up to __________________________ gallons/barrels of __________________________ for use by us at our facility located at ______________________, Florida, delivery to commence on ______________________________, at a price of $_________ per gallon/barrel. Copy of the offer, which will expire __________________, is attached hereto.

Taxes payable by us should we purchase the referenced fuel pursuant to the attached offer, would be $_________________ per gallon/barrel. Transportation costs for delivery of the fuel to our facility at ______________ from _____________________ would be $__________ per gallon/barrel.

I hereby certify on behalf of ____________________________________ that the foregoing information is true, complete and correct, and that __________________ has the facilities to utilize the fuel specified above in the amount specified above at its ____ facility. I hereby further certify that we will notify Peoples Gas System, Inc. ~~on the first day of each~~ at the end of each contract year~~monththereafter~~ of the price at which we are able to purchase the alternate fuel referred to above, and will further notify Peoples at any time there is a change in the information contained herein.

I hereby certify that _______________________________ will cease taking gas from Peoples Gas System, Inc. on ______________________________ unless such gas is priced at less than the applicable interruptible rate per therm as provided in Peoples' Rate Schedule CIS.

____
(Customer Name)

By: ____
(Signature of Corporate Officer)

____
(Title)

STATE OF ____________________
COUNTY OF ____________________

SWORN TO AND SUBSCRIBED before me this ________ day of _______________, 20__.

My commission expires:

______________________________ ___________________________________
Notary Public

ACCEPTANCE

Based upon the foregoing information, and in accordance with Rate Schedule CIS, the distribution charge for gas taken by ____________________________ on and after__________________ shall be $_________ per therm. This acceptance may be revoked or modified by Peoples Gas System, Inc., in its sole discretion, at any time.

PEOPLES GAS SYSTEM, INC.

By: ___________________________________

____
(Title)

GAS TRANSPORTATION AGREEMENT

This Gas Transportation Agreement (the "Agreement") is made and entered into as of the _____ day of _________, 20__, by and between Peoples Gas System, Inc., a Florida corporation ("PGS"), and _________________, a __________________ ("Shipper"), who hereby agree as follows:

ARTICLE I - DEFINITIONS

As used herein, the following terms shall have the meanings set forth below. Capitalized terms used herein, but not defined below, have the meanings given for such terms in PGS's FPSC Tariff.

"Actual Takes" means, for a specified period of time, the quantity of Gas passing through the meter(s) of the Customer Accounts during such specified period of time.

"Business Day" means the Days Monday through Friday (excluding any federal banking holiday falling on any such Day).

"Day" means the period of 24 consecutive hours beginning and ending at 9:00 a.m. Central Clock Time.

"Facility" means Shipper's ______________ facility located in _______, Florida.

"FPSC" means the Florida Public Service Commission or any successor agency.

"Maximum Delivery Quantity" or "MDQ" means the maximum amount of Gas that PGS is obligated to cause to be delivered for Shipper's account pursuant to this Agreement on any Day at the PGS Delivery Point(s), and is stated in Appendix B.

"Maximum Transportation Quantity" or "MTQ" means the maximum amount of Gas that PGS shall be obligated to receive pursuant to this Agreement on any Day at the PGS Receipt Point(s), and is stated in Appendix A.

"Nomination" means a notice delivered by Shipper to PGS in the form specified in PGS's FPSC Tariff, specifying (in MMBtu) the quantity of Gas Shipper desires to purchase, or to have PGS receive, transport and deliver, at the PGS Delivery Point(s).

"Nominate" means to deliver a completed Nomination.

"PGS Delivery Point(s)" means the point(s) listed in Appendix B.

"PGS Receipt Point(s)" means the point(s) of physical interconnection between Transporter and PGS, or between Shipper and PGS listed in Appendix A.

"Retainage" means 0.35% of Gas received by Company for the account of Customer at the PGS Receipt Point(s), which Company shall retain at no cost to Company to cover lost or unaccounted for gas between the PGS Receipt Point(s) and the PGS Delivery Point(s).

~~"Supplier(s)" means person(s) (other than PGS) from which Shipper purchases Gas transported hereunder.~~

~~ARTICLE II - TERM~~

~~This Agreement is effective on the date first written above. The term shall commence at the beginning of the Day commencing on ______________ and continue until the beginning of the Day~~

Attachment 6

~~commencing on ____________ (the"Termination Date") (the "Initial Term"). [PROVISIONS AGREEABLE TO PGS AND SHIPPER WITH RESPECT TO ANY EXTENDED OR "SECONDARY" TERM]~~

"Supplier(s)" means person(s) (other than PGS) from which Shipper purchases Gas transported hereunder.

"Transporter" means any upstream intrastate or interstate transport service provider.

ARTICLE II - TERM

This Agreement is effective on the date first written above. The term shall commence at the beginning of the Day commencing on ______________ and continue until the beginning of the Day commencing on ____________ (the "Termination Date") (the "Initial Term"). [PROVISIONS AGREEABLE TO PGS AND SHIPPER WITH RESPECT TO ANY EXTENDED OR "SECONDARY" TERM]

ARTICLE III - SALES AND TRANSPORTATION SERVICE

Section 3.1 Services. PGS desires to sell and Shipper desires to purchase from PGS, from time to time, for use in the Facility (but not for resale), Gas in quantities which, at Shipper's request, PGS may, in its sole discretion exercised in a not unduly discriminatory manner, agree to sell to Shipper. Shipper also engages PGS, and PGS accepts such engagement, to receive Gas for Shipper's account, up to the MTQ, at the PGS Receipt Point(s), and to cause an equivalent quantity, less the Retainage, to be redelivered to Shipper. Such sales and transportation shall be governed by PGS's FPSC Tariff and this Agreement. If there is a conflict between the ~~t~~Tariff and this Agreement, the ~~t~~Tariff shall control. Sales and transportation hereunder are interruptible in accordance with PGS's FPSC Tariff and curtailment plan~~ on file with the FPSC~~. If Shipper's service is interruptible, Shipper may select one or more of the options described in Appendix D, which may enable Shipper to continue receiving delivery of Gas during periods of curtailment or interruption. PGS shall have no obligation to make sales to Shipper in lieu of the transportation of Gas contemplated by this Agreement.

Section 3.2 Telemetry and Other Required Equipment. Telemetry and other equipment which PGS must install to provide service hereunder (the "Equipment"), if any, and the anticipated cost thereof, are listed in Appendix C. Shipper shall reimburse PGS for all costs incurred for the Equipment on receipt of PGS's invoice therefor. Unless the parties agree otherwise, all facilities used to provide service to Shipper hereunder (including without limitation the Equipment) shall be installed, owned, operated and maintained by PGS.

ARTICLE IV - NOMINATIONS

Section 4.1 General. For each Day Shipper desires service hereunder, Shipper shall provide a Nomination to PGS pursuant to Sections 4.2 and/or 4.3 for each meter at the Facility. The total quantity for the Facility may be Nominated to a single meter, with "zero" Nominations being made for any additional meters located at the Facility. All Nominations shall be made to PGS at its web site (https://custactivitiespeoplesgas.com~~www.pgsunom.com)~~ provided that, in an emergency, a Nomination may be delivered via facsimile using the form set forth in PGS's FPSC Tariff. Quantities confirmed by PGS for delivery shall be Scheduled Quantities. If requested by Shipper, PGS will allow increases or decreases in Scheduled Quantities after the Nomination deadlines set forth in this article, if the same can be confirmed by PGS, Transporters and Suppliers, and can be accomplished without detriment to services then scheduled on such Day for PGS and other shippers. The maximum quantity PGS shall be obligated to make available for delivery to Shipper on any Day (which shall not exceed the MDQ) is the sum of (a) the Transportation Quantity and (b) the Sales Quantity established pursuant to this article.

~~**Section 4.2 Nomination for Purchase.** Unless otherwise agreed, Shipper shall Nominate Gas for purchase hereunder not less than seven (7) Business Days prior to the first Day of any Month in which Shipper desires to purchase Gas. Daily notices shall be given to PGS at least two (2) Business Days (but not less than forty-eight (48) hours) prior to the commencement of the Day on which Shipper desires delivery of the Gas. If Shipper has timely Nominated a quantity for a particular Month, PGS shall confirm to Shipper the quantity PGS will tender for purchase by Shipper (the "Sales Quantity,"~~

~~which shall also be a "Scheduled Quantity") no later than 5:00 p.m. Eastern Time on the Business Day immediately preceding each Day during such Month.~~

~~**Section 4.3 Nomination for Transportation.** Unless otherwise agreed, Shipper shall, for each Month, and each Day during such Month that Shipper seeks to change any aspect of any prior Nomination, notify PGS by providing a completed Nomination. Shipper's Nomination for Gas to be~~

Section 4.2 Nomination for Purchase. Unless otherwise agreed, Shipper shall Nominate Gas for purchase hereunder not less than seven (7) Business Days prior to the first Day of any Month in which Shipper desires to purchase Gas. Daily notices shall be given to PGS at least two (2) Business Days (but not less than forty-eight (48) hours) prior to the commencement of the Day on which Shipper desires delivery of the Gas. If Shipper has timely Nominated a quantity for a particular Month, PGS shall confirm to Shipper the quantity PGS will tender for purchase by Shipper (the "Sales Quantity," which shall also be a "Scheduled Quantity") no later than 5:00 p.m. Eastern Time on the Business Day immediately preceding each Day during such Month.

