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April 20, 2026

BY E-FILING

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

Re: Docket No. 20260026-GU – Application for Rate Increase by Florida City Gas.


Dear Mr. Teitzman:

Attached, for electronic filing, on behalf of Florida City Gas, please find the Direct Testimony of Joanaugh Baugh, as well as her Exhibits JB-1, JB-2, and JB-3.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

(Document 7 of 27)

Sincerely,


Beth Keating
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20260026-GU: Petition for rate increase by Florida City Gas

Prepared Direct Testimony of Joana Baugh

Date of Filing: April 20, 2026

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1 **I. Introduction**

2 **Q. Please state your name, occupation and business address.**

3 A. My name is Joana Baugh. My business address is 1635 Meathe Drive, West Palm
4 Beach, FL 33411. I am employed by Chesapeake Utilities Corporation (“CUC”) as
5 Director of Regulatory Affairs. Chesapeake is the parent company of Florida City Gas
6 (“FCG” or the “Company”).

7 **Q. Please describe your educational background and relevant professional**
8 **experience.**

9 A. I received a Bachelor of Science in Accounting from the College of the Holy Spirit,
10 and I am a licensed Certified Public Accountant in the state of Virginia. Prior to joining
11 CUC, I was employed by the public accounting firms of Ernst & Young LLP and BDO
12 USA, LLP, in positions ranging from Staff Auditor to Manager.

13 I have been employed with CUC since 2010. Initially, I worked in the Internal Audit
14 Department as Senior Manager of Internal Audit, where I was responsible for the
15 design and implementation of the Internal Audit Program for CUC and its subsidiaries.

16 In addition, I led various operational and compliance audits across CUC. In 2021, I
17 transitioned to the Regulatory department preparing Florida Public Utilities
18 Company’s (“FPUC”) Natural Gas base rate proceeding in Docket No. 20220067-GU.

19 I have been in my current role as Director since 2025. In this role, I ensure compliance
20 with all regulatory requirements for CUC’s regulated business units in Florida,
21 Maryland, and Delaware as well as preparation of base rate proceedings.

22 **Q. Have you previously filed testimony before the Florida Public Service**
23 **Commission?**

1 A. Yes, I have provided written, pre-filed rebuttal testimony in FPUC’s natural gas rate
2 case, which was addressed in Docket No. 20220067-GU.

3 **Q. How will you refer to the Company?**

4 A. For clarity, when referring to the Florida City Gas, I will refer to it as “FCG” or the
5 “Company.” When referring to Chesapeake Utilities Corporation, the parent company,
6 I will refer to it as “CUC.”

7
8 **II. Statement of Qualifications**

9 **Q. Please describe your current responsibilities.**

10 A. My current responsibilities include directing the regulatory activities for all of CUC’s
11 regulated distribution companies. This includes regulatory analysis and preparation of
12 routine and non-recurring special filings, including rate case proceedings, before the
13 Florida Public Service Commission (“Commission”), as well as the Delaware and
14 Maryland Public Service Commissions. I also work with consultants preparing the cost
15 of service, rate design, and tariff changes.

16
17 **III. Purpose of Testimony**

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

19 A. My testimony will support certain costs on historical and projected data presented in
20 the MFRs listed in Exhibit JB-1. Specifically, I will address the costs and adjustments
21 presented within the MFR schedules for rate base, net operating income (“NOI”), and
22 cost of capital. In addition, my direct testimony will also present and explain the basis

1 for the development of the Company's revenue requirement request and the
2 Company's requested interim rate relief.

3 **Q. Are you sponsoring any exhibits in this proceeding?**

4 A. Yes. I am sponsoring Exhibits JB-1, JB-2 and JB-3. JB-1 is a list of Minimum Filing
5 Requirements ("MFR") that I am sponsoring or co-sponsoring. JB-2 is the calculation
6 of the revenue requirement associated with the ERP system. JB-3 is the proposed
7 interim rates by class.

8

9 **IV. Test Year**

10 **Q. What test year is the Company using for its proposed base rate increase?**

11 A. The Company is using a projected 2027 Tear Year based on the 12-month period
12 ending December 31, 2027. The historic base year is actual data for the 12-month
13 period ending December 31, 2025. For interim purposes, the Company is proposing a
14 historic year ending December 31, 2025. See section IX – Interim Rate Relief of my
15 testimony for more details.

16

17 **V. Rate Base**

18 **Q. Please describe how the historic base year rate base was calculated?**

19 A. For the historic base year, a 13-month average rate base was calculated for the period
20 ending December 31, 2025. MFR Schedule B-2 shows the calculation of the historic
21 base year rate base. Consistent with the Company's last rate case, net plant is defined
22 as the sum of 1) plant in service, plus corporate plant allocated, 2) construction work
23 in progress, 3) accumulated depreciation and amortization, and corporate plant

1 accumulated depreciation, and 4) previously approved acquisition adjustment.
2 Adjusted net plant for the historic base year was \$512,931,278. An allowance for
3 working capital, after adjustments, in the amount of \$27,696,052, was then added to
4 net plant to calculate total rate base. The 13-month average rate base for the Company,
5 after adjustments, was \$540,627,330.

6 **Q. What are the items that are included in net plant that have been allocated from**
7 **CUC to the natural gas operating units?**

8 A. The Company has determined that there are plant assets of its parent company, CUC,
9 which are used across all of CUC's business units. It is therefore appropriate to
10 allocate these assets to natural gas business units based on their shared utilization
11 across multiple regulated and/or non-regulated business units. These assets are also
12 detailed on MFR Schedule B-5 and referred to in my testimony as "CUC Corporate"
13 common plant.

14 **Q. What is the basis for the allocation from CUC Corporate common plant to the**
15 **Company?**

16 A. The allocation of CUC Corporate common plant to FCG is based on the modified
17 Distrigas formula, a FERC-approved formula, which weighs various aspects of each
18 of the operating units to calculate the appropriate allocation. This method of allocation
19 is further discussed in the testimony of Company witness George Navo.

20 **Q. Does the historic base year accurately reflect rate base for the Company?**

21 A. Yes, the Company has included all adjustments required by the Commission in
22 previous rate proceedings. We also made other appropriate adjustments to the historic
23 base year to remove rate base that does not belong to FCG and to include the

1 appropriate impact of the 2025 depreciation study in Docket No. 20250035-GU. As
2 such, MFR Schedule B-2 for the period ending December 31, 2025, reflects the
3 appropriate historic year rate base.

4 **Q. Please explain the adjustments to the historic base year rate base included in the**
5 **MFRs.**

6 A. The adjustments to rate base correspond to those required by the Commission. The
7 adjustments required by the Commission include adjustments made to eliminate: 1)
8 SAFE plant, SAFE CWIP and its associated reserve in the amount of \$67,168,184; 2)
9 relocation plant, relocation CWIP and its associated reserve in the amount of
10 \$648,433; 3) net leases in the amount of \$17,078; 4) “goodwill” associated with
11 CUC’s acquisition of FCG in the amount of \$445,460,721; and 5) the allowance of
12 funds used during construction (“AFUDC”) reflected in construction work in progress
13 (“CWIP”) in the amount of \$17,512,723. The Company also made appropriate
14 adjustments to remove CWIP that does not belong to FCG and to include the
15 appropriate impact of the 2025 depreciation study in Docket No. 20250035-GU,
16 finalized in February 2026. These amounts are detailed in MFR Schedule B-3.

