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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 JLB-1 through JLB-2 of Jason Bennett.

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

(Document 7 of 27)

Sincerely,

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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 Jason Bennett

Date of Filing: May 24, 2022

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

A. My name is Jason Bennett, and I'm the Assistant Vice President of Operation Services for Florida Public Utilities Company, (herein "FPUC"), FPUC-Indiantown Division, FPUC-Fort Meade, and Central Florida Gas ("CFG"), (also referred to herein jointly as "Companies"), as well as the parent corporation, Chesapeake Utilities Corporation ("Chesapeake" or "the Company"). My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

Q. Please describe your educational background and relevant professional experience.

A. I graduated from the University of South Florida in 2000 with a Bachelor of Science degree in Accounting and a minor in Management Information Systems.

Following brief stints as an office manager for a law firm and an accounting manager for an optical/vision care office, my career in the natural gas industry began in 2009 when I was employed by Black Hills Corporation. I worked in a number of accounting-related positions until I was promoted to Financial Manager for Nebraska. In 2018, I became the Manager of Regulatory and Finance and led a team responsible for the preparation and review of compliance filings, tariff updates and rate reviews as well as the budgeting, forecasting, and overall financial analysis for Black Hills Corporation's operations in Nebraska.

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

A. No, I have not.

Q. Have you previously filed testimony before any other regulatory bodies?

A. Yes. As Manager of Regulatory and Finance, I filed testimony in a number of proceedings before the Nebraska Public Service Commission, including Application No. NG-109 for a general rate increase in 2019. My testimony supported the Application in the following areas: Filing Requirements, Accounting Methods, Capital Infrastructure Projects, System Safety Infrastructure Mechanism Renewal, Data Infrastructure Integrity Program, and Acquisition and Consolidation Synergies.

Q. Please describe your current responsibilities.

A. As Assistant Vice President of Operations Services, I lead teams that focus on Construction Services, Business Transformation, and Continuous Improvement. The Construction Services team is responsible for all regulated construction throughout the Chesapeake footprint. The Business Transformation and Continuous Improvement teams provide oversight of key initiatives that ensure the enterprise meets strategic goals. They are also responsible for developing the competencies of continuous improvement and change management throughout Chesapeake, including implementation of corporate-wide improvement projects. By developing these competencies, opportunities for efficiency are properly vetted and prioritized, root cause issues are determined, and solutions are identified and implemented that are supported by leadership and the affected employees.

Q. What is the purpose of your testimony?

A. There are three primary purposes of my testimony. First, I will address the completion of the Company's Gas Reliability Infrastructure Program ("GRIP") and the potential need for a Phase 2, of GRIP. Second, I will provide support for certain safety and reliability projects being undertaken by the Company, including Safety Town. Third, I will provide support for certain Over-Under Items related to Operations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit(s):

Exhibit JLB-1, Dover Field Training Facility (Safety Town)

Q. Are you sponsoring any of the Company's Minimum Filing Requirement (MFR) schedules?

A. Yes. Attached as Exhibit JLB-2 is a list of MFRs that I am sponsoring.

<u>I. GRIP Completion</u>

Q. Please provide a brief background of the Company's GRIP?

A. On February 3, 2012, Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation filed a joint petition seeking approval of new programs for each Company that would enable each to recover costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services. All of the remaining replacement investment would occur between July 2012 and June 2022. While the respective CUC local distribution companies ("LDCS") submitted a joint petition for two separate GRIP programs, the structures of the proposed programs are identical, and built upon the steel tubing replacement program approved for FPUC in its 2008 rate case.

