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March 1, 2023

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of The Next Phase of the Gas System
Modernization Program and Associated Recovery Mechanism
("GSMP III")

BPU Docket No. ___________________

VIA ELECTRONIC MAIL
Carmen Diaz, Acting Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Acting Secretary Diaz:

Enclosed for filing is the Verified Petition of Public Service Electric and Gas Company ("PSE&G") in the above-entitled matter and the Direct Testimonies and Schedules of the following witnesses in support of the Company's Petition.

Attachment	**Witness**	**Area of Responsibility**
1	Wade E. Miller, Director – Gas Transmission and Distribution Engineering, PSE&G	Pipe replacement subprogram, and hydrogen demonstration and renewable natural gas ("RNG") projects.
2	Andrew L. Trump—Senior Principal, West Monroe Partners, LLC	Cost Benefit Analysis for Pipe Replacement Subprogram
3	Hydrogen Production and Blending Facility Cost-Benefit Analysis Panel, Andrew L. Trump and Margaret Oloriz, West Monroe Partners, LLC	Cost Benefit Analysis for Hydrogen demonstration project
4	RNG Cost-Benefit Analysis Panel, Andrew L. Trump and Shelley Hagerman, West Monroe Partners, LLC	Cost Benefit Analysis for RNG project

5	Stephen Swetz, Senior Director – Corporate Rates and Revenue Requirements, PSE&G	Revenue requirements, cost recovery methodology, and rate design
6	Legal Notice	

PSE&G is filing this Petition seeking approval by the Board of Public Utilities ("BPU" or "Board") of the third phase of PSE&G's Gas System Modernization Program ("GSMP III"). In GSMP III, the Company seeks to invest $2.54 billion, over a three year period, to modernize and enhance the safety and reliability of its gas distribution system as consistent with New Jersey's policy goals.

This submission complies with the Board's rules on Infrastructure Investment Programs, N.J.A.C. 14:3-2A, and aligns directly with Governor Murphy's February 15, 2023 Executive Order ("EO") 317, which initiates a proceeding calling for the development of natural gas utility plans to accelerate greenhouse gas emission reduction. Building on the first two phases of GSMP, GSMP III does just that, by: (1) accelerating the replacement of the most methane leak prone main in PSE&G's gas delivery system; and (2) introducing hydrogen and renewable natural gas ("RNG") projects that further support New Jersey's short and long-term decarbonization goals. Moreover, by focusing on modernization of only its existing gas systems, this proposal also supports EO-317's directive to consider minimizing investment in new infrastructure, while ensuring "reliable operation and long-term financial viability of natural gas public utilities and the business model needed to keep the gas system intact." Finally, with its emphasis on addressing methane leaks in urban areas of PSE&G's gas service territory, GSMP III confronts the important state policy concerns (as noted in EO-317) regarding particular focus on overburdened communities that disproportionately bear the burden of climate change.

PSE&G is in the eighth year of a program primarily focused on addressing cast iron main and unprotected steel in the distribution system on an accelerated basis. The Company has demonstrated that it has the capacity to increase the mileage replaced safely and cost-effectively. With this third phase of GSMP, PSE&G proposes to accelerate the pace of its Pipe Replacement Subprogram even further, replacing approximately 380 miles of main annually for a total of 1,140 miles of replacement main, consisting of 810 miles of low pressure cast iron and 50 miles of high pressure cast iron mains, 200 miles of unprotected steel mains and 80 miles of cathodically-protected steel and plastic mains.[1] At this pace, the Company anticipates that it can conclude the program in its entirety, replacing substantially all of its cast iron and unprotected steel mains and services, by 2032.

Additionally, as the industry evolves to adapt to federal and state climate goals through the exploration of low carbon sources of energy, PSE&G is likewise furthering its decarbonization efforts. Low carbon fuel sources, such as hydrogen, are part of the evolution of this evolution. As such, the Company is proposing to invest in a hydrogen blending project that includes the installation of a one megawatt ("MW") power-to-gas facility that will serve a portion of the Central 60 psig gas

[1] Resulting in the abandonment of approximately 210 district regulators, the replacement of approximately 92,100 unprotected steel services and the relocation of approximately 49,200 inside meter sets to the outside.

distribution system with a 2% supply of clean hydrogen.

While PSE&G recognizes some unique challenges with adopting hydrogen into its existing gas delivery system, it likewise understands a proof of concept demonstration project is an important first step toward incorporating this proposed clean energy source. The hydrogen demonstration project included in GSMP III will provide valuable experience with hydrogen production and distribution, preparing for larger scale hydrogen blending in the future, reducing PSE&G's carbon footprint and strengthening capacity for clean energy solutions.

Further, the inclusion of RNG in this filing is another important low carbon evolutionary step in the transition to cleaner fuels. RNG is unique, in that it is a source of energy created from a traditionally environmentally unfriendly product - - solid waste. The RNG project included in GSMP III will upgrade landfill gas to pipeline quality specifications, preparing it for injection into the Central 35 psig gas distribution system.

Building on the successes of GSMP I and GSMP II is, as discussed in the accompanying testimony, paramount to furthering the State's clean energy goals and rapid reduction of greenhouse gas emissions ("GHG"). If approved, the third phase of GSMP will:

- improve the long-term safety and reliability of the system;
- improve air quality and reduce GHG emissions by an additional ~59,000 metric tons of CO2e by the end of 2026 over the GSMP II run rate;
- reduce greenhouse gas emissions by approximately 1,000 metric tons of CO2e, or the equivalent of removing approximately 200 vehicles from the road every year, through the use of hydrogen;
- result in quantified net reductions for nitrogen oxides, carbon monoxide, sulfur dioxide, particulate matter 2.5, and particulate matter 10 air pollutants through construction of its RNG project;
- maximize the amount of purchased natural gas that is successfully delivered to customers for consumption;
- provide opportunities to accommodate technologies and appliances that cannot be adequately served by the current low-pressure system; and
- afford opportunity for continued job creation in New Jersey, specifically 3,800 full time jobs annually for the duration of the Program (an increase of approximately 1,500 full time jobs per year over GSMP II).

Attached to the testimony of Wade Miller (Attachment 1) are schedules that contain confidential information. This material will be furnished to the Board of Public Utilities Staff and the Division of Rate Counsel upon execution of a Confidentiality Agreement, which is provided herewith.

Lastly, in accordance with the Order in Docket No. EO20030254, dated March 19, 2020, the Company hereby submits this filing via electronic delivery only to the Board Secretary, and will suspend submitting such filings as paper documents until the Board directs otherwise.

Respectfully submitted,

Danielle Lopez

Attachment
cc: Service List

Public Service Electric and Gas
Company for Approval of the Next
Phase of the Gas System Modernization
Program and Associated Cost Recovery
Mechanism ("GSMP III")
BPU Docket No.

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP III")

BPU DOCKET NO. ___________________

VERIFIED PETITION

Public Service Electric and Gas Company (PSE&G, the Company, Petitioner), a corporation of the State of New Jersey, having its principal offices at 80 Park Plaza, Newark, New Jersey, respectfully petitions the New Jersey Board of Public Utilities (Board or BPU) pursuant to *N.J.S.A.* 48: 2-21, or any other statute the Board deems applicable, as follows:

INTRODUCTION AND OVERVIEW OF THE FILING

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service (BGS), and distribution of gas and the provision of Basic Gas Supply Service (BGSS), for residential, commercial and industrial purposes within the State of New Jersey. PSE&G provides service to approximately 2.4 million electric and 1.9 million gas customers in an area having a population in excess of 6.2 million persons and which extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to Camden, New Jersey.

2. Petitioner is subject to regulation by the Board for the purposes of setting its retail distribution rates and to assure safe, adequate and reliable electric distribution and natural gas distribution service pursuant to *N.J.S.A.* 48:2-21 *et seq*.

3. PSE&G is filing this Petition seeking Board approval of the next phase of its Gas System Modernization Program and associated cost recovery mechanism ("GSMP III" or

"Program") for a three-year period. The Program is an extension of PSE&G's current Gas System Modernization Program ("GSMP II").[1]

4. The Company has a long history of implementing infrastructure programs,[2] including those approved by the Board pre and post the enactment of its Infrastructure Investment Program ("IIP") regulations, as set forth in *N.J.A.C.* 14:3-2A. Specifically, this regulation was enacted to "allow a utility to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to provide safe and adequate service." The GSMP III filing has been designed to be consistent with the Board's proposed regulations. Appendix 1 attached to this Petition sets forth the location in this filing of all requirements per the Board's proposed regulations.

5. Similar to the IAP, the Company's most recent IIP filing, and PSE&G's second phase of its Gas System Modernization Program, GSMP III is likewise designed to comply with the Board's IIP regulations. Consistent with the IIP regulations, GSMP III proposes infrastructure investments to enhance safety, reliability, and/or resiliency, and modernize the Company's gas delivery systems primarily through pipeline replacement, and by way of a Hydrogen Demonstration Project ("Hydrogen Project"), and a Renewable Natural Gas ("RNG") Project. PSE&G anticipates

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[1] *I/M/O The Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Mechanism ("GSMP II"),* BPU Docket No. GR 17070776 (May 22, 2018).

[2] *I/M/O The Petition of Public Service Electric and Gas Company for Approval of an Infrastructure Advancement Program ("IAP"),* BPU Docket Nos. EO21111211 and GO21111212 (June 29, 2022), GSMP II, *supra., I/M/O The Petition of Public Service Electric and Gas Company for Approval of a Gas System Modernization Program and Associated Mechanism ("GSMP I"),* BPU Docket No. GR15030272 (November 16, 2015), *I/M/O The Petition Of Public Service Electric And Gas Company For Approval Of An Extension Of The Electric Capital Economic Stimulus Infrastructure Investment Program And Associated Cost Recovery Mechanism*, BPU Docket Nos. EO11020088 and GO10110862, "Decision and Order Approving Stipulation" (July 14, 2011); *I/M/O The Proceeding For Infrastructure Investment And Cost Recovery Mechanisms For All Gas And Electric Utilities, And I/M/O The Petition Of Public Service Electric & Gas Company For Approval Of A Capital Economic Stimulus Infrastructure Investment Program And An Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48-2-21.1*, BPU Docket Nos. EO09010049 and GO09010050, "Decision and Order Approving Stipulation" (April 28, 2009).

that GSMP III will be conducted over a three-year period 2024 through 2026, as further described herein, and is planned to commence on January 1, 2024, following Board approval.

6. The State's 2019 Energy Master Plan (EMP)[3] emphasizes investment in gas infrastructure overall as a means of lowering energy costs, decreasing carbon emissions, and enhancing energy security. Specifically, the report states that New Jersey has benefitted from the enhancement and expansion of its gas distribution system, which "will help further lower the cost of energy to New Jersey's homeowners and businesses and reduce emissions."[4] The EMP continues to encourage increased use of natural gas for residential and commercial applications, "including the use of high-efficiency natural gas appliances such as replacing distillate oil appliances with natural gas furnaces and hot water heaters."[5] The most recent EMP update specifically notes that "[the] BPU has approved almost $1 billion for natural gas utility infrastructure upgrades and mitigation projects," and that "[a]n additional $280 million in proposed projects is pending."[6] Finally, the report states that New Jersey "will continue to develop policies that remove barriers and expand the use of the entire array of alternative fuel vehicles," including vehicles powered by Compressed Natural Gas ("CNG"). PSE&G's proposed investment in gas infrastructure modernization is consistent with these EMP policies.

7. Against that backdrop, this filing aligns directly with Strategy 5 of the EMP, "Decarbonize and Modernize New Jersey's Energy System." Within that Strategy, Goal 5.4

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[3] http://d31hzlhk6di2h5.cloudfront.net/20200127/84/84/03/b2/2293766d081ff4a3cd8e60aa/NJBPU_EMP.pdf

[4] *Id.* at p. 5.

[5] *Id.* at p. 41.

[6] *Id.* at p. 5.

focuses on and calls for New Jersey to "[m]aintain existing gas pipeline system reliability and safety while planning for future reductions in natural gas consumption." A critical component of that Goal is the directive in 5.4.4 to "identify and prioritize the replacement of pipelines leaking methane." By approving this third phase of GSMP, New Jersey can achieve this goal by accelerating the reduction of methane leaks and fully eliminating PSE&G's most leak prone pipe by 2032.

8. This submission to the Board also aligns directly with Governor Murphy's February 15, 2023 Executive Order ("EO") 317, which initiates a proceeding calling for the development of natural gas utility plans to accelerate greenhouse gas emission reduction. Building on the first two phases of GSMP, GSMP III does just that, by: (1) accelerating the replacement of the most methane leak prone main in PSE&G's gas delivery system; and (2) introducing Hydrogen and RNG projects that further support New Jersey short and long-term decarbonization goals. Moreover, by focusing on modernization of only its existing gas systems, this proposal also supports EO-317's directive to consider minimizing investment in new infrastructure, while ensuring "reliable operation and long-term financial viability of natural gas public utilities and the business model needed to keep the gas system intact." Finally, with its emphasis on addressing methane leaks in urban areas of PSE&G's gas service territory, GSMP III confronts the important state policy concerns (as noted in EO-317) regarding particular focus on overburdened communities that disproportionately bear the burden of climate change.

ESTABLISHMENT, IMPLEMENTATION AND STATUS OF GAS CAPITAL INFRASTRUCTURE PROGRAMS (CIP I AND CIP II), THE GAS INFRASTRUCTURE PORTION OF ENERGY STRONG, AND GSMP I AND GSMP II

9. PSE&G's Capital Infrastructure Program ("CIP I") was established in April 2009, with the cooperation and assistance of Board Staff, the New Jersey Division of Rate Counsel ("Rate Counsel"), and the Board. The program helped mitigate the negative impacts of poor economic conditions and stimulate the State's economy through investment in additional capital projects, creating new employment opportunities in the state while enhancing service and reliability throughout PSE&G's electric and gas service territories.

10. In CIP I PSE&G proposed to undertake, and the BPU subsequently approved, a program to spend $694 million in capital infrastructure investments, of which $273 million was for gas infrastructure to be invested over a 24 month period. The results of the accelerated investment in CIP I resulted in the replacement of 200 miles of cast iron and unprotected steel mains and achieved the Board's and PSE&G's job creation and economic growth goals.

11. In July 2011 the Board approved PSE&G's request for an extension of CIP I, to enable the Company to continue that construction program and enhance the reliability of its gas distribution system under a program generally referred to as CIP II. A similar request to extend the electric portion of CIP I was reviewed in parallel with the gas extension. CIP II resulted in the replacement of 47 miles of cast iron and unprotected steel mains.

12. In February 2013, Public Service petitioned the Board for approval of its Energy Strong Program and for the recovery of costs to harden its electric and gas infrastructure to make them less susceptible to damage from wind, flying debris and water damage in anticipation of future Major Storm Events, and to increase the resiliency of PSE&G's gas delivery system. In an

Order issued in May 2014, the Board approved a Stipulation to authorize the Energy Strong Program, which includes an investment level of up to $400 million of investment in gas infrastructure designed to harden gas infrastructure to protect it from future storms.

13. Up to $350 million of the gas portion of the Energy Strong program was dedicated to the replacement of an estimated 250 miles of utilization pressure cast iron main and associated services with a higher operating pressure system utilizing plastic or cathodically protected steel mains and services in specified areas. The investment in this gas Utilization Pressure Cast Iron subprogram of Energy Strong was completed in July 2016.

14. In November 2015 the Board approved GSMP, which provided for $650 million in total spend, plus $85 million per year in stipulated base investment that would not be recovered through the GSMP cost recovery mechanism. Up to 400 miles of main were to be installed to replace utilization pressure cast iron ("UPCI") and unprotected steel ("US") mains. The stipulated base investment would include the replacement of both UPCI and elevated cast iron ("EPCI") and unprotected steel mains and associated services, as well as the costs required to uprate the UPCI systems if applicable (including the uprating of associated protected steel and plastic mains and services) to higher pressures and the elimination, where applicable, of district regulators, the installation of excess flow valves associated with the stipulated base investment, and the additional costs associated with the relocation of inside meter sets that is associated with the stipulated base as well as the program main replacements. During the three years 2016 – 2018, the Company would install no less than 110 miles of main to replace cast iron and unprotected steel mains and associated services under the stipulated base.

15. PSE&G replaced 248 miles of cast iron mains, 51 miles of unprotected steel mains under GSMP I and 141 miles associated with base investment committed to under the GSMP settlement.

16. Finally, PSE&G is in the process of replacing more than 930 miles of cast iron and unprotected steel mains under GSMP II and 138 miles associated with base investment committed to under the GSMP II settlement.

THE PROPOSED PROGRAM

17. In 2011, the Secretary of the Department of Transportation (DOT), and the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a "Call to Action," which seeks more aggressive actions on the part of pipeline operators to repair and replace infrastructure that is considered high risk. The PHMSA specifically characterizes cast iron and unprotected steel pipe as categories of pipeline infrastructure that require repair, rehabilitation and replacement. The "Call to Action" was followed by an advisory bulletin issued by PHMSA on March 23, 2012, to owners and operators of natural gas cast iron distribution pipelines and state pipeline safety representatives. The bulletin urges operators of natural gas distribution systems to accelerate replacement of aging infrastructure in order to enhance safety and requests state agencies to consider enhancements to cast iron replacement plans and programs. PSE&G's proposed Program, with a primary focus on gas projects designed to replace cast iron mains, unprotected steel mains and services, and regulators associated with this cast iron and unprotected steel plant, will provide substantial progress in addressing the goals of the "Call to Action", as described in the attached testimony of Wade E. Miller.

18. GSMP III is designed in a manner consistent with the Company's continuing efforts to modernize, enhance and maintain the safety and reliability of its electric and gas distribution systems as consistent with New Jersey's policy goals.

19. The GSMP III program is comprised of three gas utility projects amounting to $2.54 billion in investment, comprised of: $2.39 billion for gas main and service replacement and related work as described below; $0.12 billion for a Renewable Natural Gas ("RNG") project; and $0.03 billion for a Hydrogen Demonstration Project.

20. The first project is designed to replace cast iron ("CI") mains and US mains and services; address the abandonment of district regulators associated with this cast iron and unprotected steel plant; rehabilitate large diameter elevated pressure cast iron; upgrade UPCI portions of the system to EPCI; replace limited amounts of protected steel and plastic mains; and relocate inside meter sets ("Replacement Subprogram").

21. The Program will result in the replacement of approximately 380 miles of main annually for a total of 1,140 miles of replacement main, consisting of 810 miles of UPCI, 50 miles of EPCI mains, 200 miles of unprotected steel mains and 80 miles of cathodically-protected steel and plastic mains. Additionally, the proposed Program would result in the abandonment of approximately 210 district regulators, the replacement of approximately 92,100 unprotected steel services and the relocation of approximately 49,200 inside meter sets to the outside. Where appropriate, services will have excess flow valves installed for improved safety.

22. GSMP III's work prioritization will be based on grid hazard index calculations. UPCI systems will be replaced with elevated pressure systems that have improved reliability. EPCI mains will be prioritized based upon break history. Additionally, EPCI mains will be considered for

replacement if located in the vicinity of UPCI and unprotected steel replacement projects. Unprotected steel mains will be prioritized by age, diameter, pressure, and leak history.

23. PSE&G currently performs well with regard to addressing leaks in its system. Nationally, compared to companies that have large amounts of cast iron and unprotected steel in their distribution systems, PSE&G's results are better than the average of all companies in both main leak rates and service leak rates. When compared to the ten companies that have the most miles of cast iron, PSE&G is the second best in terms of having the least number of main leaks per mile in 2021. (PHMSA report data: 2021 F7100.1-1).

24. However, compared to all gas distribution utilities, PSE&G's leak rate is notably higher as the vast majority of gas distribution utilities developed later than PSE&G and primarily used modern plastic materials, resulting in fewer leaks per mile. PSE&G's GSMP III program would accelerate its replacement and meaningfully address this gap to other US gas distribution utilities.

25. PSE&G responds to over 75,000 gas emergency calls on an annual basis at a rate of 99.9% within one hour. This ranks within the top decile of peer companies. Since 2016, PSE&G has substantially reduced its average open leak inventory (61% reduction, 2016-2022); the focus on closing out open leaks has enabled the Company to maintain a relatively low baseline. Although the Company has effectively reduced its open leak inventory to date, the Replacement Subprogram will build upon this work by accelerating the replacement of the many miles of leak prone pipe that remain in PSE&G's distribution system.

26. A significant portion of our leaks occur within urban areas. GSMP continues to address leak prone gas mains in overburdened communities ("OBC"). For the UPCI

replacements, 12 of the top 22 municipalities set to receive the most miles of main replacement under GSMP III have significant OBC areas. They account for about 310 miles of distribution upgrades.

27. As the industry evolves to adapt to Federal and State climate goals through the exploration of low carbon sources of energy, the Company is likewise looking to be at the forefront of decarbonization efforts and the evolution of the industry. Low carbon sources of fuel such as hydrogen are becoming a part of the next step in this evolution. As such, the Company is proposing to invest in a hydrogen blending project which includes the installation of a one megawatt ("MW") power-to-gas facility that will serve a portion of the Central 60 psig gas distribution system with a 2% supply of clean hydrogen.

28. PSE&G recognizes there are unique challenges associated with adopting hydrogen into its existing gas delivery system and understands a proof of concept demonstration project is an important first step in incorporating this proposed clean energy source. The hydrogen demonstration project will provide valuable hands-on learning and experience with hydrogen production and distribution as larger scale hydrogen blending is considered in the future, further reducing PSE&G's carbon footprint and strengthening capacity for clean energy solutions.

29. PSE&G has continued to innovate its energy portfolio throughout the Company's history. The inclusion of renewable natural gas ("RNG") in this filing is yet another important low carbon evolutionary step in the transition to cleaner fuels.

30. RNG is unique in that it is a source of energy created from a traditionally environmentally unfriendly product – solid waste. The RNG project included in the Program will

upgrade landfill gas to pipeline quality specifications where it will then be injected into the Central 35 psig gas distribution system.

31. PSE&G is in the eighth year of a program that is primarily focused on addressing cast iron main and unprotected steel in the distribution system on an accelerated basis. The Company has demonstrated that it has the capacity to increase the mileage replaced safely and cost-effectively. With this third phase of the Gas System Modernization Program, PSE&G proposes to accelerate the pace of its Pipe Replacement Subprogram even further. At this pace, it is possible that the Company can conclude the program in its entirety, replacing substantially all of its cast iron and unprotected steel mains and services by 2032.

32. Advancing the momentum of these modernization programs by building on the successes of GSMP I and GSMP II is, as discussed in the accompanying testimony, paramount to furthering the State's clean energy goals and rapid reduction of greenhouse gas emissions ("GHG"). It also affords the opportunity for continued job creation in the state of New Jersey.

BENEFITS TO CUSTOMERS AND TO NEW JERSEY

33. The proposed Program, like the prior PSE&G Capital Infrastructure Programs and Energy Strong and GSMPs, will produce many benefits for customers, PSE&G's gas distribution system, and for the environment.[7]

34. The proposed Program is not only consistent with state law and the EMP as mentioned previously, but also with NJ's Global Warming Response Act- 80 X50 Report and with federal legislation, and will result in a number of benefits to customers and to the state of

[7] *See* Cost Benefit Analyses Testimony and Reports submitted by West Monroe Partners, LCC and included with this filing.

New Jersey as discussed further herein.

35. Aging cast iron and unprotected steel pipe in PSE&G's inventory exhibit significantly greater leak rates than current plastic and cathodically protected steel pipe. Additionally inside gas meter sets increase the potential for gas leaks within buildings, and pose potential access issues in the event of an emergency.

36. Consistent with the Company's net-zero climate vision for 2030, replacement of CI and UP pipe will be required to reduce methane leaks and reach net-zero on PSE&G Gas's emissions.

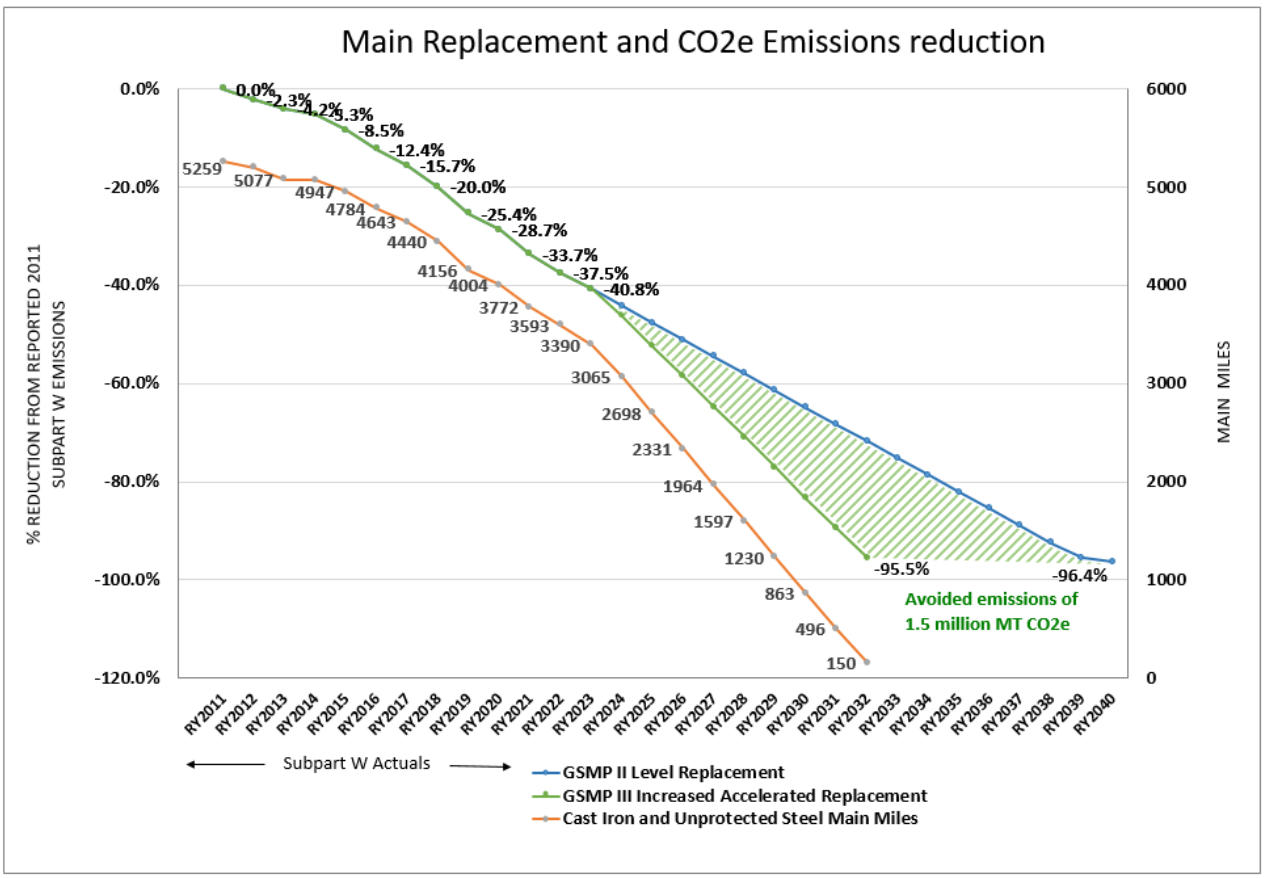
37. The proposed Replacement Subprogram serves to address these issues by improving the long-term safety and reliability of the system by, among other things, upgrading the existing leak-prone pipeline materials to a modern material that will: allow for greater application of service line excess flow values to increase system safety in the event of sudden pressure drop or increase flow rate, provide easy outside access to meters in the event of an emergency, and improve air quality and reduce GHG emissions.

38. The upgrading of low pressure systems to elevated pressure will also provide opportunities to accommodate technologies and appliances that cannot be adequately served by the current low-pressure system. Upgrading the system to elevated pressure means that PSE&G customers will no longer forego consumer appliance options such as tankless water heaters, fan assisted heaters, natural gas whole-house generators, and commercial-grade cooking equipment.

39. GHG Methane, which generally makes up over 90% of natural gas, is more than 80 times more potent at trapping heat than carbon dioxide in a 20 year period per the Environmental Defense Fund. The proposed Replacement Subprogram continues the Company's good work in

reducing emissions associated with methane leaks. This not only helps the environment, but it ensures that less natural gas needs to be produced and purchased, and maximizes the amount of purchased natural gas that is successfully delivered to customers for consumption.

40. There is undoubtedly a correlation between the decline in miles of cast iron and unprotected steel main to the decline in methane emissions. With every mile of leak-prone pipe replaced, less methane is emitted into the atmosphere as depicted by the below chart.



From 2011 through 2021, PSE&G has reduced methane emissions approximately 4% annually (5.82% annually since 2018) or a total of 250,000 metric tons of Carbon Dioxide equivalent

("CO2e") (calculated using EPA Greenhouse Gas Reporting Program: Subpart W – Petroleum and Natural Gas Systems methodology). In PSEG's 2021 Greenhouse Gas Reporting Program ("GHGRP") subpart W filing, PSE&G methane emissions equated to 525,495 metric tons of carbon dioxide equivalents. PSE&G estimated the GHG reduction based on the Title 40 CFR 98 – Mandatory Greenhouse Gas Reporting, Subpart W – Petroleum and Natural Gas System.

41. GSMP is supporting ~40% methane reduction by the end of 2023 from 2011 levels.

42. The proposed GSMP III run rate will accomplish an additional ~19% methane reduction by the end of 2026 from 2011 levels.

43. This proposed run rate will reduce an additional ~59,000 metric tons of CO2e by the end of 2026 over the GSMP II run rate.

44. In addition to the environmental benefits associated with the reduction of emissions, the present value sum for the total reductions achieved during the term of the Program, applying the Social Cost of Carbon as published by the Interagency Working Group on Social Cost of Greenhouse Gases is a cumulative value of avoided CO2e of approximately $13 million as noted below.

Three Year Estimated Value of Avoided CO2e Emissions

Scenario ($ M)	**2024**	**2025**	**2026**	**Total**
Value Reductions Base	$0.42	$0.85	$1.29	$2.56
Value Reductions GSMP III	$2.45	$5.31	$8.27	$16.03
Net Difference GSMP III	$2.03	$4.46	$6.98	**$13.47**

45. Above and beyond the benefits associated with the traditional Replacement Subprogram, the hydrogen demonstration project and the RNG project each provide additional benefits to customers and to the state.

46. The hydrogen demonstration project will yield several benefits. Specifically, the project will provide PSE&G with construction and operations experience, as well as lessons learned to develop and scale the use of hydrogen in the distribution system through this demonstration project. The project will also allow PSE&G to continue to innovate and share learnings with peer utilities.

47. Additionally, there are quantifiable emissions reductions that will be realized through the use of hydrogen. The quantifiable emissions reductions were calculated based on the amount of natural gas that would be displaced through the use of blended hydrogen. The annual totals were calculated based on the average year round flow with a 2% blend. The project is estimated to reduce greenhouse gas emissions by approximately 1,000 metric tons of CO_2e, or the equivalent of removing approximately 200 vehicles from the road every year. With future increases in blend percentages, even further methane emission reductions can be realized.

48. The RNG project will also yield many favorable benefits. Specifically, this project will introduce a unique and collaborative approach with the Middlesex County utility authority whereby PSE&G can displace traditional natural gas supply, generate revenue to mitigate customer rate impacts, and align with the goals of the EMP.

49. The gas in the RNG project will be sourced directly in PSE&G's territory and will not need to rely on transportation through interstate pipelines from out of state locations thereby reducing emission pathways. There are quantified air quality improvement and emissions reductions that will be realized through the use of RNG.

50. Further, due to the removal of the MCUA's electric generation units, the RNG project will result in a net air quality improvement for the state of New Jersey. Quantified net

reductions for the following air pollutants have been identified: nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter 2.5 ($PM_{2.5}$), and particulate matter 10 (PM_{10}).

Emissions (tons/yr)	
Air Pollutant	Quantified Reduction
NOx	-20.55
CO	-0.91
SO2	-22.82
VOC	0.25
PM2.5	-4.22
PM10	-4.21
PM	-4.20

51. PSE&G and MCUA have concluded that based on the preliminary Design Basis, no net increases of direct air pollutants are estimated to result from the RNG Project except for a minor increase in VOC. PSE&G also believes this analysis is conservative if not worst case.

52. These quantified air quality improvements are aligned and support New Jersey's efforts toward attaining National Ambient Air Quality Standards for PM2.5. These improvements are also consistent with the New Jersey's established enforceable reductions in fine particulate matter and its precursors, nitrogen oxides (NOx) and sulfur dioxide (SO2).

53. With regards to GHG reductions, RNG has distinct benefits as a decarbonization strategy. RNG has lower life cycle GHG emissions compared to natural gas and can be introduced into the gas distribution network safely and used by customers to reduce GHG emissions without any changes to existing equipment or appliances. RNG projects contribute to reducing the carbon intensity of fuels burned, capture methane emissions that would otherwise escape to atmosphere,

and leverage existing waste streams - - all of which positively impact public health, climate and air quality.

54. Proceeding with this Program will also continue PSE&G's support of enhanced employment opportunities in New Jersey.

55. Using the methodology for job creation from the introductory material to the Board's August 7, 2017 proposal for the IIP regulations, the replacement component of the proposed Program would create an estimated 3,800 full time jobs annually for the duration of the program. This is an increase of approximately 1,500 full time jobs per year over GSMP II. The hydrogen project is estimated to create 80 full time jobs per year over the two year engineering and construction timeline. The RNG project is estimated to create 229 full time jobs per year over the 3 year engineering and construction timeline.

56. There are also significant benefits of a multi-year approach, including better workforce management and reduction in procurement and construction mobilization/de-mobilization associated with completing larger projects. Providing for this Program over multiple years will enable PSE&G to plan to construct these facilities in a cost effective manner, and allow PSE&G to coordinate with municipalities in planning construction.

57. Proceeding with this Program will also continue PSE&G's support of economic development and enhanced employment opportunities in New Jersey. This Program will support additional skilled jobs. Proceeding on a multi-year basis will provide stability and permanence in the jobs the Program creates and supports.

58. It is reasonable and prudent to provide for the modernization of the PSE&G gas distribution system to further advance the long-term reliability and safety of that system through the

Program proposed herein. Accordingly, PSE&G requests that the Board approve this Program, to provide an investment of up to $2.54 billion.

COST RECOVERY

59. PSE&G is proposing a cost recovery mechanism for GSMP III that is consistent with the BPU' s IIP regulations, as addressed in detail in the attached Direct Testimony of Stephen Swetz. The cost recovery method will involve a proposed new gas rate component of the Company's IIP charges with the potential for semi-annual rate adjustment filings. This method is consistent with the IIP regulations, and the same approach is being used for PSE&G's Energy Strong II and IAP programs. The proposed schedule for these potential filings are shown in the chart below:

GSMP III Rate Adjustment Schedule				
Rate Adj #	**Initial Filing**	**Investment as of**	**Update for Actuals Filing**	**Rates Effective**
1	6/30/24	8/31/24	9/15/24	12/1/24
2	12/31/24	2/28/25	3/15/25	6/1/25
3	6/30/25	8/31/25	9/15/25	12/1/25
4	12/31/25	2/28/26	3/15/26	6/1/26
5	6/30/26	8/31/26	9/15/26	12/1/26
6	12/31/26	2/28/27	3/15/27	6/1/27
7	6/30/27	8/31/27	9/15/27	12/1/27

60. Consistent with the IIP proposal, PSE&G proposes to limit each base rate adjustment to a minimum investment level of 10 percent of the total program investment.

61. Assuming Board approval by December 31, 2023, GSMP III is estimated to be complete December 31, 2026, except for certain close out work that may occur 3 to 6 months following the conclusion of the Program. Without a firm date for completion of this close out

work, the Company is proposing a rate filing no later than June 30, 2027 comprised of all actual cost data (as opposed to projected) for rates effective December 1, 2027. Given the nature of the close out work, the final roll-in may be less than 10% of the Program, but is appropriate to provide completion of the Program. The Company proposes a WACC for the Program based upon the most recent WACC for base rates approved by the Board. PSE&G further proposes that any change in the WACC authorized by the Board in any subsequent base rate case be reflected in the subsequent revenue requirement calculations.

62. Consistent with the Energy Strong programs, IAP, and GSMPs, PSE&G proposes that the costs to be included in rates will include: depreciation/amortization expense providing for the recovery of the invested capital over its useful book life; return on the net investment, where net investment is the capital expenditures less accumulated depreciation/amortization, less associated accumulated deferred income taxes; and the impact of any tax adjustments applicable to the Program. The return on net investment will be based upon a weighted average cost of capital (WACC). The Company proposes a WACC for the Program based upon the most recent WACC for base rates approved by the Board. PSE&G further proposes that any change in the WACC authorized by the Board in any subsequent base rate case be reflected in the subsequent revenue requirement calculations. In addition, as in the prior phases of the Gas System Modernization Program, an O&M expense adjustment will be included to account for savings from leak reductions due to the Replacement Subprogram as well as ongoing annual expenses related to the operations and maintenance of the proposed Hydrogen and RNG Projects.

63. The Company is proposing to credit revenue associated with the sale of gas from the Hydrogen and RNG Projects and environmental attributes, net any selling expenses from the RNG Project to the BGSS-RSG deferral balance, which will result in lower BGSS-RSG rates.

64. BPU Staff and Rate Counsel will have an opportunity to review each rate adjustment filing to ensure that the revenue requirements and proposed rates are calculated in accordance with the BPU Order approving the Program and the IIP rules. The changes to GSMP III rates made through these rate adjustment filings would be subject to refund if the Board finds that PSE&G imprudently incurred capital expenditures in its implementation of the IAP. The prudence of the Company's actual expenditures in GSMP III will be reviewed as part of PSE&G's subsequent base rate case(s) following the rate adjustments. This is identical to the approach under the Energy Strong II and IAP programs, and the Board's regulation at *N.J.A.C.* 14:3-2A.6(e).

65. In accordance with the IIP regulations, the Company will file a rate case no later than five years from the start of the Program.

66. In addition to limiting the base rate adjustment requests to a minimum investment level of ten (10) percent of the total program investment, PSE&G is also proposing an earnings test that would serve to limit the amount of investment to be included in the rate base adjustments. Consistent with the IIP regulations, if the Company exceeds the allowed Return-on-Equity from the utility's last base rate case by fifty basis points or more for the most recent twelve month period, the pending base rate adjustment will not be allowed for the applicable filing period. Details regarding application of the earnings test are set forth in the Direct Testimony of Stephen Swetz, submitted herewith.

67. In accordance with IIP regulations, a proposed form of public notice of filing and public hearings, including the proposed rates and bill impacts attributable to the proposed implementation of the Program, is attached to this Petition. PSE&G proposes this Form of Notice will be placed in newspapers having a circulation within the Company's gas service territory once public hearings have been scheduled. PSE&G proposes public hearings to allow members of the public the opportunity to present their views on the Company's filing. PSE&G also proposes that it provide notice to the County Executives and Clerks of all municipalities within the Company's gas service territories upon receipt of public hearing dates.

68. The typical annual bill impacts for a typical residential customer as well as rate class average customers compared to rates as of March 1, 2023 are set forth in the testimony of Mr. Stephen Swetz. The forecast cumulative impact (impact from the entire Program) on the typical residential gas heating customer is an increase of approximately 10.41% on an average annual bill or about a $10.16 increase in their average monthly bill.

ATTACHED DIRECT TESTIMONY AND PROPOSED PROCEDURAL SCHEDULE

69. The attached Direct Testimonies of Wade E. Miller, Stephen Swetz, Margaret Oloriz, Dr. Shelly Hagerman, and Andrew Trump, and the Cost Benefit analyses submitted by West Monroe on behalf of the Company provide support for the forgoing and the requests herein.

70. Given the expiration of the GSMP II main replacement work in 2023, and the importance of maintaining the support for jobs through PSE&G infrastructure programs and continuity in those programs, it is important for PSE&G to receive Board approval by December 31, 2023 to begin planning for, designing and making the capital investments described herein.

Therefore, the Company respectfully requests that the Board retain this matter and utilize a schedule similar to the following procedural schedule:

- Petition and Direct Testimony filed
- Prehearing Conference
- Discovery on PSE&G Filing
- Non-Petitioner Direct Testimony Due
- Discovery Requests on Non-Petitioner Testimony
- Rebuttal Testimony – All Parties
- Discovery Requests on Rebuttal Testimony
- Settlement Conferences
- Hearings
- Initial Briefs
- Reply Briefs
- BPU Decision and Order

71. Attached are the following direct testimony with schedules and other attachments in support of the proposal in this petition:

Appendix 1 - Location of requirements per the IIP regulations at N.J.A.C. 14:3-2A

Non-Disclosure Agreement

Appendix 1- MFRs

Attachment 1 - Prepared Direct Testimony of Wade E. Miller

Attachment 2 - Prepared Direct Testimony of Andrew Trump

WP-ALT-GSMPIII-1 - CBA Calculations

Attachment 3 - Prepared Direct Testimony of the Hydrogen Demonstration Project Cost-Benefit Analysis Panel

WP-ATMO-GSMPIIIH2-1

Attachment 4 - Prepared Direct Testimony of Andrew Trump and Shelly Hagerman, West Monroe Partners, LLC regarding the Renewable Natural Gas Project

WP-ATSH-GSMPIIIRNG-1.xlsx

Attachment 5 - Prepared Direct Testimony of Stephen Swetz

WP-SS-GSMPIII-1 - Gas Revenue Requirements

WP-SS-GSMPIII-2 - Hydrogen Demonstration Project Revenue Requirements Support

WP-SS-GSMPIII-3 - RNG Project Revenue Requirements Support

WP-SS-GSMPIII-4.xlsx - Gas/Benefit Sales – BGSS-RSG Annual Bill Impacts

Attachment 6 - Legal Notice

COMMUNICATIONS

72. Communications and correspondence related to the Petition should be sent as follows:

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CONCLUSION AND REQUESTS FOR APPROVAL

For all the foregoing reasons, PSE&G respectfully requests that the Board issue an Order approving this Petition no later than December 2023 specifically finding that:

73. GSMP III is in the public interest;

74. The next phase of the Company's Gas System Modernization Program as described herein is reasonable and prudent;

75. PSE&G is authorized to implement and administer the Program under the terms set forth in this Petition and accompanying Attachments;

76. The cost recovery proposal and mechanism set forth in this Petition will provide for implementation of just and reasonable rates and is approved; and

77. PSE&G may recover all prudently-incurred Program costs, on a full and timely basis, under the cost recovery mechanism set forth herein.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Danielle Lopez

By: Danielle Lopez, Esq.

DATED: March 1, 2023

STATE OF NEW JERSEY)
:
COUNTY OF ESSEX)

Wade E. Miller of full age, being duly sworn according to law, on his oath deposes and says:

1. I am the Senior Director – Gas Transmission and Distribution Engineering Gas Company, the Petitioner in the foregoing Petition.

2. I have read the annexed Petition, and the matters and things contained therein are true to the best of my knowledge and belief.

____
Wade E. Miller

Sworn and subscribed to)
before me this 1st day)
of March, 2023)

Michele D. Falcao

Michele D. Falcao
Notary Public, State of New Jersey
Comm. # 2414516
My Commission Expires 11/14/2026

<table>
<tr><th colspan="2">PUBLIC SERVICE ELECTRIC AND GAS
Minimum Filing Requirements – Gas System Modernization Program III</th></tr>
<tr><th>Minimum Filing Requirement</th><th>Location in Filing</th></tr>
<tr><td colspan="2">14:3-2A.2 Project eligibility</td></tr>
<tr><td>a) Eligible projects within an Infrastructure Investment Program shall be:
1. Related to safety, reliability, and/or resiliency;
2. Non-revenue producing;
3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and
4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility’s petition.</td><td>See Attachment 1:
• Direct Testimony of Wade E. Miller</td></tr>
<tr><td>b) Projects within an Infrastructure Investment Program may include:
1. The replacement of gas Utilization Pressure Cast Iron mains with elevated pressure mains and associated services;
2. The replacement of mains and services that are identified as high risk in a gas utility’s Distribution Integrity Management Plan;
3. The installation of gas Excess Flow Valves where existing gas service line replacements require them, excluding Excess Flow Valves installed upon customer request pursuant to 49 CFR 192.383;
4. Electric distribution automation investments, including, but not limited to, Supervisory Control and Data Acquisition equipment, cybersecurity investments, relays, reclosers, Voltage and Reactive Power Control, communications networks, and Distribution Management System Integration;
5. The installation of break-predictive water sensors and wastewater sensors to curtail combined sewer overflows; and
6. Other projects deemed appropriate by the Board</td><td>See Attachment 1:
• Direct Testimony of Wade E. Miller</td></tr>
<tr><td>c) A utility shall maintain its capital expenditures on projects similar to those proposed within the utility’s Infrastructure Investment Program. These capital expenditures shall amount to at least ten (10) percent of any approved Infrastructure Investment Program. These capital expenditures shall be made in the normal course of business and recovered in a base</td><td>See Attachment 1:
• Direct Testimony of Wade E. Miller
• Schedule WEM-GSMPIII-2</td></tr>
</table>

rate proceeding, and shall not be subject to the recovery mechanism set forth in N.J.A.C. 14:3-2A.6.	
14:3-2A.3 Annual baseline spending levels	
a) A utility seeking to establish an Infrastructure Investment Program shall, within its petition, propose annual baseline spending levels to be maintained by the utility throughout the length of the proposed Infrastructure Investment Program. These expenditures shall be recovered by the utility in the normal course within the utility's next base rate case.	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-2
b) In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-3
14:3-2A.4 Infrastructure Investment Program length and limitations	
a) Allowance for Funds Used During Construction (AFUDC) shall be permitted under an Infrastructure Investment Program, but a utility shall not utilize AFUDC once Infrastructure Investment Program facilities are placed in service.	See Attachment 5: • Direct Testimony of Stephen Swetz
14:3-2A.5 Infrastructure Investment Program minimum filing and reporting requirements	
1) Projected annual capital expenditure budgets for a five (5) year period, identified by major categories of expenditures	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-2
2) Actual annual capital expenditures for the previous five (5) years, identified by major categories of expenditures	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-3
3) An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives, detailed cost estimates, in-service dates, and any applicable cost-benefit analysis for each project	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-6 • Schedule WEM-GSMPIII-7

	• Schedule WEM-GSMPIII-8 See Attachment 2: • Direct Testimony of Andrew L. Trump • Schedule ALT-GSMPIII-1 See Attachment 3: • Direct Testimony of Andrew L. Trump and Margaret Oloriz • Schedule ATMO-GSMPIIIH2-1 See Attachment4: • Direct Testimony of Andrew L. Trump and Shelly Hagerman • Schedule ATSH-GSMPIIIRNG-1
4) An Infrastructure Investment Program budget setting forth annual budget expenditures	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-4
5) A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f)	See Attachment 5: • Direct Testimony of Stephen Swetz
6) Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b)	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-2
7) The maximum dollar amount, in aggregate, the utility seeks to recover through the Infrastructure Investment Program; and	See Attachment 1: • Direct Testimony of Wade E. Miller • Schedule WEM-GSMPIII-2
8) The estimated rate impact of the proposed Infrastructure Investment Program on customers	See Attachment 5:

	• Direct Testimony of Stephen Swetz • Schedule SS-GSMPIII-8
14:3-2A.6 Infrastructure Investment Program Recovery	
a) Each filing made by a utility seeking accelerated recovery under an Infrastructure Investment Program shall seek recovery, at a minimum, of at least ten (10) percent of overall Infrastructure Investment Program expenditures.	See Attachment 5: • Direct Testimony of Stephen Swetz
b) A utility's expenditures made prior to the Board's approval of an Infrastructure Investment Program shall not be eligible for accelerated recovery.	N/A
c) Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be accelerated, and recovered through a separate clause of the utility's Board-approved tariff.	See Attachment 5: • Direct Testimony of Stephen Swetz
d) Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest. Prudence of Infrastructure Investment Program expenditures shall be determined in the utility's next base rate case.	See Attachment 5: • Direct Testimony of Stephen Swetz
e) A utility shall file its next base rate case not later than five (5) years after the Board's approval of the Infrastructure Investment Program, although the Board, in its discretion, may require a utility to file its next base rate case within a shorter period	See Attachment 5: • Direct Testimony of Stephen Swetz
f) An earnings test shall be required, where Return on Equity (ROE) shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.	See Attachment 5: • Direct Testimony of Stephen Swetz
g) For any Infrastructure Investment Program approved by the Board, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more, accelerated recovery shall not be allowed for the applicable filing period.	See Attachment 5: • Direct Testimony of Stephen Swetz

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE NEXT PHASE OF THE GAS SYSTEM MODERNIZATION PROGRAM AND ASSOCIATED COST RECOVERY MECHANISM ("GSMP III")

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
WADE E. MILLER
SENIOR DIRECTOR – GAS TRANSMISSION AND DISTRIBUTION ENGINEERING

March 1, 2023

Introduction

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

A. My name is Wade E. Miller, and I am Senior Director, Gas Transmission and Distribution ("T&D") Engineering of Public Service Electric and Gas Company ("PSE&G", or the "Company"), the Petitioner in this matter.

Q. Please describe your responsibilities as Senior Director of Gas Transmission and Distribution Engineering.

A. As the Senior Director of Gas T&D Engineering, I have the responsibility and accountability for three core functions of PSE&G's gas business. The first core function is delivering the natural gas. This includes gas control and system reliability to over 1.8 million customers. This also includes the operation and maintenance of 56 Metering & Regulating ("M&R") stations, one Liquefied Natural Gas ("LNG") plant, three Liquid Propane Air ("LPA") plants, and one Liquid Propane ("LP") storage facility. The second core function is gas asset management. This includes the safe and efficient engineering and design of PSE&G's gas transmission and distribution assets, capacity planning, corrosion control, replacement facility identification and prioritization, transmission pipeline maintenance, and the management of the Transmission and Distribution Integrity Management Programs. The third core function is business support and technical services. This includes the development of operating standards and procedures, material evaluation and specification, and other programs.

Q. Please describe your educational and professional background and qualifications.

A. This information is provided in Schedule WEM-GSMPIII-I, which is attached hereto.

Q. Please provide an overview of PSE&G gas operations.

A. PSE&G provides gas distribution service and Basic Gas Supply Service ("BGSS"), under

Regulation by the New Jersey Board of Public Utilities ("Board" or "BPU"). PSE&G serves approximately 1.9 million gas customers in an area that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to West Deptford, New Jersey.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony discusses the prudence and timeliness of PSE&G's proposed Third Phase of the Gas System Modernization Program ("GSMP III", or "Program"). I describe the Program and its primary focus on gas projects designed to replace cast iron mains, unprotected steel mains and services, abandonment of district regulators associated with cast iron and unprotected steel mains, and relocation of inside meter sets ("Replacement Subprogram"). Additionally, I describe a proposed hydrogen demonstration project included in the Program that will blend hydrogen into the gas distribution system. Lastly, I describe a proposed renewable natural gas ("RNG") project included in the Program that will upgrade landfill gas to pipeline quality specifications where it will then be injected into the gas distribution system. I also describe the underlying reasons for the Program, including the need for a forward-looking, efficient, long-term replacement plan for aging gas infrastructure. Further, I describe the time-frame for the Program and the estimated costs of the Program.

Q. Are there other witnesses supporting the proposed Program?

A. The benefits associated with the Program are addressed in cost benefit analyses being submitted on behalf of PSE&G by West Monroe Partners, LLC ("West Monroe"). The following witnesses from West Monroe are supporting the proposed Program. For the main and service Replacement Subprogram, please refer to the testimony of Andrew L. Trump. For the hydrogen demonstration project, please refer to the testimony of Margaret Oloriz and Andrew L. Trump. For the RNG project, please refer to the testimony of Dr. Shelly Hagerman and Andrew L. Trump. Additionally, Stephen Swetz from PSE&G will provide program cost recovery testimony.

Q. Please provide an overview of the proposed investments.

A. The estimated infrastructure investment for the proposed Program is approximately $2.54 billion. The Program is primarily a systematic cast iron and unprotected steel replacement program; the three-year Program extension will replace approximately 380 miles of main annually, for a total of 1,140 miles of replacement main. The proposed replacement miles include 810 miles of utilization pressure cast iron ("UPCI") mains, 50 miles of elevated pressure cast iron ("EPCI") mains, 200 miles of unprotected steel mains and 80 miles of cathodically-protected steel and plastic mains. Additionally, the proposed Program will result in the abandonment of approximately 210 district regulators, the replacement of approximately 92,100 unprotected steel services and the relocation of approximately 49,200 inside meter sets to the outside. Finally, the program will include the installation of a one megawatt (MW) power-to-gas facility that will serve a portion of the Central 60 psig gas distribution system with a blended supply of up to 2% of clean hydrogen and the installation of a facility that will allow the injection of RNG created from landfill gas into the Central 35 psig gas distribution system.

Q. Why is PSE&G recommending the proposed investments now?

A. PSE&G has an important opportunity to extend the Program now. GSMP III, as proposed, affords the opportunity for additional job creation, economic stimulus and a rapid reduction of direct greenhouse gas emissions in the state of New Jersey. The proposed Program will build on the successes achieved throughout GSMP I and II. Moreover, the proposal is consistent with state and federal legislation, NJ's Global Warming Response Act, 80 X50 Report, and New Jersey's Energy Master Plan. GSMP III has the added benefit of a significant amount of system upgrades in many of New Jersey's overburdened communities. As a result, now is the time to invest in this Program extension.

PSE&G is aggressively looking for opportunities to meet customers' expectations in a low carbon future. As the world is shifting priorities to focus on providing energy from more low carbon sources of energy, the Company has an important opportunity to invest in a hydrogen blending project and an RNG processing facility. Developing and scaling low carbon fuels such as hydrogen and RNG allow PSE&G to leverage existing infrastructure providing more long term value for customers. These fuels would be produced locally within PSE&G territory and would help to diversify PSE&G's energy portfolio and reduce reliance on traditional natural gas. This investment aligns with the energy goals of the state and with industry to explore more low carbon sources of energy.

Q. Please summarize your conclusions and recommendations.

A. Aging cast iron and unprotected steel pipe in PSE&G's inventory exhibit significantly greater leak rates than current plastic and cathodically protected steel pipe. Low carbon fuels are essential in progressing climate stewardship while leveraging an existing network capable of transporting these energy sources. As proposed in this testimony, the Program and the associated cost recovery mechanism represent a prudent response to the Company's long-term system needs and various federal and state legislation as described in the "Reasons for Filing" section of this testimony. The safety-related, customer, economic, environmental and other benefits attributable to the proposed three-year Program extension as presented in this testimony are compelling. The Company has demonstrated its ability to execute the proposed Program in a safe and customer conscious manner. Therefore, I request that the proposed Program be approved.

Q. How is the remainder of your testimony organized?

A. My testimony is organized into several sections following this introduction:

TABLE OF CONTENTS

Executive Summary

Q. Please provide a brief summary of GSMP.

A. PSE&G's Gas System Modernization Program ("GSMP") is an accelerated replacement program for low/utilization pressure cast iron mains ("UPCI"), elevated pressure cast iron (EPCI), and unprotected steel mains and services. GSMP III is being filed with the

New Jersey Board of Public Utilities ("BPU" or the "Board") as a 3-year program extension as part of PSE&G's reduction strategy. GSMP started when the BPU approved the first three years of the program in the first phase of GSMP. The BPU then approved GSMP II, a 5-year extension of the GSMP program, and GSMP III continues this effort.

GSMP III targets the replacement of legacy systems on a "map grid" basis, compared to the segment-by-segment approach of typical annual base plan main replacement. This allows for a systematic replacement strategy that still focuses on risk, while maximizing construction efficiency and cost-effectiveness. GSMP III continues to support a focus on replacing the highest risk and most leak prone facilities, as identified in the Company's Distribution Integrity Management Plan, and will span 3 years – replacing 380 miles of main annually, with estimated investment of approximately $795 million per year, or $2.39 billion for the full term of the Program.

The Company's experience executing GSMP I and II demonstrates that PSE&G can execute a large scale replacement program at an accelerated rate. In addition, the work completed under GSMP I and II was performed with an excellent safety record, while maintaining high customer satisfaction. The proposed Program will accelerate O&M savings and methane emissions reductions.

Q. Please describe the proposed program extension.

A. GSMP III proposes to replace 810 miles of UPCI, 50 miles of EPCI, 200 miles of unprotected/bare steel mains, and 80 miles of cathodically-protected steel and plastic main. Main replacement will result in approximately 210 abandoned district regulators, replacement of approximately 92,100 unprotected steel services, the relocation of approximately 49,200 inside meter sets to the outside, and where appropriate, services will have excess flow valves installed for improved safety. GSMP III targets all UPCI main diameters, and work prioritization is based on grid hazard index calculations.

UPCI systems will be replaced with elevated pressure ("EP") systems that have improved reliability. EPCI mains will be prioritized by break history. Additional EPCI mains will be considered for replacement based on condition or if located in the vicinity of UPCI and unprotected steel replacement projects. Unprotected steel mains will be prioritized by age, diameter, pressure, and leak history. The proposed program will also include the installation of a one megawatt (MW) power-to-gas facility that will serve a portion of the Central 60 psig gas distribution system with a supply of up to 2% of clean hydrogen. It will also include the installation of an RNG facility that will allow the injection of approximately 1 BCF/year of RNG created from landfill gas, from Middlesex County Utilities Authority Landfill in East Brunswick, into the Central 35 psig gas distribution system over the next 20 years.

Q. Please describe the Program's benefits.

A. The Program will produce many benefits for customers, for PSE&G's gas distribution system, and for the environment. Customers will benefit from a safer, more modern system that accommodates newer technologies and appliances. The replacement of mains and services will enhance the safety and reliability of the system through the use of more modern materials and construction. The replacement of infrastructure with modern materials will also result in an accelerated reduction of direct greenhouse gas emissions from legacy facilities.

The hydrogen demonstration project will also provide benefits to the environment, as well as provide valuable information that the Company can utilize for constructing and operating these types of clean energy facilities going forward. In addition, the RNG production facility will provide a low carbon fuel supply directly to New Jersey customers providing a wide range of benefits. A series of detailed cost/benefit analyses supporting the Program is included with this filing.

Reasons for the Filing

Q. Please summarize the reasons for this filing.

A. Aging cast iron and unprotected steel pipe exhibits significantly greater leak rates as compared to newer plastic and cathodically-protected steel pipe, and eventually requires replacement or rehabilitation. GSMP III and its associated cost recovery mechanism represent a prudent response to PSE&G's long-term system needs, the Department of Transportation's PIPES ("Protecting our Infrastructure of Pipelines and Enhancing Safety") Act of 2020, New Jersey's Energy Master Plan and the Board's regulations (Subchapter N.J.A.C. 14:3-2A) regarding Infrastructure Investment Programs ("IIPs"), effective as of 2018. The GSMP III Program is also consistent with the Department Of Transportation's "Call to Action" to facilitate the replacement of aging gas infrastructure. The safety-related, customer, economic, environmental and other benefits attributable to the three-year Program extension, as presented in my testimony, are compelling.

Q. Is it appropriate for PSE&G to move forward with a long-term approach to gas infrastructure replacement?

A. Yes. PSE&G's prior replacement levels supported safe and adequate service but the current phase of the GSMP program and this proposed extension will expedite the replacement above and beyond replacement levels approved for the GSMP II Program, making the system safer, more reliable, and less leak prone. This will result in O&M savings and emissions reductions that will significantly impact the amount of methane escaping into the atmosphere year over year. While there is no immediate risk posed by PSE&G's current system and operating practices, the distribution system is aging; and while PSE&G manages the risks posed by its legacy system, all cast iron and unprotected steel will eventually require replacement or rehabilitation. Although PSE&G has made significant progress in replacing legacy utilization pressure cast iron pipelines during the first two phases of GSMP, the Company still maintains the largest inventory of cast iron pipeline in the nation. Moreover, since the costs associated with the ongoing management of the legacy systems will increase as the system continues to age, now is the time to continue accelerating these infrastructure replacement and modernization efforts.

Q. Why does PSE&G feel they need the Hydrogen demonstration on their system?

A. PSE&G has a history of evolving in its delivery of gas to the customers of New Jersey. PSE&G's gas business was established in 1903 with the merger of several gas companies throughout the state. PSE&G's system consisted of manufactured or synthetic gas from the early 20th century up until the latter half of the 20th century when industry shifted in favor of sources from natural gas wells. Liquid petroleum gas was introduced into the system as an additive to increase the energy content of the manufactured gas around the 1950s. PSE&G completed its Burlington Liquefied Natural Gas ("LNG") facility in 1972, around the time when demand for alternate fuel was increasing due to the oil crisis, adding another unique facility to the gas system. Liquid petroleum gas was then utilized for peak shaving operations around the 1990s, adding another unique commodity to the gas system profile.

Low carbon sources of fuel such as hydrogen are becoming a part of the next step in this evolution. The industry is evolving quickly to adapt to Federal and State climate goals through the exploration of low carbon sources of energy. As such, the Company is looking to be at the forefront of decarbonization efforts and the evolution of the industry as it always has been in the past. PSE&G is no stranger to working with new commodities as the Company has extensive experience with operating propane and liquefied natural gas facilities for many decades. Each local distribution company has unique systems and as such each has or is expected to have unique challenges associated with adopting hydrogen into their existing natural gas systems. PSE&G recognizes these unique challenges and understands a proof of concept demonstration project is an important first step in incorporating this proposed clean energy source. The hydrogen demonstration project will provide valuable hands-on learning and experience with hydrogen production and distribution as larger scale hydrogen blending is considered in the future, further reducing PSE&G's carbon footprint and strengthening capacity for clean energy solutions. In addition, the project will help PSE&G to start establishing commercial relationships with others in the growing hydrogen industry.

Q. Why does PSE&G need RNG on their system?

A. PSE&G has continued to innovate its energy portfolio throughout the Company's history, transitioning from synthetic gas manufactured from coal to natural gas. The inclusion of RNG is an important low carbon evolutionary step in the transition to cleaner fuels. RNG is unique in how it is a source of energy created from a traditionally environmentally unfriendly product (solid waste). As an existing part of normal human society, landfills decompose and excrete the potent greenhouse gas, methane to the atmosphere. Capturing and processing this gas significantly reduces the amount of methane being emitted and repurposes it into an energy source that is compatible with both PSE&G's existing infrastructure and customer's end use appliances. Partnering with the Middlesex County Utilities Authority benefits both parties and citizens of New Jersey. Benefits include improvement of regional air quality by reduction of reportable air contaminants, reduction of greenhouse gases compared to natural gas through the RNG production pathway, and providing a new local source of clean and reliable fuel to PSE&G customers.

PIPES Act of 2020

Q. Please describe the PIPES Act of 2020 in further detail.

A. The Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("PIPES Act of 2020") was signed into law on December 27, 2020, providing funding to the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and directing the agency to take number of regulatory actions related to, among other items, natural gas distribution systems. To improve public safety, minimize the release of natural gas from pipeline facilities and protect the environment, the Bill sets forth several requirements for natural gas distribution operators. Notably, the adequacy of inspection and maintenance plans are determined by the extent to which leak prone pipelines are addressed through replacement or remediation. Pipelines may be considered leak-prone based on material, design or past operating and maintenance history. Specifically, cast iron and unprotected steel pipelines have been identified as leak-prone materials. Furthermore, the Bill requires that regulations be implemented to ensure that risks resulting from the presence of cast iron pipelines are adequately evaluated in each operator's distribution integrity management plan.

Q. Is the proposed GSMP III Program consistent with the recommendations within the PIPES Act of 2020?

A. Yes. The proposed Program addresses the requirement to replace or remediate pipelines that are considered leak-prone based on material, design or past operating and maintenance history. The Program has been specifically designed to reduce risk associated with the continued operation of leak-prone cast iron and unprotected steel pipelines. Past operating and maintenance history has demonstrated that all cast iron and unprotected steel pipelines will eventually fail and require replacement or rehabilitation. Therefore, while the Company currently manages risks associated with its distribution systems, PSE&G still maintains the largest inventory of cast iron pipeline in the nation, and expects that the maintenance costs will continue to increase as the system ages. The Program is therefore an appropriate response to provisions within the PIPES Act as it prioritizes the replacement of leak-prone pipeline through an evaluation that considers past leak and break history. Additionally, the replacement of leak-prone pipeline will substantially reduce the release of natural gas into the atmosphere.

New Jersey Energy Master Plan and New Jersey's Global Warming Response Act

Q. What requirements for Gas Utilities are set forth by New Jersey's Energy Master Plan and Global Warming Response Act 80 X 50 Report?

A. New Jersey developed a new Energy Master Plan ("EMP") in 2019 in response to the Governor's goal of achieving 100% clean energy by 2050 and the 2020 the Global Warming Response Act (GWRA) 80 x 50 scientific report to reduce New Jersey greenhouse gas emissions 80% below 2006 levels by 2050. Strategies set forth within the EMP involve modernizing the State's energy system. For natural gas utilities, this includes prioritizing the repair or replacement of pipelines that are leak-prone to reduce methane leaks. Additionally, the GWRA 80 x 50 report recommends pilot projects be implemented to demonstrate the viability of new technologies to reduce greenhouse gas emissions from the residential and building sectors, in which the majority of emissions are from space and water heating. Further, the GWRA 80 x 50 report encourages the utilization of waste as a feedstock for renewable biogas production.

Q. Is the proposed GSMP III Program consistent with the goals and strategies described within the EMP and GWRA 80 x 50 report?

A. Yes, Strategy 5 of the EMP calls for decarbonizing and modernizing New Jersey's energy system. The Program involves the replacement of leak-prone pipelines based on the Company's hazard analysis, which is based on a predictive model that integrates leak and break history with a variety of "environmental conditions" to assign a hazard score to every segment of pipeline with a leak or break history within the Company's inventory. The output is a Hazard Index ranking that prioritizes pipeline segments based on risk associated with leaks.

The program will have a direct and substantial impact on the reduction of methane emissions from the gas distribution system. In GSMP I and II, PSE&G collaborated with the Environmental Defense Fund to employ a sub-prioritization process using advanced leak detection and quantification technology that focused on methane emissions in grids that were selected for the first 3 years of the program. It is also noteworthy that this collaboration with the EDF was highlighted in NJ's GWRA 80 x 50 report as a best-in- class initiative and one of three paths forward for natural gas utilities to reduce short-lived climate pollutants.

This sub-prioritization process will be used for grids of similar hazard in the GSMP III extension. Service line excess flow valves will be installed, which will prevent the release of methane from a service line in the event of excavation damage. Moreover, the Program will replace low pressure, leak prone cast iron pipelines with elevated pressure polyethylene pipe. Elevated pressure allows for the increased ability to use higher efficiency appliances, allowing for decreased total energy consumption. Polyethylene pipe has also been proven to be compatible with hydrogen blends, preparing for the potential introduction of a low carbon fuel source to the company's gas distribution system.

The hydrogen and RNG projects likewise align with strategy 5 of the 2019 New Jersey EMP to reduce emissions and the recommendations made under the GWRA 80 x 50 report. These projects are an important first step towards decarbonizing and modernizing New Jersey's energy system and building confidence in the use of renewable alternatives to natural gas. As stated by Governor Murphy: "Clean hydrogen has the promise to expand New Jersey's diverse clean energy portfolio. Clean hydrogen technology has the potential to improve net greenhouse gas emissions and harmful air pollutant impacts. Joining together with our regional partners will allow us to build a strong coalition for the development of clean hydrogen technology and cultivate economic growth and opportunity for New Jersey.[1]"

"Call to Action"

Q. Please describe the "Call to Action" in detail.

A. In 2011, under the direction of the then Department of Transportation ("DOT") Secretary Ray LaHood, the DOT and PHMSA called for readdressing the fitness for service of the nation's natural gas system, including the replacement of aging facilities. This is the DOT's "Call to Action," which seeks more aggressive actions on the part of pipeline operators

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[1]https://www.nj.gov/governor/news/news/562022/20220324c.shtml#:~:text=%E2%80%9CClean%20hydrogen%20technology%20also%20has,and%20harmful%20air%20pollutant%20impacts

to repair and replace infrastructure that is considered high risk. PHMSA specifically includes cast iron and unprotected steel pipe as categories of pipeline infrastructure that require repair, rehabilitation and replacement. The "Call to Action" was followed by an advisory bulletin issued by PHMSA on March 23, 2012 to owners and operators of natural gas cast iron distribution pipelines and state pipeline safety representatives. The bulletin urges operators of natural gas distribution systems to accelerate replacement of aging infrastructure in order to enhance safety, and requests state agencies to consider enhancements to cast iron replacement plans and programs. Secretary LaHood called for an evaluation of the fitness for service of the aging aspects of natural gas infrastructure and for actions to be taken to address safety risks. The "Call to Action" specifically identifies the benefits of investing in infrastructure to enhance public safety and to provide for the future integrity of the pipeline system through the use of Smart Modernization.

Q. Can you please define "Smart Modernization?"

A. The concept of Smart Modernization arises from the "Call to Action" issued by Secretary LaHood, following incidents on the United States natural gas delivery system. The intention behind Smart Modernization is to balance customer needs with risk and is not an overly aggressive approach to system risk management. It is part of the implementation of the Company's Distribution Integrity Management Plan ("DIMP") program and recognizes that the risks inherent in the system cannot be eliminated without due consideration of cost and impact on customers and the community. Smart Modernization includes the replacement and upgrading of existing mains, services, and equipment by following a methodological approach. PSE&G is proposing a responsible modernization to the natural gas distribution system capable of delivering low carbon fuels and driving significant greenhouse gas emission reductions. This planning and replacement process includes careful considerations such as:

- customer and system utilization of the existing pipe targeted for replacement
- right-sizing replacement facilities for cost effectiveness;
- prioritization of selected facilities for safety and reliability, based on the DIMP;
- maximizing the abandonment to install ratio;
- the latest technologies for system design and materials;
- environmentally favorable construction (e.g., trenchless construction where applicable);
- impact to customers;
- current and future demand needs;
- leveraging existing embedded system components that are not being replaced, e.g., uprating existing plastic systems and eliminating district regulators; and
- coordinating work with other programs, e.g., replacement of unprotected steel services under BPU requirements with water company projects, and with municipal paving projects, where applicable.

Q. Please describe the appropriate course of action under the circumstances.

A. An appropriate and operationally prudent course of action is continuing with the proposed Program for the replacement of PSE&G's cast iron and unprotected steel infrastructure. I believe that the Program being proposed represents an opportunity to achieve, in a timely manner, substantial risk reduction and other benefits through a reduction of the inventory of pipe prone to leakage. The approach proposed by the Company will allow

PSE&G to achieve efficiencies; and cost savings through large-scale replacements. PSE&G's proposed Program to address its inventory of these facilities is clearly consistent with the "Call to Action" and the PHMSA advisory bulletin.

Infrastructure Investment Program

Q. Please describe the BPU's IIP Regulations.

A. The BPU adopted the IIP regulations "to allow a utility to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to provide safe and adequate service." The regulation is intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety.

Q. Are the projects in GSMP III aligned with the IIP rules?

A. Yes. The IIP regulations cover projects that are related to safety, reliability and/or resiliency and that are non-revenue producing. The GSMP III projects are consistent with this requirement in that the IIP regulations specify replacement of utilization pressure cast iron main with elevated pressure, the removal of high risk mains according to a Company's Distribution Integrity Management Plan, and the installation of excess flow valves as examples of projects eligible for the IIP. The hydrogen demonstration project sets the foundation for the expansion of the use of hydrogen on PSEG's system in the future, adding reliability and resiliency to the system by diversifying the energy supply with a clean source that can be produced locally. Further, the RNG processing facility project will allow the Company to further diversify its energy supply with a low carbon energy source that is also locally produced, reducing greenhouse gas emissions within New Jersey.

Q. Are there minimal filing requirements associated with seeking accelerated rate recovery of infrastructure investments under the IIP rules?

A. Yes. The location of all requirements under the IIP regulations in the GSMP III filing are provided in Appendix 1 to the Petition. I will address the requirements related to program eligibility, capital expenditures, selection criteria, and reporting. Mr. Swetz will address requirements associated with cost recovery.

Q. Is the Company proposing to maintain base capital expenditures on similar projects as proposed for the GSMP III Program?

A. Yes. The Company commits to spending at least 10 percent of the capital expenditures proposed for the GSMP III Program to be recovered in a base rate proceeding. See Schedule WEM-GSMPIII-2 for the annual breakdown.

Q. Is the Company proposing annual baseline spending levels over the life of the Program?

A. Yes. Please see Schedule WEM-GSMPIII-2 for the annual baseline spending levels over the GSMP III period.

Q. What is the justification for the annual baseline budget spending levels?

A. The annual baseline spending levels proposed in Schedule WEM-GSMPIII-2 are the Company's projected capital budget as recently approved in the Infrastructure Advancement Program (IAP).

Q. Is the Company proposing any limit to variations in annual spending?

A. Yes. Consistent with the proposed IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the Program. The Company will seek Board approval for any annual variances that are expected to be greater than 10 percent.

Q. Has the Company included its actual capital expenditures over the past five years and projected capital expenditures throughout the length of the proposed Program by major category?

A. Yes. Please see Schedule WEM-GSMPIII-3 for the actual capital expenditures by major category from 2017 through 2022 and Schedule WEM-GSMPIII-2 for the projected capital expenditures by major category from 2023 through 2027.

Q. Has an engineering evaluation been done to determine the projects, in-service dates, costs and benefits of the proposed Program?

A. Yes. An engineering evaluation report has been developed for the main and service Replacement Subprogram; please see Schedule WEM-GSMPIII-6. The engineering evaluation report details the projects proposed for the Replacement Subprogram, how and why they were selected, the forecasted capital expenditures, the cost estimate, including how those cost estimates were developed, and the benefits of the Replacement Subprogram. Please see Schedule WEM-GSMPIII-7 for the engineering evaluation report for the proposed hydrogen project. This engineering evaluation report details the project proposed, how and why the site was selected, and the cost estimate, including how those cost estimates were developed. Please see Schedule WEM-GSMPIII-8 for the engineering evaluation report related to the proposed RNG project. This engineering evaluation report details the project proposed, site-specific details, and the cost estimate, including how those cost estimates were developed. Additionally, cost benefit analyses have been developed for the three different programs within GSMP III by West Monroe.

Q. Have you developed an annual budget for the GSMP III Program?

A. Yes. Please see Schedule WEM-GSMPIII-4 for the monthly and annual capital expenditures for the Program. As shown in Schedule WEM-GSMPIII-4, the maximum capital expenditure dollar amount the Company seeks to recover through the Program is $2.54 billion.

Q. Is the Company proposing any reporting requirements associated with GSMP III?

A. Yes. Consistent with IIP regulations and the current GSMP II Program, the Company is proposing semi-annual status reports on the Program. The reporting requirements are detailed later in my testimony.

PSE&G Inventory and System Profile

Q. Are the materials that make up PSE&G's distribution system the types of materials you would anticipate in a system with its legacy and vintage?

A. Yes. A significant portion of PSE&G's system was installed in the first half of the 20th century when the primary material used for distribution main pipe was cast iron, and the primary material used for services was unprotected steel. There was a transition to unprotected steel materials for main in the 1950's. Cathodic protection of steel mains became widespread in the 1960's. In the 1970's there was a transition from steel to plastic materials for mains and services except for large diameter and elevated pressure installations that continued to rely on protected steel. Other factors that contribute to the system's uniqueness is the fact that the system originated in the manufactured gas era; contains a large variety of pipe materials and sizes; is subject to weather extremes; and is located in a densely populated area.

Q. Based on these distinguishing system factors, do you have any concerns with the age, materials, weather extremes and population density that impact PSE&G's distribution system?

A. New Jersey is located in the Northeastern and part of the Middle Atlantic regions of the United States. As a result, the climate and geography could adversely affect pipe integrity. Relevant factors include poorly drained soils, large temperature variations, and conditions favorable for frost heave, which is when soil expands and contracts due to freezing and thawing.

PSE&G currently serves nearly three quarters of New Jersey's population in a service area consisting of a 2,400-square-mile diagonal corridor across the state from Bergen to Gloucester Counties. PSE&G is New Jersey's largest provider of gas service, serving over 1.9 million customers in more than 300 urban, suburban, and rural communities, including New Jersey's three largest cities. New Jersey is the fourth-smallest state, but is the 11th-most populous and the most densely populated of the 50 United States.

PSE&G cannot control the weather or population density in its franchise area, and pipe age alone is not a primary factor for concern. Rather my concern is with the material types that were installed prior to 1960. PSE&G's analysis has shown that cast iron and unprotected steel typically exhibit higher leakage rates than post-1960 construction materials. PSE&G has managed pipe replacement through various means, including targeted replacement, under the Capital Infrastructure Investment Programs ("CIP I" and "CIP II"), Energy Strong, GSMP I, and GSMP II, which has resulted in removal of approximately 54% of the cast iron and unprotected steel main in PSE&G's system. Nonetheless, a significant amount of replacement work remains.

Q. Are there any concerns with a gas system distribution inventory with this age profile?

A. Yes. As discussed in my testimony, generally, the greatest concerns are associated with facilities installed prior to 1960. Pre-1960 materials constitute 19% of PSE&G's mains and 14% of its services, yet account for approximately 70% of the distribution system leaks, excluding leaks caused by third-party damage.

As of the end of 2021, PSE&G operates 2,921 miles of cast iron main, 850 miles of unprotected steel main, and approximately 84,000 unprotected steel services. Continued corrosion is likely to increase the leak rates for older materials due to the time function of the corrosion process. The primary problems presented by cast iron and unprotected steel are detailed in the engineering report and are summarized below.

Cast iron pipe has little inherent flexibility and is susceptible to leakage and breakage due to ground movement, which is most frequently caused by frost heave. Ground movement creates an excessive bending stress in the pipe which may cause it to leak at a joint connection or fail in a circumferential break and lead to a relatively large gas leak at the point of failure. Cast iron pipe sizes 12 inches and below are particularly susceptible to unpredictable breaks.

In PSE&G's system, cast iron joint leaks occur at a rate 5 to 6 times greater than cast-iron breaks. Larger size cast-iron pipes are more susceptible to joint leaks than breaks.

The primary problem encountered with unprotected steel pipe is corrosion that will develop leaks over time. Without a cathodic protection system, the steel pipe deteriorates due to contact with moisture present in the soil. The rate of corrosion varies depending on a number of characteristics of the soil, including moisture and pH. Uncontrolled corrosion will ultimately result in numerous, relatively small gas leaks.

Over-time metal loss will increase in size and location, these small leaks multiply and can grow to the point where they threaten the integrity of the pipe. In general the deterioration of unprotected steel pipe accelerates as it ages.

Q. How does PSE&G's inventory of cast iron and unprotected steel compare to other gas distribution systems in the United States?

A. PSE&G's distribution system contains a large inventory of cast iron and unprotected steel. At year-end 2021, there were 2,921 miles of cast iron pipe comprising 16% of its main system and 2,004 miles of unprotected steel main and services comprising 6% of the Company's distribution system. Nationally, PSE&G has the distinction of being ranked number one based on total miles of cast iron main and number eight in total miles of unprotected steel main and services.

Q. How does PSE&G's gas system compare to other gas operators within the state of New Jersey?

A. There are numerous differences between the gas systems of the respective utilities serving New Jersey. My response will specifically focus on the amount of cast iron and unprotected steel each of the respective utilities has in their distribution system inventory.

Referring to Exhibit 1.1, PSE&G's 2,921 miles of cast iron is twelve times greater than the cast iron in the networks of the other three New Jersey gas distribution companies combined. In addition, cast iron constitutes 16 percent of PSE&G's 18,173 mile main system, while the next largest cast iron system in a New Jersey utility is 9 percent of a much smaller 3,275 mile main system. The other two gas utilities have no cast iron in their distribution network.

Exhibit 1.1

New Jersey Utilities Cast Iron Gas Distribution Systems

Name	Total Miles of Main	Miles of Cast Iron Main	CI % of Total Main
PUBLIC SERVICE ELECTRIC & GAS CO	18,173	2,921	16%
ELIZABETHTOWN GAS CO	3,277	235	7%
NEW JERSEY NATURAL GAS CO	7,444	0	0%
SOUTH JERSEY GAS CO	6,830	0	0%

Source: Pipeline and Hazardous Materials Safety Administration
2021 Annual Report for Gas Distribution System Form F7100.1-1

Referring to Exhibit 1.2, PSE&G's 2,004 miles of unprotected steel is over 5 times greater than the combined amount of unprotected steel in the systems of the other New Jersey gas distribution companies.

Exhibit 1.2

New Jersey Utilities Unprotected Steel Main and Services Gas Distribution Systems

Name	Total Miles of Mains and Services	Miles of Unprotected Steel Main and Services	Unprotected Steel % of Total Main and Services
PUBLIC SERVICE ELECTRIC & GAS CO	35,556	2,004	6%
SOUTH JERSEY GAS CO	13,094	371	3%
ELIZABETHTOWN GAS CO	5,552	18	0%
NEW JERSEY NATURAL GAS CO	15,617	1	0%

Source: Pipeline and Hazardous Materials Safety Administration
2021 Annual Report for Gas Distribution System Form F7100.1-2

Q. What challenges does this infrastructure present?

PSE&G faces many of the same challenges as other natural gas utilities in New Jersey and across the United States that have cast iron and unprotected steel infrastructure, even though the situation for each gas distribution company is specific and unique to its system. The presence of aging cast iron and unprotected steel pipe in the natural gas infrastructure has received considerable national attention due to environmental concerns over greenhouse gas ("GHG") emissions and safety concerns associated with aging infrastructure. While utilities have long focused on managing the integrity of these elements of their infrastructure, industry members, safety regulators and other stakeholders are placing significant attention on addressing potential risks associated with aging infrastructure due to the environmental and safety impacts associated with their operation.

Managing the Gas Distribution System

Q. Does PSE&G currently operate and manage a system that can be deemed safe by industry standards?

A. Yes. In my opinion, PSE&G's operation and management of its distribution system currently provides a level of safety and of leak management that compares favorably to industry standards, including other utilities with large amounts of Cast Iron/Unprotected Steel ("CI/US") in their systems. PSE&G's leak rate for services is 0.31 leaks per 100 services, which is below (i.e., better than) the national average (all gas distribution companies reporting to PHMSA) of 0.46 leaks per 100 services. PSE&G's leak rate for mains of 0.14 leaks per mile is higher (i.e., worse than) the national average of 0.05 main leaks per mile. In fact the Company's main leak rate is almost three times the national average, largely influenced by the inventory of cast iron main relative to the newer materials that make up the national network.

Q. Please describe PSE&G's operational goals and objectives pertaining to the management of its gas infrastructure system.

A. The safe and reliable operation of PSE&G's gas distribution system is the Company's primary operational goal. Such operation is essential to the health and well-being of the customers, residents and businesses in the communities the Company serves, and of the employees who are responsible for operating the system. Moreover, the Company seeks to achieve the safe and reliable operation of its system in a cost- effective and efficient manner. There are a variety of operational requirements associated with achieving this goal, including the ongoing repair and maintenance of existing facilities, the engineering, planning and construction of new facilities to provide for growth and increased operating flexibility, and the need to rehabilitate or replace existing facilities to meet enhanced safety mandates or to address aging infrastructure concerns. In all aspects of PSE&G's operations, the Company's objective is to continuously improve and maintain top performance in the industry on a national basis for gas emergency response rate, gas leak reports per mile, open leaks and damages per 1,000 locate requests.

Q. Could you please comment on the resources required by the Company to carry out its distribution integrity management functions?

A. PSE&G requires considerable capital and staffing resources to manage the integrity of its distribution system, reflecting both the importance of and challenges associated with its commitment to safety. In terms of staffing, the Gas Delivery business unit includes more than 2,600 PSE&G employees who perform operational activities and planned construction activities throughout PSE&G's New Jersey service territory. Gas Delivery employees are supported by field offices located throughout the service territory, as well as the Company's investment in vehicles and equipment necessary to address all needs and operating circumstances. Additionally, a portion of the Asset Management and Planning staff is directly responsible for the DIMP and provides important management, engineering, construction, and financial oversight for the business unit.

Q. What is entailed in operating and maintaining a distribution system like PSE&G's?

A. Although the federal and state pipeline safety regulations establish minimum safety standards, operating and maintaining the integrity of assets such as cast iron and unprotected steel pipe necessitates the effective implementation of a robust operating and maintenance ("O&M") plan of policies, processes and procedures. The breadth and depth of PSE&G's plan is expansive because of the diversity of pipe materials (cast iron, bare steel, coated unprotected steel, protected steel, polyethylene and copper) and operating pressures (utilization, 15 psig, 60 psig and 120 psig and above). The prevention and mitigation activities in the plan include, but are not limited to:

- instrument surveys for leaks and corrosion;
- patrolling for excavation activities;
- inspection of exposed pipe and other facilities;
- preventative maintenance;
- repair, rehabilitation or replacement;
- inside safety inspections;
- public awareness programs;
- damage prevention programs; and
- emergency response.

The frequency of PSE&G's scheduled surveys, inspections, patrols and maintenance range from daily to once every 10 years. Exhibit 1.3 describes the various inspections and their frequency.

Exhibit 1.3

Frequency of Surveys and Inspections

Description	Inspection Frequency
Construction Inspection	Daily as needed
Corrosion Control – Rectifiers	2 months
Corrosion Control - Regular Structures	1 year
Corrosion Control - Separately Protected Services	10 years
Corrosion control - Short Structures	10 years
Leaks - Grade 2 Leak Re-checks	6 months
Leaks - Grade 3 Leak Re-checks	15 months
Mains - Exposed Main Inspection	1 year after install, every 3 years after
Mains - High Pressure/Transmission Patrol	2 per month
Mains - Leak Survey – Leakmobile	1 year
Mains - Leak Survey - Manhole/Business	1 year
Mains - Leak Survey - Winter Patrol	Annually as needed
Meter Set Inspection	3 years
Public Building Inspect	3 years
District Regulators	1 year
Services - Walking Survey	3 years
Valves – Distribution	1 year after installation
Valves - Line Valves	1 year
Valves - Separation Valves	1 year

Q. How does PSE&G perform in addressing leaks in its current system?

A. PSE&G currently performs well with regard to addressing leaks in its system. Nationally, compared to companies that have large amounts of cast iron and unprotected steel in their distribution systems, PSE&G's results are better than the average of all companies in both main leak rates and service leak rates. When compared to the ten companies that have the most miles of cast iron, PSE&G is the second best in terms of having the least number of main leaks per mile in 2021. (PHMSA report data: 2021 F7100.1-1). PSE&G responds to over 75,000 gas emergency calls on an annual basis at a rate of 99.9% within one hour. This ranks within the top decile of peer companies. Since 2016, PSE&G

has substantially reduced its average open leak inventory (61% reduction 2016-2022); the focus on closing out open leaks has enabled the Company to maintain a relatively low baseline.

Q. Please describe PSE&G's current approach to gas distribution pipe replacement.

A. The overall approach of PSE&G's distribution replacement is to minimize risk to the public and employees by effectively understanding the condition of the assets and their rates of failure. This enables the Company to manage replacement of assets to avoid sudden widespread failure within any asset class. Replacement of significant asset classes is as follows:

- Elevated Pressure Cast Iron, Utilization Pressure Cast Iron, and Unprotected Steel are replaced or rehabilitated at a rate consistent with managing the leak/mile rate for each respective asset class to stay within the established upper performance limit for each material; and
- Coated and Protected Steel Main is subjected to ongoing monitoring and remedial action under the requirements of 49 CFR Part 192 Subpart I. There is no significant leakage of PSE&G's coated cathodically protected steel main system relative to unprotected steel main, and to date there is no replacement program for this asset class.

Similarly, there is no significant leakage of PSE&G's plastic main system; therefore, no current replacement plan exists for this asset class.

Q. Please describe the work prioritization process you are proposing for GSMP III.

A. For Elevated Pressure Cast Iron, Utilization Pressure Cast Iron, and Unprotected Steel, individual main segments are identified for replacement through a PSE&G prioritization ranking methodology for main segments referred to as the Hazard Index. The Hazard Index is based on a predictive model that integrates leak history and cast iron break history with a variety of characteristics referred to as "environmental conditions", while also taking into account asset information (e.g., pipe diameter and operating pressure).

Q. Has PSE&G been considering the prioritization of replacement work for some time?

A. Yes. The Company periodically assesses its distribution assets to determine if specific approaches need to be developed to target the replacement of PSE&G's riskiest gas assets. Specifically, in accordance with this review, the following programs were designed to replace the following assets:

• 8" and smaller - 15 psig and 60 psig cast iron mains;

• 10" and 12" - 60 psig cast iron mains; and

• 3" UP cast iron

PSE&G will replace unprotected steel services when any of the following conditions are met:

- after unprotected steel services reach their point of failure by exhibiting a leak;
- if more than 20% of the unprotected services in a defined area have ever leaked; then all of the services in the defined area are replaced (as required by the New Jersey Administrative Code Section 14:7-1.20);
- in conjunction with the replacement main program;
- ahead of road reconstruction projects; and
- or for other reasons as determined by the PSE&G Asset Management Group.

Q. Please discuss the approaches that gas distribution operators utilize to manage cast iron and unprotected steel pipe systems.

A. One method that gas distribution companies use to manage aging cast iron and unprotected steel pipe is to repair leaks. While this is an effective short-term approach, it is not a long-term solution that provides a proactive, systematic improvement, such as can be achieved by replacing cast iron and unprotected steel pipe with modern pipe materials.

The preferred method of managing cast iron and unprotected steel pipe is to replace these materials using a combination of three replacement approaches: targeted replacement, work in conjunction with the replacement of other utilities, and program replacement:

Targeted Replacement - The targeted or condition approach for identification and retirement of cast iron and unprotected steel is based on an evaluation of several factors such as: maintenance history, soil conditions, and risks inherent in the pipe segments' characteristics and locations.

Work in Conjunction with Replacement of Other Utilities - This approach entails the removal or replacement of pipes in conjunction with other utility, government or municipal agency work to accommodate work projects such as road improvements and water infrastructure projects. It is beneficial to all parties involved if the removal and replacement of pipes can be done in conjunction with other projects, especially to minimize public inconvenience and to avoid the duplication of efforts and cost.

Program Replacement - In terms of planned replacement strategies, several gas distribution operators have approached their state regulators and obtained funding approval to systematically replace all of the cast-iron or unprotected steel and other higher risk materials in their system on an accelerated basis. Program Replacement provides for a long-term, proactive, systematic improvement of a company's distribution network, continuous removal of risk from unpredictable failure, and the reduction of greenhouse gases.

Q. Even though PSE&G has managed the integrity of its distribution system over the years, do you believe that there are challenges in the near future?

A. Yes. As discussed above, PSE&G's distribution system contains a large inventory of cast iron and unprotected steel that generates approximately 70% of the system leaks on an annual basis. Annual replacement of this inventory is one of the primary methods in the leak management process to reduce risk and to control leak rates. However, an increase in pipe deterioration rates may be of a magnitude that requires substantial, additional resources and extended time to address.

Proposed Program

Q. Please describe the proposed Program.

A. The proposed Program continues PSE&G's Gas System Modernization and builds upon the strategic vision for the system of the future and ensures an appropriate progression to accomplish the long-term goals to systematically replace cast iron and unprotected steel pipe and increase public safety, operational efficiencies, and environmental protection. It is a three-year program and approximately 380 miles of mains will be replaced each year. The summary of the Program is illustrated in Exhibit 1.4.

Exhibit 1.4

Program Scope Summary

3 YEAR PROGRAM	**Total**	**2024**	**2025**	**2026**
Description				
EP Cast Iron Main (Miles)	**50**	15	17	17
UP Cast Iron Main (Miles)	**810**	249	281	281
Unprotected Steel Main (Miles)	**200**	61	69	69
Cathodically Protected Steel and Plastic Main (Miles)	**80**	25	28	28
District Regulators Abandoned	**210**	30	80	100
Service Replacements	**92,130**	28,286	31,922	31,922
Relocate Inside Meter Set	**49,178**	16,393	16,393	16,393
Total Miles	**1,140**	**350**	**395**	**395**

Note: Table does not include the hydrogen demonstration project or RNG project

UPCI Replacement

Q. Explain the proposed UPCI replacement in more detail.

A. The proposed UPCI replacement will follow the same grid-based replacement method used in GSMP I and II to replace UPCI mains and convert the UP system to elevated pressure (the majority of the Program). This will reduce the risks of CI pipe and take advantage of economic efficiencies to reduce construction costs. This approach ensures that high-risk segments will continue to be replaced, while gaining the efficiencies and benefits of larger zone replacements such as economic opportunities in mobilization, material, and labor negotiations.