17 **Q. Please explain the adjustments to the historic base year working capital included**
18 **in the MFR filing.**

19 A. The working capital adjustments are consistent with those required by the Commission
20 in previous rate case proceedings. The adjustments made were to remove: 1) one half
21 of FCG’s Directors and Officers insurance in the amount of \$31,577; 2) the Area
22 Extension Program (“AEP”) receivables in the amount of \$775,177; and 3) deferred
23 rate case expense in the amount of \$995,276.

1 The Company also made appropriate adjustments to correct an entry recorded to FCG
2 in error for the historic year which was subsequently corrected in early 2026. Details
3 of these adjustments and amounts can be found on MFR Schedules B-3 and B-13.

4 **Q. What was the basis for projecting the rate base?**

5 A. The Company projected rate base by projecting both net plant and working capital for
6 the projected test year, using planned capital projects, retirements, and other known
7 and measurable changes. The projection of net plant is addressed further in the
8 testimony of Company witness Brian Gilliam and ERP is addressed in the testimony
9 of Michael Galtman.

10 **Q. What is the amount of the Company's capital additions for the historic base year**
11 **ending December 31, 2025, and capital budget for the projected year ending**
12 **December 31, 2026, and the projected test year ending December 31, 2027?**

13 A. The capital additions for the twelve months ending December 31, 2025, were
14 \$63,787,735, including SAFE additions. The budget amounts including SAFE for
15 capital additions for the periods ending December 31, 2026, and 2027 are \$60,491,887
16 and \$105,955,411 respectively. The amounts excluding SAFE additions are
17 \$30,025,896, \$30,918,171 and \$76,231,728 for periods ending December 31, 2025,
18 2026, and 2027, respectively. The capital projection is addressed further in the
19 testimony of Company witness Brian Gilliam.

20 **Q. Is it appropriate to include CWIP planned for the projected test year in rate**
21 **base?**

22 A. Yes, the Company should be allowed to earn a fair return on capital projects under
23 construction. Costs associated with these projects are all prudently incurred and

1 necessary, and therefore, should be included in rate base for recovery through base
2 rates. Historically, the Commission has allowed CWIP to be included in rate base for
3 the Company.¹ These projects are not subject to AFUDC, and accordingly, will not
4 receive duplicate recovery on these projects while under construction. With this
5 proceeding, the Company is asking the Commission to allow us to recover costs
6 associated with ongoing construction, because each of the projects addressed in this
7 filing is critical to maintaining and improving system safety and reliability, as well as
8 FCG's ability to meet its customers' needs.

9 **Q. What is included in working capital?**

10 A. Working capital includes the net funds necessary to meet the Company's day-to-day
11 operating expenses.

12 **Q. How did the Company project working capital for the projected years 2026 and**
13 **2027?**

14 A. In developing working capital projections, the Company reviewed each balance sheet
15 item, and where appropriate, utilized a trend factor applied to the historic 2025
16 balance, usually based on the item's history, to address fluctuations that occur due to
17 payment timing and seasonality. The trend factors used were: (a) inflation, (b)
18 customer growth, and (c) inflation and customer growth. Trend factors have been
19 applied that are appropriate for each account and consistent with prior rate
20 proceedings. The inflation trend factor is based on the average projection of the
21 Consumer Price Index ("CPI"), which is discussed in the testimony of Company
22 witness Noah Russell. The factors for customer growth, unit (therms) growth and

¹ See, for instance, Order No. PSC-2004-0128-PAA-GU.

1 revenues are based on a detailed analysis and the results from revenue related
2 projections used within this rate proceeding. A list of the projection factors used is
3 located on MFR Schedule G2-19e. For some accounts, the Company simply used the
4 balance that existed at the historic year end when there were no fluctuations. There
5 were also some accounts that were projected using a direct method such as deferred
6 rate case. These methods are described on an account-by-account basis in MFR
7 Schedule G-6.

8 **Q. Is working capital as projected appropriate for computing the projected test year**
9 **rate base for the period ending December 31, 2027?**

10 A. Yes, the working capital as projected is appropriate for inclusion in rate base for the
11 period ending December 31, 2027. The Company performed an analysis of working
12 capital accounts, reviewed the historical methodology used, and reviewed expense
13 items related to these accounts to determine the most appropriate factor to use to
14 project working capital.

15 **Q. What is the appropriate adjusted rate base for the projected test year ending**
16 **December 31, 2027?**

17 A. The appropriate adjusted rate base for the projected test year is \$742,412,956. This
18 amount reflects utility plant (including corporate plant allocated) after deductions for
19 accumulated depreciation and amortization, and other adjustments as noted for the
20 historic base year, plus a working capital allowance. This amount is shown on MFR
21 Schedule G1-1. Additional information on capital additions to rate base for the
22 projected test year is provided in the testimony of Company witness Brian Gilliam.

1 **Q. Are there any adjustments made to the projected test year rate base outside of**
2 **those made for the historic base year?**

3 A. Yes, the Company made the same initial adjustments to the projected test year as were
4 made to the historic base year but included additional items due to changes in
5 methodology addressed further herein.

6 FCG's projected SAFE investments as of December 31, 2026, were moved into rate
7 base. The Company also transferred all unrecovered excess contribution costs from
8 the current AEP program as of December 31, 2026, to the applicable capital plant
9 construction account due to recommended changes to the AEP program, which are
10 discussed in detail in Company witness Husted's testimony. This approach is
11 consistent with that approved in FPUC's last rate case by Order PSC-09-0375-PAA-
12 GU. In that proceeding, the Commission allowed FPUC to transfer the remaining costs
13 associated with existing AEPs to rate base. In addition, an adjustment was made to
14 increase the rate base to include a full year instead of the 13-month average effect for
15 FCG's portion of the new ERP technology upgrade that will be further discussed in
16 section VIII on revenue requirement of my testimony.

17

18 **VI. Net Operating Income**

19 **Q. Please describe how the historic base year net operating income was calculated.**

20 A. The Net Operating Income (NOI) was based on the historic base year for the 12 months
21 ending December 31, 2025. This calculation is shown on MFR Schedule C-1. Certain
22 adjustments to reduce NOI are reflected in MFR Schedule C-2. As shown on MFR
23 Schedule C-1, the Company's adjusted NOI for the historic base year is \$27,396,447.

1 **Q. Please explain the items and basis for any adjustments made to the operating**
2 **income for the historic base year included in MFR Schedule C-2 pages 1 and 2.**

3 A. PGA and Conservation:

4 Consistent with the prior rate proceeding, PGA and conservation revenues and
5 expenses have been eliminated from both the historic base year and projected years.
6 These items are handled in separate dockets and are recovered outside of base rates.
7 As such, they continue to be appropriate for review and approval within those separate
8 proceedings.