Q. Did the Commission approve the filing for GRIP?

A. Yes. Recognizing the national call to encourage safety-related upgrades to natural gas facilities, better assure customers of the safety of natural gas service, and proactively address these issues, the Commission approved the Companies' Gas Reliability Infrastructure Programs to facilitate replacement of suspect infrastructure by the Companies in an expeditious manner.[1]

At the time, the Commission specifically recognized the need for the Companies to replace higher risk facility segments on an expedited basis given heightened safety concerns following tragic events. There was also an acknowledged need to update infrastructure to remove facilities more susceptible to corrosion.[2]

Q. Are the Companies moving the revenue requirement associated with GRIP into rate base?

A. Yes, consistent with Commission Order No. PSC-2012-0490-FOF-GU, and as further described in the Direct Testimony of Company Witness Cassel, we are moving the GRIP investments into rate base, which will leave only the remaining true-up for the original GRIP program to be collected in the surcharge for 2023.

Q. Will the GRIP program itself terminate at the end of the 2022 calendar year?

A. Consistent with the original GRIP program and the Commission's approval of it, GRIP would be scheduled to terminate at the end of this year. However, as we progressed

[1] Order No. PSC-12-0490-TRF-GU, issued September 24, 2012, in Docket No. 120036-GU, at pgs. 11 and 19.
[2] Order No. PSC-12-0490-TRF-GU, issued September 24, 2012, in Docket No. 120036-GU, at p. 5.

on various GRIP projects, we have found that there are additional safety and access related activities that need to be addressed and could serve as the basis for an extended, or Phase 2, of the GRIP. The key issues we have identified are associated with additional problematic mains and services, as well as facilities located in rear lot easements.

Q. Are the new safety and access issues identified appropriate for a program like GRIP?

A. Absolutely. As such, the Companies anticipate requesting Commission approval, under a separate petition, for a Phase 2 of GRIP to extend the program to capture these additional safety and access-related issues on our systems. While the Company's systems are safe and adhere to industry standards, continuation of the anticipated new phase of this program will ensure that our facilities continue to meet ongoing federal initiatives and appropriately reduce any unnecessary risks to the public due to facilities that are aged or inaccessible.

Q. Is the Company seeking approval of this new Phase 2 for GRIP in the context of this rate case?

A. No. To be clear, the Company is not proposing Phase 2 for approval as part of this rate proceeding. The Company anticipates filing a separate petition to request Commission approval of Phase 2. However, given that this rate case does involve moving GRIP revenues into base and would otherwise preview the termination of the program at the end of this year, we felt it would be appropriate to advise the Commission in this context of our intent to pursue a new phase for GRIP.

II. Safety & Reliability Projects

A. Damage Prevention

Q. What does the Companies' Damage Prevention program address?

A. Across its platform, Chesapeake maintains damage prevention programs in all of its natural gas distribution areas, as reflected in its Operations and Maintenance ("O&M") Manuals. Among other damage prevention policies and best practices, the damage prevention programs in our O&M Manuals adhere to industry damage prevention standards and programs, including, federal Department of Transportation Rule 49 C.F.R. §192.614, and state programs, like Florida's Sunshine 811 "Call Before You Dig" program. While the requirements of these types of programs vary from state to state, they generally require a utility to mark the location of its facilities within a required timeframe following notification of projects involving excavation near utility facilities.

Q. Are these types of programs the only damage prevention mechanisms the Companies utilize?

A. No. These "Call Before You Dig" laws are important and create a framework for utilities to build a more comprehensive damage prevention program around, but generally speaking, these programs serve as the baseline for our damage prevention efforts. Because the specifics of the state programs vary from state to state, utilization of these programs as the only measure would result in inconsistent damage prevention standards among our various distribution areas. As such, reliance on the state programs alone would prevent us from appropriately leveraging our corporate resources and incorporating industry best practices.

Q. What more do Chesapeake and the Companies do to promote damage prevention?

A. Chesapeake has established a natural gas distribution-wide Damage Prevention Plan to drive consistency and optimize results in the area of third party damage prevention. The Damage Prevention Plan consists of collecting and analyzing data from across the Chesapeake Utilities operating units. This data is the foundation for establishing and measuring key performance indicators. This data-driven approach allows for structured problem solving, establishment of strategic priorities and efficient actions as it relates safety and performance around damage prevention. It is also the basis for post-incident reviews, public awareness, and outreach campaigns.

