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May 24, 2022

BY E-FILING

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

Re: **Docket No. 20220067-GU: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.**

Dear Mr. Teitzman:

Attached, for electronic filing, please find the Testimony and Exhibits MDC-1 through MDC-4 of Michael Cassel.

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 2 of 27)

Sincerely,

Beth Keating
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20220067-GU: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.

Prepared Direct Testimony of Michael Cassel

Date of Filing: May 24, 2022

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I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Michael Cassel. My business address is 208 Wildlight Ave., Yulee, FL 32097.

Q. By whom are you employed, and what is your position?

A. I am employed by Chesapeake Utilities Corporation ("CUC") as the Vice President of Regulatory and Governmental Affairs.

II. <u>Statement of Qualifications</u>

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Accounting from Delaware State University and a Master of Jurisprudence in Energy Law from the University of Tulsa College of Law. CUC hired me as a Senior Regulatory Analyst in March 2008. As a Senior Regulatory Analyst, I was primarily involved in the areas of gas cost recovery, rate of return analysis, and budgeting for CUC's Delaware and Maryland natural gas distribution companies. In 2010, I moved to Florida in the role of Senior Tax Accountant for CUC's Florida business units. Since that time, I have held various management roles, including Manager of the Back Office, Director of Business Management, and Assistant Vice President of Regulatory and Governmental Affairs for all of CUC's Florida business units, which include Florida Public Utilities Company (Electric and Natural Gas Divisions), Florida Public Utilities Company-Fort Meade, Florida Public Utilities Company-Indiantown Division, Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida

Gas, and Peninsula Pipeline Company. I am currently the Vice President of Regulatory and Government Affairs for the Corporation. In this role, my responsibilities include oversight of all the regulatory and governmental activities for all of Chesapeake's business units. Among other things, I have management oversight responsibility for regulatory analysis, reporting, and all filings before the Florida Public Service Commission ("FPSC"), Delaware Public Service Commission, Maryland Public Service Commission, and the Federal Energy Regulatory Commission, as well as legislative activities in all of Chesapeake's territories. Before joining Chesapeake, I was employed by J.P. Morgan Chase & Company, Inc. from 2006 to 2008 as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client-specific financial models and profit-loss statements. I was also employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil, and natural resources business. This included forecasting, financial close, and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 1996 to 1999, I was employed by J.P. Morgan, Inc., where I had various accounting/finance responsibilities for the firm's private banking clientele. Before joining private industry, I served in the United States Air Force in the meteorology field.

Q. Have you ever testified before the FPSC?

A. Yes. I've provided written, pre-filed testimony in a variety of the Company's annual proceedings, including the Fuel and Purchased Power Cost Recovery Clause, Docket No. 20160001-EI and the Gas Reliability Infrastructure Program ("GRIP") Cost Recovery Factors proceeding for FPUC and the Florida Division of Chesapeake Utilities Corporation, Docket No. 20160199-GU. I have also provided written, pre-filed testimony in FPUC's electric limited proceeding, Docket No. 20170150-EI, and the Commission's proceeding for consideration of the tax impacts to FPUC (Electric Division) associated with the Tax Cuts and Jobs Act of 2017, Docket No. 20180048-EI. Most recently, I provided both written and oral testimony in FPUC's Limited Proceeding to Recover Incremental Storm Restoration Costs, Docket No. 20180061-EI, as well as in the Commission's proceedings established to consider the impacts associated with Tax Cuts and Jobs Act of 2017 on the Company's gas divisions, Docket Nos. 20180051-20180054-GU.

III. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. My testimony will be broken into two parts. In the first part of my testimony, I provide an overview of the Company's request, introduce the Company's other witnesses providing support for FPUC's application, discuss the Company's need for rate relief, and identify the key drivers behind that need, as well as the various steps taken by the Company to avoid and delay requesting a rate increase.

I will then summarize certain aspects of our request as it relates to our Gas Reliability and Infrastructure Program ("GRIP") and Area Extension Program

("AEP"). Next, I will summarize the Company's request to address potential future federal and state income tax law changes. Then I will discuss the Company's request to remove the existing environmental costs from rate base and base rates and apply them as a surcharge similar to what CFG has done historically. I will also address the Company's request to change its current bad debt calculation. Finally, I will provide an overview of certain miscellaneous topics such as the Commission-approved acquisition adjustments that remain on the Company's books, rate case expense, MFR benchmarking, over and under adjustments, association participation and advocacy and our position on emissions reductions.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. A summary of those Exhibits follows:

Exhibit MDC-1 is a list of Minimum Filing Requirements ("MFR") that I am sponsoring or co-sponsoring. MDC-2 has been developed for informational purposes and ease of reference and identifies which Company witness support the respective MFR schedules. MDC-3 is a report provided to the Company regarding anticipated remediation efforts that will be required at certain environmental remediation sites and the expected costs associated with those efforts. Finally, Exhibit MDC-4 is the Company's Natural Gas Storybook, which is a key part of our effort to promote natural gas throughout the state.

IV. <u>Overview and Background of the Company</u>

Q. Please provide some background to the names of the Company.

A. As I will further explain in my testimony, one purpose of our filing is to seek the final regulatory consolidation of the Florida Local Distribution Company ("LDC") business units under one regulated entity – Florida Public Utilities Company. While the corporate legal and business requirements necessary to consolidate these entities have been completed, these business units still operate as distinct regulatory entities with separate rates and rate structures. However, the other non-base rate tariff components have been unified under one tariff. Given that this may lend itself to confusion when referring to the business units across multiple topics and multiple witnesses, we have endeavored to utilize specific naming conventions consistently across the testimony submitted today by our witnesses. Therefore, here at the outset of our case, I would like to explain the naming conventions which apply for purposes of my testimony, as well as that of other company witnesses in this case:

1. When referring to the Florida LDC business units as a whole; i.e., Florida Public Utilities Company (Natural Gas Division), Florida Public Utilities Company-Fort Meade, Florida Public Utilities Company-Indiantown Division, and the Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas, we will refer to these entities jointly as "FPUC" or "the Company";
2. When referring to an individual business unit, we will spell out the regulated name of the business unit, such as Florida Public Utilities Company-Fort Meade; and
3. When referring to Chesapeake Utilities Corporation, the parent company, we will refer to it as the "Corporation" or "CUC."

Q. Please give a general overview of the Company.

A. Florida Public Utilities Company was originally incorporated in 1924. Its official name became Florida Public Utilities Company in 1927. On October 28, 2009, FPUC was acquired by Chesapeake Utilities Corporation (“CUC”), a Delaware corporation. CUC also operates the Florida Division of Chesapeake Utilities Corporation, a natural gas utility in Florida, as well as unregulated energy businesses, including propane distribution operations and a propane wholesale marketing subsidiary. With the acquisition of Florida Public Utilities Company in 2009, CUC expanded its energy presence throughout the State of Florida. On August 6, 2010, FPUC acquired Indiantown Gas Company ("Indiantown") and with it, approximately 700 additional customers. On June 11, 2013, the City Commission of the City of Fort Meade voted to sell the City's natural gas system to FPUC. The purchase agreement for the sale of the system to FPUC was approved subsequently by the City at its October 8, 2013, City Commission meeting.

CUC likewise has a rich history in the natural gas industry. It began in 1859 as the Dover Gas Light Company. CUC was later incorporated in the State of Delaware as "Chesapeake Utilities Corporation" in 1947. CUC's Natural Gas Transmission subsidiaries are Eastern Shore Natural Gas Company, regulated by the FERC, and Peninsula Pipeline Company, Inc., regulated by the Florida Public Service Commission. CUC's unregulated energy businesses include its propane distribution operations, its propane wholesale marketing subsidiary, and Marlin Gas Services, which provides virtual pipeline services. Its corporate headquarters are located at 909 Silver Lake Boulevard, Dover, Delaware 19904.

CUC's natural gas distribution companies in Florida serve approximately 92,000 residential, commercial and industrial customers throughout the State.

Q. Is the Company seeking to consolidate these four LDCs?

A. Yes.

Q. Has the Company taken any steps prior to this proceeding to consolidate these LDCs?

A. Yes. In recent years, steps have been taken to align and consolidate certain aspects of each of these natural gas business units; however, each is still recognized as a separate utility by the Commission with its own rates and rate structure. In recent years, the growth of the State's population and the resulting growth in CUC's natural gas businesses in Florida have accelerated the need and opportunity to consolidate the four natural gas utilities into one. Consolidation of the four natural gas business units will ensure that: (1) customers continue to receive safe and reliable natural gas service from an efficient, unified company; and (2) the utility continues to be able to meet the growing demand for natural gas service in all of its service areas. Therefore, as part of this petition, the Company requests that the Commission approve the consolidation of the rates, use of a unified rate structure, and recognize these are now a single operation under the name Florida Public Utilities Company.

Q. What else has the Company done as part of this request to consolidate?

A. As a part of the consolidation request, the Florida Division of Chesapeake Utilities d/b/a Central Florida Gas would contribute its assets to Florida Public Utilities Company natural gas. Because Florida Public Utilities Company - Fort Meade and

Indiantown are already divisions of Florida Public Utilities Company, their assets would roll-up and consolidate into Florida Public Utilities Company natural gas.

PART I

V. Overview of the Company's Request

Q. What relief is the Company requesting in this proceeding?

A. Aside from the permanent rate relief discussed below, the Company is also seeking to consolidate the four LDCs of CUC's Florida business into one tariff and one rate schedule. In addition, The Company is requesting consolidation of the accounting of the four LDCs together into one unified company and the elimination of any requirement to maintain separate divisions. We are also requesting certain changes to the Company's Area Expansion Program ("AEP") that will reduce customer confusion and produce administrative efficiencies. FPUC is also proposing a method of handling any potential federal or state income tax law changes, implementing the CFG environmental surcharge across all of the Companies' platforms as a best practice, and miscellaneous textual changes of a conforming and clarifying nature. The Company is also proposing that the current Gas Reliability and Infrastructure revenue requirement be rolled into base rates, and the surcharge reset to $0, consistent with the Commission's original order approving the program. In addition, the Company is seeking approval of a new, environmental cost recovery surcharge to address certain ongoing remediation requirements associated with a few remaining manufactured gas plant remediation sites.

Q. What level of rate relief is the Company seeking in this proceeding?

A. Using a projected test year ending December 31, 2023, the Company is seeking an increase in its base rates of $43,817,913. Of that amount, $19,755,931 is associated with moving the Company's current GRIP investments into rate base and resetting the GRIP surcharge to $0, as contemplated by Order No. PSC-2012-0490-CO-GU.[1] The additional $24,061,982 is necessary to allow FPUC to earn a fair return on our investment. The request, net of the GRIP investment, is an overall increase of approximately 29%. On an annual basis, the total proposed increase is below both the compounded inflation rate of over 30.69% (see MFR C-37) since the historic base year in FPUC's last rate case in 2008 and the compound inflation rate of 50.64% since Indiantown's last rate case in 2003. The proposed increase is slightly above the compound inflation rate since CFG's last rate case, in 2009 of 25.86%. The Company is proposing a return on equity of 11.25% that generates an overall midpoint rate of return of 6.43%. In accordance with Rule 25-7.140, F.A.C., Test Year Notification, we have notified the FPSC that we have selected the twelve-month period ending December 31, 2023, as the appropriate projected test year for our petition to increase our rates and charges. The resulting revenue increase would allow the Company the opportunity to earn a fair return on its investments, cover its cost of service, and attract the necessary capital for system reliability improvements, customer growth, and service enhancements detailed in this proceeding.

Q. Is the Company also seeking Interim Rate Relief?

A. Yes. Using the methodology authorized by the Commission, the Company has calculated that, pending a decision on final rates, it requires an annual interim relief of $7,129,255 based on the historical test year ending December 31, 2021. The

[1] Docket No. 20120036-GU

specific calculation supporting the interim rate request will be covered in the testimony of Company Witness Everngam.

VI. Introduction of Company Witnesses

Q. Please identify the witnesses testifying on the Company's behalf and their areas of expertise.

A. In support of its request for rate relief, the Company is submitting the "Investor-owned Natural Gas Utilities Minimum Filing Requirements" (MFRs), as required by Commission Rule 25-7.039, Florida Administrative Code (F.A.C.), revised tariff sheets, and the testimony of the following witnesses:

Ms. Kelley Parmer, Assistant Vice President of Customer Care, will provide testimony regarding the Customer Care team and the improvements made in that area since the prior rate cases.

Mr. John Taylor of **Atrium Economics** will provide testimony regarding the cost of service study, rate classification changes, projected billing determinants and rate design.

Mr. Matthew Everngam, Director Regulatory Strategy, will provide testimony supporting the Company's request to implement interim rates, as well as the basis for certain service charges.

Mr. Michael Galtman, Senior Vice President and Chief Accounting Officer, will provide testimony on general accounting issues, as well as corporate and business unit allocation methods.

Michael Reno of Ernst & Young, now E&Y, will provide testimony on current and deferred income taxes.

Mr. Jason Bennett, Assistant Vice President of Operations and Engineering, will provide testimony on the operational departments of the Company. He will also provide testimony on the conclusion of the Company's GRIP, as well as the significant capital investments made by the Company in recent years to expand service to new customers and increase resiliency on the existing system. He will also address certain projected capital projects anticipated on FPUC's system.

Mr. Paul R. Moul of P. Moul and Associates, Inc., will provide testimony on the appropriate cost of capital and return on equity for the Company.

Mr. Bill Hancock, Assistant Vice President of Energy Logistics, will provide testimony on the Company's energy logistics functions and capacity requirements associated with growth.

Mr. Noah Russell, Assistant Vice President and Assistant Treasurer, will provide testimony supporting CUC's current capital structure allocation, the various components (short-term debt, long-term debt and equity) and address how FPUC has benefited from the structure, as well as testimony addressing Chesapeake's Insurance Programs.

Ms. Wraye Grimard, Pierpont & McClelland will provide testimony on the changes being made to the tariff.

Ms. Michelle Napier, Director Regulatory Distribution, will provide testimony on certain accounting adjustments made to expenses and why they were appropriate.

Ms. Kira Lake, Director Growth and Retention, will provide testimony on the requested change in the Area Expansion Program.

Ms. Devon Rudloff, Assistant Vice President Human Resources, will provide testimony on the Company's compensation plans and employee engagement activities.

Ms. Patricia Lee has conducted and will provided supporting testimony for the Company's Depreciation Study, which is also being provided in this proceeding.

Mr. Vikrant Gadgil, Vice President and Chief Information Officer, will provide testimony on the Company's Business Information Services activities and the investments made in that area in recent years that have benefitted FPUC's customers.

Mr. Terry Deason, Consultant, will provide testimony on the regulatory and policy considerations surrounding the Company's request to retain the unamortized amount of its previously approved acquisition adjustment regulatory assets.