EPCI Replacement

Q. Explain the proposed EPCI replacement in more detail.

A. EPCI is a critical integral component of the PSE&G distribution system. It is part of the trunk system that carries high volumes of gas across the territory to branch connections that supply the customers. It is present in many of the same grids as the UPCI and replacement concurrent with the UPCI upgrade provides numerous efficiencies and benefits. EPCI, similar to UPCI pipe, is leak-prone. At larger diameters and higher operating pressures, leaks on EPCI mains will release more gas than leaks on UPCI mains. This increases the risk associated with an EPCI leak. If EPCI is not replaced in a GSMP grid, then there is the need to make numerous connections to the EPCI main as the GSMP main replacements are done. The new plastic mains are tied-into the old EPCI main requiring numerous stop offs, cutouts and taps, and fittings all becoming new points for potential leaks. Then when the EPCI is replaced at a later date, there again are numerous stop offs, cutouts and threaded taps, and fittings all requiring additional excavations and inefficiencies when returning to the same locations where GSMP work was completed. When EPCI replacement is done concurrent with GSMP UPCI replacement, a new large diameter welded steel main with welded fittings and connections is installed parallel to the EPCI and greatly facilitates the upgrade of the UP system to the new higher pressure system. Municipal relations are also improved as no higher risk cast iron is left behind after the system is upgraded. Efficiencies in mobilization and paving activities are gained when EPCI and UPCI projects are completed simultaneously. Additionally, no further roadway excavation, which is an inconvenience for the community, is required after the upgrades are completed. The program would eliminate approximately 12% of all elevated pressure cast iron.

Unprotected Steel Replacement

Q. Explain the proposed Unprotected Steel replacement in more detail.

A. A targeted replacement would be used to replace the unprotected steel mains with plastic and cathodically protected steel (a much smaller part of the Program). These mains are more geographically dispersed than the UPCI and do not lend themselves to a larger grid-based replacement.

Cathodically Protected Steel and Plastic Main Replacement

Q. Will any protected steel or plastic main be replaced in this program?

A. Yes. Our experiences in GSMP I and GSMP II have shown that certain segments of cathodically protected steel and polyethylene ("PE") main that are in the UP system are required to be replaced as part of a large grid based system conversion for economic and logistical reasons. This is approximately 7% of the overall program.

Elevating Pressure

Q. Besides the replacement of legacy materials, what other improvements will be made to the system?

A. The utilization pressure portions of the system will be upgraded to higher pressure mains and services. The new elevated pressure will vary depending upon its location. An elevated pressure system has many benefits that will be discussed further in the testimony.

Q. Will the new system involve any foregone functionality?

A. Eliminating the utilization pressure system and high-risk pipe will not result in any foregone system functionality. Replacing the UPCI and unprotected steel with PE pipe will reduce operating and maintenance cost. PSE&G delivers and has delivered natural gas to over 70% of its customers at elevated pressure for many years.

Moving Inside Meter Sets

Q. Explain in more detail the benefits of moving inside meter sets to the outside.

A. Outside meter sets offer numerous benefits. Outside gas meters enable quick and ready access for shut off in the event of an emergency, for both Company and emergency response personnel. Moving meter sets to the outside also improves access for meter inspection and leak surveys, as well as meter readers. Setting the meter outside reduces the potential for gas leaks within buildings. Further, it also reduces the potential theft of gas due to visibility of the meter location.

Hydrogen Project

Q. Explain what a hydrogen power-to-gas facility is in more detail.

A. A power to gas facility involves several components that can convert electricity and water into hydrogen gas, which can be blended into the natural gas system as a low carbon fuel. The primary component is the electrolyzer, which converts supplied electricity and water into pure hydrogen gas and oxygen. The system requires two major inputs: electricity and water. Electricity can be generated on site or connected to the grid. Water is typically supplied from the nearby municipal water supply or a well. The generated oxygen can be released to atmosphere or stored for other uses. The generated hydrogen gas can then be compressed and stored in a tank for usage later or directly blended into the natural gas system. The blending occurs through a pipe skid that mixes the hydrogen into the outgoing gas stream. The blend percentage is monitored via instrumentation to ensure it does not exceed an established threshold.

Q. Can you explain PSE&G's proposed hydrogen project in more detail?

A. A selection process and engineering study was performed by an external engineering firm, Burns & McDonnell as the basis for this specific site design and can be found in Schedule WEM-GSMPIII-7. This particular site will consist of a one MW rated electrolyzer that will supply the Central 60 psig gas distribution system with a supply of up to 2% hydrogen. The electrolyzer will produce 40 lbs (2 MMBtu) of hydrogen per hour. The project will be located at a site at the existing Central M&R Station in Edison, NJ and will serve approximately 40,000 residential, commercial, and industrial customers. The facility will be connected directly to the electric distribution grid and supplied by 100% clean electricity through a Power Purchase Agreement (PPA). The site will also contain a storage tank fed by a compressor to allow supplementing the blend during the higher gas demand days of the year. Considerations have also been made during the site selection process for future on-site dedicated solar to feed this facility's full capacity needs thereby removing the need for a PPA and making the project 100% green hydrogen. Expansion considerations have been included in the layout of the demonstration facility to more easily enable higher hydrogen blend percentages in the future. The site will be connected to municipal water supply which will require a feed of 56 gallons per hour for the initial blend. Wastewater will then be expelled to nearby municipal wastewater systems at 20 gallons per hour.

Q. You mentioned the facility will blend up to 2% hydrogen as part of the initial build, why was this percentage selected?

A. A blend of up to 2% was selected for this project for several reasons. This level of blend provides the Company with a starting point that is acceptable by current industry knowledge while realizing the various benefits of the project including learnings to support further hydrogen integration into the gas distribution system. Total costs were also a driver to ensure a reasonable level of investment for a proof of concept project, while considering scalability options in the future.

Q. How will the hydrogen that is blended into the gas distribution system be considered from a value perspective to customers?

A. PSE&G plans to value the blended hydrogen on a dollar per MMBtu basis aligned with a Transco Leidy index price for natural gas that it displaces. In this way, PSE&G will consider the hydrogen as a replacement for typical natural gas purchases that supply BGSS-RSG customers. The estimated revenue is included in Schedule WEM-GSMPIII-5.

Q. Are there any adverse impacts to safety, customers, or the existing facilities that are expected from a hydrogen blend?

A. No, PSE&G researched various studies when selecting the appropriate location for this demonstration project as well as the selected blend. The candidate sites were specifically selected where there is no presence of cast iron in the system, a material that is more prone to issues such as leakage when introducing hydrogen. For the system that will be fed by this demonstration project, a NYSEARCH hydrogen blending gap analysis, which has analyzed impacts to safety, metering, gas quality, and end-use systems, was considered. These studies point to various blend thresholds that are acceptable for minimal impact to downstream infrastructure. PSE&G's elected blend percentage is well below these thresholds.

Q. Is PSE&G actively engaged in other research & development ("R&D") projects related to hydrogen?

A. In recent years, PSE&G sponsored a number of hydrogen related R&D projects through two industry associations in an effort to establish strategic planning for decarbonization and to validate safety for future implementation. PSE&G has been actively participating in seven projects coordinated under NYSEARCH, a subsidiary of Northeast Gas Association responsible for managing R&D projects for member utilities. PSE&G also partnered with the

Gas Technology Institute ("GTI") and other sponsoring utilities on a Cooperative Research and Development Agreement ("CRADA") project to study the effects of hydrogen blending. This project is also funded by other sources such as the Department of Energy, multiple national laboratories, and other industry partners. Participation will help to strengthen PSE&G's position in the hydrogen industry and ability to deploy this technology on a larger scale.

Renewable Natural Gas ("RNG") Project

Q. Explain what a RNG facility is in more detail.

A. A renewable natural gas ("RNG") facility involves several components that receive biogas from an existing source such as a landfill or other biomass source and then process and condition the gas into a pipeline quality product that can be used as an alternative to traditional natural gas. Incoming biogas has moisture, hydrogen sulfide, carbon dioxide and other trace elements that are removed in the conditioning process. A chromatograph and other sensors monitor the quality of the product being produced and are used as a means of preventing off-specification product from entering any downstream applications. The resulting renewable natural gas can be compressed and stored, used on site to create electricity or injected into an existing natural gas distribution system. A RNG plant also typically has a metering and pressure regulation component after conditioning to measure throughput and to maintain a constant pressure required for final delivery of the product into the distribution system.

Q. Can you explain PSE&G's proposed RNG facility in more detail?

A. The Middlesex County Utilities Authority ("MCUA") currently uses minimally cleaned biogas to power an existing generation facility at its Sayreville wastewater treatment plant. The biogas is sourced from the MCUA's East Brunswick landfill, captured, compressed and transported via pipeline to the Sayreville facility. The existing cogeneration facility is nearing end of life and MCUA and PSE&G have agreed to a utility-to-utility contractual sharing arrangement where the MCUA's constant supply of biogas will be processed in a RNG facility to be constructed and owned by PSE&G and will be injected into PSE&G's natural gas distribution network. An engineering study was performed by Burns & McDonnell as the basis for this specific site design and can be found in Schedule WEM-GSMPIII-8. The facility will consist of a series of gas stream conditioning components including H_2S reducers, Pressure Swing Adsorption (PSA) System, de-oxygenation catalyst and thermal oxidizer, which will remove impurities from the biogas, allowing for approximately 1,000,000 MMBTU per year of pipeline-quality RNG that will be injected into PSE&G's existing Central 35 psig gas distribution system. The facility will have approximately 93% uptime and will be able to provide a constant, clean, reliable and low-carbon form of supply to PSE&G's natural gas customers. The system will have appropriate sensing equipment, pressure regulating equipment, slam-shut capability and an on-site enclosed flare to protect the downstream system. In the event of a power supply disruption, the site will also have a standby power generator to continue operation of critical systems.

Q. Please tell me about the proposed plan that is being considered between PSE&G and the MCUA?

A. PSE&G and the MCUA ("the Parties") executed a Memorandum of Understanding (MOU) which, provides, among other things that for a period of up to 8 months the Parties will negotiate on an exclusive basis for the completion of agreements for the design, development and construction of the facilities required for the processing of MCUA's landfill gas and interconnection and supply of RNG into PSE&G's distribution system. In the MOU, the

Parties have agreed to a non-binding framework to negotiate definitive agreements to address, among other things, gas supply, custody transfer, environmental attribute considerations and revenue sharing that will mutually benefit both Parties and their respective customers. The definitive agreements must be acceptable to each of the Parties and will be conditioned upon regulatory approvals. The definitive agreements will contain terms that require the MCUA to provide landfill gas to PSE&G at no cost, and that address how the revenue generated by the RNG will be shared by the Parties. The costs for the sale and management of environmental attributes generated by the RNG are netted against the revenue. The net revenue from RNG and environmental attribute sales thereafter will be split concurrently with 67% allocated to PSE&G and 33% allocated to the MCUA. PSE&G plans to value the RNG sales on a dollar per MMBtu basis aligned with a Transco Leidy index price for natural gas that it displaces. In this way, PSE&G will consider the RNG as a replacement for typical natural gas purchases that supply BGSS-RSG customers. The estimated revenue is included in Schedule WEM-GSMPIII-5. In addition, please reference the cost benefit analysis prepared by West Monroe for further details.

Q. Are there any adverse impacts to safety, customers, or the existing facilities that are expected from an RNG facility?

A. No, PSE&G's proposed design has taken into account environmental impact studies and follows best practices for the construction and maintenance of an RNG facility. The RNG created from the biogas stream will meet PSE&G's tariff specifications and is considered analogous to traditional natural gas which will not impact customer end use. The facility will also utilize sampling and instrumentation which will prevent gas not meeting specification from entering the distribution system. The RNG being created will also be properly odorized at the station to ensure it can be detected similarly to traditional natural gas.

Duration – Proposal for 3 year program

Q. How was the basis for the proposed replacement period determined?

A. GSMP I and II have established the foundation and momentum for the overall long term program. The three-year duration of the proposed extension helps to maintain the momentum of work created by the prior programs in terms of staffing levels, contractor resources, and municipality coordination. PSEG's strategic vision – to enhance efficiency and effectiveness of its Replacement Subprogram and to accelerate benefits – has also been factored into the decision regarding the Program duration.

Q. You suggested that the Company implements a plan that involves steady, long-term modernization that would last beyond the proposed 3 year Program. Can you explain why the proposed Program is only for three years?

A. Given the age and make-up of the Company's gas infrastructure, the program to modernize the gas distribution system would take approximately fourteen additional years at the current GSMP II rate of replacement, and nine years assuming a modernization plan consistent with the Program being proposed in my testimony for GSMP III. Under the proposed Program, we estimate that the Company's inventory of high risk infrastructure will be decreased by approximately 31 percent. A three-year program will enable the Board and Company to periodically review and evaluate the Program. Prior to the expiration of the Program, the Company anticipates working with the Board to further develop and refine a plan that would continue to appropriately address the modernization needs based upon program experience to date, and technologies, techniques, and circumstances at that time.

Q. How would the Company proceed if the Replacement Subprogram ended in three years; in other words, without extending the replacement program for additional years?

A. If this replacement program is not extended beyond the initial three years proposed herein or is not extended on a time-frame that would allow continuation of work, this replacement program would involve an additional six months of a variety of work to close out the third phase of GSMP . Such work would continue into the first six months of a fourth year, i.e., assuming a January 2024 start, through June 30, 2027.

Cost of the Proposed Program

Q. Please provide a description of the estimated cost of the proposed Program.

A. PSE&G estimates the total investment for the replacement component to be approximately $2.39 billion. The estimated amount is comprised of approximately $1.75 billion for the replacement of mains, $553 million for the replacement of associated unprotected steel services, $8 million for the abandonment of district regulators associated with the main replacements, and $79 million for inside meter set relocations, not including the cost of the meters. These estimates are based on the Company's cost experience over the last five or more years, adjusted for inflation and modified to account for the overall average pipe size. In addition, the hydrogen demonstration project is estimated at $29 million and the RNG project is estimated at $123 million. Please see Schedule WEM-GSMPIII-4 for the proposed monthly cash flows for the Program.

The Company commits to maintaining base capital expenditures on projects similar to those described above. These capital expenditures are provided in Schedule WEM-GSMPIII-2 and are at least 10 percent of the overall Program capital expenditures. The spending the Company is proposing through this Program is incremental to this base capital spending.

Q. Why is this an advantageous time economically to extend and accelerate PSE&G's gas system modernization efforts?

A. PSE&G has an important opportunity to extend this Program now as it affords the opportunity for additional job creation and economic stimulus, as well as more rapid reduction of greenhouse gas emissions. Additionally, the proposed Program extension would continue to build on the successes of GSMP to date. As a result, now is the time to invest in this important modernization program.

Q. What is the least cost approach?

A. The least cost option results from a combination of an effectively run system modernization plan that is initiated and carried out without interruption and accumulates incidental O&M savings as the CI and US pipe is replaced or rehabilitated. If the System Modernization Plan is ramped-up and ramped-down after each program extension, those delays can result in significant, and unnecessary, cost increases in the total system modernization cost. These costs result from the following factors:

- Contractors are unable to plan into future with regards to labor and equipment and will reflect this risk with a higher unit price bid;
- The Company will be required to recruit, hire and train new employees to accommodate expanded workload, which will result in additional labor costs;
- The Company will be required to perform engineering, obtain permits, procure materials, and execute contracts on an expedited basis that may result in inefficiencies and reduced program management effectiveness;
- The ability to effectively and efficiently ramp-up may be delayed based on reduced contractor labor and equipment availability due to other utility main and service

replacement programs, resulting in scheduling delays;

- Contractors are required to provide operator qualified and certified labor resources and have to invest in these resources. Ramp-up and down situations may result in the loss of these resources, resulting in a loss of experience;
- Contracts with shorter time horizons reduce the opportunities for overall cost savings;
- Conflicts with municipal and other utilities due to scheduling and work moratoriums, causing delays and overall increased costs; and
- Incurring higher overall costs to re-staff and train employees

Q. Is PSE&G proposing a cost recovery mechanism for the Program?

A. Yes. Mr. Swetz's testimony explains the cost recovery mechanism proposed by the Company. The cost recovery mechanism is an essential component of the Program. As explained in Mr. Swetz's testimony, the cost recovery mechanism facilitates the Company's investments in this important program by enabling the Company to raise necessary capital in an efficient manner.

Q. How were PSE&G's estimates of capital cost developed for the Replacement Program?

A. The estimates of capital cost were developed by the Company at the unit cost level and include the Company's experience with stimulus-related programs completed and/or currently being performed, such as CIP I and CIP II, Energy Strong I and Energy Strong II, and GSMP I and GSMP II. The Company believes that the proposed three year program is within its execution capability, using internal and contract field operation forces. The Company has been involved in these programs continuously since 2009 and has proven its ability to complete the work in a timely fashion. Moreover, during the GSMP II Program, the Company has proven its ability to complete work at a further accelerated pace when compared to past replacement programs.

The foundation and summary of the Program is illustrated in Exhibit 1.3. The derived unit costs were applied to the estimated quantities of main, services and other replacements envisioned in the program. Certain classes of pipe were further disaggregated to compute unit level cost differences. For example, EPCI was estimated on the basis of 12” and larger pipe size EP type main replacements along with associated services. UPCI was estimated based on a different distribution of pipe sizes for UP main replacements, associated services, associated main uprates, and district regulators to be abandoned. Unprotected steel, protected steel, and plastic were estimated on the basis of these main types along with associated services. Meter relocation costs were estimated separately from a unit cost to perform meter set relocates. The unit costs for main replacement by type and meter relocations were applied to expected quantities per year for the program adjusted for an annual inflation rate of 3%. The costs estimated for the Program are summarized in Exhibit 1.5.

Exhibit 1.5

Estimated Replacement Program Capital Costs

Program Length	**3 YEARS**	
Program Cost ($M)	**2,388**	
Program Miles	**1,140**	
Average Cost $M/Mile	**2.09**	
EP Cast Iron Main Miles	**50**	
UP Cast Iron Main Miles	**810**	
Unprotected Steel Main Miles	**200**	
UP CP Steel and Plastic Main (Miles)	**80**	
Abandoned Regulators	**210**	
Service Replacements	**92,130**	
Relocate Inside Meter Sets	**49,178**	
ANNUAL CASH FLOW & MILES	**$M**	**Miles**
2024	**531**	**350**
2025	**796**	**395**
2026	**844**	**395**
2027	**217**	**0**
TOTAL	**2,388**	**1,140**

Q. What factors have you considered in this analysis?

A. The factors considered in the cost analysis first and foremost include PSE&G's estimate of its capability to undertake a level of replacement—amounting to approximately 380 miles per year of main and associated services, regulators and meter set relocates. The asset factors considered include primarily CI/US mains and unprotected steel services. Since the program philosophy is to replace and upgrade pressure from UP to EP, a corresponding number of district regulator assets will no longer be needed and will be abandoned. Finally, inside meter sets will be relocated outside where possible.

Q. Are these capital costs to be considered a final construction cost for the replacement program?

A. No, although we consider the estimate to be typical for purposes of budget, authorization and control. The development of the three year GSMP III Program has advanced from the conceptual to the feasibility state. PSE&G developed its estimate for each project cost component using a mix of fixed values, such as cost per mile of main replaced, and statistical estimating methods, such as leak rates. Currently, the Program cost is based on total units of work and unit cost representative of general construction throughout PSE&G's service area. As previously noted, the Program cost is based on unit-cost averages for similar work recently completed in Energy Strong, GSMP I and GSMP II. The estimate is reasonable and accurate for this stage of planning and Program development based on PSE&G prior construction cost experience. Exhibit 1.6 below shows the cost per mile comparison between GSMP I, II and III.

Exhibit 1.6

Cost Comparison

	(2016-2019) **GSMP I Actual**	**(2019-2023)** **GSMP II Forecast**	**(2024-2026)** **GSMP III Plan**	**(2017 - 2026)** **9-Yr CAGR***	**Notes**
$/MILE	$2.10	$1.69	$1.95	-0.95%	GSMP III work comparable to GSMP I + II work 3%/year inflation used for term of GSMP III
			$0.14		Increase due to elevated pressure and meter set relocation components of GSMP III
$/MILE	**$2.10**	**$1.69**	**$2.09**	**-0.06%**	

*Compound Annual Growth Rate

Q. How will the continuation of a multi-year modernization program affect the deployment of capital?

A. The adoption of a multi-year modernization program will allow PSE&G to address larger segments of pipe replacement within individual construction projects, leading to lower average replacement costs per mile as fixed aspects of the planning, engineering, and construction mobilization efforts and tie-ins are spread over a larger project. Additionally, the program will reduce, over time, the occurrence of emergency replacements that have substantially higher costs than planned replacements. Emergent work of this nature can cost 50% or greater when compared to planned, systematic modernization that includes elevating pressure and excess flow valve installations. In addition to the replacement activity, costs associated with leak investigation and monitoring also increase the overall costs associated with resolving emergent replacement projects.

Q. Please explain the estimated capital costs of the proposed hydrogen project.

A. The estimate of capital costs were developed as a Class 5 Total Installed Cost ("TIC") estimate developed by the engineering firm and reviewed and refined internally by PSE&G's Projects and Construction group. These costs have been developed using the actual cost from previous hydrogen blending construction projects that the engineering consultant has been involved with and are considered office estimates. The Class 5 TIC estimate is $28.8M. These costs include a 50% risk and contingency. The detailed cost estimate is shown on Schedule WEM-GSMPIII-7.

Q. Please explain the estimated operation and maintenance ("O&M") costs for the proposed hydrogen project.

A. PSE&G anticipates annual operation and maintenance costs for the hydrogen project once the facility is in-service. These estimated costs are included in Schedule WEM-GSMPIII-5. Categories of O&M costs include such things as: electricity, wastewater, general, and labor.

Q. Please explain the estimated capital costs of the proposed RNG project.

A. The estimate of capital costs were developed as a Class 5 Total Installed Cost ("TIC") estimate developed by the engineering firm and reviewed and refined internally by PSE&G's Projects and Construction group. These costs have been developed using the actual cost from previous RNG construction projects that the engineering consultant has been involved with and are considered office estimates. The Class 5 TIC estimate is $123M. These costs include a 40% risk and contingency. The detailed cost estimate is shown on Schedule WEM-GSMPIII-8.

Q. Please explain the estimated operation and maintenance ("O&M") costs for the proposed RNG project.

A. PSE&G anticipates annual operation and maintenance costs for the RNG project once construction begins and while the facility is in-service. These estimated costs are included in Schedule WEM-GSMPIII-5 and include a 15% contingency level. Categories of O&M costs include such things as: electricity, fuel, land lease, general, labor, and other consumables.

Experience with Programs

Q. Has the Company made investments to upgrade and modernize its system?

A. Yes. Over the past 50 years, PSE&G has replaced approximately 54% of its cast iron and unprotected steel mains and approximately 81% of its unprotected steel services. This is over 4,000 miles of main replacement and 365,000 service replacements.

Q. Could you briefly discuss the Company's experience with implementing infrastructure replacement programs of a size similar to the proposed GSMP?

A. The Company has completed extensive amounts of facilities replacement of nearly 250 miles through Capital Infrastructure Investment Programs I and II (“CIP I” and “CIP II”) from 2009 through 2012. Also, the Company has replaced 240 miles of cast iron mains under the Energy Strong Program in the 2014-2016 timeframe. PSE&G replaced 308 miles of cast iron mains and unprotected steel mains under GSMP I and 141 miles associated with base investment committed to under the GSMP settlement. Finally, PSE&G is in the process of replacing more than 930 miles of cast iron mains and unprotected steel mains under GSMP II and 138 miles associated with stipulated base investment committed to under the GSMP II settlement.

In preparation for planning under the gas main replacement component of GSMP I and GSMP II, the Company increased its resources in engineering to appropriately identify and model areas and facilities selected for replacement. This process strengthened the link between the Engineering group and Field Planning group, which is responsible for finalizing the plans for each construction project. Our Engineering and Field Planning groups have been and currently are working together to sequence our GSMP related installations, uprates and abandonments to ensure continued system reliability through the entire construction process, as well as evaluate the best technology for constructing each project. While this is a substantial undertaking, it is an essential part of implementing a large-scale replacement program. The Company successfully executed the GSMP phase I and continues to successfully execute the GSMP phase II.

Additionally, GSMP I and GSMP II demonstrate the Company’s ability to construct facilities at an accelerated rate. To address the increase in replacement facilities associated with GSMP I and then again with GSMP II, the PSE&G Gas Construction group hired additional internal resources and also engaged additional New Jersey contractors. To address the high levels of work in our northern area, we have shifted employees to the area of work through remote reporting and cascading of crews and technicians between districts. Our contractors have also met the challenge in stride by hiring and qualifying their people. They also produced the necessary equipment and expertise to support the GSMP programs. The Company is well positioned to leverage its GSMP related efforts and experienced staffing, training and qualifying resources to implement this proposed Program.

In GSMP II, results indicate that 1094 miles of main have been replaced through 2022 under PSE&G's infrastructure programs including base spending, stipulated base spending, and GSMP II across the four years since the beginning of the program. With these previous levels in mind, scaling to approximately 380 miles/year in the Program, plus associated gas main work in PSE&G's base capital program, while maintaining safety, customer satisfaction, and cost effectiveness, is manageable.

Q. Could you briefly discuss the Company's experience with constructing and operating plants?

A. Yes, the Company has extensive experience with constructing and operating plants. PSE&G operates and maintains 56 Metering & Regulating ("M&R") stations, one Liquefied Natural Gas ("LNG") plant, three Liquid Propane Air ("LPA") plants, and one Liquid Propane ("LP") storage facility. The Company also has completed and has ongoing programs involving the construction of plant facilities. In Energy Strong I PSE&G upgraded several M&R stations to make them less prone to flood hazards. For Energy Strong II the Company is modernizing six M&R stations to eliminate upstream relief and other enhancements. The Board recently approved the IAP to modernize four additional M&R stations. The construction and operation experience from our existing facilities, previous projects, and current ongoing projects will be valuable when constructing the hydrogen demonstration facility and RNG facility.

Details on Workforce

Q. Can you give us an indication of your capacity to replace aging infrastructure?

A. Exhibit 1.7 below provides a summary of replacement levels for the past several years for various programs along with base replacement:

Exhibit 1.7

Historical Main Replacement Miles

Program	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Base Replace Miles (RF & ER)	29	7	9	29	14	82	57	6	9	6	18
Stipulated Base	-	-	-	-	71	28	42	23	22	26	63
GSMP Replace Miles	-	-	-	-	118	104	86	210	318	281	112
Energy Strong Replace Miles	-	-	98	136	6	-	-	-	-	-	-
CIP II Replace Miles	27	1	-	-	-	-	-	-	-	-	-
Total	56	8	107	165	209	214	185	239	349	313	193

While large scale infrastructure programs require considerable resources, PSE&G has consistently provided the necessary resources and commitment to complete recent infrastructure replacement programs. In terms of staffing, PSE&G is currently staffed at approximately 2,600 full time PSE&G employees who perform all operational and construction activities. As part of the Gas Delivery reorganization, the Company has created a dedicated construction group to focus purely on replacement facilities and large scale or complex projects. This group currently consists of approximately 400 full time PSE&G employees. The Company's dedicated Construction group includes 33 mobile crews committed to its project work. The construction group also maintains planning for all of gas distribution.

PSE&G's Field Operations group is focused on regulatory compliance, customer driven work and system reliability, but is still deeply involved in supporting our project work. Having the ability to supplement our mobile workforce with Field Operations personnel when necessary provides maximum flexibility to support even greater infrastructure replacement programs. PSE&G plans to keep this flexibility in place through the term of any program to address aging facilities.

In addition to our dedicated construction work force and our Field Operations work force, PSE&G Gas Delivery engages outside contractors to assist in the Company's replacement facilities programs in a number of different focus areas. Contractors perform a large portion of the Company's main installation and service replacements with direct PSE&G oversight. The Company has also increased its use of engineering contractors and consultants to assist with permitting (environmental pre-planning, planning and oversight services) and process management. PSE&G also uses subcontractors to complete the bulk of street, sidewalk and lawn restoration including all of the milling and paving associated with our program work.

Q. Could you please comment on the resources required by the Company to operate the hydrogen facility?

A. The facility will require additional resources to monitor and maintain the equipment. There will be specific components for monitoring blend percentages and other instrumentation to ensure the facility operates within specific parameters. The facility will be monitored by the Company's Gas System Operations Center and routine maintenance and inspections will be conducted by PSE&G personnel. PSE&G will develop operations and maintenance processes and procedures ensuring compliance with applicable regulations.

Q. Could you please comment on the resources required by the Company to operate the RNG facility?

A. The facility will require additional resources to monitor and maintain the equipment. There will be specific components for monitoring gas quality and other instrumentation to ensure the facility operates within specific parameters. The facility will be monitored by the Company's Gas System Operations Center and routine maintenance and inspections will be conducted by PSE&G personnel. There will be a local flare to burn off any gas that does not meet specification. PSE&G will develop operations and maintenance processes and procedures ensuring compliance with applicable regulations.

Q. What is the impact of multi-year program planning and approval on utilization of contractors?

A. The implementation of a multi-year program is important because it allows contractors to make commitments to invest in additional employees and equipment with greater certainty than a program of short duration. Approval of the Company's three-year proposed Program will allow PSE&G to make a longer commitment to contractor services, enabling contractors to spread the fixed costs of the additional staff and equipment over a longer period, translating into lower costs for PSE&G.

Communicating with Customers

Q. Can you comment on the communication programs that you have implemented to make customers and public officials aware of GSMP I and II, which will assist the Company in implementing GSMP III?

A. The Company continues to utilize many existing processes including face-to-face meetings with municipalities, newspaper ads, preconstruction/construction signage, door hangers explaining upcoming work and communication through social media. Additionally, customers are able to access information on gas main replacement project statuses and paving statuses on PSE&G's website.

In recent years, the Company has expanded its use of social media platforms to reach customers. Customers can visit PSE&G at www.pseg.com or on Facebook, Twitter, LinkedIn, and the PSEG blog Energize, and the Company proactively sends out Facebook messages by zip code where gas main replacement work is scheduled. Through its website and other media platforms, the Company has developed and maintained multiple avenues for customers to "find" PSE&G and understand the work along with the Company's commitment to keeping them informed.

PSE&G has created a video that is available on the Company website to help customers understand the infrastructure replacement program. The video highlights the program details, the work process, and the ultimate benefits, including reduced greenhouse gas emissions and job creation.

PSE&G has created a dedicated outreach team, within the Gas Construction organization, to effectively communicate with customers. The outreach team will distribute notifications prior to construction, during construction, and prior to final restoration to ensure that customers are informed. Additionally, the team has developed a restoration post card to notify customers when the Company will return for final property and street restoration.

PSE&G uses the Varolii outbound phone call system to provide important information about necessary work. Where customers have provided a phone number, outbound calls will be sent with a specific message related to projects impacting those specific customers. The Company has also set up a dedicated email address to receive customer inquiries concerning construction work.

On the more traditional side, the Company continues to notify customers through a preconstruction letter campaign and during construction through the use of door hangers. The letters are published in multiple languages to assure that the message is received by as many customers as possible. Door hangers also provide a wealth of information about the construction and restoration process.

Where appropriate, the Company has increased the use of signage on construction sites. Signs are used prior to starting work and during construction where deemed useful and helpful. The Company has furnished employees with comprehensive program information and trained employees on positive customer interaction.

For the hydrogen project for this program, there will be additional communications that will occur for known industrial customers. Industrial customers require special consideration for impact to their equipment when introducing a hydrogen blend. These customers will be contacted to understand their equipment and any special considerations that may be needed.

For the RNG project for this program, the produced gas will be interchangeable with traditional natural gas and will not require any additional communication with customers.

Program Benefits and Savings

Q. What are the benefits associated with the replacement program?

A. There are a number of well-known benefits associated with the proposed replacement program:

- Improved long term safety and reliability of the system;
- Outside access to service shut-off valves at meter sets;
- Greater application of service line excess flow valves;
- Improved air quality and reduced greenhouse gas emissions;
- Increased ability to use higher-efficiency and other appliances.

As an integral part of a conversion from utilization pressure to elevated pressure, PSE&G would, where possible, relocate meters from inside to the outside of buildings. The three year Program involves relocation of approximately 49,200 meters. There are approximately 720,000 inside meters in PSE&G's distribution system. Moving meters to the outside of buildings facilitates easy access for shut off in the event of an emergency, potential reduction of gas leaks within buildings, improved access for safety inspections and meter reading, and reduction of potential theft of gas due to visibility of the meter location. Details of the qualitative and quantitative benefits of the Program are described below.

Benefits of Modernized System

Q. Please summarize some of the benefits that will be realized from the installation of newer materials for mains and services as part of the Replacement Subprogram.

A. In addition to enhanced public safety and the benefits I discussed above, the Program will reduce the Company's leak management costs. The Program will also result in the reduction of high cost emergency replacements and repairs as a greater amount of cast iron and unprotected steel pipe is replaced. Additional considerations that will enhance safety include:

- Improved Records: for new facilities the Program will provide updated main and service records. Utilizing more precise, as-built drawings will result in more accurate mark-outs, and reduced third-party damage.
- More modern construction standards will ensure:
  - Tracer Wire: for new installations of PE pipe, which will also facilitate locating the pipe for mark-outs and work; and
  - Warning Tape: is installed above new facilities; warns an excavator there is a buried pipe below.
  - Proper Bedding: using current backfill techniques and materials will improve the conditions of the pipe environment and reducing chance of future issues
- Elimination of Service Stubs: Another safety improvement associated with the replacement program is the opportunity to eliminate hard-to-locate service stubs thus reducing the potential of leakage or damage from future construction activity.

Q. Are there any benefits inherent in a utilization pressure gas distribution system such as the one that would be replaced under the proposed Replacement Subprogram?

A. The utilization pressure system is a legacy system from the period when gas was manufactured from coal. When natural gas became available, the existing system was converted to a utilization pressure natural gas distribution system. No new US gas distribution provider would consider constructing a utilization pressure distribution system today. In my opinion, a utilization pressure system is in some sense obsolete and provides no compelling benefits.

Q. Are there benefits inherent in an elevated pressure gas distribution system such as the one that would be installed under the proposed Replacement Subprogram?

A. An elevated pressure natural gas distribution system has many benefits. A large portion of an elevated pressure system can be constructed from PE pipe. Further, it is less costly to construct because natural gas is compressible and the higher operating pressure allows a smaller diameter replacement pipe to be installed, as opposed to utilization pressure, which requires the same size for the new pipe. This is particularly valuable for service line insertion. This feature allows for less costly construction techniques such as pipe insertion using the existing pipe as a conduit. From an operating and maintenance perspective, the proposed elevated pressure system would have fewer joint leaks because of the installation techniques available for modern materials. Additional considerations underlying the GSMP II Program that will enhance safety include:

Excess Flow Valves - Replacing the low-pressure system through GSMP II will enable PSE&G to install excess flow valves on residential, multi residential, and small commercial customer service lines. An excess flow valve is a device installed on the service line at the point where the service line is connected to the main. In the event that the service is cut, the sudden pressure drop and increased flow rate cause the device to be activated, slowing down the escape of gas. Excess flow valves cannot be installed on low-pressure systems because the pressure difference between the pressure in the gas main and atmospheric pressure is insufficient for the devices to function. PSE&G installs EFVs, where operationally permissible, on new services, and when older services are replaced. To date, PSE&G has installed EFVs on over 230,000 services.

District Regulators - The elimination of the CI/US low-pressure system will enable PSE&G to simplify its operating and maintenance plan. For example, the need for low pressure district pressure regulators will be significantly reduced.

Outage Restoration - Eliminating the CI/US low-pressure system will reduce the number of customers impacted by, and the duration of, unplanned gas outages. Outages caused by water infiltration will be virtually eliminated. The use of PE main will enable PSE&G crews to isolate gas leaks quickly for repair by either closing an existing valve or squeezing the pipe off upstream and downstream of the leak. An elevated pressure system also generates fewer calls from customers with appliance problems caused by insufficient gas pressure.

High Efficiency Appliances – The elevated pressure systems will allow for the expanded use of high efficiency appliances that require inlet pressures higher than the UP system can provide. The increased ability to use these appliances will improve customer satisfaction, reduce customer's energy bills, and reduce GHG emissions through improved efficiency.

Q. How do the benefits of an elevated pressure gas distribution system compare to the existing cast iron and unprotected steel utilization pressure system?

A. A large portion of an elevated pressure system can be constructed from PE pipe, which is superior to the existing cast iron and unprotected steel utilization pressure mains and services. PE pipe has fewer joint connections susceptible to leakage, can withstand ground movement caused by frost and does not corrode. Further, utilization pressure pipe, if replaced, would typically require a new pipe of the same diameter, whereas elevated pressure systems allow for the use of smaller diameter pipe. The replacement of utilization pressure pipe with new utilization pressure pipe typically excludes the use of less costly construction techniques, such as pipe insertion.

Excess flow valves, which are installed on new or replacement elevated pressure services where permissible cannot be used on utilization pressure services. Additionally, PSE&G operates approximately 1,000 district regulators that supply gas to utilization pressure systems. With the proposed Program, the Company would be able to retire 210 of these regulators, simplifying the Company's operation and maintenance plan. Further, utilization pressure systems are at a disadvantage when considering unplanned gas outages and outage restoration. Utilization pressure systems are susceptible to water infiltration, which can cause unplanned outages. Elevated pressure systems have valves that can be closed to isolate gas leaks and PE pipe can be squeezed off to isolate portions of the elevated pressure system. Utilization pressure systems are also more susceptible to low pressures which can potentially lead to issues with the operation of customer appliances.

Benefits to Customers from the Replacement Subprogram

Q. How will the new infrastructure system synergies and efficiencies translate into benefits for the customers?

A. The expected benefits to customers associated with the installation of the elevated pressure system include opportunities to accommodate technologies and appliances that cannot be adequately served by the current low-pressure system. The lack of an elevated pressure system would cause customers in New Jersey to forego consumer options or require more expensive special orders. In addition, an elevated pressure system will allow customers to install higher efficiency appliances. The following higher efficiency appliances require inlet pressures that in many cases would require either a customer-installed pressure booster or PSE&G's provision of an elevated pressure system:

- tankless water heaters;
- fan assisted heaters;
- natural gas whole-house generators; and
- commercial-grade cooking appliances.

The benefits for commercial applications would grow as well. Current commercial kitchen equipment requires a minimum of approximately 6 inches of water column as do current rooftop heating systems, which are standard for commercial use. Therefore, in many areas customers must install electric-driven gas boosters to raise the gas pressure, and back-up power supplies for the pressure boosters as a safeguard against electrical power outages. There would be additional savings for customers who have backup generators but would no longer need the booster systems.

The New Jersey Administrative Code, NJAC 8:43G-24.13(l), requires critical facilities such as hospitals to have alternate emergency power supply such as a backup generator. While the State practice is not to specify the fuel to be used, natural gas-fired generator equipment requires elevated-pressure or additional booster and back-up expenses if connected to the utilization pressure system.

In addition to the system safety advantages of replacing the low-pressure system described above, there are other benefits related to natural gas-fired generators. Because natural gas-powered back-up generators require elevated-pressure, the alternative is the less environmentally-friendly gasoline- or diesel-powered versions. The use of gasoline- or diesel-powered emergency generators is less safe than a permanently connected natural gas-fueled generator, primarily due to the risks involved in gasoline or diesel fuel storage and transfer, especially in residential applications. Natural gas generators are also more reliable in the case of a gasoline or diesel shortage, as was experienced during Superstorm Sandy.

Q. Will infrastructure improvements be done in Overburdened Communities ("OBC")?

A. Yes. There is a significant amount of UPCI system upgrades planned in OBC's. Exhibit 1.8 lists the top 12 municipalities where UPCI replacement work is planned that have greater than 50% OBC as defined by the New Jersey Environmental Justice Law[2]. The upgrades planned in these municipalities account for a full 38% of the total proposed UPCI replacement. In addition, there will be other OBC's with lesser miles that will also be upgraded in the program.

Exhibit 1.8

Municipality	GSMP III UPCI Main Replacement Miles	% of GSMP III UPCI Main Replacement Miles
Newark	45.0	5.5%
Teaneck	39.1	4.7%
Paterson	31.0	3.8%
Bloomfield	29.4	3.6%
Plainfield	25.7	3.1%
Camden	24.9	3.0%
Kearny	22.9	2.8%
Bergenfield	22.7	2.8%

[2] https://dep.nj.gov/ej/communities/#1661197424879-e89d9b57-c9da

East Orange	22.4	2.7%
Irvington	17.8	2.2%
New Milford	15.4	1.9%
Dumont	13.8	1.7%
TOTAL	**310**	**38%**

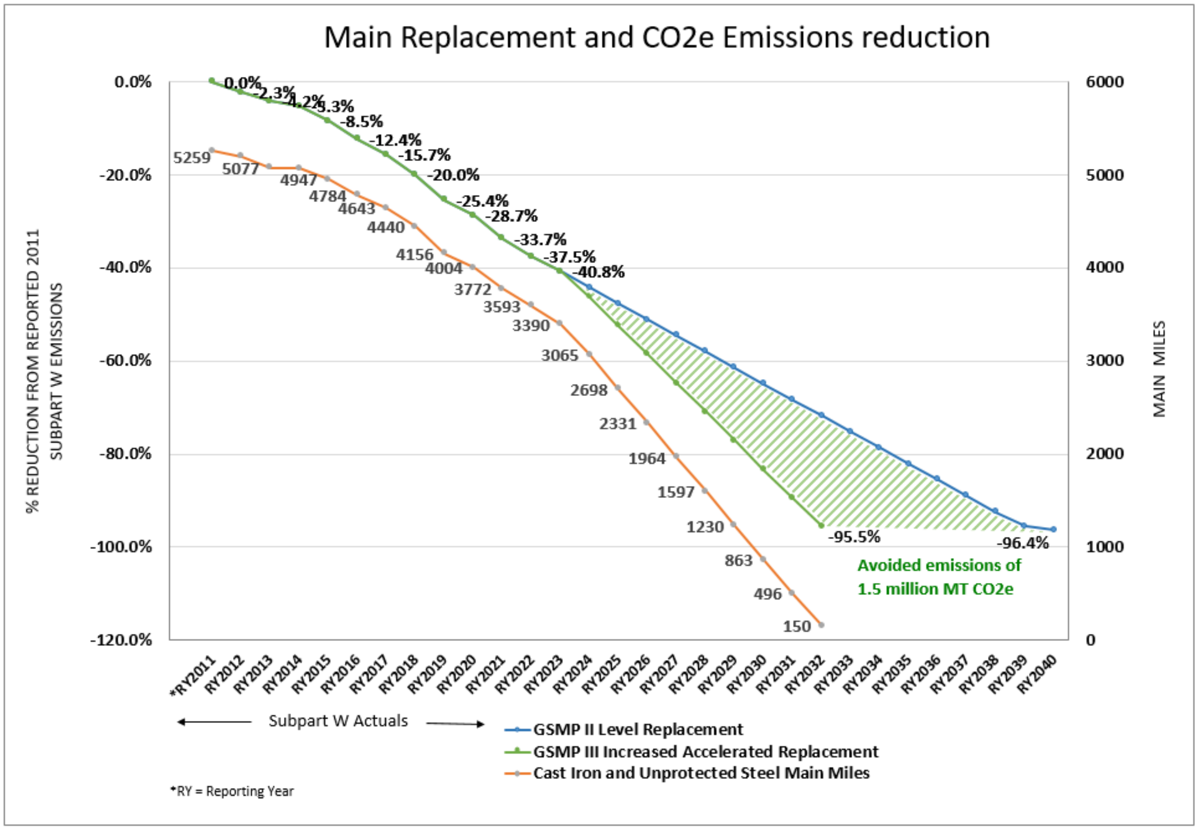
Environmental Benefits from the Replacement Subprogram

Q. Will the upgraded system provide any environmental benefits?

A. Yes. There is potential for a significant reduction in greenhouse gas emissions ("GHG").

Methane, which generally makes up over 90% of natural gas, is more than 80 times more potent at trapping heat than carbon dioxide in a 20-year period per the Environmental Defense Fund ("EDF"). Reducing emissions associated with methane leaks ensures that less natural gas needs to be produced and purchased, and maximizes the amount of purchased natural gas that is successfully delivered to customers for consumption. There is undoubtedly a correlation between the decline in miles of cast iron and unprotected steel main to the decline in methane emissions. With every mile of leak-prone pipe replaced, less methane is emitted into the atmosphere, as depicted by Exhibit 1.9.

Exhibit 1.9



GSMP is supporting approximately 40% methane reduction by 2023 from 2011 levels. The proposed GSMP III run rate will accomplish an additional approximately 19% methane reduction by 2026 from 2011 levels. This proposed run rate will reduce an additional approximately 59,000 metric tons of Carbon Dioxide equivalent ("CO2e") by the end of 2026 over the GSMP II run rate. It is also evident from the graph that the benefit of a sustained accelerated replacement program results in a significant reduction of approximately 1.5 Million tons by 2032 compared to the GSMP II run rate.

From 2011 through 2021, PSE&G has reduced methane emissions approximately 4%

annually (5.82% annually since 2018), or a total of approximately 250,000 metric tons of CO_2e (calculated using EPA Greenhouse Gas Reporting Program: Subpart W – Petroleum and Natural Gas Systems methodology). PSEG has joined the Business Ambition for 1.5°C and the Race to Zero campaigns and commits to developing science-based targets. As a part of the Company's net-zero climate vision for 2030, replacement of CI and UP ST pipe will be required to reduce methane leaks and reach net-zero on PSE&G Gas's emissions.

In PSEG's 2021 Greenhouse Gas Reporting Program ("GHGRP") subpart W filing, PSE&G methane emissions equated to 525,495 metric tons of carbon dioxide equivalents.

PSE&G estimated the GHG reduction based on the Title 40 CFR 98 – Mandatory Greenhouse Gas Reporting, Subpart W – Petroleum and Natural Gas System. The estimate considered the following sources of methane emissions for the gas distribution system using the default emission factors from the Code of Federal Regulations.

- Below Ground M&R Stations (operating pressure < 100 psia);
- Gas Distribution Mains – Unprotected Steel, Protected Steel, Plastic and Cast Iron; and
- Gas Service Lines – Unprotected Steel, Protected Steel, Plastic, and Copper.

The emission reduction was estimated using a baseline scenario in which the three year GSMP III Program begins immediately after January 1, 2024. Emission reductions were credited in the year following completion of the work. For the continued three year Program, the emission reduction would amount to approximately 145,000 metric tons of CO_2e emissions. Another way of looking at this reduction is to consider that the average vehicle over a year of driving has tailpipe CO_2e emissions of about 4.7 metric tons; removing

145,000 metric tons of CO2e emissions, would represent removing approximately 31,000 vehicles from the roads for one year.

Q. Will the upgraded system infrastructure be compatible with renewable energy sources?

A. Yes. As government entities push for the use of renewable energy, there is a renewed focus on alternate energy sources. There is ongoing research on the use of "green" fuel sources as an alternative to natural gas, including renewable natural gas ("RNG") and hydrogen blends. RNG is able to meet traditional natural gas pipeline quality standards and is fully compatible with the materials proposed under this Program. While there is still further research required on the use of hydrogen blends within natural gas distribution systems, current findings indicate that hydrogen blends are also fully compatible with the materials proposed under this Program. Promising research is also currently underway for the use of high density polyethylene in the transport of 100% hydrogen gas.

Cost Efficiency from the Replacement Program

Q. What are the quantitative benefits associated with the Program that are applied to the entire PSE&G system?

A. There are quantitative benefits from this approach to modernization, which we have estimated based on the assumptions in our analysis and estimates of certain key parameters. For example, the O&M costs associated with CI/US is significantly higher than the O&M costs associated with the replacement materials. This benefit is described as "avoided O&M costs."

Unprotected Steel services normally would not be repaired but would be replaced at a higher unit cost than the anticipated cost under a planned program. For example, PSE&G calculates that over the last several years, the cost of replacement due to individual leakage is approximately $2,000 more/per replacement as compared to the cost of service replacement as part of a planned program. The calculated individual leakage replacement cost is viewed as an “avoided capital cost” and represents a benefit under the modernization plan applied to the entire PSE&G system. Other “avoided capital costs” include the cost of CI bell joint encapsulations due to individual joint leakage.

The results of this analysis of the Program show that it has quantifiable benefits to the Company and its customers, summarized in Exhibit 1.10

Exhibit 1.10

Three Year Estimated Gross Quantifiable Benefits

3 YEAR Avoided Costs	O&M	Capital
Leak Repairs	$2.2	$42.7
Leak Rechecks	$0.3	
Clearing Mains & Drip Collection	$0.4	
Regulator Station Inspection and Maintenance	$0.3	
Total Savings	$3.3	$42.7
	$M	
Annual Avoided Costs	O&M	CAPITAL
2025	$0.5	$6.5
2026	$1.1	$14.2
2027	$1.7	$22.1
TOTAL	$3.3	$42.7

Q. Are there also quantitative benefits associated with the reduced emissions?

A. Yes, based on the nature of our improvements over the three-year period as depicted in Exhibit 1.11, the Company estimates that there is a cumulative value of avoided CO2e of approximately $13 million. This is a present value sum for the total reductions achieved during this time period, applying the Social Cost of Carbon as published by the Interagency Working Group on Social Cost of Greenhouse Gases.

Exhibit 1.11

Three Year Estimated Value of Avoided CO2e Emissions

Scenario ($ M)	**2024**	**2025**	**2026**	**Total**
Value Reductions Base	$0.42	$0.85	$1.29	$2.56
Value Reductions GSMP III	$2.45	$5.31	$8.27	$16.03
Net Difference GSMP III	$2.03	$4.46	$6.98	**$13.47**

Hydrogen Project Benefits

Q. What are the benefits associated with this project?

A. This project will yield several benefits. Specifically, the project will provide PSE&G with construction and operations experience, as well as lessons learned to develop and scale the use of hydrogen in the distribution system through this demonstration project. The project will also allow PSE&G to continue to innovate and share learnings with peer utilities. As stated before, the project aligns with the goals of the NJ EMP. There are quantifiable emissions reductions that will be realized through the use of hydrogen, a low carbon fuel.

Q. Please elaborate on the quantifiable emissions reductions expected from this project.

A. The quantifiable emissions reductions were calculated based on the amount of natural gas that would be displaced through the use of blended hydrogen. The annual totals were calculated based on the average year round flow with a 2% blend. The project is estimated to reduce greenhouse gas emissions by approximately 1,000 metric tons of CO2e, or the equivalent of removing approximately 200 vehicles from the road every year. With future increases in blend percentages, even further methane emission reductions can be realized.

Q. Will the introduction of hydrogen be compatible with the new facilities being installed under PSE&G's Gas System Modernization Program ("GSMP")?

A. Yes, the types of materials that have been installed under GSMP I, GSMP II, and being proposed for installation under GSMP III are compatible with the transport of hydrogen at the blend levels being proposed for this hydrogen project. As industry research and development continues, PSE&G will gain a greater understanding of higher blend levels and their impact to these materials. The replacements associated with GSMP synergize with this project by providing additional future value for a distribution system transporting low carbon fuels like hydrogen.

RNG Project Benefits

Q. What are the benefits associated with this project?

A. This project will yield many favorable benefits. Specifically, this project will introduce a unique and collaborative approach with a county utility authority whereby PSE&G can displace traditional natural gas supply, generate revenue to mitigate customer rate impacts, and align with the goals of the EMP. The gas will be sourced directly in PSE&G's territory and will not need to rely on transportation through interstate pipelines from out-of-state locations. PSE&G will gain valuable construction and operations experience as well as lessons learned to evaluate future opportunities with the utilization of low-carbon fuels in the distribution system. This project also aligns with New Jersey's GWRA 80 x 50 report and identified emission reduction pathways within the natural gas distribution segment. In addition, there are quantified air quality improvement and emissions reductions that will be realized through the use of RNG, a low carbon fuel.

Q. Can you speak more on how revenue will be generated to mitigate customer rate impacts?

A. Yes. As indicated earlier, the RNG facility will produce pipeline quality gas that will supply BGSS-RSG customers aligned to a Transco Leidy index price. This is the first source of revenue from the RNG project. The second source of revenue is associated with RNG-related environmental attributes that will be sold. The initial assumption is that the attributes will be sold as part of the federal Renewable Fuel Standard Program market using an assumed D3 Q-RIN value. The associated revenue from both of these sources, net the costs for the sale and management of the environmental attributes, will be subject to the revenue sharing arrangement between PSE&G and MCUA per the MOU. PSE&G's estimated revenue share is included in Schedule WEM-GSMPIII-5 and is to be credited back to customers per Mr. Swetz's analysis and the cost benefit analysis prepared by West Monroe.

Q. Please elaborate on the net air quality improvements and quantifiable emissions reductions expected from this project.

A. Due to the removal of the MCUA's electric generation units, the RNG project will result in a net air quality improvement for the state of New Jersey. Quantified net reductions for the following air pollutants have been identified in Exhibit 1.12: nitrogen oxides ("NOx"), carbon monoxide ("CO"), sulfur dioxide ("SO_2"), particulate matter 2.5 ("$PM_{2.5}$"), and particulate matter 10 ("PM_{10}").

Exhibit 1.12

Quantified Net Emissions Reductions

Emissions (tons/yr)	
Air Pollutant	Quantified Reduction
NOx	-20.55
CO	-0.91
SO2	-22.82
VOC	0.25
PM2.5	-4.22
PM10	-4.21
PM	-4.20

PSE&G and MCUA have concluded, that based on the preliminary Design Basis, no net increases of direct air pollutants are estimated to result from the RNG Project except for a minor increase in VOC. PSE&G also believes this analysis is conservative if not worst case.

These quantified air quality improvements are aligned and support New Jersey's efforts toward attaining National Ambient Air Quality Standards for PM2.5. These improvements are also consistent with the New Jersey's established enforceable reductions in fine particulate matter and its precursors, nitrogen oxides ("NOx") and sulfur dioxide ("SO2").

Regarding greenhouse gas reductions, RNG has distinct benefits as a decarbonization strategy. RNG has lower life cycle GHG emissions compared to natural gas and can be introduced into the gas distribution network safely and used by customers to reduce GHG emissions without any changes to existing equipment or appliances. RNG projects contribute to reducing the carbon intensity ("CI") of fuels burned, capture methane emissions that would otherwise escape to atmosphere, and leverage existing waste streams—all of which positively impact public health, climate and air quality.

CI values of existing approved RNG pathways vary from 7.79 to 70.2 kg CO2e/mmbtu for RNG produced from landfills. This compares to a CI of up to 85.00 kg CO2e/mmbtu for natural gas. For the purpose of this project, a CI of 40.99 kg CO2e/mmbtu was utilized consistent with average CI's utilized by the California Air Resources Board and the American Gas Foundation to calculate anticipated annual GHG reductions. As part of general compliance with USEPA's Renewal Fuel Standards ("RFS"), a final lifecycle analysis will be conducted prior to the RNG facility commissioning, and a final CI will be produced and utilized for future GHG reduction calculations. Utilizing the CI for RNG referenced above, the project is estimated to have the ability to reduce approximately 27,000-36,000 metric ton CO2e per year compared to natural gas including production and supply leakage rates supplied by the USEPA and Environmental Defense Fund. These reductions would be equivalent to removing 5,800 to 7,800 vehicles from the road per year.

Cost-Benefit Analysis

Q. Did the Company prepare a cost-benefit analysis of the Program?

A. Yes. West Monroe has completed a series of cost-benefit analyses for PSE&G of the proposed Program. The West Monroe reports are the result of analysis of both quantifiable and qualitative benefits of the three components of the Program.

Benefits to New Jersey Economy

Q. How will the infrastructure investments proposed herein benefit New Jersey's economy?

A. Using the methodology for job creation from the introductory material to the Board's August 7, 2017 proposal for the IIP regulations, the replacement component of the proposed Program would create an estimated 3,800 full time jobs annually for the duration of the program. This is an increase of approximately 1,500 full time jobs per year over GSMP II. The hydrogen project is estimated to create 80 full time jobs per year over the two year engineering and construction timeline. The RNG project is estimated to create 229 full time jobs per year over the 3 year engineering and construction timeline.

Q. Please elaborate on the labor and other resources required to successfully complete this Program.

A. The Company will need to maintain staffing for engineering, construction, construction management, and records management in order to continue the level of gas infrastructure upgrade and replacement proposed. The amount of staffing required will be based on the approved levels of work in the program. PSE&G anticipates continuing to utilize contractors for a majority of the planned replacement work under the Program. These independent contractors will need to maintain staff and equipment to complete the work to the extent that was needed in GSMP I and GSMP II. Material manufacturers and their suppliers will also need to maintain or increase production to support continuation of the Program.

Q. How does a multi-year program affect the work effort involved with the Program?

A. Significant benefits of a multi-year approach include better workforce management and reduction in procurement and construction mobilization/de-mobilization associated with completing larger projects. These programs also create long-term employment opportunities. These benefits are consistent with the BPU's IIP regulation and are discussed in more detail previously in the testimony.

Q. What is the impact of program reductions on the quantifiable benefits of the Replacement Subprogram?

A. Program reductions reduce the quantifiable benefits that accompany system modernization. The Company has estimated the quantifiable benefits of the program in terms of avoided cost in Exhibit 1.13. This exhibit illustrates the quantifiable benefits of the proposed program compared to not continuing the GSMP program and returning to a base replacement work level.

• Baseline Scenario: The three year Program begins January 1, 2024 and continues through June 30, 2027

• Scenario 1: GSMP accelerated main replacement program not pursued.

Exhibit 1.13

Three Year Avoided Costs

	O&M	Capital
Scenario 0- Program as Filed	**$3.3**	**$42.7**
Scenario 1 - Base RF Level Plan	**$0.7**	**$6.6**

GSMP I and GSMP II Status Update

Q. Please summarize PSE&G's progress in addressing leak prone pipe in the distribution system since the start of the GSMP program.

A. Since the start of GSMP I the inventory of Cast Iron main has been reduced by 1,325 miles. The top 10 municipalities in reduction of Cast Iron main are shown below with an average reduction of 65% of the starting inventory. As displayed and in comparison to Exhibit 1.8, many of these municipalities have greater than 50% OBCs further advocating the importance of continuing this much needed modernization.

Exhibit 1.14

Ten Municipalities with Most Cast Iron Main Miles Replaced

Municipality	Cast Iron Main Miles Replaced	% Reduction
Newark City	90.3	50%
Paterson City	77.7	62%
Clifton City	67.6	64%
Jersey City	58.2	50%
Nutley Town	34.2	65%
Passaic City	31.4	86%
Lyndhurst Twp	27.1	93%
Garfield City	26.9	75%
Trenton City	25.2	28%
North Plainfield Boro	24.8	79%

Since the start of GSMP I the inventory of Unprotected Steel main has been reduced by 180 miles. The top 10 Municipalities in reduction of Unprotected Steel main are shown below with an average reduction of 41% of the starting inventory:

Exhibit 1.15

Ten Municipalities with Most Unprotected Steel Main Miles Replaced

Municipality	Unprotected Steel Main Miles Replaced	% Reduction
Cinnaminson Twp	11.2	55%
Edison Twp	10.1	62%
East Brunswick Twp	9.4	43%
Lawrence Twp	9.0	37%
Hamilton Twp	7.6	33%
Sayreville Boro	7.2	53%
Princeton Twp	7.0	42%
Old Bridge Twp	6.6	20%
Hillsborough Twp	6.4	44%
Cherry Hill Twp	5.6	22%

Q. Please summarize the GSMP I approved work and investment.

A. In the GSMP I Order, the Board approved $650 million in total spend not including $85 million per year in Stipulated Base. No more than 400 miles of main were to be installed to replace UPCI and unprotected steel mains under the approved recovery mechanism. Stipulated base included the replacement of cast iron ("UP" and "EP") and unprotected steel mains and associated services, as well as the costs required to uprate the UPCI systems if applicable (including the uprating of associated protected steel and plastic mains and services) to higher pressures and the elimination, where applicable, of district regulators, the installation of excess flow valves associated with the Stipulated Base, and the additional costs associated with the relocation of inside meter sets that is associated with the Stipulated Base as well as the Program main replacements. During the three years 2016 – 2018, the Company installed no less than 110 miles of main to replace cast iron and unprotected steel mains and associated services under this Stipulated Base.

Q. Please summarize the GSMP II work and investment.

A. In the GSMP II Order, the Board approved $1.575 billion of total costs eligible for recovery under the GSMP II Rate Mechanism representing 875 miles of main to be installed to replace UPCI and unprotected steel mains and associated services, costs required to uprate the UPCI systems, the costs of excess flow valves, and the costs of eliminating district regulators. Additionally, the Order required $300 million in Stipulated Base spending at a $20 million per year minimum and $155 million in annual baseline capital expenditure over the program. Stipulated base may include replacement of UPCI and unprotected steel mains and their associated services, costs incurred to uprate the UPCI systems (including the uprating of associated protected steel and plastic mains and services) to higher pressures; eliminate district regulators, where applicable; install excess flow valves as well as replace elevated pressure cast iron ("EPCI") mains; reinforce EPCI joints; replace plastic and cathodically protected steel main; and relocate inside meter sets associated with GSMP II Rate Mechanism work or Stipulated Base main replacements to outside locations. The capital investments made by the Company as part of its baseline capital expenditure requirements are within the discretion of the Company and may include, inter alia, costs incurred by the Company in excess of $1.80 million/mile on its replacements under the GSMP II Rate Mechanism.

Q. Please comment on the work that has been completed to date under GSMP II.

A. As of December 2022, the Company has replaced approximately 921 miles of main, replaced 80,663 services, and has abandoned 148 district regulators incurring costs of $1.543 billion or $1.68 million per mile eligible for recovery under the GSMP II Rate Mechanism. Additionally, as of December 2022, the Company has incurred $275.45M in Stipulated Base spending while exceeding the $20 million per year minimum in all years of the program. Finally, as of December 2022, the Company has incurred $972 million in baseline capital expenditures over the course of the program exceeding the $155 million per year minimum in all years.

Q. How has the Company performed relative to the Open Leak reduction commitment in the GSMP II Order?

A. The Company has done an outstanding job reducing its Open Leak inventory far below the year end Open Leak Cap as stipulated in the order. The results through December 2022 are shown in Exhibit 1.16.

Exhibit 1.16

Program Year	Year End Open Leaks Cap	ACTUAL Year End Open Leaks
2019	1677	1123
2020	1660	965
2021	1643	808
2022	1627	637

GSMP I and II Lessons Learned

Q. What have you learned from GSMP I and II about working with municipalities?

A. The Company's experience with GSMP I and GSMP II has shown that proper communication with municipalities and the individual communities within those municipalities is critical to the efficient execution of the program. While many of the Company's initiatives overlap between municipal government, community and individual customer impact, pre-planned municipal meetings are designed to give officials an advanced understanding of the projects and an opportunity to address potential constituent concerns prior to project approval and construction. At these meetings, the Company's intentions concerning customer and resident outreach, preliminary schedules, restoration, and plans to minimize overall impact to the community are discussed. This includes potential traffic issues and detours, work times around schools and public buildings, and any impact to local businesses. A standardized outreach package that includes all the communication materials to be distributed to the customers is provided and the benefits of the facility upgrades are discussed. The initial meeting is followed up by a pre-construction meeting that takes place prior to construction and serves to finalize details of the construction schedule, traffic concerns, and customer communication plan. Municipal outreach meetings are held where project impacts to a community are moderate to significant and where need for additional outreach is identified.

Q. What have you learned from GSMP I and II on construction?

A. Through the Company's experience with prior replacement programs, the need for a dedicated gas construction organization was apparent. The Company has implemented a Gas Construction organization focused on the GSMP program. Since its inception, this organization has expanded to meet the needs of GSMP. The Company has implemented a project management organization within the Gas Construction Organization to address the project components not covered in its work management system or current construction practices. The project management organization has enlisted the use of project management software to assist with project scheduling and forecasting. The project management organization has also added a group dedicated to project controls and the Layout and Planning group has been expanded to support the Program replacement work.

Based on experience beginning with Energy Strong and continuing through the GSMP, Gas Delivery made many improvements including retaining licensed soil remediation professionals for linear construction projects; use of blanket type permitting with the Soil Conservation Districts ("SCDs"); and consolidating work into larger projects for permit submission greatly reducing lead times and paperwork to manage compliance with the regulations.

The success rate of moving meter sets to the outside was significantly lower than anticipated at the outset of GSMP, due to customer's resistance to moving the meter outside, primarily for aesthetic reasons. The Company implemented specific policies for conditions where leaving the meter inside is acceptable. These exceptions include limited suitable space to accommodate piping and required protection measures, insufficient clearance of the equipment with regard to safety considerations, or local requirements such as historic districts. The policy specifies that customers may object to moving the meter outside, however, if in the sole judgement of the Company there is a suitable location outside, the meter set shall be relocated outside. Additionally, information regarding the relocation of inside meter sets outside is readily available on the Company website under "Frequently Asked Questions".

Q. What have you learned from GSMP I and II on coordination of work?

A. The Company continues to make progress in coordinating work with municipal, state, and county paving programs as well as with other local construction activities. This has enabled us to minimize delays to established paving and reconstruction schedules by others and in some cases not have to complete final restoration because of this coordination.

The Company has recognized the impact that infrastructure replacement programs have on municipalities and communities. In order to reduce disruptions to roadways, the Company proposes, where applicable, to work in conjunction with other utility infrastructure replacement programs.

In addition, when dealing with large numbers of main outages in tandem, there are challenges in coordination and logistics to ensure there is no impact to system reliability. As a result, a weekly statewide system call was implemented with Gas Construction, Gas Operations and Gas Transmission & Distribution Engineering to address the coordination of these outages. These calls help to coordinate system outages and ensure reliability.

Program Reporting

Q. Does the Company intend to provide regular reporting on its progress?

A. Yes. Consistent with IIP regulations, the Company proposes to submit semi-annual status reports to Board Staff and the Division of Rate Counsel that contain the following information:

1. Forecasted and actual costs of GSMP III for the applicable reporting period, and for the Program to date, where Program projects are identified by major category;
2. The estimated total quantity of work completed under GSMP III identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided;
3. Estimated completion dates for GSMP III as a whole, and estimated completion dates for each major Program category;
4. Anticipated changes to GSMP III projects, if any; and
5. Actual capital expenditures made by the utility in the normal course of business on similar projects, identified by major category
6. Any other performance metrics concerning GSMP III required by the Board.

Q. Will the Company commit to leak reduction?

A. The Company commits to reducing the open leak inventory by one percent for each year of the Program except under extraordinary circumstances such as extreme weather, acts of war or terrorism, or other *force majeure* extraordinary circumstances that prevent the achievement of the annual reduction. The cap for the first year will be set at the average number of year-end open leaks the Company has experienced during the prior five calendar years. The cap would be reduced by one (1) percent for each of the remaining two years of the program.

Conclusion

Q. Please summarize your recommendation.

A. Aging cast iron and unprotected steel pipe serving PSE&G customers exhibits significantly greater leak rates than newer plastic and cathodically protected steel pipe and will eventually require replacement or rehabilitation. Low carbon fuels are essential in progressing climate stewardship while leveraging an existing network capable of transporting these energy sources. PSE&G has an important opportunity to make these investments as the world is shifting priorities and focus to provide energy from more low carbon sources. The proposed GSMP III and associated cost recovery mechanism represent a prudent response to PSE&G's long- term system needs, the Department of Transportation's PIPES ("Protecting our Infrastructure of Pipelines and Enhancing Safety") Act of 2020, New Jersey's Energy Master Plan, and the Board's regulations (Subchapter N.J.A.C. 14:3-2A), regarding Infrastructure Investment Programs ("IIPs"), effective as of 2018. The GSMP III Replacement Subprogram is also consistent with the Department Of Transportation's "Call to Action" to facilitate the replacement of aging gas infrastructure. The safety-related, customer, economic, environmental and other benefits attributable to the three-year Program extension, as presented in my testimony, are compelling with many of New Jersey's overburdened communities being the recipients of these infrastructure upgrades. The Company has a proven track record to show our ability to execute the proposed program in a safe and customer conscious manner. Therefore, I request that the proposed program be approved.

Q. Does this conclude your testimony?

A. Yes, it does.

SCHEDULE INDEX

CREDENTIALS
OF
WADE E. MILLER
SENIOR DIRECTOR – GAS TRANSMISSION &
DISTRIBUTION ENGINEERING

I received a Bachelor of Science Degree in Mechanical Engineering from The College of New Jersey in 2000. I also received my Engineer-In-Training certification in 2000. I became licensed as a Professional Engineer with the State of New Jersey in 2006. I also received my certification as a Project Management Professional with the Project Management Institute in 2006. In 2007, I earned the designation of Registered Gas Distribution Professional from the Gas Technology Institute.

I was employed by PSE&G in June 2000 as an Associate Engineer in the Trenton Gas Distribution District where I began my training program and was mentored under a senior engineer. In 2001, I was relocated from Trenton District to Burlington District where I acted as the sole engineer. In 2003, I was promoted to the position of Lead Engineer. During my first four years, I provided engineering and managerial support for all phases of planning, design, construction, and maintenance of the gas distribution system while adhering to the established capital and O&M budgets.

In 2004, I was promoted to the position of Supervising Engineer in the Asset Management department and given the responsibility for the approval of all engineering designs associated with new and replacement main requisitions, district and pound to pound regulator installations, large volume meter sets, higher than normal delivery pressure requests, gas load increase submittals, and written gas out procedures covering six of the twelve gas districts. In addition, I was also responsible for developing the replacement main plans for these same six districts including identification and prioritization.

In 2007, I was promoted to the position of Planning & Design Manager in the Asset Management department overseeing a team of engineers and given the responsibility for developing and maintaining Company design standards for the Gas system, maintaining system integrity, and providing technical support to gas field operations. I was also responsible for developing the annual replacement main, regulator, and system reinforcement programs for the Company.

In April 2014, I was promoted to Director – Gas Transmission & Distribution Engineering and in April 2022, I was promoted to Senior Director – Gas Transmission & Distribution Engineering. This position involves overall responsibility for system planning and reliability as well as the safe and efficient engineering, design, and operating procedures of PSE&G's gas transmission and distribution assets. I am also responsible for the management of the Transmission and Distribution Integrity Management Programs, operation and maintenance of 56 metering & regulating stations, four gas plants, and gas control to over 1.9 million customers.

I am the Committee sponsor for PSE&G's Gas Engineering Committee which is responsible for approval of action items due to regulatory changes and changes to Company technical manuals, the Operator Qualification program, Integrity Management programs, and new technology and materials.

I am a member of the Operations Safety Regulatory Action committee and the Engineering committee of the American Gas Association. In addition, I am a member of the Executive Committee of the Society of Gas Operators.

PSE&G - GSMP III

Attachment 1

Gas Delivery Capital Summary (2023 - 2027)

Schedule WEM-GSMP III-2

Capital Category ($M)	2023 Full Year Plan	2024 Full Year Plan	2025 Full Year Plan	2026 Full Year Plan	2027 Full Year Plan
Total Base	**225**	**225**	**225**	**225**	**225**
New Business	101	103	106	98	90
GSMP III - Replacement Program					
Recovery Mechanism		474	712	754	194
Average Projected Stipulated Base		56	85	90	23
GSMP III - Hydrogen Project					
Recovery Mechanism		14	15	1	
Average Projected Stipulated Base		-	-	-	-
GSMP III - RNG Project					
Recovery Mechanism		40	43	40	
Average Projected Stipulated Base		-	-	-	-
GSMP II					
Recovery Mechanism	25				
Average Projected Stipulated Base	26				
Energy Strong II					
Recovery Mechanism	-	-			
Projected Stipulated Base	37	0.3			
IAP - Gas M&R					
Recovery Mechanism	11	40	17		
Projected Stipulated Base			17	1	
Total Capital $	**$ 425**	**$ 953**	**$ 1,219**	**$ 1,207**	**$ 533**

Base Breakdown by Major Category

Replace Facilities	$ 95	$ 81	$ 89	$ 87	$ 85
System Reinforcement	$ 50	$ 51	$ 53	$ 54	$ 55
Environmental Regulatory	$ 31	$ 31	$ 31	$ 31	$ 31
Replace Meters	$ 46	$ 58	$ 49	$ 50	$ 50
Support Facilities	$ 3	$ 3	$ 3	$ 3	$ 3
Total Base $*	**$ 225**	**$ 225**	**$ 225**	**$ 225**	**$ 225**

*The Company proposes to maintain base level spending from 2022-2027 at the level shown above.

PSE&G - GSMP III **Attachment 1**

Gas Delivery Capital Summary (2018 - 2022)

Schedule WEM-GSMP III-3

Capital Category ($M)	2018 Full Year Actual	2019 Full Year Actual	2020 Full Year Actual	2021 Full Year Actual	2022 Full Year Actual
Total Base	**436**	**219**	**202**	**229**	**322**
New Business	95	90	100	94	108
GSMP I					
Recovery Mechanism	201	48			
Stipulated Base	94				
Energy Strong I	0				
GSMP II					
Recovery Mechanism		288	407	495	354
Stipulated Base		60	46	42	128
Energy Strong II					
Recovery Mechanism		0	4	16	30
Stipulated Base		0	0	0	30
IAP					
Recovery Mechanism					1
Stipulated Base					
Total Capital $	**$ 826**	**$ 703**	**$ 759**	**$ 877**	**$ 973**

Base Breakdown by Major Category

Replace Facilities	$ 229	$ 64	$ 57	$ 55	$ 116
System Reinforcement	$ 73	$ 53	$ 60	$ 59	$ 98
Environmental Regulatory	$ 38	$ 34	$ 30	$ 27	$ 28
Replace Meters	$ 61	$ 60	$ 40	$ 62	$ 48
Support Facilities	$ 35	$ 8	$ 15	$ 23	$ 25
Energy Efficiency	$ 0	$ 0	$ 0	$ 2	$ 8
Total Base $	**$ 436**	**$ 219**	**$ 202**	**$ 229**	**$ 322**

PSE&G GAS SYSTEM MODERNIZATION PROGRAM PHASE III

ATTACHMENT 1

Schedule WEM-GSMPIII-4

Cash Flows	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2024													
Direct In-Service	$ 1,746,371	$ 3,492,742	$ 6,985,485	$ 17,463,711	$ 41,912,907	$ 45,405,650	$ 49,977,649	$ 64,088,328	$ 61,944,588	$ 74,377,947	$ 60,718,635	$ 65,330,138	$ 493,444,153
CWIP Spending	$ 563,690	$ 1,103,380	$ 1,580,070	$ 1,981,760	$ 3,588,520	$ 4,391,900	$ 5,195,280	$ 5,596,970	$ 10,070,280	$ 11,275,350	$ 4,404,900	$ 4,016,900	$ 53,769,000
COR	$ 131,447	$ 262,895	$ 525,789	$ 1,314,473	$ 3,154,735	$ 3,417,630	$ 3,761,759	$ 4,823,853	$ 4,662,496	$ 5,598,340	$ 4,570,220	$ 4,917,322	$ 37,140,958
Total	**$ 2,441,508**	**$ 4,859,017**	**$ 9,091,344**	**$ 20,759,944**	**$ 48,656,162**	**$ 53,215,179**	**$ 58,934,688**	**$ 74,509,151**	**$ 76,677,364**	**$ 91,251,637**	**$ 69,693,755**	**$ 74,264,360**	**$ 584,354,110**
Program Year - 2025													
Direct In-Service	$ 21,663,482	$ 16,834,795	$ 25,752,994	$ 42,799,044	$ 75,583,813	$ 71,796,093	$ 77,397,632	$ 80,255,042	$ 76,530,825	$ 93,305,287	$ 74,973,118	$ 84,422,014	$ 741,314,138
CWIP Spending	$ 2,321,800	$ 2,471,800	$ 3,949,880	$ 5,724,880	$ 7,343,600	$ 7,343,600	$ 8,212,320	$ 6,293,600	$ 3,474,880	$ 3,474,880	$ 3,474,880	$ 3,474,880	$ 57,561,000
COR	$ 1,630,585	$ 1,267,135	$ 1,938,397	$ 3,221,433	$ 5,689,104	$ 5,404,007	$ 5,825,628	$ 6,040,702	$ 5,746,272	$ 7,010,559	$ 5,630,719	$ 6,342,490	$ 55,747,032
Total	**$ 25,615,866**	**$ 20,573,730**	**$ 31,641,271**	**$ 51,745,358**	**$ 88,616,517**	**$ 84,543,700**	**$ 91,435,580**	**$ 92,589,344**	**$ 85,751,977**	**$ 103,790,726**	**$ 84,078,716**	**$ 94,239,384**	**$ 854,622,170**
Program Year - 2026													
Direct In-Service	$ 23,095,815	$ 17,981,302	$ 27,427,399	$ 45,381,961	$ 80,057,868	$ 76,045,941	$ 81,979,053	$ 85,005,603	$ 80,862,339	$ 98,653,568	$ 79,236,257	$ 89,252,409	$ 784,979,516
CWIP Spending	$ 1,987,400	$ 1,987,400	$ 3,179,840	$ 3,179,840	$ 3,974,800	$ 3,974,800	$ 4,769,760	$ 3,974,800	$ 3,179,840	$ 3,179,840	$ 3,179,840	$ 3,179,840	$ 39,748,000
COR	$ 1,727,104	$ 1,342,141	$ 2,053,138	$ 3,412,121	$ 6,025,861	$ 5,723,888	$ 6,170,466	$ 6,398,271	$ 6,086,413	$ 7,425,537	$ 5,964,019	$ 6,717,923	$ 59,046,883
Total	**$ 26,810,319**	**$ 21,310,843**	**$ 32,660,376**	**$ 51,973,922**	**$ 90,058,530**	**$ 85,744,629**	**$ 92,919,280**	**$ 95,378,674**	**$ 90,128,591**	**$ 109,258,945**	**$ 88,380,117**	**$ 99,150,172**	**$ 883,774,399**
Program Year - 2027													
Direct In-Service	$ 26,260,469	$ 22,220,396	$ 30,300,541	$ 44,440,793	$ 42,420,757	$ 36,360,649	$ -	$ -	$ -	$ -	$ -	$ -	$ 202,003,604
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 1,976,594	$ 1,672,503	$ 2,280,686	$ 3,345,006	$ 3,192,960	$ 2,736,823	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,204,572
Total	**$ 28,237,063**	**$ 23,892,899**	**$ 32,581,226**	**$ 47,785,799**	**$ 45,613,717**	**$ 39,097,472**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 217,208,176**
Totals													
Direct In-Service	$ 72,766,136	$ 60,529,236	$ 90,466,418	$ 150,085,510	$ 239,975,346	$ 229,608,333	$ 209,354,335	$ 229,348,974	$ 219,337,751	$ 266,336,802	$ 214,928,010	$ 239,004,561	$ 2,221,741,411
CWIP Spending	$ 4,872,890	$ 5,562,580	$ 8,709,790	$ 10,886,480	$ 14,906,920	$ 15,710,300	$ 18,177,360	$ 15,865,370	$ 16,725,000	$ 17,930,070	$ 11,059,620	$ 10,671,620	$ 151,078,000
COR	$ 5,465,731	$ 4,544,674	$ 6,798,010	$ 11,293,033	$ 18,062,660	$ 17,282,348	$ 15,757,853	$ 17,262,826	$ 16,495,180	$ 20,034,437	$ 16,164,958	$ 17,977,736	$ 167,139,445
Total	**$ 83,104,757**	**$ 70,636,490**	**$ 105,974,218**	**$ 172,265,023**	**$ 272,944,926**	**$ 262,600,981**	**$ 243,289,548**	**$ 262,477,170**	**$ 252,557,932**	**$ 304,301,309**	**$ 242,152,588**	**$ 267,653,916**	**$ 2,539,958,856**

GSMP III - Replacement Main

ATTACHMENT 1
Schedule WEM-GSMPIII-4

Cash Flows	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2024													
Direct In-Service	$ 1,746,371	$ 3,492,742	$ 6,985,485	$ 17,463,711	$ 41,912,907	$ 45,405,650	$ 49,977,649	$ 64,088,328	$ 61,944,588	$ 74,377,947	$ 60,718,635	$ 65,330,138	$ 493,444,153
CWIP Spending													$ -
COR	$ 131,447	$ 262,895	$ 525,789	$ 1,314,473	$ 3,154,735	$ 3,417,630	$ 3,761,759	$ 4,823,853	$ 4,662,496	$ 5,598,340	$ 4,570,220	$ 4,917,322	$ 37,140,958
Total	**$ 1,877,818**	**$ 3,755,637**	**$ 7,511,274**	**$ 18,778,184**	**$ 45,067,642**	**$ 48,823,279**	**$ 53,739,408**	**$ 68,912,181**	**$ 66,607,084**	**$ 79,976,287**	**$ 65,288,855**	**$ 70,247,460**	**$ 530,585,110**
Program Year - 2025													
Direct In-Service	$ 21,663,482	$ 16,834,795	$ 25,752,994	$ 42,799,044	$ 75,583,813	$ 71,796,093	$ 77,397,632	$ 80,255,042	$ 76,343,325	$ 93,140,287	$ 74,808,118	$ 84,264,514	$ 740,639,138
CWIP Spending													$ -
COR	$ 1,630,585	$ 1,267,135	$ 1,938,397	$ 3,221,433	$ 5,689,104	$ 5,404,007	$ 5,825,628	$ 6,040,702	$ 5,746,272	$ 7,010,559	$ 5,630,719	$ 6,342,490	$ 55,747,032
Total	**$ 23,294,066**	**$ 18,101,930**	**$ 27,691,391**	**$ 46,020,478**	**$ 81,272,917**	**$ 77,200,100**	**$ 83,223,260**	**$ 86,295,744**	**$ 82,089,597**	**$ 100,150,846**	**$ 80,438,836**	**$ 90,607,004**	**$ 796,386,170**
Program Year - 2026													
Direct In-Service	$ 22,945,815	$ 17,831,302	$ 27,277,399	$ 45,332,461	$ 80,057,868	$ 76,045,941	$ 81,979,053	$ 85,005,603	$ 80,862,339	$ 98,653,568	$ 79,236,257	$ 89,252,409	$ 784,480,016
CWIP Spending													$ -
COR	$ 1,727,104	$ 1,342,141	$ 2,053,138	$ 3,412,121	$ 6,025,861	$ 5,723,888	$ 6,170,466	$ 6,398,271	$ 6,086,413	$ 7,425,537	$ 5,964,019	$ 6,717,923	$ 59,046,883
Total	**$ 24,672,919**	**$ 19,173,443**	**$ 29,330,536**	**$ 48,744,582**	**$ 86,083,730**	**$ 81,769,829**	**$ 88,149,520**	**$ 91,403,874**	**$ 86,948,751**	**$ 106,079,105**	**$ 85,200,277**	**$ 95,970,332**	**$ 843,526,899**
Program Year - 2027													
Direct In-Service	$ 26,260,469	$ 22,220,396	$ 30,300,541	$ 44,440,793	$ 42,420,757	$ 36,360,649	$ -	$ -	$ -	$ -	$ -	$ -	$ 202,003,604
CWIP Spending													$ -
COR	$ 1,976,594	$ 1,672,503	$ 2,280,686	$ 3,345,006	$ 3,192,960	$ 2,736,823	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,204,572
Total	**$ 28,237,063**	**$ 23,892,899**	**$ 32,581,226**	**$ 47,785,799**	**$ 45,613,717**	**$ 39,097,472**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 217,208,176**
Totals													
Direct In-Service	$ 72,616,136	$ 60,379,236	$ 90,316,418	$ 150,036,010	$ 239,975,346	$ 229,608,333	$ 209,354,335	$ 229,348,974	$ 219,150,251	$ 266,171,802	$ 214,763,010	$ 238,847,061	$ 2,220,566,911
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 5,465,731	$ 4,544,674	$ 6,798,010	$ 11,293,033	$ 18,062,660	$ 17,282,348	$ 15,757,853	$ 17,262,826	$ 16,495,180	$ 20,034,437	$ 16,164,958	$ 17,977,736	$ 167,139,445
Total	**$ 78,081,867**	**$ 64,923,910**	**$ 97,114,428**	**$ 161,329,043**	**$ 258,038,006**	**$ 246,890,681**	**$ 225,112,188**	**$ 246,611,800**	**$ 235,645,432**	**$ 286,206,239**	**$ 230,927,968**	**$ 256,824,796**	**$ 2,387,706,356**

GSMP III - Hydrogen

ATTACHMENT 1
Schedule WEM-GSMPIII-4

Cash Flows	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2024													
Direct In-Service													$ -
CWIP Spending	$ 162,000	$ 300,000	$ 375,000	$ 375,000	$ 375,000	$ 375,000	$ 375,000	$ 375,000	$ 5,250,000	$ 5,250,000	$ 388,000	$ -	$ 13,600,000
COR													$ -
Total	**$ 162,000**	**$ 300,000**	**$ 375,000**	**$ 375,000**	**$ 375,000**	**$ 375,000**	**$ 375,000**	**$ 375,000**	**$ 5,250,000**	**$ 5,250,000**	**$ 388,000**	**$ -**	**$ 13,600,000**
Program Year - 2025													
Direct In-Service									$ 187,500	$ 165,000	$ 165,000	$ 157,500	$ 675,000
CWIP Spending	$ 150,000	$ 300,000	$ 475,000	$ 2,250,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 1,950,000					$ 14,125,000
COR													$ -
Total	**$ 150,000**	**$ 300,000**	**$ 475,000**	**$ 2,250,000**	**$ 3,000,000**	**$ 3,000,000**	**$ 3,000,000**	**$ 1,950,000**	**$ 187,500**	**$ 165,000**	**$ 165,000**	**$ 157,500**	**$ 14,800,000**
Program Year - 2026													
Direct In-Service	$ 150,000	$ 150,000	$ 150,000	$ 49,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 499,500
CWIP Spending					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR													$ -
Total	**$ 150,000**	**$ 150,000**	**$ 150,000**	**$ 49,500**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 499,500**
Program Year - 2027													
Direct In-Service													$ -
CWIP Spending													$ -
COR													$ -
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Totals													
Direct In-Service	$ 150,000	$ 150,000	$ 150,000	$ 49,500	$ -	$ -	$ -	$ -	$ 187,500	$ 165,000	$ 165,000	$ 157,500	$ 1,174,500
CWIP Spending	$ 312,000	$ 600,000	$ 850,000	$ 2,625,000	$ 3,375,000	$ 3,375,000	$ 3,375,000	$ 2,325,000	$ 5,250,000	$ 5,250,000	$ 388,000	$ -	$ 27,725,000
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 462,000**	**$ 750,000**	**$ 1,000,000**	**$ 2,674,500**	**$ 3,375,000**	**$ 3,375,000**	**$ 3,375,000**	**$ 2,325,000**	**$ 5,437,500**	**$ 5,415,000**	**$ 553,000**	**$ 157,500**	**$ 28,899,500**

GSMP III - RNG

ATTACHMENT 1
Schedule WEM-GSMPIII-4

Cash Flows	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2024													
Direct In-Service													$ -
CWIP Spending	$ 401,690	$ 803,380	$ 1,205,070	$ 1,606,760	$ 3,213,520	$ 4,016,900	$ 4,820,280	$ 5,221,970	$ 4,820,280	$ 6,025,350	$ 4,016,900	$ 4,016,900	$ 40,169,000
COR													$ -
Total	**$ 401,690**	**$ 803,380**	**$ 1,205,070**	**$ 1,606,760**	**$ 3,213,520**	**$ 4,016,900**	**$ 4,820,280**	**$ 5,221,970**	**$ 4,820,280**	**$ 6,025,350**	**$ 4,016,900**	**$ 4,016,900**	**$ 40,169,000**
Program Year - 2025													
Direct In-Service													$ -
CWIP Spending	$ 2,171,800	$ 2,171,800	$ 3,474,880	$ 3,474,880	$ 4,343,600	$ 4,343,600	$ 5,212,320	$ 4,343,600	$ 3,474,880	$ 3,474,880	$ 3,474,880	$ 3,474,880	$ 43,436,000
COR													$ -
Total	**$ 2,171,800**	**$ 2,171,800**	**$ 3,474,880**	**$ 3,474,880**	**$ 4,343,600**	**$ 4,343,600**	**$ 5,212,320**	**$ 4,343,600**	**$ 3,474,880**	**$ 3,474,880**	**$ 3,474,880**	**$ 3,474,880**	**$ 43,436,000**
Program Year - 2026													
Direct In-Service													$ -
CWIP Spending	$ 1,987,400	$ 1,987,400	$ 3,179,840	$ 3,179,840	$ 3,974,800	$ 3,974,800	$ 4,769,760	$ 3,974,800	$ 3,179,840	$ 3,179,840	$ 3,179,840	$ 3,179,840	$ 39,748,000
COR													$ -
Total	**$ 1,987,400**	**$ 1,987,400**	**$ 3,179,840**	**$ 3,179,840**	**$ 3,974,800**	**$ 3,974,800**	**$ 4,769,760**	**$ 3,974,800**	**$ 3,179,840**	**$ 3,179,840**	**$ 3,179,840**	**$ 3,179,840**	**$ 39,748,000**
Program Year - 2027													
Direct In-Service													$ -
CWIP Spending													$ -
COR													$ -
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Totals													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 4,560,890	$ 4,962,580	$ 7,859,790	$ 8,261,480	$ 11,531,920	$ 12,335,300	$ 14,802,360	$ 13,540,370	$ 11,475,000	$ 12,680,070	$ 10,671,620	$ 10,671,620	$ 123,353,000
COR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 4,560,890**	**$ 4,962,580**	**$ 7,859,790**	**$ 8,261,480**	**$ 11,531,920**	**$ 12,335,300**	**$ 14,802,360**	**$ 13,540,370**	**$ 11,475,000**	**$ 12,680,070**	**$ 10,671,620**	**$ 10,671,620**	**$ 123,353,000**

Hydrogen & RNG Projects - O&M & Revenue

Attachment 1
Schedule WEM-GSMPIII-5

Hydrogen Year	Revenue Gas Sales	O&M
2024	$ -	$ -
2025	$ 20,912	$ 763,195
2026	$ 55,074	$ 1,993,075
2027	$ 56,299	$ 2,052,867
2028	$ 60,143	$ 2,356,811
2029	$ 63,691	$ 2,177,887
2030	$ 67,863	$ 2,243,223
2031	$ 67,863	$ 2,575,351
2032	$ 67,863	$ 2,379,835
2033	$ 67,863	$ 2,451,230
2034	$ 67,863	$ 2,814,155
2035	$ 67,863	$ 2,600,510
2036	$ 67,863	$ 2,678,526
2037	$ 67,863	$ 5,575,103
2038	$ 67,863	$ 2,841,648
2039	$ 67,863	$ 2,926,897
2040	$ 67,863	$ 3,360,249
2041	$ 67,863	$ 3,105,145
2042	$ 67,863	$ 3,198,300
2043	$ 67,863	$ 3,671,834
2044	$ 67,863	$ 3,393,076
2045	$ 67,863	$ 3,494,869
2046	$ 67,863	$ 4,012,313
2047	$ 67,863	$ 3,707,706
2048	$ 67,863	$ 3,818,937
2049	$ 67,863	$ 4,384,362
2050	$ 67,863	$ 4,051,511
2051	$ -	$ -

RNG	Revenue - 67% PSE&G Share		
Year	Gas Sales	Net Environ Attributes Sales	O&M
2024	$ -	$ -	$ -
2025	$ -	$ -	$ 67,083
2026	$ 246,204	$ (9,112)	$ 1,007,304
2027	$ 2,424,088	$ 26,519,945	$ 11,216,478
2028	$ 2,622,783	$ 24,867,463	$ 11,621,363
2029	$ 2,811,254	$ 25,168,653	$ 12,037,649
2030	$ 3,029,929	$ 25,457,926	$ 12,465,686
2031	$ 3,063,119	$ 25,735,745	$ 12,905,832
2032	$ 3,095,008	$ 26,002,555	$ 13,358,460
2033	$ 3,125,646	$ 26,258,787	$ 13,823,951
2034	$ 3,155,083	$ 26,504,849	$ 15,483,228
2035	$ 3,183,366	$ 26,741,138	$ 16,011,053
2036	$ 3,210,540	$ 26,968,034	$ 16,554,018
2037	$ 3,236,648	$ 27,185,899	$ 17,112,587
2038	$ 3,261,733	$ 27,395,086	$ 17,687,233
2039	$ 3,285,834	$ 27,595,929	$ 16,909,889
2040	$ 3,156,995	$ 26,508,895	$ 17,061,085
2041	$ 3,033,207	$ 25,464,335	$ 17,220,480
2042	$ 2,914,274	$ 24,460,579	$ 17,388,282
2043	$ 2,800,003	$ 23,496,022	$ 17,564,706
2044	$ 2,690,214	$ 22,569,123	$ 17,749,972
2045	$ 2,584,729	$ 21,678,400	$ 17,944,309
2046	$ 2,237,187	$ 19,087,226	$ 16,635,623

PSE&G Gas System Modernization Program Phase 3 – GSMP III

Engineering Evaluation Report

Revision: Final
Date: January 24, 2023
Prepared by: PSE&G Gas Asset Strategy

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Background

PSE&G was formed in 1903 by amalgamating more than 400 gas, electric and transportation companies in New Jersey. PSE&G's oldest predecessor, the Paterson Gas Light Company, began actual operations in 1847. This pioneering history of a manufactured gas system, creating gas from coal and distributing it predominantly for lighting, formed the beginning of what became PSE&G's legacy low-pressure gas distribution system. Some of the oldest cast-iron pipes in the Company's system date back to the late 1800s.