Section 4.3 Nomination for Transportation. Unless otherwise agreed, Shipper shall, for each Month, and each Day during such Month that Shipper seeks to change any aspect of any prior Nomination, notify PGS by providing a completed Nomination. Shipper's Nomination for Gas to be made available for delivery on the first Day of any Month shall be given by 10 a.m. on the second Business Day prior to the Day on which a nomination must be delivered to Transporter for receipt of deliveries at the PGS Receipt Point(s) on such Day. Daily Nominations for Gas to be made available for delivery other than on the first Day of a Month shall be given to PGS by 10 a.m. on the Business Day prior to the Day on which a nomination must be delivered to Transporter for the receipt of deliveries at the PGS Receipt Point(s) on such Day. The following nomination information is required for a valid nomination:

a. The Shipper's account number under which service is being nominated;
b. The receipt point location including applicable DRN and upstream pipeline name, upstream pipeline package ID, including Shipper's PGS account number, and quantity in Therms of Gas to be tendered at each PGS receipt point;
c. The downstream delivery facility name, and quantity in Therms of Gas to be delivered for each PGS Shipper account;
d. A beginning and ending date for each nomination;
e. The upstream contract identifier;

Only nominations with clearly matching upstream Transporter identifiers (including Shipper's package ID and PGS account number) and downstream (PGS) identifiers will be scheduled. If Shipper or Shipper's Agent fails to comply with provisions (a) through (e) of this section, PGS may not schedule commencement of service or change a prior nomination.

Shipper understands that PGS is subject to FERC regulations that may require PGS to post certain Shipper information on a publicly accessible website. The submission by Shipper or Shipper's Agent of a required nomination shall constitute Shipper's authorization to PGS to publicly disclose any information (including but not limited to the information provided in such nomination) required by applicable law or regulation to be disclosed by PGS.

PGS shall confirm to Shipper the quantity PGS will make available for redelivery on such Day (the "Transportation Quantity," which shall also be a "Scheduled Quantity") no later than 5:00 p.m. Eastern Time on the Business Day immediately preceding such Day. PGS has no obligation to confirm a quantity Nominated by Shipper pursuant to this section greater than the quantity which, in PGS's reasonable judgment, equals the Facility's likely consumption for a Day plus Retainage, less any Sales Quantities confirmed for delivery on such Day.

~~**Section 4.4 Other Responsibilities.** Shipper shall promptly notify PGS in writing of any change in the Sales Quantity or Transportation Quantity for any Day, and PGS will use commercially reasonable efforts to accept any such requested change as soon as practicable.~~

~~**Section 4.5 Confirmation.** If Transporter asks PGS to verify a nomination for Shipper's account, PGS shall confirm the lesser of such nomination, the Transportation Quantity or, in the case of non- or partial operation of the Facility, that quantity which in PGS's reasonable judgment (after consultation with~~

~~Shipper) is likely to be consumed at the Facility. PGS has no obligation with respect to verification or rejection of quantities not requested by Shipper.~~

Section 4.4 Other Responsibilities. Shipper shall promptly notify PGS in writing of any change in the Sales Quantity or Transportation Quantity for any Day, and PGS will use commercially reasonable efforts to accept any such requested change as soon as practicable.

Section 4.5 Confirmation. If Transporter asks PGS to verify a nomination for Shipper's account, PGS shall confirm the lesser of such nomination, the Transportation Quantity or, in the case of non- or partial operation of the Facility, that quantity which in PGS's reasonable judgment (after consultation with Shipper) is likely to be consumed at the Facility. PGS has no obligation with respect to verification or rejection of quantities not requested by Shipper.

Section 4.6 Mutually Beneficial Transactions. Shipper recognizes that PGS maintains the operation and system integrity of the PGS distribution system on a daily basis, and that PGS, as the delivery point operator for its points of interconnection with interstate pipelines, is subject to the rules and regulations of such pipelines with regard to operational flow rates, pressures and penalties. As such, PGS may from time to time need Shipper to vary its Nominated quantities of Gas to be delivered at the PGS Receipt Point(s). On such occasions, PGS may in its sole discretion request, and Shipper may agree to, a change in the quantity of Gas to be delivered for the account of Shipper at the PGS Receipt Point(s). No such change in the quantity of Gas to be delivered shall be made pursuant to this section without the consent of Shipper. Terms and conditions of any such transaction will be agreed upon between the parties at the time of the transaction and will be recorded and confirmed in writing within two Business Days of the transaction.

ARTICLE V - TRANSPORTATION AND OTHER CHARGES

Section 5.1 Transportation Charges; Purchase Price. Shipper shall pay PGS each Month for transportation service rendered by PGS, and, if applicable, ~~/or~~ for Gas purchased from PGS, in accordance with the then-applicable rate schedule in PGS's FPSC Tariff. At the time of this Agreement, ~~Currently,~~ Rate Schedule ___ is applicable. In the event Rate Schedule CIS or a fixed rate schedule is applicable, this Agreement will automatically renew following the Initial Term at the then applicable rate schedule, unless Shipper and PGS have agreed at least 30 days prior to the expiration of the then current term that Rate Schedule CIS or another rate schedule shall apply.

Section 5.2 Changes in Tariff. If the applicable rates or rate schedules change or are amended or superseded, the newly applicable rates or rate schedules shall be applicable to service hereunder. Nothing contained herein shall prevent PGS from filing with the FPSC (or Shipper from opposing) changes to the rates and other provisions in PGS's FPSC Tariff. PGS agrees to give Shipper reasonable notice of (a) all filings (except filings in FPSC Docket No. 000003-GU, In Re: Purchased Gas Adjustment (PGA) True-Up, and successor dockets) which PGS makes with the FPSC and (b) all other FPSC proceedings of which PGS becomes aware, which PGS (in the exercise of reasonable judgment) determines would affect PGS's rates or the services to be performed by PGS under this Agreement.

ARTICLE VI - BILLING AND PAYMENT

Section 6.1 Billing. PGS will bill Shipper each Month for all Actual Takes during the preceding Month, and for any other amounts due hereunder. If, during the preceding Month, PGS has purchased Gas from Shipper pursuant to an interruption or curtailment order, such bill shall show a credit for the estimated amount due Shipper for such purchase(s). If the estimated amount owed by PGS to Shipper exceeds the amount Shipper owes PGS, PGS shall pay Shipper the net amount estimated to be due Shipper at the time PGS bills Shipper.

~~**Section 6.2 Payment.** Shipper shall pay such bills, minus any disputed amounts, at the address specified in the invoice by the 20th Day following the date of PGS's mailing (as signified by the postmark) or other delivery of the bill. All sums not so paid by Shipper (or credited or paid by PGS) shall be considered delinquent.~~

~~**Section 6.3 Billing Disputes.** In the event of a bona fide billing dispute, Shipper or PGS, as the case may be, shall pay (or credit) to the other party all amounts not in dispute, and the parties shall negotiate in good faith to resolve the amount in dispute as soon as reasonably practicable. If a party has withheld payment (or credit) of a disputed amount, and the dispute is resolved, the non-prevailing party shall pay to the other party the amount determined to be due such other party, plus interest thereon at an annual rate equal to the prime interest rate of Citibank, N.A., New York, New York, plus one percent (1%), calculated on a daily basis from the date due until paid (or credited).~~

Section 6.2 Payment. Shipper shall pay such bills, minus any disputed amounts, at the address specified in the invoice by the 20th Day following the date of PGS's mailing (as signified by the postmark) or other delivery of the bill. All sums not so paid by Shipper (or credited or paid by PGS) shall be considered delinquent.

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Section 6.4 Errors or Estimates. If an estimate is used to determine the amount due Shipper for purchases by PGS pursuant to an interruption or curtailment order, PGS shall make any adjustment necessary to reflect the actual amount due Shipper on account of such purchases in the next bill rendered to Shipper after determination of the actual amount due. An error in any bill, credit or payment shall be corrected in the next bill rendered after the error is confirmed by PGS.

ARTICLE VII - FAILURE TO MAKE PAYMENT

Section 7.1 Late Payment Charge. Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of 1.5%, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted by applicable law.