VII. <u>Need for Rate Relief</u>

Q. Why is FPUC requesting rate relief at this time?

A. FPUC has made every effort to delay this request for as long as possible. However, our business is capital intensive and requires significant, long-term investments to enable us to continue to provide safe and reliable service to our customers. The Company has also been impacted by cost increases in excess of inflation and customer growth, as well as a need for additional staffing and programs to continue our level of appropriate service to our customers. Therefore, timely and sufficient revenues are critical to allow us to earn a fair rate of return, which will enhance our ability to attract capital to use for these investments.

Q. When was the last rate relief requested by FPUC and CFG?

A. FPUC's last rate relief request was filed on December 17, 2008.[2] CFG's last petition seeking rate relief was filed on July 14, 2009.[3] The previous rate case for Florida Public Utilities Company - Indiantown Division occurred well before FPUC acquired Indiantown Gas Company in 2003.[4] Prior to its acquisition in 2013 by Florida Public Utilities Company, Fort Meade was a municipally-owned gas utility. The Commission has never conducted a rate case or similar rate review for FPUC's Fort Meade division.

Q. Is the Company currently earning a reasonable rate of rate of return?

A. No. The following chart shows each Company's achieved Rate of Return ("ROR") as of December 31, 2021, as well as the projected ROR at the end of 2023:

Entity	Current ROR	Projected 2023 ROR
FPUC	4.69%	2.94%
CFG	5.18%	1.48%
Ft Meade	(6.59%)	(8.49%)
Indiantown	0.61%	(3.46%)

Q. What are the key drivers underlying FPUC's need to seek rate relief at this time?

A. There are three primary drivers causing the Company to seek relief at this time.

[2] Docket No. 20080336-GU.
[3] Docket No. 20090125-GU.
[4] Docket No. 20030954-GU.

1. **Investment** - The primary driver for this requested base rate increase is the Company's $323,974,978 increase in its total capital spend since the last rate proceedings. A significant portion of these investments are tied to extensions to serve new areas, as well as increased safety regulations imposed by federal agencies, such as the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), as detailed by Witness Bennett. New regulation changes made by PHMSA pertaining to natural gas distribution and transmission facility integrity management plans and the recent curb valve changes have contributed to the capital investment increases. Coupled with the increase in capital spending are the increases in depreciation expense resulting from the additional mains installed over this period of time. As a result, the Company has exhausted its ability to find additional cost-saving measures that would enable it to further delay a request for an increase without impacting compliance, safety, and service to customers.

2. **Economy** - Costs for the Company continue to trend upward in a variety of areas, in spite of our best efforts to keep expenses down. Many of these cost increases are beyond the control of the Company. This has further contributed to a significant decline in our rate of return in our natural gas operations. The Company believes the proposed 2023 test year will accurately reflect the economic conditions in which the Company's natural gas operations will be operating during the first twelve months that the new rates will be in effect. Therefore, this period is appropriate for rate-setting purposes. We have also faced unprecedented historical events, such as the COVID-19 Pandemic, that have had a significant, unfavorable impact on earnings since our last rate proceeding. Fortunately, the construction and housing markets

have grown at a historically high pace; however, this extraordinarily aggressive construction market has arrived at a time of 40-year high inflation. Together, this growth and historic inflation have driven increased prices on everything from labor and fuel to materials and insurance, placing additional downward pressure on our returns. When coupled with the expansion of our system, the length of time since the last rate cases, and the state of the economy, it has become necessary to seek a rate increase that will provide the Company with an opportunity to earn a fair rate of return on our investments, maintain solid financial integrity, and continue to provide safe and reliable natural gas service to our customers.

3. **Growth** - Florida is the third most populous state in the United States and is experiencing ongoing tremendous growth. Florida's population has increased by approximately twice the national average. In response to this growth, we must reinforce and extend natural gas infrastructure to underserved and unserved areas of the state, which provides support for the state's growing economy. The impacts of this historic growth will be discussed in more detail in Witness Lake's testimony.

Q. Can you please elaborate on these driving factors?

A. Yes. The Company has experienced significant consumer growth since FPUC's last rate case, which can be attributed, in part, to the aforementioned substantial population increase in the Company's historic service footprint. To accommodate this growth, FPUC has invested significant capital in expanding its existing system westward in Palm Beach County to serve West Lake and Arden, and has also expanded its system around Auburndale in Polk County. The Company has also expanded our territory in northeast Florida in Nassau County. In 2013, FPUC brought natural gas to Amelia Island, which provided the first opportunity for residents and businesses to access natural gas. Our ability to bring gas to the island required substantial investments in facilities, particularly to cross the Nassau River. Still, the benefits for Amelia Island and its residents, particularly in terms of expanded economic development opportunities, are extensive.

Likewise, in 2018, the Company worked with the City of Pensacola to provide a second access and delivery point for natural gas to Pensacola and to extend service for an industrial customer that the City was unable to serve. As will be further discussed in the testimony of Witness Bennett, we have also undertaken significant investment in the acquired Indiantown and Fort Meade systems to enhance service on those systems and ensure that customers in those areas receive the same high level of reliability and safety as customers in other parts of the state. As for those areas in which the Company has a historical presence, we have responded to the growth and economic development needs of our communities by investing in distribution main expansions to improve existing consumer service reliability in areas such as Haines City, which were previously served by constrained segments of the Company's distribution network. Similarly, population growth in the Company's service areas has necessitated numerous road expansion projects, many of which have required the relocation of the Company's facilities. Witness Bennett will further describe these capital projects, as well.

These expansions and improvements have enabled FPUC to receive and deliver larger quantities of gas at higher pressures, while ensuring that the system can maintain safe and reliable service to all customers, including customers in areas experiencing exponential growth. These capital improvements constitute prudent infrastructure investments that have significantly enhanced system reliability and safety while also allowing the Company to accommodate future growth on the system.

Q. What operational changes did the Company implement due to the COVID-19 Pandemic?

A. To ensure business continuity and the safety of our employees and customers, the Company implemented an emergency response plan, as well as other extraordinary measures, including enabling as many employees as possible to work from home, canceling all business travel, stopping the movement of employees between offices, and postponing face to face meetings and events. While these steps were necessary and effective, they are not sustainable in the long term for a business of our type and size. The result was a temporary decrease in expense associated with these types of activities and functions. At the same time, we experienced increases in other expense categories associated with our Covid response, such as cleaning supplies, safety barriers, and technology expenses necessary to increase availability of remote access for employees working from home.

Q. Has the Company taken any other steps to help customers as a result of the ongoing COVID-19 impacts?

A. Yes. The economy of the state and the nation have been adversely impacted due to the necessity to adhere to strict precautionary measures designed to slow the spread of COVID-19. Consistent with these precautionary measures, the Company took several immediate steps to protect its customers and employees, including opening more remote payment channels, suspending the assessment of late fees, suspending disconnects for most of the 2020 calendar year, and applying very flexible repayment plans to help customers through this unprecedented crisis.

VIII. Steps Taken to Avoid Requesting a Rate Increase

Q. What steps has the Company taken to avoid or delay this request?

A. The Company has implemented several cost-containment measures that have successfully limited cost increases; thereby enabling the Company to delay seeking a rate increase for almost 13 years. For example, the Company has reorganized its Operations department so that the Company's field personnel are in vertical operating units. This reorganization has enabled the Company personnel to work on distribution activities consistently across all of the Company's business units regardless of jurisdiction. Additionally, since the acquisition of FPUC by CUC, the Company has been able to take advantage of the stronger financial posture of CUC to refinance debt at lower interest rates and obtain less expensive capital. Finally, the Company has taken steps to consolidate functions across the entire FPUC platform in Florida. For instance, the Company has consolidated its Conservation Programs, Purchased Gas Adjustment ("PGA"), and GRIP to ensure the programs are implemented consistently across the Company's Florida platform. This has increased efficiency, allowing the Company to reduce the number of personnel, and therefore costs, associated with administering these programs. The Company has also spent several years identifying best practices from each of CUC's Florida LDCs' individual tariffs that could be combined and managed for greater efficiency. Taking these interim steps for efficiency outside of a full rate proceeding has also allowed the Company to avoid pursuing multiple rate cases and thereby additional rate case expense.

Q. What other efforts have been implemented by the Company to avoid or delay a rate increase?

A. The Company has pursued a couple of very intentional strategies. First, in terms of growth and expansion into previously unserved areas, the Company has pursued relationships with large industrial and commercial consumers that can serve as the basis for establishing the core infrastructure for new expansions and provide the necessary revenue streams to make such expansions economical, which then enables the Company to expand into surrounding small commercial and residential areas with a lesser economic hurdle.

Next, as will be addressed in the testimony of Witness Lake, the Company has embarked on the aggressive promotion and utilization of its Commission-approved Energy Conservation programs to advance the State of Florida's public policies regarding energy efficiency and carbon reduction, which has also helped our customers in terms of overall affordability.

PART 2

IX. Summary of Programs Changes and New Programs

A. GRIP

Q. What is the GRIP program?

A. The Gas Reliability and Infrastructure Program, known as GRIP, was implemented to replace the bare steel and cast-iron mains and service lines within the Companies' systems and was approved in Docket No. 120036-GU.

Q. Has the GRIP program been completed?

A. The original projects identified in the GRIP program will be completed by the end of 2022.

Q. Is the Company requesting the investments from this program be included in base rates during this proceeding?

A. Yes. As will be discussed in Witness Bennett's testimony, as of December 31, 2022, the Company will have identified and replaced all known bare steel and cast iron pipes on its systems. Therefore, in this proceeding, we are asking that the investments be moved to rate base and that the revenue requirement be recovered, going forward, through base rates set in this proceeding, which will reset the current GRIP surcharge to $0, as will be addressed in the testimony of Witness Bennett.

Q. Will there be a GRIP surcharge in 2023?

A. In accordance with our usual GRIP filing schedule, we anticipate that we will true up any remaining amounts in our Fall 2022 GRIP filing, which may result in a limited amount remaining to be collected in 2023.

Q. Is the Company proposing additional GRIP activity?

A. We are not requesting to extend GRIP as part of this rate proceeding; however, as addressed in the testimony of Witness Bennett, we anticipate filing a separate request to extend GRIP or establish a Phase II GRIP to address some of the new safety-related concerns that we discovered through our work on the original GRIP program, including the rear easement facilities. To be clear, this will be separate and apart from this rate proceeding; we have not included any costs associated with our anticipated Phase II request in our projected test year.

B. Area Expansion Program ("AEP")

Q. Is the Company proposing a modification to the existing Area Expansion Program ("AEP")?

A. Yes. As will be discussed in the testimony of Witness Lake, both FPUC and CFG have had AEP programs in effect for long periods of time. Over the years, both programs have evolved. Most recently, in the Companies' tariff consolidation proceeding, Docket No. 20200214-GU, the AEP programs were consolidated and unified under the FPUC version of the program. The Company has determined that it would be beneficial for our customers to make some additional changes that make the consolidated program easier to understand, particularly as it relates to calculation of the AEP surcharge and also facilitate administration of the program.

C. Income Tax

Q. Is the Company requesting approval for a rate adjustment should income tax rates change in the future?

A. Yes. The Company is proposing a change to implement future impacts to tax rates. The Company has reflected the current tax law in this filing. With the potential for federal or state tax reform always a possibility, the Company is proposing that a one-time base rate adjustment be made within 120 days of any change to the federal or state corporate tax rate becoming law. To calculate the adjustment, the Company would use the forecasted surveillance report for the calendar year when tax reform would take place to calculate the impact of tax reform on current rates and develop a uniform percentage change to base rate charges for each customer class to reflect the tax change. This adjustment would remain in effect until the tax rates change again or the Company files another base rate proceeding, whichever comes first.

Q. Why is the Company proposing this change?

A. We believe that this proposal provides the fairest mechanism for both our customers and the Company to ensure a consistent and predictable practice of collecting taxes by adjusting base rates when state or federal tax rates change to reflect the appropriate tax rate.

Q. Have any other utilities in Florida received approval to treat income tax changes similarly?

A. Yes, albeit in the context of approved settlement agreements. Similar provisions have been included in the approved settlements of TECO's rate case addressed in Docket No. 20210034-EI, and FPL's rate case addressed in Docket No. 20210015-EI.

D. Environmental

Q. Would you please provide some background on how environmental remediation costs are currently recovered on each of CUC's Florida LDCs?

A. Yes. For CFG, the Commission approved a temporary surcharge in Docket No. 20090125-GU, which was thereafter extended through August 31, 2015, by Order No. PSC-14-0052-PAA-GU, issued January 27, 2014, in Docket No. 130273-GU. By PSC-16-0562-PAA-GU, issued December 16, 2016, in Docket No. 20160153-

GU, the Commission allowed CFG to retain the final, over-collected amount of $313,430 in Account No. 254 as a regulatory liability for purposes of addressing the future expected remediation costs associated with remaining remediation requirements, which would then be reviewed in the Company's next rate case.[5] Florida Public Utilities Company's environmental costs are recovered through base rates, except for a portion related to insurance recovery, while FPUC – Ft. Meade and FPUC – Indiantown currently have no environmental remediation requirements and are not incurring, or recovering, any environmental costs.

Q. Is the Company requesting any changes to the recovery of environmental remediation costs?

A. Yes. Due to our requested consolidation, the Company is seeking approval for a consolidated methodology for recovering environmental remediation costs. We have continued to incur remediation costs on both the CFG and FPUC systems. While an amount has historically been included in FPUC's base rates to recover environmental costs, CFG relied upon the temporary surcharge, which has been terminated. When the surcharge terminated, CFG was allowed to retain the final, over-collected surcharge amount of $313,430 in a regulatory liability, because the Commission recognized that the Company was expecting to incur additional remediation costs. Since the surcharge was terminated, the Company has incurred additional remediation costs in excess of the balance in the regulatory liability. In this proceeding, in an effort to provide more rate predictability and standardize the recovery of the remaining remediation costs for the entire, consolidated Florida Public Utilities Company, we are requesting approval to establish an environmental

[5] Order NO. PSC-2016-0562-PAA-GU, at p. 3-4.

surcharge adoption of the CFG methodology of cost recovery through a monthly fixed surcharge rate for each customer class. We believe setting this as a surcharge and collecting it over a defined period of time will provide more certainty to our customers regarding the recovery period and the basis for the surcharge. In addition, the Company believes the process previously approved by the Commission for CFG in Order No. PSC-10-0029-PAA-GU, issued in Docket No. 090125-GU, on January 14, 2010, and extended through August 31, 2015, by Order No. PSC-14-0052-PAA-GU, issued January 27, 2014, in Docket No. 130273-GU, continues to reflect the most appropriate method of recovering these costs.