9 Gross Receipts and Franchise Tax:

10 Gross Receipts tax and Franchise tax revenue and expenses have also been eliminated
11 from the historic base year and projected years. Although they are not handled in
12 separate dockets, it is appropriate to remove them. They are a direct pass-through for
13 both revenues and expenses and are excluded from setting base rates as appropriate.

14 AEP:

15 Revenues, expenses and working capital related to the Company's AEP have also been
16 eliminated in compliance with Commission Order No. PSC-95-0506-FOF-GU, which
17 states that any costs to extend service to customers that exceed the Company's
18 Maximum Allowable Construction Cost ("MACC") should not be included in the rate
19 base for ratemaking and earnings surveillance report, and likewise, the related
20 surcharge recovery should be excluded from the income statement.

21 SAFE

22 SAFE revenues and related expenses have been removed from the historic base year.

23 SAFE is handled in a separate docket and is recovered outside of base rates. However,

1 the Company is proposing for the projected test year that SAFE revenue requirements
2 as of December 31, 2026, be rolled into base rates and reset the surcharge accordingly.

3 RELOCATION

4 In 2024, the Florida Legislature approved a new provision, Section 366.99, Florida
5 Statutes, which allows gas utility companies to seek recovery of costs associated with
6 certain, mandated facility relocation projects. The Commission adopted Rule 25-
7 7.150, F.A.C., implementing the new statute and has initiated a new clause proceeding,
8 Docket No. 20260011, for purposes of reviewing and addressing requests for cost
9 recovery under the new statute and rule. Relocation revenues and related expenses
10 have therefore been removed from the historic base year, because relocation costs will
11 be addressed in the new, separate docket and recovered outside of base rates.

12 Executive Incentive Compensation

13 Executive incentive compensation has been removed consistent with Order No. PSC-
14 2023-0177-FOF-GU.

15 Economic Development Costs:

16 Economic development costs have been eliminated in accordance with PSC Rule 25-
17 7.042, Florida Administrative Code.

18 Industry Association Dues

19 Lobbying costs included in membership dues have been removed consistent with
20 Order No. PSC-2023-0177-FOF-GU.

21 Directors and Officers Liability Insurance

22 One half of directors' and officers' liability insurance expense has been removed
23 consistent with Order No. PSC-2023-0177-FOF-GU.

1 2025 Depreciation Study

2 Depreciation expense has been reduced by \$504,634 as the result of the Commission's
3 decision regarding FCG's 2025 depreciation study, addressed in Order No. PSC-2026-
4 0055-FOF-GU.

5 Bad Debt Expense

6 Due to a correction of bad debt expense in the historic base year, an adjustment was
7 made to increase bad debt expense by \$639,004 to accurately reflect a five-year
8 average balance which is consistent with Commission methodology approved in prior
9 rate cases including FPUC Natural Gas in Docket No. 20220067-GU, and FPUC
10 Electric in Docket No. 20240099-EI. This is discussed further in the testimony of
11 Company witness Michael Galtman.

12 Integration Costs

13 These are costs that were incurred in historic base year but they were charged to a non-
14 utility business unit in error. They were also included in the Company's last
15 surveillance report as appropriate for the same historic year. This is discussed further
16 in the testimony of Company witness George Navo.

17 Out of Period Expenses

18 These are additional payroll expenses directly related to the 2025 historic base year
19 that were paid and recorded on the Company's books in 2026. This adjustment
20 properly reflects payroll expense in the appropriate period.

21 Income Tax Impact:

1 The effective income tax rate on the adjustments described above has been
2 appropriately included as an additional adjustment to expense in the historic year
3 ending December 31, 2025.

4 For reference, MFR Schedule C-2 includes a summary of the above adjustments.

5 **Q. Does the historic base year accurately reflect net operating income?**

6 A. Yes, MFR Schedule C-1 for the period ending December 31, 2025, reflects the
7 appropriate historic year net operating income. Other FCG adjustments were required
8 to the historic year to include appropriate items that belonged in the historic year or
9 were otherwise made to be consistent with Commission decisions in past rate
10 proceedings.

11 **Q. Have you calculated the appropriate adjustment in income taxes to reflect the
12 synchronized interest expense related to the adjusted rate base?**

13 A. Yes. The Net Operating Income (“NOI”) has been adjusted to reflect the tax effect of
14 synchronizing interest expense to rate base. Consistent with prior Commission
15 practice, the synchronized or calculated interest expense is computed by multiplying
16 the jurisdictional adjusted rate base by the weighted cost of debt included in the cost
17 of capital. This adjustment ensures that the calculated revenue requirement reflects the
18 appropriate tax deduction for the interest component of the revenue requirement
19 calculation.

20 **Net Operating Income Projections**

21 **Q. What was the basis for projecting the revenue?**

22 A. The Company did a detailed analysis of each of the revenue components for the
23 projected years ending December 31, 2026, and December 31, 2027. The projected

1 billing determinants for weather and non-weather sensitive rate classes are addressed
2 in the testimony of John Taylor and Jessica Husted, respectively. The Company also
3 made a separate projection of other revenues including negotiated rate contracts,
4 miscellaneous service charges, late fees, third party supplier charges and non-
5 sufficient fund charges which are also addressed in the testimony of Company witness
6 Jessica Husted.

7 **Q. How did FCG project Operating and Maintenance (O&M) expenses for the**
8 **projected test year ending December 31, 2027?**

9 A. On MFR Schedule G2-9a to 19d, each FERC account was separated into payroll and
10 non-payroll components.

11 1. FCG directly projected by position, payroll and related benefits as shown in MFR
12 Schedule G2-19c and 19d, column 21, which is discussed in detail by Company
13 witness George Navo. The projected salary by position is shown in Exhibit GN-2 of
14 witness George Navo's testimony.

15 2. Non-payroll O&M expenses were projected using the historic year as the starting
16 point in MFR Schedule G2-19a and 19b, column 5, making all necessary adjustments
17 as reflected in this rate proceeding. The Company then:

18 a. Trended those with an appropriate trend factor in MFR Schedule G2-19a to
19 19d, columns 2 and 14,

20 b. Or directly projected the expense using the expertise of internal managers
21 reflected on MFR Schedule G2-19c and 19d column 24 (line numbers 35, 53,54, 56
22 and 59).

1 c. Included any appropriate adjustments (labeled “over and under” in MFR
2 Schedule G2-19g and 19h) to trended numbers.

3 The final projected O&M amounts using these methods of \$52,662,873 in MFR
4 Schedule G2-19c and 19d, column 25, were subsequently reviewed by internal
5 managers and analysts and were determined to be a good estimate of expected
6 recurring prudent costs during the projected test year.

7 **Q. Please explain in more detail the basis for projecting the non-payroll O&M**
8 **expenses included in the MFR filing.**

9 A. The non-payroll O&M expenses for the historic base year ending December 31, 2025,
10 provide the basis for most of the expense items in the projected test year ending
11 December 31, 2027. All historic adjustments were made to the non-payroll
12 components to exclude ‘out of period’ items or other items as reflected in the historic
13 year adjustments described in this testimony and shown on MFR Schedule C-2.

