BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200051-GU

IN RE: PETITION FOR BASE RATE INCREASE BY

PEOPLES GAS SYSTEM

CONFIDENTIAL

PREPARED DIRECT TESTIMONY AND EXHIBITS

OF

ANDREA C. CRANE

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

August 31, 2020

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## I. STATEMENT OF QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is Andrea C. Crane and my business address is 2805 East Oakland Park Boulevard, #401, Ft. Lauderdale, FL 33306.

**Q. By whom are you employed and in what capacity?**

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in 2008.

**Q. Please summarize your professional experience in the utility industry.**

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

**Q. Have you previously testified in regulatory proceedings?**

A. Yes, since joining The Columbia Group, Inc., I have testified in over 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony over the past five years is included in Exhibit ACC-1.

**Q. Have you previously testified in regulatory proceedings in Florida?**

A. No, this is the first time that I am submitting testimony in a proceeding before the Florida Public Service Commission ("PSC" or "Commission").

**Q. What is your educational background?**

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. On June 8, 2020, Peoples Gas System ("Peoples" or "Company"), filed a Petition with the Commission seeking a base revenue increase of $85.3 million, or approximately 34.8%. This increase includes the effect of rolling-in to base rates approximately $23.6 million annually that is currently being collected through a Cast Iron / Bare Steel Rider ("CI/BSR") that was authorized by the PSC in Order No. PSC-2012-0476-TRF-GU. Therefore, the net impact of the Company's request is a net revenue increase of approximately $61.7 million or 22.9%. PGS is proposing to increase residential rates by slightly more than the system average. The Company is proposing a residential ("RS") revenue increase of 36.8%, or 25.0% after consideration of the CI/BSR roll-in.

The Company's filing is based on a Historic Base Year ending December 31, 2019, and on a Projected Future Test Year ending December 31, 2021. Hence, the entire Future Test Year is forecast in this case. PGS is requesting a return on equity of 10.75% and a capital structure consisting of 54.7% common equity (excluding customer deposits and deferred income taxes). The Company's last base rate case was filed in Docket No. 20080318-GU and was based on a 2009 Projected Test Year. That case was resolved with a Commission Order on April 5, 2010.

In addition to this base rate filing, on June 8, 2020, PGS also filed a Petition (Docket No. 20200166-GU) requesting approval of new depreciation rates for its gas system. On June 22, 2020, the Commission consolidated the depreciation case with the base rate case.

The Columbia Group, Inc. was engaged by the Office of Public Counsel ("OPC") to review the Company's Petition and to provide recommendations to the Commission regarding revenue requirement issues. In addition, David Garrett is sponsoring testimony on behalf of the OPC regarding cost of capital and capital structure issues, and depreciation issues.

**Q. What are the most significant issues in this rate proceeding?**

A. The most significant financial issues include the Company's request to utilize a fully-forecast Projected Future Test Year; its request to reflect in rates significant capital expenditures projected over a 2 year period; and the Company's requested 10.75% return on equity. The Company is also seeking increases to its depreciation rates, significant increases in labor costs, including $4.3 million for additional employees, as well as increases in Transmission Integrity Management Program ("TIMP") pipeline assessment costs, insurance premiums, storm damage costs, and manufactured gas plant ("MGP") remediation costs.

## III. SUMMARY OF CONCLUSIONS

**Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?**

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending December 30, 2019, is an acceptable Base Year to utilize in evaluating the reasonableness of the Company's claim.
2. Given the fact that the Company is using a fully-forecast Projected Test Year, consisting of the twelve months ending December 31, 2021, the PSC should be especially cautious in evaluating the projections contained in the Company's Petition.
3. As discussed in the testimony of Mr. Garrett, the PSC should authorize a pro forma cost of equity of 9.50% for PGS, and a capital structure consisting of no more than 54.7% common equity (excluding customer deposits and deferred income taxes), resulting in an overall cost of capital of 6.05% (see Exhibit ACC-2, Schedule 2).[1]
4. PGS has a pro forma, Future Test Year rate base of $1.495 billion (see Exhibit ACC-2, Schedule 3).

[1] Exhibit ACC-2 contains my Revenue Requirement schedules. Schedule 1 and Schedule 26 are Revenue Requirement Summary Schedules, Schedules 2 to 6 are Rate Base Schedules, and Schedules 7 to 25 are Operating Income Schedules.

5. PGS has pro forma, Future Test Year operating income at present rates of $58.8 million (see Exhibit ACC-2, Schedule 7).

6. Based on my recommended adjustments, the Company has a pro forma, revenue deficiency of no more than $42.3 million, as shown on Exhibit ACC-2, Schedule 1. This is in contrast to PGS' claimed deficiency of $85.3 million.

7. After consideration of the roll-in of approximately $23.6 million related to the CI/BSR, the net impact is a revenue increase of no more than approximately $18.6 million.[2]

8. In addition to the adjustments discussed in my testimony, the Commission should also reflect a parent company interest adjustment in the Company's revenue requirement. Staff requested that the Company quantify such an adjustment in Staff IRR-37, and we are currently awaiting a response to that request.

9. The Company's request to increase its annual storm damage accrual from $57,500 to $380,000 is not unreasonable. In addition, the Company's request to increase the annual amortization expense of the MGP regulatory asset from $640,000 to $1,000,000 is not unreasonable.

**Q. Are you in agreement with all of the components of the Company's revenue requirement claim, other than those specifically discussed in your testimony?**

A. No, not necessarily. I focused on the major issues in the case or issues that I believe

2 The $23.6 million was based on the Company's requested ROE, so the actual net impact of the roll-in may be slightly different.

have important policy considerations. In addition, the procedural schedule in this case required my testimony to be filed less than three months after the Company's Petition was filed, and less than eight weeks after we received responses to our initial discovery. This compressed procedural schedule did not allow me to undertake as much discovery or as detailed an analysis as I usually do in utility rate proceedings. Therefore, if a specific issue or methodology is not addressed in my testimony, it does not necessarily mean that I support the Company's position on that issue or ratemaking methodology. There may also be adjustments raised by other parties to this proceeding that have merit and that should be adopted by the Commission. For this reason, I have identified my calculated revenue deficiency as a maximum.

In addition, in some cases, the Company has utilized methodologies with which I may disagree but which have been accepted by the PSC in the past, and which I chose not to address in this testimony. Accordingly, the PSC should not assume that the OPC is necessarily in agreement with all issues that are not otherwise addressed in my testimony.

## IV. COST OF CAPITAL AND CAPITAL STRUCTURE

**Q. What is the cost of capital and capital structure that the Company is requesting in this case?**

A. The Company is requesting an authorized return on common equity of 10.75%, and a capital structure consisting of 54.7% common equity to total debt plus equity. The capital structure also includes customer deposits and deferred income taxes. Based on its proposed capital structure and cost rates, PGS is requesting an overall authorized return of 6.63%, as shown below:

| | Percent | Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 32.07% | 4.47% | 1.43% |
| Short Term Debt | 6.27% | 2.80% | 0.18% |
| Customer Deposits | 1.64% | 2.51% | 0.04% |
| Common Equity | 46.30% | 10.75% | 4.98% |
| Deferred Taxes | 13.71% | 0.00% | 0.00% |
| Total | | | 6.63% |

**Q. What is the overall cost of capital that that the OPC is recommending in this case?**

A. OPC is recommending an overall cost of capital of 6.05%, based on the following capital structure and cost rates:

| | Percent | Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 32.07% | 4.47% | 1.43% |
| Short Term Debt | 6.27% | 2.80% | 0.18% |
| Customer Deposits | 1.64% | 2.51% | 0.04% |
| Common Equity | 46.30% | 9.50% | 4.40% |
| Deferred Taxes | 13.71% | 0.00% | 0.00% |
| Total | | | 6.05% |

OPC's recommended cost of capital is based on the capital structure filed by the Company and on a recommended cost of equity of 9.5%, as discussed in the testimony of David Garrett. This is the cost of capital that I have incorporated into my revenue requirement schedules, as shown in Exhibit ACC-2, Schedule 2.

## V. RATE BASE ISSUES

**Q. What Test Year did the Company utilize to develop its rate base claim in this proceeding?**

A. The Company selected the Future Test Year ending December 31, 2021. Therefore, the Company's rate base claim includes 2 years of projected plant additions (for the years 2020 and 2021). The use of a fully-forecast Future Test Year requires a subjective analysis, since no party in this case knows with certainty what the Company's actual investment will be during this time.

**Q. What are the major components of the Company's rate base claim?**

A. The Company's rate base claim includes two major components — net utility plant in service and working capital. Net utility plant includes gross utility plant in service, common plant that is allocated to PGS, authorized acquisition adjustments, and construction work in progress, offset by accumulated depreciation and amortization and by customer advances. The Company's allowance for working capital includes all other balance sheet components except for customer deposits and deferred income taxes, which are included in capital structure. The Company's rate base is based on a thirteen-month average balance during the Projected Future Test Year.

**Q. How does the Company's rate base compare to the rate base authorized in its last base rate case?**

A. The Company's filing reflects explosive growth in its rate base between the Commission order in PGS' last rate case and the present filing. As shown in Schedule A-3 to its filing, the Company's rate base is projected to grow by approximately 182% between 2009 and 2021, largely driven by increases in gross plant and construction work in progress. What is perhaps more significant to note is that much of this growth is projected to occur between the Historic Base Year and the Projected Test Year in this case:

| | Growth 2009-2019 | Growth 2019-2021 |
|---|---|---|
| Gross Plant in Service | 74.43% | 31.63% |
| CWIP | 44.57% | 485.82% |
| Total | 73.89% | 38.51% |

Gross plant and CWIP increased by 73.89% from 2009 to 2019 and is projected to increase by another 38.51% in the two-year period between the Historic Base Year and the Projected Test Year in this case. Thus, while there are 12 years between the Projected Test Year in the last case and the Projected Test Year in this case, a disproportionate amount of the rate base growth is due to the two years of projections included by PGS in this case. It is also worth further noting that the Company has indicated it may file another rate case in 2022 with a 2023 projected test year.[3]

**Q. How do the Company's 2020 and 2021 capital budgets compare with the amounts traditionally budgeted by PGS?**

A. As shown in its response to OPC IRR-30 and Exhibit SPH-1 (Document No. 6), the Company's capital budgets have increased dramatically over the past five years, and additional growth is projected for 2020 and 2021:

| | Approved Capital Budget ($000) |
|---|---|
| 2015 | $103,970 |
| 2016 | $106,539 |
| 2017 | $148,892 |
| 2018 | $195,929 |
| 2019 | $240,014 |
| 2020 | $358,693 |
| 2021 | $263,805 |

3 PGS response to OPC POD No. 34 at Bates No. 5212.

The Company's projected spending of $358.693 million in 2020 is approximately 50% more than the capital budget in any of the prior five years. While the Company's 2021 capital budget is somewhat lower than the 2020 projection, it is still very high relative to historic levels.