Q. Do the Company's MFRs for this case reflect that the environmental cost recovery amounts embedded in Florida Public Utilities Company's rates have been removed?

A. Yes. Removal of the environmental working capital assets and liabilities is reflected in G-1, Page 4a of 28, and the removal of the environmental amortization is reflected in G-2 Page 2 of 31.

Q. Would you please discuss the status of the clean-up efforts at the Company's environmental sites?

A. The Company has three former manufactured gas plant ("MGP") sites, one of which is still an active remediation site located in West Palm Beach. The other two, one on Florida Public Utilities Company – Key West and one on CFG – Winter Haven, are not active remediation sites; rather, they are undergoing annual monitoring.

As it relates to the West Palm Beach site, there are still substantial remediation efforts to be implemented and costs are ongoing. We have been operating a bio-sparging/soil-vapor extraction (BS/SVE) system since it was installed in January 2013. On the West Parcel of the West Palm Beach site, additional demolition activities of aboveground structures such as the former office building and a garage, were completed in 2019. In 2020, the subsurface remnants of the historical MGP foundations and piping were excavated and disposed of off-site, along with tar-impacted soils and clinker.

The next phase of remedial work on the West Parcel will delineate floating product or light non-aqueous phase liquid (LNAPL) and significant pockets of coal tar present as dense non-aqueous phase liquid (DNAPL). The delineation phase is expected to be completed in 2022. In addition, in 2023, it is anticipated that an LNAPL recovery system will be installed and begin operation and that an excavation/isolation program will be implemented to address the coal tar.

Once most of the recoverable LNAPL is removed from the subsurface, a BS/SVE system like the one operating on the East Parcel will be constructed on the West Parcel. It is anticipated that the design, installation, and start-up of the West Parcel BS/SVE system will be completed by 2025.

Groundwater monitoring activities will be ongoing through the implementation of all remedial activities and will likely be continued as part of a natural attenuation monitoring program after active remedial activities are completed, and the systems are decommissioned.

Q. How long is the remediation of these expected to last?

A. Clean-up efforts and monitoring are ongoing and, according to the Company's outside consultant, can be expected to continue for at least 15 years.

Q. What are the total costs the Company anticipates incurring for the environmental clean-up of the FPUC MGP sites?

A. Currently, based on the estimates from the Company's external consultant, total costs anticipated to be incurred for environmental clean-up activities are estimated to be approximately $7.5 million to $13.9 million over the next 5 to 15 years. Attached to my testimony as Exhibit MDC-3 is the most recent analysis completed by our outside consultant regarding the anticipated costs and time frames of this ongoing clean-up.

Q. Does the Company have a specific proposal regarding the method to collect the remaining expenses?

A. Yes. The Company proposes establishing a surcharge mechanism to provide a timely recovery of these costs. This will eliminate the environmental clean-up recovery of $3.6 million annually from the rate base. In addition, the proposed surcharge mechanism will provide a means to immediately terminate the surcharge when all clean-up costs are incurred and recorded, without an expensive rate filing to eliminate base rate revenues. Therefore, the Company is requesting Commission approval of the proposed environmental cost recovery surcharge mechanism. The initial level of the surcharge is proposed at $627,995 annually, effective January 1, 2023. The Company would provide an annual report on the status of the clean-up efforts at the FPUC sites and a schedule reflecting both the clean-up costs and the amounts recovered from customers. All costs and recovery amounts would continue to be subject to Commission audit. A final true-up filing would be made after all expenses have been incurred and recorded, with a proposal addressing disposal of any over-or under-recovery.

Q. Please describe how the Company proposes to determine the appropriate costs to be included in the surcharge and how the surcharge would be calculated and applied to the various rate classes.

A. The Company proposes to determine the amount of environmental remediation costs based on an outside expert's remediation plan and time period of clean up. The Company's outside expert, Ruth & Associates, are the same consultants we have used since the previous rate proceeding. Attached to my testimony in Exhibit MDC-4, which is Ruth & Associates remediation plan and associated costs on the remaining MGP sites. The costs, as calculated by our outside experts, would be allocated based on customer usage.

Q. Has the Commission authorized other similar surcharge mechanisms in the past?

A. Yes. In addition to the temporary surcharge approved for CFG in Docket No. 20090125-GU, the Commission has also previously approved cost recovery surcharges for Gulf Power Company and Progress Energy Florida, Inc. during the 2004 storm season. Specifically for Gulf, the Commission approved the recovery of $51 million related to restoration activities resulting from Hurricane Ivan[6]; and, for PEF, it approved the recovery of $231 million for storm-related costs for restoration and operation and maintenance expenses resulting from Hurricanes Charley, Frances,

[6] Order No. PSC-05-0250-PAA-EI, issued March 4, 2005, in Docket No. 050093-EI, In re: Petition for approval of stipulation and settlement for special accounting treatment and recovery of costs associated with Hurricane Ivan's impact on Gulf Power Company.

Jeanne, and Ivan[7]. Once the costs were collected, Gulf and PEF discontinued the surcharge.

E. Bad Debt

Q. How does the Company currently recover bad debt expense from customers?

A. Currently, the Company recovers bad debt expense solely through base rates based upon the bad debt expense amount approved for each division in their most recent rate case.

Q. Is the Company requesting a change in the method of bad debt recovery?

A. Yes. Instead of recovering bad debt solely through base rates, the Company is requesting that bad debt expense be recovered through both base rates and the various clauses, conservation, environmental, and PGA.

Q. How will the bad debt expense be calculated?

A. The Company will calculate the total projected bad debt expense in the test year based upon the projected write-off factor, similar to the method used in prior cases. However, instead of including the total projected bad debt expense in the revenue requirement for base rates, a portion of bad debt will be assigned to each rate component based on the percentage of projected revenues recovered through each particular rate component. For example, if 70% of the Company's projected revenues would be recovered through base rates, 70% of the projected bad debt expense would be allocated to base rates. The remaining portion of bad debt would be allocated proportionally for recovery through the other clauses. When calculating the bad debt

[7] Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

expense for each rate component, the Company will apply the write-off factor for each customer class to the corresponding rate components for that customer class and adjust the clause rate accordingly to include the write-off factor within the total rate calculation. In the future, each time the corresponding surcharge rate changes, the rate will be grossed up to include the write-off factor, similar to how the Company's PGA rate is grossed up to include taxes.

Q. Why is the Company requesting a change to the calculation of bad debt?

A. Since the various surcharge rates change more often than base rates and bad debt is a function of the Company's total revenue and not just base rates, the Company believes that it is more appropriate to recover the costs associated with bad debt from each rate component instead of collecting the total cost through base rates. In this way, the Company's bad debt revenue recovery is adjusted as the clause rates change to more accurately recover the actual bad debt expense incurred instead of the current method, in which bad debt revenue recovery is fixed in between rate cases.

Q. In the Company's filing, how is the bad debt expense incorporated into the rate increase request?

A. The base rates proposed by the Company only reflect an increase in the bad debt expense attributable to base rate revenue. The bad debt associated with the other surcharges is not included in the rate increase request. If the Commission approves the Company's request, the Company will adjust these rate components by the bad debt write-off factor to incorporate the bad debt expense into each surcharge.

Q. If the Commission does not approve the change in bad debt methodology, how will this impact the Company's revenue requirement?

A. Since the Company has currently excluded bad debt related to the various clauses from the revenue requirement, the Company requests that the additional bad debt associated with these rate components be incorporated into the revenue requirement and recovered through the Company's base rates.

X. MISCELLANEOUS

A. Acquisition Adjustment

Q. Please explain the acquisition adjustments you are addressing.

A. The acquisition adjustments pertain to the regulatory assets for the purchase premium associated with the acquisition of FPUC by CUC and the acquisition of Indiantown Gas Company by FPUC, which were approved by the Commission in Order No. PSC-12-0010-PAA-GU and Order No. PSC-14-0015-PAA-GU, respectively. Witness Deason will discuss the Commission's historic policy related to acquisition adjustments, as well as its applicability to the Company's request to retain these existing acquisition adjustments until fully amortized.

Q. Can the Company demonstrate that it should be allowed to retain the acquisition adjustments?

A. Yes, As Witness Deason will explain, the analysis historically used by the Commission to determine whether a company should be allowed to record, and retain, a positive acquisition adjustment is comprised of five considerations on whether the acquisition resulted in: (1) increased quality of service; (2) lower operating costs; (3) increased ability to attract capital for improvements; (4) lower overall cost of capital; and (5) more professional and experienced managerial, financial, technical and operational resources.[8] These considerations are referred to as the "five factor" test. Applying the "five factor" test, the Company is able to demonstrate it should be allowed to retain both acquisition adjustments.

Q. What is the overarching purpose of the "five factor" test?

A. As I understand it, and as explained in greater detail by Witness Deason, the underlying purpose of the test is to guide the Commission in determining whether the acquisition was in the public interest, and therefore, to provide a basis for the purchase premium to be recognized as a regulatory asset. At the end of the day, the question is whether CUC's acquisition of FPUC was in the public interest, and likewise, whether FPUC's acquisition of Indiantown Gas Company was in the public interest.

Q. Has the Company met each of the factors in the "five-factor test"?

A. Yes, we have, as I will explain in greater detail below.

1. Increased quality of service

Q. Have the acquisitions resulted in improved quality of service for customers?

A. Yes. There have been quality improvements in several areas, including compliance, Customer Care, and technology. One of the ways we recognize these improvements is through a decrease in operational compliance audit findings. For example, since 2009, compliance audit findings for FPUC and CFG have been reduced by

[8] See Order No. 23376, issued August 21, 1990, in Docket No. 891309-WS, In re: Investigation of Acquisition Adjustment Policy; Order No. 23858, issued December 11, 1990, in Docket No. 891353-GU, In re: Application of Peoples Gas Systems, Inc. for a rate increase; and Order No. PSC-04-1110-PAA-GU, issued November 8, 2004, in Docket 040216-GU, In re: Application for rate increase by Florida Public Utilities Company.

approximately 95%, while compliance audit findings for Fort Meade and Indiantown have decreased by 100% since 2013.

Another area in which we have made significant improvements is Customer Care. As will be detailed in the testimony of Witness Parmer, the Company has made improvements in call handling, response to customer feedback, as well as tracking of feedback, website management, and customer communications. We have also added numerous new payment channels to facilitate expanded access for customers to make payments. Our call center team members are also geographically dispersed between the Delmarva Peninsula and Florida. This provides additional backup capabilities, supports emergency situations, and has generated efficiencies in terms of employees being located in two centralized areas that provide redundancy. The Company has also made significant Business Information Services ("BIS") improvements. This has translated into increased system availability for FPUC's employees to respond to customer inquiries. At the same time, as discussed in the testimony of Witness Gadgil, customer data is more secure now than ever before. Finally, from an operational perspective, and as detailed in the testimony of Witness Bennett, customers have significantly benefited from the capital investments we have made.

<u>2. Cost Savings</u>

Q. How have the acquisitions resulted in cost savings?

A. Our customers have benefitted by the Company having access to more robust capital opportunities at much better terms and rates than before. This has directly benefited our customers because these better terms have included lower interest rates, which results in less interest expense. We have estimated that the lower cost of debt available through Chesapeake has saved FPUC more than $9 million since the acquisition. This will be discussed in more detail in the testimony of Witness Russell.

Q. Are there other areas where the acquisitions have generated savings for customers?

A. Yes. The Company has also experienced O&M savings in the area of gas supply since the acquisition. In addition, as will be discussed in the testimony of Witness Hancock, the Company has managed to grow the distribution system without adding significant amounts of capacity.

Q. Are there any other areas of cost savings that you would like to highlight?

A. Yes. As further discussed in the testimony of Witness Rudloff, CUC's management team, which is inclusive of FPUC's leadership team, is compensated at a level that is significantly lower than their industry peers, in the 25th percentile, while the Company's actual performance is in the top quartile of performance.

Additionally, following CUC's acquisition of FPUC, the Corporation consolidated administrative oversight of the retirement plans. Previously, FPUC had utilized several third-party administrators, trustees, and advisors to oversee and manage their respective retirement savings plans and pension plans, as had Chesapeake. After the acquisition, the Employee Benefits Committee led a process to consolidate administration of the plans, thereby eliminating duplicative administrative costs and achieving cost savings in the management of the Plans. New third parties were selected as advisors and trustees, and administrators. Finally, the individual pension plans were consolidated into one Master Trust, resulting in further savings.

Savings have also been achieved through the elimination of redundant leadership roles. The gas operations teams were combined under one business unit leader in Florida instead of having two separate leaders – one for FPUC and one for CUC's Central Florida Gas division. Further, certain redundant executive positions were eliminated, such as one of the Chief Financial Officer ("CFO") roles.

Another area where cost savings were achieved was in the area of financial reporting. Becoming a subsidiary of CUC eliminated the need for FPUC to prepare and file its own financial statements with the Securities and Exchange Commission ("SEC") and to have its shares listed on an exchange. This resulted in reduced compliance and governance costs. Finally, instead of two public company financial audits, only one was required. This resulted in reduced internal and external fees, as further discussed by witness Galtman.

Finally, in reviewing the liability insurance expenses that have been incurred since the acquisition until 2019, FPUC's annual insurance expense associated with liability coverage was less than pre-acquisition levels. FPUC's portion of liability insurance premiums did not approximate the pre-acquisition amounts for more than ten years. In 2019, the insurance market continued to experience pressures from carrier consolidation and industry exposures, which resulted in insurance costs exceeding the 2008 levels for the first time.

Q. Have these cost savings resulted in any decline in service to FPUC's customers?

A. No.

<u>3. Better access to lower cost capital (Factors 3 & 4)</u>

Q. Has the Company been better able to attract capital since the acquisition?

A. Absolutely. As Witness Russell will discuss, FPUC and its customers have benefited from the enhanced ability to attract capital for infrastructure projects since the acquisition. This is due to Chesapeake's investment-grade credit rating and access to competitively priced capital. The improved access to capital has been instrumental in completing large expansion projects, as well as safety and reliability projects such as the GRIP program, which will be discussed in Witness Bennett's testimony. As a result of its acquisition by CUC, FPUC has saved approximately $9 million in interest costs due to increased availability and cost of debt capital utilized to fund FPUC's investments.

<u>5. More professional and experienced managerial, financial, technical, and operational resources:</u>

Q. How have FPUC's customers benefited from more professional and experienced financial, technical and operational resources?

A. One of the most notable benefits to our customers is the depth of the management team of the greater CUC organization. The successful projects discussed above were accomplished because the acquisition has provided FPUC with access to more professional and experienced managerial, financial, technical, and operational resources. CUC's managerial, financial, and technical expertise is significant. The leadership team has a wealth of experience in the natural gas and utility arenas and provides leadership across several industry organizations. Among other things, our leadership team has spearheaded activities demonstrating the economic benefits of natural gas in our state and highlighting the key role natural gas plays in Florida's efforts to define its energy independence and pursue cleaner energy resources, i.e., Renewable Natural Gas ("RNG"). In fact, FPUC led the successful effort to have the Florida Legislature recognize "renewable natural gas" as a renewable energy resource in 2021.