Q. What are the costs associated with this Damage Prevention Plan?

A. Chesapeake already has a corporate-wide Damage Prevention Manager, as well as a Damage Prevention Coordinator in Florida. We plan on hiring a second Damage Prevention Coordinator for Florida given the growth in the state and the expansion of our systems. Estimated costs for the personnel and publication costs are included in the revenue requirement.

Q. What are the responsibilities of the Damage Prevention Coordinators?

A. The Damage Prevention Coordinators' primary responsibilities would include: (1) Serving as the liaison between excavators, the affected public, emergency responders and Chesapeake's distribution companies; (2) Promoting damage prevention of company underground facilities from excavation activities through ongoing training and communication with 811 excavators, internal and externally contracted facility-locating technicians, and other team members; (3) Providing statewide team member training, guidance and support to ensure company-wide consistency of locate responses and 3rd party damage documentation, (4) Providing damage investigation assistance as needed.

Q. What are the customer benefits of this enhanced Damage Prevention Program?

A. Third-party damages are the top risk to our natural gas facilities, and a robust Damage Prevention Program is critical to protecting the integrity and reliability of our system and, most importantly, keeping our customers and employees safe.

B. Leak Detection

Q. Please describe current leak detection efforts.

A. Leak detection methods currently utilized across the Chesapeake platform meet all federal and state regulations and include, but are not limited to, ground-based leak surveys, public awareness, and system pressure monitoring. Ground-based leak detection typically involves a company employee or contractor walking the length of a pipeline while using handheld tools to detect the presence of methane. Ground-based leak surveys are completed at intervals consistent with the pertinent Company O&M Manual and Company procedures, but are typically 1 year, 3 year, or 5 year intervals for any given pipe based on pertinent risk factors. In recent years, Chesapeake has started moving its distribution companies towards a 3 year cycle for consistency, where applicable. Some parts of the system, such as business districts, are surveyed on an annual basis, consistent with the Pipeline and Hazardous Materials Administration's ("PHMSA") Rule 49 C.F.R. § 192.723(b)(1)("Leak Survey rule").

As a result of this schedule, the Companies will only conduct leak surveys on a portion of our pipeline system in any given year. During these surveys, leak detection equipment will inform the employee of the presence of a leak but does not quantify the leak in terms of flow rate or volume. As such, additional investigative work must be performed in order to determine the full extent of the leak, which is necessary to determine the appropriate next steps.

Q. What are the proposed enhancements to the Leak Detection Program?

A. The Companies plan to enhance our leak detection efforts through the use of satellite scans of the gas pipeline system. The Companies plan to accomplish this by receiving services from a third-party vendor that combines multispectral data from satellites and system data from the Companies.

Q. What are the advantages to this technique?

A. There are six distinct advantages to using this technique:

1) The Companies plan to scan the Companies' entire Florida system twice per year. This increases the amount of the system checked for leaks from < 50% to 200% per year.

2) This method enables leak detection without the need to put personnel and the public at potential risk.

3) The scans are completed with no environmental impact.

4) Leaks can be quantified in terms of volume and flow rate.

5) The satellite scans also enable the Companies to record additional measurements and system detail, including information on vegetation, erosions and land

movements, exposed pipe, land temperature, and change detections in the right-of-way.

6) Once the area is established and initial scans are completed, subsequent scans can be added on short notice. This can be critical in the cases of hurricanes and other natural disaster response since satellite scans can be performed quickly and over a wide area, even if an area is inaccessible by road.

Q. What are the costs associated with this program?

A. The first two years of the program are expected to have higher costs than subsequent years because of the time and external expertise needed to establish a data set for an area and to calibrate the algorithms. The current estimated costs for 2023 and 2024 are $1,458,491 and $1,393,042 respectively. Going forward beyond 2024, the annual estimated cost is $1,350,082.