Section 7.2 Other Remedies. If Shipper fails to remedy a delinquency in any payment within five (5) Days after written notice thereof by PGS, PGS, in addition to any other remedy may, without incurring any liability to Shipper and without terminating this Agreement, suspend further deliveries to Shipper until the delinquent amount is paid, but PGS shall not do so if the failure to pay is the result of a bona fide billing dispute, and all undisputed amounts have been paid. If PGS fails to remedy a delinquency in providing a credit (or making payment) to Shipper for PGS purchases pursuant to an interruption or curtailment order within five (5) Days after Shipper's written notice thereof, Shipper, in addition to any other remedy, may, without incurring liability to PGS and without terminating this Agreement, suspend PGS's right to retain and purchase Shipper's Gas pursuant to an interruption or curtailment order, but Shipper shall not do so if PGS's failure to provide a credit (or make payment) is the result of a bona fide billing dispute, and all undisputed amounts have been credited or paid by PGS.

ARTICLE VIII - MISCELLANEOUS

Section 8.1 Assignment and Transfer. Neither party may assign this Agreement without the prior written consent of the other party (which shall not be unreasonably withheld) and the assignee's written assumption of the assigning party's obligations hereunder. [SUCH EXCEPTIONS TO THE FOREGOING AS TO WHICH THE PARTIES MAY AGREE]

~~**Section 8.2 Governing Law.** This Agreement and any dispute arising hereunder shall be governed by and interpreted in accordance with the laws of Florida and shall be subject to all applicable laws, rules and orders of any Federal, state or local governmental authority having jurisdiction over the parties, their facilities or the transactions contemplated. Venue for any action, at law or in equity, commenced by either party against the other and arising out of or in connection with this Agreement shall be in a court, located within the State of Florida, having jurisdiction.~~

~~**Section 8.3 Severability.** If any provision hereof becomes or is declared by a court of competent jurisdiction to be illegal, unenforceable or void, this Agreement shall continue in full force and effect without said provision.~~

Section 8.2 Governing Law. This Agreement and any dispute arising hereunder shall be governed by and interpreted in accordance with the laws of Florida and shall be subject to all applicable laws, rules and orders of any Federal, state or local governmental authority having jurisdiction over the parties, their facilities or the transactions contemplated. Venue for any action, at law or in equity, commenced by either party against the other and arising out of or in connection with this Agreement shall be in a court, located within the State of Florida, having jurisdiction.

Section 8.3 Severability. If any provision hereof becomes or is declared by a court of competent jurisdiction to be illegal, unenforceable or void, this Agreement shall continue in full force and effect without said provision.

Section 8.4 Entire Agreement; Appendices. This Agreement sets forth the complete understanding of the parties as of the date first written above, and supersedes any and all prior negotiations, agreements and understandings with respect to the subject matter hereof. The appendices attached hereto are an integral part hereof. All capitalized terms used and not otherwise defined in the appendices shall have the meanings given to such terms herein.

Section 8.5 Waiver. No waiver of any of the provisions hereof shall be deemed to be a waiver of any other provision whether similar or not. No waiver shall constitute a continuing waiver. No waiver shall be binding on a party unless executed in writing by that party.

Section 8.6 Notices. (a) All notices and other communications hereunder shall be in writing and be deemed duly given on the date of delivery if delivered personally or by a recognized overnight delivery service or on the fifth day after mailing if mailed by first class United States mail, registered or certified, return receipt requested, postage prepaid, and properly addressed to the party as set forth below.

PGS:

Administrative Matters:
Peoples Gas System, Inc.
702 Franklin Street
P. O. Box 2562
Tampa, Florida 33601-2562
Attention:
Telephone: (813) ; Facsimile: (813)

Payment:
Peoples Gas System, Inc.
702 Franklin Street
P. O. Box 2562
Tampa, Florida 33601-2562
Attention:
Telephone: (813) ; Facsimile: (813)

~~Shipper:~~
~~Administrative Matters:~~

~~Attention:~~
~~Telephone:~~
~~Facsimile:~~

~~Invoices:~~

~~Attention:~~
~~Telephone:~~
~~Facsimile:~~

Shipper:
Administrative Matters:

____
____
____
Attention:
Telephone:
Facsimile:

Invoices:

____
____
____
Attention:
Telephone:
Facsimile:

Section 8.7 Amendments. This Agreement may not be amended except by an instrument in writing signed by the party against which enforcement of the amendment is sought. A change in (a) the place to which notices hereunder must be sent or (b) the individual designated as Contact Person shall not be deemed nor require an amendment hereof provided such change is communicated pursuant to Section 8.6.

Section 8.8 Legal Fees. In the event of litigation between the parties hereto arising out of or in connection with this Agreement, then the reasonable attorneys' fees and costs of the party prevailing in such litigation shall be paid by the other party.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective duly authorized officers as of the date first above written.

SHIPPER	**PEOPLES GAS SYSTEM, INC.**
By:________________________	By:________________________
Name:	Name:
Title:	Title:
	__________________________
	By:________________________
	Name:
	Title

APPENDIX A - GAS TRANSPORTATION AGREEMENT

PGS RECEIPT POINT(S)

Maximum Transportation Quantity: __________ MMBtu per Day plus the Retainage

PGS will accept Gas from Shipper, or for its account, for transportation pursuant to this Agreement at the following point(s):

The above point(s) may be changed by PGS from time to time on written notice to Shipper.

APPENDIX B - GAS TRANSPORTATION AGREEMENT

PGS DELIVERY POINT(S)

Gas transported or sold pursuant to this Agreement shall be delivered by PGS to Shipper at the following point(s):

NAME	PGS METER#	MAXIMUM DELIVERY QUANTITY
Meter at the Facility		__________ MMBtu per Day

APPENDIX C - GAS TRANSPORTATION AGREEMENT

EQUIPMENT

APPENDIX D -
GAS TRANSPORTATION AGREEMENT

ALTERNATIVES DURING PERIODS OF INTERRUPTION OR CURTAILMENT

Shipper may select one or more of the "Options" hereinafter described prior to or during a period of curtailment or interruption. The Options set forth below describe means through which PGS will attempt to continue deliveries to Shipper during such a period if PGS can do so in a manner that is consistent with the order of priorities of service set forth in its curtailment plan ~~on file with the FPSC~~ and that will not prevent service to customers in higher priorities of service than Shipper.

If PGS is entitled under this Agreement or PGS's FPSC Tariff to interrupt deliveries to Shipper for reasons other than Force Majeure, PGS will notify Shipper to that effect, such notice to include the estimated duration of the interruption and the estimated cost of gas required for PGS to continue deliveries to Shipper during the period of interruption. Shipper shall notify PGS within two (2) hours after receipt of PGS's notice of interruption of the option (from Options A through C below) Shipper elects during the period of interruption. ~~If Shipper fails to respond to PGS's notice within the~~

If Shipper fails to respond to PGS's notice within the aforesaid two-hour period, it shall be conclusively presumed that Shipper has elected the Option(s) (if any) previously selected by Shipper in writing. If Shipper has failed to make *any* election, either prior to PGS's notice or during the two-hour period, it shall be conclusively presumed that Shipper has elected Option D. The Options are as follows:

Option A: Shipper desires PGS to continue deliveries during the period of interruption and Shipper agrees to make available for its account (*i.e.*, to make all arrangements necessary to cause the delivery of) at the PGS Receipt Point(s) additional quantities of Gas equal to those quantities which PGS is entitled to interrupt.

Option B: Shipper desires PGS to continue deliveries during the period of interruption and agrees to make available for its account (*i.e.*, to make all arrangements necessary to cause the delivery of) at the applicable point(s) of receipt into ~~FGT's~~ [______________] pipeline system additional quantities of Gas (including the Retainage) equal to those quantities which PGS is entitled to interrupt, and desires PGS to release to Shipper (or to a Supplier designated by Shipper), for the duration of the period of interruption and at the maximum rate applicable to the capacity released, primary firm capacity on ~~FGT~~ [____________] sufficient to transport such additional quantities of Gas to the PGS Receipt Point(s). By election of this Option B, Shipper agrees to be responsible for the payment of all charges imposed by ~~FGT~~ [_____________] with respect to the capacity so released by PGS to Shipper (or Shipper's Supplier), or the use of such capacity, for the period during which such release is effective. If Shipper elects to continue deliveries during the period of interruption pursuant to this Option B, PGS agrees to release the capacity requested by Shipper if PGS determines in its sole discretion that (i) such capacity is available for release to Shipper during the period of interruption, (ii) such release can be accomplished readily and without detriment to PGS's system operations, and (iii) such release is practicable within the time constraints and requirements of ~~FGT's~~ [___________] FERC Tariff and the ready availability of PGS staff and resources.

Option C: Shipper desires PGS to continue deliveries during the period of interruption, appoints PGS as its agent to acquire (at the PGS Receipt Point(s)) additional quantities of Gas at market-based price, equal to those quantities which PGS is entitled to interrupt, to be used by Shipper during the period of curtailment, and agrees to reimburse PGS, in addition to all amounts otherwise payable for Gas pursuant to this Agreement, for the incremental additional per-Therm costs incurred by PGS (as Shipper's agent) to acquire for the account of Shipper, at the PGS Receipt Point(s), Gas to be used by Shipper during the period of interruption. As used in this Option C, "incremental additional costs" shall mean the weighted average per-Therm costs incurred by PGS to acquire, for the accounts of Shipper and other interruptible customers of PGS who have elected this Option C during a particular period of interruption, the additional quantities of Gas mentioned above to be used by Shipper and such other interruptible customers of PGS during such period of interruption, including but not limited to commodity, transportation, storage and other charges incurred by PGS.