PGS has stated that its 2020 capital budget is largely related to four projects: the Panama City Expansion Project, the Southwest Florida Expansion Project, the Jacksonville Expansion Project, and a new Liquefied Natural Gas ("LNG") facility in Miami. These four projects comprise $117.62 million of the 2020 capital budget and $15.37 million of the 2021 capital budget, as shown in the Company's response to OPC IRR-100.

Even if these four projects are excluded, the 2020 and 2021 capital budgets are high relative to capital budgets prior to the Base Year in this case. Given the Company's expressed interest in entering into new and potentially competitive markets, such as the LNG market, the Commission should be especially vigilant to ensure that projected capital projects are necessary for safe and reliable regulated gas service, and are not being undertaken in order to position PGS to expand into speculative activities or to enter competitive markets.

Q. **Are you recommending any adjustments to the net plant-in-service additions projected by PGS in its filing?**

A. Yes, I am recommending an adjustment. It is important to keep in mind that the Company's utility plant-in-service claim is largely based on projections, including costs for many projects that will not even be started by the time that new rates are effective in this case. Given the use of a Future Test Year, there is uncertainty inherent in the Company's projected plant additions. In addition, the capital budgets on which these projections are based reflect spending that far exceeds the Company's historic capital spending. Moreover, the current COVID-19 pandemic is likely to result in at least some construction delays. Therefore, even if the Company's projections were accurate when it prepared its 2020 and 2021 capital budgets, there are likely to be some delays in project completion. For all these reasons, some adjustment to the Company's net plant-in-service claim is warranted.

**Q. Does it appear that there have been delays in specific projects?**

A. Yes, it does. As previously noted, when it filed its testimony PGS identified four major projects that were responsible for a significant portion of the incremental 2020 capital budget. In its pre-filed testimony filed on June 8, 2020, PGS indicated that three of these projects (Panama City, Southwest Florida, and Jacksonville expansion projects) were projected to be in-service by December 2020. In addition, the Company indicated the Miami LNG facility was projected to go into service in June 2021.

In discovery responses provided a few weeks later, PGS indicated that, while the Panama City and Jacksonville projects are still expected to be in-service by the end of 2020, a portion of the Southwest Florida project is now projected to be delayed until March 2021 and the Miami LNG facility is not expected to go into service until April of 2022. Moreover, since those responses were filed, the COVID-19 crisis in Florida has intensified. In addition to delays in these major projects, there are likely to be additional delays in other areas of the Company's capital program, especially when one considers how aggressive the capital program is relative to historic expenditures. Therefore, some adjustment to the Company's proposed revenue requirement is appropriate.

**Q. How did you quantify your adjustment?**

A. Since the Company's claim is based on speculative projections, any adjustment to that claim will also be subjective. Accordingly, I am recommending that the Company's projected plant-in-service balance at December 31, 2020, be used to set rates in this case. At Exhibit ACC-2, Schedule 4, I have made an adjustment to reduce the Company's projected gross utility plant balance from the average Projected Test Year balance reflected in the filing to the projected balance at December 31, 2020.

**Q. How did you incorporate the additional Future Test Year Adjustments made by the Company in Schedule G-1, page 4?**

A. I examined each of the adjustments made by the Company in Schedule G-4 to determine if they were impacted by the use of the December 31, 2020, plant balances and, if so, I further adjusted my recommended gross plant-in-service balance to prevent any double-counting of adjustments. In some cases, the use of the December 31, 2020, plant balances did not necessitate any change to the rate base adjustments made by the Company; e.g., the acquisition adjustment was not dependent on the amount of gross plant added in the Future Test Year. However, the Company's CI/BSR adjustment of $16,488,118 (per Schedule G-1, page 4) was largely based on projected Future Test Year additions. Therefore, as shown on Exhibit ACC-2, Schedule 4, I reduced my recommended adjustment by $16,488,118 in order to avoid double-counting the removal of the 2021 CI/BSR plant.

In addition, the Company's adjustment to exclude non-utility common plant was based on its projected 2021 plant additions. Therefore, I also made an adjustment to non-utility common plant to synchronize the common plant allocated to PGS with the plant additions that I recommend be reflected in rate base. This adjustment was based on the Company's response to OPC IRR-114, and it also included in Exhibit ACC-2, Schedule 4.

**Q. Please describe your adjustment to construction work in progress ("CWIP").**

A. Similar to my recommended adjustment relating to gross plant, I made a similar adjustment to reflect the Company's projected December 31, 2020, CWIP balance in rate base. My adjustment is shown in Exhibit ACC-2, Schedule 5. Once again, I reviewed the Company's rate base adjustments to determine if any further adjustment was necessary to properly reflect the proposed adjustments shown on Schedule G-1, page 4 of the Company's filing. In the case of CWIP, I made two further adjustments. First, I reversed the Company's proposed adjustment relating to CI/BSR plant, for the reasons stated above. Second, I reduced my adjustment by a portion of the Company's adjustment relating to the CWIP that is eligible to accrue an allowance for funds used during construction ("AFUDC"). Both of these adjustments are shown in Exhibit ACC-2, Schedule 5.

**Q. How did you quantify the AFUDC adjustment?**

A. At Schedule G-1, page 4, the Company reduced its rate base claim by $30,814,451 to account for CWIP that is eligible to accrue AFUDC. In the response to OPC IRR-114, the Company identified the CWIP eligible to accrue AFUDC that was associated with its December 31, 2020 plant balance. I used this data to quantify my AFUDC adjustment to the Company's CWIP claim.

**Q. How do the plant balances contained in your recommendation compare with historic spending?**

A. My recommendation results in an increase in gross plant-in-service and CWIP of approximately $570 million from the Base Year to the Projected Test Year. This is still a very significant increase relative to the Company's historic spending levels and demonstrates the reasonableness of my adjustment. Moreover, if the Commission determines that the Company's rate base claim has been inflated due to capital expenditures undertaken to better position PGS with regard to speculative competitive activities, additional adjustments may be appropriate.

**Q. Did you make a corresponding adjustment to the Company's reserve for depreciation and amortization?**

A. Yes, I did. Consistent with my adjustments to utility plant-in-service and CWIP, I also made an adjustment to reduce the Company's reserve for depreciation and amortization. PGS reflected an average Projected Test Year balance in its claim. I have utilized the December 31, 2020, reserve balance in my rate base recommendation. My adjustment is shown in Exhibit ACC-2, Schedule 6.

In addition, my adjustment to accumulated depreciation also reflects corresponding revisions to the Company's adjustments relating to the CI/BSR and non-utility common plant, as discussed above.

**Q. Doesn't your recommendation effectively move the Test Year up by one year, from calendar year December 31, 2021, to calendar year December 31, 2020?**

A. No, it does not. While the Company's filing is based on the Projected Test Year ending December 31, 2021, the Company reflected average Test Year balances in its rate base claim. Assuming the Company added plant consistently during the year, the Company's filing would effectively represent plant balances at June 30, 2021, the midpoint of the Projected Test Year. Since I am recommending that the PSC utilize Projected Plant Balances at December 31, 2020, my recommendation essentially represents a difference of only six months from the Company's claim.

The purpose of my adjustments is not to change the Test Year selected by the Company. It is simply to update the capital spending anticipated for that Test Year. The data that was originally projected by the Company at December 31, 2020, is a proxy for my recommended adjustments during the Projected 2021 Test Year. Given the extremely ambitious capital program proposed in the filing, the inherent speculative nature of any projected test year, and the unique economic situation that is currently evolving in Florida, it is reasonable and appropriate for the PSC to set rates based on a less ambitious capital program. This is even more appropriate when you consider the Company intends to file another base rate case in 2022, just two years into the future, with a 2023 Projected Test Year.

**Q. What is the net impact on rate base of the plant-in-service, CWIP, and reserve adjustments that you are recommending in this case?**

A. As shown in Exhibit ACC-2, Schedule 3, my recommendations will result in a rate base reduction of $83.8 million. Applying the cost of capital recommended by Mr. Garrett, my rate base recommendations will reduce the Company's revenue requirement by approximately $6.3 million.

**Q. Did the OPC adjust its recommended capital structure to reflect the impact of your plant-in-service adjustments on deferred taxes?**

A. No, we did not. I did, however, review the percentage of deferred taxes in the Company's capital structure from the Historic Base Year through the Projected Future Test Year to ascertain the change in the percentage of deferred taxes during this period. The Company's Future Test Year capital structure contains 13.71% deferred income taxes, less than the Historic Base Year percentage.

The calculation of deferred tax reserve balances is very complex and would require input from the Company. If the Company believes that a further adjustment is necessary, I will work with PGS to determine the impact of my recommendations on the proposed capital structure prior to the Company filing its Rebuttal Testimony in this case.

**Q. Do your adjustments impact the continued operation of the Company's CI/BSR?**

A. My adjustments are not intended to impact the continued operation of the CI/BSR. The Company will continue to reflect future rate adjustments based on the amount of investment made pursuant to this rider mechanism. Therefore, in addition to any base rate increase that would result in this case, I expect that customers will experience additional annual increases related to the CI/BSR.

**Q. Do you have any additional comments regarding the Company's utility plant-in-service claim?**

A. Yes, as noted earlier, one of the four major projects that the Company included in its filing is a new LNG facility in Miami. I understand that PGS has filed a separate Petition in Docket No. 20200093-GU for approval of a tariff to provide LNG services to third parties. That proceeding is currently on-going.

The Company's LNG Tariff Petition raises serious questions about whether the Company should provide such services to third parties and if so, how the associated costs should be recovered. Until those issues are resolved, it would be premature to include either capital or operating costs associated with the Miami LNG facility in the Company's rates that result from this general rate case. PGS claims that the Miami LNG facility is being undertaken primarily in order to meet a pipeline constraint in the Miami area during peak summer hours. However, given the cruise ship business in Miami, the accessibility from Miami to various locations in the Caribbean, and the relatively small number of hours that the Miami LNG facility would be needed to serve native load, it would be naïve to assume that the Miami LNG facility would have no role in the new, competitive LNG business envisioned by PGS. The Commission may find that LNG services should be provided on an unregulated basis, or find that other ratepayer protections should be implemented to ensure that regulated natural gas customers do not subsidize LNG activities.

Furthermore, my adjustment to include no more than the December 31, 2020 plant-in-service balance in the required revenue requirement also recognizes the

Company has not demonstrated that the overall level of additions to transmission and distribution facilities are adequately allocated to any demands placed on the system by the Company's planned entry into the facilities-based competitive provision of LNG services under the proposed tariff. The Company has acknowledged that any such LNG facility demand-related capital costs should be allocated to, and captured in, the revenues collected to cover such competitive entry by the Company. However, at this point PGS has not demonstrated that competitive LNG service impacts have been removed from plant allocated to the general body of customers.