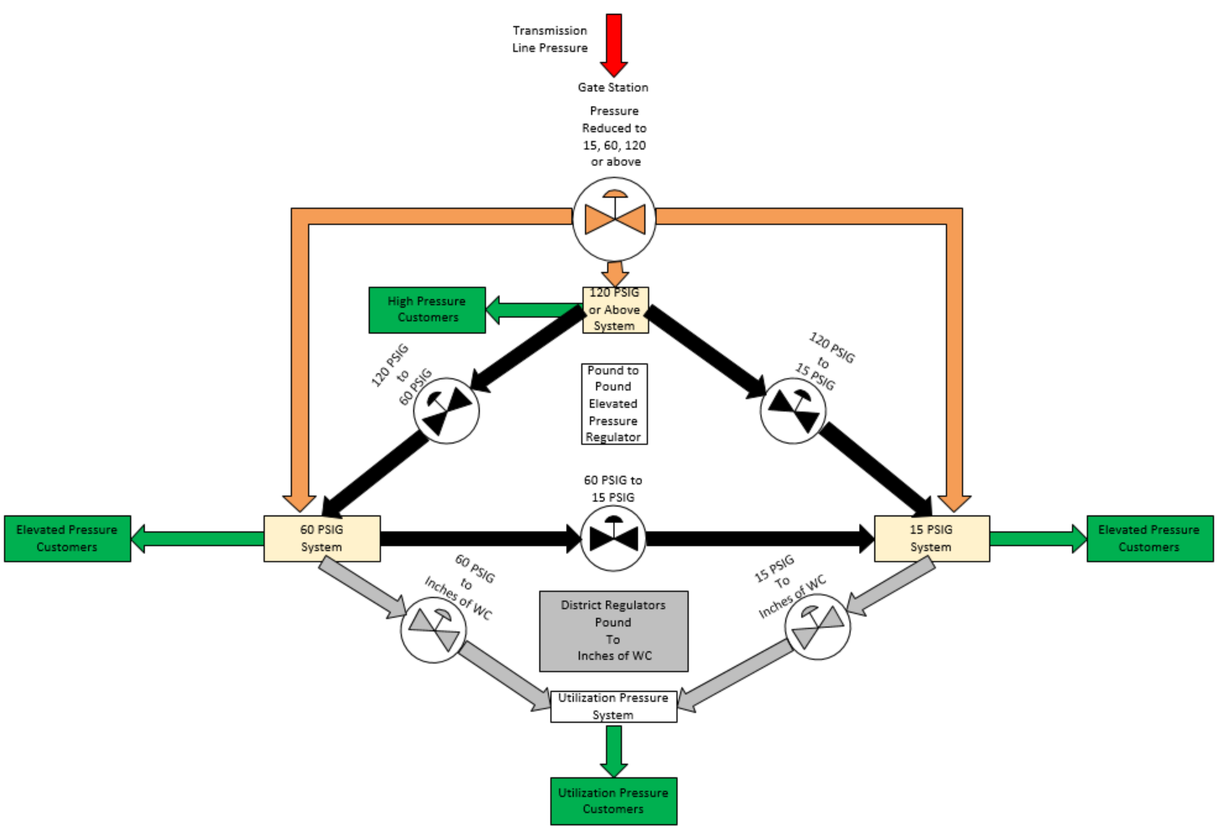
The Company's distribution system mains and services reflect the material types that were considered state-of-the-art over the years as the system grew to serve new customers. The system design has large diameter trunk mains supplied from a source (initially a manufactured gas plant; subsequently a city gate station) transporting gas to a connected network of smaller diameter mains that ultimately supply gas to customers through single service lines. In the first half of the 20th century the primary material used for distribution main pipe was cast iron, and the primary material used for services was unprotected steel pipe. In the 1950s, there was a transition to steel materials for mains. Cathodic protection of steel pipe became widespread in the 1960s. From the 1970s to the present, plastic materials for new mains and services were installed in most small diameters and steel for large diameter installations and higher pressure systems. As a result of the foregoing, the Company's current distribution system includes a mix of cast iron, steel, and plastic mains, steel and plastic services, and a very small percentage of copper services.

PSE&G's Distribution System Infrastructure

PSE&G serves over 1.8 million gas customers in a service area of almost 2400 square miles. PSE&G operates a gas distribution system network of approximately 35,600 miles of mains and services in pipe sizes ranging from ½" to 42" in diameter and composed of plastic, steel, and cast iron materials. PSE&G receives odorized gas delivered from interstate pipeline systems at 42 city gate stations, where gas volumes are measured and the pressure is reduced to distribution pressure. PSE&G operates an integrated gas distribution network comprised of four pressure systems: utilization pressure (UP) and elevated pressures (EP) (15 psig, 60 psig, and 120 psig and above). Exhibit 1.1 illustrates the major components of PSE&G's distribution network.

Exhibit 1.1

Illustrations of Distribution System Pressure Components



The reduction in pressure from either the 60 psig or 15 psig pressures to utilization pressure occurs at district regulator stations. The utilization pressure system is supplied by approximately 1,000 district regulator stations fed by either 15 or 60 psig pressure. In addition, PSE&G utilizes 41 pounds to pounds regulators to transfer gas from the 60 psig or 120 psig and above systems to a lower pressure system. Large diameter main trunk lines transport gas from the city gate stations and regulator vaults into the service territory to supply smaller diameter distribution mains to deliver gas to customers via individual service lines. In all, PSE&G operates and maintains approximately 18,173 miles of various pressure gas distribution main, and 1,269,428 individual services totaling approximately 17,375 miles of service piping supplying over 1.8 million meters serving utilization pressure, 15 psig, 60 psig and 120 psig customers. Approximately 535,000 meters serve customers connected to utilization pressure, while the remaining 1,265,000 meters provide gas service to elevated pressure customers. Approximately 234,000 of PSE&G's elevated pressure services have excess flow valves installed.

Distribution Integrity Management Program – DIMP

Distribution integrity management is a formal systematic process of identifying, evaluating and addressing direct or potential threats to the safe operation of a gas distribution system. On December 4, 2009, the PHMSA amended Federal Pipeline Safety Regulations requiring gas distribution operators to develop and implement integrity management programs by August 2, 2011. The regulations set forth an overall approach by an operator to ensure the integrity of its distribution system, including a DIMP. The purpose of the program is to enhance safety by identifying and reducing pipeline risks.

At a minimum, each distribution pipeline operator must have a written integrity management plan that contains procedures for developing and implementing seven major elements defined by PHMSA 49 CFR Part 192 Subpart P. These elements are:

1) Knowledge: Knowledge entails the documentation of information to demonstrate an understanding of the gas distribution system developed from reasonably available data. PSE&G's DIMP references data pertaining to system design, materials, operating characteristics, and environmental factors contained in the Company's geographic information system, main and service records, and leak management and corrosion control records.

2) Identify threats: Threat identification requires consideration of broad issues that may affect the safe operation of the distribution system. PHMSA identifies potential threats according to the following eight categories: corrosion, natural forces, excavation, other outside force damage, material or welds, equipment, operations, and other.

3) Evaluate and rank risks: Through the process of evaluating and ranking risks, the company determines the relative importance of all identified risks. The Company takes into consideration both the likelihood of occurrence and the consequences of occurrence. PSE&G relies primarily on analysis of leak repair data and internal subject matter experts (SMEs) to evaluate and rank risks.

4) Identify and implement measures to address risks: This element of DIMP documents actions the company takes to reduce risk of failure. Programs at PSE&G that address risks include the leak management, damage prevention, corrosion control, public awareness and operator qualification programs. Specific actions include prevention, detection, mitigation and/or replacement and upgrade.

5) Measure performance, monitor results, and evaluate effectiveness: PSE&G uses monitoring and measurement to evaluate the effectiveness of actions implemented in order to address risks. PSE&G measures performance from a variety of information based on completed work, including the collection of data on leak causes, leak classification, and leaks repaired or eliminated. The data is reported and communicated within PSE&G for evaluation and analysis and to provide input for future planning.

6) Periodic evaluation and improvement: Periodic evaluation establishes a definitive feedback loop for the overall integrity management process. The DIMP is evaluated on a periodic basis through a number of actions that take place on an established schedule. Additionally, as knowledge concerning the distribution system or potential threats is gained, the elements of the DIMP or required actions may be revised to take into account the impact of the new information.

7) Report results: Reporting on integrity management actions and results provides information to PSE&G's internal management and satisfies federal and state mandated reporting requirements. Annually, PSE&G reports data to regulators concerning the facilities in- service by vintage and material, as well as leaks and associated causes.

PSE&G's DIMP comprehensively documents the Company's risk-based approach to distribution integrity management according to the required elements. PSE&G's risk-based selection process and criteria, employed to manage cast-iron risk, are incorporated into the DIMP. PSE&G's Gas System Modernization Program (GSMP) directs resources towards reducing system risks in a comprehensive and conscientious manner, at the most hazardous assets that the DIMP identifies. It is also aimed at preventing or mitigating threats to the integrity of these distribution system assets, while managing discrete cast-iron and unprotected steel risk as it has in the past.

As summarized in Exhibit 1.2 the 3,261 mile, 0.25 psig utilization pressure system is approximately 18% of the distribution network; the 5,591 mile 15 psig system is approximately 31%; the 9,177 mile 60 psig system is approximately 51%; and the 144 mile 120 psig and above system is approximately 1%.

Exhibit 1.2

Gas Distribution Network Pressure Systems (miles at end of 2021)

Mains					
MILES	**UP**	**15 PSIG**	**60 PSIG**	**120 PSIG**	**> 120 PSIG**
Cast Iron	2488	391	42	0	0
Steel	348	1711	3433	128	12
Plastic	423	3457	5688	4	0
Other	2	32	14	0	0
Total	3261	5591	9177	132	12

Exhibit 1.3 shows the various materials that makeup PSE&G's distribution system as of the year end 2021. Approximately 21% of the main system is cast iron and unprotected steel and 7% of the service lines are unprotected steel.

Exhibit 1.3

Material Makeup of PSE&G Distribution System

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	RECONDITIONED CAST IRON	TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN	165	686		4,781	9,610	2,921	0	0.6	2.8	6.4	18,173
NO. OF SERVICES	84,232			197,177	955,973	0	0	32,046	0		1,269,428

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	RECONDITIONED CAST IRON	TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
% OF MAIN	0.9%	3.8%	0.0%	26.3%	52.9%	16.1%	0.0%	0.0%	0.0%	0.04%	100%
% OF SERVICES	6.6%	0.0%	0.0%	15.5%	75.3%	0.0%	0.0%	2.5%	0.0%	0.0%	100%

Source: 2021 Form PHMSA F7100.1-1

Approximately 12% of PSE&G's system was put in place in the first half of the 20th century when the primary material used for distribution main pipe was cast iron, and the primary material used for services was unprotected steel. There was a transition to unprotected steel materials for main in the 1950's while cast iron continued to be installed. Cathodic protection of steel mains became widespread in the 1960's and cast iron installation ended. In the 1970's there was a transition from steel to plastic materials for mains and services except for large diameter and elevated pressure installations that continued to rely on coated, cathodically protected steel.

Age of Facilities Presently In Service

Exhibit 1.4 and Exhibit 1.5 provide a profile of the age of PSE&G's distribution mains and services as of December 31, 2021.

Exhibit 1.4

Age Profile of PSE&G Gas Mains and Services				
	MAINS		SERVICES	
VINTAGE	MILES	PERCENT	COUNT	PERCENT
PRE-1940	1,972	11%	95,222	8%
1940-1949	247	1%	13,481	1%
1950- 1959	1,293	7%	59,418	5%
1960- 1969	2,889	16%	159,804	13%
1970- 1979	1,517	8%	94,182	7%
1980- 1989	3,081	17%	200,816	16%
1990- 1999	2,831	16%	184,387	15%
2000- 2009	1,934	11%	154,718	12%
2010- 2019	1,837	10%	236,307	19%
2020-2029	572	3%	71,094	6%
TOTAL	18,173	100%	1,269,429	100%

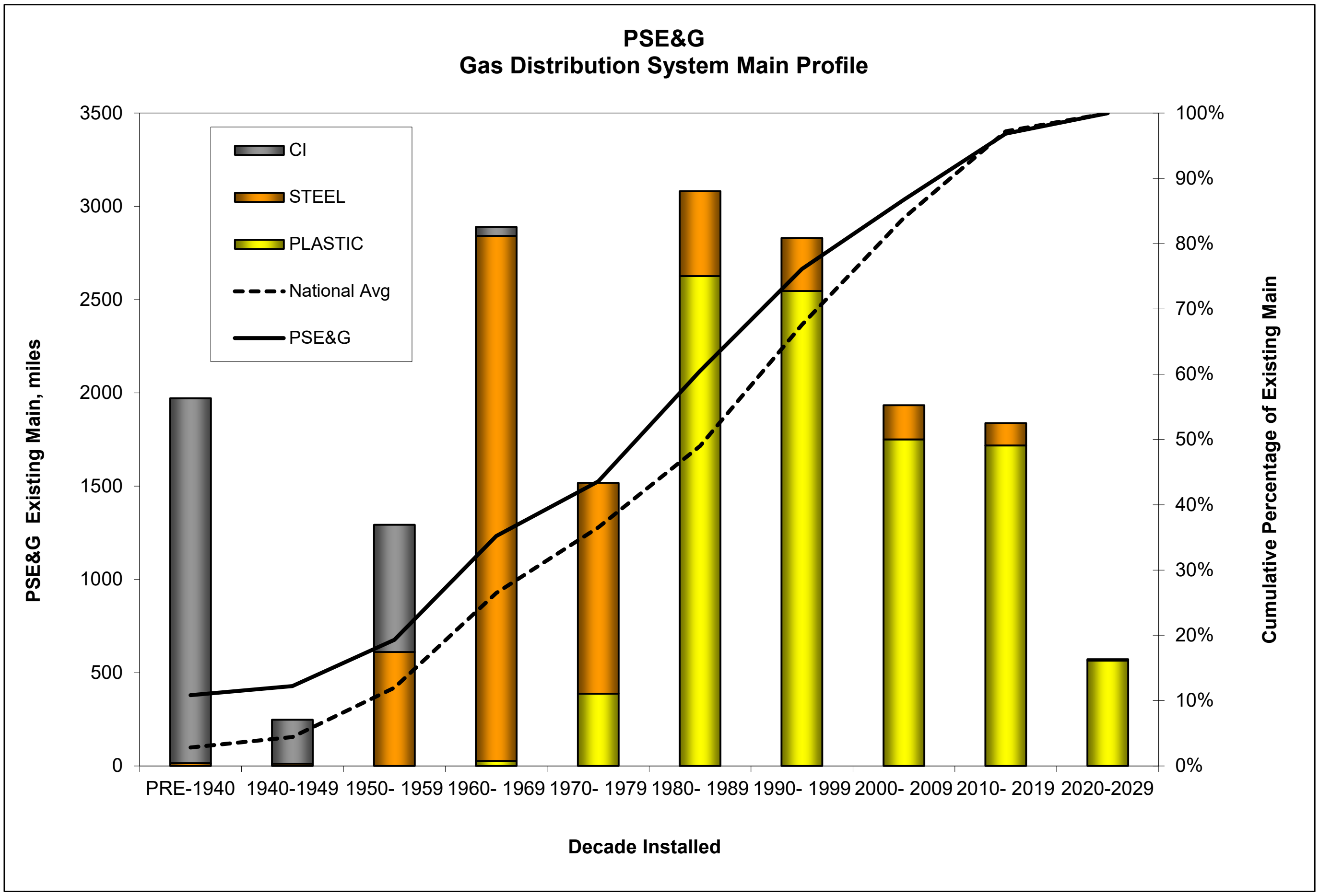
Source: 2021 Form PHMSA F7100.1-1

Exhibit 1.5

Average Age (Years)	2021 YE
Distribution Mains	43
CAST IRON	91
UNPROTECTED STEEL	65
CATHODICALLY PROTECTED STEEL	49
PLASTIC	24
Distribution Services	32
UNPROTECTED STEEL	79
CATHODICALLY PROTECTED STEEL	54
COPPER	57
PLASTIC	23

The pipe in PSE&G's distribution system is significantly older than the national average. Exhibit 1.6 describes PSE&G's gas distribution main profile as compared to the national average. PSE&G's service territory was well built out by the end of the 1950's, prior to most other utilities, resulting in an older system comprised of the materials used at that time. The vertical bars represent the amount of pipe installed by the Company in the decades between pre-1940 and 2021. The solid line shows the cumulative percentage of pipe installed by PSE&G between pre-1940 and 2021, while the dashed line shows the national average percentage over the same time span. The Company's distribution system is significantly older than the national average. This chart also visually conveys that a significant portion, 3,512 miles or 19% of PSE&G's distribution system, was installed prior to 1960, when cast iron and unprotected steel were the prevalent construction materials.

Exhibit 1.6



Source: Pipeline and Hazardous Materials Safety Administration
2021 Annual Report for Gas Distribution System Form F7100.1-1

PSE&G utilizes various performance metrics to verify the effectiveness of its DIMP. These include but are not limited to: EPCI leaks per mile, UPCI leaks per mile, UPCI breaks per mile, unprotected steel main leaks per mile, number of leak repairs on steel services, and number of leaks by cause. Performance metric analysis allows the Company to evaluate system condition and the effectiveness of leak mitigation methods that are relevant to the characteristics of the Company's infrastructure.

Issues with Aging Infrastructure

At PSE&G, the greatest concerns are associated with facilities installed prior to 1960.

Pre-1960 materials constitute 19% of PSE&G's mains and 14% of its services, yet account for an estimated 70% of the distribution system leaks, excluding leaks caused by third-party damage.

PSE&G operates 2,921 miles of cast iron main, 850 miles of unprotected steel main, and approximately 84,000 unprotected steel services. Continued corrosion is likely to increase the leak rates for older materials due to the time function of the corrosion process. The primary problems presented by cast iron and unprotected steel are summarized below.

Cast Iron Pipe – There are two primary problems with cast iron systems.

First, cast iron pipe has little inherent flexibility and is susceptible to breakage due to ground movement, which is most frequently caused by frost heave. Ground movement creates an excessive bending stress in the pipe which may cause it to fail in a circumferential break and lead to a relatively large gas leak at the point of failure. Cast iron pipe sizes 12 inches and below are particularly susceptible to unpredictable breaks.

Second, when originally installed in rigid 12 or 18 foot lengths, sections were joined either with bell and spigot type connections or mechanical joints. The annular space in bell and spigot connections was packed with jute fiber followed by lead or cement to form a gas tight joint, while mechanical joints were made with a bolted connection with a gasket seal. Time, ground movement and/or drying action of the gas can cause a joint to leak. Remedial action in the form of external clamps or internal seals then becomes necessary. Over the past 5 years, the occurrence of cast iron joint leaks is approximately 5 to 6 times greater than cast-iron breaks. Larger size cast-iron pipes are more susceptible to joint leaks than breaks.

Unprotected Steel Pipe - The primary problem encountered with unprotected steel pipe is corrosion that will develop leaks over time. Specifically, steel pipe deteriorates due to contact with moisture present in the soil. The rate of corrosion varies depending on a number of characteristics of the soil, including moisture and acidity (pH). Uncontrolled corrosion will lead to metal loss and numerous relatively small gas leaks.

Initially, a leak from an unprotected steel pipe starts as a pinhole-sized leak. Over time metal loss will increase in size and location, allowing more gas to escape; and eventually resulting in numerous relatively small gas leaks. Eventually, these small leaks multiply and can grow to the point where they threaten the integrity of the pipe. In general the deterioration of unprotected steel accelerates as it ages.

PSE&G's Inventory of Cast Iron and Unprotected Steel

PSE&G's distribution system contains a large inventory of cast iron and unprotected steel. Exhibit 1.7 shows that the Company has 2,921 miles of cast iron pipe comprising 16% of its main system at year end 2021. When compared to other distribution companies that have significant amounts of cast iron in their distribution pipe inventory, PSE&G has the most total miles of cast iron main.

Exhibit 1.7

Ten Largest Cast Iron Gas Distribution Systems

Name	Total Miles of Main	Miles of Cast Iron Main	CI % of Total Main
PUBLIC SERVICE ELECTRIC & GAS CO	18,173	2,921	16%
BOSTON GAS CO	11160	1683	15%
DTE GAS COMPANY	20620	1528	7%
PHILADELPHIA GAS WORKS	3046	1239	41%
KEYSPAN ENERGY DELIVERY - NY CITY	4190	1111	27%
PEOPLES GAS LIGHT & COKE CO	4634	1015	22%
BALTIMORE GAS AND ELECTRIC COMPANY	7527	974	13%
CONSOLIDATED EDISON CO OF NEW YORK	4408	879	20%
NIAGARA MOHAWK POWER CORP	3227	632	20%
SOUTHERN CONNECTICUT GAS CO	2513	586	23%

Source: Pipeline and Hazardous Materials Safety Administration
2021 Annual Report for Gas Distribution System Form F7100.1-1

PSE&G also has a significant amount of unprotected steel. Exhibit 1.8 shows that when PSE&G's total miles of unprotected steel mains and the total miles of unprotected services are combined they sum to 2,004 miles, which comprises 6% of the Company's distribution system. When compared to the other distribution companies that have significant amounts of unprotected steel in their distribution system inventory, PSE&G is ranked in the top ten in total miles of unprotected steel mains and services.

Exhibit 1.8

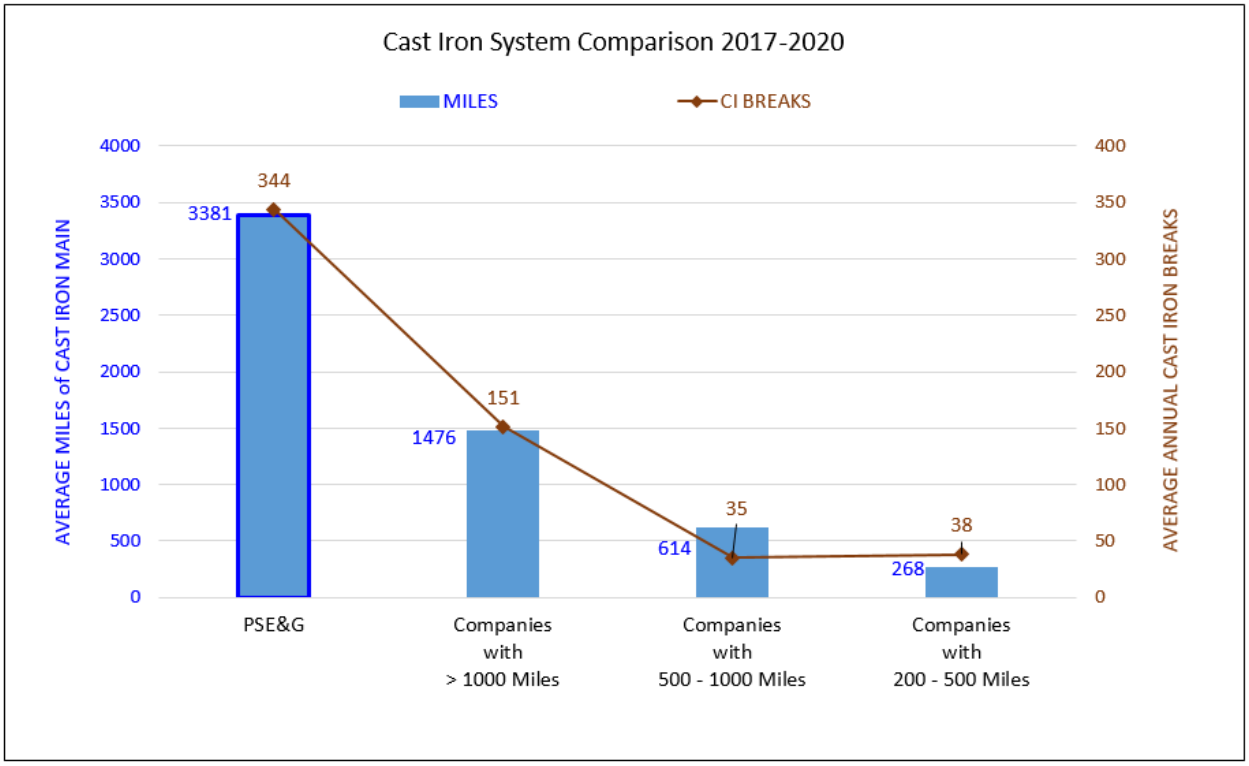
Ten Largest Unprotected Steel Main and Services Gas Distribution Systems

Name	Total Miles of Main and Services	Miles of Unprotected Steel Main and Services	Unprotected Steel % of Total Main and Services
SOUTHERN CALIFORNIA GAS CO	101603	16376	16%
ATMOS ENERGY CORPORATION - MID-TEX	48926	4305	9%
DOMINION ENERGY OHIO	31067	4103	13%
KEYSPAN ENERGY DELIVERY - LONG ISLAND	15288	3537	23%
DTE GAS COMPANY	45453	2844	6%
PEOPLES NATURAL GAS COMPANY LLC	16373	2696	16%
COLUMBIA GAS OF OHIO INC	42290	2493	6%
PUBLIC SERVICE ELECTRIC & GAS CO	35556	2004	6%
BOSTON GAS CO	18671	1994	11%
NIAGARA MOHAWK POWER CORP	16828	1890	11%

Source: Pipeline and Hazardous Materials Safety Administration
2021 Annual Report for Gas Distribution System Form F7100.1-1

The magnitude of the cast iron and unprotected steel pipe in the Company's network is a concern. Exhibit 1.9 compares PSE&G's cast iron performance to other gas companies with inventories of cast iron main greater than 200 miles for the 4 year period 2017-2020 (these are the companies that consistently reported cast iron system data over the period to PSE&G's Peer Panel). Miles of cast iron main are plotted against the average annual number of breaks. It can be seen that the key benefit of inventory reduction is a reduction in the total number of breaks. There is an inherent risk associated with a cast iron main break and the large volume of escaping gas leading to a catastrophic incident. Reducing this risk exposure requires a sustained, significant replacement program.

Exhibit 1.9



As shown in Exhibit 1.10, PSE&G's leak rate for services is 0.31 leaks per 100 services, which is below (i.e., better than) the national average (all gas distribution companies reporting to PHMSA) of 0.46 leaks per 100 services. PSE&G's leak rate for mains of 0.14 leaks per mile is higher (i.e., worse than) the national average of 0.05 main leaks per mile. In fact the Company's main leak rate is almost three times the national average. The explanation for the lower national average main leak rate reflects the reliability of the newer materials that make up the national network.

Exhibit 1.10

Comparison of PSE&G's Leak Rates to National Average

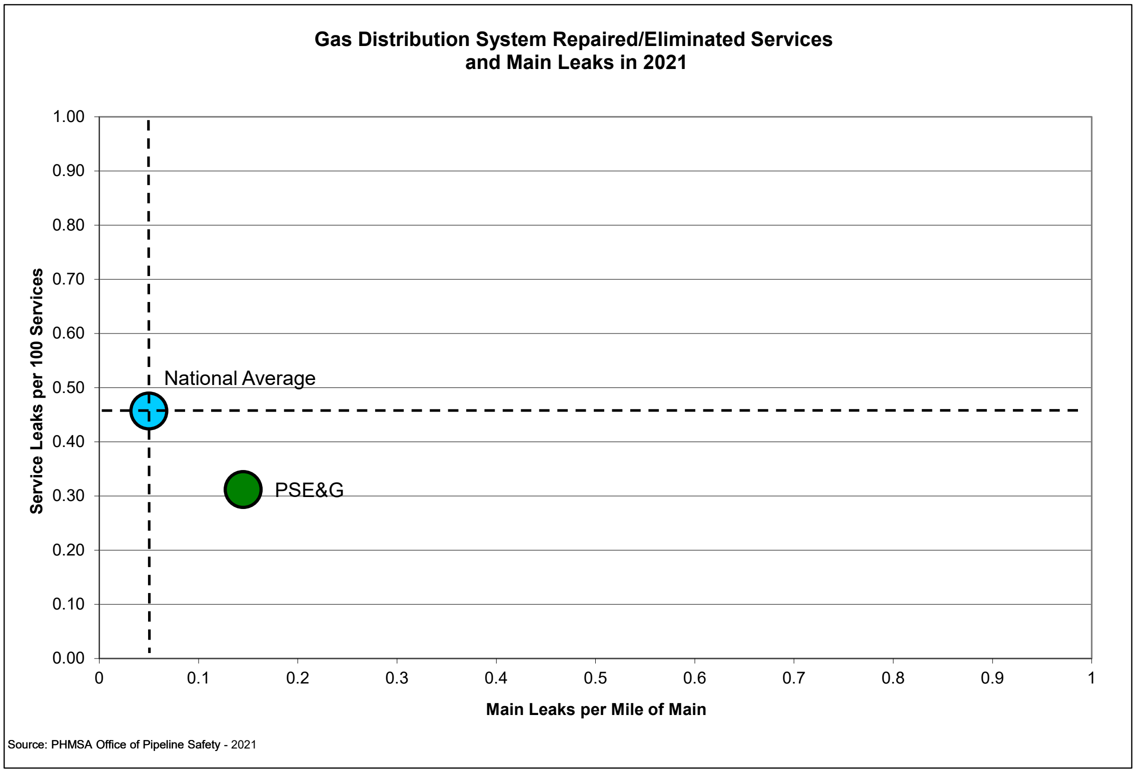


Exhibit 1.11 compares PSE&G to distribution networks that have large amounts of cast iron and unprotected steel. The data is displayed by Main Leaks per Mile of Main rate from lowest to highest. There is significant variation between main leak rates and service leak rates. In general, companies with higher percentages of cast iron main have higher main leak rates and companies with higher percentage of unprotected steel main and service have higher service leak rates. PSE&G results are better than the average of all companies in both main leak rates and service leak rates.

Exhibit 1.11

Leak Rates among Utilities with the Most Cast Iron and Unprotected Steel Main

Names	Total Miles of Main	Total # of Services	Total Main Leaks	Total Service Leaks	Main Leaks per Mile of Main	Service Leaks per 100 Service	National CI Rank	National UP ST Rank
KEYSPAN ENERGY DELIVERY - LONG ISLAND	8,399	559,566	640	1,090	0.08	0.19	24	4
PEOPLES GAS LIGHT & COKE CO	4,634	511,530	428	2,247	0.09	0.44	6	177
DOMINION ENERGY OHIO	19,832	1,186,493	2,235	6,243	0.11	0.53	49	2
COLUMBIA GAS OF OHIO INC	20,372	1,394,289	2,390	7,931	0.12	0.57	29	6
ATMOS ENERGY CORPORATION - MID-TEX	31,994	1,786,524	3,803	15,424	0.12	0.86	N/A	3
SOUTHERN CALIFORNIA GAS CO	51,670	4,468,600	6,200	36,351	0.12	0.81	N/A	1
NATIONAL FUEL GAS DISTRIBUTION CORP - NEW YORK	9,785	462,607	1,293	935	0.13	0.20	22	9
PUBLIC SERVICE ELECTRIC & GAS CO	18,173	1,269,428	2,633	3,957	0.14	0.31	1	12
DTE GAS COMPANY	20,620	1,227,718	3,416	3,498	0.17	0.28	3	8
COLUMBIA GAS OF PENNSYLVANIA	7,716	437,717	1,567	1,028	0.20	0.23	34	11
PEOPLES NATURAL GAS COMPANY LLC	10,373	633,562	2,889	2,330	0.28	0.37	31	5
MOUNTAINEER GAS CO	5,964	218,609	2,174	797	0.36	0.36	N/A	7
KEYSPAN ENERGY DELIVERY - NY CITY	4,190	572,715	1,824	890	0.44	0.16	5	27
BOSTON GAS CO	11,160	767,894	6,065	2,850	0.54	0.37	2	10
PHILADELPHIA GAS WORKS	3,046	476,600	2,274	2,794	0.75	0.59	4	21
CONSOLIDATED EDISON CO OF NEW YORK	4,408	377,982	6,093	3,761	1.38	1.00	8	15
				AVERAGE	0.31	0.45		

Source: Pipeline and Hazardous Materials Safety Administration

2021 Annual Report for Gas Distribution System Form F7100.1-1

Exhibit 1.12 summarizes PSE&G's inventory of cast iron and unprotected steel mains by size and operating pressure.

Exhibit 1.12

At-Risk Aging Infrastructure

Current Inventory at Year-End 2021

Total Miles of Cast Iron Mains

SIZE	UP	15 PSI	60 PSI
3	0	0	0
4	1242	0	0
6	822	0	0
8	249	0	0
10	37	2	0
12	128	88	0
16	9	117	9
20	2	73	20
24	0	67	9
30	0	18	0
36	0	22	4
42	0	4	0
Total	**2488**	**391**	**42**

Total Miles of Unprotected Steel Mains

SIZE	UP	15 PSI	60 PSI	120 PSI
1.25	0	0.4	0.2	0
2	1	76	217	1
3	2	36	81	1
4	8	35	70	2
6	5	21	69	1
8	3	10	42	0
10	0	0	5	0
12	1	13	79	0
16	0	3	28	0
20	0	1	4	9
22	0	0	2	0
24	0	0	0	6
26	0	1	3	2
30	0	1	2	0
36	0	0	6	0
Total	**19**	**199**	**610**	**24**

PROPOSED PROGRAM

Phase three of PSE&G's Gas System Modernization program continues and builds upon the strategic vision for the system of the future and ensures an appropriate progression to accomplish the long-term goals, maintain consistency and avoid the increased cost from potential inefficiencies such as requiring a ramp-up/ramp-down.

Work to be Done

The Program is a systematic cast iron and unprotected steel pipe replacement and rehabilitation program that will increase public safety, operational efficiencies, and environmental protection. It is a three-year program and approximately 380 miles of mains will be replaced each year. The summary of the Program is illustrated in Exhibit 1.13.

Exhibit 1.13

Program Scope Summary

Program Length	3 YEARS
Program Cost ($M)	2,388
Program Miles	1,140
Average Cost $M/Mile	2.1
EP Cast Iron Main Miles	50
UP Cast Iron Main Miles	810
Unprotected Steel Main Miles	200
UP CP Steel and Plastic Main (Miles)	80
Abandoned Regulators	210
Unprotected Steel Services	92,130
Relocate Inside Meter Sets	49,178

Materials

All new main and service materials installed will be Polyethylene (PE) or coated and cathodically protected steel pipe. PE pipe, or more generically plastic pipe, is the current state-of-the-art material for natural gas distribution systems due to its non-corrosive properties.

Where a larger diameter, or design conditions require, coated and cathodically protected steel pipe will be installed.

Plastic systems have fewer joint connections susceptible to leakage, can withstand ground movement caused by frost and will not corrode. PE pipe also enables the Company to more readily isolate and shutoff smaller areas because it can be "squeezed off," which is a technique that uses a tool that compresses the pipe to stop escaping gas, thus minimizing the impact on customers.

On large diameter replacements, PSE&G designs call for construction using coated, cathodically protected steel. Cathodically protected steel is highly resistant to the effects of corrosion due to the two levels of protection provided by the coating and the cathodic protection system. The pipe is significantly more resistant to the effects of ground stresses due to its ductile nature and is more resistant to outside damage due to the strength of the steel.

UPCI Main Replacement

Since the UPCI replacement represents the largest component of the program at this juncture it is appropriate to review the methodology of main selection as phase three accelerates and replaces more miles of UPCI annually than Phase I and II.

Has the grid based prioritization used in GSMP I and II reduced risk and is it the most cost-effective solution? Does an alternative comparably achieve the modernization goals?

Comparison of Alternatives

The UPCI replacement can be accomplished through the grid-based (UP to EP) upgrade or a targeted main selection that primarily replaces UPCI mains with UP Plastic mains (UP to UP). This is a feasible approach and will provide meaningful risk reduction. This approach however has significant foregone benefits compared to the grid-based approach.

Exhibit 1.14 compares the modernization benefit of the two replacement approaches.

Exhibit 1.14

Replacement Benefit Comparison

SYSTEM MODERNIZATION BENEFIT	UP to EP	UP to UP
Eliminate leak-prone pipe - reduce risk, reduce methane emissions	✓	✓
Eliminate outage risk due to water infiltration	✓	
Install Excess Flow Valve safety devices	✓	
Abandon District Regulators and eliminate potential overpressure methane release	✓	
Enable customer use of high efficiency appliances	✓	

It can be seen that upgrading UP to EP has multiple modernization benefits that are not achieved by replacing UP with UP.

There are also significant differences in the manner by which each alternative gets implemented. Exhibit 1.15 compares the execution of the two replacement approaches.

Exhibit 1.15

Replacement Execution Comparison

PROGRAM EXECUTION	UP to EP	UP to UP
Planning	Multi-year, strategic, design and operation upgrade	Annual, tactical, based on new main segments with breaks
Municipal coordination	Multi-year advanced notice and communication allows opportunity to coordinate schedules between multiple parties and gain synergies	Annually - limits ability to coordinate with paving and other utility programs, limits flexibility of scheduling, lost synergies
Construction efficiency	More efficient, contiguous areas modernized	More scattered construction, more tie-ins - less efficient completion of work
Pipe Size	Higher pressure allows smaller diameter replacement	Larger relative diameter most mains replaced size for size
Costs	Optimized due to work concentration, construction efficiencies, smaller pipe size, fewer tie-ins, less mobilization-de-mobilization More UPCI main replaced per $ expended	Higher material cost due to larger pipe sizes. Higher labor cost due to loss of construction efficiency, larger pipe size Less UPCI main replaced per $ expended
Customer Impact	All work in neighborhoods completed consecutively, all leak-prone pipe in contiguous areas removed with minimal need to return in future years	Some leak-prone pipe remains in neighborhood, results in mobilization into and out of neighborhoods and municipalities over multiple years for leak repairs and future replacements

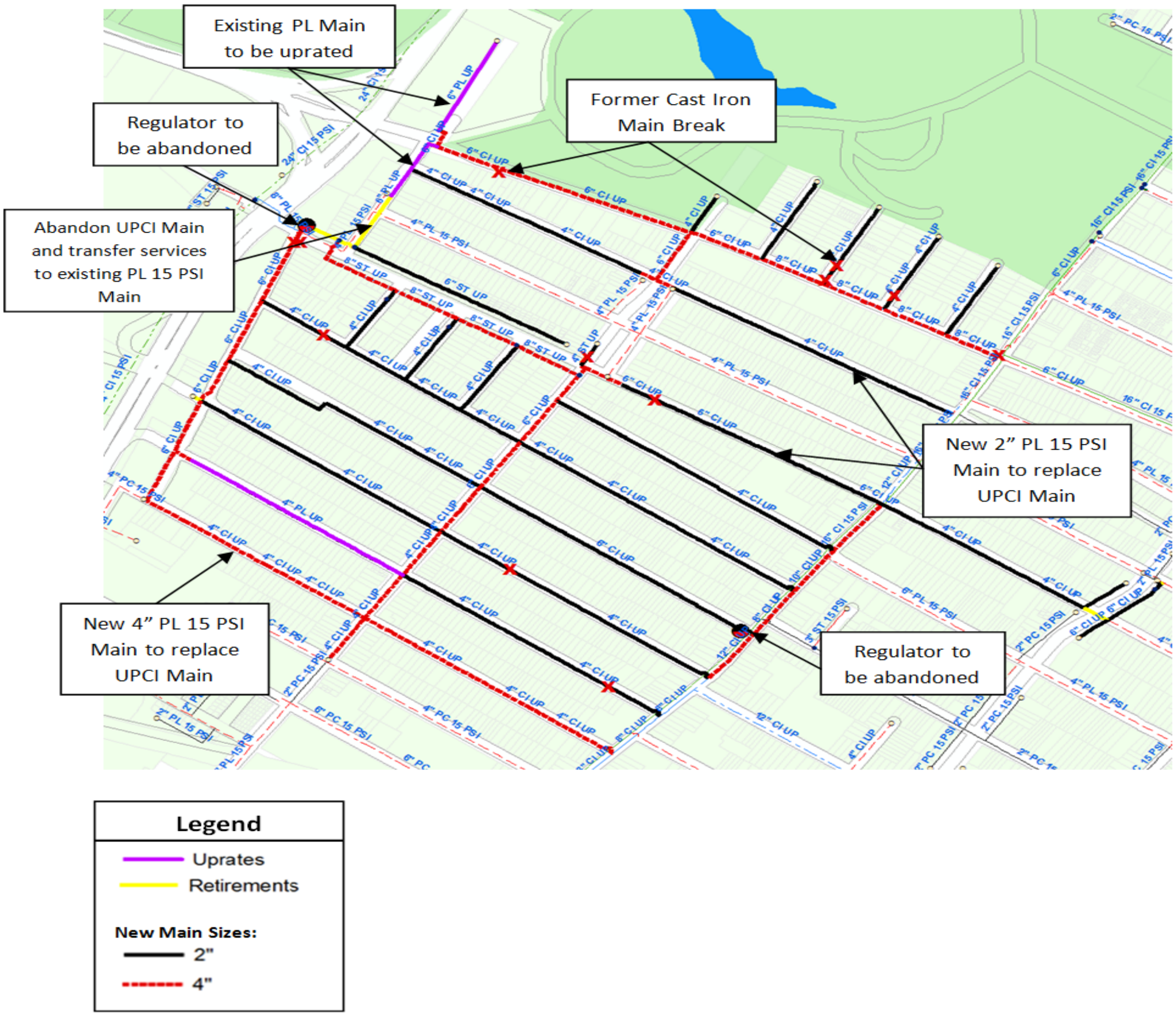
The targeted UP to UP approach doesn't lend itself to a cohesive programmatic replacement. It doesn't result in complete replacement of leak-prone pipe in contiguous areas, only a minority of mains and customers get upgraded to higher pressure. Annually the number and length of targeted mains will vary based on annual UPCI breaks experienced and as a result more or less additional main segments must be identified. Because the targeted segments must be identified each year, planning & coordinating with municipalities and other utilities is limited.

The following examples compare the Grid replacement approach UP to EP to the Targeted Replacement approach UP to UP and illustrate the types of projects that might present themselves in a grid. This particular grid sample contains:

- Utilization pressure cast iron and unprotected steel to be replaced;
- Utilization pressure cast iron to be abandoned;
- Utilization pressure plastic to be uprated;
- District regulators to be abandoned; and
- Breaks that have already occurred on cast-iron pipe are designated with an "X".

Exhibit 1.16

UP to EP Grid Replacement



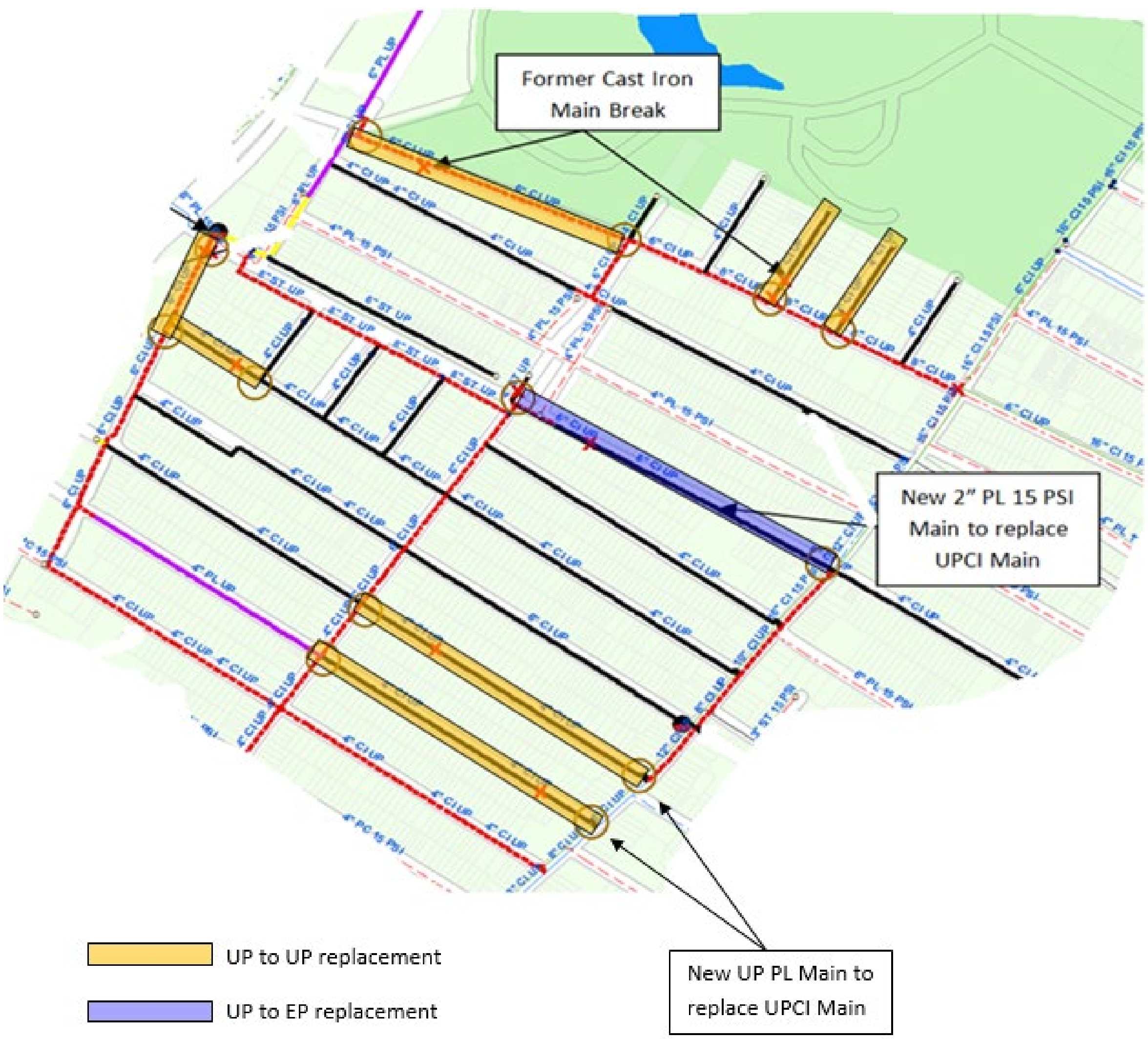
In order to execute the work in this grid, a series of work activities need to be undertaken. New plastic main is installed in locations where cast iron and unprotected steel mains are identified for replacement. These new mains are pressure tested, connected to the existing 15 psig system, and put into service. Service lines are replaced where identified as unprotected steel, and all service lines get transferred over to the new mains. Once this is complete, the existing mains can be abandoned. In locations where there are uprate activities, existing service lines will be replaced if necessary and a service regulator will be installed. A 15 psig main will be connected to the existing plastic main and pressure will be elevated in stages until complete.

Where a cast iron main is identified for abandonment alone, the existing services will be replaced if necessary and transferred to the existing pressure main. At the completion of the main and service work, the district regulators can be abandoned. The execution concept is to completely replace the entire UP CI/US pipe in a grid at one time. The entire area is upgraded to EP and no leak-prone pipe remains in the area. Employing this approach will help minimize disruption and improve work efficiency.

Exhibit 1.17 illustrates the same area addressed through targeted replacement for those segments of UPCI with a history of breaks.

Exhibit 1.17

UP to UP Targeted Replacement



In this same area, eight separate main segments would be replaced under a targeted replacement program and only one of the eight would be upgraded to Elevated Pressure since it is adjacent to an EP main and the reliability of the UP system is not dependent on the main. Thirty-five segments of UPCI main and associated unprotected steel services would not be replaced and remain potential sources of leaks and breaks. This demonstrates a less efficient use of labor and materials (More mobilizations; larger replacement pipe; multiple tie-ins and associated tap holes, pipe cutting, couplings) and less effective method of upgrading the legacy UP system. The area still operates at UP so no EFV safety devices would be installed on the services connected to the new UP PL mains, no district regulators would be abandoned and the potential for seal pot relief remains. Water infiltration is still a risk. High efficiency appliances would not be supported. Furthermore, multiple mobilization over the coming years could be expected to respond to and repair leaks and then return to replace the targeted segments.

The remaining question is does targeted UP to UP replacement provide greater risk reduction than Grid-Based UP to EP replacement to justify selecting this approach?

Risk as measured by PSE&G's Hazard Index calculates the risk associated with a specific segment experiencing another break. Applying the targeted approach strictly would reduce PSE&G's inventory of UPCI mains with break history faster than the Grid-based approach, however, in this approach mains with very low hazard values would be replaced every year. In an accelerated replacement program designed to replace all UPCI mains maintaining an inventory of low risk UPCI mains with breaks based on low Hazard Index values does not present undue risk because the risk of a future break on these segments would be relatively low due to the environmental characteristics of their location. The Grid-Based approach results in more UPCI main replaced per $ expended due to the construction efficiencies and smaller pipe size. The grid-based prioritization approach favors areas of higher densities of customers thus reducing exposure to risk for a greater number of customers more quickly and realizes all the system modernization benefits.

Modernization Plan

It is desirable to manage risk while achieving all the benefits of modernization and the grid-based approach is superior to the targeted approach in meeting this objective.

The Utilization Pressure portions of the system will be upgraded to higher pressure mains and services. The new elevated pressure will vary depending upon its location. Eliminating the utilization pressure system will not result in any foregone system functionality. Replacing the UPCI and unprotected steel with PE pipe can reduce operating and maintenance cost. PSE&G delivers and has delivered natural gas to over 70% of its customers at elevated pressure for many years.

For GSMP III, as in GSMP I and II, UPCI mains will be replaced following the Company's grid prioritization and the UP system upgraded to elevated operating pressure. This will reduce the risks of CI/US pipe and take advantage of economic efficiencies to reduce construction costs. This approach ensures that high-risk segments will continue to be replaced, while gaining the efficiencies and benefits of larger zone replacements such as economic opportunities in mobilization, material, and contractor pricing.

A grid ranking process has been developed based on the Company's Hazard Risk Index Model. The approach is the same as the hazard ranking method used in GSMP I and GSMP II. PSE&G targets the replacement of its riskiest gas assets through the use of a ranking methodology that prioritizes main segments with the highest risk, through the use of the Hazard Index. The Hazard Index is based on a predictive model constructed from leak history and "environmental factors" that include: building setback, number of underground utilities, demographic area (urban, suburban, rural), building types (industrial, commercial, or residential), and asset information (pipe diameter, operating pressure). Through the "weighted leak history" factor, past main breaks are considered and weighted based on how recently they occurred. Each map grid is evaluated by adding the hazard indexes for the individual utilization pressure segments within the grid and dividing them by the total miles of utilization pressure cast iron in the grid, arriving at a hazard index per mile for each map grid. Consistent with the hazard index per mile results, grids are ranked by highest to lowest and then placed into A, B, C and D priority grid categories.

In GSMP I and II, PSE&G collaborated with the Environmental Defense Fund to conduct a study on methane emissions in grids that were selected for the first 3 years of the program. PSE&G's valuable experience with this effort resulted in a sub-prioritization that takes into account methane quantification. This sub-prioritization will again be used for grids of similar hazard in the GSMP III extension.

PSE&G's gas distribution system is mapped into grids and each grid measures approximately one square mile. There are more than 350 grids that contain between one and 22 miles of UP cast iron pipe along with other types of pipe.

There are a number of technical and non-technical factors that need to be considered in determining the quantity and timing of replacement grids, including:

- Where similar priority grids are adjacent to each other, the full block of grids will be reviewed to determine the most effective approach for sizing and staging of the installation and abandonment work within the entire area;
- Projects will be encountered where UP CI/US mains will not end at the grid line. Consequently, it will be necessary to decide, as the strategy for working a grid is developed, whether the crossover main should be worked with the current higher priority grid, held over until the neighboring grid is worked, or performing work on both grids at the same time. This decision would be based on system reliability,

effectiveness, and efficiency;

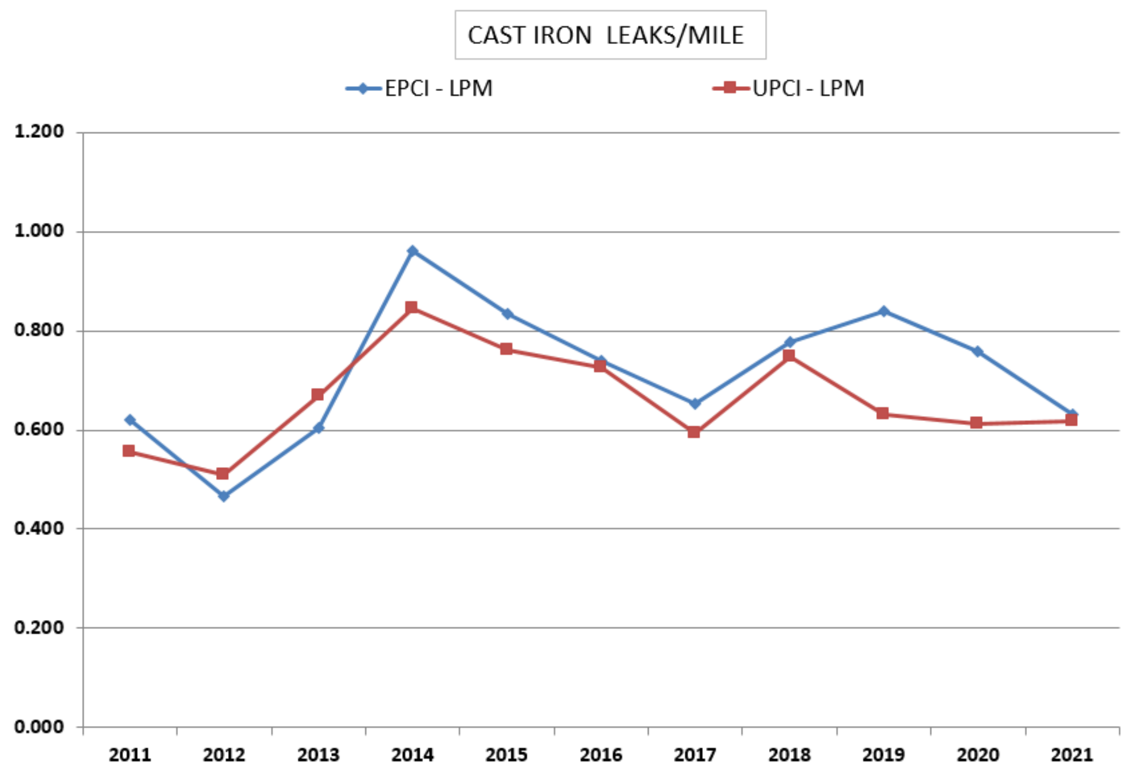
- In locations where known large scale work will be performed by other utilities, the area will be reviewed to determine if the work should be done in conjunction with the other utility to improve efficiency of road closures and paving. Also, PSE&G often observes increased breaks on CI mains after large scale construction projects, so replacing nearby CI mains in conjunction with these projects provides an increased level of reliability and safety; if warranted by engineering considerations, municipal coordination and construction synergies, PSE&G would advance a lower priority grid to be replaced.
- While the majority of gas main replacement work will not lead to new business connections, incidental requests may occur on occasion. When this occurs, facilities will be designed in accordance with PSE&G's Gas Design Manual and facility costs will be treated consistent with PSE&G's approved Gas Tariff; and
- Any unforeseen permitting issues, issues regarding cooperation from municipalities, and coordination with other construction activities will need to be taken into consideration when executing the work. Similarly, unforeseen construction issues (e.g., unanticipated buried utilities, physical obstructions) will also need to be taken into consideration as the work is executed.

The program would reduce the inventory of UPCI by approximately 37%.

EPCI Main Replacement

Similar to UPCI mains, EPCI mains are aging and prone to leakage at joints and connections. At larger diameters and higher operating pressure, leaks on these mains will release more gas than leaks on UPCI mains. This increases the risk associated with an EPCI leak. Exhibit 1.18 shows that EPCI historically has a similar leak rate to UPCI.

Exhibit 1.18



EPCI replacement can be more cost effective and practical than continued leak repair. These large diameter, higher pressure mains often require additional steps to safely effectuate repairs such as pressure reduction through valve throttling and engaging specialty contractors to perform encapsulation. The importance of the mains to the reliability of the distribution system can also require leaks to remain open longer until appropriate system adjustments can be made, particularly during the winter months when it is not possible to reduce the pressure due to system demand so repairs get deferred to warmer weather of lesser demand and thus require continued gas venting and leak re-checks. These issues are not seen on UPCI.

Not addressing the EPCI can add new risks to the continued operation of that facility related to the following:

- Service Connections – Tapping large diameter cast iron mains presents a greater risk of failure than working on plastic and steel mains, potentially leading to future leaks at tap locations and joint leaks at the excavation location due to pipe settlement. However in an effort to avoid redundant mains, where UPCI runs parallel to EPCI, the UPCI is often abandoned and services are moved to EPCI.

- Branch Connections – Many of the UPCI grids are in densely populated urban areas with many streets. There are typically mains on most if not all streets and most if not all of these streets will be fed from a feeder main. Where an EPCI feeder main exists, the new polyethylene mains installed as part of a UPCI system upgrade will be tied into it. Similar to service connections, where there are additional taps or cutouts of an EPCI main, the potential for future failures at tap locations, joints and fittings are increased. Additionally, cutouts often require special considerations to account for thrust, including the need for joint reinforcement and the installation of thrust restraint.
- Excavation – Regardless of the reason, each time excavation is performed around or in the proximity of an EPCI facility, the risk of future failure is increased. Excavation and vibrations due to excavation have the potential to cause soil settlement or instability that increases the risk of joint leaks and main breaks. Replacing the facility eliminates this risk.

Replacing this aging leak-prone EPCI pipe achieves the same benefits as UPCI replacement and should be part and parcel of a gas system modernization program. EPCI targeted inventory would include 10”, 12” and 16” EPCI located in a GSMP targeted grid to maximize construction efficiency and logistics. EPCI in a previously completed GSMP grid where final paving has not been completed would also be considered for replacement. With the following added value:

- Eliminate the need to return at a later date to replace targeted EPCI and open a road recently paved through the GSMP program or by the municipality upon completion of the work in the grid

- Reduce the total cost of restoration by distributing the restoration cost between UPCI and EPCI
- Allow PSEG to assure the municipality that the Company will not return in the near future to repair leaks or replace the targeted EPCI main
- Improve the Company's relationship with customers and communities with a onetime inconvenience to upgrade gas facilities

The program would reduce the inventory of these sizes EPCI by approximately 23%.

Cathodically Unprotected Steel Main Replacement

Corrosion is the primary threat to cathodically unprotected steel pipe. Facilities without cathodic protection typically exhibit a steadily increasing failure (leak) rate over time as the corrosion progresses which will eventually accelerate as more of the pipe deteriorates due to the corrosion resulting in widespread failure along the length of the pipe segment. Smaller diameter pipe with less metal mass will leak first, all other environmental aspects being equal. Replacement of these assets is necessary to stay ahead of the accelerating failure curve and is an important aspect of gas system modernization. The unprotected steel mains in the program will be prioritized by age, diameter, pressure, and leak history.

Cathodically Protected Steel and Plastic Main Replacement

Experiences in GSMP I and GSMP II have shown that certain segments of cathodically protected steel and plastic mains that are in the UP system are required to be replaced as part of a large grid based system conversion for economic and logistical reasons. This is approximately 7% of the overall program. In situations where small segments of cathodically protected steel or plastic mains are between sections of UP cast iron, it is more efficient and cost effective to replace the cathodically protected steel or plastic in conjunction with the UP cast iron, reducing the number of tie-ins and service interruptions. Furthermore, the Company has identified risk in uprating early vintage plastic materials and cathodically protected steel that was installed prior to the establishment of minimum standards for pipeline safety (Title 49 Part 192 of the Code of Federal Regulations). The uprating of polyethylene pipe of pre-1973 vintage is not recommended due to the known lower ductility and stress-induced slow crack growth, as well as published government performance concerns. Therefore, pre-1973 vintage polyethylene materials are replaced with current high performing polyethylene materials rather than uprated to elevated pressure. The type of construction and condition of facilities installed prior to the implementation of 49 CFR Part 192 (November 12, 1970), and the subsequent one year transition period, can vary considerably. During the initial GSMP I program, a number of cathodically protected steel mains were not uprated due to prior leak history, poor cathodic protection history, poor pipe condition or excessive mechanical couplings. The vast majority of these mains were installed prior to 1972. Additionally, some cathodically protected steel mains installed prior to 1972 that were uprated in GSMP I experienced leakage subsequent to the uprate. Therefore, pre-1972 cathodically protected steel mains are replaced with current high performing polyethylene materials rather than uprated to elevated pressure.

Moving Inside Meter Sets

Outside meter sets have numerous benefits. Having meters outside provides easy access for shut off in the event of an emergency, for both Company and emergency response personnel. Moving meter sets to the outside also improves access for meter inspection and leak surveys, as well as meter readers. It reduces the potential for gas leaks within buildings. It also reduces the potential theft of gas due to visibility of the meter location.

Compatibility with Hydrogen Blends and Renewable Natural Gas

Polyethylene pipe and coated, cathodically protected steel represent state-of-the-art gas main and service materials and are expected to perform to the same performance standards whether used with traditional natural gas or RNG. Hydrogen is a potential environmentally sustainable replacement for natural gas in the future. Although significant research is still required, there has been an abundance of information and studies in recent years on the use of natural gas blended with a minor percentage of hydrogen (up to 25% hydrogen). There is some concern with hydrogen's compatibility with natural gas infrastructure, but data indicates that up to 20% hydrogen blends can be a suitable replacement for pure natural gas in distribution systems and for end uses. Hydrogen differs from natural gas in a number of ways; it is lighter and burns faster, it has a high diffusivity and it has a wider explosive range. Polyethylene pipe has non-corrosive properties. The life-span of polyethylene pipe is not expected to be impacted by the introduction of hydrogen blends. Low-strength steel pipe that is used in distribution systems is not susceptible to hydrogen-embrittlement like higher strength steels. Therefore, hydrogen-induced failures do not present a concern for coated, cathodically protected steel pipe that is installed within the Company's distribution system. Hydrogen is a small molecule making a higher leakage rate by volume anticipated through valves, fittings and threaded connections. However, the amount of energy leaking is not expected to be higher than natural gas leaks.

Program Objectives

The GSMP objective is to upgrade and modernize PSE&G's gas distribution system by replacing 810 miles of UPCI, 50 miles of EPCI, 200 miles of unprotected/bare steel mains, and 80 miles of cathodically-protected steel and plastic main. Main replacement will result in approximately 210 abandoned district regulators, replacement of approximately 92,000 unprotected steel services, and the relocation of approximately 49,000 inside meter sets to the outside. This work will achieve:

- Improved long term safety and reliability of the system – reduced risk
- Outside access to service shut-off valves at meter sets
- Greater application of service line excess flow valves
- Reduced costs associated with leak repairs, leak re-checks, and regulator inspection and maintenance
- Avoided capital costs associated with unplanned and scattered replacement
- Reduced greenhouse gas emissions
- Increased ability to use higher-efficiency and other appliances.

Exhibit 1.19 - GSMP Risk Reduction Strategy, illustrates how the GSMP strategy responds to the assets at risk in PSE&G's distribution system as identified in the Company's DIMP. The Program drives a material risk reduction across the distribution system attributable to the improved performance of the modern assets installed and operated in a modern design configuration vs. the replaced assets and legacy UP operating system.

Exhibit 1.19

GSMP RISK REDUCTION STRATEGY

Facility	Cause	Strategy	Risk Impact
ASSETS - HIGH RISK		**GSMP RISK RESPONSE**	
Plastic Services	Excavation Damage	Excess flow valve installation in replaced or transferred services	Mitigate
Cast Iron Joints - Pre 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Steel Services	Corrosion	Replace unprotected steel services with plastic	Mitigate
Cast Iron Pipe - Pre 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
ASSETS - MEDIUM RISK			
Cast Iron Pipe - Post 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Plastic Mains - Post 1973	Excavation Damage	New Plastic has lower overall risk profile than cast iron or unprotected steel. Valves installed on new EP mains	Accept
Steel Service Valves	Corrosion	Replace unprotected steel services with plastic	Mitigate
Plastic Service Valves	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Cast Iron Joints - Post 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
ASSETS - LOW RISK			
Steel Main Service Tees	Corrosion	Replace unprotected steel mains with plastic or CP steel	Mitigate
Steel Service Mechanical Coupling	Natural Force Damage	Replace unprotected steel services with plastic	Mitigate
Steel Main Mechanical Coupling	Natural Force Damage	Replace unprotected steel mains with plastic or welded CP steel. Replace CP steel mains with excessive couplings with plastic if part of UPCI grid upgrade	Mitigate
Steel Service Mechanical Coupling	Corrosion	Replace unprotected steel services with plastic	Mitigate
Plastic Service Valves	Material Defect	New Plastic has lower overall risk profile than unprotected steel	Accept
Steel Service Mechanical Coupling	Material Defect	Replace unprotected steel services with plastic	Mitigate
Steel Main Risers	Corrosion	Replace cast iron and unprotected steel mains with plastic or CP steel	Mitigate
Steel Services	Excavation Damage	Excess flow valve installed (if feasible) in replaced or transferred services	Mitigate
ASSETS - VERY LOW RISK			
Steel Mains	Corrosion	Replace unprotected steel mains with plastic or CP steel	Mitigate
Metersets	Corrosion	Relocated meters and existing outside meters are coated with corrosion inhibitor	Mitigate
Plastic Pre-1973 Main	Excavation Damage	Replace with plastic if part of UPCI grid upgrade	Mitigate
Steel Service Mechanical Coupling	Equipment Failure	Replace unprotected steel services with plastic. Replace separately protected steel services with plastic in conjunction with main replacement	Mitigate
Steel Main Service Tee	Natural Force Damage	Replace unprotected steel mains with plastic or CP steel	Mitigate
Cast Iron Joints - Pre 1946	Other Outside Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Cast Iron Joints - Pre 1946	Corrosion	Replace cast iron mains with plastic or CP steel	Mitigate
Plastic Main Service Tee	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Plastic Service Valves	Equipment Failure	New Plastic has lower overall risk profile than unprotected steel	Accept
Plastic Services	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Steel Service Valves	Natural Force Damage	Replace unprotected steel services with plastic. Replace separately protected steel services with plastic in conjunction with main replacement	Mitigate

The following performance measures are anticipated to show improvement at the conclusion of GSMP III on an annual basis (weather normalized):

Mains

- Leaks per Mile

Cast Iron Main

- Total Hazardous Leak Repairs
- Total Cast Iron Leak Repairs
- Total Cast Iron Breaks
- HP Cast Iron Leak Repairs
- UP Cast Iron Leak Repairs

Steel Main

- Total Hazardous Leak Repairs
- Unprotected Steel Main Leak Repairs

Services

- Leaks per 100 services

Steel Services

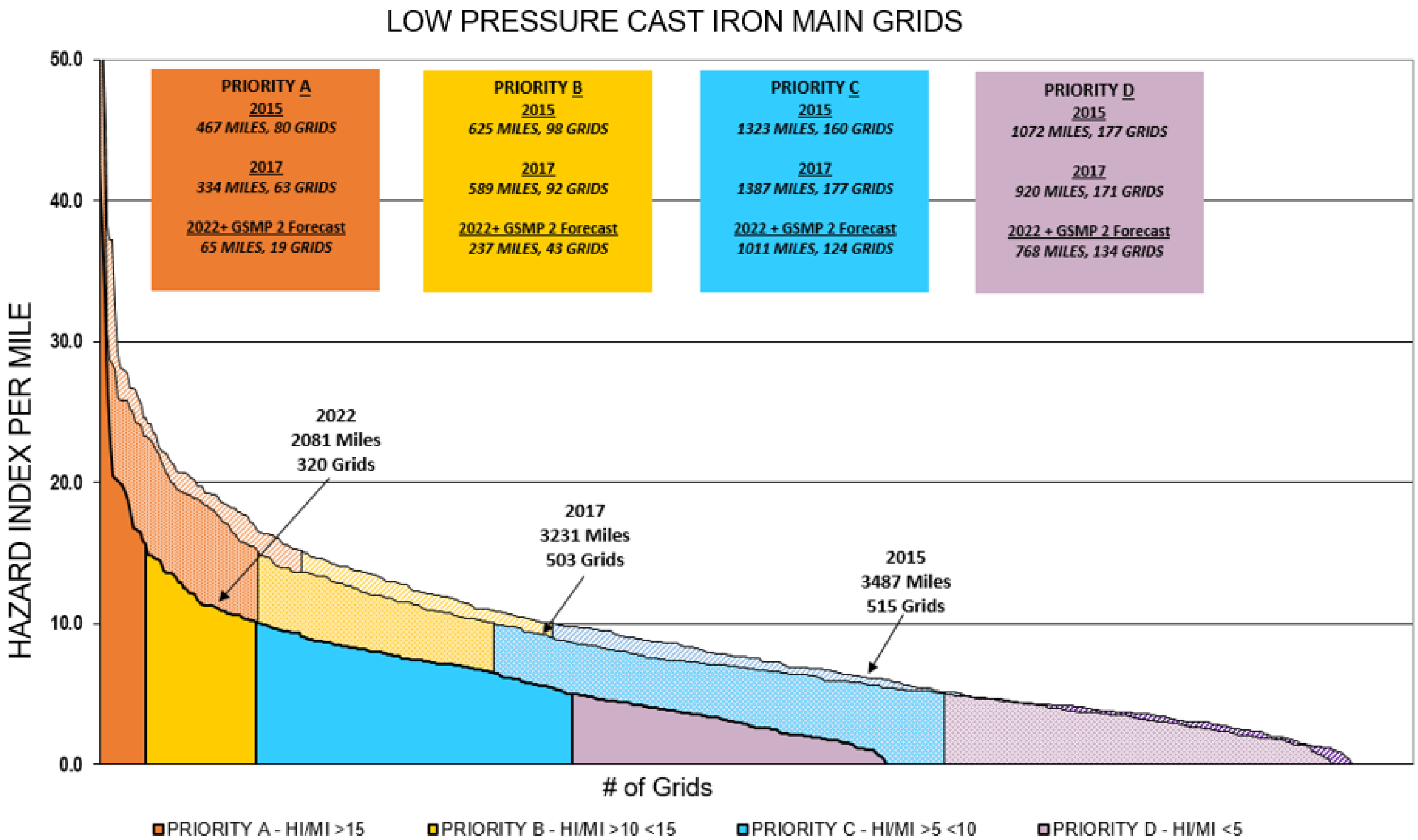
- Total Hazardous Leak Repairs
- Steel Service Leak Repairs

GSMP I + II RESULTS

Exhibit 1.20 illustrates the progress of the grid hazard ranking from prior to the implementation of GSMP I (2015) to prior to GSMP II (2017) to the anticipated ranking at the end of GSMP II. The chart demonstrates the effectiveness of the GSMP at reducing system hazard associated with the UPCI through reduction in the number of grids, total miles, and number of miles in the high priority categories.

Exhibit 1.20

Hazard Index/Mile Comparison through GSMP

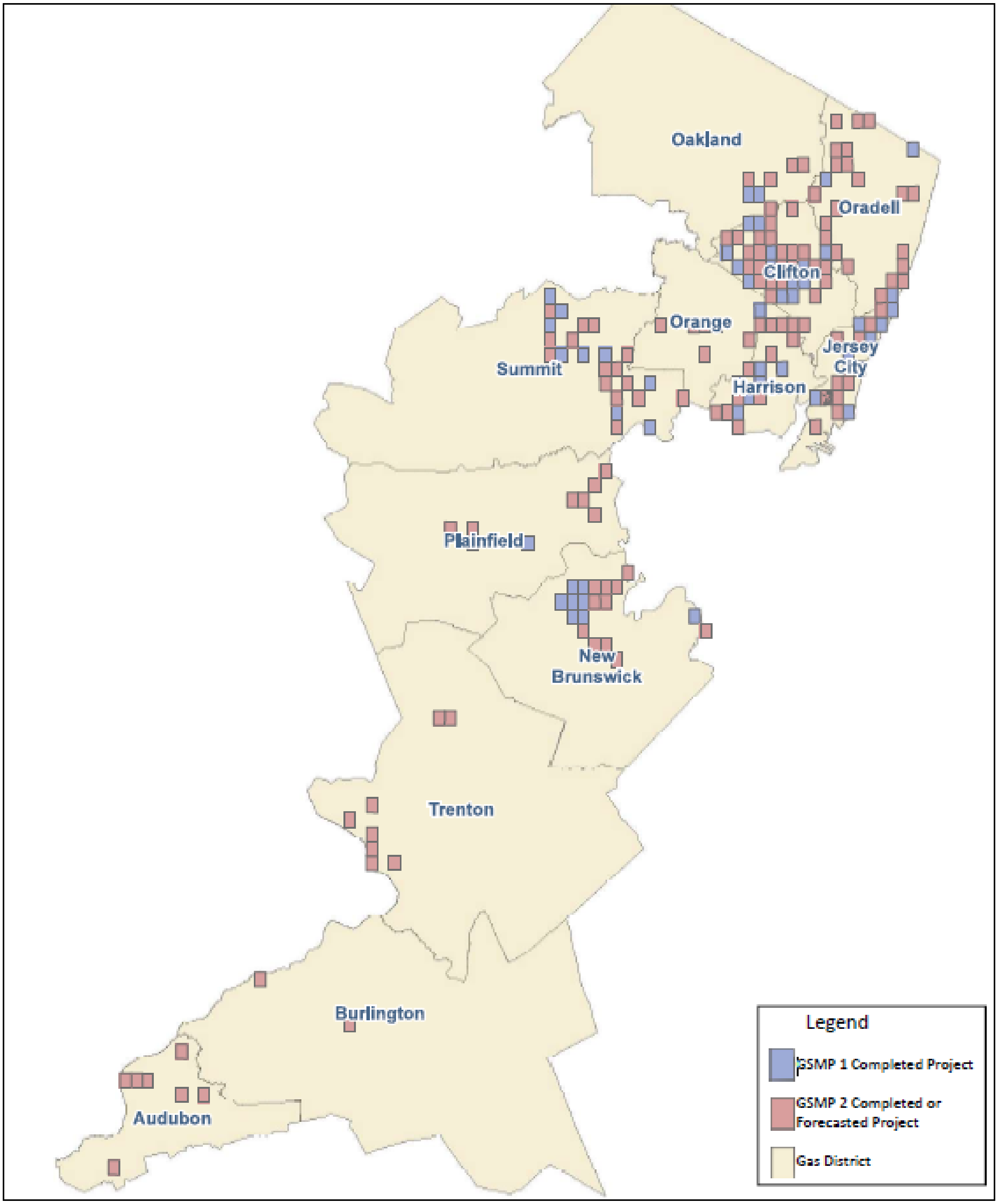


As shown in the graph above, Priority A hazard will be reduced by more than 85% through the completion of GSMP II. By the end of the GSMP III program, the Company anticipates that current Priority A, B and C hazard will be substantially reduced.

Exhibit 1.21 depicts the UPCI grids that were replaced during the GSMP I program and the UPCI grids that were replaced or are forecasted to be replaced by the end of the GSMP II program.

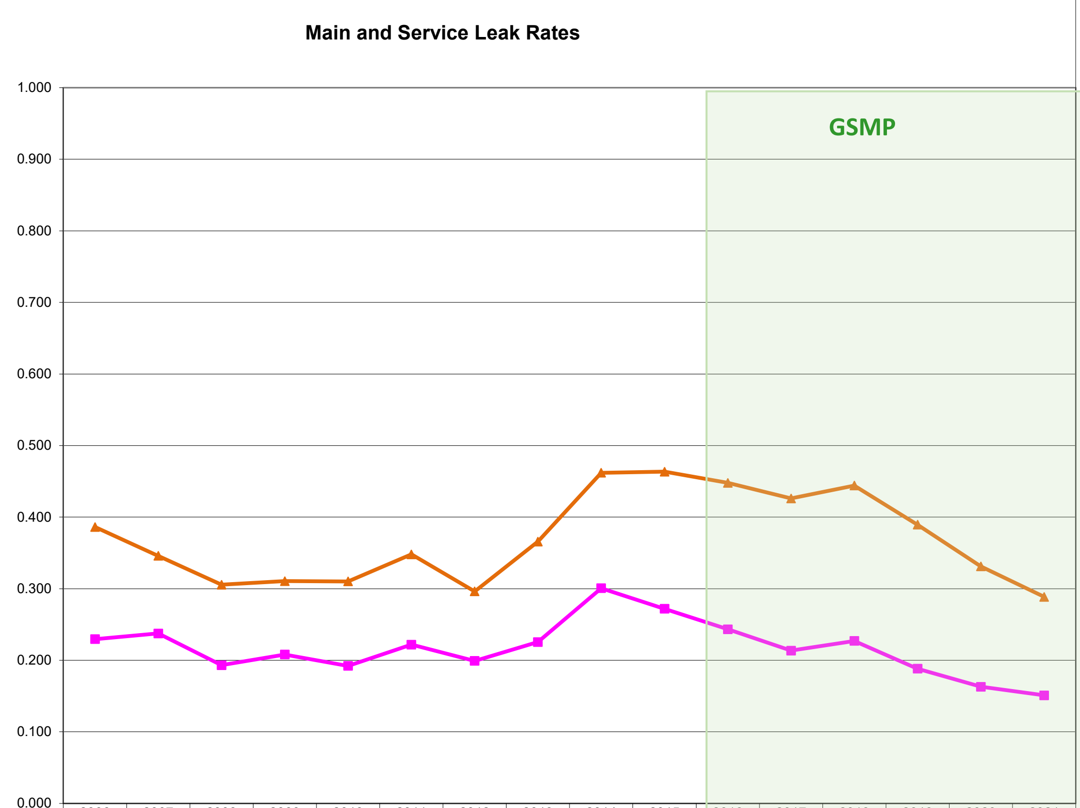
Exhibit 1.21

UPCI Grids in PSE&G Service Area Completed in GSMP I and II



As seen in Exhibit 1.22, PSE&G's leak rates on both main and services have been in a declining trend since the Gas System Modernization Program began in 2016. While annual leak rates are highly correlated to winter temperatures and the influence of ground frost on the mains and services, the accelerated reduction in the inventory of aging, leak-prone pipe through the GSMP has clearly had a positive influence on the long-term trend. Since the start of GSMP I the Company has reduced the inventory of UPCI mains by 947 miles and Unprotected Steel mains by 161 miles and Unprotected Steel services by over 98,000.

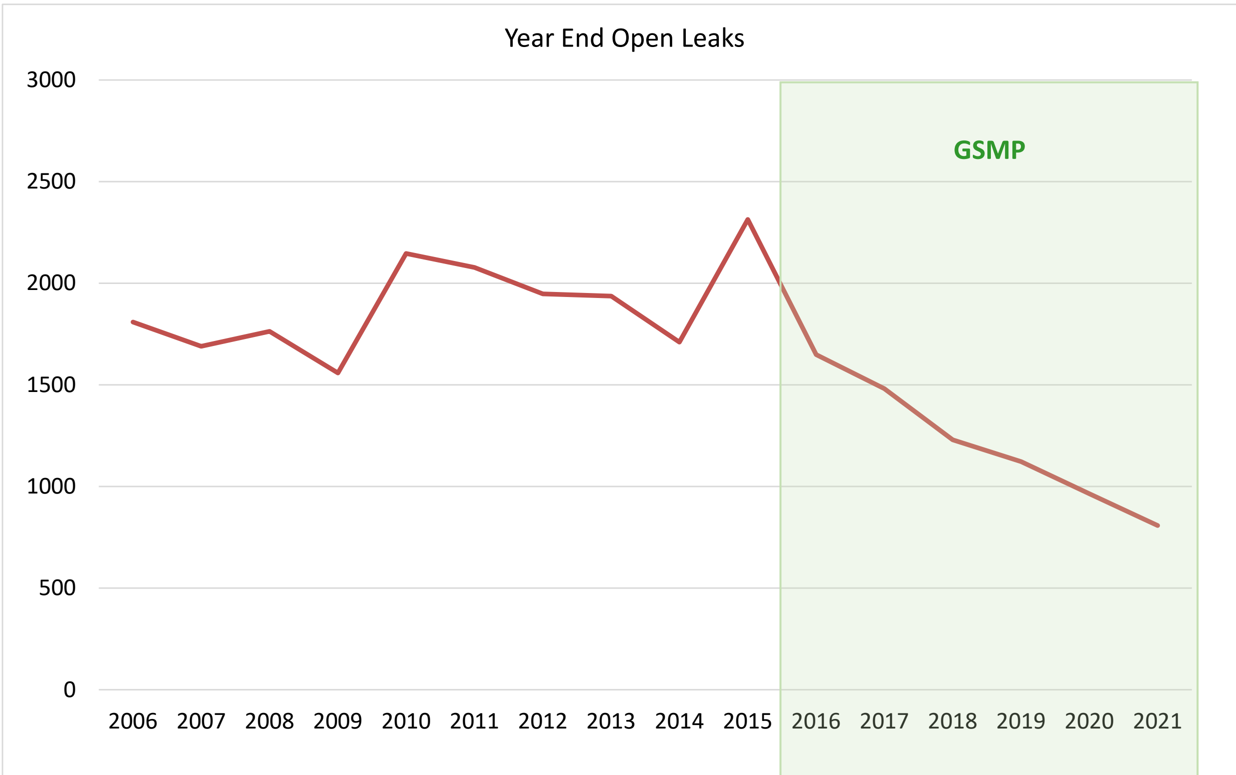
Exhibit 1.22



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Main Leaks/Mile	0.229	0.237	0.193	0.208	0.192	0.222	0.199	0.225	0.301	0.272	0.243	0.213	0.227	0.188	0.163	0.151
Service Leaks/100 Services	0.386	0.346	0.306	0.311	0.310	0.348	0.296	0.366	0.462	0.463	0.448	0.426	0.444	0.389	0.331	0.289

Similarly, the Company has been able to substantially reduce the number of Year End Open Leaks over the course of the GSMP program as shown in Exhibit 1.23.

Exhibit 1.23



Cost and In-Service Dates of Program

The cost of the proposed GSMP III Program has not been estimated at the individual project level. However, a body of work of a repetitive nature of relatively low complexity such as an ongoing program can be accurately estimated from historical experience. Deterministic methods that use the known costs actually experienced in the program including engineering, procurement, labor, construction, overhead, by cost element are analyzed. Unit costs are an accurate measure in a continuing program of similar work. By leveraging experience and a high degree of understanding of the work to be performed, estimates can be accurately scaled to the level of the program and additional contingency (other than inflation) is not applied. Exhibit 1.24 has the three year GSMP phase III program costs and units completed detailed by category.

Exhibit 1.24

3 YEAR PROGRAM Description		Miles/Units	2023 $/Unit	2023 $M	3YR TOT $M	2024 Units	2025 Units	2026 Units	2027 Units
EP Cast Iron Main (Miles)		50	3.31	165.6	177.21	15	17	17	-
	$M					$ 50.8	$ 57.4	$ 57.4	
UP Cast Iron Main (Miles)		810	1.93	1,566.3	1,676.53	249	281	281	-
	$M					$ 480.9	$ 542.7	$ 542.7	
Unprotected Steel Main (Miles)		200	1.51	303.0	324.32	61	69	69	-
	$M					$ 93.0	$ 105.0	$ 105.0	
UP CP Steel and Plastic Main (Miles)		80	1.51	121.2	129.73	25	28	28	-
	$M					$ 37.2	$ 42.0	$ 42.0	
District Regulators Abandoned *		210				30	80	100	-
*cost included in main cost									
Service Replacements *		92,130				28,286	31,922	31,922	-
*cost included in main cost									
Relocate Inside Meter Set		49,178	0.0015198	74.7	79.91	16,393	16,393	16,393	-
	$M					$ 24.9	$ 24.9	$ 24.9	
Total Miles		**1,140**	**Total $**	**2,231**	**2,388**	**350**	**395**	**395**	**-**
					$M	$ 686.8	$ 771.9	$ 771.9	$ -
					Annual Cash Flow ($Ms)	$ 515.1	$ 750.7	$ 771.9	$ 193.0
						$ 530.6	**$ 796.4**	**$ 843.5**	**$ 217.2**
Total Inflated Cash Flow (3%/year)		**2,387.7**	**Million**						
		2.09	**$M/Mile**						

The cost model is based on a continuous program. The model assumes that 25% of the cash flow each year will spill over into the following year, including the year following the third year. The model assumes that a subsequent program will be approved prior to the conclusion of the three year period to permit continuous work efforts to eliminate the maximum amount of CI/US main and US services.

Capital cost estimates are PSE&G system-wide and are not based on specifically identified physical assets. The three year program identifies the major capital elements that are part of the Program and develops unit and extended cost information based on the recent experience noted earlier. The estimates are developed in 2023 dollars and the program costs are escalated using an average escalation rate of 3%. This escalation factor was developed based on a mix of economic and engineering estimating factors. Capital cost estimates that were developed for recent major programs, including Energy Strong, GSMP I and GSMP II indicate that PSE&G has developed supportable estimates that reasonably reflect expected program costs.

Cost – Benefit Analysis

A cost – benefit analysis of the proposed GSMP Phase III has been prepared by an independent consultant, West Monroe Partners LLC, for PSE&G and accompanies this engineering report.

Schedule WEM-GSMPIII-7

Hydrogen Demonstration Engineering Report

CONFIDENTIAL

Schedule WEM-GSMPIII-8

RNG Project Engineering Report Basis of Design

CONFIDENTIAL

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE NEXT PHASE OF THE GAS SYSTEM MODERNIZATION PROGRAM AND ASSOCIATED COST RECOVERY MECHANISM (“GSMP III”)

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
ANDREW L. TRUMP
SENIOR PRINCIPAL, WEST MONROE PARTNERS, LLC

March 1, 2023

Q. Please state your name, employer and business address?

A. My name is Andrew L. Trump. I am employed by West Monroe Partners, LLC ("WMP"), a management and digital consultancy. My business address is 825 8th Avenue, 17th Floor, New York, New York, 10019.

Q. What position do you hold at WMP?

A. I am Senior Principal within WMP's Energy & Utilities ("E&U") practice.

Q. Please describe the activities of WMP.

A. WMP assists companies like PSE&G in gas and electric system modernization. This involves a wide range of matters related to the capital and operational planning and implementation of new technologies and capabilities to help electric and gas utilities efficiently and effectively manage their business and prepare for the future. The planning and implementation support provided often involves addressing questions and challenges concerning decarbonization, enabling electric vehicle market development and deployment, deploying advanced metering infrastructure, upgrading utility telecommunication systems, and integrating distributed energy resources onto the electric grid, to name a few areas of support. It also involves assisting gas local distribution companies ("LDCs") in preparing their decarbonization plans and considering other forms of gas blended in pipeline and electrification like renewable gas, certified gas, hydrogen gas, and use of hydrogen in fuel cells to electrify buildings. WMP is often asked to assist its utility clients in the program and project management including change management and business integration and digital enablement of multi-year initiatives related to these types of initiatives.

Q. Please summarize your professional background and your experience in the utility industry.

A. I have worked in a professional capacity since 1984, when I graduated from college, on a wide range of energy and transportation projects, programs, and initiatives. My experience includes work both as a consultant within management and professional services consultancies, and as an employee within technology and merchant energy firms. For example, starting in 1995 I was employed by CellNet Data Systems, a firm that developed one of the first radio frequency ("RF") based advanced metering and meter data management platforms. My role involved, amongst other responsibilities, the development of cost-benefit analyses for the company's utility customers and the negotiation of multi-year contracts for the deployment and lease of these systems. Starting in 2000 I was employed by Duke Energy North America, a wholesale power generator. At Duke I was responsible for the licensing of the development of large power plants, entailing the securing of land use, environmental, interconnection, and other necessary settlements and approvals needed to permit the Company to build these power stations. This role involved managing a large team of legal, technical, and environmental experts in multiple disciplines related to wholesale power development and large industrial site development. Starting in 2007 I began consulting on grid modernization, mainly focused on electric and gas distribution systems. I was employed by Black & Veatch Management Consulting through the end of 2018. There I performed independent consulting services, including for PSE&G, in a similar capacity on gas and electric distribution system issues. Starting in January 2021 I was hired by WMP for my current role. In this role I serve as a subject matter specialist across many areas and domains, including in performing economic and business case analysis for grid modernization plans and proving supporting testimony.

Much of my work during the past 15 years has been focused on the strategy, justification, planning, implementation, and review of a wide range of technologies of importance to electric and gas system operations. My educational background includes an undergraduate degree from Harvard College with a degree in Physical Sciences, a professional Project Management certificate from the University of California at Berkeley, and a master's degree in Public Policy from George Mason University.

Q. What is your experience related to gas systems?

A. I have supported gas system planning for several utilities throughout my career. As part of the powerplant development work, I was involved in the development of engineering and site-layout requirements, fuel quality requirements, and the environmental review associated with a gas delivery service to combustion turbines at power stations. I have also been heavily involved in the planning and implementation of new technologies, such as advanced metering, remote system monitoring, and telecommunications for several gas utilities. I have participated in assignments involving regulatory compliance issues related to indoor odor and corrosion inspection responsibilities and record keeping, and in the deployment of automated systems gas shutoff. I also supported PSE&G in its Energy Strong II proposal and program during 2017-2020, and specifically its plan to upgrade several Metering and Regulating ("M&R") stations, and to implement a series of main improvements to address system resiliency, specifically outage risks to the gas distribution system due to major events beyond (upstream) of the city gate. Most recently as part of a small team, I led and supported the development of cost benefit analysis standards of review for two large mid-western gas and electric utility companies, which were obligated pursuant to a Commission order to provide such recommendations to its Commission and stakeholders.

Q. Have you provided prior testimony to the BPU?

A. Yes. I supported PSE&G in its electric and gas improvement proposals made in the Energy Strong II proceeding by assisting with the preparation of direct and rebuttal testimony.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide evidence and analysis in support of a cost-benefit analysis ("CBA") for PSE&G's Gas System Modernization Program Phase III ("GSMP III"). The CBA is provided to fulfill filing requirements established within the New Jersey Administrative Code as found in N.J.A.C. 14:3-2 A.2 (c). This code section identifies the requirement to submit "any applicable cost-benefit analysis" for the eligible project or projects proposed as part of an Infrastructure Investment Program, or IIP.

Q. What approach was used to complete the CBA?

A. A team at WMP, myself included, worked with PSE&G gas financial, operations, engineering, and regulatory subject matter experts to structure an approach to the CBA, identify and gather up key data and information required for it, review relevant background documents, apply relevant information within an analysis MS Excel workbook, document assumptions, and author a CBA report covering these topics and providing CBA results.

Q. What are the specific work products of the WMP efforts?

A. In addition to my testimony here, WMP authored a CBA report. This report includes several attachments, which are derived from Company workpapers. The report is identified as Schedule ALT-GSMPIII-1.

Q. Was the work performed under your direct supervision?

A. Yes.

Summary of Conclusions

Q. What are your conclusions, based on your findings provided in the CBA report?

A. GSMP III drives many important benefits, some of which can be quantified and monetized, and others which are captured as being qualitative in nature. Monetized benefits include several categories of avoided capital investment and O&M expenses, and the economic value that can be assigned to the avoided social costs of greenhouse gas emissions ("GHG"), in this case methane. Qualitative benefits are tangible and material, and include the value of risk reduction, and its relation to gas network safety, reliability, and resiliency risk levels. The reduction in risk reflects the "Call to Action" of federal safety authorities for gas system operators to pursue aggressive actions to address pipeline safety.

Many qualitative benefits are also derived from upgrading the gas distribution system to elevated pressure, from the legacy utilization pressure. These benefits include the support of cost-efficient construction techniques, the installation of high efficiency equipment and appliances, and associated gas efficiency improvements, and the ability for the Company to deploy excess flow valves.

The incremental cost of the GSMP III, on a present value basis, and as compared to the reasonable alternative, is $1,697.5 million. GSMP III drives incremental benefits compared to the alternative, of half a billion dollars on a present value basis. Therefore, nearly 30% of GSMP III's new costs are offset by new monetary benefits. Additionally, there are large, additional qualitative benefits driven by the GSMP III scenario, that are additive in qualitative terms to the monetary result. These values include the value of risk reduction, including safety, and the value of the Company meeting emissions compliance obligations associated with the PIPES Act of 2020, and the "Call to Action" of federal pipeline safety authorities recommending aggressive action by gas system operators to upgrade the risk safety posture on the nation's gas systems.

GSMP III, given its accelerated pace, provides the additional advantage of positioning the Company to complete the modernization effort by 2032.

Approach and Structure of CBA

Q. What is the basis of the CBA?

A. The CBA is based on the comparison of two scenarios, both of which are plausible, realistic, and meaningful. By comparing the costs and benefits and qualitative metrics associated with each scenario, it is possible to reveal the incremental or marginal differences in costs and benefits and qualitative assessment of the choice of pursuing one direction or the other.