Option D: Shipper agrees to cease taking Gas pursuant to PGS's notice during the period of interruption.

If Shipper has elected to continue deliveries pursuant to Option A, Option B or Option C, PGS will, in implementing its interruption notice, take and pay for Shipper's Gas as provided in PGS's FPSC Tariff, but will not discontinue deliveries to Shipper unless (i) if Shipper has elected Option A, Shipper fails to make additional Gas available at the PGS Receipt Point(s), or (ii) if Shipper has elected Option B, either (a) PGS has no primary firm capacity on ~~FGT~~ [__________] available for

"Transporter Agreement" means, for purposes of this Agreement and the Capacity Release Agreement, the applicable Service Agreements for Firm Transportation Service (however named or titled) between Transporter and PGS in effect from time to time, including (a) Transporter's currently effective applicable ~~R~~rate ~~S~~schedule(s) and (b) General Terms and Conditions filed with the FERC or the FPSC (and incorporated in each said agreement by reference), as such agreements, rate schedules and general terms and conditions may be amended from time to time, and any successor firm agreement(s), firm rate schedule(s) or general terms and conditions applicable thereto.

"Transporter's Tariff" means, for purposes of this Agreement and the Capacity Release Agreement, Transporter's effective FERC or FPSC gas tariff applicable to firm transportation service under the Transporter Agreement, as such tariff may be amended from time to time.

ARTICLE II - TERM; PROGRAM CHANGES

Section 2.1 Term. This Agreement shall be effective on the date first written above. The term of this Agreement shall commence on the first Day of the Month for which PGS first delivers to Pool Manager a list of Customer Accounts as required by Section 4.1(a) (the "Effective Date") and shall continue, unless earlier terminated pursuant to this Agreement, until the first anniversary of the Effective Date (the "Initial Term"). Thereafter, the term of this Agreement shall be extended for additional periods of one year unless either party gives written notice, not less than 90 days prior to the expiration of the Initial Term (or any subsequent period for which this Agreement has been extended) to the other party, of termination.

Section 2.2 Program Changes. Pool Manager understands that PGS is entering into this Agreement as part of a program approved by the FPSC. PGS reserves the right to file with the FPSC modifications to such program (including the terms and conditions of this Agreement). PGS shall give Pool Manager reasonable notice of any such filing. In the event the FPSC approves modifications to such program (including any terms or conditions set forth in this agreement), such modifications shall become binding on the parties hereto as of the date on which approval thereof by the FPSC becomes effective. Notwithstanding any other provision of this Agreement, PGS's obligations hereunder shall at all times be subject to the lawful orders, rules and regulations of the FPSC, and to the terms and conditions of PGS's FPSC Tariff.

ARTICLE III - NON-PAYMENT BY CUSTOMER

Pool Manager may terminate its obligation to deliver Gas hereunder for a Customer Account for non-payment of charges due Pool Manager by giving five days' written notice to PGS prior to the first Day of the Month as of which such termination is to be effective. Any such notice shall be accompanied by (i) documentary evidence of the Customer's failure to make payment for a period of at least 60 days, (ii) Pool Manager's affidavit that it has made commercially reasonable and good faith efforts to collect the amount due and (iii) a non-refundable termination fee of $59.00~~52.00~~.

Section 4.2 Pool Manager's Failure to Perform.

(a) If (unless excused by Force Majeure or excused according to section 5.2 of this Agreement) Pool Manager fails to cause to be delivered on any Day any portion (the "Shortfall Quantity") of the quantity of Gas required to be delivered to PGS pursuant to Section 4.1, Pool Manager shall pay to PGS (in dollars per MMBtu), for the Shortfall Quantity, an amount equal to five (5) times the highest price, for the calendar day on which such Day commences, for spot gas delivered to a Gulf Coast pipeline, as published in Platts Gas Daily.

(1) If requested by Pool Manager, and agreed to by PGS, PGS will sell gas supply and interstate pipeline capacity on a delivered basis to the Pool Manager to offset a portion of the "Shortfall Quantity." The price for said "Backup Gas" shall be as mutually agreed between the parties plus a $100 administration fee per Day that "Backup Gas" is supplied. PGS shall have no obligation to provide said "Backup Gas" and will do so only if the same can be provided without detriment to any other customer on the PGS distribution system.

(2) The Pool Manager's "Shortfall Quantity" will be reduced by the quantity of any "Backup Gas" provided by PGS.

(b) If Pool Manager causes to be delivered on any Day a quantity of Gas exceeding the quantity required to be delivered to PGS pursuant to Section 4.1, Pool Manager shall sell to PGS, and PGS shall purchase from Pool Manager, such excess Gas (the "Excess Quantity") at a purchase price equal to:

(1) fifty percent (50%) of the price reported in Platts Gas Daily~~*Natural Gas Week*~~ for the Day ~~beginning of the Month~~ in which Pool Manager delivered such Excess Quantity, for spot gas delivered to FGT at Florida Gas zone 1~~Tivoli, Texas~~; minus

(2) the sum of any balancing, scheduling, alert day, OFO, or other penalties or charges incurred by PGS as a result of Pool Manager's delivery of the Excess Quantity; minus

(3) a fee of $0.15 per MMBtu as a liquidated amount representing incidental damages. Pool Manager agrees that it will not bill any Customer for any Excess Quantity which is purchased by PGS from Pool Manager pursuant to this paragraph (b).

(c) Billing and payment of any amounts due either party pursuant to this section shall be in accordance with Article VI.

Section 4.3 Termination. If (i) in any three-Month period, unless excused by Force Majeure, Pool Manager fails to cause to be delivered on any three (3) Days any portion of the quantity of Gas required to be delivered to PGS pursuant to Section 4.1, or (ii) Pool Manager fails to timely pay any amount due PGS pursuant to Section 4.2, or (iii) Pool Manager is delinquent in making payment of other amounts due hereunder more than three (3) times in any 12-Month period, or (iv) PGS determines that Pool Manager has delivered to PGS a letter of authorization not actually signed by the Customer named therein, PGS may, in its sole discretion, without incurring any liability to Pool Manager or any Customer, terminate this Agreement by facsimile notice of termination to Pool Manager and notice to each Customer Account in the Customer Pool, such termination to be effective when specified in such notices; provided, however, that PGS's exercise of the remedy forth in this section shall not be construed as a waiver of PGS's rights under either of Section 4.2 or

ADQ in a manner which would have the effect of reducing the quantities of Gas delivered at the Primary Delivery Point(s). For all Gas sold by Pool Manager to PGS pursuant to this section, PGS shall pay to Pool Manager an amount per MMBtu equal to the sum of (i) the price for spot Gas delivered to FGT at Florida Gas zone 2 ~~Vermillion Parish, Louisiana~~, as reported in the "Daily Price Survey" in Platts *Gas Daily* for the Day in which PGS purchased the Gas, and (ii) the 100% load factor rate at which Pool Manager acquired the Released Capacity (as defined in the Capacity Release Agreement) from PGS pursuant to the Capacity Release Agreement. PGS warrants that it will not at any time exercise its right to interrupt deliveries of Gas to the Customer Pool pursuant to PGS's FPSC Tariff based solely on a determination that Gas being delivered by Pool Manager to the Primary Delivery Point(s) is less expensive than Gas which is, at the time of PGS's exercise of such right, otherwise available to PGS. For any Month in which PGS purchases Gas from Pool Manager pursuant to this section, PGS shall make payment of the amount payable to Pool Manager on or before the last Day of the Month following the Month in which PGS purchased such Gas.

Section 5.2 Mutually Beneficial Transactions. Pool Manager recognizes that PGS maintains the operation and system integrity of the PGS distribution system on a daily basis. Pool Manager also recognizes that as Delivery Point Operator for the Transporter interconnects, PGS is subject to the rules and regulations of the applicable Transporter with regard to operational flow rates, pressures and penalties. As such, PGS may have need for the Pool Manager to vary its daily delivery from the agreed to ADQ. On those occasions, PGS may request, at its sole discretion, and the Pool Manager may agree to, a change to the Pool Manager's level of Gas supply and interstate pipeline capacity. Terms and conditions of such transaction will be agreed upon at the time of the transaction and will be recorded and confirmed in writing within two business days of the transaction.

Section 5.3 Correction of Imbalances. PGS and Pool Manager intend that all Monthly Imbalance Amounts shall be resolved as of the end of each Month. At the end of each Month, the Monthly Imbalance Amount (if any) incurred during such Month shall be resolved in kind or cash. PGS will provide Pool Manager with an online cash-out statement of the Monthly Imbalance Amount by noon on the 10th Day of the following Month, and post a list of all Monthly Imbalance Amounts on its gas management system website ~~Internet web site (or otherwise if such web site is not available)~~. Pool Manager shall have a Book-Out Period until the 14th Day of such following month to utilize the Book-Out provisions in Section 5.4 below. Pool Manager and PGS shall utilize the provisions in Section 5.5 below to resolve in cash all Monthly Imbalance Amounts (or any portions thereof) remaining after the close of the Book-Out Period.

