STATE OF FLORIDA
OFFICE OF PUBLIC COUNSEL

C/O THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
ROOM 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

EMAIL: OPC_WEBSITE@LEG.STATE.FL.US
WWW.FLORIDAOPC.GOV

KATHLEEN PASSIDOMO
President of the Senate

PAUL RENNER
Speaker of the House of Representatives

October 23, 2023

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20230023 - GU

Dear Mr. Teitzman,

Please find enclosed for filing in the above-referenced docket the Joint Post-Hearing Brief of the Office of Public Counsel and the Florida Industrial Power Users Group. This filing was designated confidential when it was originally submitted to the clerk's office on October 6, 2023. Upon inspection by Peoples Gas System, Inc., this filing has now been deemed non-confidential and is being electronically filed in its entirety along with this cover letter.

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Walt Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No. 93590

CERTIFICATE OF SERVICE
DOCKET NO. 20230023-GU

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 23rd day of October, 2023, to the following:

Jon C. Moyle, Jr.
Karen A. Putnal
Florida Industrial Power Users Group
c/o Moyle Law Firm
118 North Gadsden Street
Tallahassee FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com

Austin Watrous
Chasity Vaughn
Daniel Dose
Danyel Sims
Major Thompson
Ryan Sandy
Florida Public Service Commission
Office of General Counsel
2540 Shumard Oak Blvd.
Tallahassee, FL 32399
awatrous@psc.state.fl.us
ddose@psc.state.fl.us
dsims@psc.state.fl.us
rsandy@psc.state.fl.us
mthompso@psc.state.fl.us
cvaughn@psc.state.fl.us

J. Wahlen
M. Means
V. Ponder
Ausley McMullen
P.O. Box 391
Tallahassee, FL 32302
jwahlen@ausley.com
mmeans@ausley.com
vponder@ausley.com

Karen Bramley
Peoples Gas System, Inc.
Regulatory Affairs
Tampa FL 33601-2562
regdept@tecoenergy.com
KLBramley@tecoenergy.com

Paula K. Brown
Helen J. Wesley
Peoples Gas System, Inc.
Regulatory Affairs
Tampa FL 33601-0111
pkbrown@tecoenergy.com

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Wessling.Mary@leg.state.fl.us

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Peoples Gas Systems, Inc.	DOCKET NO. 20230023-GU FILED: October 6, 2023

JOINT POST-HEARING BRIEF OF THE OFFICE OF PUBLIC COUNSEL AND THE FLORIDA INDUSTRIAL POWER USERS GROUP

The Citizens of the State of Florida, through the Office of Public Counsel ("Citizens" or "OPC"), and the Florida Industrial Power Users Group ("FIPUG") ("Joint Parties" or "JP"), pursuant to the Order Establishing Procedure in this docket, Order No. PSC-22023-0128-PCO-GU, issued April 12, 2023, hereby submit this Joint Post-Hearing Brief.

STATEMENT OF BASIC POSITION

The Office of Public Counsel's basic position in this case is that Peoples Gas System, Inc. ("Peoples," "PGS," or "Company") has failed to meet its burden to prove that every aspect of their requested rate increase is appropriate. FIPUG joins and supports OPC's position. PGS has requested their largest increase in company history and grossly overstates the revenue requirement needed to provide safe and reliable service. The theme of PGS's petition could be summarized as "all debits, no credits." The Commission should protect customers and only approve the parts of PGS's rate request which are fair, just, and reasonable. In today's tough economic climate, PGS's customers are already under great financial pressure, so any increase will have a significant impact on them.

OPC's expert witnesses, Lane Kollen and David Garrett, testified in depth about the flawed aspects of PGS's requested rate increase. Although the parties were able to successfully work together and negotiate the resolution of several issues, including limitation on future RNG projects that could have exposed customers to undue risk, several key issues remain contested. PGS failed to meet its burden of proof on those remaining issues, including the negative impact of the 2023 Transaction on customers; the unnecessary increases in staffing levels; the absence of efficiencies in the projected test year despite implementation of Work Asset Management ("WAM") and a new supply chain team; the excessive return on equity ("ROE"), rate base, and revenue requirement; and the troublesome cost allocation procedures between PGS and Seacoast Gas Transmission, Inc., among others.

At the hearing, OPC and FIPUG identified these flaws in PGS's evidence through cross-examination, and summarize those weaknesses below. The Joint Parties ask the Commission to remember Ms. Patty's customer comment that now is not the time for the Commission to approve what amounts to the largest rate increase in PGS history. The Commission should moderate PGS's rate request in a manner consistent with OPC's expert recommendations and the evidence of record, by only approving those portions of the request for which PGS has satisfied its burden of proof.[1]

STATEMENT OF FACTUAL ISSUES AND POSITIONS

TEST PERIOD AND FORECASTING

ISSUE 1: **Is PGS's projected test period of the twelve months ending December 31, 2024, appropriate?**

JP: *With appropriate adjustments, the proposed 2024 test year may be representative of the period of time in which rates will be in effect. *

ARGUMENT:

With appropriate adjustments, the proposed 2024 test year may be representative of the period of time in which rates will be in effect.

QUALITY OF SERVICE

ISSUE 4: **Is the quality of service provided by PGS adequate?**

JP: *Customer testimony suggests that PGS's quality of service does not support the magnitude of PGS's requested rate increase.*

ARGUMENT:

The Commission should independently determine whether PGS demonstrated that its quality of service supports the requested rate increase. PGS bears the burden of proof with respect to this and every other remaining issue in this docket. The customer who chose to appear at the customer service hearing, Ms. Patty, and the other customers who chose to write to the Commission regarding PGS's requested rate increase made clear that relative to the quality of service they receive from PGS, the magnitude of the requested rate increase is not warranted. EXH 176.

DEPRECIATION STUDY

ISSUE 6: **Are vehicle retirements, including salvage, properly matched with the prudent level of additional vehicles included in rate base? If not, what adjustments should be made?**

JP: * 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.*

[1] The Joint Post-Hearing Brief only addresses issues that are not the subject of an approved stipulation.

<u>ISSUE 7:</u>	**What depreciation parameters (remaining life, net salvage percentage, and reserve percentage) and resulting depreciation rates for each distribution and general plant account should be approved?**
JP:	*The depreciation parameters and resulting depreciation rates are shown in OPC Witness Garrett's testimony and Exhibits DJG-18 and DJG-24 – DJG-26.*

ARGUMENT:

The Company filed its depreciation study and an updated study using a December 31, 2024 study date. TR 547, 549-550. However, the Company engaged in a Type 2 Stipulation agreeing that the depreciation rates that become effective on January 1, 2024 should be calculated using a depreciation study date of December 31, 2023. As OPC witness Kollen testified, it is necessary to both conceptually and practically match the depreciation study date with the beginning of the test year when the resulting depreciation rate changes are applied to the gross plant to correctly calculate depreciation expense starting in January 2024. TR 1260.

Witness Garrett correctly calculated the depreciation rates using a depreciation study date of December 31, 2023, assuming no other changes to the methodologies or parameters reflected in the Company's updated depreciation study. TR 1261. Mr. 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, a methodology that conforms to the legal standards set forth in United States Supreme Court cases and is commonly used by depreciation analysts in regulatory proceedings. TR 1039. During his review of the Company's depreciation study, Mr. Garrett recommended adoption of different lives for five of the accounts based on his analysis of the best Iowa curve to fit the "observed life table" (OLT) curve. TR 1040-1041. He accomplished this analysis through a combination of visual and mathematical curve-fitting techniques, as well as professional judgement. TR 1041.

Mr. Garrett proposes a longer life for Account 376.00-Steel Mains from the Company's proposed 65 years (R1.5–65 Iowa curve) to 70 years (R1.5-70 Iowa curve). TR 1044. Due to 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, he focused on the relatively newer vintages in this account for his statistical analysis. TR 1045. The "sum-of-squared differences" (SSD) technique measured the distance between the Iowa curve and the OLT curve mathematically. TR 1045. Mr. Garrett's SSD results showed that his choice of the R 1.5-70 curve is mathematically a closer fit to the OLT curve then the Company's choice. TR 1047.

Mr. Garrett also proposes using 82 years (R2-82 curve) life for Account 376.02- Plastic Mains over the Company's proposed 75 years (R2-75 curve). TR 1046. Due to the Company's Problematic Plastic Pipe replacement program that began around 2015 which focused on early 1970's vintage pipe, Mr. Garrett focused on the relatively newer vintages in this account for his statistical analysis. TR 1046-1047. Using the SSD technique, Mr. Garrett's results showed his choice of the R2-82 curve was mathematically a slightly closer fit to the OLT curve. TR 1047.

Mr. Garrett proposes a longer life for Account 379-Measuring and Regulating Station Equipment-City Gate from the Company's proposed 52 years (R2–52 curve) to 60 years (R2-60 curve). TR 1047. Due to the Company beginning to build new city gates which are expected to last longer than the older ones, Mr. Garrett agreed the life should be longer. TR 1048. However, he demonstrated, based on current data, that those lives should be longer than proposed by witness Watson. TR 1049. Using the SSD technique, Mr. Garrett's results showed his choice of the R2-60 curve was mathematically a closer fit to the OLT curve. TR 1049.

Mr. Garrett also proposes using 62 years (R2-62 curve) life for Account 380.02- Plastic Services over the Company's proposed 55 years (R2.5-55 curve). TR 1049. He testified that if there was a plastic service when the bare steel was replaced, it was also replaced with newer plastic service. TR 1050. Witness Watson used data with placement years dating back to 1959, whereas Mr. Garrett used a more recent placement band which indicated a slightly longer life (albeit based on a shorter OLT curve). TR 1050. Witness Garrett's SSD results showed his choice of the R2-62 curve was mathematically a slightly closer fit to the OLT curve then the Company's choice. TR 1050.

Finally, Mr. Garrett proposes a longer life for Account 382-Meter Installation from the Company's proposed 45 years (R1.5-45 curve) to 55 years (R0.5-55 curve). TR 1051. Mr. Garrett explained that due to the unusual shape of the OLT curve, it is impractical to find an Iowa curve that provides a close fit. TR 1052. However, he testified that the relevant retirement data comprising the OLT curves should be considered to a greater extent than was suggested by Mr. Watson whose selection did not have a sufficiently flat shape and trajectory to reflect the retirement data. TR 1052. Based on Mr. Garrett's visual assessment and his SSD results, his choice of the R0.5-55 Iowa curve was mathematically a slightly closer fit to the OLT curve then the Company's choice. TR 1053.

Mr. Watson sought to criticize of Mr. Garrett's analysis. He argued that Mr. Garrett only presented one band in his exhibits and work papers, although he conceded that Mr. Garrett said he reviewed multiple placement and experience bands. TR 585. Yet under cross examination, witness Watson acknowledged that his own depreciation study, which he attached to his testimony, did not present all of the possible placement and experience bands for the accounts. TR 646. In fact, he conceded that this was because the exhibit would be a thousand pages, so he gave what he thought were representative placement and experience bands for the accounts and put the rest in work papers. TR 646. Witness Watson also attacked Mr. Garrett for what he believed to be Mr. Garrett's lack of consideration of subject matter experts' (SMEs) input. TR 647. Mr. Watson acknowledged that the SMEs who are giving their opinion are employed by PGS. TR 647-648. He then qualified his reliance on the Company's experts by saying he validates their opinions based on his own engineering experience and from doing these studies for many years. TR 648. In fact, witness Watson relied on the historical books and records of the Company to make his life selection (TR 649), just like Mr. Garrett. Witness Watson acknowledged that the application of an Iowa Curve to determine the life curves does take into account the life characteristics of industrial property. TR 649. Witness Watson conceded that he was not challenging Mr. Garrett's professional qualifications as a depreciation expert, just some of his views and some of his results. TR 658. Witness Watson acknowledged that one cannot make a selection without some level of judgement in some way, form or fashion. TR 660. Given 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 consumer interests generally critique them, his observations may lack objectivity. TR 659.

Mr. Garrett reviewed Mr. Watson's depreciation study and recommends longer lives for the five accounts discussed above. 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 as discussed above. The application of the December 31, 2023 depreciation study date and Mr. Garrett's longer lives on these five accounts results in a depreciation surplus is discussed in Issue 9.

<u>ISSUE 9:</u> **Based on the application of the depreciation parameters to PGS's data that the Commission has adopted, and a comparison of the theoretical reserves to the book reserves, what, if any, are the resulting imbalances?**

JP: *For the primary OPC expert recommendation, the resulting reserve imbalance is a depreciation reserve surplus of $221.024 million. EXH 89 D16-1807. For the other resulting imbalance per PGS's lives, see OPC witness Garrett's exhibits DJG-28. EXH 90.*

ARGUMENT:

As described by witness Garrett, in contrast to the book reserve, the theoretical reserve represents the accumulated depreciation balance that would currently exist, in theory, if the currently-approved depreciation parameters (i.e. life and net salvage) had been implemented throughout the life of the assets being studied. TR 1053. He stated that if the theoretical reserve exceeds the book reserve, it creates a reserve surplus. TR 1053. Mr. Garrett testified that the key feature of remaining life depreciation rates (as opposed to whole life depreciation rates) is that the perpetual imbalance between the book and theoretical reserve is mathematically allocated over the remaining life of the plant. TR 1053. In most cases, a separate or manual reserve imbalance allocation or amortization is not conducted; however, the greater the reserve imbalance, the more appropriate it becomes to consider a short amortization period to resolve the imbalance more quickly. TR 1054. This corrective action will be discussed more fully in Issue 10.

Mr. Garrett identified four options regarding the depreciation reserve surplus amount in his testimony. TR 1054-1055. However, due to the Type 2 Stipulation regarding the Depreciation Study date of December 31, 2023, two of those options are moot. TR 1054. Should the Commission adopt all of witness Watson's depreciation lives, the depreciation reserve surplus would be $159,474,313. TR 1055; EXH 90. Witness Watson said he calculated an approximately $153.6 million surplus so while there were some differences between his calculation and Mr. Garrett's unadjusted parameters calculation, the total was close and in the same ballpark. TR 655. Using Mr. Garrett's proposed lives (Joint Parties' primary recommendation) results in a depreciation reserve surplus of $221,024,192. TR 1055; EXH 89 D16-1807.

ISSUE 10: **What, if any, corrective depreciation reserve measures should be taken with respect to any imbalances identified in Issue 9?**

JP: *The reserve imbalances resulting as described in Issue 9 should be amortized over 10 years as explained in the testimony of OPC witnesses Garrett and Kollen in accord with Commission policy. Revenue requirements should be reduced $16.980 million. *

ARGUMENT:

PGS is seeking a record increase in rates. TR 229. The vast majority of the Company's case involves significant increases in ratebase ($829 million), a huge, proposed increase in employees (from approximately 700 to 850), the cost of a spin-off transaction that has an annual negative impact on customers of $10 million, implementation of nearly $40 million capital project that promises to deliver transformational savings to the company – but only after rates are set, and an ROE of 11%. There is not a lot of customer rate benefit embedded in PGS's proposal as filed.