14 Some historic year amounts were then adjusted to normalize the expenses in MFR
15 Schedule G2-19a and 19b, column 7, for the purpose of trending historic year accounts
16 to the projected years. Normalization adjustments were made for either one-time or
17 out of period items, and annualization of partial year costs, for a more accurate
18 projection as detailed on MFR Schedule G2-19f. These adjustments only impacted the
19 projected years’ amounts and were not included for purposes of establishing the
20 historic year expenses included in the NOI for the period ending December 31, 2025.

21 The adjusted historic base year expenses, plus or minus the “normalization” amounts,
22 were then projected by multiplying the normalized 2025 costs by one of several trend
23 factors that were the most reflective of each account.

1 Some historic year items that were trended did not reflect the annual amount expected;
2 such estimates have been adjusted for specific cost estimates or increases and
3 decreases above and beyond the trended amounts (Over and Under), as shown on MFR
4 Schedule G2-19g and 19h. Certain expenses were not trended and were projected
5 solely based on direct cost estimates provided by internal management. Examples of
6 direct cost estimates include property insurance, injuries and damages, rate case
7 expense, bad debt expense and rent.

8 The application of trend factors, including over and under items plus the direct
9 projections, produced reasonable and expected results in O&M amounts for the
10 projected test year.

11 **Q. Please explain the items and the basis for any normalization adjustments made**
12 **to operating expenses for the purpose of trending non-payroll O&M expenses for**
13 **the projected test year.**

14 A. Normalization adjustments were made to the historic year to arrive at the appropriate
15 expense level by FERC account for projection purposes. Below are the descriptions of
16 the normalization adjustments made to the historic year for purposes of trending
17 projected test year expenses:

- 18 • Annualization of the new billing system post implementation expenses -
19 \$116,830
- 20 • Elimination of costs related to discontinuance of the old billing system -
21 (\$983,849)
- 22 • Compensation related to 2025 paid and accrued in 2026 - \$288,778.

- 1 • Integration costs amounting to \$1,102,379 that were charged to the incorrect
- 2 business unit for legal and TSA costs (\$538,503), system software (\$553,076)
- 3 and outside services (\$10,800).
- 4 • Elimination of integration costs – (\$1,102,379).

5 Details of these adjustments and amounts can be found on MFR Schedule G2-19f.

6 **Q. Please explain the basis of the trend factors used to project non-payroll**
7 **O&M expenses for the projected test year.**

8 A. The trend factors used for non-payroll were: (a) inflation, (b) customer growth, and
9 (c) inflation and customer growth. Trend factors have been applied that are appropriate
10 for each account and consistent with prior rate proceedings. A list of projection factors
11 used is located on MFR Schedule G2-19e. In addition, known expenses that increased
12 or decreased over and under the trended expenses were incorporated and detailed on
13 MFR Schedule G2-19g to 19h. Among the most commonly used trend factors for non-
14 payroll related expenses is Inflation and Inflation x Customer Growth. The Company
15 has applied trend factors that are most appropriate for the trended accounts and has
16 made sure that the applications of these factors have produced reasonable results. The
17 inflation trend factor is based on the average projection of the Consumer Price Index
18 (“CPI”), which is discussed in the testimony of Company witness Noah Russell. The
19 factors for customer growth, unit (therms) growth and revenues are based on a detailed
20 analysis and the results from revenue related projections used within this rate
21 proceeding. The methodology used to determine the billing determinants and revenue
22 factors for these projections have been provided by and explained in greater detail in
23 the testimony of witness John Taylor with Atrium Economics, LLC.

1 Trend factors used were consistent with those used in the expense projections.

2 **Q. Did the Company use any actual data for 2026?**

3 A. No. Due to the timing and preparation of the MFRs, the projected test year inputs were
4 developed using the historic base year ending December 31, 2025, and applied any
5 known and measurable changes.

6 **Q. Can you explain the basis for some of the expenses outside of those based on
7 historical data trended to the projected test year?**

8 A. O&M “over and under” adjustments, as well as direct projections, were made to
9 certain accounts outside of trending historical data when management determined that
10 a trend would not adequately reflect expected results. “Over and under” adjustments
11 are made when there are known and measurable adjustments to expenses that increased
12 or decreased more than inflation and growth trend factors applied to the historic level
13 of expenses. A detailed listing of the over and under adjustments, including direct
14 projections, has been included in the filing under MFR Schedule G2-19g to 19h.

15 **Q. Can you summarize the expense items that were projected on a direct basis in
16 MFR Schedule G2-19g to 19h?**

17 A. Property insurance of \$478,731 and injuries and damages of \$2,592,499 were based
18 on specific estimates from the Company’s insurance broker. These direct projections
19 are addressed within the testimony of Company witness Noah Russell.

20 The projected regulatory commission expense (i.e., rate case expense) was based on
21 specific forecasts from consultants and attorneys, as well as the in-house detailed
22 estimate of appropriate and anticipated costs. These forecasts assumed that this case
23 will go to a fully litigated hearing. The Company estimates the incremental expenses

1 related to this rate case to be \$4,215,262 and is requesting to recover these expenses
2 at a rate of \$843,052 per year over a five-year period, which is consistent with the
3 Commission's decision on this issue in the last FPUC rate case in Docket No.
4 20220067-GU. In FCG's 2022 rate case, the Commission approved amortization over
5 a 4-year period. NOI has been adjusted by \$843,052 for the projected test year.
6 Detailed specifics of these necessary and prudent costs are explained in the testimony
7 of Company witness Jessica Husted and can be found on MFR Schedule C-13.
8 The rent expense was projected to be \$0 in the 2027 projected test year. FCG has one
9 lease for office space, and it is projected to end in August 2026.

10 **Q. How did FCG project depreciation and amortization expense and taxes for the**
11 **projected test year ending December 31, 2027?**

12 Depreciation and amortization expenses for the year ended December 31, 2027, are
13 projected to be \$24,316,624 after adjustments. The detailed projected plant and the
14 applicable depreciation rates approved by Order No. PSC-2026-0055-FOF-GU in
15 Docket No. 20250035-GU were used as the basis for depreciation expense. The
16 depreciation expense is shown by plant sub-account on MFR Schedule G2-20 and G2-
17 23.

18 Amortization expense includes the remaining amortization of regulatory assets and
19 liabilities previously approved by the Commission, as well as those requested within
20 this rate proceeding. The amortization is detailed in MFR Schedule G2-21 and G2-24.
21 The assumptions used to project taxes other than income taxes components for the test
22 year ending December 31, 2027, are discussed in Schedule G-6.

1 Total income taxes for the test year ended December 31, 2027, were projected using
2 the projected taxable operating income less calculated interest expense and other
3 deductions multiplied by the current state and federal tax rates. Adjustments to the
4 resulting amount along with timing differences were estimated by the corporate office
5 of CUC. The difference between total income taxes and deferred taxes is current
6 income taxes. These calculations are shown on MFR Schedules G2-27 and G2-28 for
7 2026 and G2-30 and G2-31 for 2027.