Additionally, FPUC's recognition as a Top Workplace in Central Florida in 2019 and 2021, as well as CUC's recognition as a Top Workplace for the last ten years, along with its receipt of a Top Workplace USA award for mid-sized companies in both 2021 and 2022, demonstrates that our organization is able to attract and retain top-tier personnel. Highly engaged employees have been shown to deliver increased performance on the job, thereby generating lower operating costs and enhancing all aspects of service to our customers.

Q. How else have FPUC's customers benefited from more professional and experienced management?

A. Because of leadership with a superior command of the natural gas industry in Florida, the Company has avoided seeking a rate case for over ten years. This has directly benefited our customers by avoiding multiple rate proceedings and the associated costs and establishing a high level of predictability for our customers. During this time, the Company has also expanded its territory through acquisitions and organic growth.

B. Rate Case Expense

Q. What is the amount of rate case expense proposed to be included in this rate proceeding?

A. On Schedule C-13, the Company is requesting a total rate case expense of $3,427,575 to be amortized over a period of five years at $685,515 annually.

Q. Explain the period of time proposed for amortization of rate case expense and the amount included in the rate base.

A. We propose to amortize our expected rate case expenses over a period of five years. Our last rate proceeding was over ten years ago. The expected period of time to file another rate proceeding is within that same period of time, and five years is the appropriate number of years to amortize this expense. These expenses were necessary and prudent, and we feel that recovery should be allowed over the expected period.

Q. What is the basis for the rate case regulatory expense included in the projected test year?

A. We have projected rate case expenses based on specific forecasts, including the cost of using consultants to assist us in preparing and supporting a rate case and the cost of representation and consultation by an attorney.

Q. Why is the Company using outside consultants and temporary staffing instead of internal resources to compile the rate case?

A. The Company is not staffed at a level to allow for the preparation of rate proceedings, MFRs, or the additional rate case-related workload required after the MFRs are filed. Internally, while the Company has increased staffing since the last rate case was filed, the workload has increased beyond the corresponding increase in staffing. As a result, we now require additional resources beyond the level required in our last gas rate case. In addition, we do not have the expertise in all areas required to facilitate the preparation of a rate case; therefore, we had to hire the expertise and extra assistance to complete this process. For example, the Company has hired consultants to develop and support the cost of capital and cost of service in this rate proceeding. We also had to utilize temporary accounting staff and consultants to assist in the extra rate casework beyond the normal workload of the accounting department. Since the Company files rate proceedings infrequently, the use of consultants and temporary staffing to assist in the rate case proceeding is a more cost-effective approach than increasing staff to completely handle the rate case filing internally.

Q. Why should the Company recover the costs related to rate case expense?

A. Consistent with the FPSC's rulings in prior rate cases, reasonable rate case expenses are necessary and prudent for the Company to compile the rate proceeding. Accordingly, the Company believes that the recovery of the costs should be permitted over the projected amortization period.

<u>C. MFR Benchmarking</u>

Q. Would you please discuss the variances to benchmark for the 920 accounts as found on C-38 FPUC and CFG?

A. Several factors are consistently impacting our business since the Company's last rate proceeding, and they are evident in these benchmark schedules. First, the complexity of our business, the markets, and more frequent and detailed reporting requirements from governmental agencies have all increased significantly. Our Companies were stand-alone entities and considerably less sophisticated than today; as such, filings with government entities are more complex than they have been historically. For example, since the last rate proceeding, the accounting group has had to respond to new requirements for Generally Accepted Accounting Principles ("GAAP") reporting, such as the ASC 606, ASC 842, and ASC 326, as well as increased SEC reporting requirements related to critical audit matters. Second, in the previous rate proceeding, employees were charged to multiple areas that are now in a stand-alone area. For example, we might have had one employee who dealt with HR issues and handled customer communications. However, the increased level of activity and demand, especially around investments in the area of safety, has required that we staff in a manner that facilitates frequent and often specialized communications with our customers. Also, the regulatory payroll was part of the accounting payroll historically but is now a stand-alone area.

Third, we now require a higher-level professional staff with the evolving business, industry, and markets. For example, there was no Company or corporate General Counsel in the previous rate proceeding. We have prudently added this position to keep the Company abreast of, and compliant, with our industry's continually evolving laws and regulations. The Company also hired a CIO since the last rate proceeding. This critical and prudently added position is in response to our environment's growing complexities and threats, specifically around cybersecurity and customer data and network protection. Both of these positions have also allowed the Company to find and implement industry best practices in those respective areas. Another example is the addition of a Chief Human Resource Officer ("CHRO"). The Company has recognized that the complexities and demands discussed above also require a more strategic view of employee safety, training, and engagement. These additional leadership positions have proven to be critical additions as we serve our customers in the safest and most efficient manner.

Fourth, since the last rate case, the Company has had to operate in a very different environment when it comes to recruiting and retention of employees. In more recent history, specifically since the COVID-19 Pandemic, the Company has experienced a shift in the labor market that has led to more difficulty hiring and retaining qualified employees. This is compounded by the need to hire and retain employees with more specialized skill sets in accounting, tax, treasury, regulatory, IT, and HR. The increased technical demand combined with the constraints in the labor market has caused payroll costs to be higher than benchmarks.

Q. Are the variances to benchmark, on Schedule C-38 FPUC, for the 921 accounts similar to those for the 920 discussed above?

A. Yes. First, we have seen profound changes in technology since the last rate case. This has caused the costs related to software maintenance, ransomware, data security, and disaster recovery to increase significantly since the previous rate proceeding.

Second, the Company was far less sophisticated at the time, and the demand was less. As a result, peripheral items supporting a growing, evolving company, such as cell phones, data lines, and office supplies, have been prudently incurred. Many of these costs were very limited in the last rate proceeding because the Company was in a completely different posture regarding growth and industry leadership.

Q. Would you please discuss the variances to the benchmark of the 923 accounts on Schedule C-38 FPUC?

A. As discussed above, the Company has responded to changing markets, industry trends, and more demanding requirements by prudently incurring more technical staff and leadership. The Company also recognizes that hiring employees for every new scenario this market demands is not realistic nor prudent. We also respond to these evolving demands by using outside contractors for highly specialized skills in data security, disaster recovery, regulatory compliance, and legal assistance. The Company may retain these specialized skills for a specific project, but as we have seen consistently since the last rate proceeding, they are also necessary for ongoing projects. The utilization of outside professional assistance in these areas has allowed the Company to slow hiring full-time employees over the longer term.

Q. Would you please discuss the variances to the benchmark of the 930 accounts on Schedule C-38 FPUC?

A. Certainly. The Company now, compared to the Company in the last rate proceeding, is in a completely different posture. We now lead the industry in many ways because of our strategic insight and execution in the market. This increased ability has also increased the expectation of our customers in areas such as communication and access to our Company. These prudently incurred costs reflect our response to customers' desire to have multiple platforms to communicate with us and to access their account information. Additionally, as the Company has adapted to the new complexities of the market and industry, we have increased our interaction with agencies such as the New York Stock Exchange. This has also put increased demands on the Company to add additional corporate governance oversight expertise.

Q. Would you please discuss the variance to the benchmark of the 931 accounts on Schedule C-38 FPUC?

A. The variance related to this line is a result of the Company managing growth and expansion responsibly. Specifically, as we grow and move into new territories, we evaluate our buildings and locations. In doing this, we have found instances, in West Palm Beach, for example, where it is more appropriate at this time and in the near term to rent than to purchase or build a new facility. This will allow us time to evaluate our new facility requirements in a post COVID environment.

Q. Would you please discuss the variance to benchmark for the 885-894 accounts as found on Schedule C-38 CFG?

A. With the Company's growth and expansion, we have seen an increase in both required maintenance and an increase in the frequency of compliance audits over the historical benchmark. Since the last rate proceeding, we have implemented standardized equipment maintenance schedules and seen increased compliance audits that have increased costs above the historical benchmark. Additionally, we have established additional maintenance programs that have had the positive outcome of reducing violations and improving the safety of our systems. We have also incurred costs over the historic benchmark due to higher maintenance levels on aging regulators and meters.

Q. Are the reasons for a variance to benchmark for the 920, 930.1, and 931 accounts, as found on Schedule C-38 CFG, similar to those on the same schedule for FPUC?

A. Yes, they are.

Q. Would you please discuss the variances to benchmark for the 925 account as found on Schedule C-38 CFG?

A. The variance related to this account has three primary drivers. First, in the last rate case, CFG had no salaries related to a safety program charged to account 925. As a result of the Company’s focus on safety, there are now charges hitting this account. Second, the Company's insurance costs have increased beyond the inflation and growth factor. Third, we have obtained Errors and Omission insurance as well as credit insurance since the last rate proceeding. As the complexities of the market and our business increase, we have found it necessary and prudent to add coverages that protect the Corporation from losses resulting from mistakes or negligence committed on behalf of the Corporation as is the case for the Errors and Omissions insurance. Likewise, we have found it necessary to add coverage for credit insurance that protects the Corporation from larger customers that may default on payments. Both of these coverages help CUC mitigate potential risks that could impact the Company and ultimately our customers.

Q. Would you please discuss the variance to benchmark for the 926 account as found on Schedule C-38 CFG?

A. This variance is related to the costs associated with the Company's decision to close the CUC pension plan. While beneficial over the long-term, this cost was not in this account during CFG's last rate case.

Q. Would you please discuss the variance to benchmark for the 932 account as found on Schedule C-38 CFG?

A. This variance is associated with the Company's ongoing efforts to maintain the safest physical locations for its employees. This variance is specifically related to additional electrical work completed and fire suppression equipment installed at our building locations.

<u>D. Over and Under Adjustments</u>

Q. Please explain the direct projection of Reg. & Govt. Affairs manager salary in the 920/926 account of Schedule G-2 p. 19j Consolidated.

A. FPUC has historically staffed key regulatory functions with outside professional staff. With the increased complexity, volume, ongoing regulatory initiatives, and aging workforce, we have found it necessary to increase our internal regulatory staffing levels. The costs of these new positions are reflected in the projected test year.

Q. Please explain the over and under adjustment related to the Environmental Social and Governance ("ESG") director.

A. We have added this position, which we have not historically had, in response to the new demands from the investment community and our customers to consider factors related to the environment, social issues, and our governance activity in our business.

Q. Please explain the adjustment for consulting services for regulatory strategy on Schedule G-2 p. 19 l.

A. As discussed previously, there are a number of new complexities and demands on our business related to the way our industry moves forward. As we continue to grow, the need for highly technical and specialized skills in the regulatory area are required. The Company recognizes the need to hire full-time staff to meet these ever-increasing demands. However, we also acknowledge that a measured and responsible approach is critical for our customers and so utilizing consulting for the interim period makes the most economic sense.

Q. Please explain the adjustment for an ESG consultant on Schedule G-2 p. 19 l.

A. As discussed above, the new ESG demands on our business make it necessary for us to recruit and train new and highly specialized employees. When evaluating both the immediate and ongoing needs in the ESG space, the Company has realized that the utilization of consultants is the most prudent approach to meeting the demand. Instead of hiring another full-time employee, we can meet some of the long- and short-term needs with this type of combined staffing.

Q. Please explain the incremental cost adjustment to support the business transformation analyst.

A. To keep up with the increasing complexities of the market, higher expectations of customers, and the Company's push to find operational efficiencies, we have included an incremental amount for the hiring of an analyst in the business transformation area.

Q. Please explain the incremental cost adjustment to support the natural gas industry and associated legislation on Schedule G-2 p. 19 m.

A. This adjustment is of critical importance to both our customers and our industry. As I will discuss in more detail in the next section, this adjustment is necessary for the Company to continue reaching unserved and under-served customers in Florida. We have always participated in stakeholder education and outreach. Still, the industry is now in a position where utilities must educate and defend our customers' ability to choose natural gas. Therefore, we have added an appropriate incremental cost to support the increased activity.

E. Association Participation and Advocacy

Q. How does the Company advocate for natural gas on behalf of its customers?

A. We do this in two key ways. We advocate through industry association participation and also through our own an internally developed natural gas advocacy program.

Q. Do customers gain value from FPUC's participation in the advocacy activities of industry associations?

A. Yes. Our Company delivers essential energy services to communities throughout our state. As a good corporate citizen, we periodically engage in thoughtful, meaningful, and responsible dialogue with all levels of elected officials who represent the interests of the Company's employees, customers, investors, suppliers, partners, and the communities we serve. A policy-making process that is inclusive, diverse, and balances all stakeholder interests leads to greater societal advancement. Our objectives related to the use of Company funds for political advocacy include:

- To engage elected representatives on matters that impact the Company's business operations and its stakeholders.
- To engage in matters that provide for the betterment and sustainability of our communities.
- To be proactively involved in a diverse and inclusive policy-making process that balances all stakeholder interests, thus leading to greater societal advancement.

We fully acknowledge that the Commission has a well-documented history of disallowing expenses related to advocacy and lobbying-type activity. Likewise, FPUC has a long history of respectfully referring to historical precedent as our guide. However, there are circumstances and times in history when that precedent, which has served the people of Florida well, must be reevaluated with an eye towards the future of a rapidly changing energy economy. We believe that, given the current level of focus on issues around energy and the environment, there is value in reassessing the basis for that historical precedent now.

The Company's memberships in natural gas associations provide a couple of critical benefits to our customers and employees. First, these associations help the Company, through its employees, stay current on emerging trends within the natural gas industry and leverage best practices from other natural gas utilities to operate a safer, more reliable, and efficient natural gas system. Second, the collaboration within these associations provides "strength in numbers," which allows us to participate in activities that educate on the economic benefits of access to natural gas for our communities and that preserve our customers' ability to choose natural gas.

More than ever, energy, and particularly the use of natural gas, is the subject of political debate in a wide variety of contexts. We find ourselves forced to engage in this political landscape more than ever before to ensure that accurate environmental information pertaining to natural gas is being considered in these debates and to protect our customers' ability to choose their energy source. As such, we are respectfully asking that the Commission revisit its policy of disallowing these expenses.

Q. Could you please elaborate on your natural gas advocacy program?

A. The Company uses its natural gas advocacy program to engage key stakeholders on the importance of natural gas to customers, communities, and Florida's economy. For example, attached to my testimony as Exhibit MDC-4 is CUC's natural gas storybook. This "storybook" serves as a primary method of delivering the compelling story of natural gas. In addition, we often use our storybook as a simple way to start the education and communication around industry policy and trends that impact to our customers, communities, and ultimately our State.