The Joint Parties are contesting these cost increases that are seemingly driven by the Emera need to prop up sagging credit and cash flow metrics. TR1670 -1671, EX171, OPC BSP 16. Against this backdrop lies an issue that provides a productive place for the Commission to grant real and equitable rate relief to current customers who have overpaid in rates for depreciation expense. As pointed out by OPC experts Kollen and Garrett, PGS identified a minimum theoretical depreciation reserve surplus of $119.6 using a depreciation study date of December 31, 2024 and using present depreciation rates. In its depreciation study and utilizing proposed new parameters and depreciation rates, the Company effectively amortized a $153 million theoretical depreciation reserve surplus over the remaining average service lives for each plant account, thus reducing the depreciation rates for those plant accounts. TR 563. The Company quantified a $5.285 million reduction in annual depreciation expense, or an equivalent average amortization period of 22.6 years using the remaining life technique. TR 1263.

The Joint Parties propose that, for the benefit of the customers on the system who overpaid and to moderate PGS's enormous rate increase request, a relatively conservative return of this overpayment be implemented in 10 years, or a little less than half the time proposed by PGS. TR 1060-1061; 1265. It is undisputed that current customers have overpaid due to excessive depreciation rates. 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. Doing this will also mitigate the exorbitant rate increase requested by the Company in this proceeding and will return some of the overpayment to the deserving customers who paid that excessive expense through their base rates. TR 1263-1264.

The record demonstrates that the magnitude of the surplus when measured against the entire theoretical depreciation reserve is between 22% and 33%. TR 1213, 1994-1995; EXH 89, at 2; 90 at 2. Mr. Garrett recomputed the theoretical depreciation reserve surplus to be $221.024 million using the Joint Parties' depreciation study date of December 31, 2023 and his updated parameters. Mr. Kollen recommends helping customers using a 10-year flow back and the methodology for identifying and flowing through the surplus faster than the one on which the Company and Joint Parties agree.[2] The resulting effect of Mr. Garrett's recommendations using the Joint Parties' depreciation study date of December 31, 2023 and Mr. Kollen's recommendation to amortize the surplus over 10 years yields a net reduction in depreciation expense of $17.625 million and a net reduction in the base revenue requirement of $16.980 million. TR 1213, 1265. This is the treatment that the Joint Parties recommend.[3]

PGS does not dispute the presence of the significant imbalance in the form of a surplus. TR 2006. While suggesting that there is something called a "protocol" related to the use of the remaining life technique that should be followed, PGS does not object to the Commission amortizing the surplus over a 10 year period, to the extent Commission policy allows it. TR 1963, 1999-2000. The company agrees that the 10-year amortization would not harm the company financially and it would not violate Commission policy. TR 2004-2006. Simply put, PGS agrees that the Commission can return the over-collected depreciation dollars to the customers in accordance with its policy as stated in testimony and discovery:

> The company believes that any such revenue requirement reduction should not be the result of deviating from normal depreciation study practice, but rather should be the result of the commission's consideration of the use of an amortization method as a matter of policy.

[2] See EXH 62 and TR 1996-1997. Witnesses Kollen and Garrett performed the calculations of the revenue requirement impact of amortizing the surplus to income (reducing test year revenue requirements) based on the methodology outlined by the company.

[3] Mr. Garrett calculated a surplus of approximately $159 million (that the company deemed close enough to its calculation of $153 million) when its experts parameters and the stipulated study date of December 31, 2023 is used. TR 657, 1995; EXH 90, p. 2. If something closer to this amount is determined by the Commission, a modification of the flow back can be approximated by the Staff and Commission utilizing Mr. Kollen's workpapers in EXH 129 (Kollen workpapers).

TR 1960; 1998-1999

So what is that policy? In Order No. PSC-2010-0153-FOF-EI at p. 87, when confronted with a significant theoretical reserve surplus in a Florida Power & Light ("FPL") rate case, the Commission stated:

> We agree with OPC's position that intergenerational unfairness already exists, as witnessed by the existence of such a significant reserve imbalance. Therefore, we are of the opinion that amortizing the remainder of the reserve surplus is the most appropriate remedy to eliminate the intergenerational inequity the surplus created. The only question remaining is how long it should take to correct the situation.
>
> ***
>
> Accordingly, we find that the remaining reserve surplus amount of $894.6 million shall be amortized over a four-year period. This is consistent with our policy with respect to reserve imbalances, which has been to correct them as soon as possible without adversely impacting the company's ability to earn a fair and reasonable return.

This policy is consistent with any number of prior orders dealing with imbalances that are deficits involving amortization periods of between one and seven years.[4] Company witness Parsons conceded that intergenerational unfairness is a concern that the Commission has expressed in the past. She also agreed that the matching principle is an important concern that the Commission previously has considered when addressing methods to correct depreciation reserve imbalances as soon as possible. TR 2001.

Given 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 recorded in the theoretical depreciation reserve in a conservative 10 year period, the Joint Parties' adjustment should be made in the amount of $17.625 million, which will reduce overall revenue requirements by $16.980 million.

RATE BASE

ISSUE 13: Has PGS made the proper adjustments to remove all costs attributable to the operations of Seacoast Gas Transmission (SGT)? If not, what adjustments should be made?

---

[4] Order No. 1286, issued January 12, 1984 in Docket No. 19830268-TP (five years); Order No. 12857, issued January 10, 1984 in Docket No. 1983037-TP (five years); Order No. 12864, issued January 12, 1984 in Docket No. 19820477-TP (five years); Order No. 18736, issued January 26, 1988 in Docket No. 19871269-TL (one year; "This action will comply with our policies of correcting reserve imbalances as rapidly as possible and of accelerating the write-off of plant identified for retirement earlier than projected when these goals can be achieved without adversely affecting rates"); Order No. 22115, issued October 31, 1989 in Docket No.19890202-GU (seven years); Order No. 24004, issued January 22, 1991 in Docket No. 1990599-TP (two years); Order No. PSC-1994-1199-FOF-EI, issued September 30, 1994 (FPL proposed four years; Commission delayed approval to evaluate a faster return period);

JP: ***In its filing PGS did not demonstrate that all costs attributable to SGT were removed from the projected test year. After discovery, PGS removed an additional $190,000 in revenue requirements. The Joint Parties support this adjustment contingent upon the company conducting a comprehensive study and filing the results of it the next rate case. ***

ARGUMENT:

The Joint Parties presented extensive evidence establishing that PGS failed to provide a proper basis to attribute costs to its intrastate pipeline – Seacoast Gas Transmission, Inc. ("Seacoast" or "SGT"). The cornerstone of the Joint Parties' concern is that the basis for attributing costs to SGT is based on an impermissibly narrow basis. It appears that engineering-related costs such as cost estimating and design and construction supervision costs are only attributed to SGT based on when an actual pipeline construction project is underway. TR1810; EXH 222 at OPC BSP 2-3. This process does not take into consideration the demand that the potential Seacoast projects place on the Engineering Construction and Technology ("ECT") segment of PGS. There is evidence that in 2022, when the basis for the test year shift of costs to SGT was established, there were non-work order projects underway or being evaluated. Under the principles reflected in the evidence, these activities would not have formed the basis for costs to be allocated to SGT. TR 1806 -1810; EXH 211c, 215c, 66c.

In any case, establishing revenue requirements for a utility that performs services for an unregulated affiliate, this approach would be problematic. In this case it is even more concerning, given that PGS is seeking to increase its employee count significantly. Witness Richard acknowledged that the ECT area is seeking to put together a seven-member team that would work with the company's business development organization on projects that might touch the SGT organization. TR 1746-1748. While any incremental impact of SGT on proposed hires was not quantified, the very fact that the hiring needs of PGS could be driven in part by the demands that SGT places on the ECT organization should mitigate against authorizing the funds needed for hiring the 2024 Capital Management Team discussed elsewhere. There is significant evidence that at any given point in time, Seacoast has the potential to undertake projects that could divert resources away from the PGS ECT organization. TR 1800; EXH 175c, OPC BSP 9. Given that Seacoast has no employees and is almost entirely dependent upon PGS for management and engineering services, it is important that the allocation of costs between the regulated and SGT operations not be based on happenstance.

The Joint Parties are concerned that in a time of increasing costs, the leveraging of regulated operations funded by ratepayers should not be used for subsidizing non-regulated ventures. PGS was responsive to concerns raised by the OPC in discovery. A good faith adjustment was made to reduce revenue requirements by $190,000. The Joint Parties agree that the company has acted in good faith and has relied on a methodology that was not challenged in the past rate case. Nevertheless, in lieu of seeking an additional adjustment from the complicated record in this case, the Joint Parties would be satisfied if the Commission directed the company to re-visit its method of attributing costs to SGT. It is clear that the TECO Energy cost allocation manual ("CAM") was not designed to govern the division of costs between PGS and SGT. TR 2053; EXH 222. Only one place in the CAM alludes to the possibility that costs might be charged or allocated to an unnamed affiliate of PGS. TR 2054; EXH 222, OPC BSP 22. This is clear evidence that the company contemplates a less systematic and more *ad hoc* attribution of costs from PGS to SGT:

> 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 services provided to an affiliate.

EXH 222, OPC BSP 22. This is not good enough, especially in the post spin-off world.

Accordingly, the Joint Parties request that the Commission direct that PGS undertake a comprehensive review of its relationship to SGT, 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 SGT needs. The company indicated that it would conduct such a study if so directed by the Commission. TR 2058. The Joint Parties further request that the Commission direct that such a study be filed in the next rate case and implemented in any projected test year revenue requirement.

ISSUE 15: **Should PGS's proposed Advanced Metering Infrastructure (AMI) Pilot be approved? If not, what adjustments should be made?**

JP: ***No**. PGS bears the burden of proof to demonstrate the prudence of the proposed AMI pilot. Any approval of an AMI pilot should not be a basis for approval of wholesale implementation of an AMI project.*

ARGUMENT:

PGS admits that, to date, "only a small number of gas utilities have deployed AMI technology." TR 764. PGS also states that Tampa Electric already uses AMI technology and that PGS "is evaluating opportunities to access their existing network to support our pilot." TR 766. These statements do not satisfy PGS's burden of proof regarding the prudence of PGS's proposed AMI pilot program. The Commission should not allow the costs of the AMI pilot program to be included in customers' rates. This technology is experimental, and PGS should be required to conduct further research and evaluation before being allowed to force customers to cover the costs of such a program. Accordingly, the Commission should adjust PGS's requested revenue requirement by $2.2 million of capital expenditures and $100,000 in O&M expenditures. TR 766-767.

ISSUE 19: **Has PGS properly reflected in the projected test year the cost saving benefits to be gained from implementation of the Work and Asset Management (WAM) system? If not, what adjustments should be made?**

JP: *****No. PGS has incurred $34.4 million in capital costs for the new WAM system, yet it claims that WAM will not result in any savings whatsoever from efficiencies in the test year. The evidence indicates that the operation of the WAM system, in conjunction with other potential near-term actions, will lead to operational efficiencies that are not captured in the Company's projection of employee additions or savings in the level of contract labor expense.*

ARGUMENT:

The company is seeking approval of nearly $40 million in rate base related to a software project called WAM.[5] In keeping with its all debits, no credits filing, no benefits of this "transformational" efficiency-producing management tool have been listed as dollars saved or costs avoided.

The Joint Parties are not seeking to disallow the cost of WAM in the case. This is a work process efficiency software that PGS calls "transformational" and which management has directed the company to "leverage" for efficiencies. TR 1749-1750; EXH 174c, OPC BSP 12,13,15; 175c. Joint Parties do not doubt it is an efficiency that is warranted and perhaps overdue. PGS testified that other companies in the industry had implemented it. TR 1741. They showed it as a project in the 2020 rate case and indicated that it was under consideration since 2018. TR 1705, 1750-1751. Unfortunately, while the customers are being asked to bear the costs of this project, due to the timing of bringing it on line and the delays in implementing it, the expected benefits will not materialize until just after the test year. TR 1749, 1752- 1767; EXH 212c, 213, 214c. Full WAM cost recovery is requested, but PGS initially filed its case without reflecting any savings. TR 1768. This means that the shareholders will likely reap the post-test year benefits of any efficiencies from "sweating the asset" in the company vernacular. TR 877. The Joint Parties urge the Commission to seriously consider this confluence of this very expensive investment, the Company's intense focus on the transformational nature of the system, and the fact that a significant portion of the projected hires have not yet occurred and will not occur, if at all, until sometime in 2024.

This perfect storm of high cost impact in the test year and the potential for dramatic out-year cost savings could create a "double-whammy" impact on customers. WAM should be a basis for limiting excessive funding for hiring that can be avoided or cut back. PGS witness O'Connor conceded that WAM could factor into not hiring all of the projected employees and could positively impact contractor forces. TR 877. There is even evidence that implementation of WAM is ahead of target. TR 1770-1771. This fact could indicate that even the $750,000 reduction in revenue requirements that PGS offered up on the eve of hearing may be inadequate to reflect the "transformational" savings that Emera clearly expects with an investment approaching $40 million. It is this potential, perhaps likely outcome that the Joint Parties seek to emphasize in this case. Mr. Kollen explained it well in his testimony:

[5] Estimates range from $34.4 million (TR 1240) to $37 million (Kollen, TR 1298) to $38 million (Richard, TR 1781), to $38.8 million (Parsons, TR 1749).

> I essentially made the argument that the WAM investment, some $37 million of capital investment for the purpose of proving efficiencies in workflows, should have eliminated the need for many of those additional positions. And so because I recommended reducing the payroll and the related expenses in the forecast test year, I left the full WAM costs in without any additional adjustments.

TR 1298. The Commission should view WAM as a compelling reason to be skeptical about the need for customers to bear the cost of projected 2024 hirings.

<u>ISSUE 21:</u> **What level of projected test year plant in service should be approved?**

JP: ***The Commission should approve no more than $3,274,834,064 of projected test year plant in service. $33.331 million of purely projected plant in service should be removed from determination of the test year revenue requirements. ***

ARGUMENT:

PGS is asking the Commission to approve 100% of its projected rate base for two years. EXH 2, p. 3. This is unreasonable. This Commission should make an adjustment to this proposal for several reasons. The Company's track record is spotty at best on actually spending up to its budgeted levels. TR 1234-1235. Additionally, the Company is proposing an ambitious budget in 2023 and is showing signs of having difficulty in closing construction work to plant in service. PGS suggests that the Commission should have confidence in its purely projected 2023 and 2024 ratebase amounts due to PGS's "Capital Management Improvement Plan." However, that plan will not be effective for budgeting until 2024 at the earliest because the budget was set in 2022. Additionally, even the early implementation improvement tools are still a work in progress. TR 1712 -1720; EXH 174c, OPC BSP 11-12.