Q. Is there potential to save costs from traditional leak surveys?

A. The potential for cost reductions in other activities may arise in the near future. The use of satellites is not yet accepted in lieu of the current practice of foot-based leak surveys by PHMSA; however, the Company is working with the satellite data vendor to gain acceptance. If accepted, the Company could potentially save on labor costs related to ground-based leak surveys.

C. Safety Town

Q. Has Chesapeake taken additional steps to enhance safety for its customers and employees?

A. Yes. In late 2020, the Company completed construction of a field training facility, commonly referred to as a "Safety Town", in Dover, Delaware. Illustrations are included in Exhibit JLB-1, Dover Field Training Facility (Safety Town).

Q. What motivated Chesapeake to construct such a facility?

A. There were numerous motivating safety factors to constructing the Delaware Safety Town. Chesapeake wanted to:

1) Accelerate the learning process while complimenting on-the-job field experience for safety and compliance activities;

2) Respond to employee feedback requesting hands-on training opportunities;

3) Increase the opportunity to train with first responders;

4) Reinforce its commitment to training, safety and compliance;

5) Allow proactive preparation related to safety and compliance procedures that may arise in response to the proposed PHMSA Notice of Proposed Rulemaking Operator Qualifications Mega Rule, which revises how the integrity of pipeline systems are tested and heavily emphasizes the requirement for validation of data and records.

Q. What are some specific training opportunities available at this Delaware Safety Town?

A. Some of the training opportunities available relate to:

1) Emergency Response and situational awareness with first responders

2) Line locating

3) Atmospheric corrosion

4) Blowing Gas simulation

5) Cathodic protection

6) Welder qualifications

7) Operator qualifications (including main installation, repair and maintenance)

8) Excavation safety training

9) Leak investigation and repair

10) Excess flow valves

11) Propane Tank training

12) Certified Employee Training Program for Propane

13) Appliance venting training

14) Confined space training

15) Metering & Regulation Station Installation and repair

Q. Does the Company plan to construct a similar Safety Town in Florida?

A. Yes. The Company plans to construct a similar training facility on our existing property in DeBary, Florida. Doing so would provide local and regional employees and safety responders the same benefits experienced in Delaware.

Q. What are some other benefits of a Safety Town?

A. The main benefit is that Safety Towns provide dedicated training facilities that provide opportunities for both classroom time and hands-on experience with situations that mirror real world and emergency scenarios – both of which are critical to the training process. These facilities also provide a location where our employees can be evaluated and obtain their Operator Qualifications in a controlled simulation environment, as provided in 49 C.F.R. §192.803. A Safety Town also provides the ability for training programs to evolve as necessary to keep pace with industry changes and best practices. For employees in Florida, a new Safety Town will provide an opportunity for increased speed to competency and enhanced abilities, which will result in a more effective and skilled workforce. Less experienced workers can gain effective knowledge more quickly and all workers will have the ability to be introduced to and trained on new technologies. Ultimately, installation of a new Safety Town will lead to a reduction in workplace errors, and therefore a reduction in the risks for injury to our employees, our customers, and safer, more reliable, distribution system.

Q. What is the estimated cost and completion date of the Florida Safety Town?

A. The Company has included estimates in this filing to have Safety Town completed in Spring 2023 at an estimated cost of $1.2 million.

III. Over-Under Items related to Operations

Q. Are there any over-under items related to Operations?

A. Yes. I support adjustments over the historical test year related to headcount additions, the Damage Prevention Program and enhanced leak detection. These are included in Schedule G2-19i.

Q. Please summarize the headcount additions.

A. The company proposes 15 headcount additions that are required to support the significant growth over the past decade and to keep pace with future system expansions and growth. To be clear, these are incremental positions and are not included in base rates.