Q. Should expenses related to natural gas advocacy be allowed for recovery purposes?

A. Yes. We believe that expenses such as stakeholder communication, government affairs activity related to natural gas policy, and economic development that the Company prudently incurs in education efforts aimed at protecting energy choice for our customers. More than any other time in our history, these activities are directly related to helping our customers maintain access to safe, efficient, reliable, and economic natural gas. The expenses incurred for these activities are used to combat misinformation about natural gas safety, reliability, and economic value in our State. By educating our stakeholders on the benefits of natural gas, we can ensure that our customers continue to have long-term access to this low-cost fuel, while the Florida reaps the economic benefits of a robust natural gas industry.

Q. Can you provide any examples of how customers have benefitted from these types of expenses?

A. Yes. The use of natural gas has become more controversial in some parts of the United States. Some states have even passed legislation to ban the use of natural gas. Our Company is taking a proactive approach to educate policymakers, customers, and all stakeholders on the benefits of natural gas in an effort to keep these misguided policies from gaining ground in Florida.

An example that demonstrates another benefit derived from these advocacy efforts is the passage in 2021 of the Renewable Energy Bill, SB 896, which incorporated Renewable Natural Gas into the state's renewable energy policy as another renewable resource. This bill was actively supported by the Company. Renewable natural gas is now another tool the state can use to facilitate a cleaner environment, while encouraging additional revenue streams for our farmers and strengthening our state's energy security.

F. Emissions Reductions

Q. What is the Company's position on the gas utility's role in achieving emissions reductions?

A. Chesapeake is committed to providing safe, reliable, and affordable energy in a manner that protects the environment and helps the state and its communities meet emissions goals. Conventional and renewable natural gas will continue to offer both environmental and cost advantages for many years to come. The most cost-effective and energy-efficient way to meet the peak energy need is to continue direct customer use of natural gas.

Since 2011, CUC's Florida natural gas distribution facilities have reduced our CO_2 emissions by 7,305 MT or approximately 53%. This can be attributed to infrastructure improvement accomplished through GRIP and our investment in infrastructure and operational practices that leverage system efficiencies. Access to clean natural gas is critical for our customers, as well as Florida's economy. CUC continues to look for opportunities to reduce emissions in responsible and prudent ways for customers, while continuing to ensure our customers have safe and reliable access to this efficient, accessible fuel. Our emissions reductions to date are just one example of our commitment to deliver a cleaner, more sustainable energy future, as further reflected by CUC's inaugural ESG report found at Sustainability - Chesapeake Utilities Corporation (chpk.com). Maintaining our transmission and distribution infrastructure will also facilitate delivery of renewable natural gas, hydrogen, and other clean fuel options as they become viable supplements to traditional natural gas.

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE	TITLE	Witness
	EXECUTIVE SUMMARY	
A-1	Magnitude of Change-Present vs Prior Rate Case	M. Cassel
A-2	Analysis of Permanent Rate Increase Requested	M. Cassel
A-3	Analysis of Jurisdictional Rate Base	M. Cassel
A-4	Analysis of Jurisdictional N.O.I.	M. Cassel
A-5	Overall Rate of Return Comparison	M. Cassel / P. Moul
	NET OPERATING INCOME	
C-11	Industry Association Dues	M. Cassel
C-12	Lobbying and Political Expenses	M. Cassel
C-13	Rate Case Expenses	M. Cassel
C-19	Allocation of Depr./Amort. Expense - Common Plant	M. Napier / M. Cassel
C-35	O & M Benchmark By Function	M. Cassel
C-36	Base Year Recoverable O & M Expenses By Function	M. Cassel
C-38	O & M Benchmark Variance By Function	M. Cassel
	PROJECTED TEST YEAR	
G2-2	Adjustments to Net Operating Income	M. Napier / M. Cassel
G2-3	Adjustments to Net Operating Income (Cont.)	M. Napier / M. Cassel
G2-19 a to d	Projected Test Year - Calculation of Operation and Main Expense Supplement	M. Cassel, J. Bennett, M. Galtman, V. Gadgil, M. Napier, K. Parmer, N. Russell, K. Lake, D. Rudloff, B. Hancock
G2-19f	Over and Under Adjustments	M. Cassel, J. Bennett, M. Galtman, V. Gadgil, M. Napier, K. Parmer, N. Russell, K. Lake, D. Rudloff, B. Hancock
G2-22	Historic Base Year + 1 - Allocation Of Deprec. / Amort. Expense	M. Napier / M. Cassel
G2-25	Projected Test Year - Allocation Of Deprec. / Amort. Expense	M. Napier / M. Cassel
G3-1	Historic Base Year + 1 - Cost of Capital	M. Cassel / N. Russell
G3-2	Projected Test Year - Cost of Capital	M. Cassel / N. Russell / P. Moul
G4	Projected Test Year - Attrition Calculation of The Revenue Expansion Factor	M. Napier / M. Cassel
G5	Projected Test Year - Attrition Calculation of Revenue Deficiency	M. Napier / M. Cassel
G6	Projected Test Year - Attrition Calculation of Major Assumptions	M. Napier / M. Cassel

SCHEDULE	TITLE	Witness
	EXECUTIVE SUMMARY	
A-1	Magnitude of Change-Present vs Prior Rate Case	M. Cassel
A-2	Analysis of Permanent Rate Increase Requested	M. Cassel
A-3	Analysis of Jurisdictional Rate Base	M. Cassel
A-4	Analysis of Jurisdictional N.O.I.	M. Cassel
A-5	Overall Rate of Return Comparison	M. Cassel / P. Moul
A-6	Financial Indicators	M. Galtman
	RATE BASE	
B-1	Balance Sheet	M. Galtman / M. Napier
B-1	Balance Sheet - Florida Common	M. Galtman / M. Napier
B-2	Adjusted Rate Base	M. Napier
B-3	Rate Base Adjustments	M. Napier
B-4	Monthly Utility Plant Balances	M. Galtman
B-5	Common Plant Allocated	M. Galtman / M. Napier
B-6	Acquisition Adjustments	M. Napier
B-7	Property Held For Future Use	M. Galtman
B-8	Construction Work In Progress	M. Galtman
B-8	Construction Work In Progress Florida Common	M. Galtman / M. Napier
B-9	Accumulated Depreciation - Monthly Balances	M. Galtman
B-10	Accumulated Amortization - Monthly Balances	M. Galtman
B-11	Allocation of Depreciation/Amortization Reserve - Common Plant	M. Galtman / M. Napier
B-12	Customer Advances For Construction	M. Galtman
B-13	Working Capital Allowance	M. Galtman / M. Napier
B-13	Working Capital Allowance - Florida Common	M. Galtman / M. Napier
B-14	Miscellaneous Deferred Debits	M. Galtman
B-15	Miscellaneous Deferred Credits	M. Galtman
B-16	Additional Rate Base Components	M. Galtman
B-17	Investment Tax Credits	M. Galtman
B-18	Accumulated Deferred Income Tax	M. Galtman
	NET OPERATING INCOME	
C-1	Adjusted Net Operating Income	M. Galtman
C-2	Adjustments to Net Operating Income	M. Napier / M. Galtman
C-3	Operating Revenues By Month	M. Galtman
C-4	Unbilled Revenues	M. Galtman
C-5	O & M Expenses By Month	M. Galtman
C-6	Allocation of Expenses	M. Galtman
C-7	Conservation Revenues and Expenses	M. Galtman
C-8	Uncollectible Accounts	M. Galtman
C-9	Advertising Expenses	M. Galtman
C-10	Civic and Charitable Contributions	M. Galtman
C-11	Industry Association Dues	M. Cassel
C-12	Lobbying and Political Expenses	M. Cassel
C-13	Rate Case Expenses	M. Cassel
C-14	Miscellaneous General Expenses	M. Galtman
C-15	Out of Period Adjustments	M. Napier
C-16	Gain/Loss On Disposition of Property	M. Galtman
C-17	Depreciation Expense	M. Galtman
C-18	Amortization/Recovery Schedule	M. Napier
C-19	Allocation of Depr./Amort. Expense - Common Plant	M. Napier / M. Cassel
C-20	Reconciliation of Total Income Tax Provision	M. Galtman
C-21	State and Federal Income Tax - Current	M. Galtman
C-22	Interest Expense - Income Tax	M. Galtman
C-23	Book /Tax Differences - Permanent	M. Galtman
C-24	Deferred Income Tax Expense	M. Galtman
C-25	Deferred Income Tax Adjustment	M. Galtman
C-26	Parent Debt Information	M. Galtman

SCHEDULE	TITLE	Witness
C-27	Income Tax Returns	M. Galtman
C-28	Miscellaneous Tax Information	M. Galtman
C-29	Consolidated Return	M. Galtman
C-30	Other Taxes - Detail	M. Galtman
C-31	Outside Professional Services	M. Galtman
C-32	Affiliated Company Transactions	M. Galtman
C-33	Wage & Salary Increases Compared to C.P.I.	M. Napier
C-34	O & M Benchmark Comparisons	M. Napier
C-35	O & M Benchmark By Function	M. Cassel
C-36	Base Year Recoverable O & M Expenses By Function	M. Cassel
C-37	O & M Compound Multiplier	M. Napier
C-38	O & M Benchmark Variance By Function	M. Cassel
	RATE OF RETURN	
D-1	Cost of Capital - 13 Month Average	M. Napier / N. Russell
D-2	Long Term Debt	N. Russell
D-3	Short Term Debt	N. Russell
D-4	Preferred Stock	N. Russell
D-5	Common Stock Issues	N. Russell
D-6	Customer Deposits	M. Galtman
D-7	Sources and Uses of Funds	M. Galtman
D-8	Issuance of Securities	N. Russell
D-9	Subsidiary Investments	N. Russell
D-10	Reconciliation of Average Capital Structure to Average Jurisdictional Rate Base	M. Napier
D-11	Financial Indicators	M. Napier
D-12	Applicant's Market Data	M. Napier
	COST OF SERVICE	
E-1	Therm Sales and Revenues By Rate Class	J. Taylor
E-2	Therm Sales and Revenues Comparisons	J. Taylor
E-3	Connections and Reconnections	M.Everngam
E-3	Disconnection and Reconnections	M.Everngam
E-3	Collection in Lieu of Disconnection	M.Everngam
E-3	Administrative Costs For Name and/or Billing Address Changes	M.Everngam
E-4	System Peak Month Sales By Rate Class	J. Taylor
E-5	Bill Comparisons Present vs. Proposed	J. Taylor
E-6	Derivation of Rate Base	M. Napier
E-6	Derivation of Operating and Maintenance Expenses	M. Napier
E-7	Average Cost of Meter Set and Service By Rate Class	J. Taylor
E-8	Derivation of Facilities	J. Taylor
E-9	Tariff Sheets	J. Taylor
	INTERIM RATE RELIEF	
F-1	Average Rate Base and Rate of Return	M. Everngam
F-2	Working Capital	M. Everngam
F-3	Adjustments to Plant in Service	M. Everngam
F-3	Adjustments to Working Capital	M. Everngam
F-4	Net Operating Income	M. Everngam
F-5	Adjustments to Net Operating Income	M. Everngam
F-6	Revenue Expansion Factor	M. Everngam
F-7	Revenue Deficiency	M. Everngam
F-8	Average Cost of Capital	M. Everngam
F-9	Reconciliation of Rate Base to Capital Structure	M. Everngam
F-10	Allocation of Interim Rate Relief	M. Everngam
	PROJECTED TEST YEAR	

SCHEDULE	TITLE	Witness
G1-1	Projected Test Year Rate Base	M. Napier
G1-2	Projected Test Year Working Capital - Assets	M. Napier
G1-3	Projected Test Year Working Capital - Liabilities	M. Napier
G1-4	Rate Base Adjustments	M. Napier
G1-5	Historic Base Year + 1 Balance Sheet - Assets	M. Napier / J. Bennett
G1-6	Historic Base Year + 1 Balance Sheet - Liab. & Capitalization	M. Napier
G1-7	Projected Test Year Balance Sheet - Assets	M. Napier
G1-8	Projected Test Year Balance Sheet - Liab. & Capitalization	M. Napier
G1-9	Historic Base Year + 1 - 13-Month Average Utility Plant	J. Bennett
G1-10	Projected Test Year - 13-Month Average Utility Plant	J. Bennett
G1-11	Historic Base Year + 1 - Depreciation Reserve Balances	M. Napier
G1-12	Projected Test Year - Depreciation Reserve Balances	M. Napier
G1-13	Historic Base Year + 1 - Amortization Reserve Balances	M. Napier
G1-14	Projected Test Year - Amortization Reserve Balances	M. Napier
G1-15	Historic Base Year + 1 - Allocation Of Common Plant	M. Napier / M. Galtman
G1-16	Historic Base Year + 1 - Allocation Of Common Plant - Detail	M. Napier
G1-17	Historic Base Year + 1 - Allocation Of Common Plant - Detail (Cont.)	
G1-18	Projected Test Year - Allocation Of Common Plant	M. Napier / M. Galtman
G1-19	Projected Test Year - Allocation Of Common Plant - Detail	M. Napier
G1-20	Projected Test Year - Allocation Of Common Plant - Detail (Cont.)	M. Napier
G1-21	Historic Base Year + 1 - Alloc. Of Deprec./Amort. Reserve - Common Plant	M. Napier
G1-22	Projected Test Year - Alloc. of Deprec./Amort. - Common Plant	M. Napier / M. Galtman
G1-23	Historic Base Year + 1 - Construction Budget	M. Napier
G1-24	Historic Base Year + 1 - Monthly Plant Additions	J. Bennett
G1-25	Historic Base Year + 1 - Monthly Plant Retirements	J. Bennett
G1-26	Projected Test Year - Construction Budget	J. Bennett
G1-27	Projected Test Year - Monthly Plant Additions	J. Bennett
G1-28	Projected Test Year - Monthly Plant Retirements	J. Bennett
G2-1	Projected Test Year Net Operating Income - Summary	M. Napier / M. Galtman
G2-2	Adjustments to Net Operating Income	M. Napier / M. Cassel
G2-3	Adjustments to Net Operating Income (Cont.)	M. Napier / M. Cassel
G2-4	Historic Base Year + 1 - Income Statement	M. Napier / M. Galtman
G2-5	Projected Test Year - Income Statement	M. Napier / M. Galtman
G2-6	Historic Base Year + 1 - Revenues and Cost of Gas	M. Everngam / J. Taylor
G2-7	Historic Base Year + 1 - Revenues and Cost of Gas (Cont.)	M. Everngam / J. Taylor
G2-8	Projected Test Year - Revenues and Cost of Gas	M. Everngam / J. Taylor
G2-9	Projected Test Year - Revenues and Cost of Gas (Cont.)	M. Everngam / J. Taylor
G2-10	Projected Test Year - Revenues and Cost of Gas (Cont.)	M. Everngam / J. Taylor
G2-11	Projected Test Year - Calculation of Distribution Expenses	M. Everngam / J. Taylor
G2-12	Projected Test Year - Calculation of Distribution Expenses (Cont.)	M. Napier / M. Galtman
G2-13	Projected Test Year - Calculation of Maintenance Expenses	M. Napier / M. Galtman
G2-14	Projected Test Year - Calculation of Maintenance Expenses (Cont.)	M. Napier / M. Galtman
G2-15	Projected Test Year - Calculation of Customer Account Expenses	M. Napier / M. Galtman
G2-16	Projected Test Year - Calculation of Customer Service Expenses	M. Napier / M. Galtman
G2-17	Projected Test Year - Calculation of Selling Expenses	M. Napier / M. Galtman
G2-18	Projected Test Year - Calculation of Admin. and General Expenses	M. Napier / M. Galtman
G2-19	Projected Test Year - Calculation of Admin. and General Expenses (Cont.)	M. Napier / M. Galtman
G2-19 a to d	Projected Test Year - Calculation of Operation and Main Expense Supplement	M. Cassel, J. Bennett, M. Galtman, V. Gadgil, M. Napier, K. Parmer, N. Russell, K. Lake, D. Rudloff, B. Hancock
G2-19e	Projection Basis Factor	M. Napier / M. Galtman
G2-19f	Over and Under Adjustments	M. Cassel, J. Bennett, M. Galtman, V. Gadgil, M. Napier, K. Parmer, N. Russell, K. Lake, D. Rudloff, B. Hancock
G2-20	Historic Base Year + 1 - Depreciation / Amortization Expense	M. Napier