Mr. Kollen testified that the basis for his adjustment was that PGS failed to fully spend up to its capital expenditure budgets in each of the most recent five years, including the 2022 base year. Elsewhere, company witness Parsons has testified that a five-year trend analysis is the appropriate analytical tool. TR 2030. On average, the Company actually underspent its capital expenditure budgets by 2.6% to 15.9%, or a weighted average of 6.5%, over those five years. In 2018, its actual capital expenditures were 12.0% less than its budgeted capital expenditures. In 2019, the actual expenditures were 15.9% less than the budgeted expenditures. In 2020, the actual expenditures were 3.2% less than the budgeted expenditures. In 2021, the actual expenditures were 2.6% less than the budgeted expenditures. In 2022, the actual expenditures were 3.8% less than the revised budgeted expenditures. TR 1233-1234.

PGS attempted to rebut Mr. Kollen's testimony by contending that, with some re-engineering, the underspend on the capital budget could be made to appear less than it seemed and the trend Mr. Kollen identified could not be used to make an adjustment. TR 1639 – 1643, 1955 - 1956. This argument is without merit as it fails to capture all of the circumstances that might impact an underspend. Paramount is how the timing relates to the 2021 and 2024 rate case test years and other factors. For example, in 2021, which was the last rate case test year, the Company only appeared to underspend the budget by 2.6%. It would seem as that this would indicate that the test year matching would be reliable. The problem is that the 2021 test year has some notable "misses" on actual 2021 additions to the ratebase included in MFRs, in the form of a total of $48 million for an LNG and an RNG project. The Company told the commission that the two projects were vetted in the Integrated Resource Planning (IRP) process and could be relied upon (TR 1704 - 1705: EXH 208), but they ended up being a bust. The LNG project was never completed and the RNG project (New River) was only completed in 2023, two years behind schedule. TR 1667, 1831. The magnitude of these delays undermine the notion that the 2021 capital budget was brought in on budget. Other notable delays of significant projects include the Summerville - Dade City Connector and the FGT to JEF project. TR 1644, 1684, 1700; EXH 220 and 227; EXH 205, OPC BSP 205c. Delays are to be expected, but the issue here is that delays relative to the projected ratebase in a test year can result in overcharges to customers and windfalls to shareholders if the amount of capital approved in rates exceeds the actual capital spent. TR 1672: EXH 171, OPC BSP 17. Mr. Kollen has pointed out that there is reason for the Commission to be cautious in approving <u>all</u> of the projected rate base. The track record of the Company supports this caution not to approve 100% of the requested projected rate base.

As noted above, there is additional evidence that the Company has failed to meet its burden of demonstrating that its rate base projection are fully reliable. In the test year, PGS has developed its projected rate base by calculating test year rate base of $2,366,758,452. This projected number was predicated on the 13-month average rate base numbers shown on MFR G-1, pages 9 and 10, for the years 2023 and 2024, respectively. EXH 7. For 2023, the 13-month average rate base amount of $2,996,394,020 on EXH 7, G-1, page 9 on line 41, is a product of the beginning balance and December balance on that same line. The projected growth in those 13 months is $521,912,625. This projected number is tied to EXH 7, MFR G-1, page 23 of 28, line 34.[6] The projected "Additions To Plant In Service" amount of $550,582,924 less the projected "Retirement Amount of Related Investment" amount of $23,670,298, yields a net plant additions amount of $521,912,625, which ties to the above-noted projected 13-month growth in plant additions in 2023.

These figures, however, are just numbers on a piece of paper in a large pile of papers. The problem that arises with the PGS burden of proof is that the $550,582,924 is a non-starter. Under cross-examination witness Parsons acknowledged that the year-to-date closures of CWIP to plant in service was over $220 million short for 2023. TR 2040. EXH 210, OPC BSP 10. This demonstrates that the gross plant in service amount $550,582,924 that, as shown above, is the foundation of the 2023 capital budget, and is unlikely to

[6] On this page there are two lines numbered "34." In this case the reference is to the second line 34 which is the last line on the page.

be achieved. Even for 2022, the actual closure to plant was $90,633,829 short of budgeted amounts. EXH 210, OPC BSP 4. That amount of shortfall clearly carries over to 2023. No telling what will transpire for 2024, but it does not look promising. Additionally, since there is no actual experience to compare the 2024 budgeted CWIP closures to plant in service, the Commission should look at the best evidence: the underrun--spending less than budgeted--in closures in 2022 (which occurred after the MFRs and budgets for 2023 and 2024 were set), and the likely underrun in 2023 and conclude that achieving another $217,115,953 of plant additions or $257.585 million of capital expenditures, projected for the year 2024, which is an essential building block of the test year rate base, is in jeopardy as well. Compare EXH 7, MFR G-1, page 10 of 28, Line 39; MFR G-1, page 1, line 1, ("PROJECTED TEST YEAR UNADJUSTED AVG YR" column.) There was no evidence presented by the Company that a miraculous closure rate would overtake the most current actual, year-to-date experience. The evidence is overwhelming that PGS is in significant jeopardy of failing to meet its budgeted spending. This creates a significant risk that the Commission would approve excessive rates if were to accept 100% of what PGS has written down in the MFRs for its projected rate base.

Some of the Company's pushback on challenges to the budget reliability was grounded in its belief that it had developed new budgeting, governance and asset management process improvement measures. TR 1577-1578, 1599, 1639. These aspects of the ECT portion of the Company are important. The Joint Parties do not find fault with the implementation of these measures. The Commission should not, however, rely upon them to justify the approval of all, or even any, of the projected portion of rate base for the simple reason that the measures are untimely and cannot influence the accuracy of the capital budget. The 2023 and 2024 budgets were established in the summer of 2022. TR 1690-1693; EXH 206. Additionally, the budgeting tool for the high volume (blanket work order) work, on the surface, appeared to have been developed in 2021 for initial implementation in 2022 budget cycle. TR 1643, 1714. However, there was credible evidence from management presentations to the board and the internal auditors and a board presentation that the tool was more of a 2022 work product and in 2023 is still a work in progress. TR 1715-1716, 1725-1726; EX 174c, EXH 179c, OPC BSP 4. The other measures such as the improved governance process, early engagement, and a formalized CLASS estimating process, undoubtedly will help provide more accurate costing and asset management and budgeting process, but they were developed after the 2023 and 2024 budgets were established and will help the Company manage the budgeting, avoid project delays and provide cost controls in the future – outside of the test year. TR 1731 -1732; EXH 174c, OPC BSP 11-12. If anything, they will perhaps provide short term relief to the shareholders to the extent the Company underspends the rate base upon which rates are set. TR 1672, 1675–1676,

For these reasons, the Commission should, in recognition of the Company's failure to meet its burden of proof, accept Mr. Kollen's modest proposal and disallow $33.331 million of purely projected rate base from the test year. The associated revenue requirements for this adjustment are $2.963 million in return on ratebase and $905,000 in depreciation expense (after gross-up). TR 1235.

ISSUE 22: **What level of projected test year plant accumulated depreciation and amortization should be approved?**

JP: ***The Commission should approve $904,439,158 of projected test year accumulated depreciation and amortization.***

ARGUMENT:

The resolution of this issue is dependent upon the Commission's decision regarding Issue 21.

ISSUE 23: **What level of projected test year Construction Work in Progress (CWIP) should be approved?**

JP: ***The level of CWIP to be approved may be dependent upon the resolution of Issue 21 and the ultimate decision on the level of plant in service as it is affected by the accuracy of the PGS's budget process. PGS has not adequately demonstrated that the level of CWIP is justified based on the deficiencies in the budgets for 2023 and 2024 that were prepared in 2022.***

ARGUMENT:

The resolution of this issue is dependent upon the Commission's decision regarding Issue 21.

ISSUE 27: **What level of projected test year rate base should be approved?**

JP: ***The Commission should approve no more than $2,346,211,000 of projected test year rate base.***

ARGUMENT:

The resolution of this issue is dependent upon the Commission's decision regarding Issues 21, 49, (A&G allocation) and 57 (RNG project deferral accounting).

COST OF CAPITAL

ISSUE 28: **What amount of projected accumulated deferred taxes should be approved for the projected test year capital structure?**

JP: *The Commission should approve at least $286,705,000 in accumulated deferred taxes for the projected test year capital structure.*

ARGUMENT:

OPC witness Kollen testified that his rate base adjustments that result from the changes in depreciation expense on a net basis increase the ADIT included in the capital structure and reduce the base revenue requirement. TR 1270. He further stated that OPC's recommended changes increase the ADIT by $6.465 million and reduce the base revenue requirement by $0.532 million. TR 1270. Mr. Kollen shows the difference between the PGS cost of capital per the company's filing and the PGS cost of capital recommended by the Joint Parties on TR 1271. This recommendation shows the jurisdictionally adjusted capital for deferred income tax as $286,705,000. Thus, the Commission should approve at least $286,705,000 in accumulated deferred taxes for the projected test year capital structure.

ISSUE 29: **What cost rate should be approved for the unamortized investment tax credits for the projected test year capital structure?**

JP: *The Commission should approve $3.157 million at a 6.73% cost rate for the unamortized investment tax credits in the projected test year.*

ARGUMENT:

OPC witness Kollen pointed out the difference between the PGS cost of capital per the filing and the PGS cost of capital recommended by the Joint Parties on TR 1271. This recommendation shows the jurisdictionally adjusted capital for investment tax credits of $3.157 million at a cost rate of 6.73%. Thus, the Commission should approve $3.157 million at a 6.73% cost rate for the unamortized investment tax credits in the projected test year.

ISSUE 31: **What cost rate of short-term debt should be approved for the projected test year capital structure?**

JP: *The Commission should approve a 3.81% cost rate for short-term debt for the projected test year.*

ARGUMENT:

As further discussed in Issue 72, due to the 2023 Transaction restructuring, PGS will now be issuing its own debt on or before the end of 2023. TR 1225. Prior to the 2023 Transaction, Tampa Electric issued all of PGS's short-term debt sufficient to meet the debt financing requirements for both its electric business and the PGS natural gas division. TR 1225. Mr. Kollen noted that the debt was allocated by debt issue between the electric business and the PGS natural gas division based on the respective electric and gas financing requirements each year. TR 1225. Mr. Kollen explained that the 2023 Transaction upended the historic allocation of the debt issued for the respective electric and PGS natural gas divisions and prospectively reallocated the existing debt actually issued for the PGS natural gas division to Tampa Electric Company's electric business. TR 1225.

Mr. Kollen stated that the 2023 Transaction requires PGS to issue new and significantly higher cost debt to "repay" the entirety of its share of the Tampa Electric Company debt of approximately $910 million at the time of pay off according to PGS witness McOnie. TR 1111-1112, 1225. This requirement to "repay" is due to the Intracompany Debt Agreement (comprised of PGS's historical debt) that needs to be paid off prior to December 31, 2023, in order to avoid over $150 million of tax liability. TR 1111, 1227-1229; EXH 161, BSP G2-526, EXH 197, BSP G2-1121, EXH 198. Mr. Kollen further explained that this strips PGS and its ratepayers of the benefits of the much lower-cost debt that specifically had been issued to meet PGS's actual financing requirements ever since it was acquired by Tampa Electric Company in 1997. TR

1225. This harms PGS's customers for the foreseeable future and will permanently increase PGS's cost structure until all the new debt fully matures 30 years from now. TR 1226-1227. Mr. Kollen further stated that this reallocation of the existing debt will result in a structural increase in PGS's costs due solely to the 2023 Transaction until all the underlying debt issues mature. TR 1225. The effect of the 2023 Transaction is a one notch lower credit rating which is projected to result in an increase in the overall weighted cost of debt of roughly 8 basis points and an increase in the requested base rate increase of approximately $1.8 million. EXH 197, EXH 198, BSP G2-1126, EXH 167c, OPC BSP 4. In addition, the effect of paying off legacy debt at a blended 5.57% cost of debt results in an increase in the overall weighted cost of debt of roughly 29 basis points and an increase in the required base rate increase of approximately $7.1 million. EXH 198, BSP G2-1125.

Mr. Kollen testified that if the Commission allows the benefits of this lower cost debt to be reallocated from PGS to Tampa Electric for ratemaking purposes and new higher cost of debt to be recovered from PGS customers, then Tampa Electric, TECO, and Emera will receive and retain a net benefit of approximately $7.1 million annually for Emera shareholders until Tampa Electric's base rates are reset at some date after December 31, 2024. TR 1226; EXH 198, BSP G2-1125. PGS witness McOnie asserted that OPC did not attempt to quantify certain costs that were not incurred as "benefits" (i.e. stand-alone PGS audit fees, independent audit costs or credit rating fees) during the time period when they operated as single entity. TR 1132-113. This argument does not mitigate the real impact or negate the actual, real costs that will be incurred by PGS customers due to higher cost rates. Witness McOnie also argued that incurring market-based borrowing costs does not cause a subsidization from PGS customers to Tampa Electric customers. TR 1132. However, this speculative, future-based assertion does not address the reallocation of the historic debt incurred on PGS's behalf to Tampa Electric which will cause PGS's customers to pay higher rates than they otherwise would have if the 2023 Transaction had not occurred. TR 1229. In fact, the last earning surveillance report for the consolidated PGS and Tampa Electric operations for December 31, 2022, shows a 0.39% cost rate for short-term debt. EXH 196, BSP G2-1110.

Witness Kollen recommends that the Commission set the Company's cost of debt to retain the savings from the lower cost debt previously allocated to it regardless of the Company's actual cost of debt for the new debt issued to replace the former allocation. TR 1229. This approach mitigates the harm to PGS customers from Emera's financial engineering, from its attempt to retain the savings throughout the remainder of Tampa Electric' three-year base rate stay-out, and from its attempt to set PGS customer rates at excessive levels that has the effect of subsidizing Tampa Electric's customer rates for the foreseeable future. TR 1229. The Commission should approve a 3.81% cost rate for short-term debt for the projected test year. TR 1271.

ISSUE 32: **What cost rate of long-term debt should be approved for the projected test year capital structure?**

JP: *The Commission should approve a 4.61% cost rate for long-term debt for the projected test year.*

ARGUMENT:

As further discussed in Issues 31 and 72, due to the 2023 Transaction restructuring, PGS will now be issuing its own debt on or before the end of 2023. TR 1225. Prior to the 2023 Transaction, Tampa Electric issued all of PGS's long-term debt sufficient to meet the debt financing requirements for both its electric business and the PGS gas division. The costs were then allocated between the two based on financing needs. TR 1225.