Q. What are the two scenarios in this instance?

A. As described in the CBA report, one scenario assumes that the Company pursues the $2,387.7 million (nominal) GSMP III capital program. At the conclusion of the three-year construction phase, this scenario assumes that replacement and other maintenance capital work on the system declines to a level that is adequate to meet essential safety and reliability needs while providing a modicum of on-going modernization needs. The alternative scenario assumes that the GSMP III is not pursued, and that the Company pursues a lower level of capital work (i.e., the same long term, average level noted here) starting in 2024. This alternative scenario is referred to as Base RF Level. The word "Base" is used to suggest that this level of capital work would be that level recovered through a base rate cost recovery mechanism. RF refers to "replacement facilities". In either scenario, and as noted (but worth emphasizing) the replacement and other maintenance capital work at the Base RF Level is assumed to be adequate to meet safety and reliability compliance obligations, as established by the Company in relation to its Distribution Integrity Management Plan ("DIMP") and other compliance programs. Modernization opportunities as part of this Base RF Level are much more limited as compared to the levels assumed in the GSMP III scenario.

Q. You describe the GSMP III as a three-year program. Are all costs incurred during this period?

A. No. There are some costs that are incurred in a fourth year. The physical installation is scheduled to be completed by the end of year three. During year four there is some project closure work, and for this reason there are some costs that roll into the first half of the fourth year. For purposes of our report and testimony, I use "three year" to simplify the description: three years for construction work (end of 2026), plus a few additional months for project closure work.

Q. In years four (4) onward, are there differences in the assumed level of capital work between the two scenarios?

A. Both scenarios assume the same level of installation work in years four onward. However, as noted earlier, in year four, GSMP III has some costs related to the close out of the GSMP III program.

Q. What do you mean by "meaningful" scenarios?

A. My assumption is that the IIP requires as part of its minimum filing requirements *meaningful* scenarios, ones that have relevance to the scenarios under consideration, and help explain the nature of the choices made in terms of costs and benefits. One should avoid defining a scenario based on trivial or non-consequential differences, as this would not help reveal anything meaningful about the choices.

Q. Please explain more about this difference pertaining to the GSMP III scenario.

A. The preferred GSMP III scenario is based on the scope and costs (and related estimates of beneficial outcomes) of PSE&G's petition for cost recovery of the GSMP III net costs. It is time and scope limited out to 2027, and inclusive of the approximately 1,140 miles of mains replacement, and tens of thousands of service line upgrades. As noted earlier, the field installation work is concluded in 2026.

Q. What are the work scopes of each scenario that determine costs and benefits?

A. The work scopes for each scenario are identified in terms of the planned asset counts assumed removed and replaced with new materials and related equipment. The scopes also include the relocation of inside meter sets, the installation of excess flow valves, and the abandonment of district regulators. The asset tallies appear in the CBA Report in Table 1. The GSMP III, for example, assumes 1,140 miles of cast iron and unprotected steel mains replacement, whereas the alternative *Base RF Level* scenario assumes a much lower level (186 miles) during this same three-year period. The replacement level of the alternative *Base RF Level* scenario is 16% of the GSMP III scenario in the category of mains replacement.

Q. In terms of modernization, and at the conclusion of 2026, what are the remaining inventories of the most in-scope critical assets by scenario?

A. Assuming the GSMP III is completed as proposed, the remaining miles of cast iron and unprotected steel mains are estimated to be 2,332 miles. Assuming the alternative Base RF Level scenario the remaining miles of cast iron and unprotected steel mains are estimated to be 3,206 miles. While these assets are not the only critical assets targeted for replacement, these inventory estimates provide a representative marker of the scope and scale of the level of improvements under each scenario.

Cost for Each Scenario

Q. Explain the costs for each scenario.

A. The Company has provided to WMP the GSMP III capital investment costs during the three-year period of the construction work (2024-2026). The costs are inclusive of all cost elements that the Company includes within its cost recovery petition. The estimated costs for the GSMP III scenario have factored in the Company's estimate of construction and program management costs. The cost estimates also include the cost of removals for the assets being removed from service. The cost estimates include assumptions regarding inflationary effects as well. The Company has also estimated the costs of pursuing the alternative Base RF Level scenario using similar techniques. In both scenario estimates, unit cost factors are applied based on the Company's experiences with prior construction.

Q. Outside of the construction period, do the costs by scenario differ?

A. From 2028 – 2050, the costs for each scenario are identical. Since the CBA is based on a comparison of the two scenarios, and because there are no differences in scope and costs between the two scenarios in years beyond the construction period, the CBA calculations recognize no cost differences between the scenarios in the out years 2028-2050. In summary, the net cost difference of zero dollars ($0), is assumed from 2028 through 2050 for CBA purposes. There is a difference in costs in 2027 due to the project closure work occurring in 2027, as noted earlier.

Q. In considering the costs of each scenario, did the CBA factor in the impacts of construction itself?

A. Yes. WMP discussed with the Company, and reviewed pertinent materials, concerning whether in its experience there were impacts to the construction work itself. These impacts could materialize in relation to e.g., construction noise, traffic disruptions, accidents or injuries, service disruptions, inconvenience due to surface paving work, etc. The Company indicated that through its experience in GSMP I and II it has developed strong protocols in working with local municipalities and townships, coordinating with local utilities (such as the water company), and reaching out to customers through a variety of media channels to inform customers of the slated activities. The Company also reports to WMP for purposes of the CBA a strong track record in managing construction and traffic. For these reasons, the CBA did not add or factor in any additional direct, indirect, or secondary costs related to the GSMP III scenario, which would represent unique and incremental impacts compared to historical levels of activities associated with the alternative Base RF Level scenario.

Q. In summary, what are the cost differences of the two scenarios?

A. The GSMP III scenario costs are estimated to equal $2,068.4 million in present value terms. The alternative Base RF Level scenario costs are estimated to equal $370.9 million in present value terms. The difference is equal to $1,697.5 million in present value terms. The present value calculation is based on applying a discount rate of 6.48%, which has been provided to WMP to apply and is based on the Company's average weighted cost of capital (WACC).

Q. Table 11 of the CBA report shows an estimate of GSMP III costs that includes expenditures in 2027. Why?

A. As noted earlier in brief, the majority of the installation work for the new assets is assumed to be completed by the end of 2026. Company's cost estimates include construction expenditures extending into the first six months of 2027 to address final service replacements, main and regulator abandonments and pavement and lawn restoration. Accordingly, and for purposes of the CBA and the comparison of two scenarios, the GSMP III scenario assumes that the asset installation rate (meaning total capital installation work per year) for the Company declines in 2028 to the exact same level as that assumed under the Base RF Level scenario. At the same time, the physical number of units installed under both scenarios is assumed to be equal starting in 2027, and at a level consistent with long term compliance and safety planning.

Q. Did you or the WMP team play a role in developing the costs or assessing the quality of the cost estimates?

A. No. WMP did not play a role in developing the costs, nor did we perform an independent assessment of cost quality. Our role was to structure the costs over the forecast period consistent with the requirements of performing a CBA. The CBA Report applies the costs as developed by the Company, and which are supported in separate portions of the Company's testimonies. WMP role was limited, for purposes of the CBA and in relation to costs, in assisting the Company in the development of the assumptions for the alternative scenario, which forms part of the CBA. We also assisted the Company in the treatment and review of avoided costs for purposes of the CBA. Additionally, I observe that the Company has based its cost estimates on its recent and extensive construction experience carrying out a scope of work that is similar to that proposed in GSMP III. Finally, the costs and avoided costs as collected by WMP appear in Appendix 1 of the CBA Report.

Economic Monetary Benefits

Q. How are benefits determined for purposes of the CBA?

A. In this instance, because of the prior phases of GSMP, WMP identified the benefits inventory through workshop-type discussions with the PSE&G subject matter experts, in conjunction with reviewing past testimonies, and documentation. WMP then assembled this information for further categorization to discuss whether the benefits could be quantified, and/or monetized.

Q. Explain some of these categorization steps.

A. The CBA recognizes that there may be economic and other benefits which are difficult to quantify, and further monetize. Therefore, it is useful to discuss each area of impact, identify how it may drive benefits, and further determine if measurement is feasible. This process leads to an inventory of benefits, classified by benefit type. We have organized the benefits into five types, as shown in Table 9 of the CBA report. Some benefits are monetized, whereas other benefits are treated on qualitative terms.

Q. What are the monetary benefits that make up the CBA?

A. The CBA identifies two areas of monetary benefits. First, by replacing aging services and mains, and performing the work scope elements, the Company will reduce certain operating and capital expenditures. The Company has determined the performance difference between old and new assets, and expresses this in an improvement factor, such as a decline in leak repairs per year. It then applies an avoided cost value to this improvement factor. These factors consider the better performance of the new materials compared to the old materials removed from service. Because improvements take place under each scenario, but at different annual rates, the CBA takes the net difference of the scenarios into account for purposes of determining the net effect of pursuing the GSMP III.

Q. Does the CBA consider any instances of higher on-going costs for GSMP III?

A. Yes. Since there will be more miles of PE mains in the future, it has considered some additional level of O&M expense for this material. In other words, it applies its O&M factor assumption for PE mains to a higher count of PE main miles in the future. The resulting slight increase in O&M is significantly offset by the savings on repairs on the assets being replaced.

Q. What are the values of these avoided costs?

A. In present value dollar terms, the GSMP III scenario avoided costs are estimated to equal $323.8 million. The alternative Base RF Level scenario avoided costs are estimated as $46.2 million in present value terms. The difference is $277.5 million on a present value basis.

As with the cost estimates, the present value is determined by applying the Company's weighted average cost of capital (WACC).

Q. What is the time period associated with these avoided costs?

A. As in the consideration of costs, the CBA considers the avoided costs over a 27-year time horizon, which begins in 2024 and ends in 2050.

Q. Are there other monetary benefits that make up the CBA?

A. Yes. The other principal area of monetary benefit is driven by the fact that the contemplated infrastructure replacement will reduce methane emissions, which is an important GHG for tracking and abatement purposes. The Company assigns a value to this reduction.

Q. What is the basis of this reduction?

A. Natural gas is composed largely of methane. The Company applies emission factors to the inventory of its gas system distribution assets as a routine and compliance matter to estimate the methane emissions that escape to the atmosphere during normal operations. The U.S. EPA, as part of its oversight of federal air quality compliance reporting requirements, publishes the emission factors that are used by operators of natural gas distribution systems for purposes of compliance reporting. These emission factors are used to estimate the emissions reductions that can be reasonably estimated to occur because of the new gas infrastructure. As with the estimate of cost, and other avoided costs, the analysis of the value assignable to the emission reductions is based on the comparison of the two scenarios, both of which achieve some level of reductions.

Q. How do methane emission reductions create an economic benefit?

A. There is a broad consensus that there are costs associated with methane and other regulated GHG emissions. The cost is assumed to approximate the value of the climate change-related damage assignable to the GHG released. Through several decades of study effort, a consensus has emerged for purposes of many federal regulatory programs that a value can be assigned to the climate change-related impacts caused by methane and other GHG emissions. Conversely, if emissions are to be reduced through a regulatory program, this damage cost can be reasonably assumed to be avoided. This cost—or avoided cost depending on the direction of the change--is known as the social cost of carbon ("SCC"). The CBA applies the US EPA's SCC to the avoided methane emissions, converted to the equivalent metric tons of CO_2, to determine the economic benefit created by reducing these emissions.

Q. Where does this SCC factor come from?

A. The SCC factor expresses the economic value, in dollar terms, of the cost of one metric ton of CO_2 equivalent emissions ("CO2e") assumed to take place at some point in the future. The SCC damage cost factor is provided for use by the federal Interagency Working Group ("IWG"), which includes the EPA. The IWG periodically updates a table of SCC values for the purposes of analysis of federal regulatory programs when those programs may influence the emissions of CO_2.

Q. What is the reduction that can be expected in emissions through the implementation of GSMP III?

A. The Company has estimated, using the U.S. EPA emission factors, that implementing GSMP III as proposed will result in fewer metric tons of methane emissions released to the atmosphere, when compared to the emissions resulting from the Base RF alternative scenario. Since both scenarios include replacement activities throughout the time period (thru 2050), the CBA recognizes the increment of improvement, taking the difference for purposes of the CBA.

Overall, the GSMP III reduces methane emissions (in terms of CO_2e) from the Company's natural gas distribution system by 6.0 million metric tons by 2050. This is 3.1 million metric tons greater than what is estimated by pursuing the Base RF Level scenario over the same time period. These reductions compare to today's baseline level of emissions (i.e., the starting point at the end of 2023) of approximately 12 million metric tons.

Q. What is the monetary value of the emission reductions estimated from the GSMP III, in comparison to the alternative scenario?

A. Applying the SCC of dollars per metric ton, the economic benefit of this net reduction is estimated at $223.6 million on a present value basis. The word "net" is used because this is the difference in the emissions (and value) when comparing the two scenarios. The alternative scenario will contribute to some emission reductions proportionate with the lower level of asset replacements, but the GSMP III makes a much greater and faster contribution to emission reductions. When considering the nature of global warming, the achievement of reductions sooner is additionally beneficial.

Q. What is the total monetary benefit captured in the CBA, when considering both the value of the methane emission reductions and the avoided O&M and capital costs?

A. The GSMP III scenario avoided costs plus the value of CO_2e reductions are estimated to equal $761.3 million on a present value basis. The alternative Base RF Level scenario avoided costs plus the value of CO_2e reductions are estimated to equal $260.2 million on a present value basis. The difference is $501.1 million on a present value basis. As with costs, these benefit estimates assume an evaluation time period of 2024-2050.

Qualitative Benefits

Q. Are there other benefits associated with the CBA?

A. Yes. There are additional benefits related to how the GSMP infrastructure will improve and lower the overall level of system risk, improving the Company's risk posture as it pertains to maintaining the safe operations and maintenance of the gas system. There are also benefits related to the gas system modernization design features.

Q. Please explain how the risk posture of the system is improved.

A. As noted, and summarized in the CBA Report, there are important improvements ushered in by the GSMP infrastructure that will improve and lower system risk. System risk has at least three dimensions – safety, reliability, and resiliency. By removing aging assets that are leak and break prone and making other improvements such as installing thousands of Excess Flow Valves at the point where the services meet the distribution mains and moving meter sets outside, the overall integrity of the gas system will be improved from a risk perspective.

Q. In general terms, how is risk measured?

A. The Company measures risk systematically through highly structured asset and system risk analysis methods and analytical techniques. Many of these methods and techniques are required and guided by, federal oversight from the U.S. Department of Transportation Pipeline and Hazardous Materials safety Administration (PHMSA). The Company also has compliance obligations to the State, including agreements with the BPU in relation to the tracking of the performance of gas system assets in relation to risk. Many features of the Company's risk assessment and tracking process, procedures and results are documented in its DIMP, which it updates regularly pursuant to its safety compliance obligations.

Q. Through the GSMP III, does the Company expect to improve risk levels?

A. Yes. By implementing the GSMP III, the Company expects that several indices related to its risk measurement, and which influence individual asset categories and total risk scores, will improve. Some examples are provided in Appendix B of the CBA Report.

Q. How does federal policy address system safety?

A. As noted in the CBA Report, and as identified by Company witnesses, the DOT has issued advisory guidance to the nation's distribution system operators to take aggressive actions to identify and address risks to safety and environmental impacts of their systems. Additionally, in December 2020 the "Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES Act") was signed into federal law. The PIPES Act 2020 identifies new emphases and mandates for PHMSA as part of distribution integrity management plan and other plan requirements. It also includes new emissions compliance requirements. The Company's attention on system integrity and risk management as part of GSMP III is very much aligned with federal policy directions.

Q. Is it feasible to put an economic value on the risk reduction identified as part of the CBA as part of the GSMP III benefits?

A. I do not believe it is reasonable to put a point estimate dollar value on the value of risk reduction. Risk has many attributes, including most generally the need to identify threats (or hazards), to estimate the possibilities of these threats happening, and to estimate the consequences of the events. These three risk attributes are difficult to parameterize for purposes of assigning a discrete point estimate dollar value of benefit.

Q. How does the Company address risk?

A. It is WMP's understanding that the Company uses disciplined asset integrity risk analysis methods, combined with informed judgement, to reach insights and form conclusions, about the level of risk related to assets, classes of assets, or parts of the system. Some of the key and most important attributes of the Company's risk-aware analysis and planning activities are identified and described within its DIMP plan document. I am not a qualified expert to address DIMP, but I believe in my professional judgement based on a review of this document, that the Company has an informed risk-aware planning posture and the capability to address asset and system risk.

Q. What are the other Qualitative benefits included in the CBA?

A. As described in the CBA Report, the GSMP III improvements will further upgrade the gas distribution system in its modernization. Through the construction "map-grid" approach, PSE&G is able to address the modernization needs of a whole section of the distribution system, versus what is possible through a more limited targeted and segment-by-segment replacement approach. This means that the Company can upgrade the entire complex of mains, services, valves, and other system assets within a specific location as part of the same focused effort. The modernization includes a greater extent of the system's ability to distribute gas at elevated pressure ("EP"), replacing legacy utilization pressure ("UP") systems.

Q. What are some of the benefits of Elevated Pressure?

A. Within the CBA Report, several benefits of elevated pressure service are described, including more efficient construction, enabling the deployment of Excess Flow Valves ("EFV"), reducing outage risk caused by water infiltration, the abandonment of district regulators, and the enabling of the customer's use of high efficiency equipment and appliances. For example, an additional benefit related to the use of EP as part of the modernization effort is the placement of approximately one manually operated main valve per 100 customers. These valves facilitate isolation in the event of an accidental break in the main. Today, with UP mains, the Company must excavate the main to isolate it.

Q. How are Customer Appliances affected with Elevated Pressure?

A. When customers do not receive adequate pressure many modern equipment and appliances will not operate as efficiently as designed. Some customers pursue installing gas pressure boosting equipment to address this problem while others work with the Company to upgrade the gas service. These conditions will be alleviated with EP, saving customers money, and improving customer satisfaction. The environment also benefits in those circumstances where the equipment or the appliance is under-performing due to the low pressure that is below it design standard.

Q. Are there other examples of Qualitative Benefits?

A. Yes. The GSMP III program, in comparison to the alternative, will improve the Company's asset records for the gas system assets. More precise as-built drawings will lead to more accurate mark-outs when others are excavating near gas mains and services for their own construction or repair purposes. Other benefits include eliminating many hard-to-locate service stubs during the construction with the map-grids. Also, the new PE pipe has many features that help improve safety, such as tracer wire, warning tape installation, and attending to proper bedding as part of the installation of the new pipe, thus reducing future integrity problems due to ground conditions. Also, there are opportunities to coordinate activities as part of the modernization with other utilities, such as water utilities; this reduces the occurrences of excavating streets a second time to attend to a separate utility repair or upgrade.

Q. Are there benefits to the economy of the GSMP III?

A. The Company notes that the GSMP III is expected to further expand the number of skilled construction jobs from the level in previous GSMP phases. It estimates, in fact, that skilled construction jobs will increase from 2,338 to 3,771 annually for the duration of the program. Employment also provides other economic stimulus benefits as wages are used in the economy. The CBA recognizes this economic stimulus effect as a qualitative benefit, since it does not include a formal analysis of economic impacts, and instead relies on the Company's estimates in this regard. However, the New Jersey BPU has recognized the importance, as part of IIP regulations, of the capacity for infrastructure programs to provide economic benefits (such as that provided by skilled jobs) specifically to the State of New Jersey.

Comparing Costs and Benefits

Q. How did you compare all costs and benefits?

A. As identified in my testimony, the CBA is based on two well-defined scenarios, the GSMP III and the alternative Base RF Level scenario. These are both meaningful scenarios, in that they represent feasible and reasonable views to potential future activity and investment levels. They also help reveal certain features of the choice to pursue the GSMP III. I have identified that based on the cost comparison of the scenarios, there is a present value of (-) $1,697.5 million in costs of implementing GSMP III when compared to the alternative Base RF Level scenario. This net cost is offset by $277.5 million of incremental avoided capital and O&M costs, and $223.6 million of value associated with reductions in methane, an important GHG. This latter value is based on applying the social cost of carbon factors provided by the IWG and is a measure that is established for purposes of regulatory program review. These quantified incremental benefits of $501.1 million offset 30% of the net costs. Considering all costs and monetary benefits, comparing the two scenarios reveals a net overall difference of (-) $1,196.4 million on a present value basis. These values are displayed in Table 2 of the CBA Report.

These values do not consider the additional value assignable to qualitative benefits, such as the contributions to risk reduction – including the emphasis placed on asset integrity and risk management by regulatory oversight authorities in several instances. The benefits also include many important qualitative benefits driven by upgrading the system to a modern design standard, as identified in the Company's Engineering Report, by the Company witnesses, and within the CBA Report. The CBA Report and my testimony also explains some of the reasons why attempting to quantify and monetize the risk reduction and other qualitative benefits is impractical, due, in part, to the nature of risk assessment.

The fact that benefits are identified as qualitative in nature as part of the CBA does not mean that for purposes of a CBA they should be discounted or, worse, set aside. It simply means it may not be practical or feasible to assign a point estimate monetary value to the benefit, for purposes of integration into the CBA economic evaluation alongside quantified and monetized costs and benefits.

Q. Is there additional value related to maintaining the pace of modernization?

A. Pursuing the GSMP III at the pace that is proposed by the Company will support a milestone goal of completing the modernization by 2032, thereby securing additional methane reductions beyond those identified as part of GSMP III.

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE INDEX

WORKPAPER INDEX

ATTACHMENT 2
Schedule ALT-GSMPIII-1

COST-BENEFIT ANALYSIS

Cost-Benefit Analysis: Gas System Modernization Program Phase 3

Prepared for
Public Service Electric & Gas Company
February 15, 2023

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ACRONYMS AND DEFINITIONS

Acronym	Definition
Base RF Level	Base Replacement Facilities Level, an alternative scenario
CBA	Cost-Benefit Analysis
CI	Cast Iron
CP	Cathodically Protected
Company	Public Service Electric & Gas Company
DIMP	Distribution Integrity Management Plan
DOT	Department of Transportation
EFV	Excess Flow Valves
EP	Elevated Pressure
GHG	Greenhouse Gas Emissions
GSMP	Gas System Modernization Program
IIP	Infrastructure Investment Program
IWG	Interagency Working Group (a collection of federal agencies)
O&M	Operations and Maintenance
N.J.A.C.	New Jersey Administrative Code
PE	Polyethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEG	Public Service Enterprise Group (PSE&G Parent Company)
PSE&G	Public Service Electric & Gas Company
PV	Present Value
SCC	Social Cost of Carbon
SME	Subject Matter Experts
UP	Utilization Pressure
WACC	Weighted Average Cost of Capital
WMP	West Monroe Partners, LLC

Forward

West Monroe Partners, LLC., (hereinafter referred as “WMP”) was retained by PSE&G to perform and document a cost-benefit analysis (“CBA”) for the proposed Gas System Modernization Program Phase III (“GSMP III”).

This report is intended to accompany PSE&G’s GSMP III engineering report and to support the satisfaction of various filing requirements for an eligible Infrastructure Investment Program (“IIP”), as established as part of the New Jersey Administrative Code.

WMP worked with PSE&G gas system planners, engineers, and financial analysts to review GSMP III program investment plans, program goals and assumptions, structure an appropriate scenario-based framework for the CBA, gather and document program costs and related assumptions, identify and classify key benefits, and quantify and monetize benefits, where practical and feasible.

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Executive Summary

Background

Public Service Electric and Gas Company ("PSE&G") is New Jersey's largest utility, servicing approximately 2.2 million electric and 1.8 million natural gas customers. The PSE&G natural gas distribution system infrastructure includes approximately 35,600 miles of mains and services.

PSE&G's natural gas infrastructure is among the oldest in the nation; approximately 3,500 miles[1] of mains were installed prior to 1960 when cast iron and unprotected steel were the most used pipeline material. The age and integrity of these pipelines are of most concern to PSE&G. The pipe's susceptibility to leaks and failure due to age and rigidness of materials (e.g., cast iron) and corrosion (e.g., unprotected steel pipe) present a degree of public safety, operational, and environmental risk, which the Company has prudently managed through its distribution system integrity and asset risk management planning.

Gas System Modernization at PSE&G

Notwithstanding this prudent and effective level of risk management, beginning in 2016 PSE&G embarked on a prioritized system wide gas system modernization effort. The purpose of the Gas System Modernization Program ("GSMP") is to enhance the reliability and safety of the system in an efficient manner, to accelerate improvements and upgrades (that would otherwise take decades to achieve), and to address the needs of aging assets in a manner not possible through more limited programmatic means.

The modernization effort is highly consistent and in concert with the recommendations for risk management actions and environmental stewardship as laid out by federal and state authorities responsible for pipeline safety. PSE&G's particular focus of its modernization activities has been on replacing aging pipelines with newer ones made of non-corrosive materials, such as polyethylene pipe, or replacing them with coated and cathodically protected steel pipe. As a result of its prior modernization phases (the GSMP I and GSMP II phases), the Company has reduced the inventory of cast iron and unprotected steel mains by 31% (4,947 miles to 3,392 miles remaining).[2] The new materials directly improve system integrity, reliability, resiliency, safety, and environmental performance (particularly by reducing methane emissions).

PSE&G's gas system modernization efforts have been successful, meeting budget and installation goals, key milestones, and community and state regulator expectations. To maintain the program's momentum, the Company proposes a third modernization phase. Specifically, PSE&G is seeking approval of its Gas System Modernization Program Phase III ("GSMP III"), a

[1] Inventory as of January 2022
[2] The remaining inventory value is an estimate as of December 2023.

three-year $2,387.7 million program ($ USD nominal) to continue the modernization efforts.[3] The program begins January 1, 2024 with unit installation work finishing December, 2026 (with some field cleanup and project closure work in the first half of 2027). A key feature of this third phase is PSE&G's intention to increase the pace of replacements compared to that achieved during GSMP II.

The Cost-Benefit Analysis

The cost-benefit analysis ("CBA") for GSMP III is based on a comparison of two well-defined scenarios that extend in time over a forecast period of 27 years, to 2050.[4] The comparison contributes to the revealing of marginal or incremental impacts of the GSMP III program in relation to the alternative scenario, each described below. For each scenario, the costs and benefits are identified and considered as part of the CBA, and when practical and feasible to do so, benefits are quantified and monetized. Where not practical or feasible, a qualitative assessment of benefits is provided.[5]

The GSMP III investment scenario represents an accelerated program to replace 1,140 main miles and 92,130 services.[6] The proposed replacement miles include 810miles of utilization pressure ("UP") cast iron ("CI") mains, 50 miles of elevated pressure ("EP") CI mains, 200 miles of unprotected steel mains and 80 miles of UP cathodically protected steel and plastic mains. Additionally, the proposed program would result in the abandonment of 210 district regulators, and the relocation of approximately 49,178 inside meter sets to the outside.

The alternative scenario – referred to as the *Base RF Level* scenario (RF stands for "replacement facilities"– is much more limited and reflects a level of investment reflective of a hypothetical yet practicable base capital requirement adequate to meet essential safety and reliability compliance and to sustain a slower pace of system modernization. The Company represents that this alternative scenario pace would support the maintenance of an acceptable and compliant level of safety and reliability consistent with the Company's Distribution Integrity Management

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[3] The bulk of the physical work is slated for completion in three years. Some field work and other program closure work, occurs in the fourth year, and is reflected in all estimates and cash flows. Hence, "three-year program" is used in this report as inclusive of these program closure activities occurring in the first part of year 4. Moreover, the cash flows specify these costs occurring in year 4.
[4] 2024 through 2050.
[5] In performing the CBA, WMP has borrowed from the National Standard Practice Manual for Benefit-Cost Analysis for Distributed Energy Resources to review potential gas system-related impact categories. Specifically, the NSPM's Table 4-2, page 4-12, lists potential impacts on gas utilities of energy programs. Table S-8, page xi, also identifies certain categories of Societal benefits. These two lists serve as a useful starting mechanism to identify *potential* impacts to support the goal of comprehensiveness. www.nationalenergyscreeningproject.org/national-standard-practice-manual/.
[6] Throughout the CBA Report, WMP refers to 'accelerated' as meaning within the context of the *entirety* of the GSMP: the modernization program, as part of all of its phases (I, II, and III), *accelerates* the modernization efforts as compared to what would be achievable otherwise.

Plan ("DIMP") and other safety plans and requirements. However, at this level of work and spending, significantly less system modernization would result.

Table 1 summarizes the physical scope of these two scenarios for the principal assets subject to replacement.

Table 1: Scenario Summary: Asset Replacement Levels

Scenario	3-Year Program Scope		Remaining CI & Unprotected Steel Main Inventory Miles at Program End
	Main Miles	Number of Services	
GSMP III	1,140	92,130	2,332
Base RF Level	186	14,658	3,206

The GSMP III scenario reflects the Company's strong preferences to proceed with the replacement activities at an accelerated replacement level. GSMP III allows for a systematic replacement strategy that still focuses on risk, while maximizing construction efficiency and cost-effectiveness. The program continues to support a regulatory focus on replacing the highest risk and most leak prone facilities, as identified in the Company's Distribution Integrity Management Plan. This scenario also positions the Company to complete modernization by 2031. The Base RF Level alternative scenario, in effect, reflects a decision to significantly slow down the pace of modernization efforts.

Modernization Benefits

The comparison of the two scenarios reveals several important benefits achievable through pursuing the GSMP III. Most importantly, the gas system modernization program improves (lowers) system risk levels as part of prudent risk management practices, thereby keeping the Company in a strong posture for continued safe, reliable, and resilient operations. In fact, the Company's emphasis on risk management is in concert and concordant with federal and state authority safety and reliability planning and asset integrity management requirements and mandates, including the recent PIPES Act of 2020 ("PIPES") and PHMSA's advisory notices. The PIPES Act also requires gas system operators to reduce methane emissions. As an indicator of how risk reduction is quantified, the Company has provided (and the CBA includes) examples of risk indices it would expect to be favorably impacted over time within its asset integrity risk modeling analyses.

PSE&G prioritization ranking methodology for main segments (referred to as the Hazard Index) is based on a predictive model that integrates leak history and cast-iron break history with a variety of other characteristics referred to as "environmental conditions". The index also considers key asset information (e.g., pipe diameter and operating pressure). PSE&G has used the Hazard Index to inform its GSMP III workplan and construction schedule. This is the same prioritization process applied successfully in the first two phases of GSMP.

There are also valuable benefits associated with upgrading the system to modern design standards. Upgrading the system to operate at elevated pressure (EP) versus today's legacy utilization pressure enables customers to install high efficiency appliances, which require higher minimum delivery pressure. EP also allows for the installation of excess flow valves (which shut off gas automatically when excess gas flow is detected, as might occur with an excavation-caused break). EP also permits smaller pipe sizes (compared to alternatives), and results in fewer unplanned outages, increasing reliability. The Company has also estimated that there are sizable, positive economic impacts from prior GSMP investments, which will ostensibly continue and expand into its next phase. One primary anticipated impact is an increase in skilled jobs within the construction field over-and-above prior GSMP phases, inuring additional economic stimulus benefit to the state of New Jersey.

These benefits are significant and large, but do not include the additional benefits that are specifically quantified and monetized as part of the CBA. The monetary benefits are attributable to avoided capital and operations and maintenance ("O&M") costs that arise due to the removal of old and more leak and break prone assets. Similarly, the value of methane emission reductions is estimated within the CBA (and valued in societal economic terms). By replacing a large fraction of the current and old distribution mains in service today over an accelerated period, the Company, through its GSMP program, is reducing methane emissions to a far greater extent than what would be possible under the alternative scenario.

Comparison of Costs and Monetized Benefits

The GSMP III program's costs and monetized benefits, when compared to the Base RF Level scenario are presented in Table 2 in net present value terms over the 27-year evaluation period. The monetized benefits include an estimate of the societal value of reducing fugitive methane emissions through the installation of higher performing mains and services (and related assets); this estimate is based on applying the social cost of carbon ("SCC") damage estimate for CO_2e[7], as established by the Interagency Working Group ("IWG") to the tons of avoided emissions.[8]

Notably, 36.2% of the costs of GSMP III are offset by incremental benefits.

[7] Carbon dioxide equivalent, or CO_2e, means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A-1 in 40 CFR Part 98. – U.S. EPA

[8] WMP has relied upon the Company's experts to estimate the physical emissions reductions in terms of methane and CO2e. WMP has used this analysis result to compute the benefit value of these reductions.

Table 2: Comparison of Costs and Benefits, GSMP III vs. Base RF Level ($ millions)

Costs and Benefits ($ millions, Present Value)	**GSMP III**	**Base RF Level (Alternative)**	**Difference GSMP III vs. Base RF**
Program Costs	($2,068.4)	($370.9)	($1,697.5)
Benefit: Avoided Capital + O&M Costs	$323.8	$46.2	$277.5
Benefit: Avoided SCC (CO2e) Emissions	$437.5	$213.9	$223.6
Total Benefit	$761.3	$260.2	$501.1
Benefits Less Costs	($1,307.1)	($110.7)	($1,196.4)
Portion of Costs Offset by Benefits	37%		

Given the comprehensive nature of the GSMP III investment, Table 2 is not intended to reflect comprehensive conclusions of the CBA. In fact, it only captures what can be reasonably quantified and monetarily compared. For completeness, the CBA must also consider the value of tangible, foundational, and *qualitative* benefits of GSMP III related to risk reduction, achieving a modern design standard, and economic stimulus-related benefits, as identified earlier.

Summary Conclusion

WMP concludes that for the purposes of the cost-benefit analysis, which is based on the comparison of two meaningful scenarios, the GSMP III is estimated to generate measurable quantified and monetized benefits (Table 2), as well as additional qualitative benefits over the life of the program, which for limited purposes of the CBA is identified as 27 years. Benefits include avoided operations and maintenance costs and the value that can be assigned to reductions in CO_2e emissions, which contribute to the State's and Company's climate goals. These benefits offset 36.2% of the GSMP III investment costs.

The qualitative benefits contribute additional value, and include the reduction in system risk, consistent with prudent risk management practices and requirements, thereby improving the gas system's safety, reliability, and resiliency compared to what is achievable through base capital spending. Pursuing risk reductions for the purposes of improved safety, reliability, and resiliency (amongst other goals) is highly consistent with federal calls for aggressive actions by natural gas system asset owners and operators to reduce pipeline safety risks and reduce methane emissions. Qualitative benefits also accrue because of modernizing the system to operate at elevated pressure and driving economic growth, including job creation, through the focused program investment.

1. Introduction

1.1. GSMP III Program Background

PSE&G's proposed Gas System Modernization Program Phase III ("GSMP III") is a continuation of the GSMP II program which the Company expects to complete in 2023. Like GSMP II, GSMP III is designed as a multi-year program (three years in this case). PSE&G seeks approval for approximately $2,387.7 million (nominal) in capital investment to support the GSMP III. PSE&Gs aim is to replace 380 miles of mains annually (on average), or 1,140 main miles in total over the three-year period. Also included in the program are replacement of services, abandonment and removal of district regulators, and relocation of inside meter sets to the outside. Table 3 identifies the physical scope of the proposed GSMP III by asset types.

Table 3: GSMP III Scope Summary

Description	Count	
EP CI Main Replacement	50	Miles
UP CI Main Replacement	810	Miles
Unprotected Steel Main Replacement	200	Miles
UP CP Steel and Plastic Main Replacement	80	Miles
Abandonment of Regulators	210	Units
Unprotected Steel Service Replacement	92,130	Units
Inside Meter Set Relocations	49,178	Units

Because of the progress PSE&G has achieved and demonstrated to date in implementing GSMP I and II, PSE&G is proposing a higher annual level of capital investment and field work in GSMP III compared to the prior gas modernization program phases. The Company believes this is warranted for several reasons, including (1) cost efficiency opportunities available with the proposed larger investment, (2) contractors' current mobilization and availability (as these contractors near completion of work on GSMP II), and (3) the capacity to deliver greater benefit sooner to customers and the region. Commensurate with this higher level of proposed work the GSMP III improvements will further contribute to and improve the Company's overall asset risk profile as managed within its asset integrity management planning process.

The pace of progress of the current modernization effort provides useful context for the proposed GSMP III phase, which steps up in the level of work when compared to GSMP II. Table 4 documents the average annual unit counts of installation work in each of the prior phases, along with the GSMP III plan. This comparison documents PSE&G's goal to continue to accelerate modernization through a systematic programmatic approach. The Company also believes this plan is reasonable, and highly feasible.

Table 4: Historical and Proposed GSMP Units of Work

	GSMP I Annual Average	GSMP II Annual Average	GSMP III Plan 2024	GMSP III Plan 2025	GSMP III Plan 2026
Total Mains (miles)	150	293	350	395	395
District Regulators Abandoned	17	38	30	80	100
Service Replacements	11,848	21,211	28,286	31,922	31,922
Relocate Inside Meter Set	5,332	13,098	16,393	16,393	16,393

1.2. Cost-Benefit Analysis Methodology

Overview

The purpose of the cost-benefit analysis is to provide a meaningful framework, useful analysis, and relevant information to decision makers for consideration alongside other relevant data, information, and analysis about the GSMP III program. PSE&G is providing this cost-benefit analysis for GSMP III pursuant to New Jersey Administrative Code 14:3-2 A.5, paragraph 3, in reference to an eligible Infrastructure Investment Program (IIP) project, which states:

> *"An engineering evaluation and report identifying the specific projects to be included in the proposed infrastructure Investment Program, with descriptions of project objectives, detailed cost estimates, in-service dates, and any applicable cost-benefit analysis for each project."*

This cost-benefit analysis provides a comprehensive identification, description, and summary of the GSMP III program costs and benefits, in fulfillment of the N.J.A.C 14:3-2 A.5, paragraph 3 obligations in a manner consistent with good CBA practice for utility capital investment programs.

Scenarios

The CBA is focused on the marginal, or incremental differences that emerge due to the pursuit of a given set of actions. These are best and properly understood in terms of an alternative course of action. For this reason, the Company has defined two principal scenarios for purposes of performing the CBA. These are compared to identify the incremental differences in costs and benefits between them, thus revealing the impacts of the actions *at the margin* being proposed. Additional scenarios are discussed (Section 5) as forms of sensitivity analyses to provide additional insights in support of decision making.

The first scenario is defined by the GSMP III investment spanning the three-year period. This is the period for which GSMP III would have significantly increased levels of investment to fund the main and service pipeline and other replacement work (compared with an alternative level of work). After the three-year period, beginning in 2027, the level of construction work reverts to a level consistent with long term average capital spending levels.

In contrast to the GSMP III scenario, the alternative scenario, assumes a level of work at the base RF replacement level for all years beginning in 2024. RF stands for "replacement facilities". For purposes of the CBA, this scenario is referred to as the "Base RF Level" scenario. In fact, beginning in 2027 both scenarios are based on an equal pattern and level of average spending consistent with the Company's Distribution Integrity Management Plan (DIMP) requirements.

By carefully identifying and estimating the costs and benefits for each scenario, and then comparing them, the CBA can reveal the marginal differences that are uniquely driven by the GSMP III investment plan.

Asset Counts by Scenario

Table 5 provides a summary of the unit totals by asset category slated for installation under each scenario. The 3-year period is the period for which GSMP III would have increased investment to fund main and service pipeline replacement. The table also includes the expected annual level of replacement work to illustrate a step-down to a Base RF Level starting in 2027. For simplicity of illustration, not all remaining years of Base RF levels are shown.[9]

[9] For purposes of formalizing the avoided costs driven by the GSMP III program, the CBA assumes a 27-year time-period through 2050. However, the time horizon has no bearing on cost differences in years 2027-2050 when comparing the two scenarios because the unit counts and costs for each scenario are identical starting in 2027.

Table 5: Unit Replacements by Scenario

3-Year Program	GSMP III Program 3-Year Total	Base RF Alternative 3-Year Total	Base RF Level 3-Year Total[10]
Description			
EP CI Main (Miles)	50	12	4
UP CI Main (Miles)	810	105	35
Unprotected Steel Main (Miles)	200	69	23
UP CP Steel and Plastic Main (Miles)	80	0	0
Total Miles	1,140	186	62
District Regulators Abandoned (units)	210	3	1
Service Replacements (units)	92,130	14,658	4,886
Relocate Inside Meter Set (units)	49,178	7,824	2,608

Table 6 documents the remaining inventories for each scenario (at the start of 2027, after the completion of the three-year program). This inventory information helps to reinforce the large decrease in the cast-iron and unprotected steel mains and service inventories that will result with the GSMP III scenario when compared to the Base RF Level scenario. Given the age and performance of these older assets, there is a commensurate reduction in the Company's risk profile for its system assets, as managed through its integrity management planning process. For example, PSE&G's inventory of cast iron and unprotected steel generates approximately 70% of the leaks that the Company identifies annually, so reducing these inventory levels should significantly reduce the occurrence of leaks.[11]

[10] This is assumed as an average level only for purposes of parameterizing the two scenarios as part of the CBA.

[11] The Company has estimated avoided cost factors and costs based on empirical data on the differences in leak and break rates of the different materials within the existing inventory as compared to the new materials slated for installation. Additionally, the Company applies different emission factors for the different assets based on their type, per U.S. EPA requirements pertaining to the application of emission factors for natural gas system assets.

Table 6: Comparison of Remaining Number of Units by Scenario and Asset Category YE2026

Description	Units Remaining GSMP II (YE 2023)[12]	Units Remaining GMSP III (YE 2026)	Units Remaining Base RF Only (YE 2026)
EP Cast Iron Main (Miles)	409	359	397
UP Cast Iron Main (Miles)	2,188	1,378	2,083
Unprotected Steel Main	795	595	726
District Regulators	1,050	840	1,047
Unprotected Steel Services	270,000	177,870	255,342
Inside Service Terminus	720,000	670,820	712,176

Differences in Work Methods

An important difference between the two scenarios is in relation to how replacement work is planned and conducted. At the level of funding and work scope associated with the GSMP III, the Company can continue to support an accelerated level of replacement. In turn, this permits work planning and scheduling using a "map-grid" basis or method that targets replacement work holistically within a discrete physical area or segment of the system. Grids are approximately one square mile in area. This planning and execution approach allows the Company to consider the modernization requirements of all system assets within that location, and to modernize the grid in a balanced and complete way. This includes making modifications that allow the system to operate at elevated versus utilization pressures. This map-grid based approach also permits the Company to focus attention within certain locations and communities to minimize the potential extensiveness (in terms of calendar duration, or locations) of overall disruptions that could be caused by less efficient work planning approaches.

In contrast, and at lower and less intensive levels of funding and work scope – such as associated with the Base RF Level scenario -- the Company would most likely be forced to adopt a more selective, restrictive, and targeted approach for replacing higher risk assets. This approach would be focused on specific pipe segments and specific assets, without the additional opportunities to upgrade and modernize the grid holistically. This more limited approach would not have the resources that would enable holistic modernization upgrades (such as moving the system to elevated pressures, and abandoning district regulators) within a specific geography, and would instead focus on addressing the highest risk assets regardless of surrounding and less critical assets. This approach can also lead to repeated disruptions to local communities to coordinate a patchwork of construction and modernization activities that are likely to ensue over many years as locations are re-visited for separate purposes. This becomes

[12] Estimated ending inventory.

particularly relevant when there is coordination work with other utilities and municipal services that must be prioritized. In summary, this approach is inherently less efficient and effective across many dimensions of work execution.

There are large advantages to implementing the modernization program at scale, and within a compressed period. These advantages translate into lower cost per mile and other lower unit costs, which directly impact the CBA's estimate for costs. These advantages relate to securing and retaining a set of highly qualified contractors along with a qualified workforce due to a larger and more attractive work scope. This larger scope also permits PSE&G to exert competitive pressures to secure a consistent level of high-quality work at competitive prices and within schedule requirements across its contractor base. The Company can also realize efficiencies in the supply chain for its bill of materials and can oversee work efficiently and economically through a focused and compressed work effort over the three-year period.

Nominal Dollars, Escalation and Growth Adjustments

- The CBA considers the period of the evaluation and adjusts nominal dollar values for costs and benefits (including an inflation adjustment factor). The CBA defines 2024 as Year 1. The time horizon of the economic analysis is 27 years, ending in 2050.
- The Company has provided to WMP for use within the CBA estimates of capital costs for each of the two scenarios. These values have been adjusted by the Company to reflect expected nominal dollar values by year of the three-year period estimate. The costs beyond the initial three-year construction period are identical, and do not influence the CBA in years 2027-2050.
- For purposes of the *avoided* cost estimates for each scenario, the Company has also based its assumptions on nominal dollar (avoided) costs that considers inflationary effects.
- WMP has extended the estimate of avoided costs within the time horizon (2050) by applying a 1% escalation rate assumption for years beyond the three-year implementation period, consistent with the Company analysis supporting these estimates.
- Growth assumptions – in system miles, capacity needs, or customer counts – can often factor into the CBA for utility programs, because technology and asset needs are not static, and often increase as customers and customer loads are added to the system. However, in the case of the two scenarios under evaluation as part of this CBA, growth does not materially influence the CBA, for the following reasons:
- Any new business gas service connections are addressed by the Company separately and are outside of this analysis, and costs for these connections (meters, services, and line extensions) are not included in either Scenario's estimate of asset requirements or related costs.
- The GSMP III infrastructure assumptions are designed to replace existing gas mains and services and the program is not designed to increase the lateral miles to accommodate new residential, commercial, or industrial building or facility construction. Any placement of new

gas mains or services as part of the GSMP III work scope is incidental and determined by the needs of modernizing the gas network within the construction "grid" themselves, and is determined on a case-by-case basis for that grid

- The GSMP III scope includes the relocation of inside meter services to outside and does not include meter sets for new service connections.

Use of Discount Rates

The CBA references and uses two discount rates. One discount rate is applied to the comparison of utility costs and avoided costs (benefits). For this purpose, the Company's weighted average cost of capital ("WACC") is used, which is assumed to be 6.48%. As noted earlier, the first year for which discounting is applied is 2024.

The CBA also refers to a discount rate of 3% that relates to the valuation of the methane emissions. This rate is unique to the Social Cost of Carbon ("SCC"). The Interagency Working Group establishes the estimate of the damage cost of CO_2e for future year emissions, but it expresses these values in present worth (or present value) terms. This provides a convenient way to compare emissions (or emission reductions in this case) that occur in different years. For example, it is possible to compare 1,000 metric tons of CO_2e emission reductions that are estimated to occur in 2030 with 1,000 metric tons estimated to occur in 2040 in terms of today's value. The IWG provides present value estimates in today's dollars for each emission reduction by year the emissions reduction is assumed to occur. To determine these present values the IWG must assume some discount rate for the damage costs associated with the future year emissions.[13]

Sources and Quality of Information Used

The CBA is based on program cost and benefit information that is reasonable, recognizing that the information originates from the Company's engineering and capital planning experts' analysis. Notably, the information is based on empirically derived facts, gained through implementing similar work at the level of "accelerated replacement", during the past 10 years, that is reasonably comparable in scope and complexity. Likewise, the work does not involve materials, planning methods, participants (skilled employees and contractors), equipment, or construction techniques that are not familiar to the Company's asset managers and construction and financial planners. The Company's asset managers and planners have gained significant experience in implementing a similar scope during the most recent several years.

The Company planners have used this historical basis of information to estimate costs and avoided costs for the GSMP III and the alternative scenario. Detailed and highly pertinent information concerning the estimate of GSMP III program costs and benefits are documented

[13] The IWG provides several choices of discount rates to use in reference to the estimates of present values. The CBA uses the SCC damage values referenceable to IWG's 3% discount rate values.

elsewhere within the Company's testimonies; this information, which is provided separately, aligns and is concordant with the information presented in the CBA.

1.3. Scenario Cost Estimation

PSE&G provided program capital cost estimates for both the proposed GSMP III investment scenario as well as the alternative scenario based on a significantly lower level of replacement facilities installation work. WMP has levered this information for purposes of explaining the cost information in its application with the CBA.

A discussion on the sources, quality, and magnitude of the cost estimates for purposes of the CBA should be predicated on several over-arching observations.

- PSE&G has a recent and extensive track record of planning and completing similar work at a scale generally comparable to that proposed in GSMP III. Because of this experience in applying its "map-grid" work planning and execution method the Company's planners and contractors have a wide range of experience of possible future conditions that are likely to be encountered and can factor this range of conditions into the estimation of future work.
- PSE&G has been working with a set of contractors over an extended period in the performance of this work. The Company is aware of the 'track record' of these firms and can factor into its estimates of cost, schedule, and quality control needs and expectations real-world experience gained by working with these firms. It should be noted that the Company reports an excellent track record as part of the GSMP I and II phases in areas of safety and coordination with local municipalities.
- The Company's engineers have established a base of knowledge about the conditions that are typically encountered in the performance of this work in its service area. This should support a high degree of confidence in work planning estimation (materials, labor, equipment, supplies, etc.) and related budget requirements.
- The Company will continue to leverage a community outreach and communications program plan that has served the interests of the communities and the Company well. While this program is not a big cost-driver, the experience gained in its execution does support confidence on meeting schedule milestones, which otherwise can affect costs (if milestones are not met due to program delays).

The Company's cost estimation as applied in the CBA is unit based for main and service replacements and meter set relocations. The unit costs are inclusive of engineering, materials and equipment procurement or acquisition, skilled labor, construction services, and contractor and Company overhead costs.[14]

Given the Company's recent experiences in planning and executing similar work at scale and given the highly repetitive and relatively low complexity of the proposed work, the Company observes that it is in a strong and confident position in estimating program costs. These unit costs reflect average conditions found across the service territory and consider an appropriate basis for the locations of the work, and other relevant site conditions (rural, urban locations, other). To develop the program cost estimate, unit cost factors have been developed and applied by the Company for the following assets and categories of work:

Table 7: Unit Cost Factors by Asset Category

Description	Factor Basis	GSMP III Factor ($ mil)	Base RF Factor ($ mil)
EP Cast Iron Main Replacement	Cost Per Mile Installed	3.311	3.311
UP Cast Iron Main Replacement	Cost Per Mile Installed	1.980	2.317
Unprotected Steel Main Replacement	Cost Per Mile Installed	1.515	1.515
UP CP Steel and Plastic Main Replacement	Cost Per Mile Installed	1.515	1.515
Relocate Inside Meter Set	Cost Per Meter	0.002	0.002
District Regulators Abandoned	Included in main replacement unit cost		
Service Replacements	Included in main replacement unit cost		

The unit cost factors listed above have been developed by the Company based on 2023 nominal dollars. An escalation factor of 3% is then applied for future years within the Company's cost analysis. This factor captures the Company's expectations of future cost increases.

As noted in the Company's Engineering Report, the Company has "supportable estimates that reasonably reflect expected program costs".[15] Contingency except for escalation adjustments is not applied. The Company is able to gain confidence in its cost estimates because of what it views as the robustness of its unit cost factors scaled to the level of the GSMP III program.

[14] The cost estimates also include estimates for the removal and disposal of the old assets (Cost of Removal Expenditures). The program costs used in the CBA cover cash costs for capital expenditures. The Company does not identify any operating expenses for the program. Likewise, costs exclude consideration for changes in income or property taxes, or consideration for tax effects associated with asset retirements (such as repair allowances, if any). These excluded costs have minimal impact on the CBA based on representations by the Company on how its revenue requirements are constructed.

[15] PSE&G Engineering Report, page 42.

The Company has determined that all costs are capitalized costs, and there are no operating and maintenance expense items as part of the three-year program. This finding is consistent with GSMP I and II cost estimates.

As described earlier, both costs and benefits for each scenario are identified as part of the CBA and a comparison is made to determine the marginal difference associated with these two directions or choices. Accordingly, the Company has used its knowledge of its unit cost factors for the GSMP III, -- which reflects work at scale, and is based on the map-grid construction basis, -- to estimate the costs that would be incurred in executing the work described as part of the alternative scenario. Under the alternative scenario, which assumes a modest level of base capital spending, and would be executed with a targeted and per-segment construction planning approach (focused mostly on high-risk assets as identified as part of the Company's integrity management planning process), the Company would lose many efficiencies in conducting the work.

A comparison of the unit cost factors in Table 7 (above) reveals that there is a cost efficiency related to pursuing the work at scale, as assumed in the GSMP III scenario, specifically in programmatically replacing UP cast iron mains with EP polyethylene mains (Reference: Table 7 "UP Cast Iron Main Replacement") which allows for smaller diameter installation and improved construction efficiency.

Based on the installation units identified previously in Table 6, and the unit cost factors identified in Table 7, the Company has estimated the program's capital costs as shown in Table 8. These values are displayed in both nominal dollars and in present value terms.

Table 8: Comparison of Costs, by Scenario – Three Year Program Cost ($ millions)

Scenario	Nominal USD	Present Value, USD
GSMP III	$2,387.7	$2,068.4
Base RF Level	$427.1	$370.9
Difference	$1,960.6	$1,697.5

In future years, starting in 2028, there is no difference between the costs for each scenario. Therefore, Table 8 reveals that the marginal or incremental cost difference of pursuing the GSMP III scenario is $1,697.5 million over the evaluation term in present value terms.

1.4. Benefits Overview

The CBA for the Company's GSMP III is estimated to produce valuable benefits over the life span of the new assets slated for installation within a modern design configuration. Ideally, and as a general matter related to the development of the CBA, benefits should be monetized in terms of their economic value. This is not always practical or feasible. In the case of the CBA for the GSMP III several very important benefits are, in fact, strictly qualitative in nature.

The qualitative benefits within the CBA include the over-arching importance of the GSMP III in supporting comprehensive risk reduction, and in improving the Company's posture in relationship to federal safety recommendations for natural gas system operators to pursue aggressive actions to improve system safety.[16] This risk reduction benefit is attributable to improved assets (in a modernized system design configuration) that the Company estimates will improve safety, reliability, and resiliency risk levels when compared to the alternative scenario.[17] Additionally, by deploying more elevated pressure pipe, the modernized gas distribution system will also improve gas delivery, which in turn will benefit customers whose modern equipment and appliances are designed for pressures higher than that provided with utilization pressure systems. This is another form of benefit that the CBA considers in qualitative terms.

Another important benefit of the GSMP III program is the fact that it will enable the Company to further reduce methane emissions beyond that which is feasible under the alternative scenario. Methane is the primary greenhouse gas ("GHG") emitted by natural gas utilities and reducing its accumulation within the atmosphere is important for achieving utility and societal climate goals. These Scope 1[18] emission reductions illuminate one of the essential ways that the proposed gas system modernization leads to improved performance of the system, including, in this instance, environmental performance. Methane emission reductions, (the physical change in this instance) leads to economic benefits by estimating the social cost of these emissions. To translate the physical changes to the economic benefit the CBA considers, in part, the fugitive methane emission rates assumed for cast iron and unprotected steel mains and services (and joints, valves, and related assets).

The CBA applies methane emission factors as published by the U.S. Environmental Protection Agency (U. S. EPA). These factors are used by the Company and other natural gas system

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[16] In 2011, the U.S. Department of Transportation (DOT), and the Pipeline and Hazardous Materials Safety Administration (PHMSA is part of DOT), issued a "Call to Action" for natural gas system owners and operators to take aggressive actions to improve system safety performance through repairing and replacing high risk infrastructure. Additionally, PHMSA specifically characterizes cast iron and unprotected steel mains as categories of pipeline infrastructure that require repair, rehabilitation, and replacement. The DOT's "Call to Action" included an advisory bulletin issued by PHMSA in 2012 urging operators to accelerate aging asset replacement to enhance safety. This bulletin also requested state agencies to consider enhancements to cast iron replacement programs and plans.

[17] At the same time, quantifying and monetizing risk reduction is not practical in the case of the CBA for IIP purposes; monetizing risk reduction would require assigning monetary values to specific system risk attributes, particularly those involving consequences of hazard events. Such efforts would be unreasonably speculative for multiple reasons.

[18] "Scope 1 emissions are direct greenhouse (GHG) emissions that occur from sources that are controlled or owned by an organization" (EPA)

operators throughout the United States for purposes of environmental compliance reporting.[19] As applied in other areas of benefits as part of the CBA, the methane emission changes attributable to the GSMP III are the incremental differences revealed through a comparison of the GSMP III scenario and the alternative scenario.

The modernization of the PSE&G gas system will also result in cost savings, another noteworthy benefit of the GSMP III program. These savings are quantified and monetized within the CBA. While relatively small in comparison to the GSMP III investment costs, the Company has applied diligence and care in determining a reasonable set of mechanisms that will reduce both capital and operating costs due to the modernization. The modern materials and improved design configuration will contribute to higher levels of performance for the system (compared to the alternative scenario), due to a range of factors that otherwise contribute to leaks and breaks, and which require prompt attention today to locate, repair and/or replace. With the installation of 1,140 miles of new mains, thousands of new services, and outside meter sets as part of the GSMP III scope, the Company will lower annual recurring capital repair costs and on-going operating and maintenance expenses, compared to the alternative scenario.

Physical Changes Mapped to Economic Benefits

The goal of the CBA is to identify the material and significant economic benefits available through GSMP III investment. The process of identification is akin to assembling a “benefits inventory”, which was briefly alluded to earlier. The development of this inventory involves a stepwise process that begins with recognizing the physical changes or impacts associated with the improvements.

As part of this stepwise process, it is helpful to recognize that a physical system upgrade or replacement can drive multiple benefits. For example, moving meters from indoors to outdoors locations (physical relocation) leads to several benefits, including reducing risk (by increasing safety), and reducing operational costs (because field appointments are not required to inspect or change the meter).

The discussion above on methane emission reductions provides another example of this distinction between the physical change (the change in emissions, in metric tons and the economic value (derived by applying a social cost avoided to these emissions). This stepwise process for estimating benefits helps avoid conflating physical impacts and benefits: the benefit is the *economic* effect of the *physical* change. This process of sorting out the physical change and how it drives an economic benefit is useful in identifying the appropriate scope of benefits when developing a CBA. It also helps avoid claiming that a physical change is the exclusive

[19] PSE&G, as an owner and operator of natural gas distribution assets, is required to quantify and report its emissions to the U.S. EPA as part of its GHG compliance reporting obligations. To perform this estimation, the Company utilizes approved emission factors.

benefit (for purposes of the CBA) without asking exactly how the change drives an economic benefit.

Quantifying and Monetizing Benefits

As noted in the introduction to the discussion on benefits, it is not always feasible, reasonable, or practical to quantify benefits, and or to monetize said benefits. As an example, government agencies have shied away from attempting to place a value on human life or the value of a serious injury, because there is difficulty in reaching a consensus on these questions as part of a regulatory process. Additionally, while it may not be meaningful to assign dollar values to all benefits, it is preferable to quantify impacts where possible and where they can be reasonably estimated, even if not all benefits can be monetized. As an example, risk reduction benefits as part of the CBA are supported by recognizing that risk levels related to system assets are identified and quantified as part of the Company's asset risk registry as applied within its distribution integrity management planning and analysis process. [20]

Determining that a benefit is qualitative in nature does not demote the benefit or make it less important. It just means it is difficult, impractical, or unreasonable to quantify the benefit and apply an economic value to it. A clear example of this in relation to the GSMP III is the fact that foundational to the GSMP III's goals to support the continued system modernization is the over-arching benefit related to federal calls to action for distribution system operators to take aggressive actions to address system safety. The modernization improvements reduce system risk in areas of safety, reliability, and resiliency, consistent with fulfilling this mandate. These benefits are central to the CBA but are not quantified and monetized in economic terms because it is not practical to do so.

General Benefit Areas Identified as Part of the GSMP III CBA

To aid in interpreting the CBA results, GSMP III benefits map to five general categories, as shown in Table 9. Three are expressed in monetary terms, one of which is excluded from the CBA calculations. Two areas are qualitative in nature and are essential to the CBA. The benefits within these areas are estimated to provide significant aggregate value in relation to GSMP III costs, and in comparison, to the Base RF Level scenario. However, it is also not feasible to quantify and monetize the qualitative benefits in this instance. The main reason for this fact is that the system safety, reliability, and resiliency risk reduction benefits – which are highly relevant and material -- are impractical to quantify and monetize given their risk-based nature and their relationship to safety compliance.

[20] Appendix B provides a list of several asset risk-related indices, which the Company expects will be favorably impacted through the implementation of the GSMP III, and that would favorably influence the overall measurement of system risk. This information is taken from PSE&G's GSMP III Engineering Report.

Table 9: Benefit Areas within the CBA and Treatment

Benefit Area	How treated within the CBA
Reductions in capital and operating expenses (otherwise incurred with aging assets) Benefits include reductions in O&M and capital expense. Reduced main leak repairs; leak re-checks; regulator station inspection and maintenance; repair of steel services; reduction in water infiltration-related repairs; encapsulation of UP and HP CI joints; replacement of leaking services	Benefits are quantified and expressed in monetary terms.
Reductions in Scope 1 CO_2e emissions Due to improved, modern mains and services and related equipment	Benefits are quantified and expressed in monetary terms (based on the social cost of carbon using a 3% discount factor)
Reduction in gas distribution system risk Improved safety, reliability, and resiliency performance of more modern assets installed and operated in modern design configuration	Qualitative benefit related to the reduction in risk (and safety compliance, per DOT advisory)[21]
Modern Design, Elevated Pressure, Meter Relocations Customer satisfaction benefits; system operating benefits including higher gas delivery efficiency (due to achieving a higher level of system design); reduction in service stubs; relocation of inside meter sets	Qualitative benefits
Positive Economic Expansion Effects Skilled employment related to construction activity	Stimulus-nature of construction benefit; not formally included in CBA in monetary terms

For purposes of the CBA the area of general economic impacts is noted above but is not included within the analysis in monetary terms. However, the Company notes that as part of past GSMP phases the construction has created 2,338 skilled jobs (jobs per year), and with the larger scope of GSMP III it expects this number to increase. [22]

It is reasonable that net economic impacts, such as job growth and secondary and tertiary economic effects, add value to the GSMP III program, compared to the less intensive level of investment under the Base RF Level scenario. In fact, prior phases of modernization efforts explicitly recognized the value of modernization efforts to stimulate economic activity within the

[21] See Appendix B

[22] The Company estimates that the GSMP III construction work will require 3,771 skilled construction labor jobs (jobs per year). Job wages also stimulate additional economic activity.

state. The Company continues to recognize the importance of the stimulus-nature of the construction spending within the regional economy and the fact that this is an important aspect of the GSMP investments, including the benefits associated with local and regional job creation.

In summary, and at a minimum, the economic development and job growth impacts of the GSMP program should be recognized as important policy objectives that have been broadly recognized and embraced in prior program phases.

2. Costs

PSE&G provides estimates of capital costs as an input to the CBA for both the GSMP III and alternative Base RF Level scenarios. These estimates were developed based on the Company's experience within the last decade with similar construction and modernization programs such as Energy Strong and the previous GSMP I and II phases. PSE&G has developed a high level of confidence that its unit cost estimates, and total estimated capital costs for the proposed GSMP III reflect reasonably expected program costs.

The cost estimates for GSMP III are based on unit costs derived from recent experience. These unit costs were applied to the estimated quantities of main and service replacements and meter relocations within the three-year program scope. Table 10 summarizes the units for each program category.

Table 10: Asset Replacement Units per Year (3-year Program)

3-Year Program (GSMP III)	2024	2025	2026
EP Cast Iron Main Replacement	15	17	17
UP Cast Iron Main Replacement	249	281	281
Unprotected Steel Main Replacement	61	69	69
UP CP Steel and Plastic Main Replacement	25	28	28
District Regulators Abandoned	30	80	100
Unprotected Steel Services	28,286	31,922	31,922
Relocate Inside Meter Set	16,393	16,393	16,393

The unit cost derivation is deterministic and inclusive of costs for engineering, procurement, labor, construction, and overhead. PSE&G believes that because of its experience and high degree of understanding the work to be performed, these estimates can be accurately scaled with the level of program investment and allow for comparison of scenarios such as those included in the CBA. The unit costs consider certain classes of pipe, pipe size, and related services and meter set relocations. For example, the unit costs for replacement of elevated pressure cast iron were estimated based on previously completed 12-inch and greater pipe replacements and the replacement of related services. The utilization pressure cast iron replacements similarly are determined based on previous main and service replacements and associated main and service uprates plus the cost of district regulators to be abandoned.

The aggregate results for the capital budget needs of the program are derived from the multiplication of expected units of work per year and the associated unit costs. Moreover, the Company's GSMP III budget (based on this estimate of cash needs) assumes a continuous program from GSMP II through the three-year proposed duration (of GSMP III) to mitigate costs it would otherwise incur to demobilize and remobilize construction teams. This tactic conserves costs and maximizes the number of miles of cast iron and unprotected steel pipe in the Company's system today that the Company can remove. The program budget also assumes a 25% of annual spend to carry over into the following year, including carry over from 2026 into 2027. This amount is required to complete project work such as tie-ins, abandonments, restoration, and construction documentation records.

A comparison of budgeted costs for GSMP III compared to the alternative scenario is summarized in Table 11.

Table 11: Comparison of Annual Cost Estimates by Scenario ($ millions, nominal)

Costs ($ millions)	2024	2025	2026	2027
GSMP III	$530.6	$796.4	$843.5	$217.2
Base RF Level	$102.9	$141.3	$145.5	$37.5
Difference	$427.7	$655.1	$698.0	$179.7

For the GSMP III scenario, the installation of the new pipes and other assets is completed by the end of 2026.

While PSE&G's experience demonstrates an ability to scale GSMP III and deliver on the modernization plan as scheduled[23], the costs are based on unit averages for similar work recently completed. Therefore, the estimated capital costs do not represent a commitment of final construction costs or scope completion but rather a reasonable estimate for the purposes of budgeting, authorization, and tracking.

Other Potential Costs Due to Construction-Related Impacts

For completeness, the CBA should aim to identify other unexpected and unplanned costs that may arise through the implementation of the work. The GSMP III will involve a range of local construction impacts. These impacts could drive costs related to traffic and related delays and inconveniences, lead to construction-related air quality emissions (heavy equipment, dust),

[23] The Company expects to complete the GSMP II phase 10 months ahead of schedule.

increased noise levels, inconveniences related to the construction work to local gas services (brief outages), safety concerns, and other similar effects.

Since the GSMP III is very similar to the GSMP II work scope that is underway, it is reasonable to address this area of inquiry by reviewing whether the GSMP II implementation caused any such impacts of a material nature within the communities where the work was performed. To this end, the Company reports that its safety and compliance record related to the construction effort throughout the GSMP II term has been very good, and that its outreach efforts to customers and local government managers and representatives effective. It is also not aware of any material issues, impacts or concerns that have been communicated to the company as part of the GSMP II effort that is underway.

For these reasons, WMP has not identified or included within the CBA any impacts, or related direct or indirect costs, due to construction impacts, that otherwise should be included within the CBA, (otherwise offsetting the benefits of the GSMP III).

3. Benefits

3.1. Improving Risk Posture: Safety, Reliability, Resiliency

As introduced previously, a key value driver for the gas system modernization program is the fact that the accelerated replacement of aging system assets, -- and the upgrades of the gas distribution network to a more modern design configuration (including greater emphasis on the capacity to operate at elevated pressure) -- means that the Company will simultaneously achieve a material reduction in overall system risk, as measured through its asset risk registry-based analysis methods, and its Distribution Integrity Management Plan (DIMP) processes.[24]

This risk reduction will be driven by the retirement within the three-year construction period of 1,060 miles of cast iron and unprotected steel mains, and thousands of unprotected steel services and replacement with modern materials. The new assets will continue to provide a tangible long-term safety and reliability benefits to operation of the gas network. For example, the design includes the installation of excess flow valves (EFV) on services, an important safety device offering immediate shut-off of uncontrolled gas if the pipe integrity has been compromised and reduces the volume of fugitive emissions under these conditions. Accordingly, for purposes of the CBA, WMP identifies *risk reduction* as a key qualitative benefit of the GSMP III investment. Managing risk in the operations of the gas distribution system is a critical and essential function at the Company.

At a broad level of consideration for purposes of the CBA, this reduction in risk has three principal dimensions: *safety*, *reliability*, and *resiliency*. First, lower risk levels from aging mains

[24] Appendix B identifies several measurements, as indicators, of measured risk reduction potential. These are taken from the Company's Engineering Report.

and services improves safety risk levels. There will be a smaller inventory at the end of the GSMP III of older at-risk assets, which are more prone to failure (either leaks or breaks, due to a variety of causative factors) than newer assets. While the Company organizes and focuses its targeted replacement work to ensure it continues to fully comply with its safety compliance requirements and obligations, removing (as part of GSMP III) 1,060 miles of cast iron and unprotected steel mains, upgrading tens of thousands of services, installing excess flow valves, abandoning hundreds of district regulators, moving tens of thousands of meter sets to accessible outdoor locations, and updating and cataloguing asset location information (during the construction phase), will significantly reduce risk levels across the gas distribution system, thereby improving the overall level of safety, and measures of safety risk levels. The improvements reduce the likelihood of a dangerous leak or break occurring.

Another dimension of risk reduction relates to how the improvements in the gas distribution system improves the level of gas system reliability. When fewer and fewer assets fail to meet acceptable levels of integrity, the reliability of the system is improved. The Company is spending fewer resources on leak and break repair conditions and other types of actual or prospective asset integrity failure conditions. Customers become more confident that the system can deliver the valuable energy services they expect, and there are fewer service disruptions due to outages, with a commensurate reduction for the Company in repair, maintenance, inspection, and reporting requirements and costs. Gas system reliability plays an important role in supporting local communities and businesses.

The third dimension is resiliency. Resiliency protects the gas system from a loss of function due to extreme events or conditions. Improving resiliency involves attention on both “hardening” the system to help it sustain the impacts of certain hazards, and the ability of the system to be restored quickly after an outage (“spring back” quickly). Additionally, resiliency circumstances are often considered as being driven by low probability and high consequence events:

- During major storms, - particularly during peak winter days when gas system demand is high – many customers place a tremendous reliance on the gas system to continue to provide vital energy delivery services to sustain businesses and communities. This includes the role of natural gas to support backup electricity generators (often for critical facilities like hospitals, fire departments, police stations and schools).
- Water infiltration on the utilization pressure system can also cause outages. Outages occur due to water filtration when there are situations of ground water, flooding, or soil subsidence that contribute to driving water into the system. A system operated at elevated pressures mitigates these conditions year-round.
- Certain gas system hazards – excavation damage, frost, water main damage, tree root damage, can lead directly or indirectly to pipe integrity failure. Thus, by improving and

strengthening the gas system assets, the overall resiliency of the gas system is improved, and resiliency risks are reduced.[25]

Appendix B, which also appears in the Company's Engineering Report, identifies examples of indices that are part of its asset risk registry analysis processes. The Company contends that the GSMP III improvements will improve these indices thereby illustrating the improvements to safety, reliability, and resiliency risk levels.

3.2. Monetary Benefits

The Company has identified several *avoided* capital costs and O&M expenses that are estimated to result from implementation of the GSMP III, as compared to the alternative scenario. To perform this estimate, the Company has identified the specific assets impacted by the upgrade to new materials, and the resulting change in leak, break, and other asset-related repair activities.

The factors that are applied for estimating avoided costs are based on the Company's experience and associated data collection, asset performance tracking, and analysis of leak and break performance for current assets. Leaks and breaks, and other integrity shortfalls that require replacement or repair, arise for reasons due to natural causes (corrosion, ground movement, soil subsidence, equipment failure, etc.), and manmade factors (excavation damage, incorrect operation, etc.).

The avoided expenses estimated for purposes of the CBA relate primarily to improved performance of newly installed mains and services in relation to abating failures and risk of failures due to natural causes. Furthermore, this analysis is a 'net' analysis showing the incremental difference between the GSMP III and alternative scenario. The avoided costs are recurring. Since the inventory of assets under GSMP III is significantly upgraded by the end of 2026, these newer assets will perform better than the assets slated for removal. This means that the Company can estimate a recurring benefit over time for the life of these new assets.

Table 12 provides a summary of the net avoided costs for the first several years of the CBA evaluation period. The Company has provided estimates of the avoided costs through the GSMP III's implementation period. The CBA analysis has further extended these savings in time (out to 2050) by applying an escalation factor of 3%, reflecting the assumption of some recurring increase in material and labor costs otherwise required to carry out the repairs.

For purposes of conservatism, the CBA assumes that the leak rates do not change in time. Since the leak rate assumptions are in relation to old assets that (today) are leak and break prone (compared to new assets), it would not be unreasonable to assume an increase, over time, in the

[25] The Company's DIMP identifies classes of hazards and enumerates specific hazards. Some relate to conditions that fall within a broad resiliency class of hazards.

leak and break rate factors. The Company, however, chooses not to include any degradation in leak and break rates over time.

Table 12: Estimates of Avoided Costs ($ millions, nominal)

Net Difference between GSMP III & Base RF Level ($ millions, Nominal)	**2025**	**2026**	**2027**
Annual Capital Expense Savings	$5.4	$12.0	$18.8
Annual O&M Expense Savings	$0.4	$0.8	$1.3
Total Annual Avoided Costs	$5.8	$12.8	$20.1

As shown in the far-right column, bottom row of Table 12 , the CBA estimates that by 2027 -- once the GSMP III assets are installed and in service, -- the recurring level of avoided capital and O&M expense per year is approximately $20 million per year. This value is driven by the incremental difference in the performance of the installed assets (the leak, break, and other activity factors) provided in Appendix B for each category item identified above) between the GSMP III and the alternative scenario.

Table 13 summarizes the avoided costs over the 27-year evaluation period, on both nominal dollar and present value terms. The present value calculation uses 2024 as the base year, and applies a discount factor of 6.48%, which is equal to the Company's weighted average cost of capital (WACC).

Table 13: Comparison of Avoided Costs by Scenario ($ millions)

Costs Differences (2024 – 2050), $ millions	Nominal	PV
Avoided Capital Expense	$661.5	$259.7
Avoided O&M Expense	$45.1	$17.9
Total Avoided Expense	$706.6	$277.5

3.3. Other Qualitative Benefits

In addition to risk reduction benefits, there are many other qualitative benefits driven by improving and upgrading the design of the system to modern standards as part of the GSMP III scenario. These are integral to the CBA. This section provides a description of these qualitative benefits.

- Through the modernization construction program, the Company will achieve a greater geographic extent of design modernization. This upgrade has many beneficial attributes. For example, along with a greater degree of uniformity in its deployed materials and asset types, the Company will gain improved operational awareness of the assets' operational characteristics (since there is less variability in asset vintages and types). This simplifies the network, and will have benefits over time, as the Company continues to monitor asset performance, and integrate performance data into its asset integrity analysis.

- By improving asset records (through asset geolocation recordation during construction, the recordation of as-built construction diagrams, and the use of tracer wire on new PE pipe) means that there is better information about asset locations into the future; this improved information reduces the possibility of service repair delays and third-party damages when performing work around the gas mains and services.
- The improvements in gas system design resulting from GSMP include the extension of the gas system's elevated pressure (EP) operations and delivery capability. By replacing legacy utilization pressure (UP) pipe, the distribution system can be operated more efficiently. There are many benefits of elevated pressure. Examples of benefit areas include:
    - **Improved and Lower Cost (and Less Disruptive) Construction** – When the PE (EP) pipe can be inserted into the older, larger diameter UP, some construction cost savings result.[26]
    - **Enabling the Ability to Deploy Excess Flow Valves** – Excess flow valves (installed at the point where the service line is connected to the main) are not installed on low pressure systems because they will not work on UP. Moving to EP allows for the installation of this valuable safety device.
    - **Removing Unneeded Assets** – EP construction allows the company to simplify the network design and eliminate hundreds of district regulators, further reducing maintenance and repair costs.
    - **Customer Appliances -** Many modern appliances such as tankless water heaters, whole house backup generators and commercial kitchen stoves are designed for high inlet gas pressure to function efficiently. UP is unable to provide the higher inlet pressures in accord with the design standards of these appliances. EP offers customers, suppliers and manufacturers greater range of choices to install and supply these high efficiency appliances. At EP, these appliances will run more efficiently. This improves end-use gas efficiency, reduces customers costs, and reduces GHG emissions.
- There are also benefits tied to construction efficiencies (given the scale of the GSMP III program, vs the alternative scenario), in turn related to planning, contractor mobilization, and field work productivity. The larger program allows for a greater degree of coordination with other asset replacement efforts, such as the replacement of unprotected steel services. Similarly, it permits the Company to achieve a higher degree of coordination with other utility projects and with municipal road surface paving projects. This will tend to lower the

[26] Insertion of smaller pipe into existing pipe takes place under several circumstances, including the insertion of EP into UP in many service lines, and EP into UP in some mains. When this opportunity can be taken advantage of there are savings in materials and construction costs.

amount of duplicative work overtime, lowering burdens to communities for inconveniences tied to surface paving activities.

- Relocating gas meters from inside to outside locations improves customer safety, reduces concerns about indoor odors and possible leaks, reduces gas company service calls, and makes service calls easier (as they do not require appointment scheduling to gain access to indoor locations).
- By reducing the number of service stubs (which can be difficult to locate today) the modernization reduces potential leaks and damages as part of future construction work. These are the kinds of modest actions that lead to a simpler network that is more secure and less costly to maintain. Small or minor improvements, such as this service stub removal, cumulatively, add up over time, and make a difference in helping the Company operate and maintain the system in a safe and secure manner.
- The accelerated program also leads to certain program efficiencies, which are hard to quantify. A smaller, less-intensive, and potentially less-certain work scope (in contrast to the accelerated GSMP scope) impacts the ability of contractors to plan work, recruit, onboard, train and qualify skilled workers, and acquire the needed construction equipment. Likewise, the Company will still be required to perform engineering, obtain permits, and source materials regardless of work scope levels, but efficiencies in carrying out these responsibilities will be eroded at a lower level of scope.

3.4. Methane Emission Reductions

Identifying and reducing sources of methane emissions —an important greenhouse gas (GHG) -- are primary activities of PSE&G. The Company performs methane control and emission reduction activities in relation to a range of policy and business compliance and reporting obligations. For purposes of the GSMP III investment in gas mains and services (and related assets) the Company has estimated that it will be able to reduce its reported USEPA 40 CFR 98, Subpart W emissions by approximately one-third from today's levels. This is due to the higher performance of new asset replacements in comparison to the old and aged assets that are being removed from service.

At the conclusion of the GSMP III construction work (beginning of 2027), the PSE&G system will emit approximately 6,000 fewer metric tons of methane equal to approximately 150,000 fewer metric tons of CO_2 equivalent (CO_2e) when using U.S. EPA default global warming potentials for methane[27] from its system of natural gas distribution system.

State Policy Drivers

New Jersey policy is a driver for PSE&G's focus and actions on reducing CO_2e from its operations. It consists of legislatively established goals, Executive Orders, and energy master planning.

[27] https://www.law.cornell.edu/cfr/text/40/appendix-Table_A-1_to_subpart_A_of_part_98

In 2007, the State of New Jersey, as mandated through the Global Warming Response Act, set a goal to reduce the statewide greenhouse gas emissions and greenhouse gas emissions from electricity generated outside the state but consumed in the State by 80% from its 2006 levels by 2050.[28] By 2018, New Jersey had reduced its emissions to 20% below 2006 levels. This reduction was driven largely by the rapid transition away from coal-powered electricity generation to cleaner burning natural gas.[29]

Continued progress will require significant reductions across all sectors of the state's economy. The state's energy sector requires much greater levels of energy efficiency, and greater use of renewable energy than provided in today's fossil fuel-heavy resource mix. In May 2018, with this in mind, New Jersey Governor Phil Murphy signed Executive Order (EO) No. 28, directing the New Jersey Board of Public Utilities to develop a statewide clean energy plan to aid the state and its residents and businesses in a shift away from energy production that contributes to climate impacts.[30] Additionally, following the EO, the Governor unveiled the state's 2019 Energy Master Plan (EMP), which identified several key strategies to reach the Administration's goal of 100% clean energy by 2050.

The 2019 EMP is built around seven key strategies[31]:

1. Reducing energy consumption and emissions from the transportation sector
2. Accelerating deployment of renewable energy and distributed energy resources
3. Maximizing energy efficiency and conservation and reducing peak demand
4. Reducing energy consumption and emissions from the building sector
5. Decarbonizing and modernizing New Jersey's energy system
6. Supporting community energy planning and action with an emphasis on encouraging and supporting participation by low- and moderate-income and environmental justice communities
7. Expanding the clean energy innovation economy

The Energy Master Plan's initiatives were further reinforced by the signing of Executive Order No. 100 in 2020. The order, officially titled the Protecting Against Climate Threats (PACT), directs the N.J. Department of Environmental Protection to make regulatory reforms to reduce GHG emissions and adapt to climate change.[32]

In addition to the EMP's strategic directions, in 2011 New Jersey joined the multi-state Regional Greenhouse Gas Initiative (RGGI) after leaving the initiative. RGGI is a multi-state emissions allowance cap and investment program that requires fossil fuel power plants with a capacity greater than 25 megawatts to obtain an allowance for each ton of CO_2 emitted annually.

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[28] https://www.nj.gov/dep/aqes/docs/gw-responseact-07.pdf
[29] https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf
[30] https://www.nj.gov/emp/energy/
[31] https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf
[32] https://nj.gov/infobank/eo/056murphy/pdf/EO-100.pdf

Proceeds from purchase and sale of CO_2 allowances are invested in programs to help reduce greenhouse emissions.[33] RGGI does not have a bearing on the PSE&G gas distribution business and its operations, but it is noted here because it forms another component of state's energy policy, which is heavily focused on initiatives to help the state and the region in its decarbonization efforts.

Corporate Planning Drivers

As a corporation PSEG (PSE&G's parent company) pledged, and started to work towards, its own greenhouse gas reduction goals. Notably, in 2019 PSEG announced its Net-Zero Climate Vision to net-zero by 2050. In 2021, the parent Company accelerated its Net-Zero Climate Vision with the goal to achieve net-zero by 2030.[34] These goals cascade down to each of PSEG's operating companies, including the PSE&G's gas operations. The climate vision is comprised of three pillars:

1. Net-zero emissions for PSEG operations, including PSE&G's utility operations (Scopes 1 and 2)
2. 100% greenhouse gas (GHG), carbon-free power generation
3. Significant contributions to regional economy-wide decarbonization.

Further, on October 15, 2021, PSEG joined the Business Ambition for 1.5°C and the Race to Zero campaigns and committed to developing science-based targets. The Race to Zero and Business Ambition for 1.5°C campaigns are designed to help mobilize support from businesses, cities, regions, and investors for a healthy and resilient zero-carbon economy in line with global efforts to limit warming to 1.5°C.

In summary, the Business Ambition to 1.5°C is an umbrella campaign that aggregates net zero commitments from a range of leading networks and climate initiatives and includes setting science-based reduction targets for Scopes 1, 2, and 3.

A primary focus of PSE&G's decarbonization strategy is to reduce the Scope 1 GHG emissions from its electric and gas utility operations, including methane emissions, combustion sources across the PSE&G's operations and vehicle fleet.[35] PSE&G will do so through the modernization of its natural gas and electric transmission and distribution networks and by investing in new technologies and programs that enable electrification and improve energy efficiency.

PSE&G is a founding member of the EPA's Natural Gas STAR program[36], a voluntary initiative that encourages natural gas companies to adopt technologies and practices that reduce

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[33] https://www.nj.gov/dep/aqes/rggi.html
[34] Primarily driven by the sale of PSEG fossil generation assets in 2022.
[35] PSE&G has also described significant energy efficiency-related reductions in CO_2e, as part of its Clean Energy Future proposals and programs. Many of these emissions are from customer activities, and so they represent the Company's Scope 3 emissions.
[36] "The Natural Gas STAR Program provides a framework for Partner companies with U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary

methane emissions in a cost-effective way.[37] In 2018, PSE&G submitted a progressive proposal, Clean Energy Future (CEF), to invest in energy efficiency, advanced metering, electric vehicles, and energy storage programs. The BPU in 2020 approved the central component of CEF, a $1 billion investment in energy efficiency programs. PSE&G's energy efficiency program aims to help customers reduce their energy use resulting in $1 billion of utility bill savings and a 8 million metric ton reduction in carbon dioxide emissions. [38] PSE&G has also received approval of an electric vehicle program that will increase customer awareness and build out EV charging infrastructure and contribute an additional 14 million metric ton reduction of carbon emissions through 2035.[39] PSEG is also seeking to further reduce vehicle emissions through electrification of its own fleet. These programs, like GSMP, demonstrate a continuous commitment to address climate change and environmental justice.

Valuing CO_2e Emission Reductions

The social cost of carbon (SCC) is a monetary estimate of the economic costs, or damages, which are estimated to result from emitting one additional metric tons of carbon dioxide into the atmosphere. Similarly, the SCC also represents the value of damages avoided by an emission reduction. It forms the basis of a widely accepted and acknowledged method for valuing the benefits of reducing emissions. Climate change damages presumed to be avoided reflect changes in net agricultural productivity, human health, property damages from increased flood risk and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.[40]

The beginnings of the development of the social cost of carbon for the purposes of its integration into policy and regulatory rulemaking at the federal level stemmed from a ruling by the U.S. Court of Appeals for the Ninth Circuit in 2008. The ruling required the federal government to account for the economic effects of climate change in a regulatory impact analysis of fuel efficiency standards. As a result, President Obama convened an Interagency Working Group (IWG) in 2009 to develop an SCC value for use in federal regulatory analysis.[41]

Using specialized computer models, the social cost of carbon is calculated by considering four categorical implications:[42]

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emission reduction activities. By joining the Program, Partner companies commit to evaluate and implement cost-effective methane emission reduction opportunities and communicate and share that information across their corporation and with the Natural Gas STAR Program." – U.S, EPA

[37] https://corporate. PSE&G.com/-/media/ PSE&G/corporate/corporate-citizenship/environmentalpolicyandinitiatives/sustainability/ PSE&G_sustainability_report.ashx

[38] https://poweringprogress.pseg.com/energy-efficiency/

[39] https://poweringprogress.pseg.com/wp-content/uploads/2022/01/EV-Advocacy-Fact-Sheet_JAN_2021-1-Copy.pdf

[40] https://www.epa.gov/sites/default/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

[41] https://www.edf.org/sites/default/files/social_cost_of_greenhouse_gases_factsheet.pdf

[42] https://www.rff.org/publications/explainers/social-cost-carbon-101/

1. Future emissions based on population, economic growth, and other macroeconomic factors.
2. Future physical climate responses, such as temperature increase and sea level rise
3. The economic impact that these climate changes will have on effected areas of the economy
4. The present-day value of these future damage costs

The choice of discount rate is one of the most important issues analysts confront in estimating the SCC. GHG emissions related to manmade pollutants are stock pollutants[43], and by nature, accumulate in the atmosphere over long periods of time. Damages associated with what has accumulated occur over many decades or centuries depending on the Global Warming Potential of the gas being considered. The stream of future damages to market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption. The estimate of that stream of future damages is then discounted back to the present value of the year that the additional unit of emissions was released.

The IWG provides three discount rates to span a plausible range of certainty: 2.5, 3, and 5 percent per year. A 3% discount rate is consistent with estimates provided in the Office of Management and Budget's Circular A-4 (OMB 2003), which includes guidance for what economists refer to as the consumption rate of interest. The IWG found that the consumption rate of interest is the correct discounting rate to use when evaluating future damages from elevated temperatures. The IWG includes a 5% discount rate to represent the possibility that climate-related damages are positively correlated with market returns. This implies a certainty equivalent value higher than the consumption rate of interest. Finally, 2.5% discount rate is also included to reflect the concern that interest rates are uncertain overtime. Also, a rate below the consumption rate of interest is justified if the return to investments in climate change mitigation are negatively correlated with the overall market rate of return.[44]

As might be surmised by the preceding description, there is not one accepted or consensus discount rate used by economists. However, a 2015 survey of 197 economists found that most preferred a rate between 1% and 3%.[45] Table 14 below summarizes the social cost of carbon reference values on five-year intervals, at the three different discount rates as published by the

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[43] As defined by the IWG "GHGs, for example, CO_2, methane, and nitrous oxide, are chemically stable and persist in the atmosphere over time scales of a decade to centuries or longer, so that their emission has a long-term influence on climate. Because these gases are long lived, they become well mixed throughout the atmosphere" (IPCC 2007).

[44] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[45] http://piketty.pse.ens.fr/files/DruppFreeman2015.pdf

IWG and as discussed above.[46] An expanded table of values by year (2020 – 2050) is included in Appendix C.

Table 14: Social Cost of Carbon 2020 - 2050

Social Cost of CO_2, 2020 - 2050
(in 2020 dollars per metric ton of CO_2)

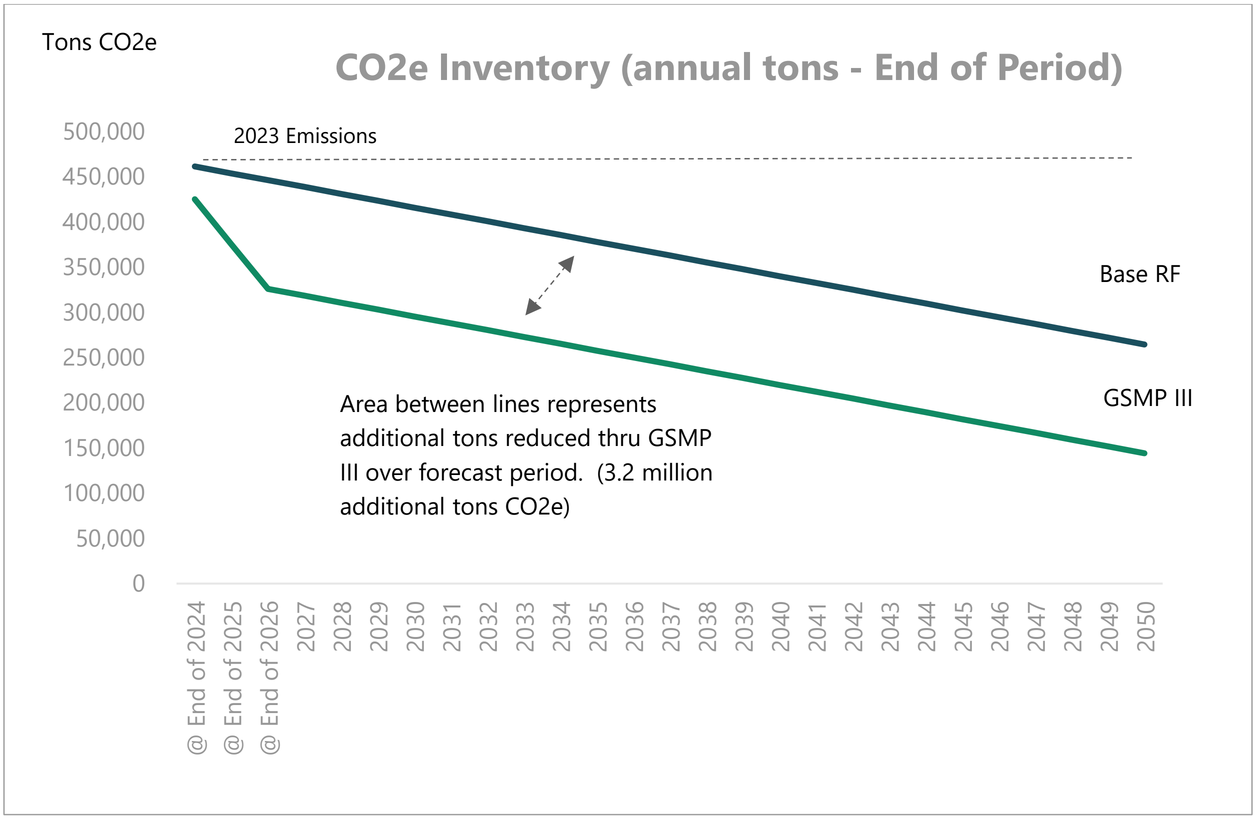
	Discount Rate and Statistic		
Emissions Year	5% Average	3% Average	2.5% Average
2020	14	51	76
2025	17	56	83
2030	19	62	89
2035	22	67	96
2040	25	73	103
2045	28	79	110
2050	32	85	116

Multiplying the social cost of carbon in *year t* by the cumulative change in emissions in *year t* will yield the monetized value of future emission changes from a *year t* perspective. This can be done for each year of the study period. To find the total present value of avoided cost of the abated emissions (using the social cost of carbon) the results for each year are summed.[47]

The carbon emissions attributed to methane leaks were calculated using the methodology outlined by Subpart W.[48] This methodology is consistent with the methodology the PSE&G used to calculate the Company's overall methane emissions for the 2021 Sustainability and Climate Report.[49]

[46] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[47] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[48] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W
[49] W. Miller, Testimony

Figure 1: Methane Reductions by Scenario



4. Cost and Benefit Comparison

The CBA for the GSMP III is based on a comparison of the costs and benefits associated with two meaningful scenarios. The one scenario assumes the implementation of GSMP III. The other assumes the Company pursues a much lower level of work under base capital. Furthermore, the CBA has identified a mix of noteworthy benefits. Some are quantified and monetized in economic terms. Others are described in qualitative terms because they cannot be easily or reasonably monetized:

- Benefits related to risk reduction are difficult to monetize because it is difficult to assign a dollar value to increments of risk level changes, because the underlying measurement of risk is multivariable in nature and subject to probabilistic treatment.[50] Additionally, risk is commonly addressing low probability events that have catastrophic levels of impact, which are unacceptable. Accordingly, greater interpretive value for purposes of the CBA is provided by reference to federal and state safety compliance standards, mandates, calls to action, advisories, requirements, and norms of practice that pay deference to the regulatory safeguards.