SCHEDULE	TITLE	Witness
G2-21	Historic Base Year + 1 - Amortization Expense Detail	M. Napier
G2-22	Historic Base Year + 1 - Allocation Of Deprec. / Amort. Expense	M. Napier / M. Cassel
G2-23	Projected Test Year - Depreciation / Amortization Expense	M. Napier
G2-24	Projected Test Year - Amortization Expense Detail	M. Napier
G2-25	Projected Test Year - Allocation Of Deprec. / Amort. Expense	M. Napier / M. Cassel
G2-26	Historic Base Year + 1 - Reconciliation of Total Income Tax Provision	M. Galtman
G2-27	Historic Base Year + 1 - State and Federal Income Tax - Current	M. Galtman
G2-28	Historic Base Year + 1 - Deferred Income Tax Expense	M. Galtman
G2-29	Projected Test Year - Reconciliation of Total Income Tax Provision	M. Galtman
G2-30	Projected Test Year - State and Federal Income Tax - Current	M. Galtman
G2-31	Projected Test Year - Deferred Income Tax Expense	M. Galtman
G3-1	Historic Base Year + 1 - Cost of Capital	M. Cassel / N. Russell
G3-2	Projected Test Year - Cost of Capital	M. Cassel / N. Russell / P. Moul
G3-3	Projected Test Year - Long-Term Debt Outstanding	N. Russell
G3-4	Projected Tesr Year - Short-Term Debt Outstanding	N. Russell
G3-5	Projected Test Year - Preferred Stock	N. Russell
G3-6	Porjected Test Year - Common Stock Issues	N. Russell
G3-7	Customer Deposits	M. Galtman
G3-8	Financing Plans - Stock and Bond Issues	N. Russell
G3-9	Projected Test Year - Financial Indicators	M. Napier
G3-10	Projected Test Year - Financial Indicators (Cont.)	M. Napier
G3-11	Projected Test Year - Financial Indicators (Cont.)	M. Napier
G4	Projected Test Year - Attrition Calculation of The Revenue Expansion Factor	M. Napier / M. Cassel
G5	Projected Test Year - Attrition Calculation of Revenue Deficiency	M. Napier / M. Cassel
G6	Projected Test Year - Attrition Calculation of Major Assumptions	M. Napier / M. Cassel
G7	Other Taxes	M. Napier

COST OF SERVICE PROGRAM

H1-1	Fully Allocated Embedded Cost of Service - Proposed Rates	J. Taylor
H1-2	Fully Allocated Embedded Cost of Service - Proposed Rate Design	J. Taylor
H1-3	Fully Allocated Embedded Cost of Service - Rate Of Return By Class	J. Taylor
H1-4	Fully Allocated Embedded Cost of Service - Rate Of Return By Class (Cont.)	J. Taylor
H1-5	Fully Allocated Embedded Cost of Service - Revenue Deficiency	J. Taylor
H1-6	Fully Allocated Embedded Cost of Service - Summary	J. Taylor
H2-1	Fully Allocated Embedded Cost of Service - Summary - (Cont.)	J. Taylor
H2-2	Allocation of Cost of Service to Customer Class	J. Taylor
H2-3	Allocation of Cost of Service to Customer Class (Cont.)	J. Taylor
H2-4	Allocation Of Rate Base To Customer Class	J. Taylor
H2-5	Development of Allocation Factors	J. Taylor
H2-6	Fully Allocated Embedded Cost of Service - Summary	J. Taylor
H3-1	Fully Allocated Embedded Cost of Service - Summary	J. Taylor
H3-2	Classification of Expenses and Derivation of Cost of Service By Cost	J. Taylor
H3-3	Classification of Expenses and Derivation of Cost of Service By Cost (Cont.)	J. Taylor
H3-4	Classification of Rate Base - Accumulated Depreciation	J. Taylor
H3-5	Classification of Rate Base - Plant	J. Taylor

ENGINEERING

I-1	Interruption of Gas Service	J. Bennett
I-2	Notification of Rule Violations	J. Bennett
I-3	Periodic Test of Customer Meters:	J. Bennett
I-4	Vehicle Allocation	M. Napier / J. Bennett

RUTH ASSOCIATES, INC.

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May 20, 2022

Ms. Michelle D. Napier
Director, Regulatory Affairs Distribution
Florida Public Utilities Company

RE: Remedial Cost Projections for Florida Public Utilities

Dear Ms. Napier:

This document has been prepared on behalf of Florida Public Utilities (FPU) to outline the remedial activities being conducted at various sites owned by FPU. These sites are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require FPU to remove or remediate impacts on the environment from the disposal or release of specified substances at current and former operating sites.

FPU is participating in active remediation at three former manufactured gas plants (MGPs) in Florida. Those sites are in West Palm Beach, Winter Haven and Key West.

West Palm Beach, Florida

FPU has is conducting remedial activities to respond to environmental impacts to soil and groundwater at, and in the immediate vicinity of three parcels of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. FPU has been operating a bio-sparging / soil-vapor extraction (BS/SVE) system since the it was installed in January 2013, after demolition of the Quonset hut was completed. On the West Parcel, additional demolition activities of aboveground structures such as the former office building, a garage, propane storage cylinders were completed in 2019, and in 2020, the subsurface remnants of the historical MGP plant foundations and piping were excavated and disposed off-site, along with tar-impacted soils and clinker.

The next phase of remedial work on the West Parcel will entail the delineation of floating product or light non-aqueous phase liquid (LNAPL) and of significant pockets of coal tar present as dense non-aqueous phase liquid (DNAPL). The delineation phase is expected to be completed in 2022. In 2023, it is anticipated that an LNAPL recovery system will be installed and begin operation and that an excavation / isolation program will be implemented to address the coal tar.

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Once most of the recoverable LNAPL is removed from the subsurface, a BS/SVE system like the one operating on the East Parcel, will be constructed on the West Parcel. It is anticipated that design, installation and start-up of the West Parcel BS/SVE system will be completed by 2025.

Groundwater-monitoring activities will be on-going through implementation of all remedial activities and will likely be continued as part of a natural attenuation monitoring program after active remedial activities are completed and the systems are decommissioned.

The total cost through installation and start-up of the West Parcel BS/SVE system, including completion of the LNAPL recovery program and on-going groundwater monitoring activities and reporting is estimated at $3,044,000, on an undiscounted basis. Annual operating costs thereafter are estimated at $200,000, until shutdown of the BS/SVE system is approved, which is projected to be 5 to 15 years after start-up. Costs for system decommissioning and site re-development are projected at $900,000.

Total remedial costs through site re-development are estimated to range from $4,944,000 to $6,944,000, on an undiscounted basis. Annual long-term monitoring costs following site re-development are estimated at $27,000. A table outlining the details of our cost estimate is attached.

Not included in these costs is the remediation of the adjacent Government Services Administration property to the south. FPU’s responsibility for this remediation has not been determined. The projected potential costs range from $560,000 to $1,060,000.

Key West, Florida

FPU formerly owned and operated a MGP in Key West, Florida. The property is currently owned and operated by Suburban Propane. In October 2012, Florida Department of Environmental Protection (FDEP) issued a Remedial Action Plan (RAP) approval order, which specified that a limited semi-annual monitoring program be conducted. Semi-annual groundwater monitoring has been conducted ever since.

Although the Natural Attenuation Default Criteria (NADC) have generally been met at all locations sampled, FDEP issued a letter dated February 27, 2020 requiring that elevated levels of naphthalene and 1-methylnaphthalene be addressed. As a result, a work plan was submitted to FDEP on January 18, 2021 to inject Petro-Fix, a mixture of micron-scale activated carbon and inorganic electron receptors in the vicinity of the one location where residual impacts persist. Three injection wells were installed to facilitate this in-situ treatment, and a round of injections was conducted March 30 through April 1 of 2021.

Although the duration of the FDEP-required limited natural attenuation monitoring (NAM) cannot be determined with certainty, we anticipate that total costs to complete the remedial action will not exceed $50,000. The annual cost to conduct the limited NAM program is not expected to exceed $8,000.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with FDEP, FPU is obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. On September 12, 2014, FDEP issued a letter approving shutdown of the sparging operations on the northern portion of the site, contingent upon continued semi-annual monitoring. On December 9, 2021, FDEP issued another letter approving suspension of all sparging operations, including at the southern portion of the site, with continued semi-annual monitoring and reporting.

It is uncertain how long continued groundwater and surface-water monitoring will be required, although it is likely to be at least five additional years. It is also possible that some additional remedial action could be required if concentrations of MGP-related constituents rebound in groundwater after extended suspension of sparging operations. Annual costs to implement the groundwater and surface-water monitoring program is less than $20,000.

Please note that our cost projections do not include any internal costs the company may incur related to relocation of facilities for remediation of any of the sites.

If you have any questions or require additional information, please don’t hesitate to ask us.

Thanks,

RUTH ASSOCIATES, INC.

Michele C. Ruth

Michele C. Ruth, PE
President
Chemical Engineer

attachment

Estimate of Anticipated Costs and Schedule of Expenditures
Former West Palm Beach Manufactured Gas Plant

Tasks Anticipated to Close Out Site	Annual Ball-Park Costs								
	2022	2023	2024	2025	2026	Obligation Not Yet Determined	Annually After 2022, Until Criteria are Met (5 - 15 yrs)	After Criteria are Met (One Time Cost)	After Criteria Are Met (Annual Cost)
WEST PARCEL									
NAPL Evaluation									
Work plan	$15,000								
Drilling program to determine extent of NAPL & appropriate remediation technologies	$80,000								
Report of findings, FDEP Interaction	$15,000								
LNAPL Recovery (Pilot Testing through Completion)									
Concise design, FDEP interaction	$20,000								
Installation of recovery / SVE wells		$60,000							
Install recovery equipment (e.g., scavenger pumps, dual-phase pumping, vacuum pump)		$50,000							
Testing and operation of product recovery			$20,000	$15,000					
Data evaluation, reporting and FDEP interaction			$10,000	$5,000					
DNAPL Excavation/Isolation in Isolated Locations									
Concise design, FDEP Interaction		$12,000							
Evaluation and contracting of excavation/disposal firm		$7,000							
Excavation and disposal (costs could range from $500K to $1,500K)		$500,000							
Site restoration (fill placement and compaction costs could range from $20K to $200K)		$70,000							
Reporting and FDEP interaction		$15,000	$5,000						
Air Sparging and Soil Vapor Extraction									
Concise Design and FDEP Interaction		$50,000	$10,000						
Evaluation and contracting of drilling and AS/SVE installation firms			$10,000						
Installation of bio-sparging wells (SVE wells installed for LNAPL recovery)			$80,000						
Blower and Ancillary Equipment			$125,000						
Compressor and Ancillary Equipment			$190,000						
Distribution Piping (assumed trenches backfilled with excavated soils)			$175,000						
Start-Up, Operation and Monitoring				$60,000	$30,000		$30,000		
Electric				$20,000	$20,000		$20,000		
Data Evaluation, Reporting and FDEP interaction				$40,000	$30,000		$30,000		
Enviromental Actions Related to Site Re-Development (ONE-TIME COST)									
West Parcel - e.g., surface soil excavation, asphalt cap, demobilization of remedial systems,								$500,000	
H&S measures during site redevelopment									
Costs could range from $100,000 to $2,000,000 total									
EAST PARCEL									
Air Sparging and Soil-Vapor Extraction									
Electric	$15,000	$15,000	$15,000	$15,000	$15,000				
Operation, monitoring and report (includes lawn maintenance)	$20,000	$20,000	$20,000	$20,000	$20,000				
Enviromental Actions Related to Site Re-Development									
East Parcel e.g., surface-soil excavation, asphalt cap, demobilization of remedial systems								$150,000	
H&S Measures during site Redevelopment									
Costs could range from $100,000 to 300,000 total									
GSA PARCEL									
Air Sparging and Soil Vapor Extraction									
Concise Design and FDEP Interaction						$30,000			
Installation of Extraction Wells						$40,000			
Installation of Air-Sparging Wells						$80,000			
Blower and Ancillary Equipment						$50,000			
Compressor and Ancillary Equipment						$70,000			
Distribution Piping (assuemd trenches backfilled with excavated soils)						$95,000			
Start-Up, Operation and Monitoring						$50,000	$25,000		
Electric						$10,000	$10,000		
Data Evaluation and Reporting						$35,000	$20,000		
Enviromental Actions Related to Site Re-Development (ONE-TIME COST)									
GSA Parcel - e.g., surface soil excavation, asphalt cap, demobilization of remedial systems,								$250,000	
H&S Measures during site Redevelopment									
Costs could range from $100,000 to $600,000 total									
Remaining Issues Related to the Feasibility Study									
Investigate Marsh Area on the GSA Parcel						$35,000			
Offsite Soil Sampling for Arsenic						$10,000			
Groundwater Monitoring / Monitored Natural Attenuation									
Groundwater Monitoring									
1 Annual event (50 wells) + 1 semiannual event (35 wells) + 2 quarterly events (22 wells)	$50,000	$50,000	$50,000	$50,000					
1 Annual event (35 wells) + 1 semiannual event (20 wells) + 2 quarterly events (10 wells)									
1 Annual event (20 wells) + 3 quarterly events (10 wells)					$40,000				
1 Annual Event (15 wells)							$30,000		$13,000
Data Evaluation and Reporting	$20,000	$20,000	$20,000	$15,000	$10,000		$10,000		$5,000
FDEP Interaction		$5,000	$5,000	$5,000	$5,000		$2,000		$2,000
Legal / Manangement / Community Relations / Administrative Costs	$50,000	$50,000	$50,000	$50,000	$50,000		$20,000		$5,000
Institiutional Controls / Deed Restrictions					$30,000		$2,000		$2,000
Total Ball-Park Annual Costs	**$285,000**	**$924,000**	**$785,000**	**$295,000**	**$250,000**	**$505,000**	**$199,000**	**$900,000**	**$27,000**


YOUR CHOICE. OUR COMMITMENT.
Natural gas is the right choice for affordable energy that contributes to a sustainable future, something Chesapeake Utilities has been committed to delivering for more than 160 years.
CHESAPEAKE UTILITIES CORPORATION

Pickering Audubon Trail

The natural gas story is an American story. It started with the first gas streetlights in 1817.