**Q. If the Commission decides that the costs associated with LNG services should be excluded from the Company's revenue requirement in this case, what impact would that decision have on your recommended revenue increase?**

A. Such a decision would not change my recommended revenue increase in this case. My recommendation is based on plant balances at December 31, 2020, as a proxy for the Future Test Year balances. Since the Company does not expect the Miami LNG facility to be in-service by the end of 2020, there should be no gross plant associated with the Miami LNG facility in the Company's December 31, 2020, utility plant balance. Moreover, PGS excluded CWIP that is eligible to accrue AFUDC from its rate base claim. Since the majority of the Miami LNG capital costs appear to be eligible for AFUDC, there should be no, or very little, CWIP associated with the Miami LNG facility included in rate base at December 30, 2020. Finally, I am recommending that operating expenses and other related expenses associated with LNG activities be excluded from the Company's revenue requirement, as discussed later in this testimony. Therefore, if the Commission rejects the Company's request to provide LNG services pursuant to a tariff, no further adjustment to my revenue recommendation would be necessary, unless the Commission or other parties identify additional costs related to LNG activities that are embedded in the Company's filing.

## VI. OPERATING INCOME ISSUES

**Q. How have the Company's operating and maintenance costs changed since the last base rate case?**

A. Costs between the 2009 Test Year used in the Company's last base rate case and the 2019 Base Year in this case have increased by more than the "O&M Benchmark" approach that has been used by the Commission in the past to evaluate operating expense increases between base rate case filings. As discussed starting on page 29 of Sean Hillary's testimony, actual Base Year operating and maintenance costs were $107.2 million, approximately $7.8 million higher than the calculated benchmark of $99.2 million using customer-growth and the CIP inflation index. This represents an excess of almost 7.9%.

In addition, the Company's Projected Future Test Year operating costs of $121.3 million are 13.2% higher than the Historic Base Period costs of $107.2 million. Most of this increase is projected to occur in 2021, since the Company projects less than a 1% increase from the Historic Base Period to 2020.

**Q. How did the Company determine its Projected Future Test Year operating and maintenance costs?**

A. The Company's costs are based on its budgeted costs for 2021. The Company claims that it verified the reasonableness of its 2021 budget by comparing the 2021 budgeted costs to costs that were adjusted based on a series of trending factors. Basically, PGS grouped its Projected Future Test Year costs into one of four categories: Trended Labor, Payroll Not Trended, Other Trended Costs, and Other Costs Not Trended.

**Q. How were each of these adjusted by PGS?**

A. The Company applied different methodologies to each category of costs. For Trended Labor costs, PGS applied a 3% annual increase from the Historic Base Period to the Projected Future Test Year. For Other Trended Costs, the Company applied either an annual Customer Growth Rate X Inflation factor or just an Inflation Factor to determine the increases between the Historic Base Period and the Projected Future Test Year. For Payroll Not Trended and Other Costs Not Trended, the Company used the 2021 budgeted amounts.

**Q. Are you recommending any adjustments to the Company's operating and maintenance costs?**

A. Yes, I am recommending adjustments to several categories of operating and maintenance costs. I am not recommending any adjustment to Trended Labor Costs. However, I am recommending that labor costs for new employees (Payroll Not Trended) be excluded from the Company's revenue requirement, as discussed below. I am also recommending adjustments to Other Trended Costs relating to inflationary increases and to membership dues expenses. Finally, I am recommending several adjustments to Other Costs Not Trended relating to LNG and Economic Development Expense, Advertising and Marketing Expense, Rate Case Costs, and others. Each of these adjustments will be discussed in more detail below.

**A. Labor Costs – Additional Employee Expense**

**Q. Please describe the payroll costs included in the Company's operating and maintenance expense claim.**

A. PGS included $36.8 million of payroll expense based on increasing the adjusted Base Period payroll costs by 3% annually. In addition, the Company included approximately $4.3 million for new employee positions. According to the testimony of Mr. O'Connor at page 38, "[a]s Peoples' system and the state of Florida move toward increased use of CNG, LNG, and RNG, Peoples needs additional expertise in the implementation and development of CNG, LNG, and RNG, as well as, the data analytics and research that support these initiatives." I am recommending that the $4.3 million in new employee positions, as well as related taxes and supporting expenses, be excluded from the revenue requirement authorized in this case.

**Q. What is the basis for your adjustment?**

A. The Company's claim for new positions reflects an increase of approximately 12.4% over the Historic Base Year payroll costs. While these costs may be included in the Company's budget, historically PGS has not filled all of its authorized positions over the past few years. In fact, the Company has not even come close to filling all its authorized positions. As shown in its response to OPC IRR-4, the Company's actual employee count through the first five months of 2020 was approximately 7.5% less than authorized. Similarly, actual employee positions were well below authorized levels in 2018 and 2019. In this case, the Company is requesting an increase of 104 new positions from the actual average Base Year employee levels, or an increase of approximately 17.8%.

In addition, PGS has not justified the need for these additional employees in its filing. While the Company points to CNG, LNG, and RNG as drivers of the need for these new positions, the Company has not yet received approval for its LNG Tariff, nor has the Company reflected revenues from these activities that would justify the need for additional personnel. While these additional employees may be an aspirational goal for PGS, neither its past experience nor its Future Test Year projections suggest the need for an employee increase of this magnitude. Moreover, the Company's proposed increase in these costs would mean that costs for ramping up the competitive LNG tariffed service would be embedded into ongoing base rates. These costs could not be allocated to the contracts with any of the Company's prospective competitive LNG customers without reducing base rates. Limiting the payroll-related O&M reduces the risk that the general body of customers will be forced to bear the competitive service costs if the LNG Tariff is approved. Therefore, at Exhibit ACC-2, Schedule 8, I have made an adjustment to eliminate the Company's claim for these new positions from its revenue requirement.

## B. Incentive Compensation Award Expense

**Q. Please describe the Company's incentive compensation award programs.**

A. PGS has two short-term incentive compensation programs, the Performance Sharing Program ("PSP") and the Balanced Scorecard Incentive Program. The PSP is available to hourly and exempt employees, including supervisors, while the Balanced Scorecard

Incentive Program is available to employees at the level of manager and above. Both of these programs provide cash awards to participants.

The PSP has a potential payout of 12% of base pay, 50% of which is based on financial benchmarks. The remaining payout is based on other benchmarks such as safety goals, employee development goals, customer service goals, and asset management goals. The Balanced Scorecard Incentive Program has similar benchmarks; however, the weighting of each benchmark differs slightly from the weightings used in the PSP.

In addition, the Company has a long-term incentive compensation program that is available to a very small number of officers and key employees. The long-term incentive compensation program is a stock award program. Fifty percent (50%) of the awards are performance-based, meaning that the awards are tied to the financial performance of Emera stock. In addition, the performance-based awards are also subject to a performance modifier, based on how Emera's average three-year total shareholder return compares with a proxy group of other utility companies. The remaining 50% of the long-term incentive awards are restricted share units and vest after three years. The restricted share units are not based on the achievement of any specific benchmarks or performance standards but are offered at the discretion of the Board.

**Q. How many employees participate in each of the incentive compensation programs?**

A. According to the response to OPC IRR-10, there are 555 participants in the PSP and

19 participants in the BSC. There are also 30 officers/key employees that participate in both the BSC and the long-term incentive award plan.

**Q. How much did the Company include in its filing relating to incentive compensation awards?**

A. As shown in its response to OPC IRR-10, the Company included $4,512,108 for short-term incentive compensation awards in its filing, which includes $477,443 associated with officers. This results in an average short-term incentive compensation award of approximately $7,500. In addition, the Company included $1,558,657 of long-term incentive compensation costs in its filing. Based on the 30 officers/key employees eligible for these awards, the average long-term incentive compensation award included in the filing is almost $52,000 per participant.

**Q. How did the Company develop its claim for incentive compensation award costs?**

A. The short-term incentive compensation awards are targeted to a percentage of each employee's eligible earnings. The long-term incentive awards are based on either pre-determined percentages of an officer's base salary or on fixed dollar amounts.

**Q. Are you recommending any adjustment to the Company's claim for incentive compensation award costs?**

A. Yes, I am recommending that the incentive compensation award costs that are tied to financial metrics, or which do not otherwise benefit ratepayers, be recovered from the Company's shareholders. Regulatory commissions frequently disallow incentive compensation costs tied to financial metrics on the basis that such metrics benefit shareholders, but may not benefit, and may even harm, ratepayers. In fact, PGS's affiliate, New Mexico Gas Company ("NMGC"), did not even seek recovery of long-term incentive compensation costs in its recent base rate filing. In addition, NMGC eliminated certain short-term incentive compensation costs tied to financial metrics from its claim. Awarding incentive compensation based on financial metrics is inconsistent with a utility's mandate to provide safe and reliable utility service at the lowest reasonable cost. In this case, not only is a portion of the Company's incentive compensation award costs tied to the financial performance of Emera, but it is also dependent upon the financial results of a proxy group of other utilities.

**Q. How did you quantify your adjustment?**

A. Approximately 50% of the Company's short-term incentive awards are based on financial metrics. Therefore, I have eliminated 50% of the Company's claim for the PSP and Balanced Scorecard Programs from my revenue requirement. I have also eliminated 100% of the long-term incentive compensation awards, since these awards are not tied directly to metrics that benefit ratepayers. My adjustments to incentive compensation award costs are shown in Exhibit ACC-2, Schedule 9.

## C. Payroll Taxes and 401K Expense

**Q. In addition to the Labor adjustment related to new employees and the Incentive Compensation Award adjustments discussed above, did you make corresponding adjustments relating to payroll taxes and 401K costs?**

A. Yes, I did. On Exhibit ACC-2, Schedule 10, I have made a corresponding payroll tax adjustment, to reflect the impact on payroll taxes of my recommended adjustments to eliminate costs for new employee positions and to eliminate 50% of the short-term incentive compensation award costs. I did not include the long-term incentive compensation costs in my payroll tax adjustment, because these awards are not made in cash and potentially have different tax treatment. My payroll tax adjustment reflects the statutory payroll tax rate of 7.65%. In addition, it is my understanding the Company's 401K claim is based on total compensation, including short-term incentive compensation awards that are made in cash. Therefore, I made an adjustment in Exhibit ACC-2, Schedule 11 to eliminate the Company's 401K match on the labor and short-term incentive compensation costs that I recommend be disallowed.

### D. Other Employee-Related Expense

**Q. In addition to labor costs, are there other costs included in the Company's claim relating to new employee positions?**

A. Yes, there are. As shown on Exhibit No. SPH-1, Document No. 5, PGS included several categories of non-labor costs in its revenue requirement claim that relate to the new employee positions that it is seeking in this case. In its response to OPC IRR-109, the Company identified $163,200 in Operation Employees Expenses and Materials costs, including travel, equipment, uniforms and other incidental expenses associated with additional employees. The Company also identified $98,000 in Additional A&G Employee expenses for "additional preventive staffing" in the Pipeline Safety Compliance Department. PGS included $607,242 in incremental Information Technology costs, $264,994 in incremental Human Resources costs, and $65,652 in other incremental Shared Services expense, all of which represent increased allocations from Tampa Electric due to projected increases in employee headcount. These employee-related costs total $1,181,088.