8 There is no Investment Tax Credit (“ITC”) amortization for the projected test year and
9 accordingly the projection is zero. Annual ITC balances and amortization details for
10 prior years appear in Schedule B-17.

11 **Q. What was the basis for the storm reserve and expense included in the projected**
12 **test year?**

13 A. The Company has included a storm accrual expense of approximately \$4,792 a month,
14 or \$57,500 a year, which is the amount approved by in the Commission Order PSC-
15 2023-0177-FOF-GU. The Company is not requesting to increase the current accruals
16 as discussed further in the testimony of Company witness Noah Russell.

17 **Q. Are there any adjustments not made to the projected test year net operating**
18 **income that was made in the historic base year?**

19 A. Yes, the Company did or did not make the following adjustments in the projected test
20 year:

21 Executive Incentive Compensation

22 The Company did not make an adjustment to remove the executive incentive
23 compensation. As discussed in the testimony of Company witness George Navo, the

1 Company does not believe that the adjustment made based on previous owners'
2 compensation plans should apply to the current executive compensation.

3 Directors and Officers Liability Insurance Expense.

4 The Company did not make an adjustment to remove 50% of the D&O insurance
5 expense as purchasing a D&O insurance policy is necessary to attract and retain
6 qualified employees and directors to provide oversight and governance around the
7 changing environment that all the Company's business units are impacted by. This
8 will be further discussed in the testimony of Company witness Noah Russell.

9 Depreciation Expense

10 An adjustment was made to increase the depreciation expense to include a full year of
11 depreciation for the Company's new ERP technology upgrade that will be further
12 discussed in the section on revenue requirement of my testimony.

13

14 **VII. Cost of Capital**

15 **Q. Please describe how the historic base year cost of capital was calculated.**

16 A. MFR Schedule D-1 shows the calculation of the historic year cost of capital. The
17 overall weighted cost of capital is 7.60% for the historic year.

18 **Q. Please explain how common equity, long-term debt and short-term debt are
19 allocated to the Company.**

20 A. The thirteen-month average total capital as determined from the trial balance for the
21 parent company, CUC, at December 31, 2025, was \$3,022,222,226. This consisted of
22 \$1,494,909,483 or 49.46% common equity, \$1,343,280,969 or 44.45% long term debt
23 and \$184,031,774 or 6.09% short term debt. The Company then applied these same

1 ratios to the FCG rate base of \$540,627,330, after the reduction related to customer
2 deposits, deferred taxes and ITC tax credits.

3 **Q. Please explain the adjustments to the historic base year capital as reflected on**
4 **MFR Schedule D-1.**

5 A. There are two types of adjustments made to the capital accounts, both consistent with
6 the last rate proceedings, as well as the Company's Earnings Surveillance reports filed
7 with this Commission. First, the Company eliminated all rate base adjustments
8 including the 2023 acquisition goodwill from the cost of capital, which is an
9 elimination from rate base. Next, common equity in the amount of \$509,385,600, long
10 term debt in the amount of \$457,718,672, and short-term debt of \$62,708,235, have
11 been adjusted to reflect the same ratio to total capital as that of CUC. The Company
12 also made an adjustment to remove leases directly from long-term debt consistent with
13 the last rate case.

14 **Q. Did the Company deviate from the cost of capital methodology and calculation**
15 **for the projected test year?**

16 A. No, the Company followed the same methodology and calculation based on the
17 projected thirteen-month average 2027 rate base, capital components of CUC and
18 adjustments. The projection of the capital components was provided by Company
19 witnesses Noah Russell, who is CUC's Assistant Vice President and Assistant
20 Treasurer and David Haag.

21

22 **VIII. Revenue Requirement**

23 **Q. How did you derive the projected revenue requirement for December 31, 2027,**

1 **test year?**

2 A. The derivation of the revenue requirement and projected revenue deficiency is
3 summarized on MFR Schedule G-5 and was determined by multiplying the projected
4 test year rate base by the required rate of return to arrive at the operating income
5 required. This required operating income was then compared to the operating income
6 for the projected test year ended December 31, 2027, shown on MFR Schedule G-2
7 page 1, using FCG's existing billing rates and charges multiplied by its projected
8 billing determinants and operating expenses. Any deficiency in operating income was
9 then expanded using the revenue expansion factor to arrive at the additional revenue
10 required to realize a fair rate of return on rate base. This required increase amounts to
11 an additional \$63,273,876 in annual natural gas rates and charges. The required rate
12 of return is 8.31% as shown on Schedule G-3. The projected rate base is \$742,412,956
13 and is shown in MFR Schedule G-1 page 1. The NOI deficiency is \$46,845,633 and is
14 shown in MFR Schedule G-5.

15 **Q. What is the revenue increase requested by FCG in this proceeding?**

16 A. As shown above, the Company is seeking an increase in its base rates of \$63,273,876.
17 Of that amount, \$16,402,944 is associated with moving the Company's current SAFE
18 investments as of December 31, 2026, into base rates, consistent with the initial order
19 approving SAFE, Order No. PSC-2015-0390-TRF-GU. An additional \$48,870,932 is
20 necessary in order to address the revenue deficiency in the projected test year ending
21 December 31, 2027. FCG is also requesting an interim increase in the amount of
22 \$16,244,207 based on a deficiency in revenues for the historic year ended December

1 31, 2025, calculated in accordance with Rule 25-7.040, Florida Administrative Code.
2 The interim increase will be discussed further in section IX of this testimony.

3 **Q. Please explain what has been included in the filing related to the enterprise-wide**
4 **Enterprise Resource Planning (ERP) system.**

5 A. As discussed in testimonies of Company Witnesses Galtman and Bhatwadekar, CUC
6 is implementing an enterprisewide Enterprise Resource Planning (“ERP”) system that
7 will streamline a number of the Company’s core processes, including: finance and
8 general ledger accounting systems; construction and project management; asset
9 management; procurement processes; and human resources and employee
10 management systems. As witnesses Galtman and Bhatwadekar explain, the
11 implementation of the ERP system is critical to all CUC companies, including FCG.
12 The new system is scheduled to go live in June 2027 of FCG’s projected test year.
13 The Company has included, in the projected test year, FCG’s allocated portion of the
14 rate base and annual expense recovery on the ERP system expected to be placed in
15 service June 2027.

16 The ERP investment and depreciation expense are included beginning in June 2027
17 in both plant and expenses. Adjustments were made to plant and expenses to reflect
18 plant at the full amount of ERP allocated to FCG along with a full year of associated
19 expenses. After adjustments, the impact to the annual revenue requirement for FCG’s
20 portion of the ERP is \$6,206,353.

21 **Q. Why does the Company feel it is appropriate to include the full amount of ERP**
22 **investment in the projected yest year?**

1 A. Absent the approval to recover the ERP investment in rate base for a full year and
2 associated annual expenses, the Company would be deficient in revenues beginning in
3 June 2027. This would diminish the Company's ability to earn a fair return on its
4 investment in the utility and necessitate a limited proceeding or other rate filing sooner
5 than would otherwise be required.