[50] Risk parameterization requires an identification of three attributes: hazards, likelihood of occurrence, and consequence. Risk measurement is "stochastic" in nature, meaning subject to probabilities.

- Operating, maintenance and other benefits of elevated pressure are hard to monetize simply due to the number of variables required, and the wide range of estimation that will result given the level of information reasonably attainable. (The CBA does include some savings, however, related to the abandonment of district regulators).[51]
- Some benefits, such as reduced "truck rolls" due to the relocation of meter sets to outside locations, are noteworthy, but small in dollar terms, and were therefore not included in the CBA.

In summary:

- The GSMP III costs (incremental costs of $1,697.5 million on a present value basis, when compared to the Base RF alternative) are offset by additional monetized benefits of over $501.1 million (on a present value basis) (also when compared to the alternative). Therefore, by pursing GSMP, the Company addresses DIMP-aligned and accelerated modernization while securing nearly a half billion dollars of additional benefit (when compared to the Base RF alternative).
- These additional monetized benefits offset nearly 30% of the incremental costs.
- The monetized benefits include:
    - Due to the accelerated replacement of a significant portion of aging assets, the upgrading of the system to a modern design and greater deployment of EP, the Company estimates $277.5 million on a PV basis of additional capital and operating expense savings.
    - The GSMP III scenario drives down methane emission reductions above that achievable under the alternative scenario. This leads to an additional reduction of 3.1 million metric tons of CO2e of over the forecast period, valued at $223.6 million.
- The monetized benefits do not include consideration of important qualitative benefits. Therefore, the net costs are *additionally* offset in non-monetary terms by several significant areas of qualitative benefit:
    - Significant levels of risk reduction proportional to the aggressive and accelerated replacement of 1,060 miles of aging cast iron and unprotected steel mains, services, and other assets; risk reduction benefits driven by system modernization

[51] For example, estimating the cost and emissions savings due to modern appliances and equipment utilizing EP vs. UP require estimates of equipment/appliance inventories over time, by types/model of equipment/appliances that customers will purchase, the performance attributes of this equipment, their specific locations on the grid, the level of use of the equipment/appliances, and the level of appliance performance improvement operating at EP (vs today's UP). The Company concluded, and WMP agrees, that these estimates would be speculative to monetize for purposes of the CBA without detailed study.

including modern materials, more extensive deployment of elevated pressures and excess flow valves.

- The construction effort will improve the quality of the asset and system records. This in turn will improve safety and operations moving forward, by assisting in the prompt and accurate location of facilities, thereby reducing risk through improved damage prevention.
- Continued operational improvements of greater deployment of EP. Today, 70% of PSE&G's customers receive gas at elevated pressure. The GSMP III's upgrades to EP for additional portions of the system continue this improvement. One benefit of EP is that a large portion of an elevated pressure system can be constructed from PE pipe. Further, an EP-designed system is less costly to construct because natural gas is compressible and the higher operating pressure allows a smaller diameter replacement pipe to be installed, as opposed to utilization pressure, which requires the same (replacement) size for the new pipe.[52]
- From an operating and maintenance perspective, the elevated pressure system also has fewer joint leaks because of the installation techniques available for modern materials. EP also permits the installation of excess flow valves, which is an additional safety feature and system enhancement.
- The elimination of the UP system, and the further migration to EP, enables PSE&G to further simplify its operations and maintenance. For example, the upgrade to EP allows for the removal from the system of low-pressure district pressure regulators.
- Eliminating the UP system will also reduce the number of customers impacted by, and the duration of, unplanned gas outages. Outages caused by water infiltration will be virtually eliminated. The use of PE main also enable PSE&G crews to isolate gas leaks quickly for repair by either closing an existing valve or squeezing the pipe off upstream and downstream of the leak. An elevated pressure system also generates fewer calls from customers with appliance problems caused by insufficient gas pressure.
- The elevated pressure systems will allow for the expanded use of high efficiency appliances that require inlet pressures higher than the UP system can provide. The increased ability to use these appliances will improve customer satisfaction, reduce customer's energy bills, and reduce GHG emissions through improved efficiency.
- Through relocation, improved access to customer meters, reducing concerns on safety and odors, and improving customer service and satisfaction.

[52] Insertion of a replacement *service* is routinely done on UP-to-UP services (in fact, approximately 80% of the time during the last two years).

- Improved customer satisfaction through system safety and reliability improvements

5. Alternatives Discussion

Section 4 provides a summary of the key differences between the GSMP III and the alternative Base RF Level scenario. With this set out it is possible to describe how changes in scope and funding levels interact, as a form of sensitivity analysis and consideration of alternatives to the core CBA results.

Accordingly, the following items describe the directional changes to the CBA assuming a material decrease in GSMP III scope:

- A decrease in GSMP III scope drives several risks. First, scale economies in the overall program may be affected, and this could increase unit costs, making a reduced program less cost-effective.
- A significant diminution in GSMP III scope runs counter to the PIPEs Act and the "Call to Action" of the federal DOT for gas system operators to take an *aggressive* posture towards the management of system risk, especially as it relates to the continued presence within the gas system networks of old CI and unprotected steel main segments and related assets.
- A significant diminution in scope would erode the protective degree of risk reduction that is created by the proposed accelerated replacement program, that is proportional to the retirement from service of 1,060 miles of aging CI and UP Steel mains.
- It also impedes the ability of the Company to modernize the system using a systematic "map-grid" construction approach that permits a holistic approach to upgrading the gas system while addressing system risk in a prudent manner.
- Decreases in scope results in fewer reductions in methane emissions, and resulting benefits tied to the social cost of carbon
- Consistent with the above, a significant diminution in scope could impede the company's ability to upgrade the network to elevated pressures (EP). This would lock in a gas distribution service at a less efficient level of utilization pressure (UP) operation. Such a "lock in" leads to higher customers costs, fewer incentives for the use of modern equipment and appliances, and higher methane emissions over time as the leak-prone pipe inventory remains in service longer.

- While cost savings are not the principal driver for the modernization effort, scope changes erode the estimated $20 million per year of recurring avoided costs (when comparing GSMP III and the Base RF Level scenarios).[53]

6. Conclusions

The CBA has identified two scenarios and has estimated the costs and benefits of each. It has also monetized many important avoided costs and savings related to environment performance. The CBA is based on an evaluation period of 27 years, ending in 2050. Costs and benefits are summarized and compared on present value terms.

The GSMP III scenario reflects the Company's strong preference to continue with the replacement activities at an accelerated replacement level.[54] This scenario keeps the modernization program on a strong footing, allowing it, in fact, to be completed by 2031 (as part of a future phase). The alternative *Base RF Level* scenario considers the costs and benefits of a more modest level of targeted capital spending that comports with the Company's planning and estimated implementation needs as reflected in its Distribution Integrity Management Plan (DIMP) and within other safety and reliability planning areas.

The *GSMP III* program's costs and monetized benefits, when compared to the *Base RF Level* scenario, are summarized in Table 19. The monetized benefits include an estimate of the societal value of reducing fugitive methane emissions through the installation of better performing mains and services and related assets; this value estimate is based on applying the social cost of carbon (SCC) damage estimate for CO_2e, as established by the Interagency Working Group (IWG).

Notably, nearly 30% of the additional cost impact of GSMP III (-) $1,697.4 million (compared to the Base RF scenario) is offset by the additional avoided costs realized, before accounting for risk reduction and other qualitative benefits.

[53] Based on the estimate of reductions achievable by the end of year 3. See Table 12.
[54] As noted previously, 'accelerated' is in reference to the pace achieved in GSMP II.

Table 15: Cost and Benefits Comparison, ($ millions, Present Value)

Costs and Benefits ($ millions, Present Value)	**GSMP III**	**Base RF Level**	***GSMP III Impact*** (Difference GSMP III vs. Base RF)
Program Costs	$2,068.4	$370.9	$1,697.5
Benefits - Avoided Costs	$323.8	$46.2	$277.5
Benefits - Avoided SCC (CO2e)	$437.5	$213.9	$223.6
Total Benefits	$761.3	$260.2	$501.1
Benefits Less Costs	-$1,307.1	-$110.7	-$1,196.4

Given the many benefits of the GSMP III investment, Table 15 does not embody the full conclusions of the CBA. Rather this table captures what can be reasonably quantified and monetarily compared. It summarizes the additional costs related to GSMP III when compared to the Base RF alternative ($1,697.5 million), and the approximately half billion dollars of additional benefit value ($501.1 million). Moreover, it identifies a net difference (when comparing the costs and benefits in the far-right column) of (-) $1,1,196.4 million, which is a comparison of the GSMP III and alternative scenario for all incremental costs and benefits. This is the difference in costs and monetized benefits between the two scenarios, over the period (2024-2050) in present value terms.

In addition to this estimate of net differences, the CBA considers the value of tangible, foundational, and *qualitative* benefits of GSMP III that are estimated to occur within three areas:

- *First*, the GSMP III qualitative benefits include the value that the gas system modernization provides in improving system risk levels, thereby keeping the Company in a strong posture for continued *safe*, *reliable*, and *resilient* operations. In fact, the Company's emphasis on risk management is in concert and deeply concordant with several federal and state authority planning requirements and mandates, including calls for aggressive actions by the nation's gas system operators to improve gas network safety risk levels. These mandates include the recent PIPES 2020 Act and PHMSA's advisory notices, both of which focus attention on reducing environmental impacts. In fact, PIPEs specifically requires gas system operators to reduce methane emissions. The improvements to risk levels are also deeply aligned and ingrained with the Company's practices in how it identifies, investigates, evaluates, manages, and addresses asset and system risk as part of its always-present federal regulatory compliance responsibilities, as reflected through its distribution integrity management planning (DIMP) and reporting processes.
- *Second*, there are valuable qualitative benefits associated with upgrading the design of the system to *modern* standards as part of the GSMP III program. Design features include migrating the system to operate at elevated pressure (EP) versus today's legacy

utilization pressure. Running at EP also fulfills customer expectations that they can buy and use modern appliances and not have to consider whether the gas distribution network functions at a level of modern design standards. Modern design features also include the installation of excess flow valves (which shut off gas automatically when excess and potentially dangerous gas flow is detected, as might occur with an excavation-caused break) and moving meter sets to outside locations (thereby reducing customer odor and safety concerns).

- *Third*, the Company has estimated that there are sizable economic stimulus effects of the GSMP investment in its prior phases, which will ostensibly continue and expand into its next phase. These effects include the positive impacts to skilled employment levels within the construction region, inuring benefit to the state of New Jersey.

In contrast to the GSMP III, the Base RF Level alternative scenario is based on a level of targeted replacement and repair activity and spending that continues to fully support the Company's ability to sustain and support adequate levels of asset risk management, as determined, and guided by its compliance obligations under federal and state law. However, the levels of asset replacements and spending associated with this scenario would require the Company to adopt a much less efficient, segment-by-segment approach for targeting high risk assets for replacement work. Consequently, this alternative scenario moves the Company far away from the efficient and cost-effective, large scale based "map-grid" construction plan that underpins the GSMP III program. Additionally, under the alternative scenario the Company is unable to achieve significant rapid reductions in its Scope 1 GHG emissions, nor is it able to complete the entire modernization program in any foreseeable future. These facts mean that the Company significantly delays and defers reducing Scope 1 emissions throughout the forecast period. Lastly, customers will remain at utilization pressure across many portions of the system, creating disincentive for the use of high efficiency appliances that are designed for service at elevated pressures.

Summary

The GSMP III's cost-benefit analysis (CBA) is based on the evaluation of two meaningful scenarios and is aligned with IIP minimum filing requirements, as identified in the New Jersey Administrative Code. The comparison of these two scenarios reveals important differences arising from the choice to continue the gas system modernization at an accelerated pace, as compared to the alternative. For each scenario, the costs and benefits are identified and considered, and when practical and feasible to do so, benefits are quantified and monetized.

WMP concludes that for the purposes of the cost-benefit analysis the GSMP III is estimated to generate measurable quantified and monetized benefits (re: Table 15), as well as additional qualitative benefits. Benefits include avoided operations and maintenance (O&M) costs and the value that can be assigned to reductions in CO_2e emissions, which contribute to the State's and Company's climate goals. These additional benefits (when compared to the Base RF scenario alternative) offset nearly 30% of the incremental costs of the GSMP III investment. The qualitative benefits contribute *additional* value, and include the reduction in system risk, consistent with prudent risk management practices and requirements, thereby improving the gas system's safety, reliability, and resiliency compared to what is achievable through base capital spending. Pursuing risk reductions is highly consistent with federal calls for aggressive actions by natural gas system operators to reduce pipeline safety risks and address methane emissions. Qualitative benefits also are estimated to accrue due to modernizing the system to operate at elevated pressure (EP) and the contributions the investment provide to jobs and general economic growth.

Appendix A - Cost-Benefit Analysis Model Excerpts

Table 166: Program Costs and Benefits by Scenario by Year

{This information is available within the work paper: **WP ALT-GSMPIII-1.xlsx**, CBA Calculations}

PSEG

Gas System Modernization Program (GSMP) III: Cost/Benefit Analysis (CBA) Version 2 (V2)

Last Updated: 20-Jan-23

Inflation Rate Assumption

Cost/Benefits Summary

(Expand rows to view table)

Costs/Benefits	PV Amount ($000s)		
	Base RF	GSMP III	Variance
TOTAL COSTS	$370,877.4	$2,068,286.8	$1,697,409.4
TOTAL BENEFITS:	$260,169.7	$749,632.2	$489,462.5
Benefits - Avoided Costs	$46,243.2	$315,975.7	$269,732.5
Benefits - Avoided SCC (CO2e)	$213,926.5	$433,656.5	$219,730.0
NET DIFFERENCE:	**($110,707.8)**	**($1,318,654.6)**	**($1,207,946.9)**

NPV Summary

(Expand rows to view table)

Cost/Benefit	Amount ($000s)
Scenario Total Costs Difference	$1,697,409.4
GSMP III Benefits - Avoided Costs	$269,732.5
Net Difference:	-$1,427,676.8
WACC:	**6.48%**
Net Present Value:	**($1,340,793.4)**
Inflation Adjustment Factor	3.0%

Timeline							
Year No.:	1	2	3	4	5	6	7
Year:	2024	2025	2026	2027	2028	2029	2030
Factors							
Inflation:	1.000	1.030	1.061	1.093	1.126	1.159	1.194
PV Cost of Carbon (per IWG Report @ 3%):	$55.00	$56.00	$57.00	$59.00	$60.00	$61.00	$62.00
Scope (Asset Types & Quantities)							
Scenario: Base RF							
Main Miles	62	62	62	62	62	62	62
EP Cast Iron Mains	4	4	4	4	4	4	4
UP Cast Iron Mains	35	35	35	35	35	35	35
Unprotected Steel Mains	23	23	23	23	23	23	23
UP CP Steel and Plastic Mains	0	0	0	0	0	0	0
District Regulators Abandoned	1	1	1	1	1	1	1
Service Replacements	4,886	4,886	4,886	4,886	4,886	4,886	4,886
Meter Relocation	2,608	2,608	2,608	2,608	2,608	2,608	2,608
Scenario: GSMP III							
Main Miles	345	390	390	62	62	62	62
EP Cast Iron Mains	14	16	16	4	4	4	4
UP Cast Iron Mains	245	277	277	35	35	35	35
Unprotected Steel Mains	61	69	69	23	23	23	23
UP CP Steel and Plastic Mains	25	28	28	0	0	0	0
District Regulators Abandoned	30	80	100	1	1	1	1
Service Replacements	27,927	31,570	31,570	4,886	4,886	4,886	4,886
Meter Relocation	16,203	16,203	16,203	2,608	2,608	2,608	2,608
Variance							
Main Miles	283	328	328	0	0	0	0
EP Cast Iron Mains	10	12	12	0	0	0	0
UP Cast Iron Mains	210	242	242	0	0	0	0
Unprotected Steel Mains	38	46	46	0	0	0	0
UP CP Steel and Plastic Mains	25	28	28	0	0	0	0
District Regulators Abandoned	29	79	99	0	0	0	0
Service Replacements	23,041	26,684	26,684	0	0	0	0
Meter Relocation	13,595	13,595	13,595	0	0	0	0
Costs							
Scenario: Base RF							
Capital Costs	$102,866,141	$141,269,500	$145,507,585	$37,468,203			
O&M Costs	$0	$0	$0	$0			
Total Costs for Scenario	$102,866,141	$141,269,500	$145,507,585	$37,468,203			
Scenario: GSMP III							
Capital Costs	$529,969,673	$796,469,540	$843,931,579	$217,312,382			
O&M Costs	$0	$0	$0	$0			
Total Costs for Scenario	$529,969,673	$796,469,540	$843,931,579	$217,312,382			
Variance							
Capital Costs	$427,103,532	$655,200,040	$698,423,995	$179,844,179			
O&M Costs	$0	$0	$0	$0			
Total Variance between Scenarios	$427,103,532	$655,200,040	$698,423,995	$179,844,179			
SUMMARY	**Nominal**	**PV**					
Scenario: Base RF	$ 427,111,429	$370,877,426					
Scenario: GSMP III	$ 2,387,683,174	$2,068,286,780					
Variance	$ 1,960,571,746	$1,697,409,355					
Benefits - Avoided Costs							
Scenario: Base RF							
Capital Avoided Costs							
Reduced Capex - Repair ST Services	$0	$753,194	$1,538,637	$2,334,147	$2,364,063	$2,394,363	$2,425,051
Reduced Capex - Encapsulated UP Joints	$0	$164,072	$337,431	$515,401	$529,112	$543,186	$557,636
Reduced Capex - Encapsulated HP Joints	$0	$151,679	$311,662	$475,604	$487,373	$499,434	$511,794
Total Capital Avoided Costs:	$0	$1,068,945	$2,187,729	$3,325,152	$3,380,548	$3,436,984	$3,494,481
O&M Avoided Costs							
Reduced Leak Repairs - CI Mains	$0	$47,493	$97,835	$149,688	$154,179	$158,804	$163,568
Reduced Leak Repairs - ST Mains	$0	$91,919	$189,353	$289,709	$298,401	$307,353	$316,573
Reduced Leak Repairs - PE Mains	$0	($5,739)	($11,822)	($18,088)	($18,630)	($19,189)	($19,765)
Reduced Leak Repairs - Protected Steel	$0	($734)	($6,089)	($11,606)	($11,954)	($12,313)	($12,682)
Reduced Leak Repairs - PE Services	$0	($35,276)	($72,668)	($111,182)	($114,517)	($117,953)	($121,491)
Reduced Re-Checks	$0	$12,261	$25,258	$38,645	$39,805	$40,999	$42,229
Clearing Mains	$0	$7,499	$15,222	$23,178	$23,178	$23,178	$23,178
Drip Collection	$0	$1,942	$3,942	$6,002	$6,002	$6,002	$6,002
Reduced Regulator Station Insp & Maint	$0	$944	$1,889	$2,862	$2,947	$3,036	$3,127
Total O&M Avoided Costs:	$0	$120,309	$242,920	$369,209	$379,410	$389,916	$400,739
Total Avoided Costs	$0	$1,189,254	$2,430,649	$3,694,360	$3,759,958	$3,826,900	$3,895,219
Scenario: GSMP III							
Capital Avoided Costs							
Reduced Capex - Repair ST Services	$0	$4,664,951	$10,229,825	$15,953,655	$16,409,354	$16,878,069	$17,360,174
Reduced Capex - Encapsulated UP Joints	$0	$1,150,068	$2,519,740	$3,925,847	$4,030,278	$4,137,488	$4,247,549
Reduced Capex - Encapsulated HP Joints	$0	$523,292	$1,145,536	$1,783,179	$1,827,307	$1,872,527	$1,918,867
Total Capital Avoided Costs:	$0	$6,338,311	$13,895,101	$21,662,680	$22,266,939	$22,888,084	$23,526,589
O&M Avoided Costs							
Reduced Leak Repairs - CI Mains	$0	$315,564	$692,457	$1,080,657	$1,113,076	$1,146,469	$1,180,863
Reduced Leak Repairs - ST Mains	$0	$245,117	$537,871	$839,408	$864,590	$890,528	$917,244
Reduced Leak Repairs - PE Mains	$0	($30,036)	($65,910)	($102,859)	($105,945)	($109,124)	($112,397)
Reduced Leak Repairs - Protected Steel	$0	($3,326)	($8,760)	($14,356)	($14,787)	($15,230)	($15,687)
Reduced Leak Repairs - PE Services	$0	($201,631)	($442,449)	($690,491)	($711,205)	($732,541)	($754,518)
Reduced Re-Checks	$0	$48,636	$106,725	$166,556	$171,553	$176,699	$182,000
Clearing Mains	$0	$52,562	$113,764	$176,801	$176,801	$176,801	$176,801
Drip Collection	$0	$13,611	$29,459	$45,783	$45,783	$45,783	$45,783
Reduced Regulator Station Insp & Maint	$0	$28,317	$102,477	$197,191	$203,107	$209,200	$215,476
Total O&M Avoided Costs:	$0	$468,814	$1,065,635	$1,698,689	$1,742,972	$1,788,584	$1,835,564
Total Avoided Costs	$0	$6,807,124	$14,960,736	$23,361,369	$24,009,911	$24,676,668	$25,362,153
Variance - GSMP III Benefit							
Capital Avoided Costs							
Reduced Capex - Repair ST Services	$0	$3,911,757	$8,691,189	$13,619,508	$14,045,291	$14,483,707	$14,935,122
Reduced Capex - Encapsulated UP Joints	$0	$985,996	$2,182,309	$3,410,445	$3,501,166	$3,594,301	$3,689,913
Reduced Capex - Encapsulated HP Joints	$0	$371,613	$833,874	$1,307,575	$1,339,934	$1,373,093	$1,407,073
Total Capital Avoided Costs:	$0	$5,269,366	$11,707,372	$18,337,528	$18,886,391	$19,451,100	$20,032,108
O&M Avoided Costs							
Reduced Leak Repairs - CI Mains	$0	$268,071	$594,622	$930,969	$958,898	$987,665	$1,017,295
Reduced Leak Repairs - ST Mains	$0	$153,198	$348,518	$549,699	$566,190	$583,175	$600,671
Reduced Leak Repairs - PE Mains	$0	($24,297)	($54,088)	($84,772)	($87,315)	($89,934)	($92,632)
Reduced Leak Repairs - Protected Steel	$0	($2,592)	($2,670)	($2,750)	($2,833)	($2,918)	($3,005)
Reduced Leak Repairs - PE Services	$0	($166,355)	($369,781)	($579,309)	($596,688)	($614,589)	($633,026)
Reduced Re-Checks	$0	$36,375	$81,466	$127,911	$131,748	$135,700	$139,771
Clearing Mains	$0	$45,064	$98,541	$153,623	$153,623	$153,623	$153,623
Drip Collection	$0	$11,669	$25,517	$39,781	$39,781	$39,781	$39,781
Reduced Regulator Station Insp & Maint	$0	$27,373	$100,589	$194,329	$200,159	$206,164	$212,349
Total O&M Avoided Costs:	$0	$348,505	$822,715	$1,329,480	$1,363,563	$1,398,667	$1,434,825
Total Avoided Costs	$0	$5,617,871	$12,530,087	$19,667,008	$20,249,953	$20,849,768	$21,466,934
SUMMARY	**Nominal**	**PV**					
Scenario: Base RF - Avoided Capital Costs	$100,691,424	$41,202,814					
Scenario: Base RF - Avoided O&M Costs	$12,747,587	$5,040,344					
Scenario: Base RF - Total Avoided Costs	$113,439,011	$46,243,158					
Scenario: GSMP III - Avoided Capital Costs	$740,912,087	$293,240,070					
Scenario: GSMP III - Avoided O&M Costs	$57,359,975	$22,735,630					
Scenario: GSMP III - Total Avoided Costs	$798,272,062	$315,975,701					
Variance - Avoided Capital Costs	$640,220,662	$252,037,256					
Variance - Avoided O&M Costs	$44,612,389	$17,695,287					
Variance - Total Avoided Costs	$684,833,051	$269,732,542					
Benefits - Avoided Social Cost of Carbon (SCC)							
Scenario: Base RF							
Baseline (tonnes, CO2e) - Start of Year	468,770	7,571	22,714	45,428	75,713	113,569	158,997
Incremental Reductions, During Period	(7,571)	(7,571)	(7,571)	(7,571)	(7,571)	(7,571)	(7,571)
New Resulting Baseline, End of Period	461,199	453,627	446,056	438,485	430,914	423,342	415,771
Total Benefit, as of End of Year	7,571	15,143	22,714	30,285	37,856	45,428	52,999
Cumulative Reductions	7,571	22,714	45,428	75,713	113,569	158,997	211,996
Avoided SCC (per IWG SCC unit cost at 3%)	$416,420	$847,983	$1,294,689	$1,786,822	$2,271,384	$2,771,088	$3,285,936
Scenario: GSMP III							
Baseline (tonnes, CO2e) - Start of Year	468,770	43,818	137,195	280,177	430,730	588,854	754,550
Incremental Reductions, During Period	(43,818)	(49,559)	(49,605)	(7,571)	(7,571)	(7,571)	(7,571)
New Resulting Baseline, End of Period	424,952	375,393	325,788	318,217	310,646	303,074	295,503
Total Benefit, as of End of Year	43,818	93,377	142,982	150,553	158,124	165,696	173,267
Cumulative Reductions	43,818	137,195	280,177	430,730	588,854	754,550	927,816
Avoided SCC (per IWG SCC unit cost at 3%)	$2,409,995	$5,229,097	$8,149,960	$8,882,629	$9,487,459	$10,107,431	$10,742,546
Variance - GSMP III Benefit							
Baseline (tonnes, CO2e) - Start of Year	0	36,247	114,481	234,749	355,017	475,285	595,553
Incremental Reductions, During Period	(36,247)	(41,987)	(42,034)	0	0	0	0
Total Benefit, as of End of Year	36,247	78,234	120,268	120,268	120,268	120,268	120,268
Cumulative Reductions	36,247	114,481	234,749	355,017	475,285	595,553	715,821
Avoided SCC (per IWG SCC unit cost at 3%)	$1,993,575	$4,381,114	$6,855,271	$7,095,807	$7,216,075	$7,336,343	$7,456,610
SUMMARY	**Total Tonnes CO2e**	**Total SCC**					
Total Value of Reductions Scenario: Base RF	2,861,944	$213,926,516					
Total Value Reductions Scenario: GSMP III	5,983,123	$433,656,477					
Net Difference - GSMP III Benefit	3,121,179	$219,729,960					

Appendix B Risk Indices

ASSETS - HIGH RISK / **GSMP RISK RESPONSE**

Facility	Cause	Strategy	Risk Impact
Plastic Services	Excavation Damage	Excess flow valve installation in replaced or transferred services	Mitigate
Cast Iron Joints - Pre 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Steel Services	Corrosion	Replace unprotected steel services with plastic	Mitigate
Cast Iron Pipe - Pre 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
ASSETS - MEDIUM RISK			
Cast Iron Pipe - Post 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Plastic Mains - Post 1973	Excavation Damage	New Plastic has lower overall risk profile than cast iron or unprotected steel. Valves installed on new EP mains	Accept
Steel Service Valves	Corrosion	Replace unprotected steel services with plastic	Mitigate
Plastic Service Valves	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Cast Iron Joints - Post 1946	Natural Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
ASSETS - LOW RISK			
Steel Main Service Tees	Corrosion	Replace unprotected steel mains with plastic or CP steel	Mitigate
Steel Service Mechanical Coupling	Natural Force Damage	Replace unprotected steel services with plastic	Mitigate
Steel Main Mechanical Coupling	Natural Force Damage	Replace unprotected steel mains with plastic or welded CP steel. Replace CP steel mains with excessive couplings with plastic if part of UPCI grid upgrade	Mitigate
Steel Service Mechanical Coupling	Corrosion	Replace unprotected steel services with plastic	Mitigate
Plastic Service Valves	Material Defect	New Plastic has lower overall risk profile than unprotected steel	Accept
Steel Service Mechanical Coupling	Material Defect	Replace unprotected steel services with plastic	Mitigate
Steel Main Risers	Corrosion	Replace cast iron and unprotected steel mains with plastic or CP steel	Mitigate
Steel Services	Excavation Damage	Excess flow valve installed (if feasible) in replaced or transferred services	Mitigate

ASSETS - VERY LOW RISK

Steel Mains	Corrosion	Replace unprotected steel mains with plastic or CP steel	Mitigate
Meter sets	Corrosion	Relocated meters and existing outside meters are coated with corrosion inhibitor	Mitigate
Plastic Pre-1973 Main	Excavation Damage	Replace with plastic if part of UPCI grid upgrade	Mitigate
Steel Service Mechanical Coupling	Equipment Failure	Replace unprotected steel services with plastic. Replace separately protected steel services with plastic in conjunction with main replacement	Mitigate
Steel Main Service Tee	Natural Force Damage	Replace unprotected steel mains with plastic or CP steel	Mitigate
Cast Iron Joints - Pre 1946	Other Outside Force Damage	Replace cast iron mains with plastic or CP steel	Mitigate
Cast Iron Joints - Pre 1946	Corrosion	Replace cast iron mains with plastic or CP steel	Mitigate
Plastic Main Service Tee	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Plastic Service Valves	Equipment Failure	New Plastic has lower overall risk profile than unprotected steel	Accept
Plastic Services	Natural Force Damage	New Plastic has lower overall risk profile than unprotected steel	Accept
Steel Service Valves	Natural Force Damage	Replace unprotected steel services with plastic. Replace separately protected steel services with plastic in conjunction with main replacement	Mitigate

Performance measures anticipated to show improvement at the conclusion of GSMP III on an annual basis (weather normalized)

Mains
- Leaks per Mile

Cast Iron Main
- Total Hazardous Leak Repairs
- Total Cast Iron Leak Repairs
- Total Cast Iron Breaks
- HP Cast Iron Leak Repairs
- UP Cast Iron Leak Repairs

Steel Main
- Total Hazardous Leak Repairs
- Unprotected Steel Main Leak Repairs

Services
- Leaks per 100 services

Steel Services
- Total Hazardous Leak Repairs
- Steel Service Leak Repairs

Appendix C - Annual Social Cost of Carbon Discount Rates and Statistic

Social Cost of CO_2, 2020 - 2050 (in 2020 dollars per metric ton of CO_2)

	Discount Rate and Statistic		
Emissions Year	5% Average	3% Average	2.5% Average
2020	14	51	76
2021	15	52	78
2022	15	53	79
2023	16	54	80
2024	16	55	82
2025	17	56	83
2026	17	57	84
2027	18	59	86
2028	18	60	87
2029	19	61	88
2030	19	62	89
2031	20	63	91
2032	21	64	92
2033	21	65	94
2034	22	66	95
2035	22	67	96
2036	23	69	98
2037	23	70	99
2038	24	71	100
2039	25	72	102
2040	25	73	103
2041	26	74	104
2042	26	75	106
2043	27	77	107
2044	28	78	108
2045	28	79	110
2046	29	80	111
2047	30	81	112
2048	30	82	114
2049	31	84	115
2050	32	85	116

Andrew Lewis Trump

Senior Principal, Energy & Utilities

Experience

Education

Total Years of Experience

Years of Experience with West Monroe

Professional Registrations

Publications

Presentations

Testimonies

Andrew is an energy regulatory and business specialist and planner with over 36 years of experience in the energy and infrastructure sector. He has worked with a wide number of diverse clients (regulated utility, non-utility affiliates, and energy industry venture companies) on the regulatory and financial justification of major investments and initiatives.

His work areas of interest and expertise include: (a) Drive infrastructure solutions for electric and gas utilities, merchants, and technology firms at formative stages of the life cycle: strategy, business case, pilot evaluation, regulatory support and justification, stakeholder support, cost recovery, project formation, change management, project monitoring and evaluation. (b) Provide expert witness testimony support on regulatory cost/benefit analysis and risk-based decision support. (c) Support a variety of client communication and representation demands within regulatory venues at local, regional, and state levels.

Andrew joined West Monroe in January 2021. Prior, he was independent for a period of two years. From 2008-2018 he was a Director with Black & Veatch's Management Consulting practice. Prior to Black & Veatch Andrew held the following progressive experiences:

- Senior Consultant at California Environmental Associates (1989-1995).
- Senior Manager, CellNet Data Systems, San Carlos, CA (1995-1999)
- Director of Development and Licensing, Duke Energy North American, Oakland, CA (2000-2007)

Experience Details:

WEST MONROE – SENIOR PRINCIPAL - ENERGY & UTILITIES PRACTICE, NEW YORK, NY 2021 - PRESENT

Support senior level energy market engagements in areas of grid capital investment planning; provide thought leadership in areas of gas planning, decarbonization strategies, DER, EV, grid planning and regulatory reform. Provide expert witness testimony and defense.

- Regulatory cost-benefit expert. Expert witness and testimony development.
- Grid investment strategies including decarbonization, EV and DER integration. Thought leadership and business development.
- Regulatory assessments in areas of gas system transition planning (as part of system-wide electrification efforts)

INDEPENDENT CONTRACTOR, NEWTOWN SQUARE, PA **2018 to 2021**

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(Includes close collaboration with Charles River Associates, Washington, DC, as an independent contributor).

Lead and support senior level energy market engagements in areas of capital investment planning, integrated resource planning (IRP), DER and technology integration, stakeholder engagement, and project management.

BLACK & VEATCH MANAGEMENT CONSULTING, NEWTOWN SQUARE, PA 2007 - 2018

A global engineering, consulting, construction, and operations company specializing in infrastructure development in energy, water, and telecommunications.

Director, Utility Practice

Expert in capital investment, risk and project valuation. Provide investment analysis of technologies, energy markets, and regulatory reform factors to determine feasibility and sustainabilty of grid modernization infrastructure opportunities. Author testimony for petitions of state commissions and strategic analysis for senior executives; Regulatory cost/benefit expert. Drive cross functional teams of analysts and engineers in time sensitive assignments.

- Delivered regulatory cost-benefit analyses in areas of grid modernization investments for electric, gas and water systems.
- Expert witness testimony.
- Delivered investment strategy and business case for 5G telecommunications opportunities.
- Delivered innovative delivery methods for utility engineering organization facing disruptive effects of Distributed Energy Resource (DER) investments and planning integration challenges.
- Performed asset valuation studies for pumped storage hydro and other generation facilities.

DUKE ENERGY NORTH AMERICA (DENA), OAKLAND, CA 2000 – 2007

Owner and operator of power generation assets throughout North America.

Licensing / Developer

Recruited for expertise in regulatory affairs, energy market reform, stakeholder collaboration and multi-party negotiation skills.

Principally charged with gaining approvals for the redevelopment of a brownfield 1,200 MW power plant located on the coast in Morro Bay, CA. $1B project presented some of the most challenging land use requirements found anywhere in the United States. Extensive levels of regulatory and public stakeholder interactions. Led all aspects of Application for Certification (AFC) before the California Energy Commission (CEC) for the proposed re-development.

- Led efforts to gain CEC approvals. Directed team in the creation of CEC application (AFC). Gained majority stakeholder support in intensive, contentious, and publicly visible effort, ultimately obtaining CEC certification. Fought ballot initiatives. Led multi-disciplinary team of experts (engineering, environmental, business, legal). Negotiated significant land use and marine biology mitigation agreements. Managed large $20M+ development budget.
- Led team in rebuttal to federal water permit legal actions threatening closure of 2,400 MW Moss Landing facility. Assessed, analyzed, and delivered successful defense of plant's federal water permit (Federal 316A and 316B). Served as lead expert witness, providing sworn testimony to responsible agency.
- Led stakeholder and CEC AFC process for 600 MW power plant development at Chula Vista

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Power Plant (San Diego region). Developed CEC licensing application (AFC). Negotiated land use agreement with Port of San Diego, aimed at integrating development into bayfront master plan. Evaluated and negotiated regional reliability benefits and long-term power purchase contract options.

OTHER CAREER APPOINTMENTS

- Senior Manager, Business Development, CellNet Data Systems, San Carlos, CA – 5 years (1996 – 2000). Develop and implement wireless telemetry systems to electric and gas utilities throughout North America. Developed and negotiated contracts.
- Senior Consultant, California Environmental Associates (CEA), San Francisco, CA – 7 years (1989 – 1996); Extensive work with the nation's Class 1 freight railroads on federal and state locomotive emission rules affecting heavy-duty diesel engine requirements. Coordinated and participated in technical studies and presented on behalf of railroad companies in workshops. Authored technical and policy comments to the California Air Resources Board (CARB), EPA, FRA, and other agencies.

Education and Formal Training:

- Harvard EdX: Data Analytics Certificate Program. Several Classes (2019-2021)
- MA, Public Policy, George Mason University, Arlington, VA (2010)
- BA, Physical Sciences (Math, Chemistry and Physics), Harvard University (1984)
- Professional Certificate, Project Management, University of California at Berkeley Extension (PMBOK-based) (2003)
- Duke Energy Corporate Media and Public Relations Training (2001)
- Program on Negotiation (PON), Harvard University (2002)

Areas of Expert Testimony Development

- Grid Modernization (gas and electric): Reliability and Resiliency Planning, Smart Grid, AMI, DA. (PSE&G Electric, PSE&G Gas, ComEd, Dominion Virginia, Vectren Indiana, Southern Maryland Energy Cooperative, PECO, BG&E, Hawaiian Electric).
- Power Plant Facility Licensing (team lead, and responsible for): Project Description, Facility Closure, Electric Transmission Interconnection, Natural Gas Supply, Water Supply, Air Quality, Transportation, Visual Resources, Hazardous Material Handling, Waste Management, Land Use, Noise, Public Health, Worker Health and Safety, Socioeconomics.
- Application of practice standards in the conducting of costs-benefit analysis (CBA) as applied

to utility pilots and demonstrations. See: In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to new technologies and business models. MPSC Case No: U-20898. Proposed Requirements and Further Guidance on Benefit-Cost Analyses for Pilot Initiatives Prepared by DTE Electric Company and Consumers Energy Company. February 1, 2023.

Publications

Trump, Andrew. "More Needed on Resiliency Valuation Challenges." Public Utilities Fortnightly. November 2022.

Trump, Andrew and Kao, Caleb. "An Adequate Level of Resilience: Valuation Challenges." Public Utilities Fortnightly. September 2022.

Trump, Andrew, South, David and Zolton, Kaitlyn. "Expanded Climate Risk Disclosure Requirements by the Security and Exchange Commission." Climate and Energy. September 2021. Volume 38, no. 2. Wiley Periodicals, Inc.

Trump, Andrew and Chastain-Howley, Andrew. "Water Utilities Are Lagging Other Utilities in the Smart Cities Effort." *Black & Veatch*. https://www.bv.com/Home/news/solutions/water/water-utilities-are-lagging-other-utilities-in-the-smart-cities-effort.

Trump, Andrew and Pletka, Ryan. "Arizona Says Net Metered Utility Customers Must Pay." *Black & Veatch*. https://www.bv.com/Home/news/solutions/energy/arizona-says-net-metered-utility-customers-must-pay.

Trump, Andrew and Azer, Rick. "Utilities Discover a New Era of Engagement as the Focus Shifts to the Customer of One." *Black & Veatch*. https://www.bv.com/Home/news/solutions/Smart-Cities-Telecom/building-smart-cities-will-require-creative-funding-approaches.

Trump, Andrew. Interview by Adam Stone. "Making a Case of Water as a Key Component of the Smart City." Government Technology, January 10, 2017, http://www.govtech.com/fs/infrastructure/Making-a-Case-for-Water-as-a-Key-Component-in-the-Smart-City.html.

Trump, Andrew. "Where is the Smart Grid Going from Here?" *Electric Light & Power*, July 13, 2010. http://www.elp.com/articles/electric-light-and-power-newsletter/articles/2010/07/where-is-the-smart-grid-going-from-here-.html.

Trump, Andrew. "Business Case Tradeoffs: Shaping Long-Term Smart-Grid Strategy." *Public Utilities Fortnightly*, June 2010. https://www.fortnightly.com/fortnightly/2010/06/business-case-tradeoffs.

Trump, Andrew. "Smart-Grid Stimulus: Utilities Hurry Up and Wait to Apply for Grant Money." Public Utilities Fortnightly, June 2009. https://www.fortnightly.com/fortnightly/2009/06/smart-grid-stimulus.

Trump, Andrew. "Planning for AMI/Smart Grid Adoption in a Difficult Economic Climate." *Electricity Today*, April 2009. http://www.electricity-today.com/.

Trump, Andrew and Steklac, Ivo. "A Planning Guide for AMI: How to Manage the Metering Selection Process." Public Utilities Fortnightly, September 2007.

https://www.fortnightly.com/fortnightly/2007/09/advanced-metering-infrastructure-special-report-planning-guide-ami.

Trump, Andrew. "An Evaluation of Natural Gas-Fueled Locomotives." California Environmental Associates, July 2006.

Trump, Andrew. "Building the Business Case for Smart Grid." *Generating Insights*, IBM, Fall 2010.

Presentations and Media Exposure

- Advanced Energy Conference (AEC), 2022, New York City, NY. "Business Models and Regulation for Resiliency, and DERs". Conference panel moderator. September 8, 2022.
- "A View of the Electricity Business Model of Tomorrow: Electric Distribution System Planning," POWER-GEN International, December 2016, Orlando, FL.
- "Recovery of Innovation Investments", Edison Electric Institute (EEI) Conference, Chicago, October 2012.
- Presentations at Executive/Senior Staff Stakeholder Sessions as part of Settlement or Mitigation Program Negotiations.
- Sponsorship and Convening of Public Workshops for the Review and Discussion of Infrastructure Projects and Programs.
- Representation of Client Projects in Open Public Settings as part of Routine or Special Sessions.
- Numerous Formal Technical Reports and Presentations as part of the Public Record.

Professional Affiliations

The Institute of Asset Management | Enterprise Risk Management (ERM) | ISO 31000 Risk Management Standard

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Grid Modernization

- Petition of Virginia Electric and Power Company, for approval of a plan for electric distribution grid transformation projects pursuant to 56-585.1 A 6 of the Code of Virginia. Case No. PUR-2021-00127. (a) Direct Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed June 21, 2021. (b) Rebuttal Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed October 1, 2021. Available at: https://scc.virginia.gov/DocketSearch#caseDocs/142210
- In The Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (*Energy Strong II*). BPU Docket Nos. EO18060629 and GO18060630. Attachment 5: Cost-benefit analyses of the electric portion of the Energy Strong II Program. Attachment 6: Cost-benefit

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analyses of the gas portion of the Energy Strong II Program. Available at: https://nj.pseg.com/aboutpseg/regulatorypage/regulatoryfilings

- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South). IURC Cause No. 44910. Direct Testimony of Andrew L. Trump, Director, Utility Practice, Black & Veatch Management Consulting, LLC. On AMI Cost Benefit Evaluation. Sponsoring Petitioner's Exhibit No. 5, Attachments ALT-1 Through ALT-3. https://iurc.portal.in.gov/legal-case-details/?id=3b675b4f-eff9-e611-80fd-1458d04e2f50
- Illinois Commerce Commission v. Commonwealth Edison Company, No. 12-0298. Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act. Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 6.0, 6.01 and 6.02, "Cost Benefit Analysis of Commonwealth Edison (ComEd) Smart Grid Advanced Metering Infrastructure Deployment Plan (AMI Plan)" (filed April 23, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=180884.
- Also, Rebuttal Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 12, 12.01, 12.02 and 12.03 (filed May 17, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=182177.
- Illinois Commerce Commission v. Commonwealth Edison Company. No. 14-0212. Petition to Approve *Acceleration* of Meter Deployment under ComEd's AMI Plan. (Petition for Statutory Approval of a Smart Grid: Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act). Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 2.0 and 2.01 (filed March 13, 2014). https://www.icc.illinois.gov/docket/files.aspx?no=14-0212&docId=210863.

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Power Plant Development

Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the Morro Bay Power Plant Project:

- Morro Bay Modernization and Replacement Power Plant Project. Application for Certification. Docket No. 00-AFC-12. October 23, 2000. http://www.energy.ca.gov/sitingcases/morrobay/.
- Expert Witness Testimony of Andrew L. Trump provided before the California Energy Resources Conservations and Development Commission (Energy Commission). http://www.energy.ca.gov/sitingcases/morrobay/index.html.

	Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the LS Power South Bay LLC South Bay Replacement Project (SBRP): ▸ South Bay Replacement Project Power Plant Licensing Case. Docket No. 06-AFC-03. Filed June 30, 2006. http://www.energy.ca.gov/sitingcases/southbay/documents/applicants/afc/. ▸ (Note, LS Power acquired Duke's interests mid-2006). Responsible for the preparation and expert witness testimony and representation of Duke Energy North America's formal legal testimony before the California State Lands Commission and the Central Coast Water Quality Control Board in the legal challenge brought by Plaintiffs to the continued operation of the 1,000 MW Moss Landing Combined Cycle Power Plant (reliant on once-through cooling technology, and in relation to the federal Clean Water Act permit authority). (2002-2003).

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FOR APPROVAL OF THE NEXT PHASE OF
THE GAS SYSTEM MODERNIZATION PROGRAM AND
ASSOCIATED COST RECOVERY MECHANISM
(“GSMP III”)
THE HYDROGEN DEMONSTRATION
(“HYDROGEN PROJECT”)

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
HYDROGEN PRODUCTION AND BLENDING FACILITY
COST-BENEFIT ANALYSIS PANEL

March 1, 2023

Q. Please introduce the members of the Hydrogen Production and Blending Facility Cost-Benefit Panel ("CBA Panel").

A. The witnesses comprising the CBA Panel are Margaret Oloriz and Andrew Trump.

Q. Ms. Oloriz, please state your name and business address.

A. My name is Margaret Oloriz, and my business address is 825 8th Avenue, 17 Floor, New York, NY 10019.

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

A. I am a Manager, employed by West Monroe Partners, LLC. ("West Monroe" or "WMP") in the Energy & Utilities Practice.

Q. Ms. Oloriz, please summarize your professional background and your experience in the utility industry.

A. I have worked in professional services and engineering roles for approximately 10 years, working with water, electric, and gas utilities. As an engineer, I helped design urban infrastructure to mitigate impacts from flooding and storm damage. As a consultant, I have worked with utilities on a wide range of projects. These projects involve developing customer programs, managing enterprise system implementations, and, most recently, supporting our clients' decarbonization planning and implementation. I hold a bachelor's and master's degree in Civil Engineering. I am a certified Professional Engineer in the states of New York and California.

Q. What is your experience related to gas systems?

A. I have supported gas system planning for several utilities and gas companies, specifically in the hydrogen space. Recently, for example, I assisted a gas utility evaluate its hydrogen pilot's suitability for federal funding. I also supported a mid-stream gas company client scope and justify its large-scale hydrogen project.

Q. What is your experience related to CBA?

A. I have worked closely with utilities on their grid modernization programs and related efforts, including helping those clients in their development of cost benefit analyses.

Q. Have you provided prior testimony to the BPU?

A. No.

Q. Mr. Trump, please state your name and business address.

A. My name is Andrew L. Trump, and my business address is 825 8th Avenue, 17 Floor, New York, NY 10019.

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

A. I am a Senior Principal, employed by West Monroe Partners, LLC. ("West Monroe" or "WMP") in the Energy & Utilities Practice.

Q. Mr. Trump, please summarize your professional background and your experience in the utility industry.

A. I have worked in a professional capacity since 1984, when I graduated from college, on a wide range of energy and transportation projects, programs, and initiatives. My experience includes work both as a consultant within management and professional services consultancies, and as an employee within technology and merchant energy firms. For example, starting in 1995 I was employed by CellNet Data Systems, a firm that developed one of the first radio frequency ("RF") based advanced metering and meter data management platforms. My role involved, amongst other responsibilities, the development of cost-benefit analyses for the company's utility customers and the negotiation of multi-year contracts for the deployment and lease of these systems. Starting in 2000 I was employed by Duke Energy North America, a wholesale power generator. At Duke I was responsible for the licensing of the development of large power plants, entailing the securing of land use, environmental, interconnection, and other necessary settlements and approvals needed to permit the Company to build these power stations. This role involved managing a large team of legal, technical, and environmental experts in multiple disciplines related to wholesale power development and large industrial site development. Starting in 2007 I began consulting on grid modernization, mainly focused on electric and gas distribution systems. I was employed by Black & Veatch Management Consulting through the end of 2018. There I performed independent consulting services, including for PSE&G, in a similar capacity on gas and electric distribution system issues. Starting in January 2021 I was hired by WMP for my current role. In this role I serve as a subject matter specialist across many areas and domains, including in performing economic and business case analysis for grid modernization plans and proving supporting testimony. Much of my work during the past 15 years has been focused on the strategy, justification, planning, implementation, and review of a wide range of technologies of importance to electric and gas system operations. My educational background includes an undergraduate degree from Harvard College with a degree in Physical Sciences, a professional Project Management certificate from the University of California at Berkeley, and a master's degree in Public Policy from George Mason University.

Q. What is your experience related to gas systems?

A. I have supported gas system planning for several utilities throughout my career. As part of the powerplant development work, I was involved in the development of engineering and site-layout requirements, fuel quality requirements, and the environmental review associated with a gas delivery service to combustion turbines at power stations. I have also been heavily involved in the planning and implementation of new technologies, such as advanced metering, remote system monitoring, and telecommunications for several gas utilities. I have participated in assignments involving regulatory compliance issues related to indoor odor and corrosion inspection responsibilities and record keeping, and in the deployment of automated systems gas shutoff. I also supported PSE&G in its Energy Strong II proposal and program during 2017-2020, and specifically its plan to upgrade several Metering and Regulating ("M&R") stations, and to implement a series of main improvements to address system resiliency, specifically outage risks to the gas distribution system due to major events beyond (upstream) of the city gate. Most recently as part of a small team, I led and supported the development of cost benefit analysis standards of review for two large mid-western gas and electric utility companies, which were obligated pursuant to a Commission order to provide such recommendations to its Commission and stakeholders.

Q. What is your experience related to CBA?

A. I have extensive and in-depth knowledge of utility CBA practices, methods, requirements, and practice norms, as gained by my many years of professional experience. I have worked on over 40 large CBA and investment valuations during the past 15 years, for example, for gas, electric and water utilities.

Q. Have you provided prior testimony to the BPU?

A. Yes. I supported PSE&G in its electric and gas improvement proposals made in the Energy Strong II proceeding by assisting with the preparation of direct and rebuttal testimony on those proceedings.

Q. Please describe West Monroe.

A. West Monroe is a business and digital services firm with approximately 2,200 employees. Our Energy & Utilities practice assists companies like PSE&G in gas and electric system modernization. This involves a wide range of matters related to the capital and operational planning and implementation of new technologies and capabilities to help electric and gas utilities efficiently and effectively manage their business and prepare for the future. The planning and implementation support provided often involves addressing questions and challenges concerning decarbonization, enabling electric vehicle market development and deployment, deploying advanced metering infrastructure, upgrading utility telecommunication systems, and integrating distributed energy resources onto the electric grid, to name a few areas of support. It also involves assisting gas local distribution companies ("LDCs") in preparing their decarbonization plans and considering other forms of gas blended in pipeline and electrification like renewable gas, certified gas, hydrogen gas, and use of hydrogen in fuel cells to electrify buildings. WMP is often asked to assist its utility clients in the program and project management including change management and business integration and digital enablement of multi-year initiatives related to these types of initiatives.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of the panel's testimony is to provide evidence and analysis in support of a cost-benefit analysis ("CBA") for PSE&G's Hydrogen Production and Blending Facility ("Hydrogen Facility" or "Project"). Our CBA report ("Report") is provided in Schedule ATMO-GSMPIIIH2-1.

Q. Please describe your understanding of the proposed Hydrogen Facility.

A. It is WMP's understanding that the Project focuses on the design, construction, and operation of a 1 MW clean power-to-gas hydrogen blending, or "hydrogen-methane blending", facility located at PSE&G's Central Metering and Regulating ("M&R") station. The Project will produce hydrogen through electrolysis and blend the hydrogen into the natural gas system at a level of 2% by volume. The Project also includes hydrogen storage and compression systems that will support achieving consistent blending levels most of the year. The Project establishes certain learning and assessment goals for an initial demonstration period, which has a planned duration of three (3) years.

Q. What does your cost-benefit analysis of the Hydrogen Facility entail?

A. West Monroe evaluated the scope of the proposed Hydrogen Facility and data and information prepared by PSE&G and an engineering consultant, Burns & McDonnell, supplemented by some research to prepare a cost-benefit analysis of the proposed Hydrogen Facility. The analysis includes costs (capital and O&M) based on estimates developed and provided by PSE&G. Additionally, West Monroe collaborated with PSE&G to identify the objectives of the Project, and its associated benefits. We conclude that the benefits are principally the learnings that PSE&G will acquire over the course of the initial demonstration period, and related to the production, storage, and injection of hydrogen into the natural gas distribution system. The Company plans to continue the operations after this initial period, using what it learns to further optimize the hydrogen facility operations moving forward.

Q. What types of benefits have been identified for the Hydrogen Facility?

A. There are several benefits associated with the Hydrogen Facility – the initial three-year project learning outcomes, greenhouse gas (“GHG”) emissions reductions, and potential federal Investment Reduction Act (“IRA”) tax credits. The anticipated learning outcomes are the main benefit of the Project, are qualitative in nature, and are not estimated in monetary terms. The GHG emissions reduction are quantified in volume terms based on the amount of hydrogen blended with natural gas; these are further estimated as an economic benefit using a social cost of carbon (“SCC”), a widely used benchmark. The federal IRA tax credit benefits are estimated based on the estimated amount of hydrogen that is produced annually and the tax credits outlined in the Inflation Reduction Act of 2022, H.R. 5376, 117th Cong. (the Act) § 13204. It should be noted that the estimate of the value of the tax credit is based on an informed opinion by PSE&G’s financial and tax experts. The CBA calculations uses the approximate value of the tax credit within its nominal dollar, and pre-revenue requirements-oriented workbook. The CBA defers to the Company’s experts the specific treatment of the tax credits within its determination of revenue requirements.

Q. Why does the Company want to learn more about hydrogen-methane blending?

A. Blending hydrogen into the natural gas distribution system is recognized by some within the natural gas industry as a potential approach to lower the carbon intensity of natural gas combustion. This initial demonstration period will enable PSE&G to develop knowledge and capabilities across asset management, engineering, construction, and operations in the production, storage, handling, and blending of hydrogen in a safe and reliable manner. The Company has identified specific learning objectives across the proposed hydrogen-methane blending system value chain. Specific areas of focus of the learning objectives include environmental and safety compliance, operating and safety procedures, validation of design basis and planning assumptions, assessing site layout choices, understanding gas blending performance, among others.

Q. Why do you describe the savings in the CBA Report as an avoided gas supply cost?

A. For purposes of the CBA Report, we choose to describe the gas supply-related benefit as an avoided cost. This comports with the convention used within a cost benefit analysis of defining at least two scenarios, including a business as usual ("BAU") scenario, which are compared to yield a result. Of course, BAU is just a construct, and will not occur under the Project. Rather, under the Project, the Company will carry out several transactions that will capture this benefit.

Q. Technically, how will this benefit be recognized by the Company, as part of these transactions?

A. The Company will produce the hydrogen for purposes of delivery to the PSE&G customers. The value of the hydrogen, based on its energy content measured in MMBtu, will be acquired by PSEG's Energy Resources & Trade LLC ("ER&T"), for inclusion in the BGSS-RSG supply. ER&T will credit (i.e. pay) the Company for the hydrogen purchased (on a MMBtu basis), using as a market index valued at a Transco-Leidy natural gas reference price.

Q. Is this credit the same value as the avoided cost as defined in the BAU scenario?

A. Yes.

Q. Isn't there also a transportation cost related to upstream gas supply?

A. There is. The CBA report notes this. Since this cost is approximately $300 annually (for energy being secured by ER&T), we choose to not include it in the workbook calculations.

Q. What does BGSS-RSG stand for?

A. Basic Gas Supply Service-Residential Service Gas. This is PSE&G's default gas supply service for its residential customers.

Q. You mention benefits include GHG emission reduction. How will the proposed Hydrogen Facility contribute to GHG emission reductions?

A. Introduction of hydrogen into PSE&G's natural gas distribution system will displace a percentage of methane in the delivery and consumption of natural gas, thereby lowering GHG emissions. While methane is the primary fugitive GHG emitted by natural gas utilities as part of their Scope 1 emissions, this Project uniquely addresses downstream emissions that result from the combustion of natural gas by the customer at the burner tip. (These are the Company's Scope 3 emissions). The Company estimates that hydrogen blending will reduce these downstream emissions by 960 metric tons of CO_2 equivalent ("CO2e") per operational year.

Q. Can GHG emission reductions be evaluated as an economic benefit?

A. Yes. There is broad consensus, especially among federal agencies, that there are impact costs associated with methane and other GHG emissions, such as carbon dioxide ("CO_2") that results from the combustion of natural gas. The US EPA and other agencies use an SCC to measure, in dollars, the climate-related damage per ton of CO_2 in a year. Accordingly, the SCC can be applied to value the damages *avoided* from a reduction in emissions. The CBA applies the US EPA's SCC to the avoided methane emissions, converted to the equivalent metric tons of CO_2, to determine the economic benefit created by reducing these emissions over the lifetime of the assets. The economic benefit for the methane reduction is estimated at a present value of $1,730,000 over the Project's life, and in relation hydrogen production beginning in 2025.

Q. Did the Company consider other options in the context of this Project?

A. Yes. PSE&G considered at least four alternatives in the development of the Project scope. For example, options include not pursuing the project, choosing different electrolyzer sizes, construct hydrogen blending operations without storage, and purchasing hydrogen from an industrial supplier versus its on-site production.

Q. Please further describe these four alternatives.

A. First, the Company considered deferring the Project activities altogether. In this alternative, PSE&G would wait to learn about outcomes of hydrogen-methane blending demonstration projects conducted by others. PSE&G concluded this was not desirable or viable due to: 1) the lack of direct knowledge and experience that Company's engineers, planners, and operations personnel could be gaining by implementing the project, 2) the missed opportunity for PSE&G to advance the adoption of hydrogen technology in New Jersey and the wider region. Second, the Company also considered building and operating a larger electrolyzer, greater than the 1 MW in the current design basis. A larger electrolyzer would produce more hydrogen allowing PSE&G to achieve a higher blending percentage for the same number of customers or expand the Project to serve more customers. This alternative would result in higher capital costs for procurement and construction, as well as the utility costs (e.g., energy, water) for operations. PSE&G determined a larger electrolyzer at the added expense would not materially improve the learning benefits of the demonstration project. Third, the Company also evaluated a Project without on-site storage. This alternative would lead to tradeoffs in the electrolyzer size or the ability to maintain a 2% blend through most of the year. Without storage during peak flow conditions, particularly in winter, the blend percentage is constrained by the production output of the 1 MW electrolyzer. To overcome this constraint without the storage, the Company would need to design and install a larger electrolyzer and increase its run time. As mentioned before, this would increase the cost for construction and operations. The preliminary design of a 1 MW electrolyzer paired with storage will enable PSE&G to maintain blends through most conditions by leveraging the higher flow rate of the storage until the reserves are depleted. Once depleted, the electrolyzer will continue to produce hydrogen and bypass the storage until temperatures moderate enough to facilitate refilling. The use of storage includes two additional benefits. During electric demand peaks, PSE&G can take the electrolyzer offline and sustain hydrogen blending from storage for a period. On-site storage also allows for maintenance of the electrolyzer without interrupting hydrogen blending. Fourth, PSE&G considered to purchase the hydrogen from an industrial supplier and have it transported via tankers to a PSE&G facility for handling and blending for the duration of the demonstration period. PSE&G rejected this option since it would not allow the Company to achieve any learning objectives related to producing and storing hydrogen. In addition, utilizing diesel-fueled trucks to transport hydrogen offsets the intent of utilizing hydrogen to reduce GHG emissions.

Q. What are the conclusions of your cost-benefit analysis?

A. From a cost perspective, PSE&G prepared estimates that are based on its experience with other major gas capital projects and cost data provided by an engineering consultant. Given the minimal design details at this stage of planning, the capital cost estimates are in line with generally accepted estimating practices. Further, the Company's experience operating and maintaining gas plants informed a preliminary annual O&M cost estimate. The Company estimates that it will incur $19.2 million ($USD nominal) of capital to design, build and commission the facilities, or $28.8 million ($USD nominal) when including an allowance for risk and contingency. This CBA also includes an estimate of annual, recurring O&M expense of $2.0 million ($USD nominal). While the learnings of this demonstration cannot be easily converted into monetary benefits, the value of these learnings are valuable to the Company, the industry, and to New Jersey and the region given the level of interest in hydrogen as a decarbonization pathway and low carbon fuel. The Company's planners, engineers, skilled operators, and leadership will gain important knowledge in the safe and reliable production, storage, and delivery of hydrogen in the natural gas system. Through the Project the Company will also develop a deeper understanding for the potential of hydrogen to help reduce GHG emissions in furtherance of New Jersey's clean energy goals.

Q. Does this conclude your testimony?

A. Yes.

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COST - BENEFIT ANALYSIS

PSEG

Hydrogen Production and Blending Facility

Prepared for
Public Service Electric & Gas Company
February 17, 2022

westMONROE

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Acronyms and Definitions

Acronym	Definition
AGA	American Gas Association
Company	Public Service Electric & Gas Company
CNG	Compressed Natural Gas
EPC	Engineering, Procurement, and Construction
GHG	Greenhouse Gas Emissions
GSMP	Gas System Modernization Program
ITC	Investment Tax Credit
IIP	Infrastructure Investment Program
IIJA	Infrastructure Investment and Jobs Act (2021)
IRA	Inflation Reduction Act (2022)
IWG	Interagency Working Group
LNG	Liquified Natural Gas
LP	Liquid Propane
LPA	Liquid Propane Air
M&R	Meter and Regulating
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
PPA	Power Purchase Agreement
PSEG	Public Service Enterprise Group (PSE&G Parent Company)
PSE&G	Public Service Electric & Gas Company
PTC	Production Tax Credit
SCC	Social Cost of Carbon
SME	Subject Matter Experts
WMP	West Monroe Partners, LLC

Forward

West Monroe Partners, LLC., (hereinafter referred as "WMP") was retained by PSE&G ("the Company") to assess the costs and benefits of a proposed hydrogen production and blending facility ("Hydrogen Facility" or "Project"). This report is a companion document to an engineering report (prepared by Burns & McDonnell). It is intended to support the fulfillment of documentation requirements for an eligible Infrastructure Investment Program ("IIP"), as established within the New Jersey Administrative Code.

WMP worked with PSE&G's Gas Asset Management and Planning organization to review the Hydrogen Facility's assumptions and goals, structure a review of costs and benefits, gather and document costs, and identify and describe benefits.

As described in the report, the principal goal of the initial three (3) years of the project is to learn as much as possible about the engineering and operations of hydrogen blending facilities across the value chain, which includes on-site production, storage, handling, and blending of a small amount of hydrogen (2% by volume) within the natural gas stream.

Report Authors:

Margaret Oloriz
Andrew L. Trump

Background

PSE&G seeks to build and operate a hydrogen production and blending facility ("Hydrogen Facility" or "Project") for the purpose of learning as much as possible about the design, engineering, and operations of such hydrogen blending facilities. The Company proposes an initial three (3)-year demonstration period followed by sustained operations over the facility's expected service life. Producing, storing, and blending hydrogen into the natural gas system will support decarbonization of natural gas use by the end use customer.

Company Overview

Public Service Electric and Gas Company ("PSE&G" or "the Company") is New Jersey's largest utility, servicing approximately 2.2 million electric and 1.9 million natural gas customers. Since its founding in 1903, PSE&G has manufactured and transported a variety of gaseous products, including natural gas, liquified natural gas, compressed natural gas (CNG), propane and, earlier in the 20th century, synthetic gas and liquid petroleum.

Today, the Company operates and maintains natural gas infrastructure that includes 56 Metering and Regulating (M&R) stations, a Liquified Natural Gas (LNG) plant, three Liquid Propane Air (LPA) plants, one Liquid Propane (LP) storage facility, and 35,600 miles of gas mains and services.

Decarbonization at PSE&G

PSEG (PSE&G's parent company) has pledged, and started to work towards achieving, certain greenhouse gas (GHG) reduction goals. Notably, in 2019 PSEG announced its Net-Zero Climate Vision, which aims to achieve net-zero emissions by 2050. In 2021, PSEG accelerated its Net-Zero Climate Vision, stepping up its goal to achieve net-zero emissions by 2030.[1] This goal cascades down to each of PSEG's operating companies and divisions, including the PSE&G's gas operations.

The Net-Zero Climate Vision is comprised of three pillars:

1. Net-zero emissions for PSEG operations, including PSE&G's utility operations. This includes scopes 1 and 2 emissions.[2]

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[1] This acceleration was primarily driven by the sale of PSEG Fossil generation assets in 2022.

[2] As defined by EPA: "Scope 1 emissions are direct greenhouse (GHG) emissions that occur from sources that are controlled or owned by an organization (e.g., emissions associated with fuel combustion in boilers, furnaces, vehicles). Scope 2 emissions are indirect GHG emissions associated with the purchase of electricity, steam, heat, or cooling. Although scope 2 emissions physically occur at the facility where they are generated, they are accounted for in an organization's GHG inventory because they are a result of the organization's energy use." See: Scope 1 and Scope 2 Inventory Guidance | US EPA

2. 100% GHG, carbon-free power generation; and
3. Significant contributions to regional economy-wide decarbonization.

The Company's goals strongly align with New Jersey Governor Murphy's vision for 100% clean energy by 2050.[3] They also align with the United States government's clean energy goals to reduce GHG emissions 50-52% below 2005 levels by 2030 and to achieve a net-zero emissions economy by 2050.[4]

Prior to announcing its Net Zero Climate Vision, PSEG had identified numerous opportunities to reduce GHG emissions. Since 2016, PSE&G has significantly reduced methane emissions from its gas distribution network through replacement of aging and leak prone cast-iron and steel mains and services.

To further support decarbonization in the region (consistent with the Net-Zero Climate Vision goals), PSE&G will need to continue investment in new programs and technologies that reduce Scope 3 emissions – these are indirect emissions resulting from the Customer's natural gas consumption.

Benefits of Hydrogen

Hydrogen is the most abundant natural element, though it rarely occurs naturally in pure form. Since hydrogen is almost always combined at the molecular level with other elements, there are many ways to produce hydrogen.[5] Once disassociated, and at standard conditions, hydrogen is a colorless, odorless, and non-toxic gas. It is also most notably, flammable. When hydrogen is combusted in the presence of oxygen the only by-product is water.[6]

Due to these properties, American Gas Association (AGA), among other policy and research organizations, advocate hydrogen's role as a "high-value decarbonization resource for multiple end-uses."[7] Accordingly, hydrogen has gained significant interest and investment for its decarbonization potential, especially for hard to decarbonize economic sectors like heavy-duty transportation, steel manufacturing, and concrete production.

The AGA and other research entities also recognize the potential to blend hydrogen into the natural gas distribution supply system for delivery and use by end customers. Low blends of hydrogen, as a percentage of natural gas volume, can safely be distributed through natural gas

[3] https://www.nj.gov/emp/energy/
[4] https://www.whitehouse.gov/climate/#:~:text=Reducing%20U.S.%20greenhouse%20gas%20emissions,clean%20energy%20to%20disadvantaged%20communities
[5] https://www.energy.gov/sites/default/files/2016/07/f33/fcto_hydrogen_production_fs.pdf
[6] https://www.britannica.com/science/hydrogen
[7] https://www.aga.org/globalassets/research--insights/reports/aga-net-zero-emissions-opportunities-for-gas-utilities.pdf

pipelines and used at the customer's burner tip.[8],[9] The primary purpose of blending hydrogen is to reduce the carbon intensity of methane and methane combustion products, thereby reducing GHG emissions and related impacts.

Several US utilities have recently announced plans and approvals to construct hydrogen blending facilities including Dominion Energy, SoCalGas, and New Jersey Natural Gas. Recent announcements of Federal funding, such as Infrastructure Investment and Jobs Act (IIJA), Inflation Reduction Act (IRA), and other DOE Hydrogen accelerator programs are aimed to encourage hydrogen investments including research and development. As a result, many utilities are evaluating opportunities for hydrogen projects.

Hydrogen's Role in PSE&G

The Company seeks to be a leader in innovation for the benefit of its customers, the State of New Jersey, and the wider region. This leadership is demonstrated through many programs and investments, such as Clean Energy Future, Energy Strong, and Gas System Modernization.

The Company intends to further its commitment to innovation through its design, engineering, construction, and operations of its Hydrogen Facility. PSE&G's proposed facility will introduce a 2% hydrogen blend by volume into a section of its natural gas distribution system, which serves approximately 40,000 natural gas distribution customers. Design, construction, and operation of the hydrogen facility will help the Company learn and understand more about the long-term role of hydrogen in its gas distribution operations for purposes of decarbonization. PSE&G estimates that the blending of hydrogen into the natural gas system during the demonstration period and beyond will lower GHG emissions that would otherwise result from the use and combustion of 100% natural gas.

[8] "Burner tip" is a generic characterization of the final point of natural gas consumption such as furnaces, water heaters, or stoves.

[9] California Public Utilities Commission issued an independent study that found hydrogen blends of up to 5 percent in the natural gas stream to be generally safe.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

1. Introduction

1.1. Project Overview

PSE&G proposes to construct and operate a 1 MW clean power-to-gas hydrogen blending facility located at its Central Metering & Regulating Station ("Central M&R") in Edison, NJ. This facility will produce hydrogen through electrolysis and blend a low volume of hydrogen (2%) into the Central M&R site's natural gas distribution system outlet piping. The primary goal of blending hydrogen with natural gas is to reduce methane emissions at the burner tip of PSE&G's customers. This project will help PSE&G better understand the potential long-term use of hydrogen to meet Company and State decarbonization goals. The Company indicates that the initial three (3) years of the project will be considered a demonstration period (2024 – 2026) to gain experience through the design, engineering, construction, commissioning, and initial operation of the facility.

1.2. Preliminary Design Basis

PSE&G commissioned a leading engineering consultant, Burns & McDonnell, to complete a Site Selection Study to determine the most suitable location for a Hydrogen Facility. After evaluating five (5) company gas facility sites, PSE&G concluded that the Company's Central M&R site is best suited for the Hydrogen Facility. The Company concluded that the Central M&R site has several key attributes that will aid in the Project, and in the support of long-term operations. It permits good access to the distribution infrastructure necessary to distribute the blended fuel to its customers, and it has key advantageous features useful for the purposes of running and maintaining the Project specifically. Long term, the Central M&R site is also large enough to accommodate an expanded blending operation, should that be further beneficial.

The scope of the Project includes the engineering, construction, and operations of hydrogen production, storage, and blending equipment. PSE&G will evaluate the blending of 2% hydrogen by volume of natural gas flow at its Central M&R site. The Central M&R site's average year-round flow is approximately 7,600 MSCFD.[10] A 2% blend by volume will result in average hydrogen flow of 152 MSCFD. PSE&G could potentially increase this blend percentage over time based on capacity and operational experience. PSE&G has indicated it has sized the equipment and facility to optimize Capital and Operations and Maintenance (O&M) costs while meeting the average summer day flow, which is approximately 25% lower than the year-round average rate.[11] To achieve this blend and meet this cost-minimization goal, PSE&G has determined that

[10] MSCFD is the abbreviation for 1,000 standard cubic feet per day, a volumetric measure for gas flow (a rate).
[11] Burns & McDonnell – "Central Hydrogen Blending: Preliminary Basis of Design" prepared for PSE&G.

it will need to design and install a 1 MW electrolyzer capable of producing hydrogen by electrically separating hydrogen molecules in water.

In alignment with PSE&G's decarbonization goals, the Company will secure power for the electrolyzer with clean energy – initially through a clean energy Power Purchase Agreement (PPA). In determining the best location for the project, PSE&G has considered the future potential for construction of an on-site solar generation facility, which could provide power to the electrolyzer as an alternative to the PPA.

Either clean energy approach would result in lower lifecycle emissions compared to hydrogen produced from an electrolyzer powered by a mix of generation available from the grid, which includes fossil fuel generation. Hydrogen production using renewable energy is referred to as "Green Hydrogen."[12]

PSE&G plans to store the hydrogen produced on-site within compressed storage tubes. The on-site storage will hold sufficient hydrogen reserves to support up to two average summer days of blending at the 2% blending target level. Under normal operations, the produced hydrogen will be compressed, stored, and then blended with natural gas. A by-pass of compression and storage will be installed to allow for either maintenance or continuous operation during periods of high demand.

The preliminary basis of design for the Hydrogen Facility includes:

1. Engineering, procurement, and construction (EPC) and commissioning of the hydrogen facility, including the following equipment:
    a. 1 MW electrolyzer
    b. Buffer tank to prevent damage to the compressor during periods with a change in demand
    c. Diaphragm compressor to pressurize hydrogen for storage
    d. Compressed hydrogen storage tubes
    e. Blending skid, which is equipment that supports blending fuels at various pressures, to support hydrogen and natural gas blend and inject the hydrogen into the local distribution system
2. Metering and other control, monitoring, and communications equipment
3. Electrical distribution equipment and service upgrades
4. Incorporation of cooling systems, instrument air, water supply, wastewater collection, and odorant skid

[12] Market Research firm Wood Mackenzie defines green hydrogen as the production of hydrogen via wind and solar using electrolysis; https://www.woodmac.com/our-expertise/focus/transition/green-hydrogen-production-2019/.

5. Determination of additional physical site requirements, including those needed to comply with applicable regulations as part of the construction, commissioning, operations and maintenance

1.3. Project Timeline

The Company plans to start design, engineering, and major equipment procurement activities during 2024 and complete facility commissioning during the third quarter of 2025 with the first year of operation to occur before the end of December 2026, as shown on Figure 1.

The Company's goal during the three (3) year period shown on Figure 1 includes acquiring a valuable base of operating and maintenance experience over a period of at least one (1) year after commissioning. This timeline also provides PSE&G with the flexibility to adjust, and further refine, learning objectives, and related monitoring activities in support of these learning objectives. The three (3)-year period shown on Figure 1 is considered by PSE&G as an initial demonstration window for the overall project.

Figure 1. Initial 3-Year Hydrogen Facility Timeline, 2024 – 2026

1.4. The Cost-Benefit Analysis

A cost-benefit analysis ("CBA") was performed for a forecast period of 27 years, to 2050.[13] PSE&G is seeking approval as part of its GSMP IIP petition (and cost recovery mechanism) of its Hydrogen Facility. A three (3)-year demonstration period, as described in Section 1.3, is planned. After the demonstration activities within the first three (3) years, PSE&G will evaluate the results and performance, and determine an on-going operating plan based on knowledge gained.

The CBA evaluates the cost of producing hydrogen and compares it to the cost of natural gas that will be displaced by the hydrogen. The CBA considers the Capital and O&M costs, the

[13] 2024 through 2050, includes facility lifetime of 25 years and the roughly two (2) years of upfront time for planning, engineering, procurement, and construction of the facility.

avoided gas supply costs, the GHG benefits, and the IRA Tax Credit benefits, all described further in the following sections.

2. Costs

The construction and operation of the Hydrogen Facility will incur both capital and operating expenditures. The basis of these estimates, and related assumptions, are described in the paragraphs below.

2.1. Capital Costs

The Company commissioned an engineering consultant, Burns & McDonnell, to prepare a Preliminary Basis of Design and a Class 5 Total Included Cost Estimate[14] for the Hydrogen facilities. The Preliminary Basis of Design is an initial project scoping document that contains a project location overview, electrolyzer and storage sizing philosophy, operational considerations for the electrolyzer, compressed gas storage, and blending systems, and utility requirements (e.g., power, water supply, wastewater). The Burns & McDonnell cost estimate is based on the estimator's prior experience and, when possible, budgetary prices for major equipment.

PSE&G then prepared a cost estimate based on the Preliminary Basis of Design and supporting Burns & McDonnell cost estimate from Burns & McDonnell. The cost estimate includes the expected costs for project management, design engineering, licensing, permitting, procurement, and construction of the proposed facility. A summary of the capital costs is provided in Table 1 below.

The estimates in Table 1 are assumed to be whole and complete and those necessary to test and commission the facility. They include consideration for normal, expected project variances, and additional allowances for risk and contingency. (Table 1 does not include the costs to operate the unit, which are described in Section 2.2).

[14] As design progresses through multiple stages (preliminary design thru construction), estimates are refined and improved. The estimate becomes more accurate as definition improves. Most engineering cost estimation systems, such as that published by AACE International, use a five-level system. A Class 5 estimate is a rough order of magnitude estimate, with an accuracy range of (-) 50% to +100% (low side, high side).

Table 1. Capital Costs by Category ($USD, nominal), Rounded to the Nearest $10,000

COST CATEGORY	CAPITAL COST
PROJECT MANAGEMENT	$1,940,000
DESIGN & PROJECT ENGINEERING	$1,070,000
LICENSING & PERMITTING	$350,000
PROCUREMENT	$7,170,000
CONSTRUCTION	$8,690,000
SUBTOTAL	$19,220,000
RISK & CONTINGENCY (50%)	$9,610,000
TOTAL ESTIMATED COSTS	**$28,830,000**

Project Management – These costs are estimated based on PSE&G's Project & Construction experience managing the construction of an M&R station with a similar project duration and complexity. The costs include labor for overall project management, project engineers, project controls, project construction, legal and regulatory support services, contract analysis, environmental compliance labor, health, safety, environmental compliance, permitting compliance, program monitoring, regional public affairs, and public outreach. These costs are incurred throughout the duration of the three (3)-year demonstration period.

Design & Project Engineering – These costs are estimated based on PSE&G's design & project engineering experience with a project at an M&R station of similar duration and complexity. They include costs for all Design & Project Engineering-related activities and occur mainly during the first two years of the project.

Licensing & Permitting – These costs are estimated based on PSE&G's Licensing & Permitting experience managing a project at an M&R station of similar duration and complexity. They include costs for labor, outside services, permitting and licensing fees, and permitting support.

Procurement – Burns & McDonnell received budgetary prices for most major equipment, including the 1 MW electrolyzer, storage tubes, compressor, and blending skid. The costs for other equipment and materials that need to be procured are based on Burns & McDonnell's experience on previous projects.

Construction – Estimates are based on a five (5)-month construction duration inclusive of construction managers, inspectors, material managers, temporary facilities (e.g., office trailers, utilities, sanitary), and PSE&G's experience with construction labor costs.

Risk and Contingency

As customary practice for PSE&G, a factor of risk and contingency was applied to the subtotal of Direct and Indirect Costs. In this instance, PSE&G applied a factor of +50% based on the degree of completeness of design. According to PSE&G, this approach is in line with accepted estimating standards and guidelines that it has applied elsewhere and are aligned with industry norms.[15]

2.2. Operations & Maintenance Costs

The hydrogen facility's primary O&M costs are electricity costs, water consumption as feedstock to the hydrogen production, labor, and replacement materials. PSE&G also expects to incur some overhead costs for asset management and operational technology support functions (e.g., communications for sensors and controls). These costs include labor related to efforts to track performance of the Hydrogen Facility.

Cost information will be evaluated at the end of the three (3)-year demonstration period to gather lessons learned and assess results from the facility's performance – this will include cost and avoided gas supply cost. This information will help determine whether, or how, to modify facility operations as part of continued operations

The Company has prepared an initial annual O&M estimate as shown in Table 2. The estimate is for the first full year of operations, which occurs in 2026.[16]

Table 2. Summary of Estimated Annual O&M Costs for One (1) Year of Operation in 2026 ($USD nominal)

Cost Description	Estimated Annual Cost
Labor	$610,000
Parts & Equipment	$40,000
Utilities	$1,340,000
TOTAL	**$1,990,000**

As shown in Table 2, utilities, including water and electricity purchased through a PPA, represent the largest expected O&M cost category.

The Company prepared the O&M estimates based on its experience of operating and maintaining its M&R facilities.[17] It also collected data on estimated utility requirements (water and electricity) and related costs.

[15] WMP understands that PSE&G has applied estimation factors aligned with the AACE International methods of estimation.
[16] The facility is slated for completion mid-2025. Therefore, during 2025, O&M costs will be incurred for the remainder of 2025, once the facility's construction is completed and it begins operations.
[17] These estimates are subject to change based on the outcomes of the design and EPC phases of the demonstration.

Labor Costs – The Labor Costs include the staff costs to operate the Hydrogen Facility. The Company has estimated these costs by using the expected hourly rate for staff that will operate the facility along with expected employee hours per year. These hours were derived from 2021 actual hours spent to operate M&R stations of comparable size in the Company's territory. Training costs were also included based on estimated of number of qualified tasks and previous training costs. There are also costs associated with additional leak surveys that may be required for the area. These are based on historical unit costs for the area.

Parts & Equipment –The Parts & Equipment Costs are comprised of replacement electrolyzer parts and other equipment. The Company developed the cost estimates from vendor quotes where available.

Utilities – The Utility Costs include water, wastewater, and electricity costs. These costs were estimated using the total predicted electrolyzer annual runtime. Water and wastewater costs were based off this annual runtime, the hourly rate of water consumption of the electrolyzer, and the cost per gallon of water. The cost per gallon of water and wastewater is estimated based on existing water tariffs. Electricity costs were estimated using the Company's experience with electrical supply contracts.

As described in Section 3 of this report, the Company plans to use the hydrogen blending demonstration learnings to determine detailed requirements for the long-term operations and maintenance of the facility. PSE&G expects that the experience gained from building and operating the Hydrogen Facility will help refine costs for continued use of the facility beyond the three-year demonstration period. The experience and lessons learned will also provide a basis of estimating O&M requirements for future expansion of the Hydrogen Facility, or construction of other similar facilities within the Company's service territory, should such efforts be beneficial.

3. Demonstration Period Learning Benefits

The Company intends to design, build, and operate the Hydrogen Facility with a particular focus on an initial three (3)-year demonstration period. The principal benefits of the demonstration are the learnings that will be gained from engineering and building the facility, and from operating it to produce, store and inject hydrogen as a blend into the natural gas delivery system and in support of decarbonization. These learnings will benefit the Company, its customers, the region, and the natural gas industry.

The Company identified several learning objectives as part of the three (3)-year demonstration period across the value chain of the proposed hydrogen system – from design through operations. The Company plans to track progress on these objectives as the three (3)-year demonstration proceeds. An overview of the learning objectives is provided below, followed by demonstration phase details and opportunities for industry collaboration.

Learning Objectives

- Identify environmental and safety compliance requirements; evaluate and update current compliance programs as necessary
- Evaluate and update Company operating and safety procedures required for the facility and future hydrogen facilities
- Validate design basis and assumptions throughout construction and operations
- Analyze cost and schedule estimates in relation to actual costs and schedule
- Identify opportunities for site optimization requirements
- Develop an understanding of how blending affects gas quality and consumption
- Develop an understanding of the relationship between gas blends and materials (e.g., pipes) performance
- Develop an understanding of system performance over a variety of operating conditions
- Validate estimate and measurement approach for GHG emission reduction accounting in areas where hydrogen blending occurs

3.1. Engineering, Procurement, and Construction (EPC)

The Company seeks to use the demonstration activities as an opportunity to advance the knowledge of hydrogen facilities amongst its engineering, procurement, construction management and project management personnel. The Company's plan to design, engineer, procure, and install an electrolyzer, compressor, storage tubs, and blending skid on a single site provides an opportunity to understand the requirements for individual equipment (and as a system) to achieve desired blend percentages and operational performance requirements.

The engineering phase will, among other learnings, provide opportunities for engineers to understand how to develop equipment specifications, conduct feasibility studies (for this Project site's expansion or future hydrogen facilities), and issue engineering packages for construction. It will also provide internal teams opportunities to understand the various land use and permitting regulations that may apply to siting and operating hydrogen facilities.

In the procurement function, the Company can expect to learn more about the manufacturing lead times, equipment acceptance testing, warranties, and shipping and receiving. The teams will also be exposed to the various vendors and products that are available and on the market.

The construction phase will provide valuable learning opportunities to validate assumptions from the engineering and design phase, while also providing opportunities for the construction and commissioning teams to develop knowledge specific of the hydrogen facilities. Moreover, at the conclusion of construction and commissioning, the Company intends to evaluate the "as-built" facility against the initial design. This comparison will identify variances, if any, in areas like cost, schedule, and design. The engineering, procurement, and construction teams will validate the cause for variances to refine design, estimate, and schedule assumptions for future hydrogen projects as well as identify opportunities to mitigate changes that led to variances.

3.2. Operations and Maintenance Expense

The Company's three (3)-year demonstration period includes a period of approximately one (1) year of "steady state operations". This occurs post commissioning. This one (1)-year period will provide PSE&G the opportunity to monitor the expected, normal day-to-day operations. It will also provide PSE&G an opportunity to estimate long-term performance factors and costs of the facility through various conditions, including seasonal variations.

The primary beneficiary of the demonstration's learning objectives are the Company's operations personnel and management. These Company employees will develop an understanding of skill and staffing requirements, procedures, safety, and regulatory compliance for operations, inspections, and maintenance of hydrogen facilities.

This one (1)-year long O&M phase of the demonstration period allows sufficient time to evaluate learnings and iteratively improve. These learnings, for example, include operation in normal (i.e., production, compression and storage, and blending) and bypass conditions (i.e., production to blending); required reporting and compliance activities; and planned and unplanned maintenance. The period is also long enough to allow for studying equipment reliability. Like the "as-built" comparisons in EPC, the Company will be able to evaluate actual equipment performance against specifications, as well as the planned operational costs (e.g., power, water, and maintenance) against actuals. These learnings will support engineers in refining specifications and operating procedures to improve on-going project planning, facilities operations, and ultimately long-term cost and safety performance.

As safety is a primary concern for the Company, the demonstration also provides the opportunity to evaluate Company policies, procedures, and training and refine as necessary to maintain strict compliance with regulations and a safe work environment. To date, the Company has participated in several research and development studies related to hydrogen; it will incorporate these learnings together with direct experience to ensure safe and reliable hydrogen operations.

The collective operational knowledge that the Company accumulates will establish a foundation for the proper discernment and decision making concerning the expansion of hydrogen's use at PSE&G. Additionally, the Company will monitor the overall operational benefits and costs to determine how, or whether, the Hydrogen Facility will be expanded or adapted to maximize benefits and minimize costs.

By conducting the three (3)-year demonstration at a low hydrogen volume blend level of 2%, the Company will develop experience and gain insights into the performance of its natural gas system at such a level. The Company anticipates evaluating its learnings together with studies performed by other entities[18] to determine criteria for planning and operating at higher blending percentage levels in the future, should this be feasible, cost-effective, reliable, and safe.

3.3. Consortia Coordination and Collaboration

The Company's has indicated that its planned, active engagement with industry affiliates, such as the AGA, New Jersey utilities, and other interested stakeholders will provide it with the opportunity to share its learnings and gain knowledge from the experiences of others. This collaboration is important as the utility industry evaluates the future role of hydrogen as a vector in supporting decarbonization.

4. Additional Benefits

Beyond the primary learning benefits, PSE&G expects that the three (3)-year demonstration will achieve additional benefits from GHG emissions, IRA tax credits, avoided gas supply costs, and regional economic benefits.

4.1. GHG Emission Reductions Benefits

The introduction of hydrogen into PSE&G's system will support net-zero carbon emission goals through GHG emissions reductions. While methane is the primary GHG emitted by natural gas utilities (through Scope 1 fugitive emissions), this Project addresses downstream, Scope 3, emissions -- the emissions that result from the combustion of natural gas by the customer at the burner tip. The Company estimates that this project will reduce approximately 960 metric tons of CO_2e[19] of Scope 3 emissions per year through displacement of methane's use with hydrogen. This equates to removing approximately 208 vehicles from the road annually.[20]

Valuing CO_2e Emission Reductions

A value for the avoided GHG emissions can be estimated using the social cost of carbon (SCC). The SCC is a monetary estimate of the economic costs, or damages, which are estimated to result from emitting one additional metric ton of carbon dioxide into the atmosphere.

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[18] The US Department of Energy is facilitating studies related to hydrogen blending in natural gas pipelines; these studies are being monitored by the Company, and learnings will be incorporated into their planning efforts.

[19] Carbon dioxide equivalent, or CO_2e, means the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A-1 in 40 CFR Part 98. – U.S. EPA

[20] The US Environmental Protection Agency states that a typical passenger vehicle emits about 4.6 Metric Tons of carbon dioxide per year. https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle

Correspondingly, the SCC therefore represents the value of damages avoided by an emission reduction. It forms the basis of a widely accepted and acknowledged method for valuing the benefits of reducing emissions.[21]

The beginnings of the development of the SCC for the purposes of its integration into policy and regulatory rulemaking at the federal level stems from a ruling by the U.S. Court of Appeals for the Ninth Circuit in 2008. The ruling required the federal government to account for the economic effects of climate change in a regulatory impact analysis of fuel efficiency standards. As a result, President Obama convened an Interagency Working Group (IWG) in 2009 to develop an SCC value for use in federal regulatory analysis.[22]

The IWG provides three discount rates to span a plausible range of certainty: 2.5, 3, and 5 percent per year. There is not one accepted or consensus discount rate among economists. However, a 2015 survey of 197 economists found that most preferred a rate between 1% and 3%.[23] Table 3 below shows the SCC for each of the years in the three (3)-year demonstration period as published by the IWG.[24]

Table 3. Social Cost of Carbon, 2024 - 2027

Social Cost of CO_2, (in 2020 dollars per metric ton of CO_2)

	Discount Rate and Statistic		
Emissions Year	5% Average	3% Average	2.5% Average
2024	16	55	82
2025	17	56	83
2026	17	57	84

A 3% discount rate is consistent with estimates provided in the Office of Management and Budget's Circular A-4 (OMB 2003) guidance for what economists refer to as the consumption rate of interest. Valuing the avoided methane using the SCC at 3% discount rate for the anticipated lifetime of the Hydrogen Facility assets would result in approximately $1.7MM of benefit (in present value through 2050 at the 2% blend volume).

4.2. IRA Tax Credit Benefits

The Company is evaluating the opportunity to receive federal tax credits through the recently passed federal IRA. The act introduces a clean hydrogen production tax credit (PTC) and broadens existing investment tax credits (ITC) in Section 48 of the Internal Revenue Code.

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[21] https://www.epa.gov/sites/default/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf
[22] https://www.edf.org/sites/default/files/social_cost_of_greenhouse_gases_factsheet.pdf
[23] http://piketty.pse.ens.fr/files/DruppFreeman2015.pdf
[24] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

The IRA provides PTCs for qualified clean hydrogen, depending on the quantity of hydrogen produced and the amount of resultant CO2e emitted per kilogram of hydrogen. The amount of tax credits to the Company can be further increased if the Company complies with the anticipated prevailing wage requirements to be set forth by the US Secretary of the Treasury. Through these mechanisms, the Company has estimated that the Hydrogen Facility could achieve a PTC of up to $3 per kg of hydrogen produced.[25]

Alternatively, the Company is evaluating pursuing the hydrogen production facility ITC within the IRA. The ITC works differently than the PTC. Specifically, the ITC provides a tax credit on capital investments. The base tax credit is 6% for qualified clean hydrogen, and this percentage can increase depending on prevailing wage and apprenticeship requirements, among others. The IRA also sets forth a new ITC section, for energy storage, which can include hydrogen storage. [26] The Company can seek an ITC for the storage portion of this demonstration as well. [27]

As a part of its demonstration, the Company intends to quantify the total lifecycle GHG emissions to determine the total estimated PTC amount that might be generated as part of hydrogen production. Moreover, as part of the CBA, PSE&G has estimated an ITC credit to apply to the capital investment. WMP has applied this as an avoided cost in the CBA. Additionally, the specific value of the ITC is addressed by PSE&G's financial and tax experts as part of its detailed analysis of any revenue requirements associated with the project.

4.3. Other Benefits

The CBA estimates that the Company and its customers will realize some additional benefits of the Project that will help offset Project costs.

First, PSE&G estimates that it will avoid natural gas supply costs for the quantity of natural gas that will be displaced by hydrogen. These avoided supply costs are estimated within the CBA based on amount of natural gas displaced. This savings is based on an estimate of the monthly supply cost of natural gas.[28] Note that this avoided supply cost estimate is based on the gas commodity cost. There are additional gas transportation cost savings, but is the value

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[25] The maximum PTC that the Company can receive, according to PSE&G's preliminary estimates, is approximately $400,000 per year.

[26] Inflation Reduction Act of 2022, H.R. 5376, 117th Cong. (the Act) § 13204.

[27] Based on West Monroe general knowledge, the Company could be eligible to receive an ITC under the IRA, which could be as large as 30%. This could offset the upfront capital costs. PSE&G provided an estimate of $7.8MM as the total ITC that the Company could receive for the Hydrogen Demonstration. The specific impact to customers will be determined through PSE&G's detailed revenue requirement assessment.