Since I am recommending that the Commission reject the Company's claim for significant new employee additions, I have made a corresponding adjustment to eliminate these costs that are either directly related to increased staffing, or are related to increased allocations from Tampa Electric as a result of the headcount. Even if PGS does increase its employee base, there is no indication that this increase would exceed changes in employee counts at Tampa Electric, or other entities that are allocated costs from Tampa Electric. Therefore, at Exhibit ACC-2, Schedule 12, I have made an adjustment to eliminate these employee-related costs from my revenue requirement recommendation.

**E. Other (Non-Labor) Trended Expense**

**Q. Did the Company utilize a general escalator to project certain Future Test Year costs?**

A. Yes, it did. The Company's Adjusted Base Period operating and maintenance costs totaled $107.2 million. The Company utilized inflation trends to support adjustments of $44.1 million or approximately 41% of these costs. Two factors were used by PGS. Certain costs were adjusted by a Customer Growth X Inflation factor, while other costs were adjusted solely by the Inflation factor. In both cases, the Company utilized 2.2% annual inflation. According to the testimony of Sean Hillary at page 36, the Company utilized Moody's Economy.com's 2020 and 2021 forecast for the CPI-U (Consumer Price Index for all Urban Consumers) as the inflation factor applied to these costs.

**Q. Are you recommending any adjustments to Other (Non-Labor) Trended Costs?**

A. Yes, I am recommending two adjustments. First, I am recommending an adjustment to all costs that were trended on a CPI-U inflation factor. Second, I am recommending an additional adjustment to the Historic Base Year Membership Dues Expense, which was also subject to the CPI inflation factor.

**Q. Do you believe that the use of 2.2% annual escalation factor is reasonable?**

A. No, I do not. While Florida utilities have the ability to file a base rate case using a future test year, that right does not relieve a utility from filing rates that are cost-based and that are linked to an historic Base Period through some reasonable means. PGS has not demonstrated that the expenses to which the general escalator was applied necessarily trend with the CPI-U, or necessarily increase at all over time.

However, even if one assumes that a general escalator is appropriate, it should not be based on speculative projections of future increases. A better approach would be to examine the historic 12-month averages. As reported by the Bureau of Labor Statistics, the CPI-U for the twelve months ending July 2020 was 1.0%, less than half the adjustment reflected in the Company's filing. More importantly, the CPI for Energy Services was -0.1%, indicating a decline in energy costs over the prior year. The CPI for Gas Service showed a greater reduction of -0.3% annually. There is no doubt that these results have been impacted by the COVID-19 pandemic. However, there is no indication that economic activity will turn around and result in a 2.2% increase in the 2020 CPI by the end of the year, followed by an additional increase of 2.2% in 2021.

**Q. What do you recommend?**

A. Given the speculative nature of adjustments that rely upon a general escalator, the fact PGS has not demonstrated that certain costs trend in line with the CPI-U, as well as the actual CPI results over the past twelve months, PGS has not shown that the use of a 2.2% general escalation factor is appropriate. Therefore, I recommend the Commission reject the general escalator reflected in the Company's cost of service. My adjustment is shown in Exhibit ACC-2, Schedule 13.

### F. Membership Dues Expense

**Q. Has the Company included any membership dues expenses in its revenue requirement claim?**

A. Yes, as shown in Schedule C-11 to the Company's filing, PGS incurred membership dues expenses of $922,483 in the Historic Base Period. The Company made certain adjustments to remove amounts classified as lobbying. The remaining costs were inflated by the annual inflation factor of 2.2% discussed above.

**Q. Are you recommending any adjustment to the Company's claim for membership dues expenses?**

A. Yes, I am recommending two adjustments. First, I am recommending that 20% of dues to the American Gas Association ("AGA") be excluded from regulated rates. Second, I am recommending an adjustment to remove additional lobbying costs from the Associated Gas Distributors of Florida that were erroneously included by the Company in its revenue requirement claim.

**Q. Please describe your first adjustment.**

A. The Company's Historic Base Year dues expense included $221,966 paid to the AGA. PGS excluded $8,050 of this amount from its revenue requirement, on the basis that this was the amount identified by the AGA as constituting lobbying. However, in addition to the narrowly-defined "lobbying" activities undertaken by AGA, it is clear that AGA participates in other advocacy activities that are designed to promote shareholder interests. For example, core strengths listed on AGA's website include such activities as "advocacy for natural gas industry issues, regulatory constructs and business models that are priorities for the industry," the promotion of "growth in the efficient use of natural gas by emphasizing before a variety of stakeholders the benefits of clean, abundant natural gas as part of the solution to the nation's energy and environmental goals," "collects, analyzes and disseminates information to opinion leaders, policy makers and consumers about the benefits provided by energy utilities and the natural gas industry," and delivery of "measurable value to AGA members." AGA actively solicits support from the National Association of Regulatory Utility Commissioners ("NARUC") and promotes a "favorable regulatory climate for gas utilities." It arranges meetings between regulators and the financial community "educating state regulatory commissioners on how their decisions impact the views of the financial community. . . ." Advocacy, both formal advocacy through its formal lobbying program and informal advocacy with regulatory commissions and other stakeholders, is a significant part of the AGA's activities. The Company's adjustment of $8,050 clearly understates the volume of AGA activities that promote shareholder interests. Accordingly, I am recommending a further adjustment to the Company's claim.

**Q. How did you quantify your adjustment?**

A. Based on a review of AGA documentation and my experience in other rate proceedings, I recommend that 20% of AGA's annual dues, or $44,393, be disallowed. Since the Company has already reflected an adjustment to eliminate $8,050 from its claim, I am recommending an additional adjustment of $36,343. My adjustment is shown in Exhibit ACC-2, Schedule 14.

**Q. Please describe your second adjustment to the Company's claim for Membership Dues Expense.**

A. In its response to OPC IRR-28, the Company indicated it had paid $50,000 in dues to the Associated Gas Distributors of Florida. $25,000 of this amount was booked below-the-line as a lobbying expenditure. The remaining $25,000 was included in the Company's revenue requirement in this case, and escalated based on the Other Trended inflation factor. However, in this response, the Company indicated that the entire $50,000 should have been classified as lobbying and excluded from the Company's claim. Therefore, at Exhibit ACC-2, Schedule 14, I have also made an adjustment to exclude the additional $25,000 from the Associated Gas Distributors of Florida from the Company's revenue requirement. Since I have already made an adjustment relating to the Other Trended inflation factor, my adjustment is limited to the $25,000 incurred in the Historic Base Period.

**G. (Non-Labor) Costs Not Trended**

**Q. Please summarize the Company's claim for Non-Labor Costs Not Trended.**

A. As shown in Sean Hillary's Exhibit No. SPH-1, Document No. 5, there are many categories of non-labor costs that were not trended by inflation or customer growth factors, but instead were separately adjusted by PGS. The Company incurred actual costs in the Historic Base Year for these activities of $28.4 million. While these costs are projected to decline to $24.1 million in 2020, PGS has projected explosive growth to $32.9 million by 2021.

As discussed in more detail below, I am recommending several adjustments to these non-labor costs. However, with one exception (TIMP-Pipeline Reassessment and Risk Analysis), I am not recommending any adjustment to cost categories for which the Company actually incurred costs in the Historic Base Year. My concern is primarily with cost categories that were not included in the Historic Base Year and instead have been incrementally added to the 2021 budget, which was used to develop the revenue requirement in this case. It is not unusual for operating budgets to contain amounts that utility managers would like to see approved – rather than amounts that are actually necessary for the provision of safe and adequate utility service at the lowest reasonable cost. Based on the lack of demonstrated support for these items, I am recommending a number of adjustments as discussed below. My adjustments generally fall into five broad categories:

- LNG and Economic Development Expense
- Advertising and Marketing Expense

- Rate Case Expense
- TIMP Pipeline Reassessment and Risk Analysis
- Other Non-Labor Costs Not Trended

**1. LNG and Economic Development Expense**

**Q. Please describe the 2021 incremental Miami LNG Storage costs and Economic Development costs included in the Company's claim.**

A. The Company has included $25,000 of Miami LNG Storage Costs, $50,000 of LNG/RNG Consulting costs, and $415,802 of new economic development activities in its filing. I am recommending that all of these costs, totaling $490,802, be disallowed.

**Q. What is the basis for your recommendation?**

A. With regard to LNG costs, the Company has not yet received approval of its LNG Tariff and there is some question as to whether these costs should be borne by PGS' ratepayers in Florida. Even if the LNG Tariff is approved, the Miami LNG facility will not be in-service during the Future Test Year in this case and revenues from that facility have not been reflected in the filing.

With regard to economic development activities, PGS has not provided detailed support for these incremental expenditures. In addition, economic development in the Company's service territory is already strong, as evidenced by continued customer growth and expansion. The Company has not provided a compelling argument for why additional economic development funding of this magnitude is necessary or will be beneficial to the long-term provision of regulated utility service. Therefore, I recommend that these costs also be disallowed, as shown in Exhibit ACC-2, Schedule

15.

**2. Advertising and Marketing Expense**

**Q. Did the Company also include incremental advertising and marketing costs in its revenue requirement claim?**

A. Yes, it did. As shown in Exhibit SPH-1, Document No. 5, PGS included incremental customer communications costs of $35,000 in the Projected Future Test Year. The Company also included $829,871 of additional marketing costs to promote natural gas, and costs related to an additional pipeline awareness campaign of $200,000.

**Q. In your opinion, has the Company justified the inclusion of these costs in the Projected Future Test Year?**

A. No, it has not. The Company claims that the Additional Customer Communications costs of $35,000 will "improve customer experience through additional customer research and segmentation."[4] A similarly vague description is used to support the Company's claim for $829,871 in additional marketing to promote natural gas, where the Company indicated that the increased "marketing work is to promote the use of natural gas, improve customer retention and develop a more integrated approach to marketing Peoples' programs and services to current and potential customers." The Company has obviously been successful in its past marketing efforts, as evidenced by its relatively strong growth rate. PGS has not justified the need for more than $850,000 in incremental costs to promote these efforts.

4 Response to OPC IRR-109.

Finally, with regard to its request for an additional $200,000 in incremental pipeline safety awareness advertising, PGS has not demonstrated that its current safety awareness efforts are inadequate. While pipeline safety is an important goal, programs to promote pipeline safety should be necessary, targeted, and cost effective.

**Q. What do you recommend?**

A. I recommend that the additional advertising and marketing costs discussed above, in the amount of $1,064,871, be disallowed. The Company has provided only vague descriptions of these programs and has not demonstrated that additional programs in these areas are needed, or that the earmarked expenditures are reasonable. Therefore, at Exhibit ACC-2, Schedule 16, I have made an adjustment to eliminate these costs from my revenue requirement recommendation.