1) 3 incremental positions for the Damage Prevention Plan that are critical to protecting the integrity and reliability of our system and, most importantly, keeping our customers and employees safe;

2) 2 incremental positions related to safety and compliance that are critical to deploying and maintaining safe practices that keep employees and customers safe;

4) 2 incremental positions related to Engineering and Compliance that are critical to supporting the design and compliance of expansion, integrity and reliability construction projects;

5) 8 incremental positions related to Operations that are critical to maintaining operational and safety compliance standards with recent additions of transmission line, gate stations and general system expansion.

Q. Why are these headcount additions necessary now?

A. These incremental headcount additions are necessary and prudent to keep our systems safe and to continue to provide safe, reliable service to our customers. The combination of an aging and retiring workforce and the increase in resignations during the COVID-19 pandemic (referred to as the Great Resignation) have resulted in an overall workforce shortage affecting all industries, but more especially the utility industry.

Q. Please summarize the Damage Prevention Plan additions.

A. As stated previously in my testimony, a robust Damage Prevention Program is critical to protecting the integrity and reliability of our system and, most importantly, keeping our customers and employees safe. In addition to the 3 positions, the Company also proposed an additional $100,000 for additional communication, training, guidance and support with excavators, the affected public, and emergency responders.

Q. Please describe the enhanced leak detection additions.

A. As stated previously in my testimony, the Company plans to work with a third-party vendor that combines multispectral data from satellites and system data to detect leaks more timely and accurately. The projected costs for 2023 are $1,458,492.

Q. Does this conclude your direct testimony?

A. Yes.

Dover
Field Training Facility
(Safety Town)