Witness Kollen stated that the 2023 Transaction requires PGS to issue new and significantly higher cost debt to "repay" the entirety of its share of the Tampa Electric Company debt. TR 1111-1112, 1225. This requirement to "repay" is due to the Intracompany Debt Agreement (comprised of PGS's historical debt of approximately $910 million) that needs to be paid off prior to December 31, 2023, to avoid $150 million of tax liability. TR 1111, 1227-1229; EXH 197, EXH 198, BSP G2-1125. This harms PGS's customers for the foreseeable future and will permanently increase PGS's cost structure until all the new debt fully matures 30 years from now solely due to the 2023 Transaction. TR 1225-1227. The effect of the 2023 Transaction is a one notch lower credit rating which is projected to result in an increase in the overall weighted cost of debt of roughly 8 basis points and an increase in the requested base rate increase of approximately $1.8 million. EXH 197, EXH 198, BSP G2-1126, EXH 167c, OPC BSP 4. In addition the effect of paying off legacy debt at a blended 5.57% cost of debt results in an increase in the overall weighted cost of debt of roughly 29 basis points and an increase in the required base rate increase of approximately $7.1 million. EXH 198, BSP G2-1125.

Mr. Kollen testified that if the Commission allows this reallocation of lower cost debt from PGS to Tampa Electric for ratemaking purposes with new higher cost replacement debt, a subsidization by PGS customers of Tampa Electric customers will occur. TR 1226-1129. PGS witness McOnie asserted that OPC did not attempt to quantify certain avoided costs as "benefits" (i.e. stand-alone PGS audit fees, independent audit costs or credit rating fees) during the time period when they operated as a single entity. TR 1127-1128. PGS's argument does not mitigate the real impact or negate the actual, real costs that will be incurred by PGS customers due to higher cost rates. Witness McOnie also argued that incurring market-based borrowing costs does not cause a subsidization from PGS customers to Tampa Electric customers. TR 1132. However, this speculative, future-based assertion does not address the reallocation of the historic debt incurred on PGS's behalf to Tampa Electric which will cause PGS's customers to pay higher rates than they otherwise would have if the 2023 Transaction had not occurred. TR 1229. In fact, the last earning surveillance report for the consolidated PGS and Tampa Electric operations for December 31, 2022, shows a 3.81% cost rate for long-term debt. EXH 196, BSP G2-1110.

Witness Kollen recommends that the Commission set the Company's cost of debt 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. TR 1229. This approach would mitigate the harm to PGS customers from Emera's financial engineering, from its attempt to retain the savings throughout the remainder of Tampa Electric' three-year base rate stay-out, and from its attempt to set PGS customer rates at excessive levels in order to subsidize Tampa Electric's customer rates for the foreseeable future. TR 1229. The Commission should approve a 4.61% cost rate for long-term debt for the projected test year. TR 1271.

ISSUE 33: **Has PGS made the proper adjustments to remove all non-utility investments from the projected test year common equity balance? If not, what adjustments should be made?**

JP: *No position.*

ISSUE 34: **What equity ratio should be approved for the projected test year capital structure?**

JP: *The Commission should approve a 49.2% equity ratio.*

ARGUMENT:

As discussed by OPC witness Garrett, capital structure refers to the way a company finances its overall operations through external financing. TR 1027. The primary sources of long-term, external financing are debt (contractual bond issuances that require payment) and equity (ownership interest in the form of stock). TR 1027. Since dividends to stockholders cannot be paid until debt obligations are satisfied, stockholders have a lower priority to claims on company assets which increases their risk and their required return relative to bondholders. TR 1027. Therefore, equity capital has a higher cost than debt capital. TR 1027. As Mr. Garrett testified, a firm can reduce their weighted average cost of capital ("WACC"), by optimizing their debt financing which can also reduce tax obligations. TR 1027. However, as Mr. Garrett stated, under a rate base, rate of return model, a higher WACC results in higher rates, all else held constant. TR 1029. Thus, since 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. TR 1029. Because utilities have low levels of risk and operate a stable business, they can afford to operate with relatively high levels of debt to achieve their optimal capital structure. TR 1030.

Mr. Garrett examined the capital structure of the proxy group (the same proxy group used by PGS witness D'Ascendis) which is inseparable from the determination of the capital asset pricing model

(CAPM). TR 1031-1032. Accordingly, Mr. Garrett determined that the average debt ratio of the proxy group is 51% (based on the reported Value Line debt ratios for the proxy group) and has an average equity ratio of 49%. TR 1031. He noted that PGS's debt ratio was only 49% and was considerably higher equity ratio of 55% than the proxy group average. TR 1031. Mr. Garrett testified that 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. TR 1031. The discrepancies in the proxy group and PGS debt and equity ratios must be accounted for – failing to do so is an analytical error. TR 1031. While PGS witness D'Ascendis agreed that it was reasonable to review the capital structures of the proxy companies, he asserted that the range of common equity ratios depicts the range of typical or proper equity ratios maintained by comparable risk companies. TR 392. Then, witness D'Ascendis concluded that the Company's proposed debt ratio is within the range of the proxy group (as seen in witness Garrett's Exhibit DJG-15). TR 392-393; EXH 77. Witness D'Ascendis used this assertion to argue that Mr. Garrett's assumption of a 51% debt ratio/49% equity ratio for the proxy group and use of a Hamada adjustment, if the Company's 55% equity ratio is used, was unnecessary. TR 392-393. However, witness D'Ascendis's argument is flawed. First, he did not dispute the average debt ratio of 51% and equity ratio of 49%. EXH 77. Second, his claim that PGS's equity ratio falls within the range is overstated because only one company, Atmos Energy Corp., has a higher equity ratio at 62% (debt ratio of 38%). The remaining five companies have equity ratios of 49% or less. EXH 77.

Mr. Garrett analyzed several notable industries that were relatively comparable to public utilities, such as Cable TV, Telecom, Power, and Water industries, which have debt ratios of at least 60% and equity ratios of 40% or lower. TR 1034. Mr. Garrett demonstrated that PGS's proposed debt ratio is clearly too low (and its equity ratio is too high). TR 1034. Mr. Garrett explained that this results in excessively high capital costs and utility rates. Based on Mr. Garrett's credible analysis, PGS's total debt ratio for ratemaking should be 51%. TR 1034. The Commission should approve a 49.2% equity ratio. TR 1269.

<u>ISSUE 35:</u> **What return on equity (ROE) should be approved for establishing PGS's projected test year revenue requirement?**

JP: *The Commission should approve a 9.00% ROE.*

ARGUMENT:

PGS is seeking an exorbitant return on equity (ROE) of 11% with a 55% equity and 45% debt. TR 963. As demonstrated by OPC Witness Garrett, a ROE of 9.0% is more reasonable, based on a capital structure of 49% equity and 51% debt consistent with the proxy group. TR 965. A 9.0% ROE gradually (rather than abruptly) moves the prior ROE of 9.9%, which is currently excessive based on current market conditions, toward the actual, current market-based ROE of 8.5% (Capital Asset Pricing Model "CAPM"). TR 965-966, 1072.

Both PGS witness D'Ascendis and OPC witness Garrett utilized the Discounted Cash Flow ("DCF") model and CAPM. Both models are widely used and widely accepted financial models for calculating the cost of equity in utility rate proceedings. TR 963. Mr. D'Ascendis and Mr. Garrett approached the application of the models differently. Witness D'Ascendis also used other risk premium models that improperly inflate his ROE recommendation which will be discussed later. TR 963. Mr. Garrett conducted two variations of both the CAPM and DCF model using a proxy group of natural gas companies with relatively similar risk profiles. TR 964, 1031-1032. Mr. Garrett conducted the DCF Model using Analyst Growth and Sustainable Growth and CAPM at the Proxy Debt Ratio and Hamada CAPM at the Company's proposed debt ratio. TR 964.

Legal Standard

The DCF model and CAPM model used by Mr. Garrett are consistent with the legal standards set forth in the governing United States Supreme Court cases. TR 972-973. In *Bluefield Water Work & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923), the Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

In *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944), the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses *but also for the capital costs of the business*. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

(Emphasis added). TR 972-973. Mr. Garrett further explained that these models closely estimate the Company's true cost of equity which comports with the *Hope* case. TR 973-974. He testified that if the Commission sets the awarded ROE at this lower and more reasonable rate of return, it will comply with these U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. TR 974.

Mr. Garrett was asked on cross-examination if there was a definitive statement in the *Hope* case that states that allowed ROEs should be based on actual cost of capital, to which he replied the exact words were not in *Hope* case, but that his interpretation is undisputed in the industry. TR 1072-1073. The *Hope* case expands on the *Bluefield* case which only permits a utility to earn a return on the value of the property employed in public service. TR 972. Mr. Garrett also 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. TR 974. He acknowledged that ROEs awarded through the regulatory process may be influenced by outside factors such as settlements and other political factors, not true market conditions. TR 974- 975. Thus, relying on award ROEs from other jurisdictions over time bears little relation to market-based cost of equity. Since 1990, utilities have been awarded ROEs above the market. TR 976-977. Mr. Garrett estimated that the market cost of equity is 9.3%, and since utility stocks are less risky, they should be below the market cost of equity. TR 977. The failure to closely track the actual market-based cost of capital is detrimental to ratepayers and to the state's economy because these much higher returns result in an inappropriate transfer of wealth from Florida ratepayers to shareholders. TR 975.

Witness D'Ascendis, who is not an attorney, criticized Mr. Garrett's application of gradualism because he claimed that Mr. Garrett, who is an attorney and has practiced law at a regulatory commission, must recognize that Mr. Garrett's ROE would be confiscatory and illegal. TR 385. Witness D'Ascendis claimed that under *Bluefield* and *Hope*, ROE equals the investor-required ROE which equals the allowed ROE. TR 387-388. However, the appropriate legal interpretation of these cases that allows for gradualism seems to have eluded witness D'Ascendis. TR 296-297, 962. *Bluefield* and *Hope* are not as rigid as he contends. Moreover, witness D'Ascendis failed to address the main issue where awarded ROEs generally have been greater than then market. TR 977. In fact, witness D'Ascendis acknowledged that Florida's awarded ROEs are generally higher than all 35 other jurisdictions where he has previously testified, excluding Alaska. TR 436, 438.

<u>Other Models, Costs, and National Average of Awarded ROEs</u>

It is generally understood that other state utility commissions undertake a similar process as the Florida PSC when awarding an ROE figure. TR 250. FIPUG's Exhibit 185 was part of a larger presentation at a February 9, 2023 Emera Board of Directors meeting to inform them of the highest, lowest, and average ROEs state regulatory commissions awarded natural gas local distribution companies over the past ten years, from 2013 to 2023. TR 221; EXH 174c, EXH 185. PGS is an operating subsidiary of Emera, Inc. The document informed the Board that PGS would seek an 11.0% ROE from this Commission. The exhibit was compiled on January 20, 2023 using data from Regulatory Research Associates, a group within S&P Global Market Intelligence.[7]

[7] During pretrial discovery, exhibit 185 was considered by PGS to be confidential; however, during the hearing, the Company agreed to declassify it. TR 534-535.

The exhibit tells the Emera Board of Directors that "PGS has requested an ROE level of 11% **mid-point** in our upcoming filing." (Emphasis added). The exhibit shows that from 2013 to 2022, natural gas local distribution companies were awarded ROEs which averaged 9.6%. In 2022, the average ROE awarded to natural gas local distribution companies was 9.4%. Notably, PGS is requesting that this Commission award them an 11% midpoint ROE, which is 160 basis points or 1.6% above the 2022 national ROE average of 9.4% for natural gas companies. When a 100 basis point range above the mid-point is taken into consideration, the effect would be to allow the Company to earn 260 basis points, or 27.6%, above the 2022 ROE national average for natural gas local distribution companies. The Commission should award PGS the 2022 average ROE, 9.4%, which is higher than the ROE recommended by OPC expert Garrett. Compared to the PGS requested midpoint of an 11.0% ROE, this would save ratepayers $24,320,000, given that each 100 basis points on ROE equals $15,200,000 in consumer rates. TR 1202. The ROE sought by PGS, if awarded, would make PGS the national leader in approved ROE by 110 basis points. The Commission should either award PGS the well-supported 9.0% ROE recommended by OPC witness Garrett or award PGS the most current annual national average for local distribution companies, 9.4%.

<u>DCF Model</u>

The DCF model uses three primary inputs: (1) stock price: (2) dividend; and (3) the long-term growth rate. TR 989. As Mr. Garrett testified, the stock prices and dividends are known inputs based on recorded data, while the growth rate projection is estimated. TR 989. Mr. Garrett used the 30-day average stock prices. Since the DCF is used to determine the current value of an asset, longer periods (60, 90, or 180 days) are past stock prices that reflect outdated information. TR 990. Witness Garrett used the 30-day averages of adjusted closing stock prices for each of the proxy group. TR 991. He used a speculative, future-based annualized dividend published by Yahoo! Finance for the dividend input to his constant growth DCF for the proxy group. TR 991. Mr. Garrett noted that the difference between his and Witness D'Ascendis' DCF model are primarily driven by the differences in their growth rate estimate. TR 992. Witness Garrett used a sustainable growth rate in his DCF limited by the U.S. economic growth rate (i.e. Gross Domestic Product ("GDP"). TR 996. He also used the projected long-term GDP growth rate of 3.9%. TR 966. While he acknowledged that it is theoretically possible for a company to outpace GDP, Mr. Garrett testified that many analysts would say one has to be careful on the constant growth rate input not being too high. TR 1075. Using the 3.9% GDP for long-term growth rate, Mr. Garrett's sustainable growth DCF produced a result of 7.5%. TR 997-998.

Mr. Garrett also conducted the DCF model using analyst growth rates that are short-term projections of earnings growth published by institutional research analysts such as Value Line and

Bloomberg. TR 994. Using the dividend growth rate estimates published by Value Line, Mr. Garrett's analyst growth DCF produced a result of 8.3%. TR 997-998.

Witness D'Ascendis' DCF produced several results which incorporated numerous growth rates that are unreasonably high and are not sustainable. TR 1002. Mr. Garrett testified that a cost of equity above 10% is significantly higher than any reasonable estimate for a low-beta security (i.e. utilities) under current market conditions. TR 1002. Mr. Garrett testified that Mr. D'Ascendis used an assumption of long-term growth of 7.7% for Atmos Energy Corp, which is about two times greater than the projected, long-term nominal U.S. GDP growth. TR 1002. He noted that this violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long term, especially a regulated utility company with a defined service territory. TR 1002. Moreover, Mr. Garrett pointed out that Mr. D'Ascendis used *short-term*, quantitative growth estimates from analyst for the *long-term* growth in the DCF model. This is inappropriate. TR 1002. Mr. Garrett also pointed out that Mr. D'Ascendis' growth rate assumptions for many of the proxy companies suffer from the same unrealistically high growth rate assumptions and are not sustainable. TR 1002-1003. Given Mr. D'Ascendis' use of incorrect inputs that overstate growth, his DCF ROE estimates are overestimated and produce unreasonable results, which would cause customers to pay unnecessarily high rates. TR 1003.