**3. Rate Case Expenses**

**Q. Please describe the Company's claim associated with rate case costs for the current rate case.**

A. PGS is seeking to recover $1,657,000 in rate case costs relating to the current rate case, as shown in Schedule C-13, page 1.

| | |
|---|---|
| Outside Consultants | $764,500 |
| Legal Services | $800,000 |
| Other Expenses | $92,500 |
| | |
| Total Rate Case Costs | $1,657,000 |

In response to OPC IRR-122, the Company provided a breakdown of its estimated consulting costs, as well as the hours and total costs billed to date:

| Consultant | Estimated Cost | Billed to Date (including expenses) | Billed Hours |
|---|---|---|---|
| PWC | $105,000 | $107,943 | 258.60 |
| Scott Madden | $120,000 | $41,806 | 140.50 |
| Dan Yardley | $287,000 | $128,700 | 390.00 |
| Susan Richards | $95,000 | $104,126 | 1,305.12 |
| Alliance Consulting | $80,000 | $39,963 | 195.75 |
| Richard Harper/ Economic Consulting | $75,000 | $18,061 | 54.75 |
| Mercer | $2,500 | $2,500 | |
| Total | $764,500 | $443,099 | 2,344.72 |

PGS is proposing to amortize these costs over three years, and has included annual amortization expense of $552,333 in (Non Labor) Costs Not Trended.

**Q. What are the typical hourly rates for the consulting firms whose charges are included in the Company's rate case cost claim?**

A. According to the response to OPC POD-3, there is a wide range of hourly billing rates for the consultants utilized by PGS, depending on the firm and the position within the firm of each consultant. Hourly rates generally range from a low of $65.00 per hour to a high of $575.00 per hour.

**Q. Are you recommending any adjustment to the rate case costs being claimed by PGS for this proceeding?**

A. I am not proposing any adjustment to the overall level of rate case costs being proposed by PGS in this case. However, I am recommending a longer amortization period. A three-year amortization period assumes that the utility will file a base rate case approximately every three years. However, the Company's last base rate was based on a 2009 future test year, 12 years prior to the test year in this case. While the Company contends that it plans to file another case in 2022, there is no assurance that it will actually do so.

**Q. What amortization period are you recommending in this case?**

A. I am recommending that rate case costs for the current case be amortized over five years, instead of over three years as proposed by the Company. While the Company's last base rate case was 12 years ago, I am not recommending an amortization period of longer than five years, given the possibility of a base rate case being filed within the next few years. However, given the rate case history of PGS, a five-year period is more reasonable than the three-year amortization period requested by the Company. My adjustment is shown in Exhibit ACC-2, Schedule 17.

**4. TIMP Pipeline Reassessment and Risk Analysis**

**Q. What adjustment are you recommending to the Company's claim for $2,107,400 in TIMP Pipeline Reassessment and Risk Analysis Costs?**

A. This is one area where I am recommending an adjustment to a cost category for which the Company also provided 2019 and 2020 actual expenditures on Exhibit SPH-1, Document No. 5. As shown in this exhibit, the Company incurred actual costs of $112,961 in the Historic Base Year and is projecting costs of $292,500 for 2020. However, PGS is seeking to include $2,107,000 in rates resulting from this proceeding.

According to the testimony of Sean Hillary at page 38, "the pipeline integrity compliance costs can vary from year-to-year depending on which pipelines are due for assessment and inspection." Witness Hillary goes on to state that PGS has scheduled several reassessments in 2021 at an estimated cost of $1.96 million. In addition, the Company "budgeted approximately $0.15 million for outside engineering assistance related to TIMP risk analysis assessments and plan updates."

**Q. How do the 2021 projected costs compare with cost projections for later years?**

A. As previously noted, the Projected Test Year costs are significantly higher than the costs incurred in 2019 or projected for 2020. In addition, the 2021 costs are also higher than costs projected in any other year during the 2021-2025 timeframe. Therefore, allowing the Company to include these costs in rates may result in a windfall in subsequent years as TIMP Pipeline Assessment costs decline.

**Q. What do you recommend?**

A. Given the fact that these costs can vary so significantly from year-to-year, as acknowledged by the Company, it would not be appropriate to include $2.1 million in prospective rates. When costs vary significantly from year-to-year, regulators frequently normalize such costs, in order to mitigate the fluctuations that occur. Based on the Company's representation that these costs vary from year-to-year, and on the significant increase being requested in 2021, I recommend that the Commission normalize these TIMP Pipeline Reassessment and Risk Analysis costs. At Exhibit ACC-2, Schedule 18, I have made an adjustment to reflect a five-year average of the anticipated TIMP Pipeline Reassessment and Risk Analysis costs, based on the Company's current schedule for 2021-2024.

**5. Other (Non-Labor) Costs Not Trended**

**Q. What additional adjustments are you recommending to Other Non-Labor Costs Not Trended?**

A. In addition to the costs outlined above related to LNG and Economic Development costs, Advertising and Marketing expenses, Rate Case costs and TIMP Pipeline Reassessment and Risk Analysis costs, I am also recommending adjustments to several of the other incremental Projected Future Test Year costs included in the Company's claim, including $300,000 in additional engineering services and $50,000 in additional engineering training. I am also proposing an amortization for the $811,166 in operating costs associated with the implementation of a new Asset Management Work system. These adjustments are shown in Exhibit ACC-2, Schedule 19.

**Q. What is the basis for your recommendation to exclude $300,000 in additional engineering services and $50,000 in additional engineering training from the Company's revenue requirement?**

A. The Company indicated that the $300,000 in additional engineering services was required "to eliminate the exemption for Professional Engineers to sign off on designs and construction drawings. Not all of this cost will be capitalizable." However, the Company provided no additional details regarding how the $300,000 was determined and how much, if any, of the $300,000 would be capitalized. It also included $50,000 for additional engineering training; however, there is no suggestion that current engineering training practices are inadequate or how this additional $50,000 would be utilized. Given the subjective nature of using a fully forecast Future Test Year based on budgeted data, the Commission should be especially vigilant to guard against claims for incremental costs that are not adequately supported by the utility.

**Q. Finally, please discuss your adjustment to the Company's claim associated with the new Work Asset Management system.**

A. The Company has included $811,166 associated with this new Work Asset Management System, representing implementation costs that cannot be capitalized. However, since the asset management system is expected to last for many years, it would be inappropriate to recover these implementation costs over one year. Therefore, at Exhibit ACC-2, Schedule 18, I have made an adjustment to reflect a five-year recovery for these costs, consistent with the recovery periods that I have used for several other expenditures in this case. My adjustment to reflect a five-year recovery period for these costs results in an adjustment of $648,933 to the Company's cost claim of $811,166.

**Q. What is the total adjustment that you are recommending for the engineering services, engineering training, and Work Asset Management implementation costs discussed above?**

A. These adjustments total $998,933 as shown in Exhibit ACC-2, Schedule 19.

**H. Depreciation Expense**

**Q. How did the Company develop its depreciation expense claim in this case?**

A. On June 8, 2020, the Company filed a Petition in Docket No. 20200166 requesting that the PSC authorize new depreciation rates effective January 1, 2021. The Company estimates that the new rates will increase its pro forma annual depreciation expense by

$3.7 million, as referenced on page 21 of Sean Hillary's testimony. The PSC subsequently consolidated the Depreciation Docket and this base rate case. The Company's requested depreciation rates were applied to projected gross plant balances, by month, to determine the projected Future Test Year depreciation expense.

**Q. Are you recommending any adjustment to the Company's depreciation rates or pro forma depreciation expense claims?**

A. Yes, I am recommending two adjustments. First, since I am recommending that the Company's rate base reflect utility plant as of December 31, 2020, it is necessary to make an adjustment to depreciation expense to synchronize this expense with my recommended utility plant balances. To quantify my adjustment, I annualized the Company's January 2021 projected depreciation expense, which reflects plant balances through December 2020. My adjustment is shown in Exhibit ACC-2, Schedule 20.

**Q. Please describe your second adjustment to the Company's depreciation expense claim.**

A. OPC witness David Garrett is recommending adjustments to several of the depreciation rates proposed by the Company in its depreciation study. At Exhibit ACC- 2, Schedule 21, I have made an adjustment to reflect the depreciation rates proposed by Mr. Garrett, applied to the December 31, 2020, plant balances that I have included in my rate base recommendation.

## I. Property Tax Expense

**Q. How did the Company determine its claim for property tax expense?**

A. As discussed by PGS witness Sean Hillary on page 18, PGS' property tax claim is based on forecasted tax rates and projected assessed values during the Projected Test Year.

**Q. Are you recommending any adjustment to the Company's property tax expense claim?**

A. I am not recommending any adjustment to the property tax rates proposed by PGS. However, consistent with my recommendation that net plant should reflect projected balances at December 31, 2020, I am recommending the PSC base its pro forma property tax allowance on plant balances as of December 31, 2020. Since property taxes are determined based on assessed values, and not on book values, I quantified my adjustment by first determining the overall percentage reduction to gross plant that I am recommending in this case. My recommendations reduce the Company's gross plant claim by approximately 3.47%. I assumed that the reduction to assessed values would be proportional to my recommended gross plant reduction. Therefore, at Exhibit ACC-2, Schedule 22, I have made an adjustment to reduce the Company's Projected Test Year property tax expense by 3.47%.

### J. Interest Synchronization and Taxes

**Q. Have you adjusted the pro forma interest expense for income tax purposes?**

A. Yes, I have made this adjustment at Exhibit ACC-2, Schedule 23. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Garrett. The rate base and cost of capital being recommended by the OPC in this case result in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under our recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

**Q. What income tax factors have you used to quantify your adjustments?**

A. As shown on Exhibit ACC-2, Schedule 24, I have used a composite income tax factor of 24.52%, which includes a state income tax rate of 4.46% and a federal income tax rate of 21%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Exhibit ACC-2, Schedule 25, incorporates these tax rates. In addition, the revenue multiplier also includes the regulatory assessment of 0.5% and PGS' claimed uncollectible rate of 0.3423%. This results in a revenue multiplier of 1.3361.

**Q. Are you also recommending that the Commission adopt a parent company interest adjustment?**

A. Yes, I am. As discussed on page 24 of Ms. Strickland's testimony, Rule 25-14.004, F.A.C., Effect of Parent Debt on Federal Corporate Income Tax, provides that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." PGS does participate in the filing of a consolidated income tax return. Nevertheless, PGS did not include a parent company interest adjustment in its filing.

**Q. Why didn't PGS include a parent company interest adjustment?**

A. Ms. Strickland states on page 25 of her testimony that she did not include a parent company adjustment because "For the 2021 projected test year, EUSHI [Emera U.S. Holdings, Inc.] will not have any debt on its balance sheet for which it will claim any interest expense deductions on its U.S. consolidated income tax return." Ms. Strickland goes on to state that while in the past EUSHI has had a number of interest-bearing loans from U.S. affiliates, Emera has now centralized the intercompany financing activities into one main financing entity owned by EUSHI."