Section 5.4 Book-Out. Pool Manager may, during the Book-Out Period, net Positive Monthly Imbalance Amounts (as hereinafter defined), or portions thereof, with Negative Monthly Imbalance Amounts (as hereinafter defined), or portions thereof, of other Pool Managers or other Customers, and may net Negative Monthly Imbalance Amounts, or portions thereof, with Positive Monthly Imbalance Amounts of other Pool Managers or Customers. A Pool Manager availing itself of the provisions of this paragraph shall submit a completed online Imbalance Trading Form via the Company's gas management system website.~~Book-Out Agreement, in form designated by PGS, via facsimile or mail to PGS before the end of the Book-Out Period. Such agreement shall not be deemed effective unless signed by an authorized representative of each Pool Manager or Customer which is a party thereto.~~ PGS shall have no responsibility or liability for incorrect, incomplete~~,~~ or late~~, lost or illegible Book-Out Agreements~~ Imbalance Trading Forms.

Section 5.5 Cashout. By the 15th Day (or the subsequent Business Day if a weekend or holiday) of the following Month, any end-of-Month imbalance remaining after trading will be resolved in cash as follows:

(a) Positive Imbalances. If a Monthly Imbalance Amount is Positive (*i.e.*, the sum of the ADQs of the Customer Pool for the Month (less the Retainage) exceeds the Actual Takes of the Customer Pool for such Month), PGS shall purchase from Pool Manager (and Pool Manager shall sell to PGS) such Monthly Imbalance Amount at a price per Therm (the "Unit Price") equal to the lowest weekly average (weeks where Friday is within the calendar Month) of the “Daily price survey” for Gas under the “Midpoint” column for “Florida Gas, zone 1”, “Florida Gas zone 2” or “Florida Gas, zone 3”, as reported in Platts Gas Daily, ~~of the average of weekly prices for spot gas delivered to FGT at Mustang Island (Tivoli), Texas, Vermillion Parish, Louisiana, or St. Helena Parish, Louisiana, as reported in *Natural Gas Week*~~ for the Month in which such Monthly Imbalance Amount was incurred. The total amount due Pool Manager pursuant to this paragraph (a) shall be the product of the Unit Price (calculated as set forth herein) and such Monthly Imbalance Amount.

(b) Negative Imbalances. If a Monthly Imbalance Amount is Negative (*i.e.*, Actual Takes of the Customer Pool exceed the sum of the ADQs of the Customer Pool for such Month less the Retainage), PGS shall sell to Pool Manager (and Pool Manager shall purchase from PGS) such Monthly Imbalance Amount at a price per Therm (the "Unit Price") equal to the sum of (i) the highest weekly average (weeks where Friday is within the calendar Month) of the “Daily price survey” for Gas under the “Midpoint” column for “Florida Gas, zone 1”, “Florida Gas zone 2” or “Florida Gas, zone 3”, as reported in Platts Gas Daily, ~~average of weekly prices for spot gas delivered to FGT at Mustang Island (Tivoli), Texas, Vermillion Parish, Louisiana, or St. Helena Parish, Louisiana, as reported in *Natural Gas Week*,~~ for the Month in which such Monthly Imbalance Amount accumulated plus (ii) an amount equal to the sum of (A) the FGT FTS-3 usage rate (including, but not limited to, usage charges, surcharges, fuel reimbursement charges, and other applicable charges, taxes, assessments and fees) for the applicable calendar month and (B) the maximum reservation rate for FGT FTS-3 capacity. The total amount due PGS pursuant to this paragraph (b) shall be the product of the Unit Price (calculated as set forth herein) and such Monthly Imbalance Amount.

(c) For any Month in which a Monthly Imbalance Amount is required by paragraph (a) to be purchased by PGS, PGS shall make payment of the amount payable to Pool Manager on or before the last Day of the Month following the Month in which the Monthly Imbalance Amount accumulated. For any Month in which a Monthly Imbalance Amount is required by paragraph (b) to be purchased by Pool Manager, the amount payable to PGS shall be billed by PGS and paid by Pool Manager pursuant to Article VI.

ARTICLE VI - BILLING AND PAYMENT

Section 6.1 Amounts Due PGS. When any amounts are payable by Pool Manager pursuant to Articles IV or V, PGS shall, as soon as practicable after such amounts are determined, deliver a bill to Pool Manager for such amounts. Pool Manager shall pay any such bill rendered by PGS, minus any disputed amounts, to PGS at the address specified in the invoice on or before the 20th Day following the date of PGS's mailing or other delivery of such bill.

(a) Charges for services due and rendered which are unpaid, and not in good faith dispute, by the due date are subject to a Late Payment Charge of 1.5% per Month, except for the accounts of federal, state and local governmental entities, agencies and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state and local governmental entities, agencies and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

(b) If Pool Manager fails to make any payment to PGS when due and such failure is not remedied by or on behalf of Pool Manager within five (5) Days after written notice by PGS of such default in payment, then PGS, in addition to any other remedy it may have, may, without incurring any liability to Pool Manager and without terminating this Agreement, suspend further deliveries of Gas to the Customer Pool until such amount

DATA ACCESS AGREEMENT

This Data Access Agreement ("Agreement") is made and entered into this _______ day of _______________, 20______ between **Peoples Gas System, Inc., a Florida corporation** ("PGS"), and __________________, a _______________________("Subscriber").

WITNESSETH

WHEREAS, PGS owns, operates and maintains natural gas measuring and regulating station facilities at _____________________________ ("Facilities"); and,

WHEREAS, Subscriber is a customer of PGS, and wishes to receive electronically data regarding Subscriber's natural gas usage ("Data");

WHEREAS, PGS is willing, subject to the terms and conditions contained below, to install, on the Facilities, certain electronic data gathering devices, including, where necessary, lines for transmission of electric power and electronic data (collectively, "Devices") that will make it possible for Subscriber to receive the Data.

NOW, THEREFORE, PGS agrees, subject to the terms and conditions contained in this Agreement, to install, operate, maintain, repair, replace and remove the Devices at the Facilities. The Data drawn from the Devices will be made available at data ports or designated analog or discrete output (collectively, the "Ports"). All Data provided to Subscriber shall be used for the sole purpose of evaluating and managing its internal usage.

Subscriber shall, within thirty (30) days of receiving an invoice, reimburse PGS for all expenses incurred by PGS in connection with, or incidental to, the installation, operation, maintenance, repair, replacement or removal of the Devices. PGS is only providing the Devices; Subscriber shall be responsible for procuring, installing and maintaining, at its own cost and expense, all computer hardware and software necessary for its own receipt and use of the Data.

Agreement shall remain in force and effect until the first to occur of (i) discontinuation of Subscriber's status as a customer of PGS, or (ii) termination of this Agreement by PGS or Subscriber on thirty (30) days written notice to the other party. In addition, PGS shall have the right to suspend the transmission of Data, and/or disconnect the Facilities during any period in which, in PGS's sole judgment, the Devices pose a threat of interference with the operation of, or access to, the Facilities, or otherwise poses a risk to person or property.

Subscriber hereby grants to PGS such access as is reasonably necessary for the installation, operation, maintenance, repair, replacement or removal of the Devices.

PGS is installing the Devices at the Facilities as a convenience to Subscriber. **PGS MAKES NO WARRANTY AS TO THE OPERATION OF, OR ACCURACY OF THE DATA PROVIDED THROUGH, THE PORTS, AND TAKES NO RESPONSIBILITY FOR SUBSCRIBER'S USE OF THE PORT AND DATA SUPPLIED THEREFROM, SINCE THEY ARE BEING SUPPLIED FOR INFORMATIONAL PURPOSES ONLY, AT NO PROFIT AND AS AN ACCOMMODATION TO SUBSCRIBER. PGS DISCLAIMS ANY AND ALL WARRANTIES, EXPRESS OR IMPLIED, INCLUDING WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE AND MERCHANTABILITY.**

PGS IS NOT LIABLE FOR, AND SUBSCRIBER HEREBY WAIVES ANY RIGHT TO, ANY AND ALL INDIRECT, INCIDENTAL AND CONSEQUENTIAL DAMAGES, INCLUDING, BUT NOT LIMITED TO, LOSS OF PROFITS, LOSS OF CAPITAL, LOSS OF DATA, COMPUTER DOWNTIME, AND COST OF SUBSTITUTE SERVICES. THE PARTIES AGREE THAT PGS SHALL NOT BE LIABLE FOR ANY COMPUTER PROBLEMS RESULTING FROM SUBSCRIBER'S ATTEMPTS TO RECEIVE OR PROCESS THE DATA, INCLUDING PROBLEMS RESULTING FROM THE USE OF ANY THIRD PARTY SOFTWARE OR FROM COMPUTER VIRUSES.