CAPM

The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk, and the CAPM estimates this expected return. TR 1003. Mr. Garrett explained and witness D'Ascendis confirmed that 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 equity premium. TR 460, 1004. Mr. Garrett utilized the 30-day average of daily U.S. Treasury yield curve rates on the 30-year Treasury bonds for his risk free rate of 3.81%. TR 1005. The second input, the beta coefficient, represents the sensitivity of a given security to movements in the overall markets. TR 1005. The market portfolio of all stocks equals one. TR 1006. Stocks with betas greater than the market beta of one are more sensitive to market risk and stocks with betas of less than one are less sensitive to market risks. TR 1006. Witness Garrett testified that the average beta for the proxy groups is only 0.84%. TR 1006.

The third input is the equity risk premium ("ERP") which is the level of return investors expected above the risk-free rate in exchange for investing in risky securities. TR 1006. Arguably this is the most important input in estimating the cost of capital and can be ascertained three ways: (1) calculating historical average; (2) taking a survey of experts; and (3) calculating implied ERP. TR 1007. While many investors use a historical ERP since they are easy to calculate, Mr. Garrett testified that the forward-looking ERP is actually *lower* than the historical ERP. TR 1007-1008. Because U.S. data is biased upwards due to survivor bias (failed companies are excluded from historical indices), Mr. Garrett relied on the other two methods to determine the ERP. TR 1008. He calculated the implied ERP using the Gordon Growth Model where he used the current value of the S&P 500 to solve for implied expected return. In other words, based on the current value of all stocks (index price) and the projected value of future cash flows, the market can tells us the return expected by investors for investing in the market portfolio. TR 1011. Witness Garrett averaged the expert survey results for IESE Business School Survey (5.7%), Kroll Report (6.0%), Damodaran (5.1%) and his own implied ERP result (5.5%) to determine the average ERP of 5.6% he used in his CAPM. TR 1013.

Mr. Garrett testified that Mr. D'Ascendis did not rely on reasonable measures for his ERP. Specifically, he pointed out that witness D'Ascendis' ERP of 9.75% is significantly higher than the estimates reported in expert surveys and estimates by other analysts. TR 1015. Mr. Garrett testified that Mr. D'Ascendis reliance of 97 year old data has no bearing on the current and forward-looking ERP. TR 1015. Witness Garrett noted that witness D'Ascendis' ERP estimate (9.75%) is nearly twice as high as his average ERP (5.6%) determined by reliable sources and the result of his implied formula. TR 1015.

Although witness D'Ascendis criticized Mr. Garrett's use of surveys, he relied on at least one "expert's" data to calculate his risk premium. EXH 179c, BSP D9-627 – D9-639. Witness D'Ascendis did not criticize Mr. Garrett's use of the Damodaran method. TR 413. However, he did object to Mr. Garrett's inputs while recognizing that Mr. Garrett followed the approach described in Damodaran's method, referred to as the 'default" assumptions. TR 416. It appears Mr. D'Ascendis has issues with inputs that are not sufficiently high enough to upwardly bias the results of his model, which are significantly higher than other expert results.

<u>Other Models and Costs</u>

Witness D'Ascendis used his firm's variation of the risk premium method, the Predictive Risk Premium Model ("PRPM"), which casts doubt on the objectivity of his results. TR 513-516; EXH 132, BSP F3030-F3035. He acknowledged that the DCF model and CAPM methodologies are widely used by regulatory bodies across the country, whereas he could only point to two jurisdictions that may have marginally relied on his PRPM. TR 521-523. Moreover, an analysis of a five-year period for natural gas companies indicated that the PRPM resulted in a higher indicated ROE than either the DCF or the CAPM most of the time. TR 514, 516; EXH 132, BSP F3030-F3035.

Despite Mr. D'Ascendis' claim that Mr. Garrett did not consider his Empirical CAPM, Mr. Garrett noted that the ECAPM premise is that the regular CAPM underestimates the required return on low beta securities. TR 1019. Mr. Garrett disputed the use of the ECAPM because the Value Line beta utilized by him and Mr. D'Ascendis already adjusted upward to account for this theory and there is empirical evidence that the Value Line adjustment overstates the beta for these low-beta industries. TR 1019. Further, he testified that Mr. D'Ascendis' ECAPM relied on the same overestimated ERP inputs of old, out-of-date data which results in an unreasonable ERP twice that of industry experts. TR 1019.

Mr. Garrett also refuted witness D'Ascendis' use of a non-utility cost of equity model, since it adds no marginal value of estimating utility cost of equity and since the non-utility, competitive firms will tend to have high risk profiles than utilities and thus have higher cost of equity. TR 1024. Witness Garrett noted that it is not surprising that this non-utility model produces the highest cost of equity out of all of witness D'Ascendis' various models. TR 1024.

Witness Garrett did not add any additional basis points for business risk, size premium and/or floatation costs. Witness Garrett testified that firm-specific business risks are unrewarded by the market. TR 1020. He rejected the small size premium adjustment of 20 basis points proposed by Mr. D'Ascendis, because studies have shown the small size premium is a dead phenomenon. TR 1021-1023. Finally, Mr. Garrett refuted the need for additional floatation costs for two reasons. TR 1025. Floatation costs are not out-of-pocket costs and the market already accounts for these costs. TR 1025.

In addition to Mr. Garrett's disagreement with witness D'Ascendis on the application of these basis point adders, the Commission's own water leverage formula, which implements the results of the DCF and CAPM model and includes size premium and floatation cost adders as a basis for comparison, demonstrates the excessiveness of witness D'Ascendis' models. EXH 182. The water leverage formula uses five natural gas companies (many of which are the same as the proxy group) and five water companies, which are generally smaller in size. TR 457-460. The water leverage formula, using the requested 54.68% equity ratio, yields a 9.68 ROE, which is much more in line with Mr. Garrett's recommendation. EXH 182.

Since PGS has much less risk relative to the proxy group due to the decreased amount of debt in the capital structure, Mr. Garrett applied the Hamada model analysis. TR 1031. The Hamada model analyzes changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. TR 1035. Witness Garrett testified that because PGS's debt ratio is so much lower than that of the proxy group, when he "relevers" PGS relative to the proxy group, it results in a much lower ROE than if PGS had been operating with a capital structure equal to the proxy group. TR 1036. Witness Garrett recommends that if the Commission adopts his capital structure, PGS's cost of equity estimate under his CAPM would be 8.5% or if the Commission adopts PGS's capital structure, then 8.1%. TR 1037.

The Commission should reject PGS's exorbitant return on equity (ROE) request of 11% with a capital structure of 55% equity and 45% debt. TR 963. The Commission should adopt witness Garrett reasonable ROE of 9.0% based on a capital structure of 49% equity and 51% debt consistent with the proxy group. TR 965. His 9.0% ROE gradually (rather than abruptly) moves from the prior currently excessive ROE of 9.9% toward actual market based ROE of 8.5% based on the CAPM. TR 965-966, 1072.

<u>ISSUE 36:</u> **What capital structure and weighted average cost of capital should be approved for establishing PGS's projected test year revenue requirement?**

JP: *The Commission should approve a weighted average cost of capital of 5.87% and the capital structure shown in the testimony of OPC's experts.*

ARGUMENT:

Witness Kollen testified that the weighted average cost of capital is 5.87% based on Mr. Garrett's 49% equity ratio and 9.0% ROE. TR 1271. In contrast, PGS requested an exorbitant 55% equity ratio and an 11% ROE. TR 1271. The effect of Mr. Garrett's capital structure recommendation is an $11.402 million reduction in base revenue requirement. TR 1269. The effect of Mr. Garrett's ROE recommendation is a $27.115 million reduction in the Company's base revenue requirement and requested base rate increase, which is incremental to Mr. Garrett's capital structure recommendation. TR 1269. Witness Kollen calculated that each 10 basis point change in the ROE equals $1.356 million in the base revenue requirement and requested base rate increase, based on an equity ratio of 49.2% on a financial basis and 42.60% on a regulatory basis. TR 1269.

PGS witness McOnie asserted that credit rating agencies view the regulatory environment as a key consideration in determining the creditworthiness of an energy utility. TR 1136. He contended that the regulator determines an appropriate capital structure and defines allowed ROE, and these are two of the key variables that go into building up a utility's revenue requirement and by extension the debt level and cash flow generating capability of the company. TR 1136. As such, a change to either or both will have an impact on the company's financial metrics and creditworthiness. TR 1136. He suggested that the company needs its requested ROE and capital structure to assure access to capital and achieve the targeted credit rating. TR 1136. However, his arguments ignore the very real impact the company's decision to spin off from Tampa Electric has on its financial strength and access to capital.

On cross-examination, witness McOnie acknowledged that prior to the spin-off, Tampa Electric had access to the capital markets on behalf of PGS. In September 30, 2022, Tampa Electric had a BBB+ credit rating from S&P, A3 from Moody's, and A from Fitch, with a stable outlook. EXH 192 BSP G2-873; TR 1144. In the December 31, 2022, Tampa Electric 10-K, the potential business risk related to the $150 million potential tax liability as of January 1, 2023 related to the spin-off of PGS was addressed. TR 1144; EXH 193, BSP G2-876. Tampa Electric's credit rating outlook changed to negative in December

2022 for all three rating agencies. TR 1146. The credit agencies' outlook continued to remain negative for Tampa Electric as of June 30, 2023. TR 1147. While Mr. McOnie attempted to downplay the negative impact of the spin-off on the credit rating of Tampa Electric (TR 1150), it is clear that the 2023 Transaction caused negative impacts to Tampa Electric and will likely cause a one notch lower credit rating for PGS, as well. EXH 198, BSP G2-1126, EXH 167c, BSP 18; TR 1177. Witness McOnie confirmed that PGS does not have a credit rating or rated debt yet (TR 1150), but is seeking an indicative rating from Fitch and Moody's based on the filings in this case. TR 1152, 1155. PGS will have to access a private placement market which will cost more to borrow money from than when they were able to access the public market with Tampa Electric. TR 1156-1157. Finally, he acknowledged that PGS would have a lower credit rating than it would have as part of Tampa Electric. TR 1174. When asked if he would agree that PGS is not expecting customers to pay a higher-than-market ROE to support a specific credit rating due the spin off in 2023, witness McOnie eventually said that any credit rating would be based on the Company's filing and updated for actual results. TR 1155.

Essentially, the impact of the Company's decision to undertake the 2023 Transaction is to increase financing costs to ratepayers. The 2023 Transaction with all its potential risks was executed solely at the discretion of the Company, so the Commission should take every opportunity to minimize its impacts to PGS's customers. One of these opportunities, is to adopt the cost of capital as proposed by OPC's witnesses Kollen and Garrett. On a jurisdictional basis, the Commission should adopt the following:

PEOPLES GAS SYSTEM, INC.
COST OF CAPITAL
DOCKET NO. 20230023-GU

PGS Cost of Capital Recommended by OPC

	Jurisdictional Adjusted Capital $ Millions	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed-Up WACC
Long Term Debt	941.736	39.79%	4.61%	1.83%	1.85%
Short Term Debt	99.358	4.20%	3.81%	0.16%	0.16%
Customer Deposits	27.528	1.16%	2.53%	0.03%	0.03%
Deferred Income Tax	286.705	12.11%	0.00%	0.00%	0.00%
Investment Tax Credits	3.157	0.13%	6.73%	0.01%	0.01%
Common Equity	1,008.304	42.60%	9.00%	3.83%	5.18%
Total Capital	2,366.788	100.00%		5.87%	7.22%

<u>ISSUE 38:</u> **Has PGS made the proper adjustments to remove all non-utility activities from projected test year operating expenses, including depreciation and amortization expense? If not, what adjustments should be made?**

JP: *See discussion in Issue 13.*

<u>ISSUE 41:</u> **What amount of projected test year contractor and contract services cost should be approved?**

JP: *The Joint Parties recommend a reduction in the level of test year contractor and contract services cost by $206,000 for in-house hiring from outside contractors.*

ARGUMENT:

OPC witness Kollen testified that the Company included in its request 90 new employees in 2023 and 69 of which were forecast in to be filled in November 2023 or later. TR 1236. He also stated that the Company included 64 new employees in 2024 forecasted to be filled by January 1, 2024, except for four in March 2024 and another four in June 2024. TR 1236.

Mr. Kollen stated that the Company in its request did not reduce contractor expense by an amount that justified the forecasted increase in employees. TR 1239. He noted that the Company reduced contractor expense by a non-trended adjustment of only $1.1135 million in the test year, less than 10% of the $11.596 million increase in expense due to new employees. TR 1239. Witness Kollen asserted that even 10% may not have been due the Company's new employees displacing contractor employees. TR 1239. Witness Kollen further testified that the Company did not and cannot demonstrate that even a subset of the increased employee expenses were actually offset by a reduction in contractor employees and the related expense. TR 1239. He noted that the Company budgets contractor expense by the dollars and not by the number of full-time equivalents like internal employees (so there is not a one-to-one correlation between internal and external resources). TR 1239. Witness Kollen examined the trend for outside contractor expense and year-end head count and demonstrated that both have been increasing and are forecasted to increase from 2018 through 2024. TR 1240.

PGS witness Bluestone testified that PGS hired 83 new people as of mid-August 2023. TR 1380. PGS witness Bluestone was questioned about whether some of the new hires in 2023 were replacing outside services. TR 1388. Witness Bluestone indicated that she did not know if the new hires were a one-to-one replacement. TR 1388. However, she clarified that she did know that the business was looking at bringing in contractors, as indicated by PGS witness O'Connor. TR 1388. After reviewing Hearing Exhibit 202 entitled "118 New Team Members in 2023 and Displacement of Outside Services," witness Bluestone indicated her memory was refreshed. TR 1389. When ask how many of the new hires were from contractors, she indicated that 24 positions were hired from outside contract services but not all of the positions were new positions. TR 1389. She further confirmed that these 24 positions displaced outside contract services. TR 1389.