**Q. Why do you recommend that that the Commission require PGS to include a parent company interest adjustment in its revenue requirement?**

A. I recommend that the Commission require a parent company interest adjustment because the filing of a consolidated income tax return conveys huge tax advantages that are not otherwise being reflected in regulated utility rates. PGS files a consolidated income tax return as part of the EUSHI consolidated income tax group. In this case, the Company is seeking to recover over $20 million of federal income tax expense annually from Florida ratepayers. However, as stated in the response to OPC IRR-36, EUSHI "did not make any payments to the IRS in each of the past three years." In addition, PGS has net operating tax loss carry-forwards of $15.9 million and is expected to generate additional federal tax losses of $36.8 million through the Future Test Year. Therefore, there is a major disconnect between the statutory income tax rates used to calculate federal income taxes for ratemaking purposes and the actual taxes being paid by the consolidated income tax group.

**Q. Did you quantify a parent company interest adjustment?**

A. No, I have not. Staff requested that the Company provide such an adjustment in Staff IRR-37, to which the Company has not yet responded. In this request, Staff requested that the Company revise "MFR Schedule C-26 using Emera Incorporated as the parent of PGS, including a parent debt adjustment in row 10." I recommend that the Commission include a parent company adjustment for PGS in its revenue requirement determination based on the Company's response to this interrogatory. While EUSHI may not be projected to have long-term debt, due to creative restructuring, that should not rob PGS' ratepayers of certain tax benefits that the Florida Legislature determined should presumptively be reflected in regulated rates. Therefore, my revenue requirement recommendation should be updated once this response is received from PGS.

## VII. REVENUE REQUIREMENT SUMMARY

**Q. What is the result of the recommendations contained in your testimony?**

A. My adjustments indicate a revenue deficiency at present rates of no more than \$42,221,562, as summarized on Exhibit ACC-2, Schedule 1. This recommendation reflects revenue requirement adjustments of \$42,103,332 to the Company's claimed revenue deficiency of \$85,324,894. My recommendations would result in a base revenue increase of no more than approximately 17.2%. The actual rate impact on ratepayers will be significantly less, since my recommended revenue increase reflects the impact of rolling-in to base rates certain costs that would otherwise be collected through the CI/BSR. Assuming that the CI/BSR would cost ratepayers $23,608,583 annually, as quantified by PGS, my recommendations would result in a net revenue increase of no more than approximately $18,612,979 or approximately 6.9%. In addition, I recommend that the Commission adopt a further adjustment to reflect a parent company interest adjustment, as discussed above.

**Q. Have you quantified the revenue requirement impact of each of your recommendations?**

A. Yes, at Exhibit ACC-2, Schedule 26, I have quantified the revenue requirement impact of each of the rate of return, rate base, and expense recommendations contained in this testimony.

**Q. Does this conclude your testimony?**

A. Yes, it does.

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**Andrea C. Crane, BA, MBA**

Andrea C. Crane has 38 years of experience in utility-related matters. Since joining The Columbia Group in 1989, Ms. Crane has testified in over 400 regulatory proceedings involving electric, gas, water, wastewater, telephone, cable television, solid waste, and navigation utilities in 17 states and the District of Columbia. Ms. Crane has testified on a wide range of issues, including revenue requirements, cost of capital, capital structure, weather normalization, renewable energy, energy efficiency, utility acquisitions, affiliated interests, cost allocations, market power, fuel pricing, fuel adjustment clauses, gas procurement, gas supply and transportation issues, and regulatory policy. Ms. Crane became President of The Columbia Group, Inc. in January 2008.

Ms. Crane has filed testimony in proceedings involving such companies as Public Service Company of New Mexico, El Paso Electric Company, New Jersey American Water Company, Public Service Electric and Gas Company, Delmarva Power and Light Company, Kansas City Power and Light Company, Southwestern Public Service Company, Atmos Energy, New Jersey Natural Gas Company, United Water Delaware, Artesian Water Company, Comcast Communications, Westar Energy, and many others. Ms. Crane has developed financial models in the areas of bond coverage ratios, cash flow forecasting, utility revenue forecasting and budgeting, and rate of return analysis. Ms. Crane has also conducted strategic planning and utility finance seminars.

Prior to becoming a consultant in 1989, Ms. Crane spent seven years in professional positions with GTE Service Corporation, where she was responsible for the economic analysis of new products and service plans for telephone operations, and with Bell Atlantic Corporation (now Verizon), which included a position in the Regulatory Department where she was responsible for Affiliated Interest rate case litigation support in seven Bell Atlantic state jurisdictions.

From 1991 to 1997, Ms. Crane served in a volunteer position as Vice-Chairman of the Water Pollution Control Commission in Redding, Connecticut.

Ms. Crane's educational background includes an M.B.A. degree in Finance (1982) and a B.A. degree in Chemistry (1979), both from Temple University in Philadelphia, Pennsylvania.

Attached is a list of testimonies filed by Ms. Crane over the past five years.

## *The Columbia Group, Inc., Testimonies of Andrea C. Crane*

| Company | Utility | State | Docket | Date | Topic | On Behalf Of |
|---|---|---|---|---|---|---|
| Peoples Gas System | G | Florida | 20200051-GU | 9/20 | Revenue Requirements | Office of Public Counsel |
| New Mexico Gas Company | G | New Mexico | 19-00317-UT | 7/20 | Revenue Requirements | Office of Attorney General |
| El Paso Electric Company | E | New Mexico | 19-00349-UT | 4/20 | CCN For Newman Unit 6 | Office of Attorney General |
| Public Service Company of New Mexico | E | New Mexico | 19-00195-UT | 12/19 | Replacement Resources for SJGS Units 1 and 4 | Office of Attorney General |
| Southwestern Public Service Company | E | New Mexico | 19-00170-UT | 11/19 | Revenue Requirements | Office of Attorney General |
| Atmos Energy Company | G | Kansas | 19-ATMG-525-RTS | 10/19 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Public Service Company of New Mexico | E | New Mexico | 19-00018-UT | 10/19 | Abandonment of SJGS and Stranded Cost Recovery | Office of Attorney General |
| Rockland Electric Company | E | New Jersey | ER19050552 | 10/19 | Revenue Requirements | Division of Rate Counsel |
| Avista Corporation | E/G | Washington | UE-190334/UG-190335 | 10/19 | Revenue Requirements | Public Counsel Unit |
| Westar Energy, Inc. | E | Kansas | 19-WSEE-355-TAR | 6/19 | JEC Capacity Purchase | Citizens' Utility Ratepayer Board |
| Empire District Electric Company | E | Kansas | 19-EPDE-223-RTS | 5/19 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Public Service Electric and Gas Co. | E/G | New Jersey | EO18060629/ G018060630 | 3/19 | Energy Strong II Program | Division of Rate Counsel |
| Southwestern Public Service Company | E | New Mexico | 18-00308-UT | 2/19 | Voluntary Renewable Energy Program | Office of Attorney General |
| Zero Emission Certificate Program (Various Applicants) | E | New Jersey | EO18080899 | 1/19 | Zero Emission Certificates Subsidy | Division of Rate Counsel |
| Public Service Company of New Mexico | E | New Mexico | 18-00043-UT | 12/18 | Removal of Energy Efficiency Disincentives | Office of Attorney General |
| Kansas Gas Service | G | Kansas | 18-KGSG-560-RTS | 10/18 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| New Mexico Gas Company | G | New Mexico | 18-00038-UT | 9/18 | Testimony in Support of Stipulation | Office of Attorney General |
| Kansas City Power and Light Company | E | Kansas | 18-KCPE-480-RTS | 9/18 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Public Service Electric and Gas Co. | E/G | New Jersey | ER18010029/ GR18010030 | 8/18 | Revenue Requirements | Division of Rate Counsel |
| Westar Energy, Inc. | E | Kansas | 18-WSEE-328-RTS | 6/18 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Southwestern Public Service Company | E | New Mexico | 17-00255-UT | 4/18 | Revenue Requirements | Office of Attorney General |
| Empire District Electric Company | E | Kansas | 18-EPDE-184-PRE | 3/18 | Approval of Wind Generation Facilities | Citizens' Utility Ratepayer Board |
| GPE/ Kansas City Power & Light Co., Westar Energy, Inc. | E | Kansas | 18-KCPE-095-MER | 1/18 | Proposed Merger | Citizens' Utility Ratepayer Board |
| Public Service Electric and Gas Co. | E | New Jersey | GR17070776 | 1/18 | Gas System Modernization Program | Division of Rate Counsel |
| Southwestern Public Service Company | E | New Mexico | 17-00044-UT | 10/17 | Approval of Wind Generation Facilities | Office of Attorney General |
| Kansas Gas Service | G | Kansas | 17-KGSG-455-ACT | 9/17 | MGP Remediation Costs | Citizens' Utility |

# The Columbia Group, Inc., Testimonies of Andrea C. Crane

| Company | Utility | State | Docket | Date | Topic | On Behalf Of |
|---|---|---|---|---|---|---|
| | | | | | | Ratepayer Board |
| Atlantic City Electric Company | E | New Jersey | ER17030308 | 8/17 | Base Rate Case | Division of Rate Counsel |
| Public Service Company of New Mexico | E | New Mexico | 16-00276-UT | 6/17 | Testimony in Support of Stipulation | Office of Attorney General |
| Westar Energy, Inc. | E | Kansas | 17-WSEE-147-RTS | 5/17 | Abbreviated Rate Case | Citizens' Utility Ratepayer Board |
| Kansas City Power and Light Company | E | Kansas | 17-KCPE-201-RTS | 4/17 | Abbreviated Rate Case | Citizens' Utility Ratepayer Board |
| GPE/ Kansas City Power & Light Co., Westar Energy, Inc. | E | Kansas | 16-KCPE-593-ACQ | 12/16 | Proposed Merger | Citizens' Utility Ratepayer Board |
| Kansas Gas Service | G | Kansas | 16-KGSG-491-RTS | 9/16 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Public Service Company of New Mexico | E | New Mexico | 15-00312-UT | 7/16 | Automated Metering Infrastructure | Office of Attorney General |
| Kansas City Power and Light Company | E | Kansas | 16-KCPE-160-MIS | 6/16 | Clean Charge Network | Citizens' Utility Ratepayer Board |
| Kentucky American Water Company | W | Kentucky | 2016-00418 | 5/16 | Revenue Requirements | Attorney General/LFUCG |
| Black Hills/Kansas Gas Utility Company | G | Kansas | 16-BHCG-171-TAR | 3/16 | Long-Term Hedge Contract | Citizens' Utility Ratepayer Board |
| General Investigation Regarding Accelerated Pipeline Replacement | G | Kansas | 15-GIMG-343-GIG | 1/16 | Cost Recovery Issues | Citizens' Utility Ratepayer Board |
| Public Service Company of New Mexico | E | New Mexico | 15-00261-UT | 1/16 | Revenue Requirements | Office of Attorney General |
| Atmos Energy Company | G | Kansas | 16-ATMG-079-RTS | 12/15 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| El Paso Electric Company | E | New Mexico | 15-00109-UT | 12/15 | Sale of Generating Facility | Office of Attorney General |
| El Paso Electric Company | E | New Mexico | 15-00127-UT | 9/15 | Revenue Requirements | Office of Attorney General |
| Rockland Electric Company | E | New Jersey | ER14030250 | 9/15 | Storm Hardening Surcharge | Division of Rate Counsel |
| El Paso Electric Company | E | New Mexico | 15-00099-UT | 8/15 | Certificate of Public Convenience - Ft. Bliss | Office of Attorney General |
| Southwestern Public Service Company | E | New Mexico | 15-00083-UT | 7/15 | Approval of Purchased Power Agreements | Office of Attorney General |
| Westar Energy, Inc. | E | Kansas | 15-WSEE-115-RTS | 7/15 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Kansas City Power and Light Company | E | Kansas | 15-KCPE-116-RTS | 5/15 | Revenue Requirements | Citizens' Utility Ratepayer Board |
| Comcast Cable Communications | C | New Jersey | CR14101099-1120 | 4/15 | Cable Rates (Form 1240) | Division of Rate Counsel |
| Liberty Utilities (Pine Bluff Water) | W | Arkansas | 14-020-U | 1/15 | Revenue Requirements | Office of Attorney General |