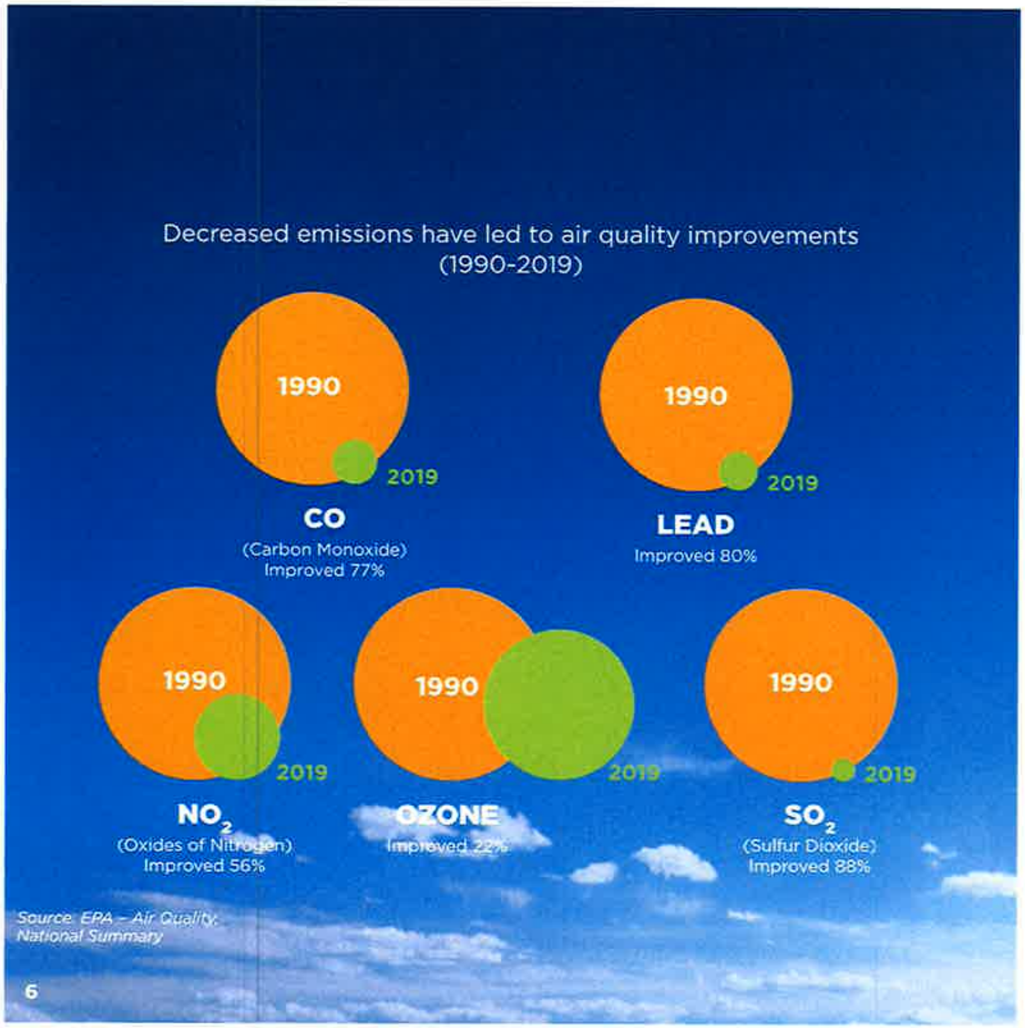
Today, through the direct delivery of natural gas, nearly 180 million American homes enjoy this resilient and reliable energy source for affordable and cleaner heating, high-efficiency appliances and a ready flame for cooking. Natural gas has transformed how we live and has moved our country toward energy independence.

When it comes to the environment, natural gas plays a critical role in enabling a sustainable future and the reduction of greenhouse gas emissions. Chesapeake Utilities Corporation is committed to finding innovative and increasingly sustainable energy solutions for our customers and the communities we serve.

Marshes near Amelia Island, Florida

NATURAL GAS IS CLEANER

Natural gas has contributed significantly to reducing carbon and lowering emissions by offsetting carbon-intense fuels. As delivery technologies improve, natural gas continues to provide environmentally sound solutions that address climate change.



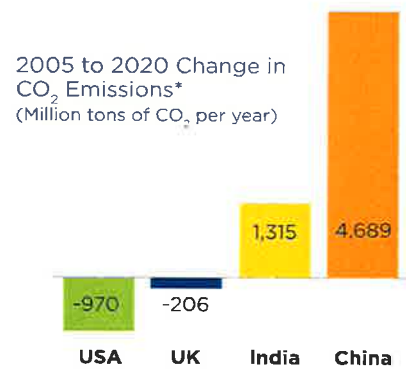
Over the past 30 years, a significant shift to natural gas-fueled power generation has improved air quality.

Natural gas is more abundant and more affordable, providing both an economic and environmental incentive to shift to natural gas.

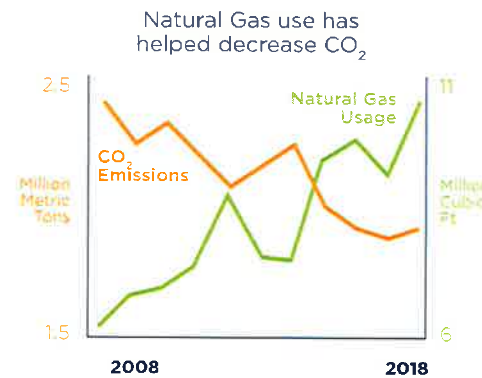
Natural gas produces 38 percent of U.S. electricity, overtaking coal.

Yet, as U.S. natural gas use increases, we've experienced **the largest CO_2 reduction of any industrialized country**.

Greenhouse gases are not the only emissions reduced. The expanded use of natural gas has reduced lead levels and emissions that contribute to ozone depletion and acid rain. **Natural gas will continue to improve the quality of the air we breathe and the water we drink.**



*CO_2 reduction in energy production



Source: US Energy Information Administration

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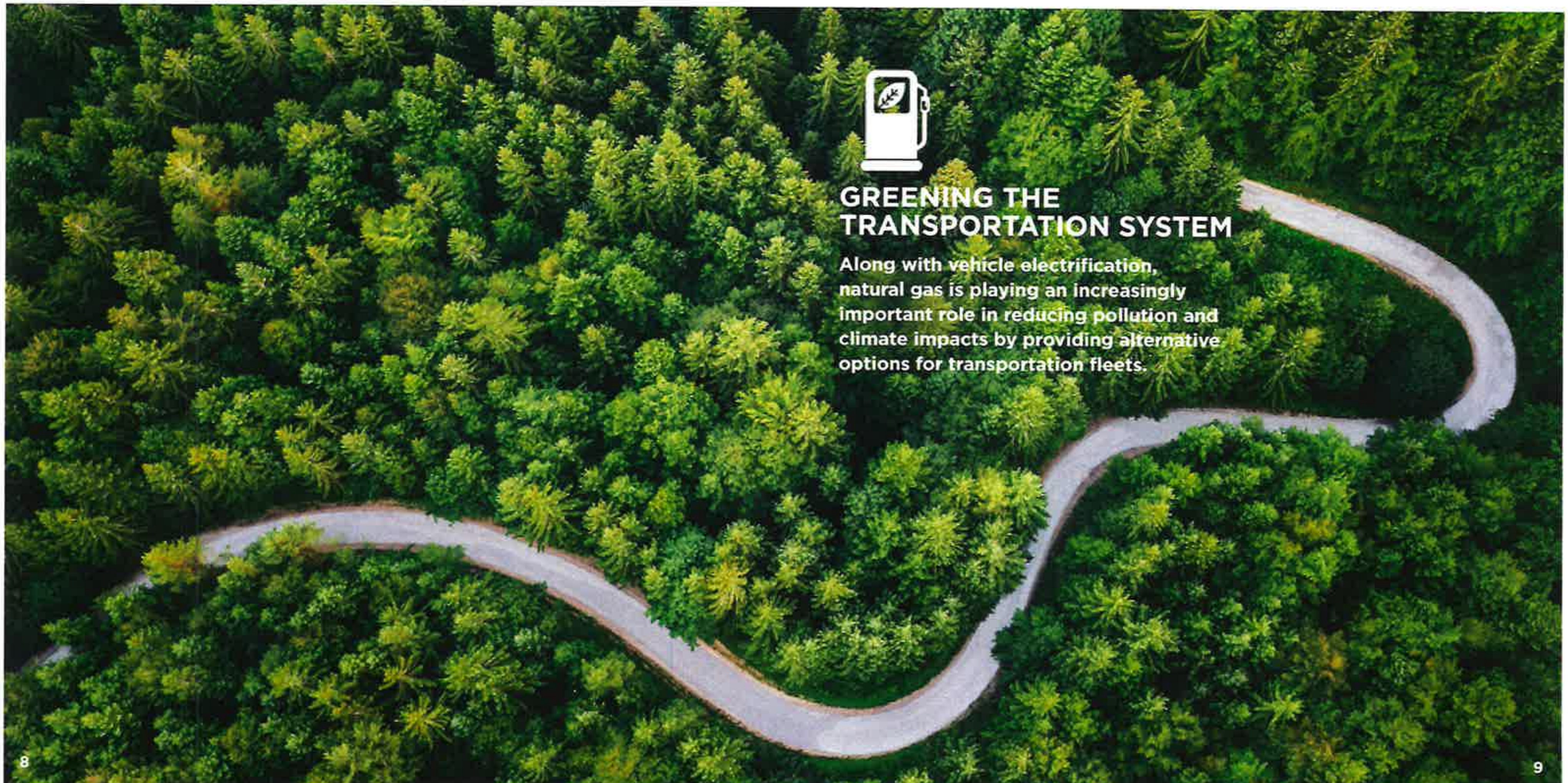


GREENING THE TRANSPORTATION SYSTEM

Along with vehicle electrification, natural gas is playing an increasingly important role in reducing pollution and climate impacts by providing alternative options for transportation fleets.

Chesapeake Utilities Corporation is a leader in providing sustainable energy solutions for alternative fuel vehicle fleets.

NATURAL GAS VEHICLES WILL REDUCE EMISSIONS
(Compared to diesel fuel use)

30% CO_2

85% CO

99% Carcinogenic Particulates

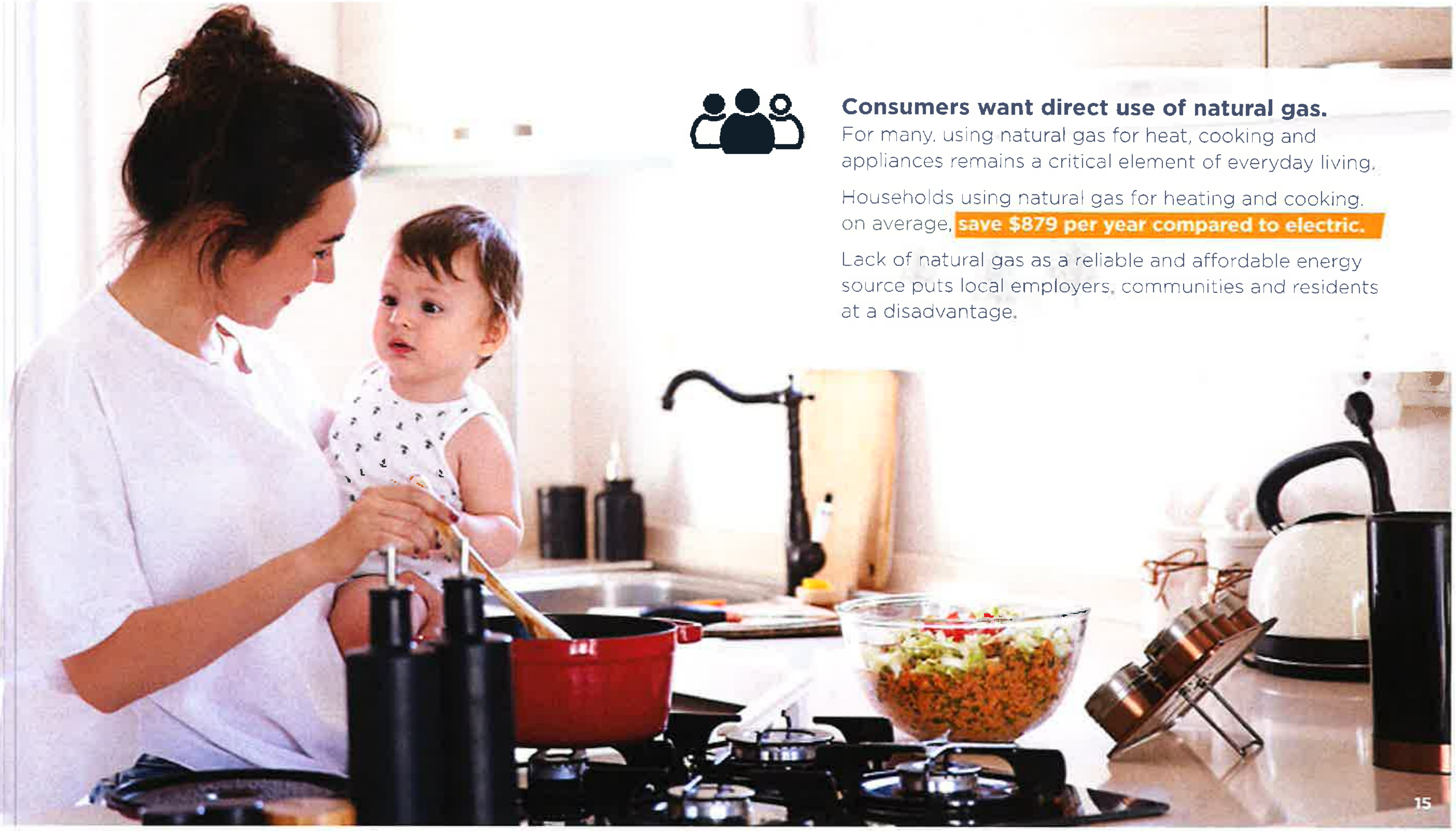
Argonne's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model

On-road vehicles create one-third of smog-producing air pollutants in the U.S. **Transportation overall causes 27 percent of greenhouse gas (GHG) emissions.**

Natural gas fuels including liquefied natural gas (LNG) and compressed natural gas (CNG) are **the most effective and affordable means to continue these emissions reductions in large transportation** fleets such as delivery trucks, buses and waste hauling vehicles.