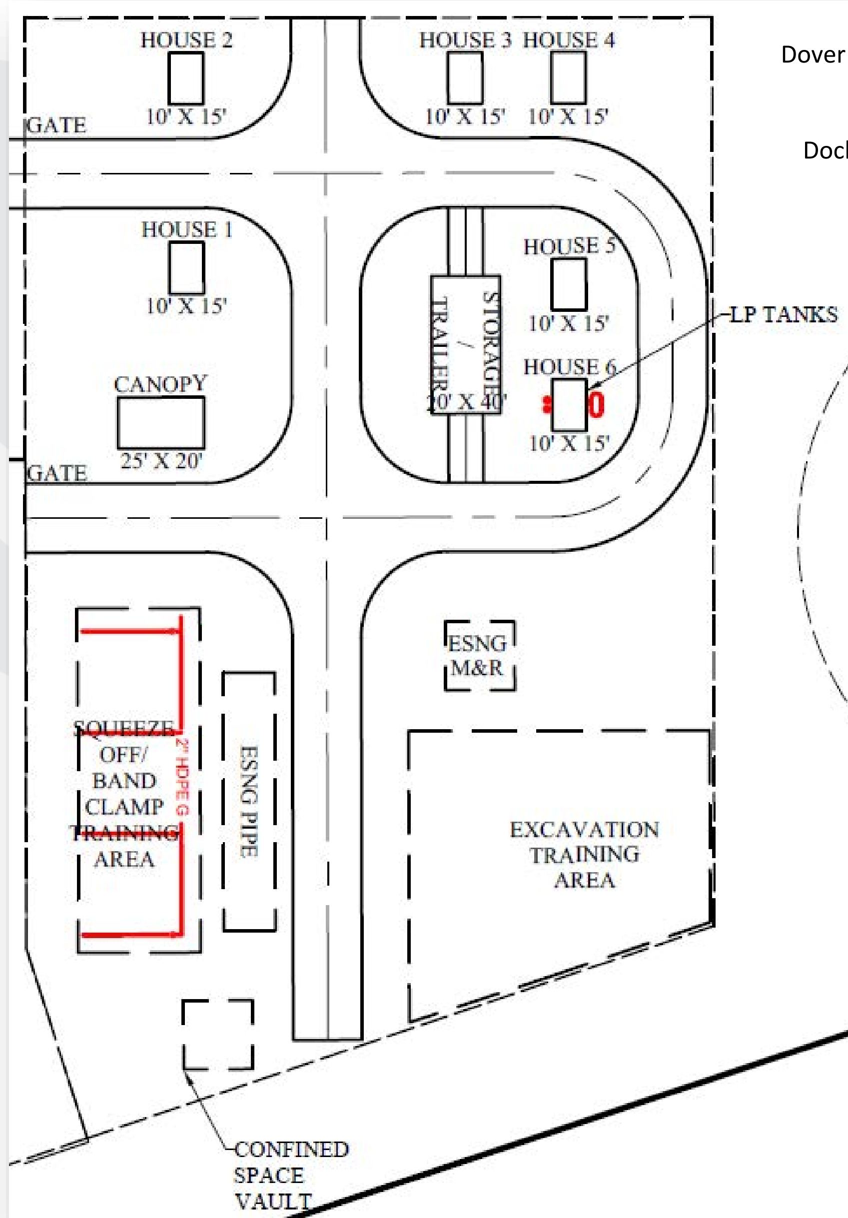
CHESAPEAKE UTILITIES

EASTERN SHORE NATURAL GAS

SHARP ENERGY

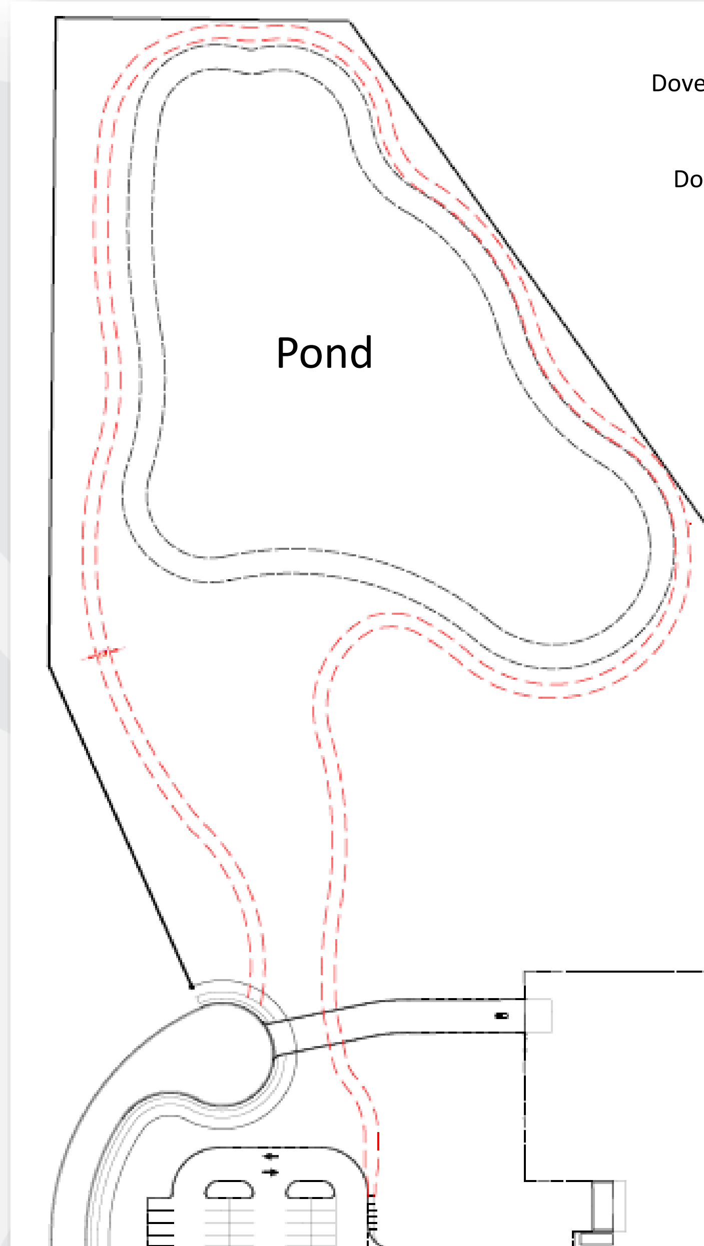
Facility

- Covers approximately 2 acres on the back side of the Energy Lane Campus
- Facility will be fenced with two access gates to facilitate construction equipment and CUC first responder vehicles