[28] Geologic Gas Price (commodity cost only) based on PSE&G projections. PSE&G is using New York Mercantile Exchange (NYMEX) and Leidy basis forward settlement prices as of 1/9/2023.

insignificant in financial terms, and PSE&G and WMP determined it could be omitted without effect.[29]

Another Project benefit is the economic activity in the region that is estimated to result from the construction and operation of the facility. The Project will require additional skilled labor, and through required training, will increase the amount of clean energy skilled workers in the region. The Company's preliminary estimate assumes 54 short-term jobs will be created because of the construction activity. [30]

Last, after the three (3)-year demonstration period, the Company will evaluate how the pilot will be expanded or if blending can be increased, based on the results of the demonstration. Depending on the determined path forward, there is a potential for expanded benefits from what is listed in this section.

5. Value of the Demonstration Activities

One way to evaluate the value of the Hydrogen Facility – inclusive of its focus on the demonstration activities over the initial three (3)-year period – is to consider what is foregone if the Company does not pursue it. To this end, the Company considered alternative project features in support of its proposed demonstration scope.

Continued monitoring of hydrogen facilities elsewhere, without investment in Company-led hydrogen projects.

For relevant and regional context, in the state of New Jersey, there are two hydrogen projects underway; New Jersey Natural Resources has developed a 175 kW Green Hydrogen production and blending facility. Additionally, South Jersey Industries has proposed to develop a 1 MW clean power-to-gas hydrogen production and blending facility.

By taking a "wait and see" posture, the Company will forego an opportunity to 1) develop hydrogen knowledge and direct experience across the hydrogen value chain, and 2) be an active industry collaborator to advance the adoption of hydrogen technology. As a result, it will lag other utilities and industrial companies that are making investments on demonstration and larger scale hydrogen projects.

Lack of its own experience base may also disqualify the Company from success at securing future grant and other funding. Alternatively, gaining experience today (with a modular design that could be expanded over time), keeps the Company well-apace of industry developments, and positions it to continue in its learning objectives related to hydrogen, as the larger community of utilities also learn more.

[29] The avoided natural gas transportation cost is approximately $300 annually.
[30] Predictions made by PSE&G based on estimated capital expenditures.

Procure and install a larger electrolyzer.

The Company evaluated the pros and cons of installing and operating an electrolyzer larger than 1 MW in relation to its initial three (3)-year demonstration learning objectives. The tradeoffs involving site suitability, electrical power requirements, capital and operating costs, production capacity, storage, and blend optimization.

The details of these tradeoffs are not easily resolved without more practical experience across the value-chain. For this reason, the Company believes it is most reasonable at this point to proceed with a modest facility to develop an understanding of potential tradeoffs of engineering and operations. With this experience, the Company is better suited to plan possible expansion of the facility or develop new larger hydrogen facilities.

Less or No Storage Facilities Onsite.

Optimizing the relationships of the electrolyzer, storage volume, and blending volume requirements is a key learning goal for the Hydrogen Facility. The Company evaluated several alternatives to maintain 2% blending for most of the year, which included an evaluation of on-site storage versus no storage.

To achieve a 2% blend through most operating conditions the design of a one 1 MW electrolyzer paired with storage will allow blending to be maintained through most conditions. During periods of higher demand, this includes leveraging higher flow rate of the storage until storage reserves are depleted. When storage is depleted, the electrolyzer will continue to produce hydrogen and bypass storage until system flowrates decrease and storage can be replenished. In addition, during electric demand peaks, the Company can take the electrolyzer offline and sustain hydrogen blending from storage during this offline period.

Without storage, to achieve the same blending performance, the Company would need to design and procure a larger electrolyzer, which would lead to an increase in capital costs and in O&M costs for electricity to run the larger electrolyzer. In addition, by using on-site storage, the Company expects to avoid some utility costs for the extended run time of the electrolyzer to maintain a consistent blend. Finally, on-site storage allows for maintenance of the electrolyzer without interrupting hydrogen blending.

Purchasing and Delivering Hydrogen from Industrial Gas Supplier.

The Company also considered whether it is necessary to produce the hydrogen on-site versus purchasing hydrogen and trucking it into the Company facility for injection and blending.

This alternative would be less capital intensive (less storage infrastructure) but would severely limit the benefits that the Company can realize. By limiting the scope to a blending exercise only, the Company would not be able to achieve most of the learning objectives it seeks to achieve through the Hydrogen Facility as currently scoped. This includes the planning, implementation, and operation of hydrogen production facilities. In addition, since the Company would need to have hydrogen delivered to the facility for this alternative, additional greenhouse gases will be emitted through the trucking process, reducing the Project's impact on GHG reduction.

6. Conclusion

The Company recognizes the importance of hydrogen as a potential low carbon fuel in support of decarbonization. As the technology for producing, storing, and managing hydrogen continues to advance, and as other companies pursue hydrogen activities (pursuant to federal grant funding opportunities or otherwise), the Company believes pursuing the Hydrogen Facility is a unique and valuable opportunity.

By building a facility to produce and blend hydrogen into the natural gas system, the Company will increase the experience levels of its engineers, operators, procurement specialists and financial experts. In turn, this increase in the level of experience and expertise will allow the Company experts to contribute to the broader collaboration within the utility industry to develop hydrogen as a low carbon fuel for use within the natural gas system.

Table 4 and Table 5 provide a summary of the Hydrogen Facility's costs and benefits in nominal dollars and present value terms, respectively. The estimated costs have been determined by an engineering consultant's direct experience in building similar facilities, and through validation from the Company's internal estimators.

For this stage of engineering completeness, the accuracy of the capital cost estimates including a factor of contingency are in line with accepted estimating practices. Furthermore, the Company's experience operating and maintaining M&R stations and research on potential utility costs informed an annual O&M cost estimate. WM observes that the Company has applied reasonable and prudent engineering planning and design assumptions, which have been provided to it for purposes of conducting the CBA.

While the learnings of the demonstration cannot be estimated in monetary terms, the value of these learnings provide important and valuable contributions to the Company's decarbonization activities, in furtherance of its and the State of New Jersey's decarbonization goals. The Company's planners, engineers, skilled operators, and leadership will gain knowledge in the safe and reliable production, storage, and delivery of hydrogen for purposes of blending in the natural gas distribution system. In parallel to developing a deeper understanding for the potential of hydrogen blending, the Company will also be contributing to the reduction of GHG emissions, contributing to New Jersey's clean energy goals.

Table 4 Hydrogen Project: Summary of Costs and Benefits in Nominal $USD

Costs & Benefit Cateogries		Nominal Dollars			
		Demonstration Period (2024-2026)	Representative Year of Operation*	Outside Demonstration Period (2027-2050)	**Total Project Period**
Costs	Capital	($28,830,000)	$0	$0	($28,830,000)
	Electric O&M	*($1,880,000)*	*($1,340,000)*	*($47,460,000)*	*($49,340,000)*
	Other O&M	*($880,000)*	*($650,000)*	*($28,420,000)*	*($29,290,000)*
	Total O&M	($2,760,000)	($1,990,000)	($75,870,000)	($78,630,000)
	Total Costs	($31,590,000)	($1,990,000)	($75,870,000)	($107,460,000)
Avoided Cost Benefits\	Avoided Gas Supply Costs	$80,000	$60,000	$1,610,000	$1,690,000
	ITC Tax Credit^	$7,780,000	$0	$0	$7,780,000
Other Benefits - Societal	Value of GHG Emissions ***	*Treated under PV Terms Only*			
Net Difference		($23,730,000)	($1,930,000)	($74,260,000)	($97,990,000)

* Based on the first full year of production, which is 2026

^The ITC is based on applying a 30% credit assumption to 90% of the capital estimate. The precise value of the ITC is determined through PSE&G's separate revenue requirements analysis.

Table 5 Hydrogen Project: Summary of Costs and Benefits in Present Value Terms (using a weighted average cost of capital of 6.482%)[31]

Costs & Benefit Cateogries		Present Value Terms		
		Demonstration Period (2024-2026)	Outside Demonstration Period (2027-2050)	**Total Project Period**
Costs	Capital	($26,990,000)	$0	($26,990,000)
	Electric O&M	($1,630,000)	($18,640,000)	($20,280,000)
	Other O&M	($770,000)	($11,290,000)	($12,060,000)
	Total O&M	($2,400,000)	($29,940,000)	($32,340,000)
	Total Costs	($29,390,000)	($29,940,000)	($59,330,000)
Avoided Cost Benefits	Avoided Gas Supply Costs	$70,000	$680,000	$750,000
	ITC Tax Credit^	$7,280,000	$0	$7,280,000
Other Benefits - Societal	Value of GHG Emissions **	$80,000	$1,650,000	$1,730,000
Net Difference		($21,960,000)	($27,610,000)	($49,570,000)

* Based on the first full year of production, which is 2026

** Based on Social Cost of Carbon per IWG Report starting at $55 in 2024 using the 3% discount factor

^The ITC is based on applying a 30% credit assumption to 90% of the capital estimate. The precise value of the ITC is determined through PSE&G's separate revenue requirements

7. Appendix

Table 6 Appendix of assumptions used to develop the Cost Benefit Analysis

Assumption	**Value**
Weighted Average Cost of Capital	6.482%
Design / Build Start Date (Day/Month/Year)	1/1/2024
Risk & Contingency (%)	50%
Average Year-Round Daily Production Rate of H2 (mscfd)	152.14
Hydrogen Heating Value (HHV) (BTU/scf)	320.60
Electrolyzer Production Rate (lb of hydrogen per hour)	40.00
Electrolyzer Annual Run Hours	7,312
Hydrogen Energy Content (HHV) (Btu/lb of hydrogen)	60,340
Annual Hydrogen Energy Production (MMBtu/year)	17,648
Average Year-Round Monthly Production Rate of H2 (mscf/mo)	4,587.3
Evaluation Period (yrs)	27
Annual Emissions Reductions from Hydrogen Displacement (MT CO2e)	958.8
Hydrogen Heating Value (BTU/scf)	320.60
Hydrogen Heating Value (MMBTU/mscf)	0.321
Annual Hydrogen production (MMBTU/year)	17648.243
Maximum ITC Tax Credit ($):	$7,780,000
Escalation Factor (Applied to Capital Costs, O&M, and Certain Avoided Costs) ($):	3%

[31] The nominal dollar value and present value of the ITC-related benefit are the same in both tables because this benefit is assumed within the CBA as occurring at the beginning of year 1. The CBA does not attempt to analyze the specific effects of this tax credit and defers any such assessment to the Company's tax specialists.

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Andrew Lewis Trump

Senior Principal, Energy & Utilities

Experience **Education** **Total Years of Experience** **Years of Experience with West Monroe** **Professional Registrations** **Publications** **Presentations** **Testimonies**	Andrew is an energy regulatory and business specialist and planner with over 36 years of experience in the energy and infrastructure sector. He has worked with a wide number of diverse clients (regulated utility, non-utility affiliates, and energy industry venture companies) on the regulatory and financial justification of major investments and initiatives. His work areas of interest and expertise include: (a) Drive infrastructure solutions for electric and gas utilities, merchants, and technology firms at formative stages of the life cycle: strategy, business case, pilot evaluation, regulatory support and justification, stakeholder support, cost recovery, project formation, change management, project monitoring and evaluation. (b) Provide expert witness testimony support on regulatory cost/benefit analysis and risk-based decision support. (c) Support a variety of client communication and representation demands within regulatory venues at local, regional, and state levels. Andrew joined West Monroe in January 2021. Prior, he was independent for a period of two years. From 2008-2018 he was a Director with Black & Veatch's Management Consulting practice. Prior to Black & Veatch Andrew held the following progressive experiences: - Senior Consultant at California Environmental Associates (1989-1995). - Senior Manager, CellNet Data Systems, San Carlos, CA (1995-1999) - Director of Development and Licensing, Duke Energy North American, Oakland, CA (2000-2007) ***Experience Details:*** **WEST MONROE – SENIOR PRINCIPAL - ENERGY & UTILITIES PRACTICE, NEW YORK, NY 2021 - PRESENT** Support senior level energy market engagements in areas of grid capital investment planning; provide thought leadership in areas of gas planning, decarbonization strategies, DER, EV, grid planning and regulatory reform. Provide expert witness testimony and defense. - Regulatory cost-benefit expert. Expert witness and testimony development. - Grid investment strategies including decarbonization, EV and DER integration. Thought leadership and business development. - Regulatory assessments in areas of gas system transition planning (as part of system-wide electrification efforts)

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INDEPENDENT CONTRACTOR, NEWTOWN SQUARE, PA **2018 to 2021**

(Includes close collaboration with Charles River Associates, Washington, DC, as an independent contributor).

Lead and support senior level energy market engagements in areas of capital investment planning, integrated resource planning (IRP), DER and technology integration, stakeholder engagement, and project management.

BLACK & VEATCH MANAGEMENT CONSULTING, NEWTOWN SQUARE, PA **2007 - 2018**

A global engineering, consulting, construction, and operations company specializing in infrastructure development in energy, water, and telecommunications.

Director, Utility Practice

Expert in capital investment, risk and project valuation. Provide investment analysis of technologies, energy markets, and regulatory reform factors to determine feasibility and sustainabilty of grid modernization infrastructure opportunities. Author testimony for petitions of state commissions and strategic analysis for senior executives; Regulatory cost/benefit expert. Drive cross functional teams of analysts and engineers in time sensitive assignments.

- Delivered regulatory cost-benefit analyses in areas of grid modernization investments for electric, gas and water systems.
- Expert witness testimony.
- Delivered investment strategy and business case for 5G telecommunications opportunities.
- Delivered innovative delivery methods for utility engineering organization facing disruptive effects of Distributed Energy Resource (DER) investments and planning integration challenges.
- Performed asset valuation studies for pumped storage hydro and other generation facilities.

DUKE ENERGY NORTH AMERICA (DENA), OAKLAND, CA **2000 – 2007**

Owner and operator of power generation assets throughout North America.

Licensing / Developer

Recruited for expertise in regulatory affairs, energy market reform, stakeholder collaboration and multi-party negotiation skills.

Principally charged with gaining approvals for the redevelopment of a brownfield 1,200 MW power plant located on the coast in Morro Bay, CA. $1B project presented some of the most challenging land use requirements found anywhere in the United States. Extensive levels of regulatory and public stakeholder interactions. Led all aspects of Application for Certification (AFC) before the California Energy Commission (CEC) for the proposed re-development.

- Led efforts to gain CEC approvals. Directed team in the creation of CEC application (AFC). Gained majority stakeholder support in intensive, contentious, and publicly visible effort, ultimately obtaining CEC certification. Fought ballot initiatives. Led multi-disciplinary team of experts (engineering, environmental, business, legal). Negotiated significant land use and marine biology mitigation agreements. Managed large $20M+ development budget.
- Led team in rebuttal to federal water permit legal actions threatening closure of 2,400 MW Moss Landing facility. Assessed, analyzed, and delivered successful defense of plant's

federal water permit (Federal 316A and 316B). Served as lead expert witness, providing sworn testimony to responsible agency.

- Led stakeholder and CEC AFC process for 600 MW power plant development at Chula Vista Power Plant (San Diego region). Developed CEC licensing application (AFC). Negotiated land use agreement with Port of San Diego, aimed at integrating development into bayfront master plan. Evaluated and negotiated regional reliability benefits and long-term power purchase contract options.

OTHER CAREER APPOINTMENTS

- Senior Manager, Business Development, CellNet Data Systems, San Carlos, CA – 5 years (1996 – 2000). Develop and implement wireless telemetry systems to electric and gas utilities throughout North America. Developed and negotiated contracts.
- Senior Consultant, California Environmental Associates (CEA), San Francisco, CA – 7 years (1989 – 1996); Extensive work with the nation's Class 1 freight railroads on federal and state locomotive emission rules affecting heavy-duty diesel engine requirements. Coordinated and participated in technical studies and presented on behalf of railroad companies in workshops. Authored technical and policy comments to the California Air Resources Board (CARB), EPA, FRA, and other agencies.

Education and Formal Training:

- Harvard EdX: Data Analytics Certificate Program. Several Classes (2019-2021)
- MA, Public Policy, George Mason University, Arlington, VA (2010)
- BA, Physical Sciences (Math, Chemistry and Physics), Harvard University (1984)
- Professional Certificate, Project Management, University of California at Berkeley Extension (PMBOK-based) (2003)
- Duke Energy Corporate Media and Public Relations Training (2001)
- Program on Negotiation (PON), Harvard University (2002)

Areas of Expert Testimony Development

- Grid Modernization (gas and electric): Reliability and Resiliency Planning, Smart Grid, AMI, DA. (PSE&G Electric, PSE&G Gas, ComEd, Dominion Virginia, Vectren Indiana, Southern Maryland Energy Cooperative, PECO, BG&E, Hawaiian Electric).
- Power Plant Facility Licensing (team lead, and responsible for): Project Description, Facility Closure, Electric Transmission Interconnection, Natural Gas Supply, Water Supply, Air

Quality, Transportation, Visual Resources, Hazardous Material Handling, Waste Management, Land Use, Noise, Public Health, Worker Health and Safety, Socioeconomics.

- Application of practice standards in the conducting of costs-benefit analysis (CBA) as applied to utility pilots and demonstrations. **See:** In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to new technologies and business models. **MPSC Case No: U-20898.** Proposed Requirements and Further Guidance on Benefit-Cost Analyses for Pilot Initiatives Prepared by DTE Electric Company and Consumers Energy Company. February 1, 2023.

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Trump, Andrew. "Building the Business Case for Smart Grid." *Generating Insights*, IBM, Fall 2010.

Presentations and Media Exposure

- Advanced Energy Conference (AEC), 2022, New York City, NY. "Business Models and Regulation for Resiliency, and DERs". Conference panel moderator. September 8, 2022.
- "A View of the Electricity Business Model of Tomorrow: Electric Distribution System Planning," POWER-GEN International, December 2016, Orlando, FL.
- "Recovery of Innovation Investments", Edison Electric Institute (EEI) Conference, Chicago, October 2012.
- Presentations at Executive/Senior Staff Stakeholder Sessions as part of Settlement or Mitigation Program Negotiations.
- Sponsorship and Convening of Public Workshops for the Review and Discussion of Infrastructure Projects and Programs.
- Representation of Client Projects in Open Public Settings as part of Routine or Special Sessions.
- Numerous Formal Technical Reports and Presentations as part of the Public Record.

Professional Affiliations

The Institute of Asset Management | Enterprise Risk Management (ERM) | ISO 31000 Risk Management Standard

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Grid Modernization

- Petition of Virginia Electric and Power Company, for approval of a plan for electric distribution grid transformation projects pursuant to 56-585.1 A 6 of the Code of Virginia. Case No. PUR-2021-00127. (a) Direct Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed June 21, 2021. (b) Rebuttal Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed October 1, 2021. Available at: https://scc.virginia.gov/DocketSearch#caseDocs/142210

- In The Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (*Energy Strong II*). BPU Docket Nos. EO18060629 and GO18060630. Attachment 5: Cost-benefit analyses of the electric portion of the Energy Strong II Program. Attachment 6: Cost-benefit analyses of the gas portion of the Energy Strong II Program. Available at: https://nj.pseg.com/aboutpseg/regulatorypage/regulatoryfilings
- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South). IURC Cause No. 44910. Direct Testimony of Andrew L. Trump, Director, Utility Practice, Black & Veatch Management Consulting, LLC. On AMI Cost Benefit Evaluation. Sponsoring Petitioner's Exhibit No. 5, Attachments ALT-1 Through ALT-3. https://iurc.portal.in.gov/legal-case-details/?id=3b675b4f-eff9-e611-80fd-1458d04e2f50
- Illinois Commerce Commission v. Commonwealth Edison Company, No. 12-0298. Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act. Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 6.0, 6.01 and 6.02, "Cost Benefit Analysis of Commonwealth Edison (ComEd) Smart Grid Advanced Metering Infrastructure Deployment Plan (AMI Plan)" (filed April 23, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=180884.
- Also, Rebuttal Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 12, 12.01, 12.02 and 12.03 (filed May 17, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=182177.
- Illinois Commerce Commission v. Commonwealth Edison Company. No. 14-0212. Petition to Approve *Acceleration* of Meter Deployment under ComEd's AMI Plan. (Petition for Statutory Approval of a Smart Grid: Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act). Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 2.0 and 2.01 (filed March 13, 2014). https://www.icc.illinois.gov/docket/files.aspx?no=14-0212&docId=210863.

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Power Plant Development

Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the Morro Bay Power Plant Project:

- Morro Bay Modernization and Replacement Power Plant Project. Application for Certification. Docket No. 00-AFC-12. October 23, 2000. http://www.energy.ca.gov/sitingcases/morrobay/.

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	- Expert Witness Testimony of Andrew L. Trump provided before the California Energy Resources Conservations and Development Commission (Energy Commission). http://www.energy.ca.gov/sitingcases/morrobay/index.html. Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the LS Power South Bay LLC South Bay Replacement Project (SBRP): - South Bay Replacement Project Power Plant Licensing Case. Docket No. 06-AFC-03. Filed June 30, 2006. http://www.energy.ca.gov/sitingcases/southbay/documents/applicants/afc/. - (Note, LS Power acquired Duke's interests mid-2006). Responsible for the preparation and expert witness testimony and representation of Duke Energy North America's formal legal testimony before the California State Lands Commission and the Central Coast Water Quality Control Board in the legal challenge brought by Plaintiffs to the continued operation of the 1,000 MW Moss Landing Combined Cycle Power Plant (reliant on once-through cooling technology, and in relation to the federal Clean Water Act permit authority). (2002-2003).

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Margaret Oloriz, P.E.

Manager, Energy & Utilities

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Education
Columbia University, Master's of Science, Civil Engineering

University of Notre Dame, Bachelor's of Science, Civil Engineering

Professional Registrations: Professional Engeering License (NY, CA)

Total Years of Experience: 10

Years of Experience with West Monroe: 5

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Margaret is an engineer and project manager with over 9 years of experience in the energy and infrastructure sector. Throughout her career, she has worked with a variety of clients on planning, designing, and implementing new utility technology solutions for electric vehicle (EV) infrastructure, clean energy projects, smart grid solutions, and distributed energy resources (DERs).

Margaret has been immersed in the clean energy industry, with a recent focus on hydrogen project development. Recently, Margaret helped a Mid-Atlantic gas utility evaluate their hydrogen pilot's suitability for federal funding and she identified opportunities to help a mid-stream gas company develop the scope and justification for their large-scale hydrogen project. Other projects that Margaret worked on recently include: Supported a Large-Size East Coast Utility in developing their EV Fleet and Public Charging Programs using a business case analysis tool which involved simulating customer rates and load profiles. Margaret also helped a transportation authority plan for the adoption of electric buses across their service territory, modeling their routes and their dwell times, developing a level 5 cost estimate of the facility upgrades.

PROJECT EXPERIENCE:

Hydrogen Project Development for DOE Funding
Mid-Stream Gas Company, *April 2022 – Present*

- Managing development of a hydrogen project for the utility, taking the project from a concept to a fully developed project ready for DOE funding
- Coordinating vendors, partners, and stakeholders to ensure project is well supported
- Identifying project gaps and developing plans to fill them to position the project for DOE funding

Federal Funding Opportunity Assessment
Large East Coast Utility, *February 2022 – June 2022*

- Led team of subject matter experts to identify federal funding opportunities for current utility projects and align those projects to funding; categorized and prioritized current projects for pursuing funding, including 4 hydrogen related opportunities

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- Conducted workshops and held 20+ 1-1 meetings with utility staff and leaders to understand priorities and ability of projects to be applicable for federal funding opportunities
- Recommended projects for utility to pursue federal infrastructure funding for; wrote pre-application summaries which included engineering information and key win themes

Electric Vehicle Assessments and Bill Simulation for Fleet Operators
Mid-Size Midwest Utility, *September 2021 – Present*

- Leading a team of subject matter experts and analysts to conduct end-to-end fleet assessments on behalf of the electric utility with their C&I customers. Assessments involve gathering data on their fleet, analyzing data, modeling various load profiles, quantifying lifetime savings of EV conversion, and developing a report
- Updated West Monroe modeling tools with utility rates and unique program elements to accurately predict customer bills depending on various load profiles of fleet vehicles
- Conducting interviews with each C&I fleet customers to understand operations and unique business requirements for EV conversion

Digital EV Fleet Calculator
Mid-Size West Coast Utility, *July 2021 – August 2021*

- Updated West Monroe modeling tools with utility-specific rates and program elements
- Supported development of website that allows fleet customers in utility's jurisdiction to predict their energy bills given their unique load profile and utiity tariff

EV Program Design and Regulatory Support
Large East-Coast Utility, *February 2021 – June 2022*

- Built business case model for EV Fleet and Public charging programs that calculated program costs and benefits based on number of enrolled customers; enhanced model to evaluate customer costs of entering EV program, including modeling fleet customer bills with the various utility EV tariffs that the customer would be eligible for
- Optimized program design to maximize benefits for the customer while keeping program costs within budget
- Proposed various EV fleet rates for customers considering rates and tariffs offered across the country and modeled their impact to utility customers
- Supported regulatory filing of EV program that led to the program receiving approval by the regulatory commission. Regulatory support included development of material and testimony for EV program regulatory filing that included justification for the EV program costs and benefits. Answered discovery and intervenor questions as necessary during the filing process

EV Bus Garage Planning (Prior Employer)
New Jersey Transit, *November 2019 – January 2021*

- Led overall effort to help the client understand opportunities for electrification at four bus garages across their service territory
- Oversaw work of electrical, fire protection, and structural engineers to identify garage upgrades needed for electrification and develop cost estimates
- Led analysis of bus routes, digitizing weekday and weekend bus schedules to understand dwell times, route characteristics, and charging needs; used this information to optimize future charging times to reduce energy consumption and energy bills.
- Worked with utility to develop load letter for energy increases at each facility
- Identified operational gaps and training updates needed to transition staff to electric buses
- Developed report outlining implementation recommendations for EV Buses at four garages and for the first 100 electric buses

Public Curbside EV Pilot Design (Prior Employer)
City of Cambridge, Massachusetts, *September 2019 – June 2020*

- Worked with city planning to design a curbside residential EV pilot
- Modeled city infrastructure and analyzed infrastructure data to identify ideal locations for public EVSE
- Conducted requirements gathering and vendor analysis to select short list of potential vendors for curbside EVSE
- Led discussions with City stakeholders to share pilot updates and gather feedback
- Presented updates on the EV pilot at publicly held meetings

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

**IN THE MATTER OF THE PETITION OF
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FOR APPROVAL OF THE NEXT PHASE OF
THE GAS SYSTEM MODERNIZATION PROGRAM AND
ASSOCIATED COST RECOVERY MECHANISM
("GSMP III")
THE RENEWABLE NATURAL GAS ("RNG") PROJECT**

BPU Docket No. __________

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF**

**ANDREW L. TRUMP and SHELLY HAGERMAN
WEST MONROE PARTNERS, LLC**

March 1, 2023

Q. Please state your name, employer, and business address?

A. My name is Andrew L. Trump. I am employed by West Monroe Partners, LLC ("WMP"), a management and digital consultancy. My business address is 825 8th Avenue, 17th Floor, New York, New York, 10019.

Q. What position do you hold at WMP?

A. I am a Senior Principal within WMP's Energy & Utilities ("E&U") practice.

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

A. My name is Dr. Shelly Hagerman. I am employed by WMP, a management and digital consultancy. My business address is 311 West Monroe Street, 14th Floor, Chicago, IL 60606.

Q. What position do you hold at WMP?

A. I am a Senior Principal within WMP's E&U practice.

Q. Please describe the activities of WMP.

A. WMP assists companies like PSE&G in gas and electric system modernization. This involves a wide range of matters related to the capital and operational planning and implementation of new technologies and capabilities to help electric and gas utilities efficiently and effectively manage their business and prepare for the future. The planning and implementation support provided often involves addressing decarbonization-related questions and challenges, enabling electric vehicle market development and deployment, deploying advanced metering infrastructure, upgrading utility telecommunication systems, and integrating distributed energy resources onto the electric grid, to name a few areas of support. It also involves assisting gas local distribution companies ("LDCs") in preparing their decarbonization plans and considering other forms of gas blended in pipeline and electrification like renewable gas, certified gas, hydrogen gas, and use of hydrogen in fuel cells to electrify buildings. WMP provides in-depth cost-benefit analysis ("CBA") services as part of these focus areas. Additionally, WMP is often asked to assist its utility clients in the accompanying program and project management, including change management, business integration, and digital enablement of multi-year projects and programs related to these types of initiatives.

Q. Mr. Trump, please summarize your professional background and your experience in the utility industry.

A. I have worked in a professional capacity since 1984, when I graduated from college, on a wide range of energy and transportation projects, programs, and initiatives. My experience includes work both as a consultant within management and professional services consultancies, and as an employee within technology and merchant energy firms. For example, starting in 1995, I was employed by CellNet Data Systems, a firm that developed one of the first radio frequency ("RF") based advanced metering and meter data management platforms. My role involved, amongst other responsibilities, the development of cost-benefit analyses for the company's utility customers and the negotiation of multi-year contracts for the deployment and lease of these systems. Starting in 2000, I was employed by Duke Energy North America, a wholesale power generator. At Duke, I was responsible for the licensing of the development of large power plants, entailing the securing of land use, environmental, interconnection, and other necessary settlements and approvals needed to permit the Company to build these power stations. This role involved leading and managing a large team of legal, technical, and environmental experts in multiple disciplines related to wholesale power development and large industrial site development. Starting in 2007, I began consulting on grid modernization, mainly focused on electric and gas distribution systems. I was employed by Black & Veatch Management Consulting through the end of 2018. There I performed independent consulting services, including for PSE&G, in a similar capacity on gas and electric distribution system issues. Starting in January 2021, I was hired by WMP for my current role. In this role, I serve as a subject matter specialist across many areas and domains, including in performing economic and business case analysis for grid modernization plans and providing supporting testimony. Much of my work during the past 15 years has been focused on the strategy, justification, planning, implementation, and review of a wide range of technologies of importance to electric and gas system operations. My educational background includes an undergraduate degree from Harvard College with a degree in Physical Sciences, a professional Project Management certificate from the University of California at Berkeley, and a master's degree in Public Policy from George Mason University.

Q. What is your experience related to gas systems?

A. I have supported gas system planning for several utilities throughout my career. As part of the powerplant development work, I was involved in the development of engineering and site-layout requirements, fuel quality requirements, and the environmental review associated with a gas delivery service to combustion turbines at power stations. I have also been heavily involved in the planning and implementation of new technologies, such as advanced metering, remote system monitoring, and telecommunications for several gas utilities. I have participated in assignments involving regulatory compliance issues related to indoor odor and corrosion inspection responsibilities and record keeping, and in the deployment of automated systems gas shutoff. I also supported PSE&G in its Energy Strong II proposal and program during 2017-2020, and specifically its plan to upgrade several Metering and Regulating ("M&R") stations, and to implement a series of main improvements to address system resiliency, specifically outage risks to the gas distribution system due to major events beyond (upstream of) the city gate. Most recently, as part of a small team, I led and supported the development of cost benefit analysis standards of review for two large mid-western gas and electric utility companies, which were obligated pursuant to a Commission order to provide such recommendations to its Commission and stakeholders.

Q. What is your experience related to CBA?

A. I have extensive and in-depth knowledge of utility CBA practices, methods, requirements, and practice norms, as gained by my many years of professional experience. I have worked on over 40 large CBA and investment valuations during the past 15 years, for example, for gas, electric, and water utilities.

Q. Have you provided prior testimony to the BPU?

A. Yes. I supported PSE&G in its electric and gas Energy Strong II petitions with the preparation of direct and rebuttal testimony on those proceedings.

Q. Dr. Hagerman, please summarize your professional background and your experience in the utility industry.

A. I have been working at WMP since 2016. I serve as the lead of our Distributed Energy Resources ("DER") team within WMP and specialize in developing strategies and business cases of new technologies and business models. These efforts have also involved the preparation of regulatory cost-benefit analyses. Much of my focus has been in developing core elements of utility decarbonization plans, including clean energy implementation and transportation electrification plans. My educational background includes a PhD in Engineering & Public Policy from Carnegie Mellon University and a B.S. in Engineering from Smith College. My PhD Dissertation was titled *Economics of Behind-the-Meter Solar PV and Energy Storage*.

Q. What is your experience related to CBA?

A. I have developed CBAs for a range of utility investments and programs, spanning grid modernization, distributed energy resources, non-wire alternatives, transportation electrification, outage management systems, and fiber leasing. I also have experience in implementing guiding principles and frameworks from the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources.

Q. Have you provided prior testimony to the BPU?

A. No.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to provide evidence and analysis in support of a CBA for PSE&G's Renewable Natural Gas ("RNG") Project. The CBA is provided to fulfill petition requirements established within the New Jersey Administrative Code as found in N.J.A.C. 14:3-2 A.2 (c). This code section identifies a requirement for a report for "any applicable cost-benefit analysis" for the eligible project or projects proposed as part of New Jersey's Infrastructure Investment Program, or IIP.

Q. What approach was used to complete the CBA?

A. A team at WMP, ourselves included, worked with PSE&G, MCUA, and Burns &

McDonnell gas system planners, engineers, and financial analysts to review the RNG facility design basis, investment plans, program goals and assumptions, to structure an appropriate scenario-based framework for the CBA, to gather and document initiative costs and related assumptions, to identify and classify key benefits, and to quantify and monetize benefits, where practical and feasible. The resulting CBA is reflected in WP ATSH-GSMPIIIRNG-1.xlsx and documented within Schedule ATSH-GSMPIIIRNG-1, which covers these topics and provides CBA results.

Q. What are the specific work products of the WMP efforts?

A. In addition to the testimony here, WMP authored a CBA report, identified as Schedule ATSH-GSMPIIIRNG-1. The supporting CBA is identified as WP ATSH-GSMPIIIRNG-1.xlsx. Lastly, the credentials of Mr. Trump and Dr. Hagerman are provided in Schedule ATSH-GSMPIIIRNG-2 and ATSH-GSMPIIIRNG-3, respectively.

Q. Was the work performed under your direct supervision?

A. Yes. We jointly oversaw, directed, and performed the work.

Summary of Conclusions

Q. What are your conclusions, based on your findings provided in the CBA report?

A. The RNG Project represents a collaboration with a local landfill and utility entity (The Middlesex County Utility Authority, or "MCUA") to source and deliver to the PSE&G customer renewable natural gas, or RNG. This will displace the need to source and deliver natural gas from distant upstream sources. This project has four general and fundamental mechanisms: First, investment in a low carbon fuel such as RNG can unlock value for the fuel's Environmental Attributes ("EA"). Second, these EAs have recognized market value and therefore create a source of revenues that can offset investment and operating costs. Third, the investment in low carbon fuel production creates a mechanism to reduce greenhouse gas ("GHG") emissions. Fourth, under the right program arrangements, customers can participate directly in decarbonization as a result. These four components form the basis of PSE&G's RNG Project and therefore the basis of the CBA.

The RNG Project has been structured, in collaboration with MCUA, such that it generates adequate revenues and offsetting costs to avoid the requirement of new customer charges. This is the central financial conclusion of the CBA. This conclusion is based, of course, on the underlying assumptions, which have been carefully documented as part of the CBA Report and supporting workpapers (a MS Excel analysis file). The CBA includes a sensitivity analysis to explore the central result. Additionally, this result takes a utility-centric point of view. The CBA notes but does not aim to speculate on separate MCUA financial benefits, which may accrue to its customers, and that are not accounted for in the CBA result.

There are several over-arching benefits of the RNG Project. The Project provides a potential pathway for PSE&G customers to participate in decarbonization. PSE&G has expressed a strong interest in a future energy system that includes a far larger proportion of low carbon fuels as part of its delivered energy mix. The RNG Project is a significant step in further supporting this aspiration. This interest and aspiration also strongly aligns with the State of New Jersey climate goals and separately articulated PSEG sustainability programs.

The RNG Project is estimated to reduce direct criteria air pollutants (NOx, SOx, PM2.5, other) at the project site. This is an important project benefit derived from the fact that the Project will install modern and efficient gas processing equipment. These reductions are improvements for local and regional air qualities. Also, based on a PSE&G performed life cycle analysis, the RNG Project is estimated to reduce GHG emissions by around 27,000 – 36,000 metric tons carbon dioxide equivalent ("CO2e") per year. These emission reductions represent Scope 3 emissions. As such, they complement the additional emissions reductions that are described as part of the GSMP III (Scope 1 emissions) and Hydrogen initiative (Scope 3 emissions).

The RNG Project assists the MCUA in addressing its site operational requirements in relation to aging combustion equipment. It also assists the MCUA in streamlining its operations. These improvements benefit the wider region. It should be noted that PSE&G and MCUA have overlapping customers, so benefits that accrue to MCUA customers also accrue to PSE&G customers.

Sourcing natural gas closer to its point of use makes good sense for several reasons. Generally speaking, methane will escape from landfills, creating a source of fugitive emissions, unless it is collected and used as part of combustion process or is otherwise used; mitigation of fugitive methane emissions is a key reason why there are strong policies and regulations that encourage RNG development. By using RNG at the "burner tip", the customer takes an equivalent level of demand away from the upstream natural gas supply requirement. This avoided supply cost also forms one of the avoided costs that support the CBA result. Sourcing gas locally also provides an additional measure of fuel source diversity and security, which in turn aids in improving the energy system's level of reliability and resiliency. PSE&G customers are better off having access to more supply sources than fewer, as a general proposition.

The incremental costs and monetized benefits of the RNG Project, on a present value basis, are $269.5M (on a revenue requirement basis) and $270.4M, respectively. This symmetry in result (nearly equal costs and monetized benefits) is based on the assumed value of EAs used in the CBA and within PSE&G planning, and further based on a revenue sharing mechanism PSE&G has established with the MCUA. The reason these are nearly equal is because PSE&G and MCUA estimated the EA price and used it inform their revenue sharing arrangements.

Approach and Structure of CBA

Q. What is the basis of the CBA?

A. The CBA is based on the comparison of two scenarios, both of which are realistic and meaningful. By comparing the costs and benefits – including qualitative metrics – associated with each scenario, it is possible to reveal the incremental or marginal differences in costs and benefits between the two scenarios both in terms of strictly financial results as well as from a perspective that includes the contribution from qualitative benefits.

Q. What are the two scenarios in this instance?

A. As described in the CBA report, one scenario assumes that the Company pursues the $123.4 million (nominal) RNG Project. This is the capital cost of building the RNG facilities. At the conclusion of the three-year construction phase, this scenario assumes RNG production begins and PSE&G is able to deliver this alternative source of high quality natural gas to its distribution system. The alternative scenario assumes Business As Usual ("BAU") at the MCUA landfill operation. This includes the continued sourcing by PSE&G of upstream natural gas, the traditional supply source. The RNG Project and BAU scenarios are compared to determine the incremental effects of pursuing the RNG Project.

Q. You describe the RNG Project as a three-year construction program. Are all costs incurred during this period?

A. No. The CBA identifies PSE&G's estimates of the on-going costs (and avoided costs) of building, owning, and operating the RNG facility, and handling programmatic costs related to the sale and transfer of the RNG-related EAs. The RNG facilities are designed for a useful operating life of 20 years; this forms the basis of the operating period assumption that is used in the CBA.

Q. What do you mean by "meaningful" scenarios?

A. Our assumption is that the IIP requires, as part of its minimum filing requirements, *meaningful* scenarios – ones that have relevance to the decision that is under consideration and help explain the nature of the decision choices in cost and benefit terms. One should avoid defining a scenario based on trivial or non-consequential differences, as this would not help reveal anything meaningful about the choices.

Q. What is the scope of the RNG Project that informs the CBA?

A. PSE&G proposes to construct and operate RNG-related facilities at MCUA's Central Treatment Plant ("CTP") in Sayreville, NJ. This facility will upgrade landfill gas ("LFG") to pipeline quality standards and inject it into the PSE&G gas distribution network. MCUA currently collects and pipes LFG seven miles from its East Brunswick Municipal Solid Waste (MSW) facility to the CTP, partially treats it, and uses it for producing electricity used on site. As part of the RNG Project, MCUA will transfer the custody of the LFG to PSE&G at the CTP before it is treated. The new PSE&G gas upgrade facility will then produce RNG at pipeline quality standards and inject it into the PSE&G gas distribution network. PSE&G has sized the RNG plant to accept and treat a maximum of 6,000 standard cubic feet per minute ("SCFM") of LFG. Capital costs support the design, engineering, procurement, construction, testing and commissioning of the facilities needed to generate the RNG for purposes of injecting it into the PSE&G gas distribution system.

Cost for Each Scenario

Q. Explain the costs for each scenario.

A. The CBA does not speculate about MCUA costs, including, most relevantly, any new incremental costs (or avoided costs) due to the Project. Rather, the focus of the CBA is on PSE&G-centric costs, avoided costs and other forms of benefits. For the RNG Project, the CBA identifies capital and operating costs as gathered by the West Monroe team working closely with PSE&G's experts, including those of its Engineering Consulting partner Burns & McDonnell. Burns & McDonnell has developed a Project Engineering Report (GSMP III RNG Project Engineering Report Basis of Design) that is detailed and provides many of the estimates on the costs for the facility's construction and operations. The costs are inclusive of all cost elements that the Company includes within its cost recovery petition. The estimated costs for the RNG Project scenario have also factored in the Company's estimate of site lease expenses and the program costs related to the qualification and brokering of the EAs that are the source of revenues to the project. The cost estimates include assumptions regarding inflationary effects as well.

Q. In summary, what are the cost differences of the two scenarios?

A. The RNG Project scenario costs are estimated to equal $252 million in present value terms. This includes all capital and operating expenses. As noted, there are no separate, incremental BAU costs. The present value calculation is based on applying a discount rate of 6.48%, which has been provided to WMP to apply and is based on the Company's average weighted cost of capital ("WACC").

Q. Did you or the WMP team play a role in developing the costs and avoided costs, or assessing the quality of the cost estimates?

A. Yes. WMP did play a role in developing the costs and the avoided costs. We (a) worked with PSE&G and its team of consultants to identify and gather all relevant and material cost data, (b) identified how the costs and avoided costs align to the agreement structure that PSE&G has put in place with MCUA, (c) identified where adjustments to the costs were needed in order to account for inflationary effects, (d) worked with PSE&G's experts to determine a reasonable estimate of future costs for natural gas supply costs, (e) similarly worked with PSE&G to determine a reasonable estimate for future D3 Q-RIN credit prices, and (f) worked with PSE&G's experts to incorporate revenue requirement calculation results into the financial evaluation model. Furthermore, we conducted a sensitivity analysis to explore how changes to key variables influence CBA results. One of the sensitivities explored the effects of the cost estimate range on the overall result. Another sensitivity explored the price sensitivity of the Environmental Attributes. Finally, the costs and monetized benefits as collected by WMP appear in Appendix A of the CBA Report.

Economic Monetary Benefits

Q. How are benefits determined for purposes of the CBA?

A. To approach the identification of benefits, WMP identified the benefits inventory related to the RNG Project through workshop-type discussions with PSE&G subject matter experts. We levered a structure and set of tables from a well-accepted CBA guidance document used within the utility industry to perform CBA. This provided a starting point for discussions with PSE&G's experts. This approach provides an objective basis for the benefit inventory development. WMP then assembled information for further categorization of the identified benefits to discuss whether the benefits could be quantified and/or monetized.

Q. Explain some of these categorization steps.

A. The CBA recognizes that there may be economic benefits and other benefits which are difficult to quantify and further, monetize. This does not mean that a qualitatively stated benefit is not relevant or important, only that it is difficult to further parameterize it. Therefore, to be thorough and comprehensive, it is useful to discuss each area of impact, identify how it may drive benefits, and further determine if measurement is feasible. This process leads to an inventory of benefits, classified by benefit type. We have identified and organized the benefits as monetary, quantified (but not monetized), and qualitative, as shown in Table 4 of the CBA report. The financial results of the CBA incorporate the monetized benefits only and do not reflect the additional quantified or qualitative benefits discussed in the CBA report.

Q. What are the monetary benefits that make up the CBA?

A. The CBA identifies several monetary benefits. First, the RNG Project will receive revenues from the PSEG Energy Resources & Trade ("ER&T") group (based on a price reflecting natural gas commodity costs from today's upstream sources) for inclusion in Basic Gas Supply Service – Residential Service Gas ("BGSS-RSG") supply. Second, there will be additional benefits to BGSS-RSG supply customers through avoided costs related to the gas transportation cost otherwise imposed on the Company to transport the upstream gas commodity. Third, the RNG Project will gather revenues through the sale of the RNG-related credit, which is the key environmental attribute of the RNG. This credit is referred to as RIN, which stands for Renewable Identification Number. RINs have a specific meaning as part of federal law and within a market for environmental credits related to this law. The CBA also examines the impacts of the Investment Tax Credit within the Sensitivity Analysis; however, this is not included in the base scenario due to uncertainty around Project eligibility (due to timing of approvals and construction).

Q. Please explain the basis of the benefit related to the gas commodity.

A. The CBA assumes that PSEG's ER&T will pay the RNG Project for the renewable natural gas valued at a reference Transco-Leidy gas supply price. The CBA assumes (a) initial period prices (2025-2030) taken from Leidy and Nymex forward pricing through December 2030, (b) then, for years beyond this initial forecast period WMP worked with PSE&G's SMEs to determine a reasonable estimate of gas prices and extended the monthly prices of 2030 through the end of the asset life with no escalation.

Q. Please explain the basis of the benefit related to the sale of RINs.

A. WMP, for purposes of the CBA, assumes PSE&G will monetize the Environmental Attributes ("EA") of the RNG based on its production, distribution, and use to and by its customers. Properly verified, tracked, and administered, the RNG will generate a credit, known as a RIN. The number of RINs will be based on volume of RNG supplied, and other factors that are recognized by the U.S. EPA as part of Renewable Fuel Standard ("RFS") compliance requirements. By way of explanation, the Obligated Parties subject to the RFS must blend low carbon fuels into their product to meet Clean Air Act compliance. If they are unable to do this in any given compliance period, they must secure sufficient RINs to make up the difference. Under the terms of the RFS, these parties can purchase and retire the RINs. Accordingly, there is a market in RINs. Because there are different categories of RINs, PSE&G has determined that the feedstock LFG and production pathway (the proposed RNG facilities design basis) of the RNG Project will qualify to generate a D3 Q-RIN.

Q. Please explain what D3 and Q-RIN means?

A. The U.S. EPA, as part of the RFS, has established different categories, or "D-codes", that map to different fuels, feedstocks, and production processes. PSE&G has determined that the RNG Project's gas production will qualify under EPA's D3 classification. Additionally, the "Q" in Q-RIN is used to designate that the PSE&G RINs will go through a value-enhancing, formal audit and quality assurance process ("QAP") for purposes of meeting RFS compliance requirements. The RIN has a higher market value due to the QAP, and thus gets the Q-RIN designation.

Q. Why are these designations important to the RNG Project?

A. Each D-code RIN type is exchanged at a different price, since they relate to different compliance needs of the Obligated Parties under the RFS. Therefore, the D3 Q-RIN designation informs the specific value of the RIN credit, which is used within the CBA.

Q. What value is used for the D3 Q-RIN in the CBA?

A. The CBA uses a D3 Q-RIN price of $3.07 per RIN. This price is applied uniformly, without adjustment over the project life span. PSE&G believes this is a reasonable assumption to apply given market dynamics. This price is also equal to the average sale price of D3 Q-RINs during the 12 months ending December 31, 2022, as tracked, and reported by the U.S. EPA. EPA tracks prices carefully, along with volumes and counterparties, as part of RFS compliance monitoring. As part of the sensitivity analysis, the CBA explores a range of RINs prices in order to examine impacts of price changes. As noted in the CBA Report, RINs prices are subject to various market forces.

Q. Please explain the basis of the ITC Benefit?

A. The CBA assumes that the project will not be eligible for the ITC benefit. The results of including the ITC benefit are explored as part of a sensitivity analysis, where the ITC is assumed to be 30%. Including the ITC improves the CBA result by lowering the overall impact of capital expense.

Q. Does the CBA consider any instances of higher on-going costs at MCUA as part of the RNG Project scenario?

A. Yes, but only as a qualitative matter. The CBA recognizes that there may be changes at the MCUA's facilities, and it may incur new costs as well as new avoided costs. The CBA, however, does not speculate about either of these effects. It is PSE&G's understanding that MCUA will receive net new benefits on whole due to this Project. As further noted in the CBA report, any additional financial benefits to MCUA would be beneficial to both MCUA and PSE&G customers.

Q. Are there other benefits that make up the CBA?

A. Yes. The CBA identifies several benefits, including the reduction of direct criteria air pollutant emissions at the MCUA Central Treatment Plant ("CTP"). This statement is based on detailed PSE&G analysis of before BAU and after RNG Project conditions. Additionally, and separately, the RNG Project is estimated to reduce GHG emissions by approximately 27,000 – 36,000 metric tons CO_2e per year, or 540,000 – 720,000 metric tons CO_2e over the project life. These are identified in the CBA as qualitative benefits. They are quantified but not formally expressed in monetary terms.

Q. What is the basis of the GHG reduction estimate?

A. PSE&G performed a lifecycle analysis of the RNG Project that considered the end-to-end value chain of the sourcing and use of the natural gas. This analysis compares the alternative pathway today of natural gas sourced and distributed to the PSE&G customer. Natural gas is composed largely of methane. The methane undergoes combustion as part of the customer's use of natural gas – converting the methane into useful energy and resulting in by-products of mainly CO_2 and water vapor. The Company applies emission factors in the lifecycle analysis to determine the net change in GHG under the before BAU and after RNG Project scenarios.

Q. Under the GSMP III Project the Company recognizes an economic benefit to the reduction of GHGs. Does the RNG Project treat the GHG benefits differently?

A. Yes. The economic benefit of the GHG under the RNG Project is derived from the sale of D3 Q-RINs. These are applied to meet certain Clean Air Act compliance requirements for transportation fuel producers, importers, and exporters as part of the federal RFS. It would not be appropriate to assign additional economic value to the use of the RINs (the RNG-created credit, embodying the GHG benefits) beyond what is captured in the value of the RINs. It would be "double counting" to ascribe additional value to the credit.

Q. Are there benefits to the PSE&G system in areas of reliability and resiliency?

A. Yes. Measures that reduce reliance on gas supplies from more distant locations, and which increase the diversity of supply sources, benefit energy system reliability and resiliency. The more resources available, and the higher the range of diversity of them, the more reliable and resilient the energy system will be, as a general proposition.

Q. Are there economic benefits related to the investment, in terms of employment?

A. Yes. The RNG Project investment requires the deployment of highly skilled workers. PSE&G has estimated an average of 229 jobs/year will be created because of the construction activity of the RNG Project.

Q. Are there other benefits associated with the CBA?

A. Yes. As explained in the CBA report, PSE&G has an interest in securing and delivering low carbon fuels to its customers. The RNG Project is an important first step in this goal. There are additional pathways that PSE&G could potentially leverage to support low carbon fuels in the service of decarbonization. As we noted very early in the testimony, the RNG Project has four general mechanisms. The fourth identifies the condition of "right program arrangements" whereby customers might participate directly in decarbonization. PSE&G sees opportunities for regulatory innovation in this area. Such mechanisms might provide customers a direct form of participation in decarbonizing measures if properly structured.

Comparing Costs and Benefits

Q. How did you compare all costs and benefits?

A. As identified in our testimony, the CBA is based on two well-defined scenarios, the RNG Project and the alternative BAU scenario. There is a present value net benefit of $0.9M, which takes into account the revenue requirements of the costs and the flow through of certain monetary benefits. It is based on the agreement structure that PSE&G has arranged with the MCUA in support of this Project.

This value – of returning all costs and yielding a neutral revenue requirement result – does not consider the additional value assignable to qualitative benefits, such as the reductions in direct site emissions, and the reduction in GHG emissions. Moreover, the result does not consider additional value creation because of the incremental net benefits to MCUA, which are largely unaddressed in our CBA and testimony. As we have noted, the CBA does not speculate on the specific costs and avoided costs that MCUA may experience due to the RNG Project. PSE&G has been informed by the MCUA that the Project offsets its separate, unique, and incremental costs.

The fact that benefits are identified as qualitative in nature as part of the CBA does not mean that for purposes of a CBA they should be discounted or, worse, set aside. This is particularly relevant to the important emission reduction benefits (both criteria air pollutants at the CTP and reductions in GHG). It simply means it may not be practical or feasible to assign a point estimate monetary value to the benefit, for purposes of integration into the CBA economic evaluation alongside quantified and monetized costs and benefits.

Q. Does this conclude your testimony?

A. Yes.

SCHEDULE INDEX

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COST-BENEFIT ANALYSIS

Renewable Natural Gas Project
Schedule ATSH-GSMPIIIRNG-1

Prepared for
Public Service Electric & Gas Company
February 17, 2023

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ACRONYMS AND DEFINITIONS

Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
BAU	Business as Usual
BCF	Billion Cubic Feet
BGSS-RSG	Basic Gas Supply Service – Residential Service Gas
BPU	New Jersey Board of Public Utilities
CAGR	Compound Annual Growth Rate
CBA	Cost-Benefit Analysis
CEF	PSE&G Clean Energy Future Proposal
CI	Carbon Intensity
CO_2e	Carbon Dioxide Equivalent
Company	Public Service Electric & Gas Company
CTP	MCUA’s Central Treatment Plant in Sayreville, NJ – proposed site of RNG facility
EA	Environmental Attribute
EMP	Energy Master Plan
EPA	[United States] Environmental Protection Agency
ER&T	PSEG Energy Resources & Trade LLC
GHG	Greenhouse Gas Emissions
GSMP	Gas System Modernization Program
IIP	Infrastructure Investment Program
IWG	Interagency Working Group (a collection of federal agencies)
JCP&L	Jersey City Power and Light
LCFS	Lower Carbon Fuel Standard
LFG	Landfill Gas
MCUA	Middlesex County Utilities Authority

MMBtu	Million British Thermal Units – for gas energy measurement
MOU	Memorandum of Understanding
MSW	Municipal Solid Waste
N.J.A.C.	New Jersey Administrative Code
NOx	Nitrogen Oxides
NSPM	National Standard Practice Manual (for Distributed Energy Resources)
NPV	Net Present Value
O&M	Operations and Maintenance
PM2.5	Particulate Matter (2.5-micron diameter and smaller)
PSE&G	Public Service Electric & Gas Company
PSEG	Public Service Enterprise Group (PSE&G Parent Company)
PV	Present Value
REC	Renewable Energy Credits
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	Renewable Natural Gas
RNG-CI	Renewable Natural Gas Collaborative Initiative
RTC	Renewable Thermal Credit
QAP	EPA’s Quality Assurance Program
Q-RIN	QAP-verified RIN
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SCFM	Standard Cubic Feet Per Minute
SME	Subject Matter Expert
SOx	Sulfur Oxides
UCT	Utility Cost Test

VOC	Volatile Organic Compounds
WACC	Weighted Average Cost of Capital
WMP	West Monroe Partners, LLC

Foreword

West Monroe Partners, LLC., (hereinafter referred as "WMP") was retained by PSE&G to perform and document a cost-benefit analysis ("CBA") for the proposed Renewable Natural Gas (RNG) Project. The RNG Project forms an element of the Company's Gas System Modernization Program Phase III ("GSMP III").

This report is intended to accompany PSE&G's RNG Project engineering report and to support the satisfaction of various filing requirements related to cost-benefit analysis for an eligible Infrastructure Investment Program ("IIP"), as established as part of the New Jersey Administrative Code.

WMP worked with PSE&G, MCUA, and Burns & McDonnell gas system planners, engineers, and financial analysts to review the RNG facility design basis, investment plans, program goals and assumptions, to structure an appropriate scenario-based framework for the CBA, to gather and document initiative costs and related assumptions, to identify and classify key benefits, and to quantify and monetize benefits, where practical and feasible.

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Executive Summary

Public Service Electric and Gas Company ("PSE&G") is New Jersey's largest utility, serving approximately 2.3 million electric and 1.9 million natural gas customers. The Company sources and distributes approximately 323 billion cubic feet (BCF) of natural gas yearly as part of its service obligations to its customers.[1] PSE&G and its parent company PSEG are committed to providing safe, reliable, and affordable natural gas service. The Company is also committed to reducing its Scope 1 carbon emissions (direct emissions) as well as taking prudent, reasonable, and timely actions to reduce indirect Scope 2 and 3 emissions.[2] Such actions are in accordance with the Company's environmental and sustainability goals, and business and investment policies.

This cost-benefit analysis ("CBA") identifies and estimates the costs and benefits of PSE&G's proposed Renewable Natural Gas ("RNG") Project. This Project is a collaborative effort between PSE&G and the Middlesex County Utilities Authority ("MCUA"). PSE&G proposes to build, own, operate, and maintain RNG-related facilities at MCUA's Central Treatment Plant ("CTP") in Sayreville, NJ. This facility will upgrade landfill gas ("LFG") to pipeline quality standards and inject it into the PSE&G gas distribution network. Key benefits of the Project include reducing Scope 3 emissions by providing a source of natural gas with a lower carbon intensity. As part of the air permitting and air quality analysis, the project will also reduce direct criteria air pollutant emissions (NOx, SOx, PM, etc.) at the CTP by installation of modern gas processing facilities and decommissioning the CTP's existing (but aging) combustion equipment.[3] Note, decommissioning of the aging combustion equipment is not monetized within the CBA, but this assumption was made as part of the air permitting and netting analysis. These outcomes are achieved at no incremental revenue requirement over the estimated useful life of the facilities.

The basic mechanisms of the RNG Project are straightforward and involve four components. First, investment in a low carbon fuel can unlock value for the fuel's Environmental Attributes ("EAs"). Second, these EA's have recognized market value and therefore a source of revenues that can offset investment costs. Third, the investment in the low carbon fuel production creates a mechanism to reduce GHG emissions (through the retirement of the existing CTP combustion

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[1] PSEG 2021 BPU Annual Report. pp. 520, https://nj.pseg.com/-/media/pseg/global/gathercontentdocuments/8-4-5-bpuannualreports/2021-bpu-annual-report-public.ashx

[2] Scope 1, 2 and 3 emissions refer to direct operations emissions, indirect energy use emissions, and all other indirect upstream and downstream emissions of a company, respectively. These are defined by the WRI/WBCSD in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. https://ghgprotocol.org/corporate-standard

[3] The estimate of the decrease in direct emissions is based on a PSE&G/Burns & McDonnell netting analysis that considers current (BAU) conditions and future RNG project activities, for both MCUA and PSE&G CTP sources.

equipment, and the upgrading of gas processing facilities). Fourth, under the right program arrangements, customers can participate directly in decarbonization as a result. These four components form the basis of PSE&G's RNG Project.

MCUA currently collects and pipes LFG seven miles from its East Brunswick Municipal Solid Waste ("MSW") facility to the CTP. At the CTP, the MCUA carries out partial treatment of the LFG. The CTP also uses the 'brown gas' (after desulfurization) to meet the CTP's electrical load requirements by operating a power station on site. MCUA has determined that the generating station requires replacement due to its age and operating performance. As part of the RNG Project, MCUA will transfer the custody of the LFG to PSE&G at the CTP before it is treated. The new PSE&G gas upgrade facility will then produce RNG to pipeline quality standards and inject it into the PSE&G gas distribution network. PSE&G has sized the RNG plant to accept and treat a maximum of 6,000 SCFM of LFG. PSE&G's plan is for the RNG facility to be in-service on December 1, 2026.

The CBA results include the value of the sale by PSE&G of RNG-related environmental credits, known as Renewable Identification Numbers ("RINs"). In the context of the PSE&G RNG Project, each RIN represents a certain energy quantity of RNG. RINs are used within U.S. transportation fuels markets to help meet federal Clean Air Act compliance requirements. Their use was established by the U.S. EPA as part of the Renewable Fuel Standard ("RFS") two decades ago.[4] The registration and verified use of RINs provides a recognized pathway for fuels markets to meet formal, mandatory, environmental compliance obligations.[5] The generation and sale of the RINs are expected to offset a portion of the costs for building and operating the facility.

Capital costs support the design, engineering, procurement, construction, testing and commissioning of the facilities needed to generate the RNG for purposes of injecting it into the PSE&G gas distribution system. The CBA also includes estimates of the O&M costs for operating

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[4] "The Renewable Fuel Standard (RFS) program was created by the Energy Policy Act of 2005 (EPAct), which amended the Clean Air Act (CAA). The Energy Independence and Security Act of 2007 (EISA) further amended the CAA by expanding the RFS program. EPA implements the program in consultation with U.S. Department of Agriculture and the Department of Energy." https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard. Due to the expansion, it is sometimes referred to as "RFS2".

[5] The federal RFS establishes a mechanism to create RINs to support CAA compliance for certain obligated parties such as transportation fuel producers. RINs are used by obligated parties to demonstrate compliance with the RFS volume-based standard. Obligated parties must obtain sufficient RINs in an extended one-year period to demonstrate compliance with its annual obligation. A 50-state market exists to qualify, register, and trade RINs, in support of compliance obligations. RINs are classified by fuel producer type (such as ethanol), feedstock (that generates the renewable fuel), and production process used to convert the feedstock to the renewable fuel. Separate RIN "D" codes are used to designate unique pathways which are assessed and qualified by the US EPA. Four "D" codes are typically considered renewable – D3, D4, D5, and D6. D3 is the highest quality renewable fuel. PSE&G's RNG Project is based on RNG production that the Company, in consultation with Burns & McDonnell, has concluded qualifies for D3 RIN, which includes processes that convert cellulosic biomass to fuel.

the RNG facility over its estimated useful life. These costs are described at a high level within the Costs section. As identified in the Benefit Valuation subsection, savings are achieved by the sale of RNG and of the associated RINs. The details of the physical changes at the CTP as part of this initiative are highly relevant to the CBA and are described in both the CBA and in much greater detail within the Company's Engineering Report Design Basis, dated February 14, 2023, prepared by PSE&G's engineering consultant Burns & McDonnell.

Certain CBA assumptions are based on terms established as part of a recently completed Memorandum of Understanding ("MOU") between PSE&G and MCUA. The Project will require continued collaboration between PSE&G and MCUA to fulfill the MOU's goals. The MOU provides the basis to negotiate a formal agreement to allow for sharing of revenues from the sale of gas and RINs (or other environmental attributes over time).

As presented within the Comparison of Costs and Benefits section, the present value revenue requirement of the RNG Project is estimated to be $270M, offset by equivalent monetized benefits of $270M. Thus, the benefits are anticipated to fully offset the revenue requirements.

It is significantly important to the CBA to recognize that there will be non-monetized benefits that are not reflected in the strictly financial result (in this case of net revenue requirements). These include the reduction in the criteria air emissions at the site, the reduction in total GHG emissions (natural gas compared to the RNG, as determined through a lifecycle analysis), local community benefits due to direct emission reductions, and the benefits of supporting MCUA's operations by providing a means for beneficial use of LFG over the next two decades. The RNG Project also provides a possible pathway that PSE&G's gas customers may directly benefit from decarbonization. Project benefits and discussion are provided in the Benefit Valuation section.

In summary, the PSE&G RNG Project represents a unique and valuable opportunity for the New Jersey region to secure and mitigate methane from landfill gas in a cost-effective way over the long term. Moreover, the US EPA recognizes RNG as a viable source of D3 RINs for the RFS compliance market. Revenues from participation in this market provide one of the mechanisms to support the Project in such a way that does not increase PSE&G customer revenue requirements.

Introduction

Public Service Electric and Gas Company ("PSE&G") is New Jersey's largest utility, serving approximately 2.3 million electric and 1.9 million natural gas customers. The PSE&G natural gas distribution system infrastructure includes approximately 35,600 miles of mains and services. The Company sources and distributes approximately 323 BCF of natural gas to its residential, commercial, and industrial customers annually.

PSE&G – and its parent company PSEG – are committed to the safe, reliable, and affordable sourcing and distribution of natural gas. PSE&G is also committed to reducing its Scope 1 carbon emissions (direct emissions) as well as taking prudent, reasonable, and additional actions, when cost-effective and feasible, to reduce indirect Scope 2 and 3 emissions.[6] Such actions are in accordance with PSEG's environmental and sustainability goals, and business and investment policies.

This cost-benefit analysis ("CBA") identifies and estimates the costs and benefits of PSE&G's proposed Renewable Natural Gas ("RNG") Project. RNG is a renewable and low carbon fuel which can be substituted for natural gas. PSE&G has planned the RNG Project in such a way to minimize incremental PSE&G customer costs – this is accomplished through an innovative agreement between PSE&G and the Middlesex County Utilities Authority ("MCUA"); the Project includes the sale of RNG-related credits – known as RINs – that are monetized in an important federal transportation fuels market associated with meeting Clean Air Act compliance requirements. [7]

As part of the RNG Project, PSE&G proposes to construct and operate facilities at MCUA's Central Treatment Plant ("CTP") for the purposes of upgrading landfill gas ("LFG") to pipeline quality standards and then injecting it into the PSE&G gas distribution network. As a general proposition, when customers are afforded the opportunity to use RNG to heat homes, power businesses, or fuel vehicles they do so while capturing and destroying methane otherwise

[6] Scope 1, 2 and 3 emissions refer to direct operations emissions, indirect energy use emissions, and all other indirect upstream and downstream emissions of a company, respectively. These are defined by the WRI/WBCSD in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. https://ghgprotocol.org/corporate-standard

[7] "The Renewable Fuel Standard (RFS) program was created under the Energy Policy Act of 2005 (EPAct), which amended the Clean Air Act (CAA). The Energy Independence and Security Act of 2007 (EISA) further amended the CAA by expanding the RFS program. EPA implements the program in consultation with U.S. Department of Agriculture and the Department of Energy." https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard. Due to the expansion, it is sometimes referred to as "RFS2".

released to the atmosphere at landfills and other locations.[8] For this reason, the U.S. EPA and other state agencies recognize RNG for its air quality improvements and GHG reduction benefits. Further, U.S. EPA governs the Renewable Fuel Standard ("RFS") and Renewable Identification Number ("RIN") market, which enables the Project to generate and earn revenue credits from the environmental attributes of produced RNG.

The RNG Project has several principal benefits, including (a) reductions in criteria air pollutant emissions at the CTP site ("direct site emissions" in the CBA), and (b) reductions in GHG due to upgrading CTP-related facilities (based on a lifecycle emissions analysis). By using locally produced gas, PSE&G's customers can participate in decarbonization with the knowledge that natural gas sourced upstream of the region is being displaced with a local energy source. Projects like this also enable PSE&G to potentially provide pathways for its customers to participate directly in low carbon fuel-driven decarbonization.

The RNG Project's revenues are driven by the sale of RNG to PSEG's Energy Resources & Trade ("ER&T") for inclusion in BGSS-RSG[9] supply and the sale of the qualified RINs through the process of producing and distributing the RNG.[10] Moreover, as explained in the CBA, the investment is estimated to be fully offset by savings over the life of the Project.

PSE&G and MCUA have identified ways the RNG project provides mutual gains for their respective customers, many of whom overlap. This Project provides a mechanism by which both entities can provide leadership within the growing RNG market. Many CBA assumptions are based on terms contained within a recently concluded Memorandum of Understanding ("MOU") between PSE&G and MCUA. The MOU provides for a sharing mechanism for the revenues from the RIN sales. Lastly, the Project will require continued collaboration between PSE&G and MCUA throughout its pursuit.

Structure and Scope of the CBA

The CBA describes the costs and benefits of the RNG Project scenario over the project's lifetime, in relation to a *Business as Usual* ("BAU") scenario, which does not contemplate changes at the CTP. These two scenarios are compared in the CBA to estimate the incremental changes from BAU conditions over the forecast horizon.

The basis for the costs and benefits are identified and explained in the CBA, and many if not most are substantiated in PSE&G's Design Basis and engineering report prepared by Burns &

[8] The methane is destroyed as part of combustion by end users, by virtue of it being converted to useful energy and combustion waste products, which are methane to useful energy, and combustion waste products of (primarily) CO_2 and water.
[9] BGSS-RSG (Basic Gas Supply Service) is PSE&G's default gas supply service for its residential customers.
[10] PSE&G will also pursue the use of federal investment tax credits (ITC) established in recent federal environmental law, however, project eligibility cannot be determined until approval and permitting requirements and associated timelines are known.

McDonnell. The details of the physical changes planned at the MCUA's CTP are highly relevant to the CBA and are described in detail within the Company's Design Basis Engineering Report.

IIP-related investment capital will support the design, engineering, procurement, construction, testing and commissioning of the facilities needed to generate the RNG for purposes of injecting it into the PSE&G gas distribution system. There are also requirements (and minor costs) associated with verifying and qualifying the environmental attributes of the RNG to create the RINs and facilitate their sale. The CBA also summarizes estimates of the operations and maintenance cost of running the RNG facilities over the estimated useful life.

Regarding the structure of the CBA, benefits include several quantified and qualitative benefits. An example is the reduction in the direct site emissions, which are quantified but have no specific monetary value is assigned to them. Additionally, costs and benefits are aligned in time and compared in terms of their nominal dollar and present value sums. West Monroe also worked with the PSE&G financial and rate subject matter experts to translate the nominal dollar 'cash flows' into revenue requirement equivalents.

The CBA also includes a sensitivity analysis, a discussion on Alternatives considered by PSE&G, and background on the RNG-driven credit market (for RINs), which is the basis of offsetting many of the RNG Project costs.

Role of RNG in Decarbonization

The Context of Methane Emission Reduction Opportunities for PSE&G

PSE&G's interest in the RNG Project is directly related to its active focus on programs and investments that support the State of New Jersey in its decarbonization goals.

Identifying and reducing sources of methane emissions – an important source of greenhouse gas ("GHG") emissions – are primary activities of PSE&G. The Company performs methane control and emission reduction activities in relation to a range of policy and business compliance and reporting obligations. For example, and as described elsewhere in PSE&G's reports and testimonies, the purposes of the GSMP III investment in gas mains and services (and related assets) include reducing its reported USEPA 40 CFR 98, Subpart W emissions. The reductions are estimated to be achieved due to the higher performance standard of the new assets slated for installation, as compared to those being removed from service.

PSE&G's focus can be aligned to the three different scopes of GHG emissions.[11] In the case of the GSMP III, PSE&G expects to reduce its Scope 1 emissions. These are direct emissions from Company activities. PSE&G also pursues reductions in its Scope 2 and 3 emissions.[12] Scope 3 emissions are value chain emissions associated with the direct consumption of natural gas by customers.[13] The RNG Project is designed to reduce Scope 3 emissions.

State Policy Drivers

New Jersey policy is a driver for PSE&G's focus and actions on reducing CO_2e from its operations. It consists of legislatively established goals, Executive Orders, and energy master planning.

In 2007, the State of New Jersey, as mandated through the Global Warming Response Act, set a goal to reduce the statewide greenhouse gas emissions and greenhouse gas emissions from electricity generated outside the state but consumed in the State by 80% from its 2006 levels by

[11] The Scope emissions framework is supported by the U.S. EPA. It is embodied in the GHG Protocol, which "establishes a comprehensive global, standardized frameworks to measure and manage GHG emissions from public and private sector operations, value chains, and mitigation actions." See: https://ghgprotocol.org/about-us.

[12] Scope 2 emissions are the Company's indirect GHG emissions. For example, Scope 2 emissions result from the Company's use of electricity for its buildings and gas metering stations.

[13] "Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly affects in its value chain. Scope 3 emissions include all sources not within an organization's Scope 1 and 2 boundaries. The Scope 3 emissions for one organization are the Scope 1 and 2 emissions of another organization. Scope 3 emissions, also referred to as value chain emissions, often represent the majority of an organization's total greenhouse gas (GHG) emissions." See the U.S. EPA website: https://www.epa.gov/climateleadership/scope-3-inventory-guidance

2050.[14] By 2018, New Jersey had reduced its emissions to 20% below 2006 levels. This reduction was driven largely by the rapid transition away from coal-powered electricity generation to cleaner burning natural gas.[15]

In May 2018, New Jersey Governor Phil Murphy signed Executive Order ("EO") No. 28, directing the New Jersey Board of Public Utilities to develop a statewide clean energy plan to aid the state and its residents and businesses in a shift away from energy production that contributes to climate impacts.[16] Additionally, following the EO, the Governor unveiled the state's 2019 Energy Master Plan ("EMP"), which identified several key strategies to reach the Administration's goal of 100% clean energy by 2050.

Because continued progress on meeting state goals requires significant reductions across all sectors of the state's economy, the state's energy sector requires greater levels of energy efficiency, and greater use of renewable energy than provided in today's fossil fuel-heavy resource mix. (Notable for this project, RNG is recognized as a renewable fuel). Accordingly, the 2019 EMP is built around seven key strategies:[17]

1. Reducing energy consumption and emissions from the transportation sector
2. Accelerating deployment of renewable energy and distributed energy resources
3. Maximizing energy efficiency and conservation and reducing peak demand
4. Reducing energy consumption and emissions from the building sector
5. Decarbonizing and modernizing New Jersey's energy system
6. Supporting community energy planning and action with an emphasis on encouraging and supporting participation by low- and moderate-income and environmental justice communities
7. Expanding the clean energy innovation economy

The RNG Project intersects several of these strategies.

In 2020, the Energy Master Plan's ("EMP") initiatives were further reinforced by the signing of Executive Order No. 100. The order, titled Protecting Against Climate Threats ("PACT"), directs the N.J. Department of Environmental Protection to make regulatory reforms to reduce GHG emissions and adapt to climate change.[18]

In addition to the EMP's strategic directions, in 2019 New Jersey rejoined the multi-state Regional Greenhouse Gas Initiative ("RGGI").[19] RGGI is a multi-state emissions allowance cap and investment program that requires fossil fuel power plants with a capacity greater than 25 megawatts to obtain an allowance for each ton of CO_2 emitted annually. Proceeds from

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[14] https://www.nj.gov/dep/aqes/docs/gw-responseact-07.pdf
[15] https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf
[16] https://www.nj.gov/emp/energy/
[17] https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf
[18] https://nj.gov/infobank/eo/056murphy/pdf/EO-100.pdf
[19] https://www nj.gov/dep/aques/rggi.html

purchase and sale of CO_2 allowances are invested in programs to help reduce greenhouse emissions.[20] RGGI does not have a bearing on the PSE&G gas distribution business and its operations, but it is noted here because it forms another component of state's energy policy, which is heavily focused on initiatives to help the state and the region in its decarbonization efforts.

In 2022, the NJ BPU accepted a study of natural gas capacity in New Jersey performed by London Economics International LLC.[21] This report found that gas capacity is ample to meet demand (including extreme weather cases) through 2030 without adding gas pipelines if the State can implement non-pipeline alternatives. Accordingly, locally produced RNG is identified within the Study as one of the supply-side non-pipeline solutions that local gas distribution companies ("GDCs") should pursue to support system reliability.

Sustainability Drivers

PSEG pledged and started progress towards greenhouse gas reduction goals. In 2019, PSEG announced its Net-Zero Climate Vision[22] to achieve "net-zero" by 2050.[23] In 2021, PSEG accelerated its Net-Zero Climate Vision with the goal to achieve net-zero by 2030.[24] These goals cascade down to PSEG's operating companies, including the PSE&G's gas operations.[25]

PSEG's climate vision as embodied in the Net-Zero Climate Vision, is comprised of three pillars:

1. Net-zero emissions for PSEG operations, including PSE&G's utility operations (Scopes 1 and 2)
2. 100% greenhouse gas (GHG), carbon-free power generation
3. Significant contributions to regional economy-wide decarbonization.

Furthermore, on October 15, 2021, PSEG joined the *Business Ambition for 1.5°C* and the *Race to Zero* campaigns.[26] As part of this later campaign, PSEG also expressed its commitment to the

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[20] https://www.nj.gov/dep/aqes/rggi.html
[21] https://www.nj.gov/bpu/pdf/boardorders/2021/20211215/9B%20LEI%20Final%20Gas%20Capacity%20Report%2011%2005%202021%20Public%20Redacted.pdf
[22] See: https://nj.pseg.com/newsroom/newsrelease100
[23] "Net zero" refers to Scope 1 and 2 emissions, with any residual emissions post-2030 balanced by the purchase of carbon offsets.
[24] The primarily means to reach this goal is through the divestiture of PSEG fossil generation assets in 2022. See: https://nj.pseg.com/newsroom/newsrelease231
[25] In their *2021 Sustainability and Climate Report*, the Company lists gas system modernization, reduced fossil fuel use through fleet electrification/right-sizing and renewable fuels, and energy efficiency improvements as key focus areas to achieve net-zero goals. See: https://corporate.pseg.com/-/media/pseg/corporate/corporate-citzenship/environmentalpolicyandinitiatives/sustainability/pseg_sustainability_report.ashx
[26] See: https://www.prnewswire.com/news-releases/pseg-joins-un-race-to-zero-initiative-commits-to-setting-science-based-emissions-reduction-targets-301401186.html

development of science-based emission targets. *The Race to Zero* and *Business Ambition for 1.5°C* campaigns are designed to mobilize support from businesses, cities, regions, and investors for programs and initiatives that contribute towards a healthy and resilient zero-carbon economy (in line with global efforts to limit warming to 1.5°C).

PSE&G Activities

A primary focus of PSE&G's decarbonization strategy is to reduce the Scope 1 GHG emissions from its electric and gas utility operations, including methane emissions, combustion sources across the PSE&G's operations and vehicle fleet. PSE&G will do so through the modernization of its natural gas and electric transmission and distribution networks and by investing in new technologies and programs that enable electrification and improve energy efficiency.[27]

Promoting and encouraging energy efficiency is a core component of PSE&G's decarbonization initiatives. PSE&G is a founding member of the EPA's Natural Gas STAR program[28], a voluntary initiative that encourages natural gas companies to adopt technologies and practices that reduce methane emissions in a cost-effective way.[29] Also, in 2018, PSE&G submitted a progressive proposal, Clean Energy Future ("CEF"), to invest in energy efficiency, advanced metering, electric vehicles, and energy storage programs. In 2020, the NJ BPU approved the central component of CEF, a $1 billion investment in energy efficiency programs. PSE&G's energy efficiency program aims to help customers reduce their energy use – with targets of $1 billion in utility bill savings and an eight (8) million metric ton reduction in carbon dioxide emissions.[30]

PSE&G has also received approval of an electric vehicle program, which aims to increase customer awareness and build out EV charging infrastructure; PSE&G estimates that this will contribute an additional 14 million metric ton reduction of carbon emissions through 2035.[31] PSEG is also seeking to further reduce vehicle emissions through electrification of its own fleet. These programs, like GSMP, demonstrate a continuous commitment to address climate change and environmental justice.

Role of RNG

[27] PSE&G has also described significant energy efficiency-related reductions in CO_2e, as part of its Clean Energy Future proposals and programs. Many of these emissions are from customer activities, and so they represent the Company's Scope 3 emissions.

[28] "The Natural Gas STAR Program provides a framework for Partner companies with U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities. By joining the Program, Partner companies commit to evaluate and implement cost-effective methane emission reduction opportunities and communicate and share that information across their corporation and with the Natural Gas STAR Program." – U.S. EPA

[29] See: https://corporate. PSE&G.com/-/media/ PSE&G/corporate/corporate-citzenship/environmentalpolicyandinitiatives/sustainability/ PSE&G_sustainability_report.ashx

[30] See: https://poweringprogress.pseg.com/energy-efficiency/

[31] See: https://poweringprogress.pseg.com/wp-content/uploads/2022/01/EV-Advocacy-Fact-Sheet_JAN_2021-1-Copy.pdf

RNG represents a renewable energy source and PSE&G believes it should and will play an important and growing part of its decarbonization activities. By capturing methane and converting it to useful energy and end use combustion products (mainly CO_2 and water vapor), total CO_2e is reduced. This basic mechanism is at the core of the US EPA's recognition of RNG as a carbon neutral energy source. It is worth quoting from the US EPA to explain the basic conversion mechanism:

> "Raw biogas has a methane content between 45 and 65 percent, depending on the source of the feedstock, and must go through a series of steps to be converted into RNG. Treatment includes removing moisture, carbon dioxide (CO_2) and trace level contaminants (including siloxanes, volatile organic compounds, or VOCs, and hydrogen sulfide), as well as reducing the nitrogen and oxygen content. Once upgraded, the gas has a methane content of 90 percent or greater. Typically, RNG injected into a natural gas pipeline has a methane content between 96 and 98 percent" […] "RNG projects capture and recover methane produced at a landfill or anaerobic digestion (AD) facility. Methane has a global warming potential more than 25 times greater than CO_2 and a relatively short (12-year) atmospheric life, so reducing these emissions can achieve near-term beneficial impacts in mitigating global climate change".[32]

[32] See: https://www.epa.gov/lmop/renewable-natural-gas

RNG Technical and Market Background

The Environmental Attributes of RNG

Underpinning the PSE&G RNG Project's costs and benefits is the fact that the RNG's production and use can be associated with certain RNG-related environmental attributes ("EA"), which in turn have monetary value as part of the United States transportation fuels market.[33] This value is tied to federal policy and the U.S. EPA's administered Renewable Fuel Standard ("RFS") program. The CBA has used the descriptor "RNG credits" to capture the meaning of this value. The specific credit in this instance are RINs (introduced and described earlier).

Because of the importance of the RINs to the CBA, this section provides background about the RFS, and the nature of these RIN credits in relation to the specific renewable fuel that PSE&G intends to produce and distribute. First, the legal foundation of the RFS is established in the federal Clean Air Act, the Energy Policy Act ("EPAct") of 2005, and the Energy Independence and Security Act of 2007: The U.S. EPA explains:

> Congress created the renewable fuel standard (RFS) program to reduce greenhouse gas emissions and expand the nation's renewable fuels sector while reducing reliance on imported oil. This program was authorized under the Energy Policy Act of 2005 and expanded under the Energy Independence and Security Act of 2007. – U.S. EPA https://www.epa.gov/renewable-fuel-standard-program

The RFS requires that transportation fuels produced by domestic refiners, fuel importers, and fuel exporters contain a minimum volume of renewable fuel.[34] As a general matter, the U.S. EPA has determined that if the renewable fuel is blended into the nonrenewable fuel, then the end user's fuel combustion is cleaner, with a lower GHG impact. These requirements are established for each fuel category, such as diesel or gasoline. Each year the US EPA determines and announces the volume and percentage blend of renewable fuels (by category) that are required

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[33] "Environmental attributes" means any and all environmental claims, credits, benefits, emissions reductions, offsets, and allowances attributable to the production of renewable natural gas and its avoided emission of pollutants. The environmental attributes of renewable natural gas include, but are not limited to, the avoided greenhouse gas emissions associated with the production, transport, and combustion of a quantity of RNG compared with the same quantity of natural gas.

[34] The description of the RFS requirements draws the U.S. EPA website that provides a comprehensive description of the RFS. https://www.epa.gov/renewable-fuel-standard-program. It also draws on CRS Insight, (IN10576). Renewable Identification Numbers (RINs) and Renewable Fuel Standard (RFS) Compliance. December 16, 2016. Kelsi Bracmort.

in the market. The goal is to match end use requirements with the volume and blend percentage supplied during the compliance period, which is an annual requirement.[35]

The compliance obligation (expressed in terms of gallons, percentage blend volume, by fuel category) is technically known within the RFS as the Renewable Volume Obligation ("RVO").[36] It applies to the forementioned obligated parties: fuel importers, exporters, and producers. Under the RVO, the RFS requires that each obligated party must sell a certain volume of renewable fuel based on the company's total fuel sales.[37]

The RVO compliance requirement must be met by the obligated party either by blending sufficient quantities of renewable fuel into their product or by submitting credits to the U.S. EPA as an alternative means of compliance. The credits are known as Renewable Identification Numbers, or RINs. It has this label because fuel volumes produced and transported are identified, verified, and tracked to point of distribution and sale with numbers as part of the compliance reporting apparatus. In fact, the RFS is designed to ensure that the blended fuel makes its way to the end user. The RINs are tradeable credits, and there has been an active market for RINs for many years.

There are options for meeting compliance: the fuel producer or importer can contract directly with counterparties to secure renewable fuels for blending purposes, produce it themselves, or secure RIN credits to meet their compliance obligation as an alternative. The RIN credits ensure that elsewhere in the renewable fuel value chain a renewable fuel has been produced and used, and therefore the producer or importer can secure and retire the credits in fulfillment of the RFS requirements.

In the case of PSE&G's RNG Project, its goal is to produce and distribute RNG to its distribution system customers in New Jersey (displacing natural gas) and separate this credit attribute from the fuel volume, certify the volume for participation in the RIN market, and sell the credits. This method directly supports the third compliance pathway listed above. The RIN credit revenue is then applied to lower RNG Project costs which flow through the PSE&G revenue requirement. As noted in the CBA, this revenue is expected to be one of the benefits that partially offset the costs of the RNG Project.

Pathways and D-Codes

RINs have specific codes, known as D-codes, which are determined by the "pathway" of the renewable fuel. The Company has determined that the RNG product will generate "D3" RINs. The pathways have three attributes: feedstock, production process and fuel type, as established by the U.S. EPA:

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[35] The RFS has provisions and flexibility to extend the annual period's compliance requirements.
[36] The RFS applies to fuel producers and importers operating in 49 states. Alaska is exempt.
[37] See: https://afdc.energy.gov/laws/RIN.html

> A renewable fuel pathway includes three critical components: (1) feedstock, (2) production process and (3) fuel type. Each combination of the three components is a separate fuel pathway. Qualifying fuel pathways are assigned one or more D codes representing the type of Renewable Identification Number (RIN) (i.e., renewable fuel, advanced biofuel, biomass-based diesel, cellulosic biofuel or cellulosic diesel) they are eligible to generate.[38]

To appreciate the D-codes, and the D3 status of the RNG Project fuel, note that the RFS program establishes four categories of renewable fuel and several related D-codes in relation to the pathways: Advanced Biofuel (D-code 5), biomass-based Diesel (D-code 4), Cellulosic Biofuel (D-code 3 or 7) and Renewable Fuel (D-Code 6). The D3 designation is within the Cellulosic Biofuel category. EPA defines this category as a renewable fuel produced from cellulose, hemicellulose, or lignin. Additionally, the pathway must reduce lifecycle greenhouse gas emissions by at least 60% compared to the petroleum baseline.[39] Notably, most landfill-derived gas qualifies for D3 classification.

Appendix B – Selected Reference Material Excerpts provides a summary table extracted from a similar data table from the U.S. EPA on the several D3- related pathways. The Company has determined that the RNG Project qualifies through Pathway Q.

Steps in RIN Monetization

The fuel producer or importer go thru several steps to show RFS compliance. The general steps are modified here to explain their relationship to the RNG Project:

1. Prior to the routine injection and use of the RNG, and prior to the monetization of RINs, PSE&G will work with an engineering partner to establish the quality of the fuel pursuant to RFS requirements. This work occurs during the latter part of the construction period, and during the first instances (months) of RNG production. This is a critical step in the RIN value creation process.
2. PSE&G will produce a batch of renewable fuel, in this case RNG. In the case of the RNG, the production process is continuous, excepting for times of RNG plant downtime for normal maintenance or unexpected outages.[40] PSE&G will meter the RNG as it is injected into the distribution system.
3. PSE&G will separate the RIN (the environmental attribute) from the RNG product. (This is a paperwork separation, not a physical one). The RINs are assigned to "batches" of

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[38] See: https://www.epa.gov/renewable-fuel-standard-program/what-fuel-pathway
[39] See: https://www.epa.gov/renewable-fuel-standard-program/what-fuel-pathway
[40] PSE&G's design basis has made careful assumptions about the RNG plant's expected utilization, taking into account maintenance and other outage circumstances.

renewable fuel. PSE&G will establish an apparatus to carefully record and track the RINs, tied to the RNG production and injection into the system.[41]

4. The RNG, valued at a market index, would be incorporated into PSE&G's BGSS-RSG portfolio. As an internal matter, PSEG's ER&T (for inclusion in BGSS-RSG supply) will financially credit the RNG Project with a value equal to the RNG production, valued at a Transco-Leidy reference price.
5. PSE&G will sell the separated RINs to support obligated parties' RVO. PSE&G will have many options for how it will sell the RINs, under a variety of contractual arrangements. The RIN market involves many potential counterparties, including fuel producers, importers, gas storage and upstream gas companies, fuel end users, and RIN market brokers and marketers.
6. Ultimately the obligated party – the fuel producer or importer – will take custody of the RINs and use them to meet its RVO. They will submit the RINs to the U.S. EPA to satisfy RVO compliance requirements.[42]

For additional context purposes, there is a growing ecosystem of sophisticated marketers and brokers who are involved in the RINs and related environmental offset and credit markets. Their services include connecting counterparties who produce or require a range of environmental products, including carbon credits, air emission credits (e.g., SOx, NOx), EV credits, and Renewable Energy Credits ("RECs"). They also engage in a wide range of advisory and compliance services.

PSE&G has not identified its specific path to market yet for the RINs, but it has estimated its costs to qualify the RINs and market them through intermediaries, or to engage in other forms of exchange that may fit well with PSE&G's needs. It recognizes that there will be a need in the

[41] The RFS establishes both Assigned RINs and Separated RINs, for purposes of market support. Assigned RINs are directly associated with a batch of fuel and travel with the fuel. PSE&G's project would sell Separated RINs.

[42] From the U.S. EPA: The EPA created a RIN tracking system—the EPA Moderated Tracking System (EMTS)—to track RFS compliance of obligated parties. The RIN is a 38-character number assigned to each physical gallon of renewable fuel produced or imported. Obligated parties must register with EPA and comply with RIN record and reporting guidelines on a quarterly basis. Under the physical arrangements whereby the fuel producer complies by taking custody of the renewable fuel for blending purposes, the RIN is attached to the physical gallon of renewable fuel as it is transferred to a fuel blender. After blending, RINs are separated from the blended gallon and are used by obligated parties (blenders, refiners, or importers) as proof that they have sold renewable fuels to meet their RFS mandated volumes. Alternatively, as noted, the obligated party can secure sufficient RINs to meet RFS compliance requirements, but proof of the RINs is still required. See: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/how-use-emts-report-transactions-fuel-programs

future for services involving facility registration, monthly and quarterly credit generation, and further credit marketing, sale, and transfer.

Finally, PSE&G has identified additional requirements and certain restrictions related to the RINs, including:

- The compliance period restricts the use of RINs for the year they are generated, or the following year. RINs that are carried over into the next year are called carryover RINs.[43]
- PSE&G must register as a renewable fuel producer to generate RINs. RFS registration of each RNG production facility must also be amended should there be major changes to the production process in the future.
- Market participants – such as those selling RINs – are formally designated by the U.S. EPA. PSE&G will therefore need to work through these administrated steps.
- The U.S. EPA tracks and monitors the RIN market through its transaction tracking system, EMTS. PSE&G will need to establish the 'back office' procedures and system interfaces to interface with EMTS and meet its tracking requirements.
- The RIN requirements include a quality assurance program ("QAP"), the goal of which is to audit and verify RINs.[44] PSE&G has made allowances in its cost estimate for the QAP.

Market Prices for Q-D3 RINs

The CBA costs and benefits assume that PSE&G will be able to sell D3 RINs[45] into the RINs marketplace, thereby supporting the RFS compliance needs of obligated parties, as part of their RVOs. (These RINs can be classified as Q-RINs because of their qualified status, which is explained in more detail below). Moreover, the CBA has assumed a fixed and static price assumption over the forecast period of $3.07 per Q-RIN. This price assumption is based on the compliance needs of an obligated party in support of one (1) gallon of ethanol – this is a common basis for denominating D3 Q-RIN prices. Within the CBA calculations, this reference

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[43] Exceptions include fuel exporters have to retire RINs for compliance within one month of the export event.
[44] To improve the RIN market performance, EPA has taken steps to protect against fraudulent RIN transactions by encouraging third-party verification of RINs generation. Furthermore, EPA enacted a Quality Assurance Program (QAP) under which third-party auditors evaluate producers of renewable fuel to certify they are, in fact, producing the required product in compliance with RFS regulations. The RINs certified under this voluntary program are known as Q-RINs, and the Quality Assurance Program provides the Q-RIN owner with certain legal protections as part of contract risk management. Excerpted from https://stillwaterassociates.com/the-problem-of-invalidated-rins-in-the-renewable-fuel-standard/.
[45] The CBA assumption for the D3 RIN price, also assumes that it is fully qualified, per the RFS. The acronym QRIN is used to indicate that the production has undergone a strict audit and verification process (QAP). Uncertified RINs are also traded in the market. Sale of these eRIN also help bridge periods during which time audits are being performed or completed.

price is then converted to a MMBTU equivalent basis for association with the RNG Project gas volumes.[46] This price is equal to the average price paid in the federal market for D3 Q-RIN during all of 2022. The CBA also applies a sensitivity analysis to the D3 Q-RIN price assumption, which is a key variable in the CBA result.