6 **Q. Is the Company proposing an alternative to implement rates that would recover**
7 **the full, incremental revenue requirement?**

8 A. No. The Company has adjusted the filing to include all costs of the ERP system.
9 However, if the Commission does not approve the increases to recover the full year,
10 as an alternative, the Company would propose that the revenue requirement associated
11 with the ERP system be removed from the calculation of rates to be implemented
12 January 1, 2027. Thereafter, when the ERP goes into service, an increase in rates
13 would be recalculated to include the revenue requirement associated with the ERP
14 system, which would then be implemented as a step rate increase approximately mid-
15 year 2027. Given the revenue requirement associated with the ERP system, FCG
16 believes that the delayed recovery of that amount could help reduce rate shock to
17 customers, while more closely tying recovery of the ERP with its anticipated in-service
18 date. The calculation of the ERP system's revenue requirement is shown on page 1 of
19 Exhibit JB-2. If the Company's requested \$6.2 million revenue requirements on JB-2
20 is denied, page 2 of JB-2 provides the proposed filing rates and what the rates would
21 be excluding the \$6.2 million in revenue requirement for ERP. See testimony of
22 witness John Taylor for further discussion on calculation of the rates. In this scenario,
23 consistent with the ratemaking principle of gradualism, FCG would propose a step

1 increase for the \$6.2 million (or actual) upon the implementation of its new,
2 enterprisewide ERP system. A step-in approach would allow full recovery of this
3 necessary system, without the need for an additional costly rate proceeding or limited
4 proceeding. At that time, the rates would be increased through step rates as described
5 in the alternative proposal in this filing.

6

7 **IX. Interim Rate Relief**

8 **Q. Is the Company seeking interim rate relief in this proceeding?**

9 A. Yes, the Company is seeking interim rate relief because, as of the historic 2025 year,
10 FCG is not earning a sufficient return on its investment to provide the Company an
11 opportunity to earn a fair rate of return. Without appropriate rate relief, continuing to
12 earn at this level will hinder the Company's ability to provide efficient, reliable and
13 safe service to the communities and customers that it serves at the levels they have
14 come to expect. Given the length of the rate case process, interim rates will mitigate
15 FCG's negative earnings posture through the pendency of the rate case until final rates
16 can be put in place. Utilizing the methodology authorized in Section 366.071, Florida
17 Statutes, the Company has calculated that it requires annual interim relief of
18 \$16,244,207, based on the historical test year ending December 31, 2025. At that time,
19 the Company earned below the bottom of its approved earnings range with its return
20 being 5.07%. Without rate relief, FCG is projected to continue to experience declining
21 returns.

22 **Q. How did you derive the revenue deficiency used in your interim rate relief**
23 **calculation?**

1 A. The calculation of the 2025 revenue deficiency is summarized on the MFR Schedule
2 F-7 in the minimum filing requirements, with the total calculated interim rate relief of
3 \$16,244,207 found on the Company's MFR Schedule No. F-7, Line 7 - "Revenue
4 Deficiency".

5 The interim rate relief revenue requirement is determined by multiplying the end-of-
6 period rate base at December 31, 2025, by the required rate of return as stated in
7 Section 366.071(5)(b)(2) of the Florida Statutes, which provides the operating income
8 required. This required operating income is then compared to the 2025 operating
9 income from the achieved rate of return, as stated in Section 366.071(5)(b)(1), which
10 is the rate of return earned by the utility with appropriate adjustments, to determine
11 the Company's revenue deficiency. The Company's adjustments are detailed in MFR
12 Schedules F-3 and F-5. The deficiency in operating income is expanded using the
13 revenue expansion factor of 1.3511 (see MFR Schedule F6 for the calculation of the
14 revenue expansion factor) to arrive at the additional revenue required to realize a fair
15 rate of return on rate base. The Company's required rate of return is 7.16% as is shown
16 on Schedule F-8 (Year-End) page 2 in the MFR, and the December 31, 2025, rate base
17 is \$551,813,687 as provided in Schedule F-1. The Company's interim rate relief
18 requirement is based on its end-of-period rate base investment, as allowed in
19 366.071(5)(a), since this amount represents the actual used and useful plant providing
20 service to customers. In determining the required rate of return for interim rates, the
21 Company applied the parameters prescribed in 366.071(5)(b)(2), F.S., and utilized the
22 calculation set forth in Rule 25-7.040, F.A.C.

1 **Q. How has the Company applied the requested interim rate relief to the rate**
2 **classes?**

3 A. On Schedule F-10 (Year-End) page 2 the total requested interim rate relief is divided
4 by total customer charge and energy charges in order to calculate a percentage
5 increase. That percentage is then multiplied by the customer and energy charge for
6 each individual rate class to derive the dollar increase per rate class. This dollar
7 increase is divided by annual therm sales to calculate the per therm increase to be
8 charged to each class during the interim rate period.