Witness Bluestone affirmed that 22 of the 24 positions were pipeline locator positions. TR 1390. Hearing Exhibit 202 said that the pipeline locator positions will displace the use of 22 pipeline locators provided by outside service vendors within seven of the company's service areas. The exhibit further states that the cost savings for moving these positions in-house was approximately $200,000. The exhibit also states that two Administrative Specialists will displace the use of two administrative support positions provided by vendors with two of the company's service areas. It further described that the cost savings for moving these administrative positions in-house was $6,000. These cost savings of $206,000 for in-house hiring from outside contract services should reduce the level of contractors and contract services accordingly.

ISSUE 42: **What number of projected test year employees should be approved for ratemaking purposes?**

JP: *The number of projected test year employees should remain at 746, the 2023 level as of the hearing, or a maximum of 777, which eliminates the requested 21 unfilled positions included in the request. The requested 2024 increases in employees and related expenses should be excluded from the projected test year revenue requirement.*

ARGUMENT:

Witness Bluestone testified that PGS had 708 employees as of December 31, 2022. TR 1319, 1377. She broke down the employee counts as follows: 93 collective bargaining members; 329 non-covered, non-exempt employees; and 286 exempt employees. TR 1320.

Mr. Kollen testified that the Company included in its request 90 new employees in 2023, 69 of which were forecast to be filled specifically in the fourth quarter of 2023. TR 185, 1236. He also stated that the Company included 64 new employees in 2024 forecast to be filled by January 1, 2024, except for four employees in March 2024 and another four employees in June 2024. TR 1236. Witness Kollen testified that the Company forecast 840 employees at the end of the test year (net of 23 vacancies) compared to the actual 630 employees in the beginning of the base year, an increase of 210 employees, or 33% over the three-year period, two years of which were forecast. TR 1237. He noted that the comparison of the forecasted 2023 and 2024 employee counts versus the actual employee count from 2019 through March 2023 showed the forecasted employee count for 2023 and 2024 was significantly greater. TR 1237. The employee count range for these years are as follows: 2019 – 569 low (March) to 606 high (December); 2020 – 601 low (February) to 625 high (October); 2021 – 611 low (May) to 711 high (November); and 628 low (March) to 711 high (November). TR 1237. He noted that the Company's headcount ranged from a low of 704 in February to a high of 709 in January. TR 1237.

Witness Bluestone confirmed an employee headcount of 743 as of August 3, 2023, with 94 union employees; 341 non-covered, non-exempt employees and 308 exempt employees. EXH 199, BSP G2-852; TR 1379. She confirmed that as of mid-August, PGS had hired 83 new people to fill a combination of backfilled positions and new positions. TR 1380. Witness Bluestone stated that 63 of the 90 requested new positions had been filled as of August 15, 2023. TR 1382-1384. She testified that out of the 16 requested positions she was supporting, an additional 3 employees had been added since August 3, 2023. TR 1396-1399. Witness Bluestone stated that of the 61 positions filled (of the 90 requested positions), 46 were backfilled and/or replacements positions and 15 were brand new positions. TR 1387. She testified that 30 of the requested positions remained unfilled in 2023. TR 1383-1384. In other words, the majority of the new employees filled existing positions.

By comparison, PGS provided an excel spreadsheet showing the actual and projected headcounts from 2021 through the end of the 2024 test year. EXH 132, BSP F2722. In both the projected years 2023 and 2024, PGS subtracted from the total requested positions for those years the Field Ops 5% vacancy, 20 and 22 respectively, and the Pipeline Environmental 5% vacancy, 1 for each year. EXH 132, BSP F2722. When adjusted for these vacancy percentages in these operations, the reduced total of requested positions for 2023 is 777 and for 2024 is 840. EXH 132, BSP F2722.

To reconcile the hearing testimony with the above discovery response (EXH 132, BSP F2722), the 777 requested positions for 2023 per discovery are further adjusted for the 30 remaining open positions as of August 15, 2023, which more or less equals the headcount of 743 plus the 3 additional positions (746) per Ms. Bluefield's testimony. EXH 132, EXH 199; TR 1396-1399. In sum, the company forecasted a 798 headcount by December 31, 2023, (777 excluding the 21 unfilled positions), while the actual headcount was 746 as of August 15, 2023, with 61 positions filled and 30 unfilled positions remaining. EXH 132, BSP F2722, EXH 199, BSP G2-852. The utility seeking a rate change always bears the burden of proof,[8] and PGS has failed to meet their burden of proof regarding the magnitude of PGS's projected test year position increases as Mr. Kollen testified the forecasted increase in employees and the forecast employees in the test year compared to the base year and prior years are unreasonable and excessive. TR 1241. The Commission should only approve an increased revenue requirement for which PGS has satisfied their burden of proof.

Therefore, the ratepayers should only fund positions that are actually filled as of the hearing, or are likely to be filled by the end of 2023. PGS has operated as a separate gas division with its own employees before the spin-off. As Mr. Kollen testified, the addition of employees is discretionary, the Company is already staffed for continued growth in customers and related infrastructure, and the Company did not

[8] *Florida Power Corp. v. Cresse*, 413 So. 2d 1187, 1191 (Fla. 1982).

reduce contractor expense by an amount that justifies the forecasted increase in new employees. TR 1238-1239, 1241. The Commission should eliminate the 21 "vacancy" positions from 2023 that even PGS deducted from their headcount that represent the 5% vacancy in gas operations (20 positions) and 5% vacancy in pipeline safety (1 position). EXH 132, BSP F2722. As Mr. Kollen testified, the Company's actual employees reflect significant vacancies compared to the employees budgeted (8% less than budget in 2021 and 10% less than budget in 2022). TR 2041. Moreover, the requested new positions do not reflect efficiencies from WAM or any other efficiencies. TR 1241. The Commission should also eliminate the requested 65 positions for 2024 since these are discretionary or otherwise should be covered by customer growth. Thus, the Commission should find that the number of projected test year employees should remain at 746, the 2023 level as of the hearing, or a maximum of 777, which would fund the 30 addition positions that PGS witness Bluestone testified remained unfilled in 2023 with the elimination the 21 vacancy positions included in 90 new positions in the as filed request, but eliminated by the Company.

To the extent that the Commission deems a more granular approach to tempering PGS's staffing request, an alternative follows. This approach is grounded in the lack of objective metrics to support the proposed hiring, the advent of WAM and the fact it is producing benefits ahead of expectations, and the changing testimony on the timing of hirings. This, plus the fact that PGS has raided its contract services corps to accelerate hires that were not to be made until after the rate case outcome was known, demonstrates why the Commission should allow no more than the level of hiring that is projected for 2023 in establishing revenue requirements.

The Commission can take an even more targeted approach in the ECT and Gas Operations areas based on the specifics of those areas. Specifically, the Commission should exclude the costs of hiring the 2024 component of the Capital Management Team. This largely projected employee complement is part of a project that is designed to yield benefits in the budgeting and cost control arena beyond the test year. Six of the seven hirings are not projected to occur before the middle of 2024. TR 1714. They can have no impact on the accuracy of the 2023 and 2024 budgets which were effectively set in the summer of 2022. TR 1739 - 1740. These proposed ECT hires, if made, will not be in place in time to have any material impact on even the 2025 budget. To the extent that the team coalesces, it will be impacting projects and capital budgeting for the budget years 2026, at best. Even its earliest effective impact in 2025 will still be for projects that will be coming on line after the test year. These facts cry out for the application of the matching principle that pairs costs and revenues with the same period. TR 2062. Accordingly, future revenues related to those out-years capital projects should be matched with the costs of this proposed team's development of them.

With regard to the second further alternative related to Gas Operations, the record demonstrates that the company failed to sustain its burden to demonstrate the need for the entire complement of 29 proposed Gas Operations hires that are included in the test year as projections. The impending WAM transformation, the curious hiring of contractor forces, the lack of any cohesive metric or principled approach to making hires, along with a "cookie-cutter" approach to explanations or justification for the extraordinary level of projected staffing levels in Gas Operations fall well short of the company's burden of proof. TR 809 – 810, 818, 821, 856; EXH 164. For example, witness O'Connor read an identical justification for 61 positions (32 backfills and 29 new) regardless of whether the position is to be an apprentice (15 such positions) or a leak survey technician, a locator or corrosion coordinator or a storekeeper. TR 821; EXH 164. This evidence is contradictory at best. It falls short of meeting a burden of proof though.

The same can be said of the fact that there are no objective metrics supporting the proposed geographical distribution of new hires. TR 809-810. Mr. O'Connor acknowledged that he did not manage his organization to the metrics shown in his rebuttal testimony (TR 793-797) and that they were not part of the reporting to executive or board management. TR 857. When put to the test, Mr. O'Connor acknowledged that the historical and forecast job tasks, such as service orders, locates, compliance and meter reading, yielded inconsistent results when compared to historical and forecast hires within the various districts. He also acknowledged that the company was not experiencing any safety problems and its service was the highest rated in a national survey. TR 880-883. Most of the proposed hires seemed to be targeted to areas where the tasks per employee were significantly higher that the company-wide average. One would assume that there goal was to bring the workload down to a more manageable level. TR 869; EXH 42. Mr. O'Connor attempted to deflect attention away from the point by suggesting that less tasks per employee was a metric that indicated ***less efficiency***. TR 873. But clearly, the company made an effort to add employees to bring the workload per employee down. Sarasota is a good example. In 2020, employees each shouldered an annual average of 35,569 tasks. A projected increase of 80% in employees from 21 to 38 from 2022 to 2024 drops that average 25,402 tasks. EXH 188, OPC BSP 9. In other instances, though, the level of tasks per employee was below the company average but additional positions were nevertheless forecast (Lakeland, Daytona, St. Petersburg, and Jacksonville). TR 867-868; EXH 188, OPC BSP 3,6,14,15. The point is that while the official explanation shown in Interrogatory No 13 (Exhibit 164) was canned and generic, the data from Exhibits 27 and 188 tell a story with neither rhyme nor reason. Mr. O'Connor attempted to apply some local color to the various regions after suggesting that the additional projected hires would only make the district employees les efficient. TR 873.

Mr. O'Connor acknowledged that WAM could flatten the hiring curve for both employees and contractors. TR 818, 877. The hodgepodge of evidence and the task/per employee numbers demonstrate one thing – WAM, which is aimed at making these very tasks easier to perform on a per person basis, will sort these inconsistencies out and allow the company to make transformational reductions in costs. TR 762

-763, 815 – 816, 862, 880; EXH 187, OPC BSP 2. The 15 apprentice hires projected for 2024 are doubly problematic. Not only do they take 18 months to achieve a skill level sufficient to work independently, but follow-through on their hiring seems especially vulnerable to the advent of WAM. TR 878.

Furthermore, the fact that PGS reached into its contractor ranks to place individuals on the payroll has a "robbing Peter-to-pay-Paul" feel to it. On one hand, the need for backfills or even apprentices may have gone away given the likelihood that the contractors are experienced. On the other hand, the contractor ranks are potentially depleted in a difficult hiring environment. Accordingly, the record has a void with regard to whether the cost of contract service might require a corresponding decrease in the test year given the hiring from its ranks. While admitting to plundering the contractor ranks to quickly fill its own complement, Mr. O'Connor was simultaneously unable to state whether the contractors themselves would now be short of workers. TR 856. The belated revelation at trial off this information precluded the Joint Parties from conducting meaningful discovery on this point. This absence of data should be chalked up as a failure in the company's burden of proof and not against the customers.

This state of the record calls for the Commission to limit employee-related revenue requirements as proposed by the Joint Parties or, failing that, to at least make targeted cuts in the ECT and Gas Operations areas as discussed above.

<u>ISSUE 43:</u> **What amount of projected test year salaries and benefits, including incentive compensation, should be approved?**

JP: *Limiting the employee count to the 2023 hearing level of 746 (eliminating the requested 29 additional 2023 positions) results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $5.997 million. In the alternative, eliminating the requested 2024 increase in employees (64) and related expenses and limiting approval of an employee count to a maximum of 777, results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $3.844 million. Further, the more reasonable 4.0% and 3.0% escalation factors for trended payroll in 2023 and 2024, respectively, should be applied. The effect of this adjustment is $1.918 million, after gross-up, for Commission assessment fees and bad debt expense. By limiting the requested merit pay increases for employees, the Commission should reduce the payroll and payroll related projected test year costs by an additional $1,918,000.*

ARGUMENT:

As discussed in Issue 42, the Commission should fund only the filled 746 positions as of the hearing, or a maximum of 777 positions which includes the approximately 30 positions that remain unfilled in 2023.

Witness Kollen testified that Company calculated the trended payroll expenses for the test year starting with the historic calendar year 2022 as the base year, then escalated the base year payroll expense by 5.0% for 2023 and then escalated that result by another 5.0% for 2024. TR 1242. He further testified that the Company did not distinguish between non-union contractual payroll increases for 2023 and 2024 for this purpose. TR 1242. Witness Kollen stated that the 5% escalation factors for trended payroll expenses in 2023 and 2024 are significantly greater than the actual non-union payroll expense increases of 3.75% in 2022, 2.70% in 2021, 2020, and 2019, and 3.0% in 2018. TR 1243. He also noted that the 5% trended factor was significantly greater than the contractual union increases for 2023 and 2024, which range from 2.75% to 3.0% during those years, other than for IBEW 2072 (which 2023 range was 5.0% to 13.8% depending on employee classification). TR 1248. Witness Kollen also noted that the 5.0% was greater than inflation of 2.8% and 2.2% for 2023 and 2024, respectively. TR 1243. Witness Kollen testified that the 5% trended factor is unreasonable based on historic and general inflation assumptions. TR 1244. He recommends using a more reasonable 4.0% and 3.0% escalation factors for trended payroll in 2023 and 2024, respectively. TR 1244. The effect of Mr. Kollen's adjustment is $1.918 million after gross-up for Commission assessment fees and bad debt expense. TR 1244.

Witness Bluestone argued in her rebuttal that the 5.0% payroll escalator in 2023 and 2024 will allow wages to catch up to CPI. TR 1372. However, the CPI has remained below 3.0%, for every year except the 2021 and 2022 outliers after the COVID epidemic. EXH 203; TR 1402. She acknowledged that the actual merit increases for 2023 and 2024 would be less than 5%, but claimed PGS needed extra money for competitive contracting, signing bonuses, moving expenses, growing compensation demands for new employees due to market demands, and adjustment compensation of existing employees who are at risk of being recruited away. TR 1379. However, witness Bluestone acknowledged that no actual merit increases for 2023 had been given as of August 3, 2023. TR 1403. She confirmed that most of the union pay raises were for 3.0% for 2023 and 2024. TR 1391. Witness Bluestone acknowledged that the Company had implemented wage premiums of 5% in 2022 for Miami, Ft. Myers, Jupiter, Ft. Lauderdale areas to compensate for increased cost of living and labor cost. TR 1391. She also acknowledged the premium wage differential would have been included in the test year. TR 1391. Further, PGS's team members are at an average of 0.97 compa-ratio as of January 23, 2023 meaning that PGS is close to the national market average, 1.0 being national average. TR 1392. Moreover, witness Bluestone confirmed that non-trended payroll is exclusively for the increases in headcount. TR 1395.