Subscriber shall not attempt, and shall not permit any third party to attempt, to adjust, modify or remove the Devices without the prior written approval of PGS. Subscriber agrees to protect, indemnify and hold PGS harmless from and against any and all liability, costs, damages and expenses in any way attributable to Subscriber's failure to comply with this Agreement or Subscriber's negligence or fault. This indemnification shall include, but is not limited to, (1) PGS'<u>s</u> attorney's fee and court costs, and (2) any liability, costs, damages and expenses resulting from the use of the data signal from the Port. This indemnification provision is in addition to (and does not replace) similar provisions relating to the same subject matter in the Gas Transportation Agreement, if applicable.

Notwithstanding any provision of this Agreement to the contrary, measurement of gas delivered to or consumed by Subscriber shall be governed by the applicable provisions of PGS's natural gas ~~t~~Tariff on file with the Florida Public Service Commission (or its successor) and in effect from time to time.

IN WITNESS WHEREOF, this Agreement is executed as of the day and year first hereinabove written.

PEOPLES GAS SYSTEM, INC.	**NAME OF SUBSCRIBER**
	______________________
By: ______________________	By: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

MINIMUM VOLUME COMMITMENT
GAS TRANSPORTATION AGREEMENT

This Minimum Volume Commitment Gas Transportation Agreement (the "Agreement") is made and entered into as of the ______ day of __________, 20___, by and between Peoples Gas System, Inc., a Florida corporation ("PGS"), and ________________, a ____________________ ("Shipper"), who hereby agree as follows:

ARTICLE I - DEFINITIONS

As used herein, the following terms shall have the meanings set forth below.

Capitalized terms used herein, but not defined below, have the meanings given for such terms in PGS's FPSC Tariff.

"Actual Takes" means, for a specified period, the quantity of Gas passing through the meter(s) of the Customer Accounts during that period.

"Business Day" means the Days Monday through Friday (excluding any federal banking holiday falling on any such Day).

"Day" means the period of 24 consecutive hours beginning and ending at 9:00 a.m. Central Clock Time..

"Facility" means Shipper's ________________ facility located in __________, Florida.

"FPSC" means the Florida Public Service Commission or any successor agency.

"Gas" shall have the same meaning as given for such term in PGS's FPSC Tariff.

"Gas Service" shall have the same meaning as given for such term in PGS's FPSC Tariff.

"MAT Deficiency Charge" means the difference between the applicable MAT set forth in Article VI and the actual quantity of Gas delivered during the twelve-month delivery period, multiplied by the applicable rate schedule in effect at the end of the twelve-month delivery period.

"Maximum Delivery Quantity" or "MDQ" means the maximum amount of Gas that PGSobligated to cause to be delivered for Shipper's account pursuant to this Agreement on any Day at the PGS Delivery Point(s), and is stated in Appendix B.

"Maximum Transportation Quantity" or "MTQ" means the maximum amount of Gas that PGS shall be obligated to receive pursuant to this Agreement on any Day at the PGS Receipt Point(s), and is stated in Appendix A.

"Minimum Annual Take" or "MAT" means the quantity of minimum annual delivery of natural gas at the facility agreed to by Shipper and set forth in Article VI.

"Minimum Delivery Obligation" means the sum of Shipper's total Gas requirements over the Term of this agreement as set forth in Article VI.

"Nomination" means a notice delivered by Shipper to PGS in the form specified in PGS's FPSC Tariff, specifying (in MMBtu) the quantity of Gas Shipper desires to purchase, or to have PGS receive, transport and deliver, at the PGS Delivery Point(s).

"Nominate" means to deliver a completed Nomination.

"PGS Delivery Point(s)" means the point(s) listed in Appendix B.

"PGS Receipt Point(s)" means the point(s) of physical interconnection between Transporter and PGS, or between Shipper and PGS listed in Appendix A.

"Retainage" means 0.35% of Gas received by PGS for the account of the Customer at the Primary Delivery Point(s) to account for lost and unaccounted Gas between such point(s) and the meters of the Customer Accounts.

"Supplier(s)" means person(s) (other than PGS) from which Shipper purchases Gas transported hereunder.

"Transporter" means any upstream intrastate or interstate transport service provider.

"Twelve-Month Delivery Period" means each twelve-month period commencing on the date of Gas Service is available to the Facility and continues on an annual basis throughout the Term of this Agreement.

ARTICLE II – TERM

This Agreement is effective on the date first written above. The term shall commence upon the initiation of Gas Service and continue until the last day of the Twelve-Month Delivery Period or when the Minimum Delivery Obligation is satisfied. (the "Termination Date") (the "Term"). The Term shall reflect the recovery period for the extension of Gas Service. In no instance will the Term exceed (10) years. At the end of the Term, the Customer will be placed in the applicable rate schedule.

ARTICLE III – SALES AND TRANSPORTATION SERVICE

Section 3.1 Services. PGS desires to sell and Shipper desires to purchase from PGS, from time to time, for use in the Facility (but not for resale), Gas in quantities which, at Shipper's request, PGS may, in its sole discretion exercised in a not unduly discriminatory manner, agree to sell to Shipper. Shipper also engages PGS, and PGS accepts such engagement, to receive Gas for Shipper's account, up to the MTQ, at the PGS Receipt Point(s), and to cause an equivalent quantity, less the Retainage, to be redelivered to Shipper. Such sales and transportation shall be governed by PGS's FPSC Tariff and this Agreement. If there is a conflict between the Tariff and this Agreement, the Tariff shall control. Sales and transportation hereunder are interruptible in accordance with PGS's FPSC Tariff and PGS's curtailment plan. If Shipper's service is interruptible, Shipper may select one or more of the options described in Appendix D, which may enable Shipper to continue receiving delivery of Gas during periods of curtailment or interruption.

PGS shall have no obligation to make sales to Shipper in lieu of the transportation of Gas contemplated by this Agreement.

Section 3.2 Telemetry and Other Required Equipment. Telemetry and other equipment which PGS must install to provide service hereunder (the "Equipment"), if any, and the anticipated cost thereof, are listed in Appendix C. Shipper shall reimburse PGS for all costs incurred for the Equipment on receipt of PGS's invoice therefor. Unless the parties agree otherwise, all facilities used to provide service to Shipper hereunder (including without limitation the Equipment) shall be installed, owned, operated and maintained by PGS.

ARTICLE IV – NOMINATIONS

Section 4.1 General. For each Day Shipper desires service hereunder, Shipper shall provide a Nomination to PGS pursuant to Sections 4.2 and/or 4.3 for each meter at the Facility. The total quantity for the Facility may be Nominated to a single meter, with "zero" Nominations being made for any additional meters located at the Facility. All Nominations shall be made to PGS at its website (https://custactivitiespeoplesgas.com) provided that, in an emergency, a Nomination may be delivered via facsimile using the form set forth in PGS's FPSC Tariff. Quantities confirmed by PGS for delivery shall be Scheduled Quantities. If requested by Shipper, PGS will allow increases or decreases in Scheduled Quantities after the Nomination deadlines set forth in this article, if the same can be confirmed by PGS, Transporters and Suppliers, and can be accomplished without detriment to services then scheduled on such Day for PGS and other shippers. The maximum quantity PGS shall be obligated to make available for delivery to Shipper on any Day (which shall not exceed the MDQ) is the sum of (a) the Transportation Quantity and (b) the Sales Quantity established pursuant to this article.

Section 4.2 Nomination for Purchase. Unless otherwise agreed, Shipper shall Nominate Gas for purchase hereunder not less than seven (7) Business Days prior to the first Day of any Month in which Shipper desires to purchase Gas. Daily notices shall be given to PGS at least two (2) Business Days (but not less than forty-eight (48) hours) prior to the commencement of the Day on which Shipper desires delivery of the Gas. If Shipper has timely Nominated a quantity for a particular Month, PGS shall confirm to Shipper the quantity PGS will tender for purchase by Shipper (the "Sales Quantity," which shall also be a "Scheduled Quantity") no later than 5:00 p.m. Eastern Time on the Business Day immediately preceding each Day during such Month.

Section 4.3 Nomination for Transportation. Unless otherwise agreed, Shipper shall, for each Month, and each Day during such Month that Shipper seeks to change any aspect of any prior Nomination, notify PGS by providing a completed Nomination. Shipper's Nomination for Gas to be to be made available for delivery on the first Day of any Month shall be given by 10 a.m. on the second Business Day prior to the Day on which a nomination must be delivered to Transporter for receipt of deliveries at the PGS Receipt Point(s) on such Day. Daily Nominations for Gas to be made available for delivery other than on the first Day of a Month shall be given to PGS by 10 a.m. on the Business Day prior to the Day on which a nomination must be delivered to Transporter for the receipt of deliveries at the PGS Receipt Point(s) on such Day. The following nomination information is required for a valid nomination:

a. The Shipper's account number under which service is being nominated;
b. The receipt point location including applicable DRN and upstream pipeline name, upstream pipeline package ID, including Shipper's PGS account number, and quantity in Therms of Gas to be tendered at each PGS receipt point;

c. The downstream delivery facility name, and quantity in Therms of Gas to be delivered for each PGS Shipper account;
d. A beginning and ending date for each nomination;
e. The upstream contract identifier.