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**REVENUE REQUIREMENT SUMMARY**

| | Company Claim | Recommended Adjustment | Recommended Position | |
|---|---|---|---|---|
| | (A) | | | |
| 1. Pro Forma Rate Base | $1,578,725,509 | ($83,819,368) | $1,494,906,141 | (B) |
| 2. Required Cost of Capital | 6.63% | -0.58% | 6.05% | (C) |
| 3. Required Return | $104,638,261 | ($14,215,081) | $90,423,180 | |
| 4. Operating Income @ Present Rates | 40,779,039 | 18,044,499 | 58,823,538 | (D) |
| 5. Operating Income Deficiency | $63,859,222 | ($32,259,580) | $31,599,642 | |
| 6. Revenue Multiplier | 1.3361 | 1.3361 | 1.3361 | (E) |
| 7. Required Revenue Increase | **$85,324,894** | **($43,103,332)** | **$42,221,562** | |
| 8. Roll in of Cast Iron/Bare Steel Rider | **$23,608,583** | **$0** | **$23,608,583** | (A) |
| 9. Net Revenue Increase | **$61,716,311** | **($43,103,332)** | **$18,612,979** | |

Sources:
(A) PGS Application, Exhibit A.
(B) Exhibit ACC-2, Schedule 3.
(C) Exhibit ACC-2, Schedule 2.
(D) Exhibit ACC-2, Schedule 7.
(E) Exhibit ACC-2, Schedule 25.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**REQUIRED COST OF CAPITAL**

| | Capital Structure (%) | Cost Rate (%) | Weighted Cost (%) | |
|---|---|---|---|---|
| | (A) | (A) | | |
| 1. Long-Term Debt | 32.07% | 4.47% | 1.43% | (A) |
| 2. Short-Term Debt | 6.27% | 2.80% | 0.18% | (A) |
| 3. Customer Deposits | 1.64% | 2.51% | 0.04% | (A) |
| 4. Common Equity | 46.30% | 9.50% | 4.40% | (B) |
| 5. Deferred Taxes | 13.71% | 0.00% | 0.00% | (A) |
| 6. Total Cost of Capital | | | 6.05% | |

Sources:
(A) Company Filing, Schedule A-5, page 1.
(B) Reflects cost of equity recommendation of Mr. Garrett.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**RATE BASE SUMMARY**

| | Company Claim | Test Year Adjustment | | Recommended Position |
|---|---|---|---|---|
| | (A) | | | |
| 1. Utility Plant in Service | $2,264,926,587 | ($78,493,890) | (B) | $2,186,432,697 |
| 2. Construction Work in Progress | 154,563,081 | (24,247,327) | (C) | 130,315,754 |
| 3. Acquisition Adjustment | 2,084,900 | | | 2,084,900 |
| 4. Accumulated Depreciation | (795,890,364) | 18,921,849 | (D) | (776,968,515) |
| 5. Accumulated Amortization | (21,334,035) | | | (21,334,035) |
| 6. Acquisition Adj. Amortization | (2,148,582) | | | (2,148,582) |
| 7. Customer Advances | (11,423,077) | | | (11,423,077) |
| 8. Net Utility Plant | $1,590,778,510 | ($83,819,368) | | $1,506,959,142 |
| 9. Allowance for Working Capital | (12,053,001) | | | (12,053,001) |
| 10. Total Rate Base | **$1,578,725,509** | **($83,819,368)** | | **$1,494,906,141** |

Sources:
(A) Company Filing, Schedule A-3.
(B) Exhibit ACC-2, Schedule 4.
(C) Exhibit ACC-2, Schedule 5.
(D) Exhibit ACC-2, Schedule 6.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**GROSS UTILITY PLANT-IN-SERVICE**

| | | |
|---|---|---|
| 1. Company Claim | $2,282,796,547 | (A) |
| 2. Projected 12/31/20 Balance | 2,187,842,296 | (A) |
| 3. Recommended Adjustment | ($94,954,251) | |
| 4. Reverse Company's Bare Steel Adjustment | 16,488,118 | (B) |
| 5. Adjustment to Non-Utility Common Plant | (27,757) | (C) |
| 6. Total Plant in Service Adjustment | **($78,493,890)** | |

Sources:
(A) Company Filing, Schedule G-1, page 7.
(B) Company Filing, Schedule G-1, page 4.
(C) Response to OPC IRR-114.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**CONSTRUCTION WORK IN PROGRESS**

| | | |
|---|---|---|
| 1. Company Claim | $187,485,085 | (A) |
| 2. Projected 12/31/20 Balance | 157,646,200 | (A) |
| 3. Recommended Adjustment | ($29,838,885) | |
| 4. Reverse Cast Iron/ Bare Steel Rider Adjustment | 2,107,553 | (B) |
| 5. Reverse Portion of Eligible AFUDC Adjustment | 3,484,005 | (C) |
| 6. Total CWIP Adjustment | **(24,247,327)** | |

(A) Company Filing, Schedule G-1, page 7.
(B) Company Filing, Schedule G-1, page 4.
(C) Response to OPC IRR-114.

Docket No. 20200051-GU
Exhibit ACC-2
Schedule 6
Page 1 of 1

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**ACCUMULATED DEPRECIATION**

| | | |
|---|---|---|
| 1. Company Claim | ($822,803,629) | (A) |
| 2. Projected 12/31/20 Balance | (803,815,901) | (B) |
| 3. Recommended Adjustment | $18,987,728 | |
| 4. Reverse Cast Iron / Bare Steel Rider Adjustment | (84,198) | (C) |
| 5. Adjustment to Non-Utility Common Plant | 18,319 | (D) |
| 6. Total Adjustment | **$18,921,849** | |

Sources:
(A) Company Filing, Schedule G-1, page 12.
(B) Company Filing, Schedule G-1, page 13.
(C) Company Filing, Schedule G-1, page 4.
(D) Response to OPC IRR-115.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**OPERATING INCOME SUMMARY**

| | | | Schedule No. |
|---|---|---|---|
| 1. | Company Claim | $40,779,039 | Schedule 1 |
| | Recommended Adjustments: | | |
| 2. | Additional Employees Expense | 3,232,167 | Schedule 8 |
| 3. | Incentive Compensation Award Expense | 2,879,274 | Schedule 9 |
| 4. | Payroll Tax Expense | 467,525 | Schedule 10 |
| 5. | 401K Expense | 325,676 | Schedule 11 |
| 6. | Other Employee Related Expense | 891,464 | Schedule 12 |
| 7. | Other (Non Labor) Trended Expense | 1,523,652 | Schedule 13 |
| 8. | Membership Dues Expense | 46,301 | Schedule 14 |
| 9. | LNG and Economic Development Expense | 370,448 | Schedule 15 |
| 10. | Advertising and Marketing Expense | 1,064,871 | Schedule 16 |
| 11. | Rate Case Expense | 166,756 | Schedule 17 |
| 12. | TIMP Pipeline Reassessment and Risk Analysis | 503,756 | Schedule 18 |
| 13. | Other (Non Labor) Not Trended Expenses | 753,976 | Schedule 19 |
| 14. | Depreciation Expense - Plant | 1,634,220 | Schedule 20 |
| 15. | Depreciation Expense - Rates | 4,104,580 | Schedule 21 |
| 16. | Property Tax Expense | 419,024 | Schedule 22 |
| 17. | Interest Synchronization | (339,194) | Schedule 23 |
| 18. | Operating Income | **$58,823,538** | |

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**ADDITIONAL EMPLOYEES EXPENSE**

| | | | |
|---|---|---|---|
| 1. Recommended Adjustment | | $4,282,254 | (A) |
| 2. Income Taxes @ | 24.52% | 1,050,087 | |
| 3. Operating Income Impact | | **$3,232,167** | |

Souces:
(A) Company Filing, Schedule G-2, page 19.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**INCENTIVE COMPENSATION AWARD EXPENSE**

| | | | |
|---|---|---|---|
| 1. Company Claim - STIP | $4,512,108 | | (A) |
| 2. Recommended Adjustment (%) | 50.00% | | (B) |
| 3. Recommended Adjustment ($) | | $2,256,054 | |
| 4. Company Claim - LTIP | $1,558,657 | | (A) |
| 5. Recommended Adjustment (%) | 100.00% | | (B) |
| 6. Recommended Adjustment ($) | | $1,558,657 | |
| 7. Total Recommended Adjustment | | $3,814,711 | |
| 8. Income Taxes @ | 24.52% | 935,437 | |
| 9. Operating Income Impact | | **$2,879,274** | |

Sources:
(A) Response to Interrogatory OPC-10.
(B) Percentage based on financial metrics or other factors not benefitting Ratepapers, per the response to Interrogatory OPC-10.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**PAYROLL TAX EXPENSE**

| | | | |
|---|---|---|---|
| 1. Additional Employees Expense | | $4,282,254 | (A) |
| 2. Incentive Compensation Award Adjustment | | 3,814,711 | (B) |
| 3. Total Labor Adjustments | | $8,096,965 | |
| 4. Tax Rate Per Company | | 7.65% | (C) |
| 5. Recommended Payroll Tax Adjustment | | $619,418 | |
| 6. Income Taxes @ | 24.52% | 151,893 | |
| 7. Operating Income Impact | | **$467,525** | |

Sources:
(A) Exhibit ACC-2, Schedule 8.
(B) Exhibit ACC-2, Schedule 9.
(C) Company Filing, Schedule C-30, page 1.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**401K EXPENSE**

| | | | |
|---|---|---|---|
| 1. Additional Employees Expense | | $4,282,254 | (A) |
| 2. Incentive Compensation Award Adjustment | | 3,814,711 | (B) |
| 3. Total Labor Adjustments | | $8,096,965 | |
| 4. Contribution Rate Per Company | | 4.02% | (C) |
| 5. Recommended Payroll Tax Adjustment | | $325,676 | |
| 6. Income Taxes @ | 24.52% | 79,862 | |
| 7. Operating Income Impact | | **$245,814** | |

Sources:
(A) Exhibit ACC-2, Schedule 8.
(B) Exhibit ACC-2, Schedule 9.
(C) Estimated based on 401K expense of $1,833,213 per the response to Interrogatory OPC-21 and total labor costs (including STIP) of $45,577,385 ($41,065,277 if salary cost per Company Filing, Schedule G-2, page 19 plus STIP of $4,512,108 per the response to Interrogatory OPC-10.)