DELIVERING ENERGY THAT MAKES LIFE BETTER FOR THE COMMUNITIES WE SERVE

Access to affordable energy helps families lower their energy costs and supports significant economic development for their communities.



Consumers want direct use of natural gas.

For many, using natural gas for heat, cooking and appliances remains a critical element of everyday living.

Households using natural gas for heating and cooking, on average, **save $879 per year compared to electric.**

Lack of natural gas as a reliable and affordable energy source puts local employers, communities and residents at a disadvantage.

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Natural gas helps address inequities by ensuring energy security and access to cleaner fuels.

Communities of color and low income households are disproportionately impacted by energy poverty and the environmental impacts of polluting fuels such as coal and fuel oil.

We can help address inequities and social justice challenges by ensuring energy security and access to cleaner fuels.

A CASE STUDY: SOMERSET COUNTY

Located on Maryland's Eastern Shore, Somerset is the state's poorest county and has the third largest percentage of African American residents. Somerset was one of only three counties in Maryland without access to natural gas, resulting in high energy costs, little economic development and poor air quality.

Working hand-in-hand with the county and the University of Maryland Eastern Shore, Chesapeake Utilities led the effort to bring natural gas infrastructure to the county, allowing the college to replace polluting fuel oil and woodchips as energy sources. This means lower energy costs, significantly better local air quality and more economic development opportunity for the county.

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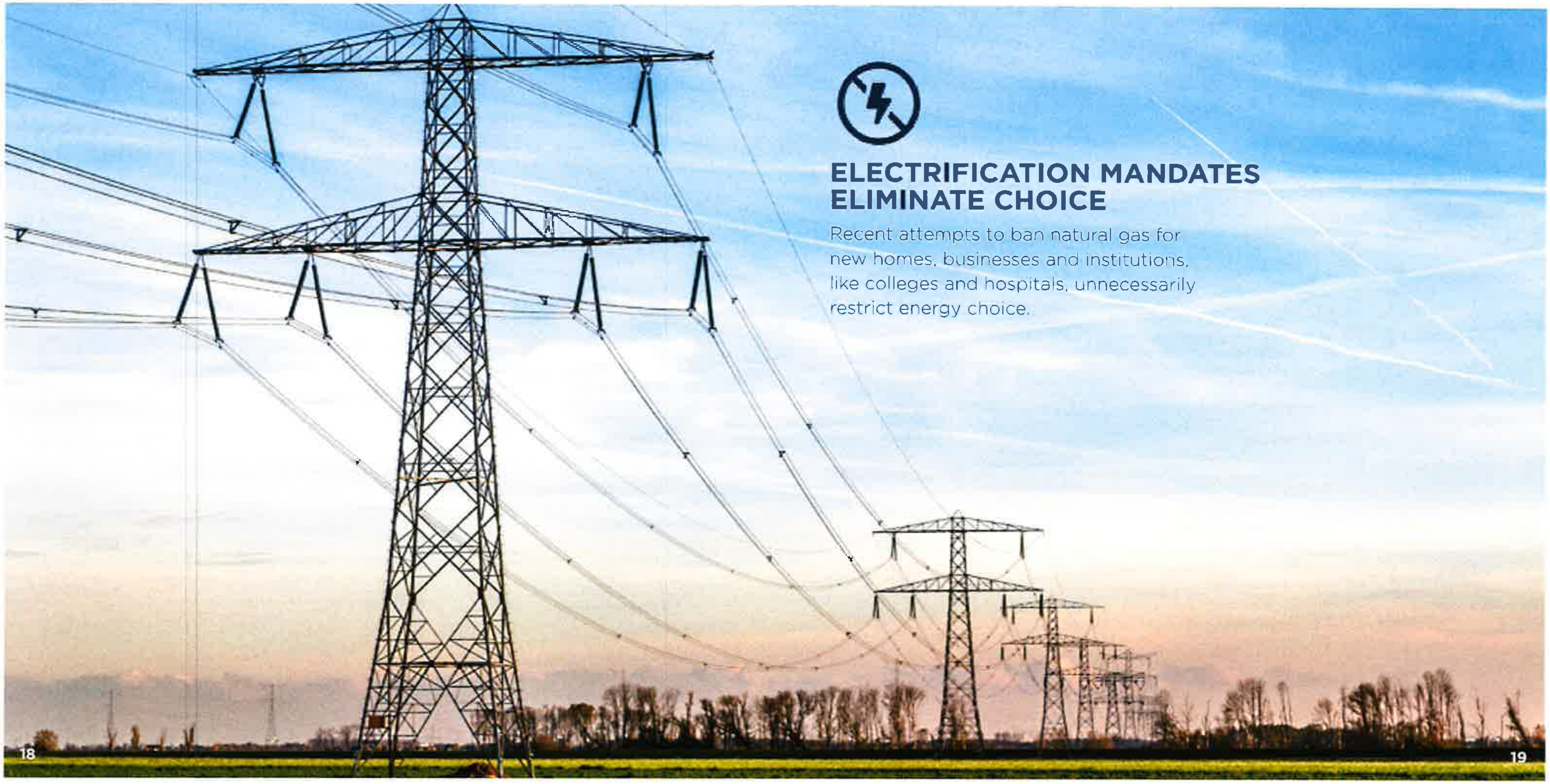

ELECTRIFICATION MANDATES ELIMINATE CHOICE

Recent attempts to ban natural gas for new homes, businesses and institutions, like colleges and hospitals, unnecessarily restrict energy choice.

High energy costs impact lower income families three times as much as higher income families.

In many areas, banning natural gas from new construction merely increases demand for electricity generation.

Electrification would also result in the need for hundreds of billions of dollars in new spending on the country's electric generation, transmission and distribution infrastructure – all costs that would transfer to consumers.

If 60 percent of households were converted from natural gas to electricity by 2035, the total economy-wide increase in energy-related costs would range from $590 billion to $1.2 trillion. Converting from natural gas to electricity would **add $1,060 to $1,420 per year in increased costs for each family.**

Studies show that higher energy costs take up a disproportionate percentage of low-income family budgets.

Electrification will have devastating financial impacts on those who can afford it the least and economically disadvantages communities and its citizens.

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Sunrise in Frederica, Delaware

A LEADER IN DELIVERING ENERGY THAT CONTRIBUTES TO A SUSTAINABLE FUTURE

Through responsible sourcing and exploring new technologies like renewable natural gas and renewable hydrogen, the natural gas delivery system is an essential tool in achieving a lower carbon footprint.

RENEWABLE NATURAL GAS (RNG)

RNG captures methane from existing food waste, animal manure, wastewater sludge and garbage, and redirects it away from the environment, repurposing the methane as an energy source.

Reducing methane is important as it is a potent greenhouse gas (GHG). By capturing more GHGs than it emits, RNG is carbon negative.

HYDROGEN

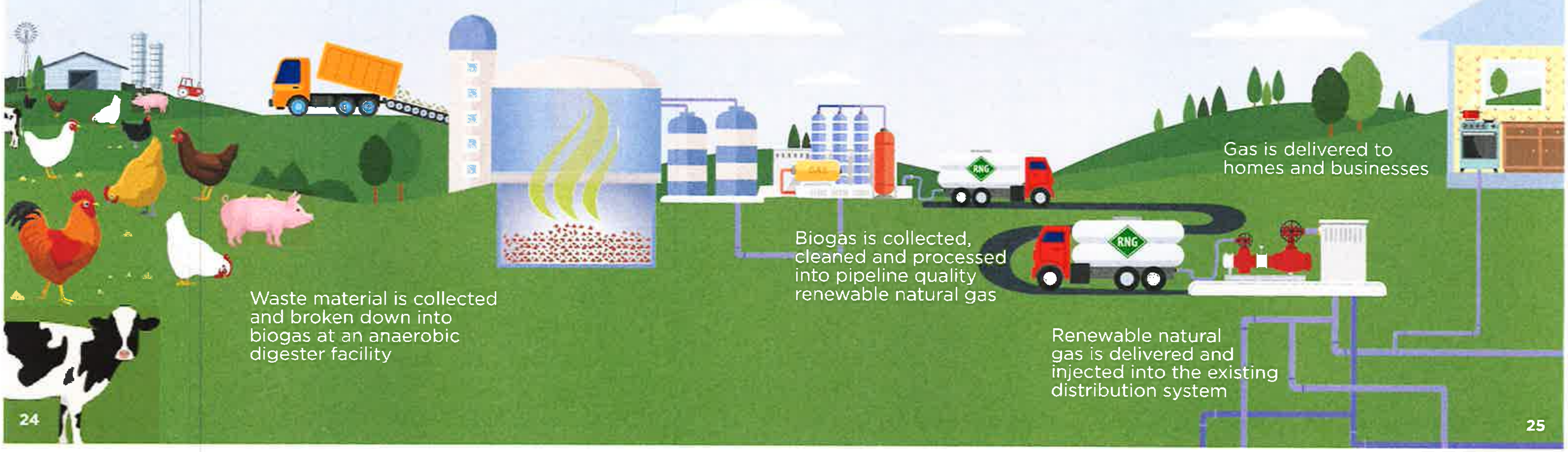
Hydrogen is the most abundant element on earth. Hydrogen combines with other elements to form numerous compounds such as water, methane and even table sugar.

Hydrogen can be used for energy. Today, we are exploring opportunities to use it even more. Most importantly, it's a zero emission energy source.

Hydrogen and RNG are compatible with existing natural gas infrastructure, appliances and power generation. As we blend these low and zero carbon sources into our existing natural gas system, we will be taking additional steps to becoming carbon neutral.

RECYCLING WASTE INTO USABLE FUEL CAN SUPPORT LOCAL AGRICULTURE

Using farm waste as fuel stock provides diversified farm income, creates new jobs, protects against runoff that can pollute local waterways and decarbonizes the agriculture industry.



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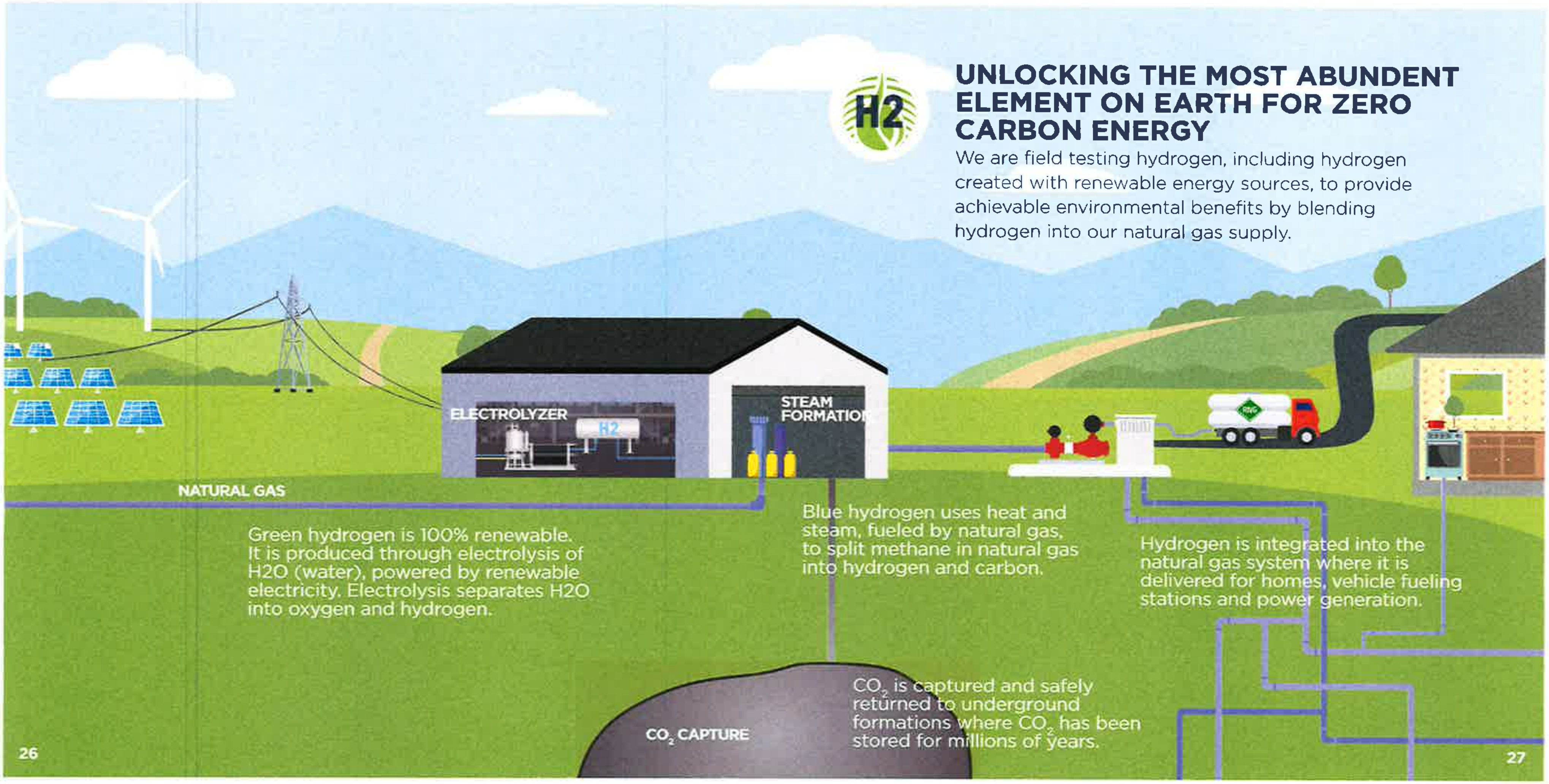

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Our energy delivery businesses have been part of the largest reduction in carbon emissions in U.S. history.

Chesapeake Utilities Corporation is committed to continuing our efforts to reduce emissions and develop lower-carbon sources of energy.

- JEFF HOUSEHOLDER
President & CEO

www.chpk.com