Other Markets and Market Potential for RNG-Related Credits

As explained, the CBA uses as the valuation basis the sale of Q-RINs to obligated parties in the RFS transportation fuels market. However, other markets for the EA associated with RNG are also present and growing. For example, California has adopted its Low Carbon Fuels Standard ("LCFS"). Other states (Oregon included) have or are contemplating promulgating rules creating similar compliance markets. These mechanisms and markets create compliance pathways for various fuel producers and end users. There are opportunities to expand the markets into home heating fuels. On top of compliance markets, there is also a growing voluntary market for RNG-related EA. Large institutions, such as a food processor for example, are investigating how they might acquire offsets in support of their corporate sustainability goals. As indicated by these state and voluntary markets, policy support for the EA associated with RNG is growing.

An additional marker of support is the recent federal legislation (2022 Inflation Reduction Act) that included an investment tax credit ("ITC") for qualified renewable fuel production investments.[47] The US EPA has also been active in further updating the RFS standard to improve oversight and market functions.

This growth in policy and market support appears commensurate with both the need and the opportunity. The American Gas Foundation, amongst others, have reported on the extensive potential market size of the RNG production market. RNG production today is small in relation to market potential, particularly when consider all feedstock types and the diverse range of process opportunities. It is also worth noting that the number of RINs across all D-codes falls short of need by the fuel producers, importers and exporters.[48]

Notwithstanding the existence and growth of these other markets, and continued policy support from the U.S. EPA and Congress, PSE&G has concluded that it should not base its RNG Project CBA on additional market opportunities in addition to the RFS compliance market.

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[46] The conversion factor is: Each gallon of ethanol is equal to 77,000 BTU on a low heating value basis.
[47] 26 U.S. Code Section 48:
https://uscode.house.gov/view.xhtml?req=(title:26%20section:48%20edition:prelim)
[48] The U.S. EPA has put in place alternative compliance means to address the shortage of RINs.

Project Scope and Scenarios

To conduct the CBA, West Monroe worked closely with PSE&G and Burns & McDonnell experts to understand the RNG project's scope and to structure two meaningful scenarios for comparison purposes.

Today, MCUA collects and pipes LFG seven miles from its East Brunswick MSW facility to its Central Treatment Plant in Sayreville, NJ. This apparatus will not be altered by the Project and is outside its scope. At the CTP, the MCUA (today) carries out partial treatment of the LFG to remove sulfur compounds before combusting the gas at an on-site power plant which supplies the CTP's electricity. For the RNG Project scenario used in this CBA, the Company has assumed that this generating station will be decommissioned.

Under the RNG Project, MCUA will transfer the custody of the LFG to PSE&G at the CTP before it is treated (the MCUA will abandon its desulfurization treatment facilities). The new PSE&G gas upgrade facility will upgrade the LFG to RNG specifications, which means meeting rigorous pipeline quality standards. The RNG will then be injected into the PSE&G gas distribution network. Customers will not perceive any difference as the RNG is now indistinguishable from natural gas in its distribution and use.

PSE&G has sized the RNG plant to accept and treat a maximum of 6,000 SCFM of LFG. The actual LFG volumes will change from month to month, and year to year, due to physical variables related to the facility operations, temperature conditions, and the decay of organic materials. This gas volume and other key details of the physical attributes of the gas volumes, (such as gas collection efficiency factors) and the nature of the planned PSE&G and MCUA facilities, are highly relevant to the CBA. They are summarized in the CBA and described in greater detail in the Company's Design Basis engineering report prepared by PSE&G's engineering partner Burns & McDonnell.[49] Some key CBA assumptions are also based on terms within a recently completed Memorandum of Understanding ("MOU") between PSE&G and MCUA.

Investment capital supports the design, engineering, procurement, construction, testing and commissioning of the facilities needed to upgrade the gas to pipeline quality standards and inject it into the PSE&G gas distribution system. The CBA also includes an estimate of long-term O&M costs for operating and maintaining the RNG facilities over the estimated useful life, including cost estimates for facility lease and permitting. Cost estimates are also included for program administration which addresses certification, qualification, and management of the

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[49] PSE&G requested that Burns & McDonnell apply a Class 5 level of estimate quality to the Design Basis. Class 5 refers to the AACE International estimation standard. See: AACE International. Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction Industries. TCM Framework: 7.3 – Cost Estimating and Budgeting. August 7, 2020.

RINs. Electricity and gas service is required to power this facility and provide a source of backup power which will be built, owned, operated, and maintained by PSE&G. The RNG will be metered and transported approximately 3,000 feet within a new section of PSE&G-owned pipe, which will be interconnected onto the PSE&G's gas distribution network at Sayreville.

PSE&G plans for the RNG Project facilities to be in-service December 1, 2026 and assumes a facility operating life of 20 years. PSE&G estimates that it may also qualify for a federal Investment Tax Credit ("ITC") as codified in the federal Inflation Reduction Act of 2022 depending on construction schedule. This is discussed further in **Costs** section.

As a result of this Project and collaboration, MCUA will be able to abandon its end-of-life power plant at the CTP, which relies on the LFG today. It plans to install additional standby generators for occasional reliability and extended, emergency backup "resiliency" needs. It will also abandon the sulfur scrubbing equipment. The CTP will rely on grid electrical service ("JCP&L") for its routine station power requirements.

Through this Project, MCUA assumes it will be able to manage its ongoing operations more cost-effectively (less complexity and streamlined operations) and address end-of-life conditions at the current CTP facility (LFG-fueled combustion for power generation). PSE&G has estimated that the total direct air emissions at CTP will be lowered due to the RNG Project improvements.[50] Per the contemplated MOU, the monetization (sale) of the RNG provides a source of revenue to MCUA to offset any incremental, new costs.[51]

Scenario Attributes

The CBA evaluates costs and benefits over an evaluation period of 23 years, from the beginning of engineering design in 2024 through the end of the operational term in 2046.[52] For each scenario (BAU and the RNG Project), the costs and benefits are identified as part of the CBA, and when practical and feasible to do so, benefits are quantified and monetized. Where not practical or feasible, a qualitative assessment of benefits is provided.[53] Costs and benefits qualify for inclusion in the CBA when they are relevant and material.

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[50] The estimate of the decrease in direct emissions is based on a PSE&G/Burns & McDonnell netting analysis that considers current (BAU) combustion sources and future RNG project process equipment.
[51] PSE&G's CBA provides some general characterizations of the before- and after- site conditions at the CTP for facilities and equipment currently and to-be-owned by the MCUA. As explained elsewhere in the CBA any impacts to MCUA are captured as part of secondary cost-effectiveness testing. The primary cost-effectiveness test used by PSE&G rests on assumptions the PSE&G project scope.
[52] 2024 through 2046. The RNG facility in-service date is planned for December 1, 2026, which marks the beginning of commercial operations. Facility assets are assumed to have a useful life of 20 years, an assumption which is used to 'bookend' the CBA financial evaluation.
[53] In performing the CBA, WMP has borrowed from the National Standard Practice Manual for Benefit-Cost Analysis for Distributed Energy Resources to review potential gas system-related impact categories. Specifically, the NSPM's Table 4-2, page 4-12, lists potential impacts on gas utilities of energy programs.

As noted, the CBA's RNG Project scenario involves new capital and operating funds needed by PSE&G to build, own, operate, and maintain the RNG treatment plant. Costs are offset by the sales revenues received by the RNG Project from PSEG's ER&T for inclusion in BGSS-RSG supply for the RNG product of approximately 1 BCF annually, and by the sale of the D3 RINs that will be created. The BAU scenario is based on MCUA *not* pursuing the collaboration and facing end-of-life challenges associated with its aging facilities that require upgrades and new investment.

Table 1 summarizes key attributes of each scenario related to the physical design features, the costs for each scenario, and related benefits.

Table 1: Scenario Summary

Facility Scope, Asset of Feature	RNG Project	BAU
LFG Volume	Design basis is 6,000 SCFM at peak	5,126 SCFM in 2022 and estimated to increase over time
MSW Waste Delivery	Same for both scenarios, at approximately ~ 240 trucks, and 1,750 tons, per day of mixed waste.	~ same
LFG-collection facilities	No change from today's conditions	~ same
MCUA's CTP facilities	MCUA anticipates retiring end-of-life power generation system. Install new backup generator. Retire sulfur scrubbing.	Incur high operating costs and potential reliability and resiliency issues with end-of-life power generation system.
MCUA Grid Power Assumptions	Contract for electrical grid power for station and backup power (JCP&L is the provider)	Contract for electrical grid power, primarily for backup power purposes (JCP&L is the provider)
MCUA Electrical Backup Power Assumptions	MCUA will install additional standby generators.	MCUA will continue to rely on existing standby generators.
PSE&G Electrical Backup Power Assumptions	PSE&G will build, own, operate, and maintain backup power generator for critical system needs of RNG facilities.	n/a
PSE&G facilities at CTP	PSE&G builds, owns, operates, and maintains facility to upgrade LFG gas to pipeline quality	n/a
PSE&G facilities elsewhere	PSE&G builds, owns, operates, and maintains ~ 3,000-foot lateral, as well as RNG metering and odorizing systems needed to	n/a

Table S-8, page xi, also identifies certain categories of Societal benefits. These two lists serve as a useful starting mechanism to identify *potential* impacts. www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

	interconnect onto PSE&G distribution system at Sayreville NJ	
PSE&G Gas supply requirements (natural)	Reduced annual and seasonal purchase requirements from natural sources of ~ 1 BCF	Assumes sale of ~ 1 BCF of RNG gas valued at the Transco Leidy index to PSEG's ER&T for inclusion in the BGSS-RSG supply
PSE&G Operations & Maintenance Responsibilities	New responsibilities at CTP; new tracking and verification requirements to broker RINs. MCUA will host PSE&G operators as part of lease operations.	n/a
MCUA Operations & Maintenance Responsibilities	MCUA has increased O&M at its facilities as its grid power requirement increases. This is partially offset by retiring existing power generation equipment and by new RNG revenue sharing.	MCUA has increased O&M at its facilities as power generation equipment reaches end of life.
MCUA Landfill Closure Plan	Same for both scenarios	~ same
Direct Air Emissions at CTP	PSE&G's netting analysis of direct air emissions estimates that there will be a large reduction in direct air emissions (NOx, SOx, PM2.5, PM10, PM)[54]	Today's conditions are estimated to continue over forecast period
RNG Credits (D3 Q-RINs)	PSE&G secures D3 Q-RINs based on environmental attributes. PSE&G sells Q-RINs into the RFS market (or potential voluntary markets as an alternative, long term, as conditions permit). PSE&G and MCUA will share in Q-RIN revenue per MOU.	MCUA gets some renewable benefit related to the sale of environmental attributes associated with landfill gas prior to combustion.
Environmental Justice Compliance	New State of NJ Environmental Justice compliance rules will require additional notice and work with local stakeholders.	n/a

Decrease in CTP Physical Air Emissions

The CBA notes the results of a netting analysis performed by PSE&G and Burns & McDonnell of the direct air emissions (criteria pollutants subject to various air permit conditions) related to the change in state at the MCUA's facilities. MCUA proposes certain physical changes at its facilities, including the construction of new backup generation and a greater degree of reliance on the

[54] PSE&G estimates a small increase in VOC of approximately 0.25 tpy.

electrical grid for primary power and backup power reliability and resiliency. PSE&G and MCUA have concluded, that based on the preliminary Design Basis, no net increases of direct emissions are estimated to result from the RNG Project except for a minor increase in VOC. PSE&G also believes this analysis is conservative if not worst case.

Costs

Cost Overview

In working closely with Burns & McDonnell (engineering consultant) and with collaboration and input from MCUA, PSE&G has developed a preliminary, detailed cost estimate supporting the permitting, design, engineering, procurement (for major and other balance of plant equipment), construction, testing, and commissioning of the facilities needed to convey the landfill gas, upgrade the gas to RNG, and inject into the PSE&G gas distribution system. There are also requirements (and minor costs) associated with verifying and qualifying the environmental attributes of the RNG to facilitate the sale of D3 RINs. The RNG Project includes the costs to meter the gas and to construct a ~ 3,000-foot distribution pipe to the point of interconnection to the PSE&G system.

The CBA also provides estimates of the operations and maintenance costs of running the RNG facilities over their estimated useful life. The costs and their treatment within the analysis framework are summarized in the CBA, as reflected in Appendix A – CBA Inputs, Assumptions, and Results. Assumptions are substantiated by Burns & McDonnell and PSE&G's SMEs.

Recognizing BAU vs. RNG Project Costs

The primary focus and effort of the cost analysis within the CBA is on the relevant and material impacts of the RNG Project as compared to the BAU scenario. Therefore, the CBA identifies and estimates the new, *incremental* costs required to support the RNG Project, as summarized above.

Similarly, the CBA should identify areas of cost impacts related to the BAU scenario for consideration. Only material and relevant cost impacts need to be considered, and ones that are uniquely driven by the Project circumstances. In brief, these BAU cost areas that have been considered are:

- Under BAU, PSE&G will incur gas supply and associated transportation costs associated with approximately 1 BCF of natural gas a year. This BAU assumption does not apply of course under the RNG Project. Under the RNG Project, PSEG's ER&T for inclusion in BGSS-RSG supply will provide revenue to the RNG Project to cover the sale, by the RNG Project, of the RNG production. The sales revenue received by the RNG Project offsets RNG Project costs and is recognized as a project benefit.[55]

[55] As a matter of convention this avoided costs could be simply listed as a "cost" of BAU, and then when comparing the two scenarios it would be realized as an offset. For simplicity, the CBA includes these avoided costs under the "Benefit" category, achieving the equivalent financial result.

Generally, the CBA chooses to not speculate about MCUA costs, including, most relevantly, any new incremental costs (or avoided costs) due to the Project. Some change in costs is inferable, however, through the revenue sharing arrangements related to the monetization of the RINs, methane, and all other Environmental Attributes. Rather, the focus of the CBA is on PSE&G-centric costs, avoided costs and other forms of benefits.[56]

Cost Description and Summary Results

The costs used in the CBA reflect the following considerations:

- Costs are largely derived from the Design Basis. WMP has coordinated with Burns & McDonnell and imported cost data (expressed in $USD on a nominal basis) into the CBA calculations, as reflected in Appendix A – CBA Inputs, Assumptions, and Results.
- Additional costs reflect input by the MCUA on certain site expenses (land lease).
- Costs estimates are provided related to the qualification, certification, management, and brokering / marketing of RINs.
- Costs are expressed in monthly terms over the forecast period in tight conformance to the project schedule provided by Burns & McDonnell.
- The asset life is assumed to be 20 years (once commissioned and producing RNG).
- Capital costs are spread over an assumed 36-month design and build period and are an AACE Class 5 Estimate; Class 5 is for concept screening.[57] Burns & McDonnell has cited an accuracy range of +50% and -30%, (consistent with the Class 5 Estimate standard) and the CBA reflects a capital contingency of +40%.
- Operations & Maintenance (O&M) of both fixed and variable costs occur from the start of the Project and continue through the asset operating life and are assumed to have an O&M contingency of +15%.
- Costs are escalated at an assumed rate of 3%/year.[58]

Table 2 summarizes the summary cost components of the CBA. Appendix A – CBA Inputs, Assumptions, and Results contains further details.

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[56] The focus of the CBA is on a utility cost test. Costs and avoided costs extending beyond PSE&G would be captured as part of secondary cost test.

[57] AACE 18R-97 – Cost Estimate Classification System: https://www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf

[58] 3.00% escalation rate provided by Burns & McDonnell and PSE&G for alignment with other CBAs. Land lease costs are excluded from escalation.

Table 2: Summary of Cost Components of the CBA.

Cost Item/Element	Description	Value ($USD, Nominal w/ Escalation)
RNG Facility Capital Items (40% Contingency)	See Appendix A for details. Based on Burns & McDonnell Basis of Design.	$123.4M
RNG Facility Operations & Maintenance Items (15% Contingency)	See Appendix A for details. Based on Burns & McDonnell Basis of Design and Land Lease Costs per MOU terms with MCUA.	$309.8M
Total		**$433.2M**
Revenue Requirement		**$560.5M**

An aim of cost-benefit analysis is to determine the net project impacts (RNG Project vs. BAU) and to express these impacts in terms of a utility cost-centric viewpoint. The CBA uses as cost input the results shown in Table 2, and further expresses these costs in terms of NPV of revenue requirement.

Revenue Requirement Impacts

WMP gathered many of the relevant and material cost impacts (listed in GSMP III RNG Project Engineering Report Basis of Design and within CBA inputs and assumptions provided in Figure 2). It then interfaced with PSE&G revenue requirement experts to translate these cost impacts into their incremental revenue requirements, recognizing various components of return.[59] Table 2 summarizes the PSE&G revenue requirement analysis outputs that are relevant to the CBA results.

Other Potential Costs Due to Construction-Related Impacts

For completeness, the CBA should aim to identify other unexpected and unplanned costs that may arise through the implementation of the work. The RNG Project will involve construction activities at the CTP and along a 3,000-foot easement from the facility for purposes of interconnection at PSE&G's Sayreville facilities. These activities are not anticipated to cause any significant impacts and are otherwise addressed through local permitting requirements and conditions.

[59] PSE&G's detailed revenue requirement models consider a variety of factors that influence the IIP cost recovery including timing of costs, the return on capital, O&M recovery, plant depreciation accounting assumptions, etc. These considerations are outside the scope of the CBA Report.

Impacts to construction hypothetically involve such inconveniences as traffic delays, construction-related air quality emissions from heavy equipment, increased noise levels, safety concerns, and other similar effects. The CBA notes the possibility for these types of impacts but concludes that it would not be reasonable to conclude they are relevant (or material) because the construction work will be carefully guided through permit conditions and land use conditions. Additionally, construction will follow required construction standards and professional norms and PSE&G intends to select engineers and construction firms that will comply with its safety and quality requirements. Additionally, no changes at the landfill operation itself are contemplated as part of the RNG Project.

For these reasons, WMP has not identified or included within the CBA any impacts, or related direct or indirect construction-related costs, that should be noted as part of the CBA and that would otherwise offset the project benefits.

Benefits

The RNG Project is estimated to provide numerous benefits to PSE&G customers and to the wider region. These benefits are estimated based on the Design Basis for the facility, including a specific estimate of gas input (LFG) and output (RNG) volume and quality by month and year of the project, over its lifetime. The benefits are also based on an analysis of direct air emissions and GHG lifecycle emissions that result through a comparison of the BAU and RNG Project scenario.

RNG Project benefits (estimated to be achieved at no incremental customer cost) include:

- The production of RNG from a local landfill creates a modern and secure pathway for PSE&G to acquire (through its production) pipeline quality gas close to the source of its end use versus reliance on the gathering and transportation of natural gas across a much more geographically dispersed value chain.
- PSE&G estimates that direct air emissions (NOx, SOx, PM2.5, other) from the CTP site will be reduced due to the replacement of the combustion equipment used at the CTP to generate electricity with the modern RNG production facility. Reducing direct air emissions at the CTP provides benefits to the local community by further reducing any concerns about direct air emissions.
- Through a lifecycle emissions analysis, PSE&G has estimated that net GHG emissions will be reduced by the RNG Project, when comparing the lifecycle emissions of the displaced natural gas production vs. the RNG. The value of these GHG emission reductions flows to the transportation fuels markets in support of federal Clean Air Act compliance.
- Long term, it may be possible for PSE&G to work with local customers and large entities (such as food processors, campuses, etc.) to create in-state market mechanisms for the RNG-provided environmental attributes, thus providing local firms with a mechanism to participate in the RNG Project's decarbonization outcomes.

The RNG Project includes mechanisms that reduce total project costs. First, the RNG Project will receive revenues commensurate with the renewable gas delivered to the PSE&G distribution system. Second, PSE&G plans to sell the RNG credit (Q-RINs) into the RFS compliance market and use this revenue to reduce customer costs.

Creating a Benefits Inventory

In performing the CBA, WMP has adopted relevant frameworks from the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources to review potential gas system-related impact categories. Relevant impacts are summarized in Table 3. Specifically, the NSPM's Table 4-2, page 4-12, lists potential impacts on gas utilities of energy programs. Table S-8, page xi within the NSPM also identifies certain categories of Societal benefits. These lists serve as a useful starting point and review mechanism to identify potential impact areas of the RNG Project.[60] The CBA adopts excerpts from each of these two tables within the NSPM to create the left-hand column shown in Table 3.

Table 3: Benefit Inventory, Gas Programs and Projects – All potential benefit areas for further screening

NSPM-Identified General Impact Area	**Description of *Potential* Nexus to RNG Project**
Utility – Fuel and Variable O&M	The RNG Project will sell the RNG to PSEG's ER&T for inclusion in BGSS-RSG supply and therefore realize a source of revenue. This reduces Project costs.
Utility – Performance Incentives	Generation/sale of environmental attribute credits. This Project may also qualify for Investment Tax Credit from the Inflation Reduction Act.
Utility – Resilience	Local source of gas production provides increment of additional gas system diversity and resilience (from disruptions on the upstream gas system).
Societal – GHG Emissions	Quantified by net emissions reduction analysis. Monetized by generation/sale of environmental attribute credits (RINs).
Societal – Economic and Jobs	Job creation from infrastructure development.
Societal – Other Environmental	Landfill gas will be processed with lower site emissions (NOx, PM2.5, etc.) by the RNG facility compared to the retiring cogen currently at the landfill.
Societal – Public Health	Lowered site emissions benefit the health of the local community near the site.

Based on this initial review, the following specific benefits were identified for the RNG project as described in Table 4.

Table 4: Benefit Inventory, RNG Project

Item	**Description**	**Key Assumptions**
Monetary Benefits [61]		

RNG Sale Revenues	The RNG Project will sell RNG to PSEG's ER&T for inclusion in BGSS-RSG supply and receive sales revenues in exchange.	Transco-Leidy valued supply
D3 Q-RIN Revenues	Revenue related to the sale D3 Q-RINs	Use of average price during 2022 (as reported by the U.S. EPA through EMTS) as the go-forward basis.
Avoided Natural Gas Transport Costs	The Company will save on transport costs for the RNG-displaced natural gas	PSE&G-approximated percentage of Leidy price
Quantified (But Not Monetized) Benefits		
Direct Air Emissions at CTP	Decrease in direct criteria air emissions at the CTP.	Based on a "netting analysis" of permit limits and conditions for all CTP combustion sources.
Economic Impacts	Increase in local construction jobs and associated prevailing wages; purchase of materials from local and regional suppliers	PSE&G estimates that the construction activity will generate 229 jobs/year.
Qualitative Benefits		
Customer	Support for RNG market development in support of decarbonization	Potential for customers to participate in the future through a voluntary RNG program
Public Health	Reduction of local air emissions; continued support for safe, reliable, landfill operations providing important public service to region	Local Community

Benefit Valuation

[60] See: www.nationalenergyscreeningproject.org/national-standard-practice-manual/
[61] As noted previously, PSE&G will also seek to leverage Investment Tax Credits, if eligible.

For those benefits that can be monetized, WMP has estimated the value of this benefit and applied it within the CBA calculations. The results of this valuation are presented in Table 5.

Table 5: Benefit Valuation

Item	Description	Benefit Value (20 years, $USD Nominal)
Gas Sale Revenues	Sale of RNG to PSEG's ER&T for inclusion into BGSS-RSG supply portfolio. • 1 BCF per year on average • Transco-Leidy Forward Pricing (through 2030) and extended with no escalation	$88.3M
D3 Q-RIN Revenues	Revenue related to the sale of RNG-related credits (RINs) subject to various sharing mechanisms per the MOU. • Based on recent average D3 Q-RIN 2022 price of $3.07 • Excludes of brokerage costs, addressed elsewhere • Sales tax implications addressed in revenue requirement	$840.9M
RIN Transaction Costs (includes annual 3% escalation)	Transaction Costs include marketing & management fees, pathway registration, EPA Quality Assurance Program (QAP) onboarding and annual costs, and compliance consulting costs.	$-86.2M
Avoided Natural Gas Transport Costs	The Company will save on transport costs for the RNG-displaced natural gas.	$0.4M
Total		**$843.5M**

Reductions in Direct Emissions from the CTP and Local Community Impacts

Through its lowering of emissions, the RNG Project supports environmental policy objectives within the State of New Jersey.

- **First**, PSE&G has estimated that – through a comparison of emissions today (BAU) versus the RNG Project – there is a significant reduction in direct criteria air pollutant emissions

(NOx, SOx, PM2.5, etc.) over all periods of the operating life of the project. This comparison considers all sources of combustion emissions at the current vs. new facility. Table 6 shows these estimated criteria air pollutants reductions.

- **Second**, due to the efficient RNG production process, the RNG Project is estimated to result in approximately 27,000 – 36,000 / year fewer metric tons of CO_2e being released to the atmosphere (compared to BAU). These emission reductions represent a reduction in Scope 3 GHG emissions.

Using these two evaluations – the estimate of direct emissions reductions, and the lifecycle analysis of the "end to end" GHG reductions – these project impacts can be carefully distinguished.

Table 6: Criteria Air Pollutant Reductions at the CTP

Criteria Pollutant	Description	Estimated Net Increase (+) / Reduction (-) (Tons/Year)	Significant Increase Threshold (Tons/Year)
CO	Carbon Monoxide	-0.91	100
NOx	Nitrogen Oxides, primarily NO_2	-20.55	25
SO_2	Sulfur Dioxide	-22.82	100
VOC	Volatile Organic Compounds, including methane	0.25	25
$PM_{2.5}$	Particulate Matter less than or equal to 2.5 microns in diameter	-4.22	100
PM_{10}	Particulate Matter less than or equal to 10 microns in diameter	-4.21	100
PM	Particulate Matter of any size	-4.20	100

Securing these direct emission reductions at the site and within the local region is a valuable benefit that improves air quality for both the immediately surrounding local community and the wider region.

RNG Benefits Beyond the RIN valuation: PSE&G Customer Participation in Decarbonization

The CBA assumes that the RNG-related credits are sold as part of the federal RFS market. The exchange is based on D3 Q-RINs, which trade in this market. A price assumption is used (based on recent actuals) to estimate revenues, which offset the RNG production facility costs (and other Project costs).

PSE&G sees the D3 Q-RIN market participation as a starting point. For example, a potential voluntary program allowing PSE&G customers to purchase all or some percentage of the environmental attribute ("EA") value associated with the RNG would lead to benefits for all stakeholders. Customers that choose to opt into the program would have a vehicle to claim EAs for the fuel they consume. Customers that choose not to opt in would not incur any rate increases due to the undertaking of the RNG project.

For such a program structure to be put in place, the program would require express approval from the NJ BPU. The EAs would need to be valued at a price such that PSE&G/MCUA would recover the necessary project and program costs without increasing rates to non-participating customers. Properly orchestrated, this price-setting would also serve to mitigate the downside and upside EA program risks, which come from exposure to the volatility of the RIN (or other EA) markets.

As previously noted, voluntary programs for the purchase of EA value for RNG have been previously proposed and successfully implemented elsewhere; these instances and examples are recorded in Appendix G of GSMP III RNG Project Engineering Report Basis of Design provided by Burns & McDonnell.

New Pathways for Revenues, Savings and Decarbonization Potential

Other pathways are opening to monetize the Environmental Attributes ("EA") of renewable fuels. The CBA briefly notes previously (in the description of general RIN market issues), that states across the US have considered low-carbon fuel standards ("LCFS") to incentivize cleaner transportation fuels such as RNG. California and Oregon have implemented LCFS programs.

In addition to the potential for voluntary markets in New Jersey, infrastructure is developing for larger voluntary markets for EAs associated with clean energy sources like RNG. The Midwest Renewable Energy Tracking System ("M-RETS"), for example, provides a database to track renewable certificates in support of current and potential voluntary markets. Another version of a voluntary market could be a long-term Power Purchase Agreement ("PPA") between PSE&G and a large customer in its service area.

Finally, the potential for new legislation incentivizing RNG projects remains as an opportunity for further financial and regulatory upside.[62]

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[62] NJ Assembly Bill A577 was voted unanimously out of the New Jersey Assembly Environment Committee on December 5th, 2022. The bill directs the BPU to establish a renewable natural gas (RNG) program and provide gas public utilities with a customer rate recovery mechanism for costs associated with the program.

Comparison of Costs and Benefits

The RNG Project costs and monetized benefits, when compared to the BAU scenario are presented in Table 7 in net present value terms of revenue requirements over the 23-year evaluation period.

The orientation of the CBA is towards the overall cost-effectiveness of the result, when comparing the net costs to the net benefits. "Net" is used to capture the incremental or new component of value of the RNG Project when compared to BAU. This is the key difference – the increment of value that occurs because of the RNG Project, over-and-above what would happen anyway (BAU). Importantly, the overall CBA result also considers value that may not be quantified and/or monetized.

The basic mechanism of the costs, avoided costs and other monetized benefit considerations that are applied with the CBA calculation can be generalized as follows:

Outflow: Raises Energy System Costs

$$\sum \text{CapEx} + \text{O\&M}$$

Inflow: Lowers Energy System Costs

$$\sum \text{Gas Sale} + \text{Avoided Gas Transport} + \text{Q-RIN Revenues - RIN Transaction Cost}$$

The CBA's primary result considers the *Company's* costs and avoided costs, and without consideration of additional value to MCUA customers that may accrue. As explained further below, additional value-add due to the positive attributes of the RNG Project to MCUA are best captured as part of the secondary cost test, if feasible to perform. This keeps the CBA results well-ordered and allows additional effects to be carefully separated and inspected.

In the instance of the primary test result, shown in Table 7, the D3 Q-RIN revenue is that portion of revenue that is allocated to PSE&G based on the structuring of the MOU. The CBA assumes a D3 Q-RIN price of $3.07 over the forecast period. Additionally, PSE&G will incur costs to validate, certify and register the D3 Q-RIN, as part of the marketing of the Q-RIN to obligated parties holding RVO as part of RFS compliance requirements.

Table 7: Comparison of Costs and Benefits, RNG Project vs. BAU[63]

Costs and Benefits	$ millions, Nominal	$ millions, Present Value	$ millions, Present Value Revenue Requirement
Capital Costs*	$123.4M	$112.5M	
O&M Costs*	$309.8M	$139.5M	
Total Costs	$433.2M	$252M	
Revenue Requirement - Before Benefits			**$269.5M**
Benefit: Gas Supply Sale Revenues to Project	$88.3M	$41.9M	
Benefit: RIN Revenue**	$754.7M	$361.4M	
Total Benefits	$843M	$403.3M	
Portion of Benefits to PSE&G	$564.8M	$270.2M	
Additional Benefit: Avoided Natural Gas Transport Costs	$0.4M	$0.2M	
Total PSE&G Benefits	$565.3M	$270.4M	
Benefits Less Revenue Requirement		**$0.9M**	

*Includes contingency
**Less marketing/transaction costs

The summary of costs and benefits provided in Table 7 include the costs and benefits that impact the PSE&G revenue requirement and therefore may impact customer charges (depending on the result). As shown, however, the resulting NPV of Project revenue requirement after benefits is $0.9M over the project life. The benefits are returned to customers in the form of credits to the revenue requirements.

[63] For completeness, PSE&G assumes that there are no new costs due to construction period or long-term operations impacts. Such impacts could potentially offset beneficial claims. This conclusion is based on assumptions that the new RNG Project facilities will be built in accordance with reasonable permit and land use conditions. Moreover, as explained elsewhere, the RNG Project is estimated to reduce direct air emissions, due to the modernizing of the CTP facilities, and the lowering of GHG emissions in real terms, when compared to BAU.

There is additional value of the RNG Project not captured under the primary test. To the extent that there are additional Q-RIN revenues, these flow to both PSE&G and MCUA, per the terms of the MOU. These additional revenues would further offset PSE&G costs and lead to additional avoided costs for MCUA. This additional source of benefit would be captured in the secondary test. However, to avoid un-due speculation, the CBA does not include estimates about additional revenue effects and therefore ignores a formal, secondary cost-effectiveness test evaluation.

Notwithstanding this qualification about the potential for additional revenues, it is important to note the role of certain qualitative benefits – these add additional value to the RNG Project, but which are difficult to express in monetary terms. These additional benefits include:

- PSE&G has estimated that the RNG Project will reduce direct criteria air emissions (NOx, SOx, PM2.5, other) at the CTP, based on a comparison of RNG Project vs. BAU emissions estimates.[64]
- PSE&G estimates that the RNG Project will reduce GHG emissions based on a life-cycle analysis it performed. The lifecycle emissions analysis compares the entire pathway of GHG emissions of natural gas (originating at upstream locations to the customer burner tip), to the RNG Project gas pathway (also ending at the burner tip). This comparison yields a result for the Carbon Intensity, or CI, for the RNG Project. In this case the CI is 40.99 kg CO_2/MMBTU. This compares to the calculated CI range of natural gas of 60.61 – 68.43 kg CO_2/MMBTU.

Sensitivity Analysis

This section presents a sensitivities analysis of key CBA assumptions. Its goal is to explore how changes to key variables may influence the CBA results. Table 8 below lists the key factors that have been evaluated; each has been treated independently in the analysis calculations.

Table 8: Sensitivity Analysis

Factor (Independent of Each Other)	Adjustment (Low NPV of Benefits Less Revenue Requirement, High NPV of Benefits Less Revenue Requirement)
Natural Gas Price	Transco/Leidy + Long-Term EIA, Extended Forecast w/ Monthly CAGR[65]
ITC (Yes/No)	No (0%), Yes (30%)
RNG Production	Standard Collection Efficiency (75%), High Collection Efficiency (84.8%)

[64] A minor increase of 0.25 tpy is estimated for VOC.
[65] The Transco-Leidy price is used to value the sale of RNG from the RNG Project, and the resulting revenues back to the RNG Project.

Project Capital Costs	50% contingency from Burns & McDonnell Base Estimate, -30% from Burns & McDonnell Base Estimate
Project O&M Costs	+50% contingency on Burns & McDonnell Base Estimate, -30% from Burns & McDonnell Base Estimate
D3 RIN Price	$1.53/RIN (-50% from 2022 average), $3.50/RIN (all-time weekly high)

These factors, and their results, are presented in Figure 1, which is known as a "Tornado Diagram". It captures the relative magnitude of each variable on the project results, or in other words, the degree to which the financial value of the project is sensitive to different sources of risk.

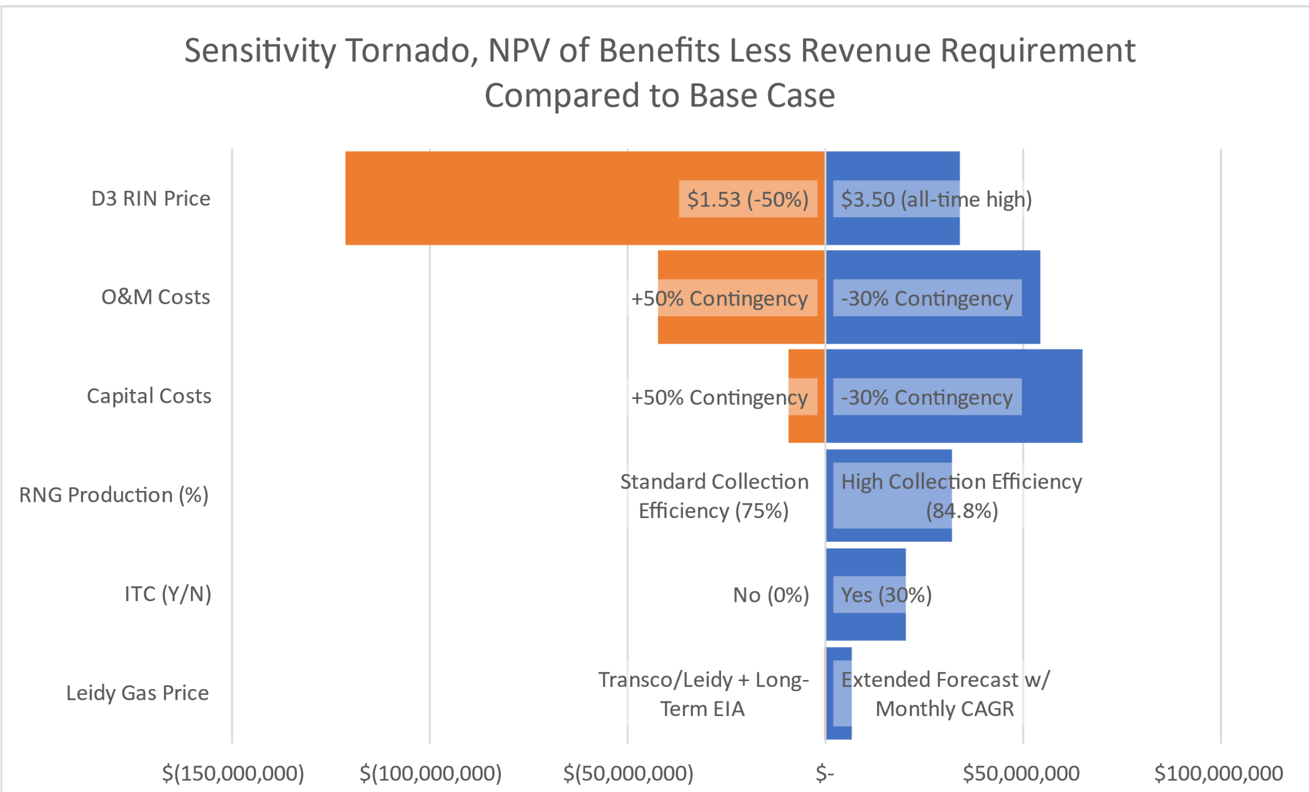

Figure 1: Sensitivity Analysis Relative Impacts on NPV

WMP has inspected the CBA model and determined which variables warrant the greatest amount of attention. This sensitivity analysis indicates that the CBA results are most sensitive to the D3 RIN price assumption and the estimated Project costs.

- The RNG Project's economic results are sensitive to RIN credit values. Looking forward, it is reasonable to assume that these values will be influenced by a variety of market forces including total credit demand by Obligated Parties, and potential adjustments by the Federal government in the underlying RFS requirements affecting these parties. Accordingly, the CBA includes a sensitivity on the Q-RINs price assumption. Historically, D3 RIN prices have experienced volatility (some seasonal), along with a long-term upward trend.

- There is also a large variance in the CBA results due to O&M and capital costs; however, PSE&G's baseline assumptions of 15% O&M contingency and 40% capital contingency create an appropriate baseline at this stage of the project.

Conclusions

PSE&G has worked with its design and engineering subject matter experts, and with the MCUA, to the RNG Project that proposes to make valuable improvements to the MCUA Central Treatment Plant ("CTP"). These improvements will take landfill gas, upgrade it, and distribute it to PSE&G customers as a high-quality natural gas substitute. PSE&G estimates that it can supply its BGSS-RSG customers around 1 BCF of locally sourced, high quality natural gas in this manner.

PSE&G's RNG Project represents a unique and valuable opportunity for the New Jersey region to secure and destroy methane from landfill gas in a cost-effective way over the long term. The US EPA recognizes the renewable fuel pathway that is proposed for the gas processing, and thus the assumption that the RNG produced will support participation in the D3 RIN marketplace is reasonable. *This participation and resulting revenues provide a mechanism to structure the RNG Project in such a way that it is estimated to not increase PSE&G customer revenue requirements*.

The MOU that PSE&G and MCUA have structured enables PSE&G and MCUA, and their respective customers, to mutually benefit. MCUA can secure a pathway for its operations and physical facilities without a significant outlay of additional capital to address its aging infrastructure, and it will be able to streamline operations. PSE&G can take custody of the raw gas stream from the landfill, upgrade it, use the RNG to as part of its BGSS-RSG supply (offsetting natural gas purchases while providing a revenue source to offset project revenue requirements), and, through the Q-RIN credit mechanism, offset customer costs. In addition, ITC savings will be pursued to offset up to 30% of the facility investment.

The RNG Project reduces emissions in two ways. First, the physical direct criteria air pollutant emissions resulting at the CTP site will be reduced. This benefits the local community, and the wider region. Secondly, PSE&G has performed a life cycle analysis that estimates that there will be a net reduction in GHG of approximately 27,000 – 36,000 metric tons CO_2e annually when compared to direct use of natural gas.

The CBA described in this Report is formed based on utility cost-centric perspective. Results show that PSE&G can return incremental costs through several forms of savings, particularly the sale of D3 RINs, to offset the project costs, and reduce Project risk. A sensitivity analysis shows that the key factors driving the CBA from a financial model perspective are RIN prices and Project costs. Should the RNG Project experience additional RIN revenues, these revenues would flow to both MCUA and PSE&G customers, and capture additional benefit beyond those strictly assigned to PSE&G.

The RNG Project provides a potential future pathway for PSE&G's gas customers to participate in a growing low carbon fuels market. Instead of sourcing and distributing natural gas from distant, out-of-state upstream supplies, the RNG Project allows PSE&G to source and distribute an equivalent amount of high-quality renewable natural gas from a local source in New Jersey. Other forms of participation in low carbon fuels markets may emerge overtime, commensurate with market changes and growth.

Appendices

Appendix A – CBA Inputs, Assumptions, and Results

INPUTS & ASSUMPTIONS

Figure 2 provides a summary of general inputs and assumptions of the CBA. Additional inputs to the CBA include the Burns & McDonnell Basis of Design, historical D3 Q-RIN prices, Transco-Leidy forward pricing, and Revenue Requirements calculated by PSE&G.

Name	Value
Evaluation Period Start Date (Year):	1/1/2024
Design/Build Start Date (Year):	1/1/2024
RNG Project Lifecycle Timeline (yrs):	20
In Operation Date:	12/1/2026
Yearly Cost Escalation (%):	3.00%
Post-Tax WACC (%):	6.48%
RFS Pathway Registration ($):	$20,000
RFS QAP Year 1 Onboarding ($):	$10,000
RFS QAP ($/yr):	$45,000
RIN Management ($/yr):	$20,000
Compliance Consulting ($):	$50,000
End of Term RNG Facility Removal ($):	$0
RIN "Marketing and Management" Fee (%):	10.0%
Avoided Gas Transportation Costs (% of Leidy):	0.5%
Initial Lag in Revenues from EA (months):	3
Land Lease Cost ($/month):	$8,333
Raw Landfill Gas Cost (% of Leidy):	0%

Figure 2: General CBA Inputs & Assumptions.

Table 9: Summary of O&M and Revenue

Revenue - 67% PSE&G Share			
Year	**Gas Sales**	**Net Environmental Attributes Sales**	**O&M**
2024	$0	$0	$0
2025	$0	$0	$67,083
2026	$246,204	-$9,112	$1,007,304
2027	$2,424,088	$26,519,945	$11,216,478
2028	$2,622,783	$24,867,463	$11,621,363
2029	$2,811,254	$25,168,653	$12,037,649
2030	$3,029,929	$25,457,926	$12,465,686
2031	$3,063,119	$25,735,745	$12,905,832
2032	$3,095,008	$26,002,555	$13,358,460
2033	$3,125,646	$26,258,787	$13,823,951
2034	$3,155,083	$26,504,849	$15,483,228
2035	$3,183,366	$26,741,138	$16,011,053
2036	$3,210,540	$26,968,034	$16,554,018
2037	$3,236,648	$27,185,899	$17,112,587
2038	$3,261,733	$27,395,086	$17,687,233
2039	$3,285,834	$27,595,929	$16,909,889
2040	$3,156,995	$26,508,895	$17,061,085
2041	$3,033,207	$25,464,335	$17,220,480
2042	$2,914,274	$24,460,579	$17,388,282
2043	$2,800,003	$23,496,022	$17,564,706
2044	$2,690,214	$22,569,123	$17,749,972
2045	$2,584,729	$21,678,400	$17,944,309
2046	$2,237,187	$19,087,226	$16,635,623

Figure 3 shows annual cost and benefit calculations alongside sums in nominal and present value for the project. The monthly details of these calculations are provided within 'RNG Project CBA 2.17.23.xlsx' and will be provided electronically for the filing.

						2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
1. TIMELINE																												
• Evaluation Period																												
RNG Facility Lifetime (No. Yrs):	(1)	20																										
Evaluation Period Start Date (Year):	(2)	1/1/2024																										
Design/Build Start Date:	(3)	1/1/2024																										
In Operation Date (Year):	(4)	12/1/2026				2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
End of Term Removal Start (Year):	(5)	12/1/2046																										
Evaluation period (No. Months):	(6)	276				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
2. RNG PROJECT COSTS																												
• RNG Facility Capital Costs		Total (w/o escalation)	Total (w/ escalation)	NPV																								
Direct Costs																												
Mechanical & Electrical Equipment Cost Timing:	(7)					60%	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mechanical & Electrical Equipment Cost ($):	(8)	$29,796,440	$31,990,376	$30,086,534		$18,966,626	$13,023,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mechanical, Structural Construction Cost Timing:	(9)					0%	40%	60%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mechanical, Structural Construction Cost ($):	(10)	$13,784,560	$15,333,891	$13,472,878		$0	$6,025,104	$9,308,786	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electrical, I&C Construction Cost Timing:	(11)					0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Electrical, I&C Construction Cost ($):	(12)	$6,318,000	$7,110,965	$6,113,344		$0	$0	$7,110,965	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PSE&G Interconnect Cost Timing:	(13)					8%	48%	44%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PSE&G Interconnect Cost ($):	(14)	$2,123,100	$2,345,187	$2,089,588		$180,192	$1,113,585	$1,051,410	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
JCP&L Interconnect Cost Timing:	(15)					10%	90%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
JCP&L Interconnect Cost ($):	(16)	$2,500,000	$2,723,861	$2,556,445		$265,225	$2,458,636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subcontractors (W/O Inspection) Cost Timing:	(17)					100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subcontractors (W/O Inspection) Cost ($):	(18)	$200,000	$212,180	$210,103		$212,180	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MCUA Site Improvements Timing:	(19)					100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MCUA Site Improvements Costs ($):	(20)	$1,000,000	$1,060,900	$1,050,514		$1,060,900	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indirect Costs																												
Professional Services - Engineering Cost Timing:	(21)					45%	44%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Professional Services - Engineering Cost ($):	(22)	$5,473,910	$5,922,830	$5,526,355		$2,613,272	$2,631,855	$677,703	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Professional Services - CM/CI Cost Timing:	(23)					10%	30%	60%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Professional Services - CM/CI Cost ($):	(24)	$8,210,865	$9,107,601	$8,022,334		$871,091	$2,691,670	$5,544,841	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Professional Services - Commissioning and Startup Cost Timing:	(25)					2%	2%	96%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Professional Services - Commissioning and Startup Cost ($):	(26)	$2,736,955	$3,075,136	$2,619,505		$58,073	$59,815	$2,957,248	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Permitting Cost Timing:	(27)					85%	15%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Permitting Cost ($):	(28)	$2,571,200	$2,740,061	$2,646,880		$2,318,618	$421,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Owners Cost Timing:	(29)					34%	40%	26%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Owners Cost ($):	(30)	$5,948,832	$6,486,779	$5,953,628		$2,145,779	$2,600,180	$1,740,820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs																												
Total Capital Cost Estimate ($):	(31)	$80,663,862	$88,109,766	$80,348,108		$28,691,956	$31,026,038	$28,391,773	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital Cost 40% Contingency ($):	(32)	$32,265,545	$35,243,906	$32,139,243		$11,476,782	$12,410,415	$11,356,709	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Cost Estimate with 40% Contingency ($):	(33)	$112,929,407	$123,353,672	$112,487,351		$40,168,738	$43,436,453	$39,748,482	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
• RNG Facility O&M Costs			Total (w/ escalation)	NPV	Avg Annual																							
General O&M, Labor, Safety/Envir., Consumables, G&A Cost ($/yr):	(34)		$131,818,120	$58,925,075		$0	$0	$397,867	$4,917,641	$5,065,170	$5,217,125	$5,373,639	$5,534,848	$5,700,893	$5,871,920	$6,048,078	$6,229,520	$6,416,406	$6,608,898	$6,807,165	$7,011,380	$7,221,721	$7,438,373	$7,661,524	$7,891,370	$8,128,111	$8,371,954	$7,904,520
Fuel Cost ($):	(35)		$59,869,013	$27,068,262		$0	$0	$174,109	$2,181,058	$2,275,261	$2,371,990	$2,471,326	$2,573,349	$2,678,144	$2,785,795	$2,896,392	$3,010,027	$3,126,793	$3,246,787	$3,370,108	$3,496,861	$3,460,539	$3,424,595	$3,389,024	$3,353,823	$3,318,987	$3,284,513	$2,979,531
Electrical Cost ($)	(36)		$70,126,933	$31,706,122		$0	$0	$203,941	$2,554,760	$2,665,103	$2,778,406	$2,894,762	$3,014,265	$3,137,015	$3,263,111	$3,392,659	$3,525,763	$3,662,536	$3,803,089	$3,947,541	$4,096,011	$4,053,466	$4,011,363	$3,969,698	$3,928,465	$3,887,660	$3,847,280	$3,490,042
Large Capital Replacement Costs - Year 10 ($/yr):	(37)		$5,450,082	$2,492,027		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,026,548	$1,057,344	$1,089,065	$1,121,737	$1,155,389	$0	$0	$0	$0	$0	$0	$0	$0
Land Lease Cost ($):	(38)	$8,333	$2,150,000	$1,081,592		$0	$58,333	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$91,667
End of Term RNG Facility Removal ($):	(39)	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Facility O&M Cost Estimate ($):	(40)		$269,414,148	$121,273,078		$0	$58,333	$875,917	$9,753,459	$10,105,533	$10,467,521	$10,839,727	$11,222,463	$11,616,052	$12,020,827	$13,463,676	$13,922,654	$14,394,799	$14,880,510	$15,380,203	$14,704,251	$14,835,726	$14,974,331	$15,120,246	$15,273,657	$15,434,758	$15,603,747	$14,465,759
Facility O&M Cost 15% Contingency ($):	(41)		$40,412,122	$18,190,962		$0	$8,750	$131,388	$1,463,019	$1,515,830	$1,570,128	$1,625,959	$1,683,369	$1,742,408	$1,803,124	$2,019,551	$2,088,398	$2,159,220	$2,232,077	$2,307,030	$2,205,638	$2,225,359	$2,246,150	$2,268,037	$2,291,049	$2,315,214	$2,340,562	$2,169,864
Total Facility O&M Cost Estimate with 15% Contingency ($):	(42)		$309,826,270	$139,464,039	$15,491,314	$0	$67,083	$1,007,304	$11,216,478	$11,621,363	$12,037,649	$12,465,686	$12,905,832	$13,358,460	$13,823,951	$15,483,228	$16,011,053	$16,554,018	$17,112,587	$17,687,233	$16,909,889	$17,061,085	$17,220,480	$17,388,282	$17,564,706	$17,749,972	$17,944,309	$16,635,623
• RNG Total Costs			Total	NPV																								
Total Capital Cost Estimate with 40% Contingency ($):	(43)	$112,929,407	$123,353,672	$112,487,351		$40,168,738	$43,436,453	$39,748,482	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total O&M Cost Estimate with 15% Contingency ($):	(44)		$309,826,270	$139,464,039		$0	$67,083	$1,007,304	$11,216,478	$11,621,363	$12,037,649	$12,465,686	$12,905,832	$13,358,460	$13,823,951	$15,483,228	$16,011,053	$16,554,018	$17,112,587	$17,687,233	$16,909,889	$17,061,085	$17,220,480	$17,388,282	$17,564,706	$17,749,972	$17,944,309	$16,635,623
Total ($):	**(45)**		$433,179,942	$251,951,390		$40,168,738	$43,503,536	$40,755,786	$11,216,478	$11,621,363	$12,037,649	$12,465,686	$12,905,832	$13,358,460	$13,823,951	$15,483,228	$16,011,053	$16,554,018	$17,112,587	$17,687,233	$16,909,889	$17,061,085	$17,220,480	$17,388,282	$17,564,706	$17,749,972	$17,944,309	$16,635,623
3. RNG PROJECT BENEFITS																												
• Avoided Costs from Gas Supply			Total	NPV	Avg Annual																							
Annual RNG Production - Higher Heating Value (MMBTU/yr):	(47)					0	0	93,254	1,134,168	1,148,693	1,162,648	1,176,057	1,188,940	1,201,317	1,213,209	1,224,635	1,235,613	1,246,161	1,256,294	1,266,031	1,275,386	1,225,377	1,177,329	1,131,166	1,086,812	1,044,198	1,003,254	883,589
Gas Commodity Price ($/MMBTU):	(48)					$3.05	$3.11	$3.12	$3.19	$3.41	$3.61	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.85	$3.78
Pass-Through Avoided Gas Supply Costs ($):	(49)		$88,310,214	$41,905,214	$4,415,511	$0	$0	$367,468	$3,618,042	$3,914,601	$4,195,901	$4,522,282	$4,571,819	$4,619,415	$4,665,144	$4,709,080	$4,751,293	$4,791,851	$4,830,819	$4,868,258	$4,904,230	$4,711,933	$4,527,175	$4,349,662	$4,179,109	$4,015,244	$3,857,804	$3,339,085
LFG Purchase from MCUA ($):	(50)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Pass-Through Avoided Gas Supply Costs ($):	(51)		$88,310,214	$41,905,214		$0	$0	$367,468	$3,618,042	$3,914,601	$4,195,901	$4,522,282	$4,571,819	$4,619,415	$4,665,144	$4,709,080	$4,751,293	$4,791,851	$4,830,819	$4,868,258	$4,904,230	$4,711,933	$4,527,175	$4,349,662	$4,179,109	$4,015,244	$3,857,804	$3,339,085
• Revenues from Environmental Attributes			Total	NPV	Avg Annual																							
Annual RNG Production - Lower Heating Value (MMBTU/yr):	(52)					0	0	84,177	1,023,771	1,036,882	1,049,479	1,061,583	1,073,211	1,084,384	1,095,119	1,105,433	1,115,342	1,124,863	1,134,010	1,142,799	1,151,243	1,106,102	1,062,731	1,021,061	981,025	942,558	905,600	797,583
RNG to RIN Conversion (gal ethanol/MMBTU)	(53)	12.987																										
Annual RIN Production (gal ethanol/yr):	(54)		274,012,409			0	0	1,093,208	13,295,724	13,466,001	13,629,601	13,786,787	13,937,810	14,082,910	14,222,321	14,356,266	14,484,959	14,608,606	14,727,404	14,841,544	14,951,209	14,364,964	13,801,705	13,260,533	12,740,580	12,241,015	11,761,038	10,358,224
Q-RINs Market Price ($/RIN):	(55)	$3.07				$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07	$3.07
RINs Start Date:	(56)	3/1/2027																										
Annual Q-RINs Revenue ($):	(57)		$840,916,681	$402,662,928	$42,045,834	$0	$0	$0	$44,158,193	$41,325,810	$41,827,884	$42,310,271	$42,773,744	$43,219,043	$43,646,882	$44,057,945	$44,452,891	$44,832,350	$45,196,930	$45,547,215	$45,883,765	$44,084,637	$42,356,054	$40,695,249	$39,099,566	$37,566,450	$36,093,448	$31,788,354
• Total RNG Project Revenues			Total	NPV	Avg Annual																							
Total RNG Project Revenues ($):	(58)		$929,226,895	$444,568,141	$46,461,345	$0	$0	$367,468	$47,776,235	$45,240,412	$46,023,785	$46,832,553	$47,345,563	$47,838,458	$48,312,026	$48,767,025	$49,204,184	$49,624,201	$50,027,749	$50,415,474	$50,787,995	$48,796,570	$46,883,229	$45,044,911	$43,278,675	$41,581,694	$39,951,252	$35,127,438
RINs Marketing & Management Fees ($):	(59)	10%	$84,091,668	$40,266,293	$4,204,583	$0	$0	$0	$4,415,819	$4,132,581	$4,182,788	$4,231,027	$4,277,374	$4,321,904	$4,364,688	$4,405,795	$4,445,289	$4,483,235	$4,519,693	$4,554,722	$4,588,377	$4,408,464	$4,235,605	$4,069,525	$3,909,957	$3,756,645	$3,609,345	$3,178,835
RFS Pathway Registration Timing:	(60)					0	0	1	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RFS Pathway Registration ($):	(61)	$20,000	$23,129	$18,712		$0	$0	$1,876	$21,253	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RFS QAP Year 1 Onboarding Timing:	(62)					0	0	1	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RFS QAP Year 1 Onboarding ($):	(63)	$10,000	$11,565	$9,356		$0	$0	$938	$10,627	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RFS QAP ($/yr):	(64)	$45,000	$1,398,353	$625,089		$0	$0	$4,221	$52,167	$53,732	$55,344	$57,005	$58,715	$60,476	$62,291	$64,159	$66,084	$68,067	$70,109	$72,212	$74,378	$76,609	$78,908	$81,275	$83,713	$86,225	$88,811	$83,853
RIN Management ($/yr):	(65)	$20,000	$621,490	$277,817		$0	$0	$1,876	$23,185	$23,881	$24,597	$25,335	$26,095	$26,878	$27,685	$28,515	$29,371	$30,252	$31,159	$32,094	$33,057	$34,049	$35,070	$36,122	$37,206	$38,322	$39,472	$37,268
Compliance Consulting Timing:	(66)					0	0	1	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compliance Consulting ($):	(67)	$50,000	$57,823	$46,781		$0	$0	$4,690	$53,133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total RNG Transaction Costs ($):	**(68)**		$86,204,029	$41,244,049		$0	$0	$13,600	$4,576,186	$4,210,194	$4,262,730	$4,313,367	$4,362,185	$4,409,259	$4,454,663	$4,498,469	$4,540,744	$4,581,553	$4,620,961	$4,659,027	$4,695,812	$4,519,122	$4,349,583	$4,186,922	$4,030,876	$3,881,192	$3,737,628	$3,299,956
Total Net RNG Project Revenues ($):	**(69)**		$843,022,866	$403,324,093	$42,151,143	$0	$0	$353,868	$43,200,049	$41,030,217	$41,761,055	$42,519,186	$42,983,378	$43,429,199	$43,857,362	$44,268,556	$44,663,440	$45,042,647	$45,406,788	$45,756,446	$46,092,184	$44,277,448	$42,533,646	$40,857,989	$39,247,799	$37,700,502	$36,213,624	$31,827,482
67% PSE&G Share of Net Revenues ($):	**(70)**		$564,825,320	$270,227,142	$28,241,266	$0	$0	$237,092	$28,944,033	$27,490,245	$27,979,907	$28,487,854	$28,798,863	$29,097,563	$29,384,433	$29,659,933	$29,924,505	$30,178,574	$30,422,548	$30,656,819	$30,881,763	$29,665,890	$28,497,543	$27,374,853	$26,296,025	$25,259,336	$24,263,128	$21,324,413
• Avoided Costs from Gas Transport			Total	NPV	Avg Annual																							
Avoided Transportation Costs ($/MMBTU):	(71)	0.5%																										
Pass-Through Avoided Transportation Costs ($):	(72)		$441,551	$209,526	$22,078	$0	$0	$1,837	$18,090	$19,573	$20,980	$22,611	$22,859	$23,097	$23,326	$23,545	$23,756	$23,959	$24,154	$24,341	$24,521	$23,560	$22,636	$21,748	$20,896	$20,076	$19,289	$16,695

Figure 3: Calculations Annual View from CBA.

Appendix B – Selected Reference Material Excerpts

Table 10: D3 RIN Pathways, Data Table Excerpts Table from the US EPA[66]

Table 1 to § 80.1426—Applicable D Codes for Each Fuel Pathway for Use in Generating RINs				
	Fuel type	**Feedstock**	**Production process requirements**	**D-Code**
K	Ethanol	Crop residue, slash, pre-commercial thinnings and tree residue, switchgrass, miscanthus, energy cane, Arundo donax, Pennisetum purpureum, and separated yard waste; biogenic components of separated MSW; cellulosic components of separated food waste; and cellulosic components of annual covercrops.	Any process that converts cellulosic biomass to fuel.	3 (cellulosic biofuel)
M	Renewable Gasoline and Renewable Gasoline Blendstock; Co-Processed Cellulosic Diesel, Jet Fuel and Heating Oil	Crop residue, slash, pre-commercial thinnings, tree residue, and separated yard waste; biogenic components of separated MSW; cellulosic components of separated food waste; and cellulosic components of annual cover crops.	Catalytic Pyrolysis and Upgrading, Gasification and Upgrading, Thermo-Catalytic Hydrodeoxygenation and Upgrading, Direct Biological Conversion, Biological Conversion and Upgrading utilizing natural gas, biogas, and/or biomass as the only process energy sources providing that process used converts cellulosic biomass to fuel; any process utilizing biogas and/or biomass as the only process energy sources which converts cellulosic biomass to fuel.	3 (cellulosic biofuel)

[66] 40 CFR part 80 subpart M, U.S. EPA. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-80/subpart-M

Table 1 to § 80.1426—Applicable D Codes for Each Fuel Pathway for Use in Generating RINs				
	Fuel type	**Feedstock**	**Production process requirements**	**D-Code**
N	Naphtha	Switchgrass, miscanthus, energy cane, Arundo donax, and Pennisetum purpureum	Gasification and upgrading processes that converts cellulosic biomass to fuel.	3 (cellulosic biofuel)
Q	Renewable Compressed Natural Gas, Renewable Liquefied Natural Gas, Renewable Electricity.	Biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; and biogas from the cellulosic components of biomass processed in other waste digesters.	Any	3 (cellulosic biofuel)

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Andrew Lewis Trump

Senior Principal, Energy & Utilities

Experience

Education

Total Years of Experience

Years of Experience with West Monroe

Professional Registrations

Publications

Presentations

Testimonies

Andrew is an energy regulatory and business specialist and planner with over 36 years of experience in the energy and infrastructure sector. He has worked with a wide number of diverse clients (regulated utility, non-utility affiliates, and energy industry venture companies) on the regulatory and financial justification of major investments and initiatives.

His work areas of interest and expertise include: (a) Drive infrastructure solutions for electric and gas utilities, merchants, and technology firms at formative stages of the life cycle: strategy, business case, pilot evaluation, regulatory support and justification, stakeholder support, cost recovery, project formation, change management, project monitoring and evaluation. (b) Provide expert witness testimony support on regulatory cost/benefit analysis and risk-based decision support. (c) Support a variety of client communication and representation demands within regulatory venues at local, regional, and state levels.

Andrew joined West Monroe in January 2021. Prior, he was independent for a period of two years. From 2008-2018 he was a Director with Black & Veatch's Management Consulting practice. Prior to Black & Veatch Andrew held the following progressive experiences:

- Senior Consultant at California Environmental Associates (1989-1995).
- Senior Manager, CellNet Data Systems, San Carlos, CA (1995-1999)
- Director of Development and Licensing, Duke Energy North American, Oakland, CA (2000-2007)

Experience Details:

WEST MONROE – SENIOR PRINCIPAL - ENERGY & UTILITIES PRACTICE, NEW YORK, NY 2021 - PRESENT

Support senior level energy market engagements in areas of grid capital investment planning; provide thought leadership in areas of gas planning, decarbonization strategies, DER, EV, grid planning and regulatory reform. Provide expert witness testimony and defense.

- Regulatory cost-benefit expert. Expert witness and testimony development.
- Grid investment strategies including decarbonization, EV and DER integration. Thought leadership and business development.
- Regulatory assessments in areas of gas system transition planning (as part of system-wide electrification efforts)

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INDEPENDENT CONTRACTOR, NEWTOWN SQUARE, PA **2018 to 2021**

(Includes close collaboration with Charles River Associates, Washington, DC, as an independent contributor).

Lead and support senior level energy market engagements in areas of capital investment planning, integrated resource planning (IRP), DER and technology integration, stakeholder engagement, and project management.

BLACK & VEATCH MANAGEMENT CONSULTING, NEWTOWN SQUARE, PA **2007 - 2018**

A global engineering, consulting, construction, and operations company specializing in infrastructure development in energy, water, and telecommunications.

Director, Utility Practice

Expert in capital investment, risk and project valuation. Provide investment analysis of technologies, energy markets, and regulatory reform factors to determine feasibility and sustainabilty of grid modernization infrastructure opportunities. Author testimony for petitions of state commissions and strategic analysis for senior executives; Regulatory cost/benefit expert. Drive cross functional teams of analysts and engineers in time sensitive assignments.

- Delivered regulatory cost-benefit analyses in areas of grid modernization investments for electric, gas and water systems.
- Expert witness testimony.
- Delivered investment strategy and business case for 5G telecommunications opportunities.
- Delivered innovative delivery methods for utility engineering organization facing disruptive effects of Distributed Energy Resource (DER) investments and planning integration challenges.
- Performed asset valuation studies for pumped storage hydro and other generation facilities.

DUKE ENERGY NORTH AMERICA (DENA), OAKLAND, CA **2000 – 2007**

Owner and operator of power generation assets throughout North America.

Licensing / Developer

Recruited for expertise in regulatory affairs, energy market reform, stakeholder collaboration and multi-party negotiation skills.

Principally charged with gaining approvals for the redevelopment of a brownfield 1,200 MW power plant located on the coast in Morro Bay, CA. $1B project presented some of the most challenging land use requirements found anywhere in the United States. Extensive levels of regulatory and public stakeholder interactions. Led all aspects of Application for Certification (AFC) before the California Energy Commission (CEC) for the proposed re-development.

- Led efforts to gain CEC approvals. Directed team in the creation of CEC application (AFC). Gained majority stakeholder support in intensive, contentious, and publicly visible effort, ultimately obtaining CEC certification. Fought ballot initiatives. Led multi-disciplinary team of experts (engineering, environmental, business, legal). Negotiated significant land use and marine biology mitigation agreements. Managed large $20M+ development budget.
- Led team in rebuttal to federal water permit legal actions threatening closure of 2,400 MW Moss Landing facility. Assessed, analyzed, and delivered successful defense of plant's

federal water permit (Federal 316A and 316B). Served as lead expert witness, providing sworn testimony to responsible agency.

- Led stakeholder and CEC AFC process for 600 MW power plant development at Chula Vista Power Plant (San Diego region). Developed CEC licensing application (AFC). Negotiated land use agreement with Port of San Diego, aimed at integrating development into bayfront master plan. Evaluated and negotiated regional reliability benefits and long-term power purchase contract options.

OTHER CAREER APPOINTMENTS

- Senior Manager, Business Development, CellNet Data Systems, San Carlos, CA – 5 years (1996 – 2000). Develop and implement wireless telemetry systems to electric and gas utilities throughout North America. Developed and negotiated contracts.

- Senior Consultant, California Environmental Associates (CEA), San Francisco, CA – 7 years (1989 – 1996); Extensive work with the nation's Class 1 freight railroads on federal and state locomotive emission rules affecting heavy-duty diesel engine requirements. Coordinated and participated in technical studies and presented on behalf of railroad companies in workshops. Authored technical and policy comments to the California Air Resources Board (CARB), EPA, FRA, and other agencies.

Education and Formal Training:

- Harvard EdX: Data Analytics Certificate Program. Several Classes (2019-2021)
- MA, Public Policy, George Mason University, Arlington, VA (2010)
- BA, Physical Sciences (Math, Chemistry and Physics), Harvard University (1984)
- Professional Certificate, Project Management, University of California at Berkeley Extension (PMBOK-based) (2003)
- Duke Energy Corporate Media and Public Relations Training (2001)
- Program on Negotiation (PON), Harvard University (2002)

Areas of Expert Testimony Development

- Grid Modernization (gas and electric): Reliability and Resiliency Planning, Smart Grid, AMI, DA. (PSE&G Electric, PSE&G Gas, ComEd, Dominion Virginia, Vectren Indiana, Southern Maryland Energy Cooperative, PECO, BG&E, Hawaiian Electric).

- Power Plant Facility Licensing (team lead, and responsible for): Project Description, Facility Closure, Electric Transmission Interconnection, Natural Gas Supply, Water Supply, Air

	Quality, Transportation, Visual Resources, Hazardous Material Handling, Waste Management, Land Use, Noise, Public Health, Worker Health and Safety, Socioeconomics. - Application of practice standards in the conducting of costs-benefit analysis (CBA) as applied to utility pilots and demonstrations. **See:** In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to new technologies and business models. **MPSC Case No: U-20898.** Proposed Requirements and Further Guidance on Benefit-Cost Analyses for Pilot Initiatives Prepared by DTE Electric Company and Consumers Energy Company. February 1, 2023. ***Publications*** Trump, Andrew. "More Needed on Resiliency Valuation Challenges." Public Utilities Fortnightly. November 2022. Trump, Andrew and Kao, Caleb. "An Adequate Level of Resilience: Valuation Challenges." Public Utilities Fortnightly. September 2022. Trump, Andrew, South, David and Zolton, Kaitlyn. "Expanded Climate Risk Disclosure Requirements by the Security and Exchange Commission." Climate and Energy. September 2021. Volume 38, no. 2. Wiley Periodicals, Inc. Trump, Andrew and Chastain-Howley, Andrew. "Water Utilities Are Lagging Other Utilities in the Smart Cities Effort." *Black & Veatch*. https://www.bv.com/Home/news/solutions/water/water-utilities-are-lagging-other-utilities-in-the-smart-cities-effort. Trump, Andrew and Pletka, Ryan. "Arizona Says Net Metered Utility Customers Must Pay." *Black & Veatch*. https://www.bv.com/Home/news/solutions/energy/arizona-says-net-metered-utility-customers-must-pay. Trump, Andrew and Azer, Rick. "Utilities Discover a New Era of Engagement as the Focus Shifts to the Customer of One." *Black & Veatch*. https://www.bv.com/Home/news/solutions/Smart-Cities-Telecom/building-smart-cities-will-require-creative-funding-approaches. Trump, Andrew. Interview by Adam Stone. "Making a Case of Water as a Key Component of the Smart City." Government Technology, January 10, 2017, http://www.govtech.com/fs/infrastructure/Making-a-Case-for-Water-as-a-Key-Component-in-the-Smart-City.html. Trump, Andrew. "Where is the Smart Grid Going from Here?" *Electric Light & Power*, July 13, 2010. http://www.elp.com/articles/electric-light-and-power-newsletter/articles/2010/07/where-is-the-smart-grid-going-from-here-.html. Trump, Andrew. "Business Case Tradeoffs: Shaping Long-Term Smart-Grid Strategy." *Public Utilities Fortnightly*, June 2010. https://www.fortnightly.com/fortnightly/2010/06/business-case-tradeoffs. Trump, Andrew. "Smart-Grid Stimulus: Utilities Hurry Up and Wait to Apply for Grant Money." Public Utilities Fortnightly, June 2009. https://www.fortnightly.com/fortnightly/2009/06/smart-grid-stimulus.

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Trump, Andrew. "Planning for AMI/Smart Grid Adoption in a Difficult Economic Climate." *Electricity Today*, April 2009. http://www.electricity-today.com/.

Trump, Andrew and Steklac, Ivo. "A Planning Guide for AMI: How to Manage the Metering Selection Process." Public Utilities Fortnightly, September 2007. https://www.fortnightly.com/fortnightly/2007/09/advanced-metering-infrastructure-special-report-planning-guide-ami.

Trump, Andrew. "An Evaluation of Natural Gas-Fueled Locomotives." California Environmental Associates, July 2006.

Trump, Andrew. "Building the Business Case for Smart Grid." *Generating Insights*, IBM, Fall 2010.

Presentations and Media Exposure

- Advanced Energy Conference (AEC), 2022, New York City, NY. "Business Models and Regulation for Resiliency, and DERs". Conference panel moderator. September 8, 2022.
- "A View of the Electricity Business Model of Tomorrow: Electric Distribution System Planning," POWER-GEN International, December 2016, Orlando, FL.
- "Recovery of Innovation Investments", Edison Electric Institute (EEI) Conference, Chicago, October 2012.
- Presentations at Executive/Senior Staff Stakeholder Sessions as part of Settlement or Mitigation Program Negotiations.
- Sponsorship and Convening of Public Workshops for the Review and Discussion of Infrastructure Projects and Programs.
- Representation of Client Projects in Open Public Settings as part of Routine or Special Sessions.
- Numerous Formal Technical Reports and Presentations as part of the Public Record.

Professional Affiliations

The Institute of Asset Management | Enterprise Risk Management (ERM) | ISO 31000 Risk Management Standard

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Grid Modernization

- Petition of Virginia Electric and Power Company, for approval of a plan for electric distribution grid transformation projects pursuant to 56-585.1 A 6 of the Code of Virginia. Case No. PUR-2021-00127. (a) Direct Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed June 21, 2021. (b) Rebuttal Testimony of Andrew L. Trump. Virginia Electric and Power Company, filed October 1, 2021. Available at: https://scc.virginia.gov/DocketSearch#caseDocs/142210

- In The Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (*Energy Strong II*). BPU Docket Nos. EO18060629 and GO18060630. Attachment 5: Cost-benefit analyses of the electric portion of the Energy Strong II Program. Attachment 6: Cost-benefit analyses of the gas portion of the Energy Strong II Program. Available at: https://nj.pseg.com/aboutpseg/regulatorypage/regulatoryfilings
- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South). IURC Cause No. 44910. Direct Testimony of Andrew L. Trump, Director, Utility Practice, Black & Veatch Management Consulting, LLC. On AMI Cost Benefit Evaluation. Sponsoring Petitioner's Exhibit No. 5, Attachments ALT-1 Through ALT-3. https://iurc.portal.in.gov/legal-case-details/?id=3b675b4f-eff9-e611-80fd-1458d04e2f50
- Illinois Commerce Commission v. Commonwealth Edison Company, No. 12-0298. Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act. Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 6.0, 6.01 and 6.02, "Cost Benefit Analysis of Commonwealth Edison (ComEd) Smart Grid Advanced Metering Infrastructure Deployment Plan (AMI Plan)" (filed April 23, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=180884.
- Also, Rebuttal Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 12, 12.01, 12.02 and 12.03 (filed May 17, 2012). https://www.icc.illinois.gov/docket/files.aspx?no=12-0298&docId=182177.
- Illinois Commerce Commission v. Commonwealth Edison Company. No. 14-0212. Petition to Approve *Acceleration* of Meter Deployment under ComEd's AMI Plan. (Petition for Statutory Approval of a Smart Grid: Advanced Metering Infrastructure Deployment Plan pursuant to Section 16-108.6 of the Public Utilities Act). Direct Testimony of Andrew L. Trump on behalf of Commonwealth Edison Company. Ex. 2.0 and 2.01 (filed March 13, 2014). https://www.icc.illinois.gov/docket/files.aspx?no=14-0212&docId=210863.

Abbreviated List of Formal Testimonies as part of Litigated Proceedings – Power Plant Development

Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the Morro Bay Power Plant Project:

- Morro Bay Modernization and Replacement Power Plant Project. Application for Certification. Docket No. 00-AFC-12. October 23, 2000. http://www.energy.ca.gov/sitingcases/morrobay/.

	- Expert Witness Testimony of Andrew L. Trump provided before the California Energy Resources Conservations and Development Commission (Energy Commission). http://www.energy.ca.gov/sitingcases/morrobay/index.html. Directly responsible for the preparation and representation of the Duke Energy North America Application for Certification (AFC) before the California Energy Commission for the LS Power South Bay LLC South Bay Replacement Project (SBRP): - South Bay Replacement Project Power Plant Licensing Case. Docket No. 06-AFC-03. Filed June 30, 2006. http://www.energy.ca.gov/sitingcases/southbay/documents/applicants/afc/. - (Note, LS Power acquired Duke's interests mid-2006). Responsible for the preparation and expert witness testimony and representation of Duke Energy North America's formal legal testimony before the California State Lands Commission and the Central Coast Water Quality Control Board in the legal challenge brought by Plaintiffs to the continued operation of the 1,000 MW Moss Landing Combined Cycle Power Plant (reliant on once-through cooling technology, and in relation to the federal Clean Water Act permit authority). (2002-2003).

Shelly Hagerman, PhD

Senior Principal, Energy & Utilities

Education Carnegie Mellon University, PhD in Engineering & Public Policy Smith College, B.S. in Engineering, B.A. in Music **Total Years of Experience:** 10 **Years of Experience with West Monroe:** 6.5	Shelly is a new technology strategy and business case specialist, with over 10 years of experience in the energy and infrastructure sector. Throughout her career, she has worked with a variety of clients on developing strategies and developing cost-benefit analysis to support utilities in decarbonization and grid modernization. Shelly has led the development of decarbonization strategies for utilities, including a Clean Energy Implementation Plan, and a Transportation Electrification Plan. Through these experiences, among others, Shelly supports utilities in developing portfolios of programs and enabling investments to meet clean energy mandates while creating equitable access and participation by all customers in a way that balances rate impacts. Shelly has led the development of cost-benefit analysis, spanning grid modernization, distributed energy resources, non-wire alternatives, transportation electrification, outage management systems, and fiber leasing. Shelly also has experience in implementing guiding principles and frameworks from the National Standard Practice Manual for BCA of DERs. ***EXPERIENCE HIGHLIGHTS:*** **Uniform BCA Requirements for Pilot Proposals** ***Two Mid-Size Midwest Utilities,*** *September 2022 – December 2022* • Led the development of proposed uniform, state-specific BCA requirements for all pilot proposals • Developed Jurisdiction-Specific Test based on policy and regulatory objectives and applying the National Standard Practice Manual framework • Conducted multi-utility workshops with over 50 stakeholders, navigating BCA requirement discussions across a diverse set of pilot use cases **Virtual Power Plant Operating Model** ***Large West Coast Utility,*** *March 2022 – October 2022* • Served as Technical Lead to develop Virtual Power Plant strategy to enhance value from a portfolio of over 200 MW of flexible load resources

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- Developed budget, forecast, and plant parameter sheet of Virtual Power Plant through 2030
- Developed business and technical requirements to support Vendor selection though end-to-end business process mapping and grid service activity sequence diagrams

Digital TCO Platform
Multiple Utilities, *October 2019 – Present*

- Creator of West Monroe's model that underlies multiple deployments of web-based and offline Total Cost of Ownership calculator for EVs
- Developed the calculations for the total costs and benefits of EV adoption, for both fleet electrification and consumer EV adoption
- Lead technical advisor for Fleet Concierge Assessments

Clean Energy Implementation Plan & DER CBA Model
Large West Coast Utility, *December 2019 – December 2020*

- Developed a multi-perspective CBA model for DERs to evaluate various program concepts and advised on applications for RFP vendor selection
- Helped establish the preferred portfolio selection process for over 120 MW of DERs
- Primary contributor of the DER-related sections of Clean Energy Implementation Plan

EV Fleet and Public Charging Business Cases & Filing Support
Multiple Utilities, *August 2019 – June 2022*

- Led the design of multiple EV programs and tariffs that have been approved by public utility commissions
- Developed the underlying CBAs to quantify costs and benefits to the utility and program participants
- Coordinated with rates and regulatory teams to calculate revenue requirements
- Developed testimony and drafted responses to staff and stakeholder comments and inquiry

Grid Transformation Plan CBA
Large East-Coast Utility, *April 2019 – September 2019*

- Led GHG and reliability benefit calculations of $3B grid transformation plan
- Leveraged industry tools (e.g., ICE Calculator) and developed bottoms-up benefit calculations for GHG savings

PUBLICATIONS & SPEAKING ENGAGEMENTS:

	Podcast: *Utility or "Trusted Energy Advisor"…or both.* Beyond the Data, Utility Analytics Summit. https://beyond-the-data.simplecast.com/episodes/utiity-or-trusted-energy-advisoror-both *EV 101*. EUCI, January 2022, April 2021, and April 2020 (Presenter and Moderator for 4+ hours of a 1.5-day EV training course *EUCI Leadership Confernce for Women in EVs and Transportation.* October 2021 (Moderator) *Building a DER Portfolio through Business Case Modeling*, PLMA Hot Topic Conversation, April 2021 (Presenter) Guest Lecturer at the University of Illinois Chicago. March 2021, March 2019, March 2018, and March 2017. Topics included Grid Modernization, EVs, and DERs. *Webinars: EV Fleet and Total Cost of Ownership, Transportation Electrification Business Case*. West Monroe, 2020 (Panelist) *Lessons from the Cutting Edge of EV Load Management.* PLMA, April 2020 (Presenter) *Sustainability Trends in the Transportation Industry*. IISE, April 2019 (Presenter) *The Role of Energy Storage in Grid Modernization*. Energy Storage Global Innovation Forum, June 2018 (Presenter and Moderator) *Economics of Energy Storage for Commercial and Industrial Customers.* Carnegie Mellon Electricity Industry Center. October 2016 (Presentation) S. Hagerman, P. Jaramillo, and M. G. Morgan, "Is rooftop solar PV at socket parity without subsidies?" *Energy Policy*, vol. 80, pp. 84-94, 2016 *Evaluating the Economics of Solar PV for Residential, Commercial, and Industrial Customers.* USAEE/IAEE North American Conference, October 2015 (presentation)

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE NEXT PHASE OF THE GAS SYSTEM MODERNIZATION PROGRAM AND ASSOCIATED COST RECOVERY MECHANISM (“GSMP III”)

BPU Docket No. __________

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

March 1, 2023

PUBLIC SERVICE ELECTRIC
AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

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

A. My name is Stephen Swetz and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS-GSMPIII-1.

Q. Please describe your responsibilities as the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation.

A. As Senior Director - Corporate Rates and Revenue Requirements, my primary duties are to plan, develop and direct Public Service Electric and Gas Company's ("PSE&G" or "the Company") calculation of electric and gas revenue requirements for the Company's base rates as well as all cost recovery clauses. I also direct the retail pricing strategies, retail rate design, embedded and marginal cost studies, and development and interpretation of tariff provisions.

Q. What is the purpose of your direct testimony in this proceeding?

A. My testimony provides the details for the calculation of PSE&G's Gas System Modernization Program III ("GSMP III" or "the Program") revenue requirements, the associated cost recovery methodology and rate design for the GSMP III Petition filed with the New Jersey Board of Public Utilities ("BPU" or "the Board"). This testimony also provides detailed schedules setting forth the projected revenue requirements, rates and bill impacts over the expected Program life.

Q. Please describe the work contained in the GSMP III Program?

A. As defined in Mr. Wade Miller's Testimony on page 3, the primary focus of the Program is to replace cast iron mains, unprotected steel mains and services, abandonment of district regulators associated with cast iron and unprotected steel mains, and relocation of inside meter sets ("Replacement Subprogram"). Additionally, the Company proposed a Hydrogen Demonstration Project ("Hydrogen Project") that will blend hydrogen into the gas distribution system as well as Renewable Natural Gas ("RNG") Project ("RNG Project") that will upgrade landfill gas to pipeline quality specifications where it will then be injected into the gas distribution system.

Q. Please briefly describe PSE&G's proposed GSMP III cost recovery methodology.

A. PSE&G's proposed GSMP III cost recovery mechanism is consistent with the BPU's "Infrastructure Investment And Recovery" regulation under which utilities may propose Infrastructure Investment Programs ("IIP")[1]. The GSMP III cost recovery proposal is also consistent with Gas System Modernization Program II ("GSMP II") where applicable, which was approved by the Board in Docket No. GR17070776 on May 22, 2018. Due to the unique nature of Hydrogen and RNG Projects, they also provide financial benefits via gas sales and environmental attributes. As part of this proposal, these financial benefits would be returned to customers as detailed further below in this testimony.

[1]. N.J.A.C. 14:3-2A.

Cost Recovery for Capital Expenditures and O&M Expenses:

Q. How does PSE&G propose to calculate the revenue requirements related to Capital Expenditures and O&M Expenses ?

A. PSE&G proposes to calculate the revenue requirements associated with the Program costs using the formula below:

*Revenue Requirements = ((After Tax Cost of Capital * Rate Base) + Net of Tax Amortization and/or Depreciation + Expense Adjustment + Tax Adjustment)* Revenue Factor*

This calculation is the same as the calculations utilized in PSE&G's Infrastructure Programs as approved by the Board in the respective Board Orders. The Company is proposing to recover the revenue requirements through semi-annual rate adjustment filings as described below, consistent with the BPU's IIP regulations.

Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation.

"After-Tax Cost of Capital" is PSE&G's overall after tax weighted average cost of capital ("WACC") for the Program. PSE&G shall earn a return on its net investment in the GSMP III based upon an authorized return on equity ("ROE") and capital structure including income tax effects. The Company's initial After Tax WACC for the Program will be based on the ROE, long-term debt rate, and capital structure authorized by the Board in the Company's base rate case proceeding adjusted for current income taxes. Any change in the WACC authorized by the Board in a subsequent gas base rate case will be reflected in the subsequent monthly revenue requirement calculations. See Schedule SS-GSMPIII-3 for the calculation of the current After-Tax WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in any subsequent electric, gas, or combined base rate case would be reflected in the appropriate corresponding rate adjustment filing explained in more detail below. Any changes to current Federal or State tax rates would also be reflected in an adjustment to the After-Tax WACC.

"Rate Base" - Contains Gross Plant less the associated accumulated depreciation and/or amortization less Accumulated Deferred Income Taxes ("ADIT"). Gross Plant is equal to all Direct Plant In-Service, Construction Work in Progress ("CWIP") that is transferred into Service, along with its corresponding Allowance of Funds Used during Construction ("AFUDC") – both debt and equity components.

The book recovery of each asset class or specific asset and its associated tax depreciation will be based on book depreciation rates in accordance with the Company's Capital Asset Policy. The current annual book depreciation rates are listed in the table below. These depreciation rates are periodically updated during a base rate case or when new asset classes are added.

ADIT is calculated as the cumulative sum of annual deferred income taxes. Annual deferred income taxes are calculated as Book Depreciation Expense (Tax Basis) less Tax Depreciation Expense, multiplied by the Company's effective tax rate, which is currently 28.11%. Annual Book Depreciation Rates and Tax Depreciation Methods for capital expenditures are listed in the table below. Cost of Removal expenditures are depreciated 100% in the year incurred for tax purposes.

Asset Class / Asset[2]	Annual Book Depreciation Rates	Tax Depreciation (Years) - MACRS)
Distribution Plant – Mains	1.39%	20 yr.
Distribution Plant - Services	1.81%	20 yr.
Distribution Plant - House Regulator Installations	3.27%	20 yr.
RNG Project	5.00%	20 yr.
Hydrogen Project	4.00%	20 yr.

While current Tax legislation does not allow bonus depreciation tax deductibility for utility investment, at this time, any future changes to the book, or tax depreciation rates, such as, but not limited to, reinstatement of "bonus depreciation" during the construction period of the Program and at the time of each base rate adjustment, will be reflected in the accumulated depreciation and/or ADIT calculation described above.

"Net of Tax Depreciation and/or Amortization" - Allows for recovery of the Company's investment in the Program assets over the useful book life of each asset class less income tax effects. PSE&G proposes to depreciate GSMP III assets in accordance with the Company's depreciation rates. The book recovery of each asset class or specific asset will be based on the Company's actual depreciation rates (see table above for current rates). For Plant in Service investments, the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. For CWIP projects that accrue AFUDC because they are not yet in service, there is no tax deduction for the equity portion of the capitalized AFUDC. As a result, the net of tax depreciation expense is calculated as the depreciation expense associated with the Gross Plant (defined above), excluding the equity

[2] The RNG an Hydrogen Projects Assets will be depreciated using the End of life deprecation methodology with 20 and 25 year lives respectively

portion of AFUDC, multiplied by one minus the current tax rate. Since the equity portion of AFUDC will not be included in the tax basis of the Program assets, the equity portion must be grossed-up for taxes in order for the Company to earn its allowed rate of return. Any future changes to the book depreciation or tax rates during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the net of tax depreciation expense calculation described above.

"Expense Adjustment" – Includes Operational and Maintenance ("O&M") savings from leak reductions due to the Replacement Subprogram as well as ongoing annual expenses related to the operations and maintenance ("O&M") of the proposed RNG and Hydrogen Projects. The Replacement Subprogram savings, based upon Mr. Wade Miller's Testimony, are expected to save $2,895/mile ($3.3 million / 1,140 miles) and will be incorporated to each rate adjustment based upon the miles of main in service related to each rate adjustment period. The ongoing annual O&M expenses for the Hydrogen and RNG Projects are the annual average for the initial five (5) full calendar years of operation for each project. These amounts are located in Mr. Wade Miller's testimony, Schedule WEM-GSMPIII-5

"Tax Adjustment" - Includes any applicable tax items that may impact the revenue requirement calculation for the Program.

Currently, it is anticipated that the Hydrogen Project will be eligible for an Investment Tax Credit ("ITC") of thirty (30) percent of eligible construction expenditures providing construction starts by December 31, 2024. The Company will return all of the ITC it utilizes to customers in accordance with Federal income tax law. The return of the ITC to ratepayers must be amortized over the book life of the assets. The ITC benefit is partially offset by the tax impact associated with the tax basis reduction equal to fifty (50) percent of the ITC. This tax basis reduction is prescribed by Federal income tax law governing the ITC. The impact on revenue requirements is generated by applying the book depreciation method to the difference between the book basis and the tax basis multiplied by the tax rate. Details of these calculations can be found in WP-SS-GSMPIII-2a.xlsx

While the RNG Project could be eligible for the same ITC, the Company is not forecasting receiving the ITC due to its construction start date occurring after the December 31, 2024 deadline. However, if the RNG project is able to meet the requirements for ITC eligibility, the Company will include the ITC in the calculation of the project's revenue requirements.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes, the BPU and Rate Counsel ("RC") Annual Assessments Fees and for Gas Revenue Uncollectibles (See Schedule SS-GSMPIII-4). The BPU/RC Assessment Expenses consist of payments, based upon a percentage of revenues collected (updated annually), to the State based on the gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2022 fiscal year assessment. The percentage used to calculate the gas uncollectible expense is based upon the rate approved in the Company's last base rate case. Any change in the uncollectible rate in any future base rate case proceeding will be reflected in the any subsequent GSMP III rate adjustment proceeding calculation. Any future changes impacting the revenue factor at the time of each base rate adjustment would be reflected in the revenue factor described above.

Q. Please describe the type of expenditures to be included in Rate Base?

A. The Program will include requests for recovery in its GSMP III rates of all capital expenditures associated with the GSMP III projects, including actual costs of engineering, design and construction, cost of removal (net of salvage) and property acquisition, including actual labor, materials, overhead, and capitalized AFUDC associated with the projects (the "Capital Investment Costs"). Capital Investment Costs will be recorded, during construction, in an associated CWIP account or in a Plant In-Service account upon the respective project being deemed used and useful.

Q. Are there any items that may affect the tax impacts of the Program?

A. Yes. While other items may arise in the future, such as tax bonus depreciation, there are three areas that the Company wishes to make the BPU aware of that may affect this Program in the future. These are:

1. The amount and vintage of assets that will be removed and retired may impact various tax deductions such as repair allowance, retirements, and cost of removal. At the time such actual information becomes available, the impact of these deductions on either rate-base or tax expense will be incorporated into the ADIT balance.
2. The IRS has announced that it will be issuing further guidance regarding the tax repair deduction that applies to gas distribution activities. This guidance is anticipated to be released and effective within the Program investment period. As these rules are not yet known, they have not been incorporated in this filing.

3. The recent Inflation Reduction Act implement many tax code changes that may impact the Revenue Requirement Calculation. The Calculation will be modified to reflect these changes as required..

Q. Will any of the GSMP III expenditures be eligible for AFUDC?

A. Yes, but only for those projects that meet the Company's criteria for accrual of AFUDC. AFUDC is a component of construction costs representing the net cost of borrowed funds and an equity return rate used during the period of construction. Under the Company's current policy, only projects that have both costs exceeding $5,000 and a construction period longer than 60 days are eligible for AFUDC. Most of the investments under this Program are not anticipated to be eligible to accrue AFUDC because they will take less than 60 days to construct. However, the Hydrogen and RNG projects will require more than 60 days of construction and will therefore accrue AFUDC. In the event the Company's criteria for the accrual of AFUDC changes, the Company's criteria in place at the time the expenditures are incurred would then be applied.

Q. How will AFUDC be calculated on eligible projects?

A. The Company accrues AFUDC on eligible projects at a rate that is calculated utilizing the "full FERC method" as set forth in FERC Order 561. AFUDC is accrued monthly and added to CWIP until the project is placed into service[3].

Q. Will the Company utilize AFUDC once the projects are placed into service?

A. No. The projects will not utilize AFUDC once they have been placed into service.

[3] Construction Work in Progress (CWIP) is an account into which the costs are recorded that are directly associated with constructing an asset which is not yet in-service.

Q. What is the source of the capital expenditures you use to calculate the revenue requirements?

A. The projected monthly capital expenditures for the Replacement Subprogram, Hydrogen and RNG Projects are provided in Mr. Wade Miller Testimony, Schedule WEM-GSMPIII-4.

Q. Is the Company planning capital expenditures similar to those included in GSMP III that will not be recovered via GSMP III?

A. Yes, the Company plans to maintain capital expenditures of at least 10% of the approved GSMP III expenditures on projects similar to those proposed in GSMP III. These capital expenditures shall be made in the normal course of business and recovered in future base rate proceedings, and shall not be subject to the recovery via the GSMP III cost recovery mechanism.