Given that PGS already has premium wages included in payroll and is near the national average, there is no justification for allowing a payroll factor that is almost 2% higher than PGS's merit increases from 2018 through 2021 and 1.25% greater than payroll increases in 2022. EXH 203, BSP G2-866. Given that PGS employees have received merit increases every year for the last five years, where three out of the five raises were greater than CPI, no "catching-up" to CPI is needed. EXH 203, BSP G2-866. Moreover, CPI is projected by the Company to be 2.80% and 2.20% for 2023 and 2024, respectively, which is less than Mr. Kollen's recommended wage increases of 4.0% and 3.0%, respectively. The Commission should adopt Mr. Kollen's more reasonable 4.0% and 3.0% escalation factors for trended payroll in 2023 and 2024, respectively. TR 1244.

Therefore, limiting the employee count to the 2023 hearing level of 746 (eliminating the requested 29 additional 2023 positions) results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $5.997 million. In the alternative, eliminating the requested 2024 increases in employees (64) and related expenses and limiting approval of an employee count to a maximum of 777 results in an annual reduction in payroll and payroll related costs for staffing reductions, after gross-up, of $3.844 million. Further, the more reasonable 4.0% and 3.0% escalation factors for trended payroll in 2023 and 2024, respectively, should be applied. The effect of this adjustment is $1.918 million, after gross-up, for Commission assessment fees and bad debt expense.

<u>ISSUE 47:</u> **What adjustments, if any, should be made to projected test year expenses being incurred by, or charged to, PGS related to merger & acquisition development or pursuit activity?**

JP: *****The Joint Parties believe that this issue is moot.*

<u>ISSUE 49:</u> **What amount of projected test year O&M expenses should be approved?**

JP: *****The Commission should reduce the projected test year O&M Expenses by at least $46,595,000. PGS's under allocation of A&G expense to construction is addressed here given that it is the bottom-line O&M issue.*

ARGUMENT:

This issue is relatively straightforward. The company believes that it has some discretion to adjust the projected transfer of Administrative and General ("A&G") expense to construction work. TR 2016 - 2017; EXH 220. In so exercising this putative discretion, PGS has proposed that an amount of $11 million so transferred in the 2022 base year should be held constant in both the base year plus one (2023) and the 2024 test year. Several rationales are offered for this, none of which hold water.

The issue was not directly addressed in the company's initial testimony. The OPC's expert Kollen pointed out the error in holding the transfer flat after framing the accounting treatment required by the Federal Energy Regulatory Commission's (FERC) Uniform system of Accounts ("USOA"):[9]

> Account 922 (administrative and general expenses transferred – credit) is defined in the USOA as "[t]his account shall be credited with administrative expenses recorded in accounts 920 and 921 which are transferred to construction costs or non-utility accounts." Account 922 is used to credit these two A&G expense accounts for an allocation to capital (capital expenditures) so that the net of the three accounts is the expense recorded for

[9] Application of the USOA is mandatory for gas companies by Commission rule 25-7.014 (1), F.A.C, Records and Reports in General.

> administrative and general salaries and related office supplies and expense, excluding the credit to capital expenditures.
>
> The A&G credit allocated to capital expenditures in turn is capitalized to the relevant construction projects included in construction work in progress ("CWIP"), and ultimately, is included in plant in service after the construction is completed and the CWIP is closed to plant. In this manner, the A&G included in plant in service is deferred and subsequently expensed through depreciation over the service lives of the assets. Thus, it is important that the A&G credit allocated to capital expenditures be calculated in a manner that is consistent with the A&G included in CWIP and then plant in service.

TR 1245. Mr. Kollen identified the specific error in this case in this way:

> The Company forecast the account 922 credit for A&G allocation to capital as $11.000 million. This is the same amount that it recorded in the base year. The Company made no attempt to increase the A&G allocation to capital to synchronize and match the increase in the forecast capital expenditures in the test year compared to the base year or to increase the A&G allocation to capital to synchronize and match the increase in the forecast A&G expense in accounts 920 and 921 in the test year compared to the base year.

TR 1246. Mr. Kollen noted that the company was artificially holding down the A&G transfer in the following manner:

> The account 922 credit for A&G allocation to capital should increase as capital expenditures increase and as A&G expenses increase. The Company significantly increased the capital expenditures and the A&G expense in the test year compared to the base year. Yet the Company held the account 922 credit for A&G allocation to capital constant in the test year compared to the base year, thus overstating the A&G expense among the three accounts on a net basis in the test year.

TR 1246. The Joint Parties ask the Commission to correct this error by reference to the percentage increase in both A&G expense and capital expenditures. A&G expense is forecast to increase by 34.9% (including additional payroll expense associated with the proposed hires; excluding the hires still shows a 19.3% increase). Additionally the projected base year to test year increase in capital expense increased for the same period by 11.4%. To rectify this error, Mr. Kollen applied a conservative[10] 19.3% adjustment to the artificially frozen A&G transfer. TR 1247.

The Company's response was two-fold. While there was no dispute about the expense increase, PGS essentially asserted (1) that the level of transfer is within their discretion, and (2) that a large project was removed from proposed test year recovery. For these reasons, PGS argued that the capital budget increase trend was not as OPC represented.

[10] The adjustment is conservative because it assumes that the payroll adjustment proposed by Mr. Kollen is accepted by the Commission. To the extent that it is not, the $2.125 million adjustment (reduction in expense) may be needlessly conservative.

These assertions are without merit and should be rejected by the Commission as discussed below. The company's proposed accounting treatment lacks merit because it is arbitrary and overstates revenue requirements. The *ad hoc* capital budget revision's suggested by PGS also lacks merit upon a closer look. Perhaps most problematic is that a post-rate case increase in the transfer in the last rate case test year (2021) provided an immediate boost in company earnings while customer rates stayed as set in reliance on the last rate case MFRs. TR 2010. Finally, the Company conceded that they did not perform any analysis or study required by the USOA because they did not have enough time. TR 2010 - 2011, 2015, 2019 - 2020.

The last concern is addressed first. As the Commission is aware, the company indisputably has the burden of proof to demonstrate the reasonableness and prudence of costs for which it is seeking recovery. The hurdle to meet this burden is reasonably heightened when a case is based on purely projected costs prepared over a year in advance. An admission that the company just did not have enough time to perform a study to evaluate whether the increased revenue requirement associated with its failure to increase the transfer in accordance with the increasing construction activities and A&G expenses fails this burden. The Commission should categorically reject the suggested frozen A&G transfer level based on this facet of the issue alone.

The Joint Parties ask the Commission to consider the significant downside to allowing a company to make its own subjective assessment of such a transfer. Customers may well be forced to provide shareholder windfalls if the Commission sets rates based on an $11 million transfer and PGS revises the test year income statement to transfer additional expense dollars to capital. Two problems occur in this scenario. First, rates are by definition excessive. Second, customers will pay for certain costs twice - once in rates as an expense and again through deferring the same dollars and paying a return of, and a return on, the capitalized portion of the same dollars when rates are next changed.

This concern is more than a theoretical one. In the 2020 rate case, PGS set the stage with the same scenario, except that scenario for the fact that the frozen transfer number was $8 million. TR 2008; EXH 219. While the case settled, there was no mention in the settlement order [11]of any upward revision of the $8 million transfer. Nevertheless, the company subsequently increased the transfer to $9 million, despite the MFRs – upon which the Commission was asked to rely for a fully projected test year – indicating the transfer would be limited to $8 million. The series of journal entries to effect that increase in transfer meant that the customers who paid rates based on the transfer limitation of $8 million are now paying to cover O&M expense in rates based on the balance of expenses ***not transferred.*** A portion of the original non-transferred test year O&M was then capitalized (the transfer was increased from $8 million to $9 million) in 2021. The transfer amount was again increased (from $9 million to $11 million) in 2022. TR 2010. These

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

dollars being recovered as O&M, but transferred between rate cases to capital, represent, at best, a break of faith in this element of pure-forecast ratemaking. At worst, it indicates that 2024 test year net rate base will be overstated. The Commission should now set a transfer amount that is based on reality and that minimizes the Company's ability to enhance shareholder windfalls. Mr. Kollen's analysis is a very conservative adjustment that is consistent with the growth in both the A&G expenses and the capital expenditures.

PGS's efforts to exclude the FGT to JEF project from consideration of this issue should be disregarded. The project is an active one and the stipulated testimony by the company executive responsible for the project indicates that while delayed, the project is accompanied by activities that would be related to construction supervision. TR 2021 - 2023. Witness Parsons made an attempt to provide out-of-responsibility testimony that the project was further delayed beyond the stipulated time frame that was included in Mr. Rutkin's direct testimony.[12] TR 2021 - 2023. Regardless, there was no testimony that, despite the delay, ongoing engineering and engineering supervision activities were not continuing. More importantly, even if it was delayed, there was no evidence that the project would not be ongoing in the test year. A project need not be included in the test year rate base or even in plant in service to draw a proper allocation of A&G expenses.

It is worth noting that the USOA states that expenses allocated to direct construction costs are not permitted to be added based on arbitrary percentages or amounts to cover assumed overheads. What is required is allocation based on direct time card distribution or a special study. TR 2019 - 2020; EXH 221 at OPC BSP 3-4. By Commission rule, these requirements and prohibitions apply in the ratemaking process based on the test year accounting and in any post-test year revision of the A&G transfer. Rule 25-7.014(1), F.A.C.

The Joint Parties would also note that despite the resistance to Mr. Kollen's observations about the increase in capital spend and the budgeted A&G expense, the relationship of the A&G transfer to capital in the years 2019 to 2022 did not support the company's rationale for not increasing the transfer. For example,when the actual capital spend increased 68% from 2019 to 2020, the $8 million A&G transfer remained the same. From 2020 to 2021 the capital spend ***declined*** 9%, but the transfer (after rates were set base on $8 million), ***increased*** 12.5%. Just as arbitrarily, between 2021 and 2022, the actual capital spend increased only 2.6% but the transfer amount increased $2 million or 22.2%. EXH 206, OPC BSP 7. The facts indicate that there is no consistencey in how the process is handled. PGS asserts that the allocation

[12] Mr. Rutkin testified that the project "is expected to be under contract by the end of the second quarter of 2023, under construction by the third quarter of 2024, and in-service by the third quarter of 2025, which is later than the company projected in our 2023 and 2024 capital budgets." TR 926, 2022.

should track the capital spend but there is no actual correlation to that in practice. The facts suport a trend that is more akin to the abrbitrariness that the USOA and Commission rule prohibit.

Given the Company's failure to meet its burden in the form of performing any time study or other special study or to justify its proposed limitation on the A&G transfer, the adjustment to increase the A&G transfer by $2.1423 million (before gross-up) should be made under the facts and applicable Comission rule 25-7.014(1), F.A.C.

ISSUE 50: **What amount of projected test year Depreciation and Amortization Expense should be approved?**

JP: *The Commission should reduce the projected test year Depreciation and Amortization Expense by at least $26,404,000.*

ARGUMENT:

Witness Garrett reviewed Mr. Watson's depreciation study and recommended longer lives for the five accounts discussed in Issue 7. Witness Garrett's recommendations are "better fitting" of the Iowa Curve to the OLT curve mathematically and based on considerations of factors impacting the data as discussed above. For the reasons discussed in Issue 7, the Commission should accept the application of the December 31, 2023 depreciation study date and Mr. Garrett's longer lives on five accounts.

Witness Kollen testified that the effect of Mr. Garrett's recommendations, including the stipulated December 31, 2023 study date, is a $7.257 million reduction in depreciation expense and a $6.991 million reduction in the base revenue requirement, comprised of the reduction in depreciation expense grossed-up for Commission assessment fees and bad debt expense offset in part by the related return on the reduction in accumulated depreciation. TR 1213, 1262; EXH 129 (Kollen's Workpapers).[13] In addition, there is a net reduction in base revenue requirement of $16.980 million using the stipulated study date of December 31, 2023 and a 10 year amortization period for the $221 million reserve surplus. TR 1264-1265. This net reduction in the base revenue requirement is comprised of the reductions due to the amortization of the depreciation reserve surplus, grossed-up for Commission assessment fees and bad debt expense; offset in part by an increase in depreciation expense due to an increase in Mr. Garrett's depreciation rate recommendations, also grossed-up for Commission assessment fees and bad debt expense and offset in part by the related return on reduction in accumulated depreciation. TR 1265. The Commission should reduce the projected test year Depreciation and Amortization Expense by at least $26,404,000.

ISSUE 51: **What amount of projected test year Taxes Other than Income should be approved?**

[13] Note: The documents moved into the record (TR 12) as EXH 129 included the workpapers, some of which are excel spreadsheets with formulas intact, for OPC witness Kollen. A search of Commission files, including the docket and Case Center, shows that these documents have yet to be attached to Document No. 05288-2023 in this docket. Therefore, OPC is unable to cite to a specific Bates page even though the entirety of EXH 129 was admitted.

JP: *The amount of Taxes Other than Income that should be approved is a fallout number.*

ARGUMENT:

PGS corrected the projected property tax by lowering the estimate by $2.008 million caused by an error. TR 1254. Given this adjustment, the customers drop their objection to the use of the five year trending analysis, given its applicability on other Issues such as Issue 21.

ISSUE 52: What amount of Parent Debt Adjustment is required by Rule 25-14.004, Florida Administrative Code?

JP: *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 the Commission approves a greater amount of equity in the company's capital structure, there should be a concomitant increase in the adjustment.*

ARGUMENT:

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 the Commission approves a greater amount of equity in the company's capital structure, there should be a concomitant increase in the adjustment

ISSUE 53: What amount of projected test year Income Tax Expense should be approved?

JP: *This is a fallout issue. The Joint Parties have not separately quantified the level of Income Tax Expense that would remain after consideration of its revenue requirement adjustments. The Joint Parties' adjustments are made on an incremental revenue requirement basis*

ISSUE 54: What amount of projected test year Total Operating Expenses should be approved?

JP: *This is a fallout issue. The Joint Parties have not separately quantified the level of Total Operating Expenses that would remain after consideration of its revenue requirement adjustments. The Joint Parties adjustments are made on an incremental revenue requirement basis.*

ISSUE 55: What amount of projected test year Net Operating Income should be approved?

JP: *This is a fallout issue. The Joint Parties have not separately quantified the level of Net Operating Income that would remain after consideration of its revenue requirement adjustments. The Joint Parties adjustments are made on an incremental revenue requirement basis.*

ISSUE 57: What annual operating revenue increase should be approved for the projected test year?