9 The proposed interim rates by class are shown in Exhibit JB-3.

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

11 A. Yes.

Florida City Gas
Witness Joanah Baugh's Sponsored and Co-Sponsored MFRs

SCHEDULE	TITLE	WITNESS
A-1	Magnitude of Change-Present vs Prior Rate Case	J. Baugh, M. Everngam
A-2	Analysis of Permanent Rate Increase Requested	J. Baugh, M. Everngam
A-3	Analysis of Jurisdictional Rate Base	J. Baugh, M. Everngam
A-4	Analysis of Jurisdictional N.O.I.	J. Baugh, M. Everngam
A-5	Overall Rate of Return Comparison	J. Baugh, D. Haag
B-1	Balance Sheet	G. Navo, J. Baugh
B-2	Adjusted Rate Base	G. Navo, J. Baugh
B-3	Rate Base Adjustments	G. Navo, J. Baugh
B-5	Common Plant Allocated	G. Navo, J. Baugh
B-6	Acquisition Adjustments	M. Everngam, J. Baugh, G. Navo
B-11	Allocation of Accumulated Depreciation/Amortization - Common Plant	G. Navo, J. Baugh
B-13	Working Capital Allowance	G. Navo, J. Baugh
B-16	Additional Rate Base Components	J. Baugh
C-1	Adjusted Net Operating Income	G. Navo, J. Baugh
C-2	Adjustments to Net Operating Income	G. Navo, J. Baugh
C-15	Out of Period Adjustments	G. Navo, J. Baugh
C-19	Allocation of Depr./Amort. Expense - Common Plant	G. Navo, J. Baugh
C-33	Wage & Salary Increases Compared to C.P.I.	N. Russell, T. Barrington, J. Baugh
C-36	Base Year Recoverable O & M Expenses By Function	J. Baugh
D-1 1 of 2	Cost of Capital - 13 Month Average - Consolidated	N. Russell, J. Baugh
D-10	Reconciliation of Average Capital Structure to Average Jurisdictional Rate Base	N. Russell, G. Navo, J. Baugh
E-6 1 of 5	Derivation of Rate Base - Plant	J. Baugh, G. Navo, B. Gilliam
E-6 2 of 5	Derivation of Rate Base - Accumulated Depreciation	J. Baugh, G. Navo
E-6 3 of 5	Derivation of Operating and Maintenance Expenses	J. Baugh, G. Navo
E-6 4 of 5	Derivation of Operating and Maintenance Expenses	J. Baugh, G. Navo
E-6 5 of 5	Derivation of Expenses and Cost of Service	J. Baugh, G. Navo
F-1	Average Rate Base and Rate of Return	J. Baugh
F-2	Working Capital - 13 Month Average	J. Baugh
F-2	Working Capital - Year-End	J. Baugh
F-3	Adjustments to Rate Base - 13 Month Average	J. Baugh
F-3	Adjustments to Rate Base - Year-End	J. Baugh
F-3	Adjustments to Working Capital	J. Baugh
F-4	Net Operating Income - 13 Month Average	J. Baugh
F-4	Net Operating Income - Year-End	J. Baugh
F-5	Adjustments to Net Operating Income - 13 Month Average	J. Baugh
F-5	Adjustments to Net Operating Income - Year-End	J. Baugh
F-6	Revenue Expansion Factor	J. Baugh
F-7	Revenue Deficiency	J. Baugh
F-8	Cost of Capital - 13 Month Average	J. Baugh
F-8	Cost of Capital - Year-End	J. Baugh
F-9	Reconciliation of Rate Base to Capital Structure - 13 Month Average	J. Baugh
F-9	Reconciliation of Rate Base to Capital Structure - Year-End	J. Baugh
F-10	Allocation of Interim Rate Relief - 13 Month Average	J. Baugh
F-10	Allocation of Interim Rate Relief - Year-End	J. Baugh
G1-1	Projected Test Year Rate Base	G. Navo, B. Gilliam, J. Baugh, M. Galtman
G1-2	Projected Test Year Working Capital - Assets	G. Navo, J. Baugh
G1-3	Projected Test Year Working Capital - Liabilities	G. Navo, J. Baugh
G1-4	Rate Base Adjustments - Projected Test Year	J. Baugh, M. Galtman
G1-4a	Rate Base Adjustments - Historic Base Year +1	J. Baugh
G1-5	Historic Base Year + 1 Balance Sheet - Assets	G. Navo, B. Gilliam, J. Baugh
G1-6	Historic Base Year + 1 Balance Sheet - Liab. & Capitalization	G. Navo, J. Baugh
G1-7	Projected Test Year Balance Sheet - Assets	G. Navo, B. Gilliam, J. Baugh
G1-8	Projected Test Year Balance Sheet - Liab. & Capitalization	G. Navo, J. Baugh
G2-1	Projected Test Year Net Operating Income - Summary	J. Baugh, G. Navo
G2-2	Adjustments to Net Operating Income	J. Baugh
G2-3	Adjustments to Net Operating Income (Cont.)	J. Baugh
G2-4	Historic Base Year + 1 - Income Statement	J. Baugh, G. Navo
G2-5	Projected Test Year - Income Statement	J. Baugh, G. Navo
G2-6	Historic Base Year + 1 - Revenues and Cost of Gas	J. Baugh, J. Husted, J. Taylor
G2-7	Historic Base Year + 1 - Revenues and Cost of Gas (Cont.)	J. Baugh, J. Husted, J. Taylor
G2-8	Projected Test Year - Revenues and Cost of Gas (Current Rate Class)	J. Baugh, J. Husted, J. Taylor
G2-9 to G2-11	Projected Test Year - Revenues and Cost of Gas (Current rates-proposed rate classes)	J. Baugh, J. Husted, J. Taylor
G2-12	Projected Test Year - Calculation of Distribution Expenses	J. Baugh, G. Navo
G2-13	Projected Test Year - Calculation of Distribution Expenses (Cont.)	J. Baugh, G. Navo
G2-14	Projected Test Year - Calculation of Maintenance Expenses	J. Baugh, G. Navo, W. Haffacke
G2-15	Projected Test Year - Calculation of Customer Account Expenses	J. Baugh, G. Navo, K. Estrada, M. Galtman
G2-16	Projected Test Year - Calculation of Sales Promotion Expenses	J. Baugh, G. Navo
G2-17	Projected Test Year - Calculation of Admin. and General Expenses	J. Baugh, G. Navo, M. Galtman, A. Bhatwadekar, W. Haffacke, N. Russell, M. Everngam

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SCHEDULE	TITLE	WITNESS
G2-18	Projected Test Year - Calculation of Admin. and General Expenses (Cont.)	J. Baugh, G. Navo, J. Husted, N. Russell
G2-19	Projected Test Year - Calculation of Total Operation & Maintenance Expenses	J. Baugh, G. Navo
G2-19a-d	Projected Test Year - Calculation of Total Operation & Maintenance Expenses (Cont.)	J. Baugh, G. Navo
G2-19e	Projected Test Year - Projection Basis Factors	J. Baugh, G. Navo, N. Russell
G2-19f	Projected Test Year - Over and Under Adjustments - Historic Base Year	G. Navo, A. Bhatwadekar, K. Estrada, J. Baugh
G2-20	Historic Base Year + 1 - Depreciation / Amortization Expense	J. Baugh, G. Navo
G2-21	Historic Base Year + 1 - Amortization Expense Detail	J. Baugh, G. Navo
G2-22	Historic Base Year + 1 - Allocation Of Deprec. / Amort. Expense	J. Baugh, G. Navo
G2-23	Projected Test Year - Depreciation / Amortization Expense	J. Baugh, G. Navo
G2-24	Projected Test Year - Amortization Expense Detail	J. Baugh, G. Navo
G2-25	Projected Test Year - Allocation Of Deprec. / Amort. Expense	J. Baugh, G. Navo
G4	Projected Test Year - Attrition Calculation of The Revenue Expansion Factor	J. Baugh
G5	Projected Test Year - Attrition Calculation of Revenue Deficiency	J. Baugh, M. Everngam
G6	Projected Test Year - Attrition Calculation of Major Assumptions	B. Gilliam, J. Baugh, G. Navo
G7	Other Taxes	J. Baugh, N. Russell, G. Navo

Line No.	Description		Amount
1	ADJUSTED ERP NET PLANT	\$	23,584,551
2	REQUESTED RATE OF RETURN		<hr/> 8.31%
3	N.O.I. REQUIREMENTS		1,959,876
4	LESS: ERP ADJUSTED N.O.I.		(2,635,078)
5	N.O.I. DEFICIENCY	\$	<hr/> 4,594,954
6	EXPANSION FACTOR		1.3507
7	ERP REVENUE REQUIREMENT	\$	<hr/> <hr/> 6,206,353