Only nominations with clearly matching upstream Transporter identifiers (including Shipper's package ID and PGS account number) and downstream (PGS) identifiers will be scheduled. If Shipper or Shipper's Agent fails to comply with provisions (a) through (e) of this section, PGS may not schedule commencement of service or change a prior nomination.

Shipper understands that PGS is subject to FERC regulations that may require PGS to post certain Shipper information on a publicly accessible website. The submission by Shipper or Shipper's Agent of a required nomination shall constitute Shipper's authorization to PGS to publicly disclose any information (including but not limited to the information provided in such nomination) required by applicable law or regulation to be disclosed by PGS.

PGS shall confirm to Shipper the quantity PGS will make available for redelivery on such Day (the "Transportation Quantity," which shall also be a "Scheduled Quantity") no later than 5:00 p.m. Eastern Time on the Business Day immediately preceding such Day. PGS has no obligation to confirm a quantity Nominated by Shipper pursuant to this section greater than the quantity which, in PGS's reasonable judgment, equals the Facility's likely consumption for a Day plus Retainage, less any Sales Quantities confirmed for delivery on such Day.

Section 4.4 Mutually Beneficial Transactions. Shipper recognizes that PGS maintains the operation and system integrity of the PGS distribution system on a daily basis, and that PGS, as the delivery point operator for its points of interconnection with interstate pipelines, is subject to the rules and regulations of such pipelines with regard to operational flow rates, pressures and penalties. As such, PGS may from time to time need Shipper to vary its Nominated quantities of Gas to be delivered at the PGS Receipt Point(s). On such occasions, PGS may in its sole discretion request, and Shipper may agree to, a change in the quantity of Gas to be delivered for the account of Shipper at the PGS Receipt Point(s). No such change in the quantity of Gas to be delivered shall be made pursuant to this section without the consent of Shipper. Terms and conditions of any such transaction will be agreed upon between the parties at the time of the transaction and will be recorded and confirmed in writing within two Business Days of the transaction.

ARTICLE–V - TRANSPORTATION AND OTHER CHARGES

Section 5.1 Transportation Charges; Purchase Price. Shipper shall pay PGS each Month for transportation service rendered by PGS, and, if applicable, for Gas purchased from PGS, in accordance with the then-applicable rate schedule in PGS's FPSC Tariff. At the time of execution of this Agreement, Rate Schedule ____ is applicable. In the event rate schedule CIS or a fixed rate schedule is applicable, this Agreement will automatically renew following the Initial Term at the then applicable rate schedule unless Shipper and PGS have agreed at least thirty (30) days prior to the expiration of the then current term that Rate Schedule CIS or another rate schedule shall apply.

During the Term of this Agreement, Buyer agrees to a MAT of natural gas at the Facility which will follow the schedule outlined in Section 6.2.

Section 5.2 Changes in Tariff. If the applicable rates or rate schedules change or are amended or superseded, the newly applicable rates or rate schedules shall be applicable to service hereunder. Nothing contained herein shall prevent PGS from filing with the FPSC (or Shipper from opposing) changes to the rates and other provisions in PGS's FPSC Tariff. PGS agrees to give Shipper reasonable notice of (a) all filings (except filings in FPSC Docket No. 000003-GU, In Re: Purchased Gas Adjustment (PGA) True-Up, and successor dockets) which PGS makes with the FPSC and (b) all other FPSC proceedings of which PGS becomes aware, which PGS determines would affect PGS's rates or the services to be performed by PGS under this Agreement.

ARTICLE VI - REQUIREMENTS

Section 6.1 Minimum Delivery Obligation. The sum of Shipper's total Gas requirements over the Term of this Agreement are estimated to be ________ Therms.

Section 6.2 Minimum Annual Take. PGS requires the following MAT for each Twelve-Month Delivery Period as applicable:

Period	Therms
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	

Section 6.3 Shortfall and MAT Deficiency Charge. If the Shipper fails to take delivery of the MAT in any Twelve-Month Delivery Period, the Shipper shall pay PGS a MAT Deficiency Charge calculated as follows: the difference between the applicable MAT and the actual quantity of Gas delivered during the Twelve-Month Delivery Period, multiplied by the rate schedule in effect at the end of the Twelve-Month Delivery Period. If, during any Twelve-Month Delivery Period, the actual quantity of Gas delivered to the Facility exceeds the applicable MAT, said excess shall be carried forward to the next Twelve-Month Delivery Period for purposes of offsetting any MAT Deficiency Charge hereunder.

Section 6.4 Financial Guarantee. Shipper shall furnish to PGS an irrevocable standby letter of credit issued by a bank acceptable to PGS or such other form of guarantee acceptable to PGS (the "Financial Guarantee") in an amount equal to [ ]. PGS may adjust the amount required in the Financial Guarantee at the end of each Twelve-Month Delivery Period.

Shipper's failure to maintain the Financial Guarantee, which for the avoidance of doubt includes notice of termination of security without acceptable alternative Financial Guarantee being provided, shall constitute a default of this Agreement.

ARTICLE VII - BILLING AND PAYMENT

Section 7.1 Billing. PGS will bill Shipper each Month for all Actual Takes during the preceding Month, and for any other amounts due hereunder. If, during the preceding Month, PGS has purchased Gas from Shipper pursuant to an interruption or curtailment order, such bill shall show a credit for the estimated amount due Shipper for such purchase(s). If the estimated amount owed by PGS to Shipper exceeds the amount Shipper owes PGS, PGS shall pay Shipper the net amount estimated to be due Shipper at the time PGS bills Shipper.

Section 7.1.1 Billing of MAT Deficiency Charge(s). PGS will bill Shipper for the MAT Deficiency Charge within thirty (30) days after the end of each Twelve-Month Delivery Period.

Section 7.2 Payment. Shipper shall pay all such bills, minus any disputed amounts, at the address specified in the invoice by the 20th Day following the date of PGS's mailing (as signified by the postmark) or other delivery of the bill. All sums not so paid by Shipper (or credited or paid by PGS) shall be considered delinquent and subject to later payment schedules as set forth below.

Section 7.3 Termination Payment. If the Shipper terminates Gas Service hereunder after execution of this Agreement, Shipper shall pay PGS any MAT Deficiency Charge(s) applicable at the time of termination and any future MAT Deficiency Charge(s) pursuant to the schedule in Section 6.2. resulting from such termination (the "Termination Payment"). Shipper agrees that it will make any such Termination Payment to PGS within twenty (20) days after receipt of PGS' invoice.

Section 7.4 Billing Disputes. In the event of a bona fide billing dispute, Shipper or PGS, as the case may be, shall pay (or credit) to the other party all amounts not in dispute, and the parties shall negotiate in good faith to resolve the amount in dispute as soon as reasonably practicable. If a party has withheld payment (or credit) of a disputed amount, and the dispute is resolved, the non-prevailing party shall pay to the other party the amount determined to be due such other party, plus interest thereon at an annual rate equal to the prime interest rate of Citibank, N.A., New York, New York, plus one percent (1%), calculated on a daily basis from the date due until paid (or credited).

Section 7.5 Errors or Estimates. If an estimate is used to determine the amount due Shipper for purchases by PGS pursuant to an interruption or curtailment order, PGS shall make any adjustment necessary to reflect the actual amount due Shipper on account of such purchases in the next bill rendered to Shipper after determination of the actual amount due. An error in any bill, credit or payment shall be corrected in the next bill rendered after the error is confirmed by PGS.

Each party's performance obligation hereunder shall abate proportionately during a Force Majeure event and during any period that a party is unable to perform its obligations due to the other party's performance failure. The term of this Agreement shall be extended for a period equal to the length of any such abatement(s).

ARTICLE VIII - FAILURE TO MAKE PAYMENT

Section 8.1 Late Payment Charge. Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of 1.5%, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted by applicable law.

Section 8.2 Other Remedies. If Shipper fails to remedy a delinquency in any payment within five (5) Days after written notice thereof by PGS, PGS, in addition to any other remedy may, without incurring any liability to Shipper and without terminating this Agreement, suspend further deliveries to Shipper until the delinquent amount is paid (including Late Payment Charges), but PGS shall not do so if the failure to pay is the result of a bona fide billing dispute, and all undisputed amounts have been paid. If PGS fails to remedy a delinquency in providing a credit (or making payment) to Shipper for PGS purchases pursuant to an interruption or curtailment order within five (5) Days after Shipper's written notice thereof, Shipper, in addition to any other remedy, may, without incurring liability to PGS and without terminating this Agreement, suspend PGS's right to retain and purchase Shipper's Gas pursuant to an interruption or curtailment order, but Shipper shall not do so if PGS's failure to provide a credit (or make payment) is the result of a bona fide billing dispute, and all undisputed amounts have been credited or paid by PGS.