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**OTHER EMPLOYEE-RELATED EXPENSE**

| | | | |
|---|---|---|---|
| 1. Operation Employee Materials Expense | | $163,200 | (A) |
| 2. Additional A&G Employee Expense | | 98,000 | (A) |
| 3. Information Technology Allocation Expense | | 607,242 | (A) |
| 4. Human Resources Allocation Expense | | 246,994 | (A) |
| 5. Other Shared Services Expense | | 65,652 | (A) |
| 6. Total Company Claim | | $1,181,088 | |
| 7. Income Taxes @ | 24.52% | 289,624 | |
| 8. Operating Income Impact | | **$891,464** | |

Sources:
(A) Company Filing, Exhibit No. SPH-1, Document No. 5, page 1.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**OTHER (NON LABOR) TRENDED EXPENSE**

| | | | |
|---|---|---|---|
| 1. Company Claim | | $47,430,576 | (A) |
| 2. Adjusted Test Year Ex. CPI Adjustment | | 45,411,910 | (B) |
| 3. Recommended Adjustment | | $2,018,666 | |
| 4. Income Taxes @ | 24.52% | 495,014 | |
| 5. Operating Income Impact | | **$1,523,652** | |

Sources:
(A) Company Filing, Schedule G-2, page 19.
(B) Company Filing, Schedule G-2, page 19, modified
to reflect 0% inflation in 2020 and 2021.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**MEMBERSHIP DUES EXPENSE**

| | | | |
|---|---|---|---|
| 1. AGA Membership Dues | | $221,966 | (A) |
| 2. Recommended AGA Adjustment (%) | | 20.00% | (B) |
| 3. Recommended AGA Adjustment ($) | | $44,393 | |
| 4. Amount Excluded by Company | | 8,050 | (C) |
| 5. Additional Recommended AGA Adjustment | | $36,343 | |
| 6. Associated Gas Distributors of Florida | | 25,000 | (C) |
| 7. Total Recommended Adjustment | | $61,343 | |
| 8. Income Taxes @ | 24.52% | 15,042 | |
| 9. Operating Income Impact | | **$46,301** | |

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**LNG AND ECONOMIC DEVELOPMENT**

| | | | |
|---|---|---|---|
| 1. Miami LNG Storage O&M Expense | | $25,000 | (A) |
| 2. LNG/RNG Consulting Expense | | 50,000 | (A) |
| 3. Economic Development Initiatives | | 415,802 | (A) |
| 4. Total Company Claim | | $490,802 | |
| 5. Income Taxes @ | 24.52% | 120,354 | |
| 6. Operating Income Impact | | **$370,448** | |

Sources:
(A) Company Filing, Exhibit No. SPH-1, Document No. 5, page 1.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**ADVERTISING AND MARKETING EXPENSE**

| | | | |
|---|---|---|---|
| 1. Additional Customer Communications Expense | | $35,000 | (A) |
| 2. Additional Marketing to Promote Natural Gas Expense | | 829,871 | (A) |
| 3. Additional Pipeline Awareness Campaign Expense | | 200,000 | (A) |
| 4. Total Company Claim | | $1,064,871 | |
| 5. Income Taxes @ | 24.52% | 261,126 | |
| 6. Operating Income Impact | | **$803,745** | |

Sources:
(A) Company Filing, Exhibit No. SPH-1, Document No. 5, page 1.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**RATE CASE EXPENSE**

| | | | |
|---|---|---|---|
| 1. Projected Rate Case Costs | | $1,657,000 | (A) |
| 2. Recommended Amortization Period | | 5 | (B) |
| 3. Annual Amortization Expense | | $331,400 | |
| 4. Company Claim | | 552,333 | (C) |
| 5. Recommended Adjustment | | $220,933 | |
| 6. Income Taxes @ | 24.52% | 54,177 | |
| 7. Operating Income Impact | | **$166,756** | |

Sources:
(A) Company Filing, Schedule C-13, page 1.
(B) Recommendation of Ms. Crane.
(C) Company Filing, Exhibit No. SPH-1, Document No. 5.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**TIMP PIPELINE REASSESSMENT AND RISK ANALYSIS**

| | | | |
|---|---|---|---|
| 1. Recommended Annual Amortization | | $1,439,980 | (A) |
| 2. Company Claim | | 2,107,400 | (B) |
| 3. Recommended Adjustment | | $667,420 | |
| 4. Income Taxes @ | 24.52% | 163,664 | |
| 5. Operating Income Impact | | **$503,756** | |

Sources:
(A) Five Year Average, Based on TIMP/DIMP Workpaper.
(B) Company Filing, Exhibit No. WPH-1, Document No. 5, page 1.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**OTHER (NON LABOR) NOT TRENDED EXPENSE**

| | | | |
|---|---|---|---|
| 1. Engineering Services Expense | | $300,000 | (A) |
| 2. Engineering Training Expense | | 50,000 | (A) |
| 3. New Work Asset Management O&M Expense | | 648,933 | (B) |
| 4. Total Recommended Adjustment | | $998,933 | |
| 5. Income Taxes @ | 24.52% | 244,957 | |
| 6. Operating Income Impact | | **$753,976** | |

Sources:
(A) Company Filing, Exhibit No. SPH-1, Document No. 5, page 1.
(B) Reflects a five-year recovery of requested costs.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**DEPRECIATION EXPENSE - PLANT-IN-SERVICE**

| | | | |
|---|---|---|---|
| 1. Company Claim | | $56,958,392 | (A) |
| 2. Annualized at January 2021 | | 54,793,236 | (B) |
| 3. Recommended Adjustment | | $2,165,156 | |
| 4. Income Taxes @ | 24.52% | 530,936 | |
| 5. Operating Income Impact | | **$1,634,220** | |

Sources:
(A) Company Filing, Schedule G-2, page 23.
(B) Annualized Based on January 2021 Expense per Schedule G-2, page 23.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**DEPRECIATION EXPENSE - RATES**

| | | | |
|---|---|---|---|
| 1. Recommended Adjustment | | $5,438,102 | (A) |
| 2. Income Taxes @ | 24.52% | 1,333,522 | |
| 3. Operating Income Impact | | **$4,104,580** | |

Sources:
(A) Reflects December 2020 plant and Mr. Garrett's recommended depreciation rates.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**PROPERTY TAX EXPENSE**

| | | | |
|---|---|---|---|
| 1. Company Claim | | $16,019,000 | (A) |
| 2. Recommended Adjustment (%) | | 3.47% | (B) |
| 3. Recommended Adjustment | | $555,159 | |
| 4. Income Taxes @ | 24.52% | 136,135 | |
| 5. Operating Income Impact | | **$419,024** | |

Sources:
(A) Response to Interrogatory OPC-29.
(B) Based on gross plant adjustment per Schedule ACC-4.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**INTEREST SYNCHRONIZATION**

| | | | | |
|---|---|---|---|---|
| 1. | Rate Base Adjustment | | ($83,819,368) | (A) |
| 2. | Weighted Interest Cost | | 1.65% | (B) |
| 3. | Pro Forma Interest Expense | | ($1,383,232) | |
| 4. | Increase in Income Taxes @ | 24.52% | (339,194) | (C) |
| 5. | Operating Income Impact | | **$339,194** | |

Sources:
(A) Exhibit ACC-2, Schedule 3.
(B) Exhibit ACC-2, Schedule 2.
(C) Tax rate per Exhibit ACC-2, Schedule 24.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**COMPOSITE INCOME TAX RATE**

| | | | |
|---|---|---|---|
| 1. Revenue | | 100.00% | |
| 2. State Income Taxes @ | 4.46% | 4.46% | (A) |
| 3. Federal Taxable Income | | 95.54% | |
| 4. Income Taxes @ | 21.00% | 20.06% | (A) |
| 5. Operating Income | | 75.48% | |
| 6. Total Tax Rate | | **24.52%** | (B) |

Sources:
(A) Tax rates per Company Filing, Schedule G-4, page 1.
(B) Line 1 - Line 5.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**REVENUE MULTIPLIER**

| | | (A) |
|---|---|---|
| 1. Revenue | | 100.00% |
| 2 Regulatory Assessment | | 0.50% |
| 3. Bad Debt Expense | | 0.34% |
| 4. Taxable Income | | 99.16% |
| 4. State Income Taxes @ | 4.46% | 4.42% |
| 5. Federal Taxable Income | | 94.74% |
| 6. Income Taxes @ | 21.00% | 19.89% |
| 7. Operating Income | | 74.84% |
| 8. Revenue Multiplier | | **1.3361** |

Sources:
(A) Company Filing, Schedule G-4.

**PEOPLES GAS SYSTEM**
**TEST YEAR ENDING DECEMBER 31, 2021**
**REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS**

| | | |
|---|---|---|
| 1. | Capital Structure/Cost of Capital | ($12,219,079) |
| | **Rate Base Adjustments:** | |
| 2. | Utility Plant in Service | (6,343,864) |
| 3. | Construction Work in Progress | (1,959,665) |
| 4. | Accumulated Depreciation | 1,529,261 |
| | **Operating Income Adjustments** | |
| 5. | Additional Employees Expense | (4,318,630) |
| 6. | Incentive Compensation Award Expense | (3,847,115) |
| 7. | Payroll Tax Expense | (624,679) |
| 8. | 401K Expense | (435,149) |
| 9. | Other Employee Related Expense | (1,191,121) |
| 10. | Other (Non Labor) Trended Expense | (2,035,814) |
| 11. | Membership Dues Expense | (61,864) |
| 12. | LNG and Economic Development Expense | (494,971) |
| 13. | Advertising and Marketing Expense | (1,422,817) |
| 14. | Rate Case Expense | (222,810) |
| 15. | TIMP Pipeline Reassessment and Risk Analysis | (673,089) |
| 16. | Other (Non Labor) Not Trended Expenses | (1,007,418) |
| 17. | Depreciation Expense - Plant | (2,183,548) |
| 18. | Depreciation Expense - Rates | (5,484,296) |
| 19. | Property Tax Expense | (559,874) |
| 20. | Interest Synchronization | 453,210 |
| 21. | Total Recommended Adjustments | ($43,103,334) |
| 22. | Company Claim | 85,324,894 |
| 23. | Recommended Revenue Requirement Deficiency | **$42,221,561** |