Proposed Class Code	Proposed Annual Applicability	FCG Proposed Rates (Revenue Requirement as Filed)			FCG Alternate Proposal (excluding \$6.2M of ERP Rev Req)		
		Customer Charge	Demand Charge	Distribution Charge	Customer Charge	Demand Charge	Distribution Charge
RS	n/a	\$ 36.50	\$ -	\$0.91502	\$ 36.50	\$ -	\$ 0.79473
GS - 1	< = 9999	\$ 85.00	\$ -	\$0.93355	\$ 85.00	\$ -	\$ 0.86216
GS - 2 (10K)	>= 10000 < = 49999	\$ 155.00	\$ -	\$0.83077	\$ 155.00	\$ -	\$ 0.77500
GS - 3 (50K)	>= 50000 < = 119999	\$ 600.00	\$ -	\$0.73250	\$ 600.00	\$ -	\$ 0.68384
GS - 4 (120K)	>= 120000 < = 1249999	\$ 750.00	\$ 0.92517	\$0.36219	\$ 750.00	\$ 0.92517	\$ 0.34777
GS - 5 (1250K)	>= 1250000 < = 10999999	\$ 1,250.00	\$ 0.92517	\$0.14125	\$ 1,250.00	\$ 0.92517	\$ 0.13824
GS - 6 (11M)	>= 11000000 < = 24999999	\$ 2,500.00	\$ 0.92517	\$0.10688	\$ 2,500.00	\$ 0.92517	\$ 0.10137
GS - 7 (25M)	>= 25000000	\$ 5,000.00	\$ 0.92517	\$0.05344	\$ 5,000.00	\$ 0.92517	\$ 0.05069
RSG	n/a	\$ 54.27	\$ -	\$0.91502	\$ 54.11	\$ -	\$ 0.79473
CSG	<120,000	\$ 231.58	\$ -	\$0.83077	\$ 233.30	\$ -	\$ 0.77500

RESIDENTIAL SERVICE – 1 (RS-1)

APPLICABILITY

Service is available to Residential Customers using between 0 and 99 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge	\$18.00
Distribution Charge, per therm	\$1.40576
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

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Volume No. 11

Fourth Revised Sheet No. 30
Cancels Third Revised Sheet No. 30

RESIDENTIAL SERVICE - 100 (RS-100)

APPLICABILITY

Service is available to Residential Customers using between 100 and 599 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubicfoot.

*MONTHLY RATE

Customer Charge	\$19.00
Distribution Charge, per therm	\$0.91507
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.
2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

RESIDENTIAL SERVICE - 600 (RS-600)

APPLICABILITY

Service is available to Residential Customers using 600 or more therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge	\$25.00
Distribution Charge, per therm	\$0.91517
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.
2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 1 (GS-1)

APPLICABILITY

Service is available to Non-Residential Customers using between 0 and 5,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$31.00	\$31.00
Distribution Charge, per therm	\$0.71926	\$0.71926
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 6K (GS-6K)

APPLICABILITY

Service is available to Non-Residential Customers using between 6,000 and 24,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$44.00	\$44.00
Distribution Charge, per therm	\$0.58814	\$0.58814
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.
2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 25K (GS-25K)

APPLICABILITY

Service is available to Non-Residential Customers using between 25,000 and 119,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$188.00	\$188.00
Distribution Charge, per therm	\$0.53493	\$0.53493
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

Issued by:
Florida City Gas

Effective:

GENERAL SERVICE - 120K (GS -120K)

APPLICABILITY

Service is available to Non-Residential Customers using between 120,000 and 1,249,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$375.00	\$375.00
Demand Charge, per DCQ	\$0.719	\$0.719
Distribution Charge, per therm	\$0.34948	\$0.34948
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY(DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE - 1,250K (GS -1,250K)

APPLICABILITY

Service is available to Non-Residential Customers using between 1,250,000 and 10,999,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$625.00	\$625.00
Demand Charge, per DCQ	\$0.719	\$0.719
Distribution Charge, per therm	\$0.17957	\$0.17957
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY(DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE – 11M (GS - 11M)

APPLICABILITY

Service is available to Non-Residential Customers using between 11,000,000 and 24,999,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$1,250.00	\$1,250.00
Demand Charge, per DCQ	\$0.719	\$0.719
Distribution Charge, per therm	\$0.10320	\$0.10320
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY(DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE – 25M (GS - 25M)

APPLICABILITY

Service is available to Non-Residential Customers using 25,000,000 or more therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	<u>Gas Supply from PGA</u>	<u>Gas Supply from TPS</u>
Customer Charge	\$2,500.00	\$2,500.00
Demand Charge, per DCQ	\$0.719	\$0.719
Distribution Charge, per therm	\$0.05160	\$0.05160
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY(DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GAS LIGHTING SERVICE (GL)

AVAILABILITY

See "Limitations of Service" below.

APPLICABILITY

Firm gas service for continuous street or outdoor lighting devices installed upstream of the Customer's meter.

LIMITATIONS OF SERVICE

This Rate Schedule is closed and is restricted to Customers who were served prior to March 17, 1975.

*MONTHLY RATE

Distribution Charge	\$13.38 per lamp (\$0.74315 per therm X 18 therms)
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*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. For the purpose of applying Riders or other billing adjustments usage of eighteen therms per lamp per month will be assumed.

MINIMUM BILL

The minimum monthly bill shall be the Monthly Rate.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

RESIDENTIAL STANDBY GENERATOR SERVICE (RSG)

APPLICABILITY

Service is available to Residential Customers whose only gas usage is for a standby electric generator.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge:	\$25.00	
Distribution Charge:	0 - 14 therms	\$0.00000 per therm
	More than 14 therms	\$2.63782 per therm

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Subject to special condition 3 below, a customer receiving service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month term unless the customer terminates the service in writing within 30 days before the end of the term.
2. If the customer terminates the service before the 12-month term ends, the Customer will be billed the minimum bill for the remaining months of the service.
3. If the customer installs an additional gas appliance at the premise at which service is provided, then the customer will be transferred to the applicable rate schedule based on total therms.
4. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

COMMERCIAL STANDBY GENERATOR SERVICE (CSG)

APPLICABILITY

Service is available to Non-residential Customers whose only gas usage is for a standby electric generator with annual consumption of less than 120,000 therms.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge:	\$36.00	
Distribution Charge:	0 - 26 therms	\$0.00000 per therm
	More than 26 therms	\$1.15159 per therm

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Subject to special condition 3 below, a Customer receiving service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month term unless the Customer terminates the service in writing within 30 days before the end of the term.

2. If the Customer terminates the service before the 12-month term ends, the Customer will be billed the minimum bill for the remaining months of the service.

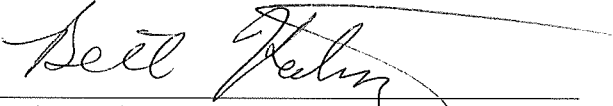
3. If the Customer installs an additional gas appliance at the premise at which service is provided, then the Customer will be transferred to the applicable rate schedule based on total therms.

4. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Testimony and Exhibits of Joana Baugh have been furnished by Electronic Mail to the following parties of record this 20th day of April, 2026:

Jennifer Crawford Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399 jcrawfor@psc.state.fl.us	Office of Public Counsel Walter Trierweiler/Charles Rehwinkel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399-1400 Trierweiler.walt@leg.state.fl.us Rehwinkel.Charles@leg.state.fl.us
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