Facility

- Will include a walking trail around the pond
- Seating arena near pond
- Roads will be CR6



EASTERN SHORE NATURAL GAS
CHESAPEAKE UTILITIES
SHARP ENERGY

Facility

- Houses will be custom built sheds with shingled roofs, vinyl siding, and faux electrical

EASTERN SHORE NATURAL GAS CHESAPEAKE UTILITIES SHARP ENERGY

Facility

- Pole Barn to store materials and the DNG Training trailer
- Canopy building to house valve manifolds for gas leak simulations
    - Also used as a training and meeting area for classes

Facility

- Landscaping throughout the facility as required
- Design of the Project LC will match the Energy Lane Campus in color schemes and appearance

Training Opportunities

Training Opportunities

Leak Investigation

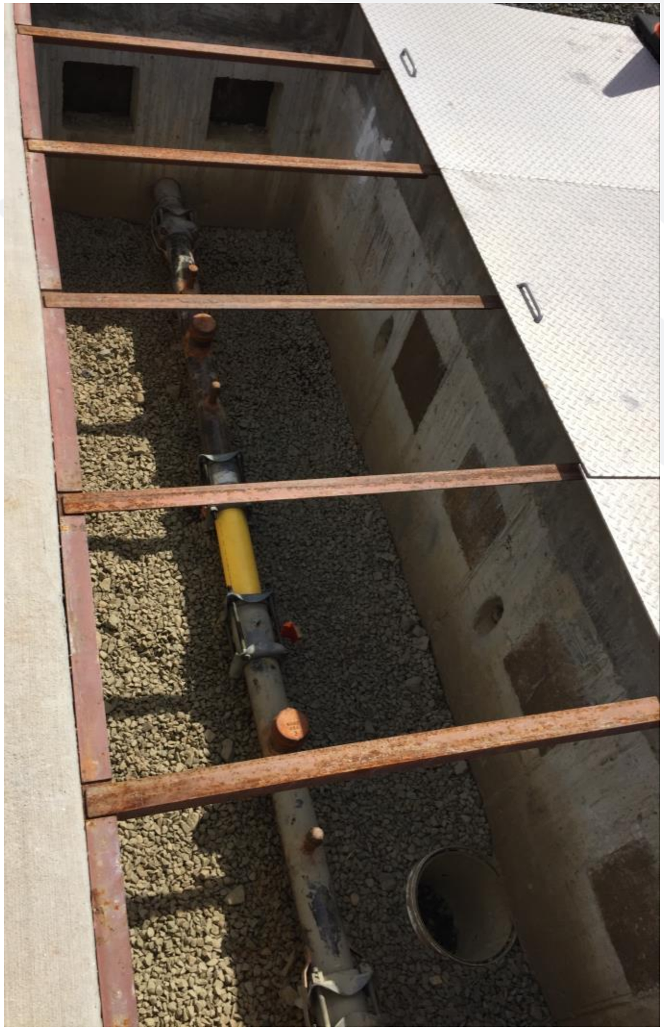
Line Locating

EASTERN SHORE NATURAL GAS

CHESAPEAKE UTILITIES

SHARP ENERGY

Project LC Training Opportunities



Steel Main Installation, Repair & Maintenance

Project LC Training Opportunities

Confined Space

Valve Types & Operation

Project LC Training Opportunities

M&R & Meter Installation / Repair

EASTERN SHORE NATURAL GAS
CHESAPEAKE UTILITIES
SHARP ENERGY

SCHEDULE	TITLE	Witness
PROJECTED TEST YEAR		
G1-5	Historic Base Year + 1 Balance Sheet - Assets	M. Napier / J. Bennett
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
G1-24	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
G2-19 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
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