JP: *The Commission should approve a base revenue increase – including the transfer of Cast Iron/Bare Steel Rider revenues - of no more than $42,903,000. Resolution of the cost deferral related to the stipulated Issues 16 and 17 issue requires a revenue neutral revenue requirement recognition of the two customer-backed RNG projects.[14]*

ARGUMENT:

[14] It is discussed here by agreement and because it significantly affects bottom line revenue requirements.

The lone Renewable Natural Gas ("RNG") issue remaining from the stipulation on Issues 16-18 is whether the Commission should order a revenue neutral revenue requirement effect related to the two grandfathered RNG projects (Brightmark and New River) left in test year revenue requirements. OPC expert Kollen supported this as the only proper outcome. PGS acknowledged that the intent of "customer-backed" ventures like these RNG projects was to hold the general body of customers harmless. TR 2042. Unfortunately, the projects that remain in the test year revenue requirement will, if not corrected, impose an increase of $1.5 million in revenue requirements on the general body of customers, the impact of which would be perpetuated for as long as rates are not reset. TR 1292, 1992.

The Company contends that the Commission should effectively determine the "hold harmless" effect based on the 15-year life of the projects. TR 55-552. PGS further asserts that zeroing out the impact in the test year, and thus rates, will deprive future customers of the benefit of the turnaround from a deficiency to a surplus, even while acknowledging that current customers will bear a "lion's share" of the $1.5 million deficiency during the time that these rates will be in effect. TR 2043. There are two problems with this approach. First, customers in 2024 and the next several years will bear a majority of the costs of these projects – which is contrary to the very principle underlying them. Second, there is no guarantee of being a customer long enough to receive any such benefits which would have to be timely baked into the rates.

Mr. Kollen explained how this could be remedied by creating a deferred asset[15] that would levelize the cost in a way that matches them with the customer contract revenue and insulates the rest of the ratepayers from absorbing the cost. TR 1292. The Company agreed that they could accomplish this revenue neutrality if the Commission approved a deferral.[16] TR 2045; EXH 57. There was an indication that the company did not wish to incur the expense of tracking the deferred cost. This is nonsense because the cost of tracking and accounting for this process is provided for in the regulatory cost element of the test year revenue requirement. Furthermore, a little bit of customer funded administrative inconvenience is an insufficient basis for heaping an unintended revenue requirement on customers and is inconsistent with the

[15] The levelized revenues already provide the Company with a return on rate base over the terms of the contracts through the levelization formula, which embeds a rate of return on the revenue deficiencies until they are fully recovered from the participant. TR 1252.

[16] Commission approval to create a deferred asset in accord with Generally Accepted Accounting Practices or GAAP can be accomplished in this rate case. As the Commission has acknowledged in many orders, removal of expenses from the income statement and current period recovery and inclusion on the balance sheet (asset) for deferral and recovery on an amortized basis is permissible if the regulator approves it and gives reasonable assurances of future recovery. PSC Order No. PSC-2013-0193-PAA-EI (Issued May 6, 2013), Docket No. 2012-0303-EI, *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*. Simple authorization of this process in this case will give the reasonable assurance necessary for outside auditors to sign off. PGS did not express any reservations about the mechanics of creating the deferral. Mr. Kollen, a Certified Public Accountant, agreed when he testified that this would be in accord with Generally Accepted Accounting Principles, or GAAP. TR 1297.

company's burden of proof to demonstrate that a cost like this is reasonable or prudent. Accordingly, Mr. Kollen's recommended adjustment to neutralize the $1.533 million impact should be made. TR 1992; EXH 56, BSP D15-1651, EXH 57.

ISSUE 71: **Should the Commission approve PGS's proposed long-term debt cost rate true-up mechanism?**

JP: ***Based solely on the unique factual circumstance where an electric company has spun off its gas division in this case, and if the Commission deems the 2023 Transaction to be prudent in decision and execution, the Joint Parties will not object to the one-time long-term debt cost rate true-up mechanism -- for debt that is issued unrelated to that required to replace the Tampa Electric Company debt allocated to PGS pre-transaction -- after the gas company's first debt issuance; however, the Commission should disallow the incremental interest expense and other financing costs of the 2023 Transaction.***

ARGUMENT:

The Commission should not find that the 2023 Transaction was prudent, as further argued in Issue 72 *infra*. However, if the Commission finds otherwise, the Commission should require PGS to true-up the long term debt cost rate after the first debt issuance. PGS customers should receive the benefit of lower debt costs that may be realized following PGS's first debt issuance. TR 1277-1285. To the extent to Commission disallows the incremental costs of the transaction that would not have occurred but for the 2023 transaction, for debt that is issued unrelated to that required to replace the Tampa Electric Company debt allocated to PGS pre-transaction, the Commission should also require PGS to true-up the long term debt cost rate after the first debt issuance on a one-time basis limited to the specific facts of a an electric company spinning off its natural gas LDC division

ISSUE 72: **What adjustments, if any, should be made to the projected test year related to the spin-off of PGS?**

JP: *The Commission should disallow all costs associated with the discretionary 2023 Transaction and reduce the requested revenue requirement by at least $9,699,000.*

ARGUMENT:

PGS has failed to meet its burden of proof to show why the Commission should force PGS customers to pay the price for PGS's expensive, unilateral decision to spinoff PGS from Tampa Electric Company. The evidence shows that PGS customers will receive, at best, only intangible, unquantified, and merely potential benefits from the so-called "2023 Transaction" while paying a known, fixed, and extremely high price if approved by the Commission. In reality, the only guaranteed "benefit" to PGS customers of the 2023 Transaction is a lighter wallet.

Emera, Tampa Electric Company, and People's Gas System chose to move PGS from a division of Tampa Electric Company to a separate legal entity. TR 129. This corporate spinout was long contemplated by Emera since at least when Emera purchased Tampa Electric (and therefore PGS) in 2016. TR 126. In 2019, Emera undertook a due diligence review of the possible spinout and analyzed the various risks and benefits to Emera of undertaking such a transaction. TR 130; EXH 160c. The analysis included both a low-end and high-end estimate of how much it would cost Emera in one-time costs to execute the 2023 Transaction; however, this analysis did *not* include or even attempt to quantify any costs or benefits to customers of the 2023 Transaction. T. 260, EXH 160c. This shows that PGS did not consider either the positive or negative impact that the 2023 Transaction would have on customers.

Once the company decided to move forward with the 2023 Transaction, PGS again put the company's interests ahead of consumer interests when deciding how and when to carry out the 2023 Transaction. When asked about the reasons for undertaking the transaction, the company responded:

> The primary consideration when planning the structure and timing of the 2023 Transaction was the company's desire to avoid incurring a capital gain tax, which was informally and conservatively estimated to be a one-time tax expense in the year of the transaction of approximately $150 million.

EXH 161 BSP G2-526.[17]

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. This resulted in approximately $9.69 million of annually recurring costs for which PGS now seeks to have customers bear the burden of for the foreseeable future. TR 128, 1222; EXH 37, 198. Emera had total discretion over whether and when to move forward with the 2023 Transaction and chose to do so at a time that would be extremely costly to customers due to higher interest rates and amid Emera and Tampa Electric's credit rating challenges that will likely have a further negative effect on both PGS's credit rating and financing costs going forward for years to come. TR 86-87; EXH 54c BSP 9558, EXH 167c, OPC BSP 4. OPC witness Kollen summarized this danger, testifying, "Emera structured the 2023 Transaction, including the Intercompany Debt Agreement, for its benefit and it is a fact that this structure will harm PGS customers." TR 1229. OPC witness Kollen further states:

> This is true, not only for the test year in this proceeding, but also for the foreseeable future, because the higher cost of debt will result in a permanent increase in PGS cost structure until all the new debt fully matures 30 years from now.

TR 1226-1227.

The evidence shows that PGS's decision to undertake the 2023 transaction and the decisions regarding when and how to carry out the 2023 Transaction were devoid of any consideration of the negative

[17] See also, Private Letter Ruling EXH 162c.

impact that these decisions would have on PGS customers. These increased costs will harm PGS customers not only in this proceeding but also in future rate proceedings absent Commission action to protect PGS customers from the effects of the 2023 Transaction. TR 1214.

Furthermore, there is scant evidence supporting any customer benefit as a result of the 2023 Transaction. When PGS filed the pending request for a rate increase on April 4, 2023, it included direct pre-filed testimony of several PGS witnesses, including company President and CEO, Helen Wesley. TR 49-98. After acknowledging that PGS may experience higher financing costs in the short term as a result of the 2023 Transaction, Ms. Wesley's testimony included two reasons why, in the company's view, customers will find some benefit from the 2023 Transaction. TR 86-87, 89-90.

The first reason mentioned by Ms. Wesley related to the make-up of the PGS Board of Directors:

> Although the members of the Tampa Electric and Peoples Boards of Directors are essentially the same, the [2023 Transaction] enables Peoples, if it so chooses, to populate its board in the future with different board members.

TR 90.

Even accepting *arguendo* there is discernable and meaningful benefit to its customers of the PGS Board of Directors not being identical to Tampa Electric's Board of Directors, which Joint Parties do not concede, this is merely a potential benefit that may never materialize. TR 168. In fact, nine months have passed since the 2023 Transaction became effective on January 1, 2023, and PGS has added one board member to the Board of Directors during that time, but that board member was also added to the Tampa Electric Board of Directors. TR 168. Any purported benefit to customers represented by this possibility has already eluded customers since the 2023 Transaction occurred. Furthermore, the phrase "if it so chooses" suggests that PGS is not committing to make such a change to the Board of Directors, but merely saying that it could. This casts further doubt upon whether customers will ever benefit from this potentiality.

The second purported customer benefit of the 2023 Transaction listed by Ms. Wesley is the purported "risk mitigation effect" of having the assets and liabilities of Tampa Electric and PGS in separate legal entities. TR 90. While no party wishes that PGS, Tampa Electric, or any other utility experiences a catastrophic event that might test whether this benefit ever materializes, the fact remains that this, too, is a benefit from which customers may never realize one single dollar's benefit. Additionally, customers (of both PGS and Tampa Electric) are already paying for a significant amount "risk mitigation" in the form of insurance premiums. $6,466,885 worth of PGS's property, injuries, and damages insurance premiums are currently being recovered from current PGS customers through rates. EXH 7, BSP K257. Furthermore, PGS has requested a hefty increase to $7.9 million in insurance premiums and fees in the 2024 test year. EXH 7 BSP K257. If the Commission allows PGS to recover both the costs of the 2023 Transaction and the increased projected insurance expense, PGS customers will be forced to pay more for the effects of the discretionary 2023 Transaction, premised in part on risk mitigation, than they would pay for all PGS insurance premiums combined. EXH 7 BSP K257. If PGS had not chosen to undertake the 2023 Transaction, or had at least exercised better discretion by undertaking it at a time when interest rates were closer to PGS's historical debt rate, this customer harm would have been mitigated; but it was not.

In Ms. Wesley's rebuttal testimony, she acknowledges that, "Mr. Kollen correctly notes that we have not identified any quantifiable, short-term financial benefits from the 2023 Transaction for customers." TR 110. Ms. Wesley also claims that the decision to move forward with the 2023 Transaction was designed, at least in part, "to allow our customers to benefit from the many intangible benefits described in my testimony." TR 105. While Peoples asserts that it considered the interests of PGS customers before deciding to move forward with the 2023 Transaction, the evidence submitted by PGS simply does not support that claim. The evidence provided by PGS to satisfy PGS's burden of proof that the 2023 Transaction was prudent falls short – it shows that PGS did not conduct any due diligence to determine quantifiable benefits to customers prior to deciding to undertake the 2023 Transaction or in the structure or timing of the 2023 Transaction. The evidence also shows that the chosen structure and timing of the 2023 Transaction, will save Emera shareholders $150 million in tax liability but will cost PGS customers almost $10 million annually for the foreseeable future. The evidence is also overwhelming that the merely potential and "intangible" benefits to customers of the 2023 Transaction may never materialize. It is equally clear that the shareholders will receive speedy and full recovery of the nearly $10 million tangible and material recurring costs of the 2023 Transaction unless the Commission disallows these costs, as it should. Mr. Kollen testified:

> The Commission had no statutory authority to approve or otherwise address the structure or results of the 2023 Transaction before it was implemented. However, the Commission does have the authority to address the effects of the 2023 Transaction for ratemaking purposes in this proceeding and future proceedings in order to protect customers from the adverse effects of the 2023 Transaction.

TR 1216.

The Commission should find that PGS's decision-making related to the 2023 Transaction was imprudent, and the Commission should adjust PGS's rate request by removing the costs associated with the 2023 Transaction, lowering PGS's requested revenue requirement by $9,699,000.

<u>ISSUE 74:</u> **Should FCG be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?**

JP: *****Yes.*

<u>ISSUE 75</u>: **Should this docket be closed?**

JP: ***No.***

Dated this 6th day of October, 2023.

Respectfully submitted,

Walt Trierweiler

Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No. 93590

Charles J. Rehwinkel
Deputy Public Counsel
Florida Bar No. 0527599

Patricia Christensen
Associate Public Counsel
Florida Bar No. 989789

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm 812
Tallahassee, FL 32399-1400

Attorneys for Office of Public Counsel

/s/ *Jon C. Moyle*
Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, Florida 32301
Telephone: (850) 681-3828
Facsimile:(850) 681-8788
jmoyle@moylelaw.com
kputnal@moylelaw.com

<u>CERTIFICATE OF SERVICE</u>
<u>DOCKET NOS. 20230023-GU</u>

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 6th day of October, 2023, to the following:

J. Wahlen
M. Means
V. Ponder
Ausley McMullen
P.O. Box 391
Tallahassee, FL 32302
jwahlen@ausley.com
mmeans@ausley.com
vponder@ausley.com

Austin Watrous
Chasity Vaughan
Daniel Dose
Danyel Sims
Major Thompson
Ryan Sandy
Florida Public Service Commission
Office of General Counsel
2540 Shumard Oak Blvd.
Tallahassee, FL 32399
awatrous@psc.state.fl.us
ddose@psc.state.fl.us
dsims@psc.state.fl.us
rsandy@psc.state.fl.us
mthompso@psc.state.fl.us
cvaughan@psc.state.fl.us

Paula K. Brown
Peoples Gas System, Inc.
Regulatory Affairs
Tampa FL 33601-0111
pkbrown@tecoenergy.com

Karen L. Bramley
Peoples Gas System, Inc.
Regulatory Affairs
Tampa FL 33601-2562
regdept@tecoenergy.com
klbramley@tecoenergy.com

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Wessling.Mary@leg.state.fl.us

/s/__Jon C. Moyle___
Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm, P.A.
jmoyle@moylelaw.com
kputnal@moylelaw.com