ARTICLE IX – MISCELLANEOUS

Section 9.1 Assignment and Transfer. Neither party may assign this Agreement without the prior written consent of the other party (which shall not be unreasonably withheld) and the assignee's written assumption of the assigning party's obligations hereunder. [SUCH EXCEPTIONS TO THE FOREGOING AS TO WHICH THE PARTIES MAY AGREE]

Section 9.2 Governing Law. This Agreement and any dispute arising hereunder shall be governed by and interpreted in accordance with the laws of Florida and shall be subject to all applicable laws, rules and orders of any Federal, state or local governmental authority having jurisdiction over the parties, their facilities or the transactions contemplated. Venue for any action, at law or in equity, commenced by either party against the other and arising out of or in connection with this Agreement shall be in a court, located within the State of Florida, having jurisdiction.

Section 9.3 Severability. If any provision hereof becomes or is declared by a court of competent jurisdiction to be illegal, unenforceable or void, this Agreement shall continue in full force and effect without said provision.

Section 9.4 Entire Agreement; Appendices. This Agreement sets forth the complete understanding of the parties as of the date first written above, and supersedes any and all prior negotiations, agreements and understandings with respect to the subject matter hereof. The appendices attached hereto are an integral part hereof. All capitalized terms used and not otherwise defined in the appendices shall have the meanings given to such terms herein.

Section 9.5 Waiver. No waiver of any of the provisions hereof shall be deemed to be a waiver of any other provision whether similar or not. No waiver shall constitute a continuing waiver. No waiver shall be binding on a party unless executed in writing by that party.

Section 9.6 Notices. (a) All notices and other communications hereunder shall be in writing and be deemed duly given on the date of delivery if delivered personally or by a recognized overnight delivery service or on the fifth day after mailing if mailed by first class United States mail, registered or certified, return receipt requested, postage prepaid, and properly addressed to the party as set forth below.

PGS:

Administrative Matters:
Peoples Gas System, Inc.
702 Franklin Street
P. O. Box 2562
Tampa, Florida 33601-2562
Attention:
Telephone: (813) ; Facsimile: (813)

Payment:
Peoples Gas System, Inc.
702 Franklin Street
P. O. Box 2562
Tampa, Florida 33601-2562
Attention:
Telephone: (813) ; Facsimile: (813)

Shipper:

Administrative Matters:

Attention:
Telephone:
Facsimile:

Invoices:

Attention:
Telephone:
Facsimile:

Section 9.7 Amendments. This Agreement may not be amended except by an instrument in writing signed by the party against which enforcement of the amendment is sought. A change in (a) the place to which notices hereunder must be sent or (b) the individual designated as Contact Person shall not be deemed nor require an amendment hereof provided such change is communicated pursuant to Section 8.6.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective duly authorized officers as of the date first above written.

SHIPPER

By: ________________________
Name:
Title:

PEOPLES GAS SYSTEM, INC.

By: ________________________
Name:
Title:

By: ________________________
Name:
Title:

APPENDIX A - GAS TRANSPORTATION AGREEMENT

PGS RECEIPT POINT(S)

Maximum Transportation Quantity: MMBtu per Day plus the Retainage

PGS will accept Gas from Shipper, or for its account, for transportation pursuant to this Agreement at the following point(s):

The above point(s) may be changed by PGS from time to time on written notice to Shipper.

APPENDIX B - GAS TRANSPORTATION AGREEMENT

PGS DELIVERY POINT(S)

Gas transported or sold pursuant to this Agreement shall be delivered by PGS to Shipper at the following point(s):

NAME	PGS METER#	MAXIMUM DELIVERY QUANTITY
Meter at the Facility		MMBtu per Day

APPENDIX C - GAS TRANSPORTATION AGREEMENT

EQUIPMENT

APPENDIX D - GAS TRANSPORTATION AGREEMENT

ALTERNATIVES DURING PERIODS OF INTERRUPTION OR CURTAILMENT

Shipper may select one or more of the "Options" hereinafter described prior to or during a period of curtailment or interruption. The Options set forth below describe means through which PGS will attempt to continue deliveries to Shipper during such a period if PGS can do so in a manner that is consistent with the order of priorities of service set forth in its curtailment plan and that will not prevent service to customers in higher priorities of service than Shipper.

If PGS is entitled under this Agreement or PGS's FPSC Tariff to interrupt deliveries to Shipper for reasons other than Force Majeure, PGS will notify Shipper to that effect, such notice to include the estimated duration of the interruption and the estimated cost of gas required for PGS to continue deliveries to Shipper during the period of interruption. Shipper shall notify PGS within two (2) hours after receipt of PGS's notice of interruption of the option (from Options A through C below) Shipper elects during the period of interruption.

Shipper has elected the Option(s) (if any) previously selected by Shipper in writing. If Shipper has failed to make *any* election, either prior to PGS's notice or during the two-hour period, it shall be conclusively presumed that Shipper has elected Option D. The Options are as follows:

Option A: Shipper desires PGS to continue deliveries during the period of interruption and Shipper agrees to make available for its account (*i.e.*, to make all arrangements necessary to cause the delivery of) at the PGS Receipt Point(s) additional quantities of Gas equal to those quantities which PGS is entitled to interrupt.

Option B: Shipper desires PGS to continue deliveries during the period of interruption and agrees to make available for its account (*i.e.*, to make all arrangements necessary to cause the delivery of) at the applicable point(s) of receipt into [ ] pipeline system additional quantities of Gas (including the Retainage) equal to those quantities which PGS is entitled to interrupt, and desires PGS to release to Shipper (or to a Supplier designated by Shipper), for the duration of the period of interruption and at the maximum rate applicable to the capacity released, primary firm capacity on [ ] sufficient to transport such additional quantities of Gas to the PGS Receipt Point(s). By election of this Option B, Shipper agrees to be responsible for the payment of all charges imposed by [ ] with respect to the capacity so released by PGS to Shipper (or Shipper's Supplier), or the use of such capacity, for the period during which such release is effective. If Shipper elects to continue deliveries during the period of interruption pursuant to this Option B, PGS agrees to release the capacity requested by Shipper if PGS determines in its sole discretion that (i) such capacity is available for release to Shipper during the period of interruption, (ii) such release can be accomplished readily and without detriment to PGS's system operations, and (iii) such release is practicable within the time constraints and requirements of [ ] FERC Tariff and the ready availability of PGS staff and resources.

Option C: Shipper desires PGS to continue deliveries during the period of interruption, appoints PGS as its agent to acquire (at the PGS Receipt Point(s)) additional quantities of Gas at market-based price, equal to those quantities which PGS is entitled to interrupt, to be used by Shipper during the period of curtailment, and agrees to reimburse PGS, in addition to all amounts otherwise payable for Gas pursuant to this Agreement, for the incremental additional per-Therm costs incurred by PGS (as Shipper's agent) to acquire for the account of Shipper, at the PGS Receipt Point(s), Gas to be used by Shipper during the period of interruption. As used in this Option C, "incremental additional costs" shall mean the weighted average per-Therm costs incurred by PGS to acquire, for the accounts of Shipper and other interruptible customers of PGS who have elected this Option C during a particular period of interruption, the additional quantities of Gas mentioned above to be used by Shipper and such other interruptible customers of PGS during such period of interruption, including but not limited to commodity, transportation, storage and other charges incurred by PGS.

Option D: Shipper agrees to cease taking Gas pursuant to PGS's notice during the period of interruption.

If Shipper has elected to continue deliveries pursuant to Option A, Option B or Option C, PGS will, in implementing its interruption notice, take and pay for Shipper's Gas as provided in PGS's FPSC Tariff, but will not discontinue deliveries to Shipper unless (i) if Shipper has elected Option A, Shipper fails to make additional Gas available at the PGS Receipt Point(s), or (ii) if Shipper has elected Option B, either (a) PGS has no primary firm capacity on [ ] available for release to Shipper (or Shipper's Supplier) during the period of interruption without detriment to service required by PGS's customers in a curtailment category having a higher priority than Shipper's curtailment category under PGS's curtailment plan, or (b) PGS determines either that the release of capacity contemplated by Option B would not result in Shipper's (or Shipper's Supplier's) being able to make the additional quantities of Gas available at the PGS Receipt Point(s) for delivery to Shipper during the period of interruption or that the release of capacity cannot be made pursuant to Option B, or (iii) if Shipper has elected Option C, PGS, having exercised commercially reasonable efforts, is unable to acquire for Shipper's account, at the PGS Receipt Point(s), additional Gas for delivery to Shipper during the period of interruption. In the event of the occurrence of any of the circumstances described in items (i) through (iii), PGS will provide Shipper with not less than two (2) hours' notice to cease taking Gas during the period of interruption, and Shipper shall not have the benefit of Options A through C above.