Q. Are there schedules showing the calculation of the revenue requirements?

A. Yes. See Schedules SS-GSMPIII-2 and SS-GSMPIII-2a for the calculation of the GSMP III revenue requirements. Schedule SS-GSMPIII-2 contains the summary for all seven (7) rate adjustments while Schedule SS-GSMPIII-2a contains the detailed calculations for third and sixth rate adjustments. Rate adjustments one, two, four, five and seven only contain revenue requirements for the Replacement Subprogram. The third rate adjustment includes revenue requirements for the Replacement Subprogram and the Hydrogen Project. The sixth rate adjustment includes revenue requirements for the Replacement Subprogram and the RNG Project.

Q. How does the Company propose to recover the revenue requirements?

A. The Company proposes to recover the revenue requirements associated with the Program via new GSMP III rate components of its Infrastructure Investment Program Charges ("IIPCs") for the Gas Tariffs. The Company plans to recover the revenue requirements through semi-annual rate adjustment filings, which is in compliance with the BPU's IIP regulations.

The schedule for the Initial Filing, Investment as of, Update for Actuals Filing, and Rates Effective dates for all gas and gas rate adjustment filings, assuming Board approval of the Program by December 31, 2023, are listed below.

Each Initial Filing shall provide the actual cost and forecast for investment data, revenue requirement calculations, proposed GSMP III rates, and related data to support rates based on GSMP III capital costs, including engineering costs, commencing upon the Board's approval of the Program as indicted the schedule below.

The Update for Actuals Filing, updates all forecasted cost and investment data, revenue requirement calculations, proposed GSMP III rates, and related information from the Initial Filing to data based on all actual historical data. GMSP III investments included in rates in the Update for Actuals Filing shall only include GSMP III investment not in the Company's base rates and actually placed in-service according to the schedule below.

The Rates Effective dates for each filing below shall be as indicated in the table below, with the Initial filing no later than June 30, 2024 resulting in rates effective December 1, 2024 subject to Board approval. See table below

GSMP III Rate Adjustment Schedule

Rate Adj #	Initial Filing	Investment as of	Update for Actuals Filing	Rates Effective
1	6/30/24	8/31/24	9/15/24	12/1/24
2	12/31/24	2/28/25	3/15/25	6/1/25
3	6/30/25	8/31/25	9/15/25	12/1/25
4	12/31/25	2/28/26	3/15/26	6/1/26
5	6/30/26	8/31/26	9/15/26	12/1/26
6	12/31/26	2/28/27	3/15/27	6/1/27
7	6/30/27	8/31/27	9/15/27	12/1/27

The IIP regulations limit each gas rate adjustment request to a minimum investment level of 10 percent of total Program investment. Therefore, actual rate adjustments filings may occur less frequently then reflected in the table above. Based upon the Company's estimated investment expenditures, the first rate adjustment filing is projected to occur no later than June 30, 2024.

The GSMP III is scheduled to be complete by December 31, 2026, except for certain close out work that may occur for up to 3 to 6 months following the conclusion of the Program. Without a firm date for completion of this close out work, the Company is proposing a rate filing no later than June 30, 2027 comprised of all actual cost data (as opposed to projected) for rates effective December 1, 2027. Given the nature of the close out work, the final rate adjustment may be less than 10 percent of the Program, but is appropriate to provide completion of the Program.

Q. Is the Company proposing a minimum investment level to complete a base rate roll-in?

A. Yes. Consistent with the proposed IIP regulations, the Company proposes to limit each base rate adjustment to a minimum investment level of 10 percent of the total program investment. The program investment is defined as all capital expenditures as defined previously in my testimony excluding AFUDC. As a result, based on the proposed capital expenditure forecast, the first base rate adjustment filing will occur no later than June 30, 2024 for rates effective December 1, 2024.

Q. Is there any other proposed limit that could impact the amount of investment to be included in a rate base roll-in?

A. Yes, the Company is also proposing to limit the amount of investment to be included in the rate base adjustment by an earnings test. If the Company exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more for the most recent twelve (12) month period, the pending base rate adjustment shall not be allowed for the applicable filing period.

Q. How does the Company propose to calculate this earnings test?

A. Per IIP regulations, the earnings test shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.

Q. What is the corresponding period for the earnings test?

A. The Company will utilize the twelve (12) month period corresponding to the latest available SEC quarterly/annual filing. In the same manner as capital expenditures, the Company will provide nine (9) months of actual data and three (3) months of forecasted data at the time of its initial filing. The three (3) months of forecasted data will be updated with actual information at the same time the Company updates investment for actuals per the schedule above.

Q. Is there any issue with calculating common equity balances for gas?

A. Yes. As the only combined electric, gas and transmission company in the state, calculating deferred taxes and rate base specific to the gas utility on a monthly basis is impractical.

Q. So how do you propose to calculate the starting and ending common equity balance for the earnings test?

A. I'm proposing that the common equity balance to be used in the Company's earnings test be calculated based on the starting and ending net plant balances multiplied by the ratio of net plant to common equity determined in the Company's most recent base rate case.

Q. Is there precedence for this earnings test calculation methodology?

A. Yes. This is the same methodology utilized in the Company's Board approved Energy Strong II Programs ("ES II"), Infrastructure Advancement Program ("IAP"), GSMP II and Conservation Incentive Program ("CIP").

Q. How will the Company address an extension of the GSMP III as described in the testimony of Mr. Miller?

A. Consistent with the long term, continuous effort to replace or rehabilitate all cast iron and unprotected steel mains in its system described in the testimonies of Mr. Miller, PSE&G anticipates filing for a further extension of the Gas System Modernization Program. The intent of the extension request before the end of this three year replacement period is to avoid the costs and delays of ramping down for the end of the current Program and then ramping investment back up for the extension. The Company may seek Board approval to extend the Program beyond the three (3) year term. Any such extension proposal shall be supported by the results of activities from the first two (2) years under this Program. In order to expedite the decision-making process for an efficient continuation of the Program in the event of an extension, the Company may initially file for such extension with no more than six (6) months of projected data for part of the second year of the Program, with updates through the end of the second year to be filed in sufficient time to allow full consideration as part of the proceedings to consider the proposed extension.

Q. Under this proposal, what opportunity will the BPU and/or Rate Counsel have to review the actual expenditures of the Program?

A. Upon BPU approval of the Program, PSE&G will make semi-annual filings, pursuant with the IIP regulations, subject to the minimum investment level of 10 percent of the total program investment, with actual expenditures based on the schedule described above. BPU Staff and Rate Counsel can review each base rate adjustment filing to ensure the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the Program. The actual prudency of the Company's expenditures involved in implementing GSMP III will be reviewed as part of PSE&G's subsequent base rate case(s) following the base rate adjustment(s).

Q. Does the Company plan to file a base rate case in connection to the proposed GSMP III?

A. Yes. In accordance with the IIP regulations, the Company will file a base rate case no later than five years from the start of the Program[4].

Q. What is the revenue requirement for the initial rate recovery period?

A. The revenue requirement for the first rate is currently forecasted to be $22.992 million. See Schedule SS-GSMPIII-2.

Q. Does the Company plan to do engineering work once Board approval is received for GSMP III?

A. Yes. The Company anticipates conducting engineering work as soon as Board approval is received and include those costs in future rate adjustments.

Q. What rate design is the Company proposing to use for these adjustments?

A. The detailed calculations supporting the gas rate design for the first forecasted rate adjustment is shown in Schedule SS-GSMPIII-5. The rate design for all of the estimated GSMP III rate adjustments would use the same methodology as approved by the Board in the latest approved base rate case. The Company reserves the right to request changes in rate design for the program. In addition, Schedule SS-GSMPIII-6 provides a summary of the proposed GSMP III rates for the forecasted revenue requirements.

Q. What billing determinants does the Company propose to use for each rate adjustment filing?

A. The Company proposes to use the latest weather normalized billing determinants available for setting the rates in each rate adjustment. The estimated rates calculated in

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[4] See N.J.A.C § 14:3-2A.6(f) Infrastructure Investment Program expenditure recovery

Schedule SS-GSMPIII-5 for the first forecasted rate adjustment are based on weather normalized billing determinants approved in the Company's most recent base rate case, which are currently being used for the Company's other IIP programs. For rate adjustments that are effective subsequent to the Company's base rate cases, those corresponding billing determinants will be used once approved by the BPU. To the extent the Company seeks to utilize more current weather normalized billing determinants for any future roll-in filings subsequent to the latest approved base rate case or to change the methodology used to weather normalize billing determinants, PSE&G shall provide those updated billing determinants and supporting data to Board Staff and Rate Counsel a minimum of 60 days prior to any GSMP III rate adjustment filing. The ability to update billing determinants and weather normalization methodology is consistent with the Company's other IIP programs.

Q. Please describe how the financial benefits from the Hydrogen and RNG Projects will be returned to customer?

A. As described in Mr. Wade Miller's Testimony on pages 72-73, and 76, the project will monetize the gas as well as any environmental benefits they produce. The Company is proposing to credit this revenue, net any selling expenses to the BGSS-RSG deferral balance, which will result in lower BGSS-RSG rates.

Q. What are the forecasted annual rate reductions from gas and net environmental benefits sales to the typical residential customer?

A. The BGSS-RSG annual rate reductions are shown in Schedule SS-GSMPIII-7. They are based upon the forecasted gas and net environmental benefit sales included in the electronic workpapers of Mr. Andrew J. Trump, Dr. Shelly Hagerman, and Ms. Margaret Oloriz. See WP-ATMO-GSMPIIIH2-1.xlsx and WP-ATSH-GSMPIIIRNG-1.xlsx. The BGSS-RSG rate reductions associated with the Hydrogen and RNG Projects are shown in Schedule SS-GSMPIII-7a and Schedule SS-GSMPIII-7b respectively.

Q. What are the annual bill impacts to the typical residential customer?

A. Based upon the forecasted rates shown in Schedules SS-GSMPIII-6 and SS-GSMPIII-7, the typical annual bill impacts for a residential customer compared to rates as of March 1, 2023 are set forth in Schedule SS-GSMPIII-8[5]. Based on the estimated revenue requirements provided in Schedule SS-GSMPIII-2 and the BGSS-RSG rate reductions in Schedule SS-GSMPIII-7, the initial annual impact of the proposed rates for the first rate adjustment period to the typical residential gas heating customer who uses 172 therms in a winter month and 1,040 therms annually is an increase of $2.10 per month or approximately 1.12%. The maximum **cumulative** impact (impact from the entire Program) on the typical residential gas heating customer is an average annual increase of approximately 10.41% or about a $10.16 increase in their average monthly bill.

Q. Will the Company hold public comment hearings?

A. Although PSE&G is not proposing a rate increase at this time, the Company proposes public comment hearings similar to those that are held when rate increases are proposed. A proposed form of public notice of filing and public hearings, including the proposed rates and bill impacts attributable to the proposed implementation of the Program are set forth in Attachment 6.

[5]The bill impacts assume that customers receive commodity service from PSE&G under the applicable Basic Gas Supply Service (BGSS) rate.

Q. Does this conclude your testimony?

A. Yes, it does.

SCHEDULE INDEX

Schedule SS-GSMPIII-1	Credentials of Stephen Swetz
Schedule SS-GSMPIII-2	Gas Revenue Requirements Calculation
Schedule SS-GSMPIII-3	Weighted Average Cost of Capital (WACC)
Schedule SS-GSMPIII-4	Revenue Factor Calculation
Schedule SS-GSMPIII-5	Proof of Revenue and Forecasted Rates
Schedule SS-GSMPIII-6	Summary of Rate Adjustments
Schedule SS-GSMPIII-7	Gas/Benefit Sales BGSS-RSG Annual Bill Impacts
Schedule SS-GSMPIII-8	Annual Bill Impacts

WORKPAPER INDEX

WP SS-GSMPIII-1.xlsx	Gas Revenue Requirements
WP SS-GSMPIII-2.xlsx	Hydrogen Demonstration Project Revenue Requirements Support
WP SS-GSMPIII-3.xlsx	RNG Project Revenue Requirements Support
WP SS-GSMPIII-4.xlxs	Gas/Benefit Sales – BGSS-RSG Annual Bill Impacts

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	Energy Strong II Program (Energy Strong II) - First Roll-In
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER18070688 & GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 & GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER18010029 & GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 & GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 & GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 & GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 & GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757 & GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389 & GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II
Public Service Electric & Gas Company	G	ER14070656	written	Jul-14	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER14070651 & GR14070652	written	Jul-14	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER14070650	written	Jul-14	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR14050511	written	May-14	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR14040375	written	Apr-14	Remediation Adjustment Charge-RAC 21
Public Service Electric & Gas Company	E/G	ER13070603 & GR13070604	written	Jun-13	Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	ER13070605	written	Jul-13	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR13070615	written	Jun-13	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR13060445	written	May-13	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO13020155 & GO13020156	written/oral	Mar-13	Energy Strong / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GO12030188	written/oral	Mar-13	Appliance Service / Tariff Support
Public Service Electric & Gas Company	E	ER12070599	written	Jul-12	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12070606 & GR12070605	written	Jul-12	RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR12060489	written	Jun-12	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR12060583	written	Jun-12	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12030207	written	Mar-12	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER12030207	written	Mar-12	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR11060338	written	Jun-11	Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR11060395	written	Jun-11	Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO11010030	written	Jan-11	Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Oct-10	RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E/G	ER10080550	written	Aug-10	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER10080550	written	Aug-10	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR09050422	written/oral	Mar-10	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER10030220	written	Mar-10	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E	EO09030249	written	Mar-09	Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	EO09010056	written	Feb-09	Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO09020125	written	Feb-09	Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO08080544	written	Aug-08	Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Jun-08	Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval

PSE&G Gas System Modernization Program III Attachment 5

Gas Rate Adjustment Calculations - Summary Schedule SS-GSMPIII-2

in ($000)

Rate Adjustment Filing	Rate Adj 1	Rate Adj 2	Rate Adj 3	Rate Adj 4	Rate Adj 5	Rate Adj 6	Rate Adj 7
Rate Effective Date	12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027
Plant In Service as of Date	8/31/2024	2/28/2025	8/31/2025	2/28/2026	8/31/2026	2/28/2027	8/31/2027
Rate Base Balance as of Date	11/30/2024	5/31/2025	11/30/2025	5/31/2026	11/30/2026	5/31/2027	11/30/2027

RATE BASE CALCULATION

		Rate Adj 1	**Rate Adj 2**	**Rate Adj 3**	**Rate Adj 4**	**Rate Adj 5**	**Rate Adj 6**	**Rate Adj 7**	**Total**	
1	Gross Plant	$206,492	$268,864	$363,788	$330,044	$353,605	$490,686	$137,191	**$2,150,670**	= ln 17
2	Accumulated Depreciation	$14,009	$17,716	$22,182	$21,730	$23,865	$20,221	$8,978	**$128,701**	= ln 20
3	Net Plant	$220,501	$286,580	$385,970	$351,774	$377,469	$510,907	$146,170	**$2,279,370**	= ln 1 + ln 2
4	Accumulated Deferred Taxes	-$5,776	-$9,577	-$9,459	-$11,837	-$9,877	-$14,362	-$3,796	**-$64,683**	= See "Dep-" Wkps Row 724 & Schedule SS-GSMPIII-2a
5	Rate Base	$214,725	$277,003	$376,511	$339,937	$367,592	$496,545	$142,374	**$2,214,688**	= ln 3 + ln 4
6	Rate of Return - After Tax (Schedule WACC)	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	**6.48%**	See Schedule SS-GSMPIII-3
7	Return Requirement (After Tax)	$13,918	$17,955	$24,404	$22,034	$23,826	$32,185	$9,228	**$143,549**	= ln 5 * ln 6
8	Depreciation Exp, net	$2,519	$3,280	$5,154	$4,026	$4,314	$9,298	$1,674	**$30,264**	= ln 26
9	Expense Adjustment (After Tax)	-$222	-$289	$1,197	-$355	-$380	$8,281	-$148	**$8,083**	= ln 39
10	ITC and Tax Basis Adjustment	$0	$0	-$278	$0	$0	$0	$0	**-$278**	= ln 27 + ln 28
11	Revenue Factor	1.418	1.418	1.418	1.418	1.418	1.418	1.418	**1.418**	See Schedule SS-GSMPIII-4
12	**Total Revenue Requirement**	**$22,992**	**$29,700**	**$43,216**	**$36,449**	**$39,363**	**$70,564**	**$15,249**	**$257,535**	= ((ln 7 + ln 8 + ln 9 + ln 10) * ln 11)

SUPPORT

	Gross Plant									
13	Plant in-service	$206,492	$268,864	$333,843	$330,044	$353,605	$354,308	$137,191	**$1,984,347**	= See "Dep-" Wkps Row 702 & Schedule SS-GSMPIII-2a
14	CWIP Transferred into Service	$0	$0	$28,835	$0	$0	$123,354	$0	**$152,188**	= See "Dep-" Wkps Row 703 & Schedule SS-GSMPIII-2a
15	AFUDC on CWIP Transferred Into Service - Debt	$0	$0	$261	$0	$0	$3,066	$0	**$3,327**	= See "Dep-" Wkps Row 704 & Schedule SS-GSMPIII-2a
16	AFUDC on CWIP Transferred Into Service - Equity	$0	$0	$849	$0	$0	$9,958	$0	**$10,807**	= See "Dep-" Wkps Row 705 & Schedule SS-GSMPIII-2a
17	**Total Gross Plant**	**$206,492**	**$268,864**	**$363,788**	**$330,044**	**$353,605**	**$490,686**	**$137,191**	**$2,150,670**	= ln 13 + ln 14 + ln 15 + ln 16
	Accumulated Depreciation									
18	Accumulated Depreciation	-$1,533	-$2,521	-$2,946	-$3,112	-$2,751	-$6,448	-$1,348	**-$20,659**	= See "Dep-" Wkps Row 711 & Schedule SS-GSMPIII-2a
19	Cost of Removal	$15,542	$20,237	$25,128	$24,842	$26,615	$26,668	$10,326	**$149,359**	= See "Dep-" Wkps Row 706 & See Schedule SS-GSMPIII-2a
20	**Net Accumulated Depreciation**	**$14,009**	**$17,716**	**$22,182**	**$21,730**	**$23,865**	**$20,221**	**$8,978**	**$128,701**	= ln 18 + ln 19
	Depreciation Expense (Net of Tax)									
21	Depreciable Plant (xAFUDC-E)	$206,492	$268,864	$362,939	$330,044	$353,605	$480,728	$137,191	**$2,139,862**	= ln 13 + ln 14 + ln 15
22	AFUDC-E	$0	$0	$849	$0	$0	$9,958	$0	**$10,807**	= ln 16
23	Depreciation Rates - Composite/Blended Rate	1.70%	1.70%	1.97%	1.70%	1.70%	2.61%	1.70%		=ln 24 / (ln 21 + ln 22)
24	Depreciation Expense	$3,504	$4,562	$7,162	$5,601	$6,000	$12,831	$2,328	**$41,989**	= See Dep- Wkps Row 711 & Schedule SS-GSMPIII-2a
25	Tax @28.11%	$985	$1,282	$2,009	$1,574	$1,687	$3,534	$654	**$11,725**	= ln 21 * ln 23 * Tax Rate
26	Depreciation Expense (Net of Tax)	**$2,519**	**$3,280**	**$5,154**	**$4,026**	**$4,314**	**$9,298**	**$1,674**	**$30,264**	= ln 24 - ln 25
	Tax Adjustment									
27	ITC Amortization	$0	$0	-$323	$0	$0	$0	$0	**-$323.4**	= See Schedule SS-GSMPIII-2a
28	Tax Assoc. w/50% ITC Basis Reduction (net)	$0	$0	$45	$0	$0	$0	$0	**$45.5**	= See Schedule SS-GSMPIII-2a
	Expense Adjustments									
29	Miles of Main Replaced	107	139	173	171	183	183	71	**1026**	See "Miles Replaced" Wkps
30	O&M Savings/ Mile	-2.8947	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89		= $3.3M / 1,140 miles
31	Mains & Services O&M Savings	-$309	-$402	-$500	-$494	-$529	-$530	-$205	**$0**	= ln 29 * ln 30
32	Hydrogen O&M Expense	$0	$0	$2,165	$0	$0	$0	$0	**$2,165**	See Schedule SS-GSMPIII-2a
33	RNG O&M Expense	$0	$0	$0	$0	$0	$12,049	$0	**$12,049**	See Schedule SS-GSMPIII-2a
34	Expense Adjustment	($309)	($402)	$1,665	($494)	($529)	$11,519	($205)	**$11,244**	= ln 31 + ln 32 + ln 33
35	Tax @28.11%	($87)	($113)	$468	($139)	($149)	$3,238	($58)	**$3,161**	= ln 34 * Tax Rate
36	Expense Adjustment (Net of Tax)	**($222)**	**($289)**	**$1,197**	**($355)**	**($380)**	**$8,281**	**($148)**	**$8,083**	= ln 34 - ln 35

PSE&G Gas System Modernization Program III
Gas Rate Adjustment Calculations - Detail
in ($000)

Attachment 5
Schedule SS-GSMPIII-2a

Ln	Item	Replacement Subprogram	Hydrogen	Total	Replacement Subprogram	RNG	Total	
	Rate Adjustment Filing	Rate Adj 3	Rate Adj 3	Rate Adj 3	Rate Adj 6	Rate Adj 6	Rate Adj 6	
	Rate Effective Date	12/1/2025	12/1/2025	12/1/2025	6/1/2027	6/1/2027	6/1/2027	
	Plant In Service as of Date	8/31/2025	8/31/2025	8/31/2025	2/28/2027	2/28/2027	2/28/2027	
	Rate Base Balance as of Date	11/30/2025	11/30/2025	11/30/2025	5/31/2027	5/31/2027	5/31/2027	
	RATE BASE CALCULATION	**Rate Adj 3**	**Rate Adj 3**	**Rate Adj 3**	**Rate Adj 6**	**Rate Adj 6**	**Rate Adj 6**	
1	Gross Plant	$333,843	$29,945	$363,788	$354,308	$136,378	$490,686	= ln 17
2	Accumulated Depreciation	$22,531	-$349	$22,182	$23,346	-$3,125	$20,221	= ln 20
3	Net Plant	$356,374	$29,595	$385,970	$377,654	$133,253	$510,907	= ln 1 + ln 2
4	Accumulated Deferred Taxes	-$9,325	-$133	-$9,459	-$12,649	-$1,712	-$14,362	'See "Hydrogen & RNG" Wkps
5	Rate Base	$347,049	$29,462	$376,511	$365,005	$131,541	$496,545	= ln 3 + ln 4
6	Rate of Return - After Tax (Schedule WACC)	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	See Schedule SS-GSMPIII-3
7	Return Requirement (After Tax)	$22,495	$1,910	$24,404	$23,659	$8,526	$32,185	= ln 5 * ln 6
8	Depreciation Exp, net	$4,073	$1,088	$5,154	$4,322	$5,042	$9,298	= ln 26
9	Expense Adjustment (After Tax)	-$359	$1,556	$1,197	-$381	$8,662	$8,281	= ln 39
10	ITC and Tax Basis Adjustment	$0	-$278	-$278	$0	$0	$0	= ln 27 + ln 28
11	Revenue Factor	1.418	1.418	1.418	1.418	1.418	1.418	See Schedule SS-GSMPIII-4
12	**Total Revenue Requirement**	**$37,163**	**$6,064**	**$43,216**	**$39,136**	**$31,523**	**$70,564**	= ((ln 7 + ln 8 + ln 9 + ln 10) * ln 11)
	SUPPORT							
	Gross Plant							
13	Plant in-service	$333,843	$0	$333,843	$354,308	$0	$354,308	'See "Hydrogen & RNG" Wkps
14	CWIP Transferred into Service	$0	$28,835	$28,835	$0	$123,354	$123,354	'See "Hydrogen & RNG" Wkps
15	AFUDC on CWIP Transferred Into Service - Debt	$0	$261	$261	$0	$3,066	$3,066	'See "Hydrogen & RNG" Wkps
16	AFUDC on CWIP Transferred Into Service - Equity	$0	$849	$849	$0	$9,958	$9,958	'See "Hydrogen & RNG" Wkps
17	**Total Gross Plant**	**$333,843**	**$29,945**	**$363,788**	**$354,308**	**$136,378**	**$490,686**	= ln 13 + ln 14 + ln 15 + ln 16
	Accumulated Depreciation							
18	Accumulated Depreciation	-$2,597	-$349	-$2,946	-$3,322	-$3,125	-$6,448	'See "Hydrogen & RNG" Wkps
19	Cost of Removal	$25,128	$0	$25,128	$26,668	$0	$26,668	'See "Hydrogen & RNG" Wkps
20	**Net Accumulated Depreciation**	**$22,531**	**-$349**	**$22,182**	**$23,346**	**-$3,125**	**$20,221**	= ln 18 + ln 19
	Depreciation Expense (Net of Tax)							
21	Depreciable Plant (xAFUDC-E)	$333,843	$29,096	$362,939	$354,308	$126,420	$480,728	= ln 13 + ln 14 + ln 15
22	AFUDC-E	$0	$849	$849	$0	$9,958	$9,958	= ln 16
23	Depreciation Rates - Composite/Blended Rate	1.70%	5.00%	1.97%	1.70%	5.00%	2.61%	=ln 24 / (ln 21 + ln 22)
24	Depreciation Expense	$5,665	$1,497	$7,162	$6,012	$6,819	$12,831	'See "Hydrogen & RNG" Wkps
25	Tax @28.11%	$1,592	$409	$2,009	$1,690	$1,777	$3,534	= ln 21 * ln 23 * Tax Rate
26	Depreciation Expense (Net of Tax)	**$4,073**	**$1,088**	**$5,154**	**$4,322**	**$5,042**	**$9,298**	= ln 24 - ln 25
	Tax Adjustment							
27	ITC Amortization	$0	-$323	-$323	$0	$0	$0	'See "Hydrogen & RNG" Wkps
28	Tax Assoc. w/50% ITC Basis Reduction (net)	$0	$45	$45	$0	$0	$0	'See "Hydrogen & RNG" Wkps
	Expense Adjustments							
29	Miles of Main Replaced	173	-	173	183	0	183	See "Miles Replaced" Wkps
30	O&M Savings/ Mile	-2.89	0.00	-2.89	-2.89	0.00	-2.89	= $3.3M / 1,140 miles
31	Mains & Services O&M Savings	-$500	$0	-$500	-$530	$0	-$530	= ln 29 * ln 30
32	Hydrogen O&M Expense	$0	$2,165	$2,165	$0	$0	$0	See "Hydrogen" Wkps
33	RNG O&M Expense	$0	$0	$0	$0	$12,049	$12,049	See "RNG" Wkps
34	Expense Adjustment	($500)	$2,165	$1,665	($530)	$12,049	$11,519	= ln 31 + ln 32 + ln 33
35	Tax @28.11%	($140)	$609	$468	($149)	$3,387	$3,238	= ln 34 * Tax Rate
36	Expense Adjustment (Net of Tax)	**($359)**	**$1,556**	**$1,197**	**($381)**	**$8,662**	**$8,281**	= ln 34 - ln 35

PSE&G Gas System Modernization Program III
Weighted Average Cost of Capital (WACC)

Attachment 5
Schedule SS-GSMPIII-3

November 2018 Forward

	Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After-Tax Weighted Cost
Common Equity	54.00%	9.60%	5.18%	7.21%	5.18%
Customer Deposits	0.47%	0.87%	0.00%	0.00%	0.00%
Long-Term Debt	45.53%	3.96%	1.80%	1.80%	1.30%
Total	100.00%		6.99%	9.02%	6.48%

Income Tax Rates

Federal Income Tax	21.00%
State NJ Business Incm Tax	9.00%
Tax Rate	28.11%

PSE&G Gas System Modernization Program III
Revenue Factor Calculation

Attachment 5
Schedule SS-GSMPIII-4

	GAS	
Revenue Increase	100.0000	
Uncollectible Rate	1.6000	2018 Base Rate Case
BPU Assessment Rate	0.2483	2022 BPU Assessment
Rate Counsel Assessment Rate	0.0531	2022 RC Assessment
Income before State of NJ Bus. Tax	98.0986	
State of NJ Bus. Income Tax @ 9.00%	8.8289	
Income Before Federal Income Taxes	89.2697	
Federal Income Taxes @ 21%	18.7466	
Return	70.5231	
Revenue Factor	**1.4180**	

<u>Gas Revenue Requirement Allocation Explanation of Format</u>

Pages 2 through 5 presented in Schedule SS-GSMPIII-5 are the 4 relevant pages from the complete cost of service and revenue requirement allocation methodology based on the 2018 Base Rate Case Settlement, approved by the Board on October 29, 2018. Page 2 Part 1 shows the "Final" revenue requirement allocation to the each rates class and its associated functions as defined in the 2018 PSE&G Base Rate Case (Rate Case). Part 2 allocates the GSMP III Revenue Increase in accordance with the Rate Case Board Order. Pages 3 and 4 provide the interclass revenue allocations based upon the rate rules approved in the Rate Case. Page 5 provides the service charges calculations for each rate class by which are calculated in accordance with the Rate Case Board Order.

<u>Gas Rate Design (Proof of Revenue by Rate Class) Explanation of Format</u>

The summary provides by rate schedule the Annualized Weather Normalized (all customers assumed to be on BGSS) revenue based on current tariff rates and the proposed initial rate adjustment. Pages 6 through 14 presented in Schedule SS-GSMPIII-5 are the relevant pages from the complete rate change workpapers from the Company's 2018 Gas Base Rate Case and have been appropriately modified per my testimony to reflect this GSMP III Program Initial Rate Adjustment.

<u>Annualized Weather Normalized (all customers assumed to be on BGSS) and the Proposed Detailed Rate Design</u>

In the detailed rate design pages, all the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Balancing, Societal Benefits Charge, Margin Adjustment Charge, Weather Normalization Charge, Green Programs Recovery Charge, Tax Adjustment Credit, Conservation Incentive Program Charge, Miscellaneous items, and Unbilled Revenue.

Column (1) shows the annualized weather normalized billing units. Column (2) shows present Delivery rates (without Sales and Use Tax, SUT) effective March 1, 2023. The commodity rates in the Column (2) reflect April 2022 through December 2022, and January 2023 through March 2023's class-weighted averages (BGSS-RSG uses the rate as of 3/1/2023). Column (3) presents annualized revenue assuming all customers are provided service under their applicable BGSS provision. Column (4) repeats the billing units of Column (1). Column (5) shows the proposed rates without SUT that result in the proposed revenues shown in Column (6). Columns (7) and (8) show the proposed base rate revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks. The proposed tariff charges (with and without SUT) are provided on pages 1 and 2 of Schedule SS-GSMPIII-6.

Cost of Service and Rate Design Sync

Part 1: 2018 Base Rate Case Final Revenue Allocation

					Notes:
1	Requested increase in Revenue Requirements	$	123,141,000		2018 Rate Case Schedule SS-G7 R-2, pg 2, line 16
2	Total Target Distribution Revenue Requirements	$	888,460,440		2018 Rate Case Schedule SS-G7 R-2, pg 2, line 17
3	Sum of Initial Sync Revenue Requirements	$	893,411,330		2018 Rate Case Schedule SS-G7 R-2, pg 2, line 18
4	Final Sync Adjustment Factor		0.99446		2018 Rate Case Schedule SS-G7 R-2, pg 2, line 19

		Total	RSG	GSG	LVG	SLG	
5	Distribution Access	$ 348,181,228	$ 285,567,880	$ 40,848,700	$ 21,728,392	$ 36,257	2018 Rate Case Schedule SS-G7 R-2, pg 2, line 20
6	Distribution Delivery	$ 362,951,052	$ 231,037,735	$ 42,604,570	$ 89,282,536	$ 26,211	2018 Rate Case Schedule SS-G7 R-2, pg 2, line 21
7	Streetlighting Fixtures	$ 417,670	$ 0	$ 0	$ 0	$ 417,670	2018 Rate Case Schedule SS-G7 R-2, pg 2, line 22
8	Customer Service	$ 80,199,946	$ 72,101,419	$ 6,313,852	$ 1,783,392	$ 1,284	2018 Rate Case Schedule SS-G7 R-2, pg 2, line 23
9	Measurement	$ 96,710,544	$ 70,884,585	$ 16,046,249	$ 9,779,669	$ 41	2018 Rate Case Schedule SS-G7 R-2, pg 2, line 24
10	Total	$ 888,460,440	$ 659,591,618	$ 105,813,371	$ 122,573,988	$ 481,463	

Part 2: GSMPIII Rate Adjustment Revenue Allocation

11	Requested increase in Revenue Requirements	$	22,992,390	Schedule SS-GSMPIII-2 Rate Adjustment 1
12	Total Target Distribution Revenue Requirements	$	1,097,250,823	= line 11 + page 3, col 2
13	Rate Case Minus Streetlight Fixtures	$	888,042,770	= line 10 - line 7
14	Target Minus Streetlight Fixtures	$	1,096,833,153	= line 12 - line 7
15	Final Sync Adjustment Factor		1.23511	= line 14 / line 13

		Total	RSG	GSG	LVG	SLG	
16	Distribution Access	$ 430,043,155	$ 352,708,595	$ 50,452,759	$ 26,837,019	$ 44,781	= line 5 * line 15
17	Distribution Delivery	$ 448,285,555	$ 285,357,705	$ 52,621,458	$ 110,274,019	$ 32,373	= line 6 * line 15
18	Streetlighting Fixtures	$ 417,670	$ 0	$ 0	$ 0	$ 417,670	= line 7
19	Customer Service	$ 99,055,994	$ 89,053,398	$ 7,798,320	$ 2,202,690	$ 1,586	= line 8 * line 15
20	Measurement	$ 119,448,449	$ 87,550,472	$ 19,818,930	$ 12,078,996	$ 51	= line 9 * line 15
21	Total	$ 1,097,250,823	$ 814,670,170	$ 130,691,468	$ 151,392,724	$ 496,461	

Inter Class Revenue Allocations

Calculation of Increase Limits

line #		(in $1,000)		Notes:
1	Requested Revenue Increase to be recovered from rate schedule charges =	$ 22,992		Schedule SS-GSMPIII-2 Rate Adjustment
2	Present Distribution Revenue =	$ 1,074,258	from RSG, GSG, LVG & SLG	Page 4, col 3, line 11
3	Present Total Customer Bills (all on BGSS) =	$ 2,824,280		Page 4, col 5, line 11
4	Average Distribution Increase =	2.140%		= Line 1 / Line 2
5	Average Total Bill Increase =	0.814%		= Line 1 / Line 3
6	Lower Distribution increase limit =	1.070%	in Distribution charges	= 0.5 * Line 4
7	Upper Distribution increase limit #1 =	3.210%	in Distribution charges	= 1.5 * Line 4
8	Upper Bill increase limit #2 =	1.628%	in Bill Increase	= 2.0 * Line 5

all rounded to 0.001%

Inter Class Revenue Allocations

Calculation of Increases

line #	Rate Schedule (1)	(2) Proposed Distribution Revenue Requirement (from COS) (in $1,000)	(3) Present Distribution Revenue (in $1,000)	(4) Unlimited COS Distribution Charge $ Increase (in $1,000)	(5) Present Total Bill Revenue (all on BGSS) (in $1,000)	(6) Unlimited Distribution Charge Increase (%)	(7) Change in MAC & BGSS credits (in $1,000)	(8) Limited Final Distribution Charge Increase (%)	(9) Proposed Total Bill Increase (%)	(10) Proposed Distribution Revenue Increase (in $1,000)
	Calculation of TSG-F Increase									
1	TSG-F	$ 3,304.030	$ 3,637	$ (332.577)	$ 27,120.073	-9.145%	$ (2.644)	1.070%	0.134%	$ 38.912
							$ -			
	Calculation of TSG-NF & CIG Increase									
2	TSG-NF	----	$ 12,112	----	$ 161,070	----	$ -	2.140%	0.161%	$ 259
3	CIG	----	$ 3,530	----	$ 34,954	----	$ -	2.140%	0.217%	$ 76
4	CSG[1]	----	$ 7,477	----	$ 7,861	----		----	0.178%	$ 14
	Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase									
5	RSG	$ 814,670	$ 797,636	$ 17,034	$ 1,547,366	2.136%	$ (248)	2.141%	1.088%	$ 17,077
6	GSG	$ 130,691	$ 127,959	$ 2,732	$ 427,435	2.135%	$ (39)	2.141%	0.632%	$ 2,739
7	LVG	$ 151,393	$ 148,226	$ 3,167	$ 847,961	2.136%	$ (96)	2.142%	0.363%	$ 3,175
8	SLG	$ 496.461	$ 437.433		$ 1,518.140					
9	Distribution Only	$ 78.792	$ 22.841	$ 55.951		244.957%	$ (0.098)	3.210%	0.042%	$ 0.733
10	Fixtures	$ 417.670	$ 414.592	$ 3.078		0.742%		0.000%	0.000%	$ -
11	Total for Margin Rates	$ 1,097,251	$ 1,074,258	$ 22,992	$ 2,824,280	2.140%	$ (383)	2.140%	0.801%	$ 22,992

[1] CSG Credits all flow back through BGSS

Notes:		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		for TSG-F - from 2018 Rate Case Schedule SS-G7 R-2, pg 1, col 6, line 6 for RSG, GSG, LVG & SLG from page 1, line 21	SS-GSMPIII-1 workpapers	= (2) - (3)	Page 6	= (4) / (3)	SS-GSMPIII-1 workpapers	calculated on limits	= (Col 10 + Col 7) / Col 5	= (3) * (8)

Service Charge Calculations

line #	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	Notes:
1			Average Distribution Increase =		2.140%					page 3, line 4
	Rate Schedule	Distribution Access Rev Req	Customer Service Rev Req	Measurement Rev Req	COS Indicated Total Rev Req	# of Customers	Cost Based Monthly Service Charge	Current Monthly Service Charge	Proposed Limited Monthly Service Charge	
		(in $1,000)	(in $1,000)	(in $1,000)	(in $1,000)		($/month)	($/month)	($/month)	
2	RSG	352,709	89,053	87,550	529,312	1,635,900	$ 26.96	$ 8.08	$ 8.08	Fixed per 2018 Base Rate Case
3	GSG	50,453	7,798	19,819	78,070	140,771	$ 46.22	$ 18.58	$ 19.18	move to costs, limited @ 1.5 times overall avg Distribution % increase
4	LVG	26,837	2,203	12,079	41,119	18,375	$ 186.48	$ 164.99	$ 170.29	move to costs, limited @ 1.5 times overall avg Distribution % increase
5	TSG-F	530	400		930	37	$ 2,095.57	$ 883.64	$ 912.00	move to costs, limited @ 1.5 times overall avg Distribution % increase
6	TSG-NF							$ 883.64	$ 912.00	set equal to new TSG-F Service Charge
7	CIG							$ 196.33	$ 200.53	increase current @ average Distribution % increase
8	CSG							$ 883.64	$ 912.00	set equal to new TSG-F Service Charge
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Notes:		values for RSG, GSG & LVG for Cols 2, 3, & 4 from page 2, lines 16, 19 & 20 values for TSG-F for Cols 2, 3 & 4 from 2018 Rate Case Schedule SS-G7 R-2, page 1, lines 1, 4 & 5			= (2) + (3) + (4)	RSG, GSG & LVG from 2018 Rate Case Schedule SS-G7 R-2, page 2, line 1 TSG-F from COS workpapers	= Col 5 * 1000 / Col 6 / 12 rounded to $0.01	From Tariff	based on methodology described	

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

Line	Rate Schedule		Annualized Weather Normalized		Proposed		Difference	
			Therms	Revenue	Therms	Revenue	Revenue	Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,494,928	$1,547,366	1,494,928	$1,564,345	$16,979	1.10
2	GSG		297,484	427,435	297,484	430,165	2,730	0.64
3	LVG		740,103	847,961	740,103	851,116	3,155	0.37
6	SLG		679	1,518.140	679	1,518.845	0.705	0.05
7		Subtotal	2,533,194	2,824,280	2,533,194	2,847,145	22,865	0.81
8								
9	TSG-F		25,950	27,120.073	25,950	27,158.985	38.912	0.14
10	TSG-NF		179,184	161,070	179,184	161,329	259	0.16
11	CIG		41,067	34,954	41,067	35,030	76	0.22
12	CSG		789,848	7,861	789,848	7,875	14	0.18
13		Subtotal	1,036,049	231,005	1,036,049	231,393	388	0.17
14								
15		Totals	3,569,243	3,055,285	3,569,243	3,078,538	$23,253	0.76
16								
17								
18					Less change in MAC included above		$261	
19								
20					Gas Revenue Requirement		$22,992	
21								
22								

Line	Rate Schedule		Increase Before Mac Adjustment	Increase Above	MAC Adjustment
23					
24	RSG		$16,828	$16,979	151
25	GSG		2,700	2,730	30
26	LVG		3,080	3,155	75
27	SLG		0.636	0.705	0.069
28		Subtotal	22,609	22,865	256
29					
30	TSG-F		36.268	38.912	2.644
31	TSG-NF		259	259	0
32	CIG		76	76	0
33	CSG		14	14	0
34		Subtotal	385	388	3
35					
36		Totals	$22,994	$23,253	259

37
38
39 Notes:
40 All customers assumed to be on BGSS.
41 SLG units and revenues shown to 3 decimals.
42 TSG-F revenues shown to 3 decimals.
43 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
44 plus applicable BGSS charges.

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	19,630.803	8.08	$158,617	19,630.803	8.08	$158,617	0	0.00
2	Distribution Charge	1,494,872	0.429896	642,639	1,494,872	0.441371	659,793	17,154	2.67
3	Off-Peak Dist	56	0.214948	12	56	0.220686	12	0	0.00
4	Balancing Charge	917,326	0.094435	86,628	917,326	0.094435	86,628	0	0.00
5	SBC	1,494,928	0.043873	65,587	1,494,928	0.043873	65,587	0	0.00
6	Margin Adjustment	1,494,928	(0.005821)	(8,702)	1,494,928	(0.005821)	(8,702)	0	0.00
7	Weather Normalization	917,326	0.000000	0	917,326	0.000000	0	0	0.00
8	Green Programs Recovery Charge	1,494,928	0.007148	10,686	1,494,928	0.007148	10,686	0	0.00
9	Tax Adjustment Credit	1,494,928	(0.045216)	(67,595)	1,494,928	(0.045216)	(67,595)	0	0.00
10	Gas Conservation Incentive Program	1,494,928	0.027367	40,912	1,494,928	0.027367	40,912	0	0.00
11	Facilities Charges			0			0	0	0.00
12	Minimum			0			0	0	0.00
13	Miscellaneous			(15)			(15)	0	0.00
14	Delivery Subtotal	1,494,928		$928,769	1,494,928		$945,923	$17,154	1.85
15	Unbilled Delivery			(4,192)			(4,269)	(77)	1.84
16	Delivery Subtotal w unbilled			$924,577			$941,654	$17,077	1.85
17									
18	**Supply**								
19	BGSS-RSG	1,494,872	0.419800	$627,548	1,494,872	0.419800	$627,548	$0	0.00
20	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
21	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	1,494,928	(0.000066)	(99)	(99)	0.00
22	Off-Peak Comm. Charge	46	0.351150	16	46	0.351150	16	0	0.00
23									
24	Miscellaneous			(1)			(1)	0.00	0.00
25	Supply subtotal	1,494,918		$627,563	1,494,918		$627,464	(99.00)	(0.02)
26	Unbilled Supply			(4,774)			(4,773)	1.00	(0.02)
27	Supply Subtotal w unbilled			$622,789			$622,691	(98.00)	(0.02)
28									
29	Total Delivery + Supply	1,494,928		$1,547,366	1,494,928		$1,564,345	16,979.00	1.10

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
36 plus applicable BGSS charges.

RATE SCHEDULE GSG
GENERAL SERVICE
Schedule SS-GSMPIII-5

(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1,689.246	18.58	$31,386	1,689.246	19.18	$32,400	$1,014	3.23
2	Distribution Charge - Pre 7/14/97	2,183	0.324411	708	2,183	0.330180	721	13	1.84
3	Distribution Charge - All Others	295,256	0.324411	95,784	295,256	0.330180	97,488	1,704	1.78
4	Off-Peak Dist Charge - Pre 7/14/97	0	0.162206	0	0	0.165090	0	0	0.00
5	Off-Peak Dist Charge - All Others	45	0.162206	7	45	0.165090	7	0	0.00
6	Balancing Charge	173,170	0.094435	16,353	173,170	0.094435	16,353	0	0.00
7	SBC	297,484	0.043873	13,052	297,484	0.043873	13,052	0	0.00
8	Margin Adjustment	297,484	(0.005821)	(1,732)	297,484	(0.005821)	(1,732)	0	0.00
9	Weather Normalization	173,170	0.000000	0	173,170	0.000000	0	0	0.00
10	Green Programs Recovery Charge	297,484	0.007148	2,126	297,484	0.007148	2,126	0	0.00
11	Tax Adjustment Credit	297,484	(0.039158)	(11,649)	297,484	(0.039158)	(11,649)	0	0.00
12	Gas Conservation Incentive Program	297,484	0.027807	8,272	297,484	0.027807	8,272	0	0.00
13	Facilities Charges			0			0	0	0.00
14	Minimum			2			2	0	0.00
15	Miscellaneous			(313)			(313)	0	0.00
16	Delivery Subtotal	297,484		$153,996	297,484		$156,727	$2,731	1.77
17	Unbilled Delivery			464			472	8	1.72
18	Delivery Subtotal w unbilled			$154,460			$157,199	$2,739	1.77
19									
20	**Supply**								
21	BGSS	297,484	0.859260	$255,616	297,484	0.859260	$255,616	$0	0.00
22	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
23	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	297,484	(0.000028)	(8)	(8)	0.00
24									
25	Miscellaneous			(51)			(51)	0	0.00
26	Supply subtotal	297,484		$255,565	297,484		$255,557	(8)	0.00
27	Unbilled Supply			17,410			17,409	(1)	(0.01)
28	Supply Subtotal w unbilled			$272,975			$272,966	(9)	0.00
29									
30	Total Delivery + Supply	297,484		$427,435	297,484		$430,165	$2,730	0.64
31									
32									
33									
34	Notes:								
35	All customers assumed to be on BGSS.								
36	Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023								
37	plus applicable BGSS charges.								
38									

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	220.495	164.99	$36,379	220.495	170.29	$37,548	$1,169	3.21
2	Demand Charge	18,017	4.3241	77,907	18,017	4.4016	79,304	1,397	1.79
3	Distribution Charge 0-1,000 pre 7/14/97	8,974	0.034950	314	8,974	0.032008	287	(27)	(8.60)
4	Distribution Charge over 1,000 pre 7/14/97	45,378	0.048909	2,219	45,378	0.050725	2,302	83	3.74
5	Distribution Charge 0-1,000 post 7/14/97	145,700	0.034950	5,092	145,700	0.032008	4,664	(428)	(8.41)
6	Distribution Charge over 1,000 post 7/14/97	540,051	0.048909	26,413	540,051	0.050725	27,394	981	3.71
7	Balancing Charge	361,999	0.094435	34,185	361,999	0.094435	34,185	0	0.00
8	SBC	740,103	0.043873	32,471	740,103	0.043873	32,471	0	0.00
9	Margin Adjustment	740,103	(0.005821)	(4,308)	740,103	(0.005821)	(4,308)	0	0.00
10	Weather Normalization	361,999	0.000000	0	361,999	0.000000	0	0	0.00
11	Green Programs Recovery Charge	740,103	0.007148	5,290	740,103	0.007148	5,290	0	0.00
12	Tax Adjustment Credit	740,103	(0.018161)	(13,441)	740,103	(0.018161)	(13,441)	0	0.00
13	Gas Conservation Incentive Program	740,103	0.003779	$2,797	740,103	0.003779	$2,797	0	0.00
14	Facilities Charges			1			1	0	0.00
15	Minimum			218			218	0	0.00
16	Miscellaneous			(279)			(278)	1	(0.45)
17	Delivery Subtotal	740,103		$205,258	740,103		$208,434	$3,176	1.55
18	Unbilled Delivery			(52)			(52)	0	0.00
19	Delivery Subtotal w unbilled			$205,206			$208,382	$3,176	1.55
20									
21									
22	**Supply**								
23	BGSS	740,103	0.866063	$640,976	740,103	0.866063	$640,976	$0	0.00
24	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
25	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	740,103	(0.000028)	(21)	(21)	0.00
26									
27	Miscellaneous			(143)			(143)	0	0.00
28	Supply Subtotal	740,103		$640,833	740,103		$640,812	($21)	0.00
29	Unbilled Supply			1,922			1,922	0	0.00
30	Supply Subtotal w unbilled			$642,755			$642,734	($21)	0.00
31									
32	Total Delivery + Supply	740,103		$847,961	740,103		$851,116	$3,155	0.37
33									
34									
35									

36 Notes:
37 All customers assumed to be on BGSS.
38 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
39 plus applicable BGSS charges.

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	10.392	13.2351	$137.539	10.392	13.2351	$137.539	$0.000	0.00
2	Double Inverted	0.108	13.2351	1.429	0.108	13.2351	1.429	0.000	0.00
3	Double Upright	0.588	13.2351	7.782	0.588	13.2351	7.782	0.000	0.00
4	Triple prior to 1/1/93	18.096	13.2351	239.502	18.096	13.2351	239.502	0.000	0.00
5	Triple on and after 1/1/93	0.420	67.4762	28.340	0.420	67.4762	28.340	0.000	0.00
6	Distribution Therm Charge	678.777	0.052817	35.851	678.777	0.053897	36.584	0.733	2.04
7	SBC	678.777	0.043873	29.780	678.777	0.043873	29.780	0.000	0.00
8	Margin Adjustment	678.777	(0.005821)	(3.951)	678.777	(0.005821)	(3.951)	0.000	0.00
9	Green Programs Recovery Charge	678.777	0.007148	4.852	678.777	0.007148	4.852	0.000	0.00
10	Tax Adjustment Credit	678.777	(0.075809)	(51.457)	678.777	(0.075809)	(51.457)	0.000	0.00
11	Gas Conservation Incentive Program	678.777	0.000000	0.000	678.777	0.000000	0.000	0.000	0.00
12	Facilities Charges			0.000			0.000	0.000	0.00
13	Minimum			0.000			0.000	0.000	0.00
14	Miscellaneous			(13.010)			(13.010)	0.000	0.00
15	Delivery Subtotal	678.777		$416.657	678.777		$417.390	$0.733	0.18
16	Unbilled Delivery			0.000			0.000	0.000	0.00
17	Delivery Subtotal w unbilled			$416.657			$417.390	$0.733	0.18
18									
19	**Supply**								
20	BGSS	678.777	0.888262	$602.932	678.777	0.888262	$602.932	$0.000	0.00
21	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
22	BGSS Contrib. from TSG-F, TSG-NF & CIG	0.000	0.000000	0.000	678.777	(0.000028)	(0.019)	(0.019)	0.00
23	Miscellaneous			131.390			131.390	0.000	0.00
24	Supply Subtotal	678.777		$734.322	678.777		$734.303	($0.019)	0.00
25	Unbilled Supply			367.161			367.152	(0.009)	0.00
26	Supply Subtotal w unbilled			$1,101.483			$1,101.455	($0.028)	0.00
27									
28	Total Delivery + Supply	678.777		$1,518.140	678.777		$1,518.845	$0.705	0.05
29									
30									
31									

32 Notes:
33 All customers assumed to be on BGSS.
34 SLG units and revenues shown to 3 decimals.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
36 plus applicable BGSS charges.

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.166	196.33	$33	0.166	200.53	$33	$0	0.00
2	Margin 0-600,000	32,835	0.087742	2,881	32,835	0.089617	2,943	62	2.15
3	Margin over 600,000	8,232	0.077742	640	8,232	0.079617	655	15	2.34
4	Extended Gas Service	0	0.150000	0	0	0.150000	0	0	0.00
5	SBC	41,067	0.043873	1,802	41,067	0.043873	1,802	0	0.00
6	Green Programs Recovery Charge	41,067	0.007148	294	41,067	0.007148	294	0	0.00
7	Tax Adjustment Credit	41,067	(0.012602)	(518)	41,067	(0.012602)	(518)	0	0.00
8	Gas Conservation Incentive Program	41,067	0.000000	0	41,067	0.000000	0	0	0.00
9	Facilities Charges			0			0	0	0.00
10	Minimum			0			0	0	0.00
11	Miscellaneous			0			0	0	0.00
12	Delivery Subtotal	41,067		$5,132	41,067		$5,209	$77	1.50
13	Unbilled Delivery			(35)			(36)	(1)	2.86
14	Delivery Subtotal w unbilled			$5,097			$5,173	$76	1.49
15									
16	**Supply**								
17	Commodity Component	41,067	0.664353	$27,283	41,067	0.664353	$27,283	$0	0.00
18	Pilot Use	1,249	1.89	2,361	1,249	1.89	2,361	0	0.00
19	Penalty Use	0		0	0		0	0	0.00
20	Extended Gas Service	5		338	5		338	0	0.00
21	Miscellaneous			0			0	0	0.00
22	Supply Subtotal	42,321		$29,982	42,321		$29,982	$0	0.00
23	Unbilled Supply			(125)			(125)	0	0.00
24	Supply Subtotal w unbilled			$29,857			$29,857	$0	0.00
25									
26	Total Delivery + Supply	41,067		$34,954	41,067		$35,030	$76	0.22
27									
28									
29									
30	Notes:								
31	All customers assumed to be on BGSS.								
32	Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023								
33	plus applicable BGSS charges.								
34									

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.494	883.64	$436.518	0.494	912.00	$450.528	$14.010	3.21
2	Demand Charge	487	2.1786	1,060.978	487	2.1952	1,069.062	8.084	0.76
3	Demand Charge, Agreements	0	0.0000	0.000	0	0.0000	0.000	0.000	0.00
4	Distribution Charge	25,950	0.083275	2,160.986	25,950	0.083910	2,177.465	16.479	0.76
5	Distribution Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
6	SBC	25,950	0.043873	1,138.504	25,950	0.043873	1,138.504	0.000	0.00
7	SBC, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
8	Margin Adjustment	25,950	(0.005821)	(151.055)	25,950	(0.005821)	(151.055)	0.000	0.00
9	Margin Adjustment, Agreements	0	(0.005821)	0.000	0	(0.005821)	0.000	0.000	0.00
10	Green Programs Recovery Charge	25,950	0.007148	185.491	25,950	0.007148	185.491	0.000	0.00
11	Green Programs Recovery Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
12	Tax Adjustment Credit	25,950	(0.015352)	(398.384)	25,950	(0.015352)	(398.384)	0.000	0.00
13	Gas Conservation Incentive Program	25,950	0.000000	0.000	25,950	0.000000	0.000	0.000	0.00
14	Facilities Charges			0.000			0.000	0.000	0.00
15	Minimum			0.000			0.000	0.000	0.00
16	Miscellaneous			(54.034)			(54.039)	(0.005)	0.01
17	Delivery Subtotal	25,950		4,379.004	25,950		4,417.572	38.568	0.88
18	Unbilled Delivery			39.069			39.413	0.344	0.88
19	Delivery Subtotal w unbilled			4,418.073			4,456.985	38.912	0.88
20									
21	**Supply**								
22	Commodity Charge, BGSS-F	25,950	0.874836	$22,702.000	25,950	0.874836	$22,702.000	$0.000	0.00
23	Emergency Sales Service	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply Subtotal	25,950		$22,702.000	25,950		$22,702.000	$0.000	0.00
26	Unbilled Supply			0.000			0.000	0.000	0.00
27	Supply Subtotal w unbilled			$22,702.000			$22,702.000	$0.000	0.00
28									
29	Total Delivery + Supply	25,950		$27,120.073	25,950		$27,158.985	$38.912	0.14
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 TSG-F revenues shown to 3 decimals.
36 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
37 plus applicable BGSS charges.

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.218	883.64	$1,960	2.218	912.00	$2,023	$63	3.21
2	Dist Charge 0-50,000	99,839	0.097384	9,723	99,839	0.099339	9,918	195	2.01
3	Dist Charge 0-50,000, Agreements	600	0.023333	14	600	0.023333	14	0	0.00
4	Dist Charge over 50,000	67,427	0.097384	6,566	67,427	0.099339	6,698	132	2.01
5	Dist Charge over 50,000, Agreements	11,318	0.023502	266	11,318	0.023502	266	0	0.00
6	SBC	167,266	0.043873	7,338	167,266	0.043873	7,338	0	0.00
7	SBC, Agreements	11,918	0.042876	511	11,918	0.042876	511	0	0.00
8	Green Programs Recovery Charge	167,266	0.007148	1,196	167,266	0.007148	1,196	0	0.00
9	Green Programs Recovery Charge, Agreements	11,918	0.005370	64	11,918	0.005370	64	0	0.00
10	Tax Adjustment Credit	167,266	(0.006883)	(1,151)	167,266	(0.006883)	(1,151)	0	0.00
11	Gas Conservation Incentive Program	167,266	0.000000	0	167,266	0.000000	0	0	0.00
12	Facilities Charges			5			5	0	0.00
13	Minimum			0			0	0	0.00
14	Miscellaneous			(277)			(277)	0	0.00
15	Delivery Subtotal	179,184		$26,215	179,184		$26,605	$390	1.49
16	Unbilled Delivery			(8,821)			(8,952)	(131)	1.49
17	Delivery Subtotal w unbilled			$17,394			$17,653	$259	1.49
18									
19	**Supply**								
20	Commodity Charge, BGSS-I	179,184	0.829522	$148,637	179,184	0.829522	$148,637	$0	0.00
21	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
22	Pilot Use	26	1.890000	49	26	1.890000	49	0	0.00
23	Penalty Use	19	0.947368	18	19	0.947368	18	0	0.00
24	Miscellaneous			2			2	0	0.00
25	Supply Subtotal	179,229		$148,706	179,229		$148,706	$0	0.00
26	Unbilled Supply			(5,030)			(5,030)	0	0.00
27	Supply Subtotal w unbilled			$143,676			$143,676	$0	0.00
28									
29	Total Delivery + Supply	179,184		$161,070	179,184		$161,329	$259	0.16
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
36 plus applicable BGSS charges.

RATE SCHEDULE CSG
CONTRACT SERVICES
Schedule SS-GSMPIII-5
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge - Power	0.0800	883.64	$71	0.0800	912.00	$73	$2	2.82
2	Service Charge - Power- Non Firm	0.0120	883.64	11	0.0120	912.00	11	0	0.00
3	Service Charge - Other	0.1090	883.64	96	0.1090	912.00	99	3	3.13
4	Distribution Charge - Power	599,445	0.006051	3,627	599,445	0.006051	3,627	0	0.00
5	Distribution Charge - Power- Non Firm	4,755	0.097384	463	4,755	0.099339	472	9	1.94
6	Distribution Charge - Other	185,648	0.011904	2,210	185,648	0.011904	2,210	0	0.00
7	Maintenance - Power	599,445	0.000142	85	599,445	0.000142	85	0	0.00
8	Maintenance - Power- Non Firm	4,755	0.000000	0	4,755	0.000000	0	0	0.00
9	Maintenance - Other	185,648	0.000113	21	185,648	0.000113	21	0	0.00
10	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
11	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
12	Balancing Charge (applicable only if customer uses BGSS-F)	0	0.000000	0	0	0.000000	0	0	0.00
13	SBC	789,848	0.043873	980	789,848	0.043873	980	0	0.00
14	Green Programs Recovery Charge	789,848	0.007148	149	789,848	0.007148	149	0	0.00
15	Tax Adjustment Credit	789,848	(0.001000)	(790)	789,848	(0.001000)	(790)	0	0.00
16	Gas Conservation Incentive Program	789,848	0.000000	0	789,848	0.000000	0	0	0.00
17	Facilities Chg.			840			840	0	0.00
18	Minimum			271			271	0	0.00
19	Sales Tax Discount - Delivery			(428)			(428)	0	0.00
20	Misc.			300			300	0	0.00
21	Delivery Subtotal	789,848		7,906	789,848		7,920	14	0.18
22	Unbilled Delivery			(94)			(94)	0	0.00
23	Delivery Subtotal w/ Unbilled	789,848		7,812	789,848		7,826	14	0.18
24									
25	**Supply**								
26	BGSS-Firm - Power	0	0.000000	0	0	0.000000	0	0	0.00
27	BGSS-Firm - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
28	BGSS-Firm - Other	0	0.000000	0	0	0.000000	0	0	0.00
29									
30	BGSS-Interruptible - Power	0	0.000000	0	0	0.000000	0	0	0.00
31	BGSS-Interruptible - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
32	BGSS-Interruptible - Other	0	0.000000	0	0	0.000000	0	0	0.00
33									
34	Emergency Sales Svc. - Power	0	0.000000	0	0	0.000000	0	0	0.00
35	Emergency Sales Svc. - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
36	Emergency Sales Svc - Other	0	0.000000	0	0	0.000000	0	0	0.00
37									
38	Pilot Use	26	1.89	49	26	1.89	49	0	0.00
39	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
40	Misc.	19		0	19		0	0	0.00
41	Supply Subtotal	45		49	45		49.140	0	0.00
42	Unbilled Supply	0		0	0		0	0	0.00
43	Supply Subtotal w/ Unbilled	45		49	45		49.140	0	0.00
44									
45	**Total Delivery & Supply**	789,893		7,861	789,893		7,875	14.00	0.18
46									

47 Notes:
48 All customers assumed to be on BGSS.
49 Annualized Weather Normalized Revenue reflects Delivery rates as of 3/1/2023
50 plus applicable BGSS charges.

PSE&G GSMPIII Component of IIPC
Gas Tariff Rate Summary

		Present GSMPIII IIPC 3/1/2023		Rate Adjustment 1 12/1/2024		Rate Adjustment 2 6/1/2025		Rate Adjustment 3 12/1/2025		Rate Adjustment 4 6/1/2026	
Rate Schedule		Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT
RSG	Service Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Distribution Charges	$0.000000	$0.000000	$0.011475	$0.012235	$0.014823	$0.015805	$0.021570	$0.022999	$0.018193	$0.019398
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
	Off-Peak Use	$0.000000	$0.000000	$0.005738	$0.006118	$0.007411	$0.007902	$0.010785	$0.011500	$0.009097	$0.009700
GSG	Service Charge	$0.00	$0.00	$0.60	$0.64	$0.78	$0.83	$1.15	$1.23	$0.99	$1.05
	Distribution Charge - Pre July 14, 1997	$0.000000	$0.000000	$0.005769	$0.006151	$0.007433	$0.007926	$0.010734	$0.011445	$0.008932	$0.009524
	Distribution Charge - All Others	$0.000000	$0.000000	$0.005769	$0.006151	$0.007433	$0.007926	$0.010734	$0.011445	$0.008932	$0.009524
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
	Off-Peak Use Dist Charge - Pre July 14, 1997	$0.000000	$0.000000	$0.002884	$0.003075	$0.003717	$0.003963	$0.005367	$0.005723	$0.004466	$0.004762
	Off-Peak Use Dist Charge - All Others	$0.000000	$0.000000	$0.002884	$0.003075	$0.003717	$0.003963	$0.005367	$0.005723	$0.004466	$0.004762
LVG	Service Charge	$0.00	$0.00	$5.30	$5.65	$6.92	$7.38	$10.19	$10.87	$8.76	$9.34
	Demand Charge	$0.0000	$0.0000	$0.0775	$0.0826	$0.0995	$0.1061	$0.1437	$0.1532	$0.1198	$0.1278
	Distribution Charge 0-1,000 pre July 14, 1997	$0.000000	$0.000000	-$0.002942	-$0.003136	-$0.003924	-$0.004184	-$0.005954	-$0.006349	-$0.005403	-$0.005761
	Distribution Charge over 1,000 pre July 14, 1997	$0.000000	$0.000000	$0.001816	$0.001937	$0.002374	$0.002531	$0.003505	$0.003737	$0.003039	$0.003240
	Distribution Charge 0-1,000 post July 14, 1997	$0.000000	$0.000000	-$0.002942	-$0.003136	-$0.003924	-$0.004184	-$0.005954	-$0.006349	-$0.005403	-$0.005761
	Distribution Charge over 1,000 post July 14, 1997	$0.000000	$0.000000	$0.001816	$0.001937	$0.002374	$0.002531	$0.003505	$0.003737	$0.003039	$0.003240
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
SLG	Single-Mantle Lamp	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Double-Mantle Lamp, inverted	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Double Mantle Lamp, upright	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Triple-Mantle Lamp, prior to January 1, 19933	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Triple-Mantle Lamp, on and after January 1, 1993	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Distribution Therm Charge	$0.000000	$0.000000	$0.001080	$0.001152	$0.001410	$0.001503	$0.002079	$0.002217	$0.001786	$0.001904
TSG-F	Service Charge	$0.00	$0.00	$28.36	$30.24	$37.04	$39.49	$54.60	$58.22	$46.90	$50.01
	Demand Charge	$0.0000	$0.0000	$0.0166	$0.0177	$0.0210	$0.0224	$0.0296	$0.0316	$0.0240	$0.0256
	Distribution Charges	$0.000000	$0.000000	$0.000635	$0.000677	$0.000802	$0.000855	$0.001133	$0.001208	$0.000917	$0.000978
TSG-NF	Service Charge	$0.00	$0.00	$28.36	$30.24	$37.04	$39.49	$54.60	$58.22	$46.90	$50.01
	Distribution Charge 0-50,000	$0.000000	$0.000000	$0.001955	$0.002084	$0.002529	$0.002697	$0.003665	$0.003908	$0.003078	$0.003281
	Distribution Charge over 50,000	$0.000000	$0.000000	$0.001955	$0.002084	$0.002529	$0.002697	$0.003665	$0.003908	$0.003078	$0.003281
	Special Provision (d)	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
CIG	Service Charge	$0.00	$0.00	$4.20	$4.48	$5.43	$5.78	$7.90	$8.43	$6.66	$7.10
	Distribution Charge 0-600,000	$0.000000	$0.000000	$0.001875	$0.001999	$0.002387	$0.002545	$0.003433	$0.003661	$0.002922	$0.003115
	Distribution Charge over 600,000	$0.000000	$0.000000	$0.001875	$0.002000	$0.002387	$0.002545	$0.003433	$0.003660	$0.002922	$0.003116
	Special Provision (c) 1st para	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
BGSS RSG	Commodity Charge including Losses	$0.000000	$0.000000	-$0.000067	-$0.000071	-$0.000087	-$0.000093	-$0.000129	-$0.000137	-$0.000107	-$0.000114
CSG	Service Charge	$0.00	$0.00	$28.36	$30.24	$37.04	$39.49	$54.60	$58.22	$46.90	$50.01
	Distribution Charge - Non-Firm	$0.000000	$0.000000	$0.001955	$0.002084	$0.002529	$0.002697	$0.003665	$0.003908	$0.003078	$0.003281

PSE&G GSMPIII Component of IIPC
Gas Tariff Rate Summary

		Rate Adjustment 5 12/1/2026		Rate Adjustment 6 6/1/2027		Rate Adjustment 7 12/1/2027		Total GSMPIII IIPC Rate Adjustments	
Rate Schedule		Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT
RSG	Service Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Distribution Charges	$0.019647	$0.020949	$0.035221	$0.037554	$0.007610	$0.008114	$0.128539	$0.137054
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
	Off-Peak Use	$0.009823	$0.010473	$0.017611	$0.018778	$0.003805	$0.004057	$0.064270	$0.068528
GSG	Service Charge	$1.08	$1.16	$1.97	$2.10	$0.44	$0.47	$7.01	$7.48
	Distribution Charge - Pre July 14, 1997	$0.009585	$0.010220	$0.016997	$0.018123	$0.003590	$0.003828	$0.063040	$0.067217
	Distribution Charge - All Others	$0.009585	$0.010220	$0.016997	$0.018123	$0.003590	$0.003828	$0.063040	$0.067217
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
	Off-Peak Use Dist Charge - Pre July 14, 1997	$0.004792	$0.005109	$0.008499	$0.009062	$0.001795	$0.001914	$0.031520	$0.033608
	Off-Peak Use Dist Charge - All Others	$0.004792	$0.005109	$0.008499	$0.009062	$0.001795	$0.001914	$0.031520	$0.033608
LVG	Service Charge	$9.60	$10.23	$17.48	$18.64	$3.12	$3.33	$61.37	$65.44
	Demand Charge	$0.1282	$0.1366	$0.1137	$0.1213	$0.0536	$0.0571	$0.7360	$0.7847
	Distribution Charge 0-1,000 pre July 14, 1997	-$0.006036	-$0.006436	-$0.007203	-$0.007680	-$0.001782	-$0.001900	-$0.033244	-$0.035446
	Distribution Charge over 1,000 pre July 14, 1997	$0.003315	$0.003535	$0.008463	$0.009024	$0.001247	$0.001329	$0.023759	$0.025333
	Distribution Charge 0-1,000 post July 14, 1997	-$0.006036	-$0.006436	-$0.007203	-$0.007680	-$0.001782	-$0.001900	-$0.033244	-$0.035446
	Distribution Charge over 1,000 post July 14, 1997	$0.003315	$0.003535	$0.008463	$0.009024	$0.001247	$0.001329	$0.023759	$0.025333
	Balancing Charge	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
SLG	Single-Mantle Lamp	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Double-Mantle Lamp, inverted	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Double Mantle Lamp, upright	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Triple-Mantle Lamp, prior to January 1, 19933	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Triple-Mantle Lamp, on and after January 1, 1993	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Distribution Therm Charge	$0.001958	$0.002088	$0.003565	$0.003801	$0.000791	$0.000843	$0.012669	$0.013508
TSG-F	Service Charge	$51.40	$54.80	$93.61	$99.82	$20.77	$22.14	$332.68	$354.72
	Demand Charge	$0.0250	$0.0266	$0.0431	$0.0460	$0.0087	$0.0093	$0.1680	$0.1792
	Distribution Charges	$0.000955	$0.001018	$0.001648	$0.001757	$0.000333	$0.000355	$0.006423	$0.006848
TSG-NF	Service Charge	$51.40	$54.80	$93.61	$99.82	$20.77	$22.14	$332.68	$354.72
	Distribution Charge 0-50,000	$0.003319	$0.003539	$0.005930	$0.006323	$0.001274	$0.001359	$0.021750	$0.023191
	Distribution Charge over 50,000	$0.003319	$0.003539	$0.005930	$0.006323	$0.001274	$0.001359	$0.021750	$0.023191
	Special Provision (d)	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
CIG	Service Charge	$7.19	$7.67	$12.90	$13.75	$2.79	$2.98	$47.07	$50.19
	Distribution Charge 0-600,000	$0.003141	$0.003349	$0.005650	$0.006025	$0.001217	$0.001297	$0.020625	$0.021991
	Distribution Charge over 600,000	$0.003141	$0.003349	$0.005650	$0.006024	$0.001217	$0.001298	$0.020625	$0.021992
	Special Provision (c) 1st para	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
BGSS RSG	Commodity Charge including Losses	-$0.000113	-$0.000121	-$0.000206	-$0.000220	-$0.000044	-$0.000046	-$0.000754	-$0.000803
CSG	Service Charge	$51.40	$54.80	$93.61	$99.82	$20.77	$22.14	$332.68	$354.72
	Distribution Charge - Non-Firm	$0.003319	$0.003539	$0.005930	$0.006323	$0.001274	$0.001359	$0.021750	$0.023191

PSE&G Gas System Modernization Program III
Hydrogen & RNG Demonstation Projects
Gas/Benefit Sales - BGSS-RSG Annual Bill Impacts

Attachment 5
Schedule SS-GSMPIII-7

6.625% SUT Rate
1,533,608 RSG Annual Therm Sales (000)

1,040 Typical RSG Therms / yr.
0.471764 Current BGSS-RSG ($/therm)

172	89	29	Monthly Therms
4	2	6	# of Months/year

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				RSG Typical Annual Average Rate w/SUT - $/therm[1]	Typical BGSS- RSG ($)						
Incurred Period	Net Gas/Benefit Sales	BGSS-RSG Rate Impact w/o SUT ($/therm)	BGSS-RSG Rate Impact w/SUT ($/therm)	RSG	Dec-Mar Monthly Bill	Nov & Apr Monthly Bill	May-Oct Monthly Bill	Annual Bill	Change in RSG Typcial Annual Bill ($'s)	RSG Typical Annual Bill ($'s)[2]	% Change in RSG Typical Annual Bill
Current				1.125788	81.14	41.99	13.68	490.62		1,170.82	
Oct25-Sep26[3]	(61,835)	(0.000040)	(0.000043)	1.125745	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct26-Sep27	(22,474,054)	(0.014654)	(0.015625)	1.110163	78.46	40.60	13.23	474.42	-$16.20	1,154.62	-1.38%
Oct27-Sep28	(27,408,927)	(0.017872)	(0.019056)	1.106732	77.87	40.29	13.13	470.84	-$19.78	1,151.04	-1.69%
Oct28-Sep29	(27,931,515)	(0.018213)	(0.019420)	1.106368	77.80	40.26	13.12	470.44	-$20.18	1,150.64	-1.72%
Oct29-Sep30	(28,432,067)	(0.018539)	(0.019767)	1.106021	77.74	40.23	13.11	470.08	-$20.54	1,150.28	-1.75%
Oct30-Sep31	(28,788,805)	(0.018772)	(0.020016)	1.105772	77.70	40.21	13.10	469.82	-$20.80	1,150.02	-1.78%
Oct31-Sep32	(29,090,588)	(0.018969)	(0.020226)	1.105562	77.66	40.19	13.09	469.56	-$21.06	1,149.76	-1.80%
Oct32-Sep33	(29,380,422)	(0.019158)	(0.020427)	1.105361	77.63	40.17	13.09	469.40	-$21.22	1,149.60	-1.81%
Oct33-Sep34	(29,658,770)	(0.019339)	(0.020620)	1.105168	77.60	40.15	13.08	469.18	-$21.44	1,149.38	-1.83%
Oct34-Sep35	(29,926,080)	(0.019514)	(0.020807)	1.104981	77.56	40.14	13.08	469.00	-$21.62	1,149.20	-1.85%
Oct35-Sep36	(30,182,781)	(0.019681)	(0.020985)	1.104803	77.53	40.12	13.07	468.78	-$21.84	1,148.98	-1.87%
Oct36-Sep37	(30,429,284)	(0.019842)	(0.021157)	1.104631	77.50	40.10	13.07	468.62	-$22.00	1,148.82	-1.88%
Oct37-Sep38	(30,665,986)	(0.019996)	(0.021321)	1.104467	77.48	40.09	13.06	468.46	-$22.16	1,148.66	-1.89%
Oct38-Sep39	(30,893,267)	(0.020144)	(0.021479)	1.104309	77.45	40.08	13.06	468.32	-$22.30	1,148.52	-1.90%
Oct39-Sep40	(30,038,377)	(0.019587)	(0.020885)	1.104903	77.55	40.13	13.08	468.94	-$21.68	1,149.14	-1.85%
Oct40-Sep41	(28,858,123)	(0.018817)	(0.020064)	1.105724	77.69	40.20	13.10	469.76	-$20.86	1,149.96	-1.78%
Oct41-Sep42	(27,723,994)	(0.018078)	(0.019276)	1.106512	77.83	40.27	13.12	470.58	-$20.04	1,150.78	-1.71%
Oct42-Sep43	(26,634,177)	(0.017367)	(0.018518)	1.107270	77.96	40.34	13.14	471.36	-$19.26	1,151.56	-1.65%
Oct43-Sep44	(25,586,931)	(0.016684)	(0.017789)	1.107999	78.08	40.40	13.17	472.14	-$18.48	1,152.34	-1.58%
Oct44-Sep45	(24,580,580)	(0.016028)	(0.017090)	1.108698	78.20	40.47	13.19	472.88	-$17.74	1,153.08	-1.52%
Oct45-Sep46	(23,613,518)	(0.015397)	(0.016417)	1.109371	78.32	40.53	13.21	473.60	-$17.02	1,153.80	-1.45%
Oct46-Sep47	(3,925,573)	(0.002560)	(0.002730)	1.123058	80.67	41.74	13.60	487.76	-$2.86	1,167.96	-0.24%
Oct47-Sep48	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct48-Sep49	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct49-Sep50	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct50-Sep51	(17,311)	(0.000011)	(0.000012)	1.125776	81.14	41.99	13.68	490.62	$0.00	1,170.82	0.00%
	Sum of 7a & 7b	Col 1 / (Therm Sales)	Col 2 * (1 + SUT Rate) Rnd 6	Current Class Avg Rate + Col 3	(Cur. BGSS-RSG + Col 3) * Dec-Mar Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * Nov & Apr Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * May-Oct Monthly Therms Rnd 2	(4 * Col 5) + (2 * Col 6) + (6 * Col 7)	Col 8 - Current Col 8	Current Col 10 + Col 9	Col 9 / Current Col 10 Rnd 4

[1]Customer assumed to have BGSS Supply
[2]The rates are based on a typical residential bill as of March 1, 2023
[3]Includes Gas/Benefit Sales from Aug-25 & Sep-25

PSE&G Gas System Modernization Program III

Attachment 5

Hydrogen Demonstration Project

Schedule SS-GSMPIII-7a

Gas/Benefit Sales - BGSS-RSG Annual Bill Impacts

		1,040	Typical RSG Therms / yr.		
6.625%	SUT Rate	0.471764	Current BGSS-RSG ($/therm)		
1,533,608	RSG Annual Therm Sales (000)	172	89	29	Monthly Therms
		4	2	6	# of Months/year

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				RSG Typical Annual Average Rate w/SUT - $/therm[1]	Typical BGSS- RSG ($)						
Incurred Period	Net Gas/Benefit Sales	BGSS-RSG Rate Impact w/o SUT ($/therm)	BGSS-RSG Rate Impact w/SUT ($/therm)	RSG	Dec-Mar Monthly Bill	Nov & Apr Monthly Bill	May-Oct Monthly Bill	Annual Bill	Change in RSG Typcial Annual Bill ($'s)	RSG Typical Annual Bill ($'s)[2]	% Change in RSG Typical Annual Bill
Current				1.125788	81.14	41.99	13.68	490.62		1,170.82	
Oct25-Sep26[3]	(61,835)	(0.000040)	(0.000043)	1.125745	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct26-Sep27	(55,710)	(0.000036)	(0.000038)	1.125750	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct27-Sep28	(59,144)	(0.000039)	(0.000042)	1.125746	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct28-Sep29	(63,061)	(0.000041)	(0.000044)	1.125744	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct29-Sep30	(66,921)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct30-Sep31	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct31-Sep32	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct32-Sep33	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct33-Sep34	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct34-Sep35	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct35-Sep36	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct36-Sep37	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct37-Sep38	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct38-Sep39	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct39-Sep40	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct40-Sep41	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct41-Sep42	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct42-Sep43	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct43-Sep44	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct44-Sep45	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct45-Sep46	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct46-Sep47	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct47-Sep48	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct48-Sep49	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct49-Sep50	(67,863)	(0.000044)	(0.000047)	1.125741	81.14	41.98	13.68	490.60	-$0.02	1,170.80	0.00%
Oct50-Sep51	(17,311)	(0.000011)	(0.000012)	1.125776	81.14	41.99	13.68	490.62	$0.00	1,170.82	0.00%
	From WP-SS-GSMPIII-2.xlsx	Col 1 / (Therm Sales)	Col 2 * (1 + SUT Rate) Rnd 6	Current Class Avg Rate + Col 3	(Cur. BGSS-RSG + Col 3) * Dec-Mar Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * Nov & Apr Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * May-Oct Monthly Therms Rnd 2	(4 * Col 5) + (2 * Col 6) + (6 * Col 7)	Col 8 - Current Col 8	Current Col 10 + Col 9	Col 9 / Current Col 10 Rnd 4

[1]Customer assumed to have BGSS Supply

[2]The rates are based on a typical residential bill as of March 1, 2023

[3]Includes Gas/Benefit Sales from Aug-25 & Sep-25

PSE&G Gas System Modernization Program III

Attachment 5

Renewable Natural Gas (RNG) Project

Schedule SS-GSMPIII-7b

Gas/Benefit Sales - BGSS-RSG Annual Bill Impacts

1,040 Typical RSG Therms / yr.
6.625% SUT Rate
0.471764 Current BGSS-RSG ($/therm)
1,533,608 RSG Annual Therm Sales (000)

	Dec-Mar	Nov & Apr	May-Oct	
Monthly Therms	172	89	29	
# of Months/year	4	2	6	

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				RSG Typical Annual Average Rate w/SUT - $/therm[1]	Typical BGSS- RSG ($)						
Incurred Period	Net Gas/Benefit Sales	BGSS-RSG Rate Impact w/o SUT ($/therm)	BGSS-RSG Rate Impact w/SUT ($/therm)	RSG	Dec-Mar Monthly Bill	Nov & Apr Monthly Bill	May-Oct Monthly Bill	Annual Bill	Change in RSG Typcial Annual Bill ($'s)	RSG Typical Annual Bill ($'s)[2]	% Change in RSG Typical Annual Bill
Current				1.125788	81.14	41.99	13.68	490.62		1,170.82	
Oct25-Sep26	-	-	-	1.125788	81.14	41.99	13.68	490.62	$0.00	1,170.82	0.00%
Oct26-Sep27	(22,418,344)	(0.014618)	(0.015586)	1.110202	78.46	40.60	13.23	474.42	-$16.20	1,154.62	-1.38%
Oct27-Sep28	(27,349,783)	(0.017834)	(0.019016)	1.106772	77.87	40.29	13.13	470.84	-$19.78	1,151.04	-1.69%
Oct28-Sep29	(27,868,454)	(0.018172)	(0.019376)	1.106412	77.81	40.26	13.12	470.48	-$20.14	1,150.68	-1.72%
Oct29-Sep30	(28,365,146)	(0.018496)	(0.019721)	1.106067	77.75	40.23	13.11	470.12	-$20.50	1,150.32	-1.75%
Oct30-Sep31	(28,720,942)	(0.018728)	(0.019969)	1.105819	77.71	40.21	13.10	469.86	-$20.76	1,150.06	-1.77%
Oct31-Sep32	(29,022,726)	(0.018924)	(0.020178)	1.105610	77.67	40.19	13.10	469.66	-$20.96	1,149.86	-1.79%
Oct32-Sep33	(29,312,559)	(0.019113)	(0.020379)	1.105409	77.64	40.17	13.09	469.44	-$21.18	1,149.64	-1.81%
Oct33-Sep34	(29,590,908)	(0.019295)	(0.020573)	1.105215	77.60	40.16	13.08	469.20	-$21.42	1,149.40	-1.83%
Oct34-Sep35	(29,858,218)	(0.019469)	(0.020759)	1.105029	77.57	40.14	13.08	469.04	-$21.58	1,149.24	-1.84%
Oct35-Sep36	(30,114,918)	(0.019637)	(0.020938)	1.104850	77.54	40.12	13.07	468.82	-$21.80	1,149.02	-1.86%
Oct36-Sep37	(30,361,421)	(0.019797)	(0.021109)	1.104679	77.51	40.11	13.07	468.68	-$21.94	1,148.88	-1.87%
Oct37-Sep38	(30,598,123)	(0.019952)	(0.021274)	1.104514	77.48	40.09	13.06	468.46	-$22.16	1,148.66	-1.89%
Oct38-Sep39	(30,825,404)	(0.020100)	(0.021432)	1.104356	77.46	40.08	13.06	468.36	-$22.26	1,148.56	-1.90%
Oct39-Sep40	(29,970,515)	(0.019542)	(0.020837)	1.104951	77.56	40.13	13.08	468.98	-$21.64	1,149.18	-1.85%
Oct40-Sep41	(28,790,260)	(0.018773)	(0.020017)	1.105771	77.70	40.21	13.10	469.82	-$20.80	1,150.02	-1.78%
Oct41-Sep42	(27,656,131)	(0.018033)	(0.019228)	1.106560	77.84	40.28	13.12	470.64	-$19.98	1,150.84	-1.71%
Oct42-Sep43	(26,566,315)	(0.017323)	(0.018471)	1.107317	77.97	40.34	13.15	471.46	-$19.16	1,151.66	-1.64%
Oct43-Sep44	(25,519,068)	(0.016640)	(0.017742)	1.108046	78.09	40.41	13.17	472.20	-$18.42	1,152.40	-1.57%
Oct44-Sep45	(24,512,718)	(0.015984)	(0.017043)	1.108745	78.21	40.47	13.19	472.92	-$17.70	1,153.12	-1.51%
Oct45-Sep46	(23,545,655)	(0.015353)	(0.016370)	1.109418	78.33	40.53	13.21	473.64	-$16.98	1,153.84	-1.45%
Oct46-Sep47	(3,857,711)	(0.002515)	(0.002682)	1.123106	80.68	41.75	13.60	487.82	-$2.80	1,168.02	-0.24%
Oct47-Sep48	-										
Oct48-Sep49	-										
Oct49-Sep50	-										
Oct50-Sep51											
	From WP-SS-GSMP3.xlsx	Col 1 / (Therm Sales)	Col 2 * (1 + SUT Rate) Rnd 6	Current Class Avg Rate + Col 3	(Cur. BGSS-RSG + Col 3) * Dec-Mar Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * Nov & Apr Monthly Therms Rnd 2	(Cur. BGSS-RSG + Col 3) * May-Oct Monthly Therms Rnd 2	(4 * Col 5) + (2 * Col 6) + (6 * Col 7)	Col 8 - Current Col 8	Current Col 10 + Col 9	Col 9 / Current Col 10 Rnd 4

[1]Customer assumed to have BGSS Supply

[2]The rates are based on a typical residential bill as of March 1, 2023

PSE&G Gas System Modernization Program III
Annual Bill Impact Summary[1, 2]

Incremental Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027	End of Program Customer Bill ($)
RSG	1,040	1,170.82	12.70	16.36	23.62	20.06	21.64	22.62	4.86	1,292.69
GSG	2,115	2,894.05	20.67	26.73	38.96	32.75	35.54	63.51	13.76	3,125.97
LVG	40,278	46,132.97	176.29	227.33	329.33	275.90	296.55	520.86	117.89	48,077.12
TSG-F	633,000	680,852.35	989.82	1,266.10	1,817.45	1,506.11	1,600.11	2,825.58	594.57	691,452.09
TSG-NF	969,000	1,001,169.68	2,382.28	3,087.26	4,485.54	3,779.37	4,086.93	7,324.79	1,582.55	1,027,898.40
CIG	3,023,000	2,357,185.28	5,718.53	7,281.07	10,472.75	8,913.13	9,581.55	17,234.74	3,712.46	2,420,099.51

Incremental Annual Percent Change From Current Typical Annual Bill
By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027	Total Percent Change from Current Bill
RSG	1,040	1,170.82	1.08%	1.40%	2.02%	1.71%	1.85%	1.93%	0.42%	10.41%
GSG	2,115	2,894.05	0.71%	0.92%	1.35%	1.13%	1.23%	2.19%	0.48%	8.01%
LVG	40,278	46,132.97	0.38%	0.49%	0.71%	0.60%	0.64%	1.13%	0.26%	4.21%
TSG-F	633,000	680,852.35	0.15%	0.19%	0.27%	0.22%	0.24%	0.42%	0.09%	1.58%
TSG-NF	969,000	1,001,169.68	0.24%	0.31%	0.45%	0.38%	0.41%	0.73%	0.16%	2.68%
CIG	3,023,000	2,357,185.28	0.24%	0.31%	0.44%	0.38%	0.41%	0.73%	0.16%	2.67%

[1] All customers assumed to receive BGSS supply

[2] RSG Rate Class includes BGSS-RSG rate reductions as a result of forecasted gas/benefit sales

PSE&G Gas System Modernization Program III
Annual Bill Impact Summary[1, 2]

Cumulative Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027
RSG	1,040	1,170.82	12.70	29.06	52.68	72.75	94.39	117.01	121.87
GSG	2,115	2,894.05	20.67	47.40	86.36	119.11	154.65	218.16	231.92
LVG	40,278	46,132.97	176.29	403.62	732.95	1,008.85	1,305.40	1,826.26	1,944.15
TSG-F	633,000	680,852.35	989.82	2,255.92	4,073.37	5,579.48	7,179.59	10,005.17	10,599.74
TSG-NF	969,000	1,001,169.68	2,382.28	5,469.54	9,955.08	13,734.45	17,821.38	25,146.17	26,728.72
CIG	3,023,000	2,357,185.28	5,718.53	12,999.60	23,472.35	32,385.48	41,967.03	59,201.77	62,914.23

Cumulative Percent Changes From Current Typical Annual Bill
By Rate Class[3]

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027
RSG	1,040	1,170.82	1.08%	2.48%	4.50%	6.21%	8.06%	9.99%	10.41%
GSG	2,115	2,894.05	0.71%	1.64%	2.98%	4.12%	5.34%	7.54%	8.01%
LVG	40,278	46,132.97	0.38%	0.87%	1.59%	2.19%	2.83%	3.96%	4.21%
TSG-F	633,000	680,852.35	0.15%	0.33%	0.60%	0.82%	1.05%	1.47%	1.56%
TSG-NF	969,000	1,001,169.68	0.24%	0.55%	0.99%	1.37%	1.78%	2.51%	2.67%
CIG	3,023,000	2,357,185.28	0.24%	0.55%	1.00%	1.37%	1.78%	2.51%	2.67%

[1]All customers assumed to receive BGSS supply

[2]RSG Rate Class includes BGSS-RSG rate reductions as a result of forecasted gas/benefit sales

[3]Total percent change may not tie to the cumulative percent due to rounding

PSE&G Gas System Modernization Program III
IIPC Component Annual Bill Impact Summary[1]

Incremental Typical Annual Bill Impacts By Rate Class										
			Rate Adjustment Date							
Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027	End of Program Customer Bill ($)
RSG	1,040	1,170.82	12.70	16.36	23.64	20.06	21.64	38.80	8.44	1,312.47
GSG	2,115	2,894.05	20.67	26.73	38.96	32.75	35.54	63.51	13.76	3,125.97
LVG	40,278	46,132.97	176.29	227.33	329.33	275.90	296.55	520.86	117.89	48,077.12
TSG-F	633,000	680,852.35	989.82	1,266.10	1,817.45	1,506.11	1,600.11	2,825.58	594.57	691,452.09
TSG-NF	969,000	1,001,169.68	2,382.28	3,087.26	4,485.54	3,779.37	4,086.93	7,324.79	1,582.55	1,027,898.40
CIG	3,023,000	2,357,185.28	5,718.53	7,281.07	10,472.75	8,913.13	9,581.55	17,234.74	3,712.46	2,420,099.51

Incremental Annual Percent Change From Current Typical Annual Bill By Rate Class										
			Rate Adjustment Date							
Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027	Total Percent Change from Current Bill
RSG	1,040	1,170.82	1.08%	1.40%	2.02%	1.71%	1.85%	3.31%	0.72%	12.09%
GSG	2,115	2,894.05	0.71%	0.92%	1.35%	1.13%	1.23%	2.19%	0.48%	8.01%
LVG	40,278	46,132.97	0.38%	0.49%	0.71%	0.60%	0.64%	1.13%	0.26%	4.21%
TSG-F	633,000	680,852.35	0.15%	0.19%	0.27%	0.22%	0.24%	0.42%	0.09%	1.58%
TSG-NF	969,000	1,001,169.68	0.24%	0.31%	0.45%	0.38%	0.41%	0.73%	0.16%	2.68%
CIG	3,023,000	2,357,185.28	0.24%	0.31%	0.44%	0.38%	0.41%	0.73%	0.16%	2.67%

[1]All customers assumed to receive BGSS supply

PSE&G Gas System Modernization Program III

IIPC Component Annual Bill Impact Summary[1]

Cumulative Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027
RSG	1,040	1,170.82	12.70	29.06	52.70	72.77	94.41	133.21	141.65
GSG	2,115	2,894.05	20.67	47.40	86.36	119.11	154.65	218.16	231.92
LVG	40,278	46,132.97	176.29	403.62	732.95	1,008.85	1,305.40	1,826.26	1,944.15
TSG-F	633,000	680,852.35	989.82	2,255.92	4,073.37	5,579.48	7,179.59	10,005.17	10,599.74
TSG-NF	969,000	1,001,169.68	2,382.28	5,469.54	9,955.08	13,734.45	17,821.38	25,146.17	26,728.72
CIG	3,023,000	2,357,185.28	5,718.53	12,999.60	23,472.35	32,385.48	41,967.03	59,201.77	62,914.23

Cumulative Percent Changes From Current Typical Annual Bill
By Rate Class[2]

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Rate Adjustment Date 12/1/2024	6/1/2025	12/1/2025	6/1/2026	12/1/2026	6/1/2027	12/1/2027
RSG	1,040	1,170.82	1.08%	2.48%	4.50%	6.22%	8.06%	11.38%	12.10%
GSG	2,115	2,894.05	0.71%	1.64%	2.98%	4.12%	5.34%	7.54%	8.01%
LVG	40,278	46,132.97	0.38%	0.87%	1.59%	2.19%	2.83%	3.96%	4.21%
TSG-F	633,000	680,852.35	0.15%	0.33%	0.60%	0.82%	1.05%	1.47%	1.56%
TSG-NF	969,000	1,001,169.68	0.24%	0.55%	0.99%	1.37%	1.78%	2.51%	2.67%
CIG	3,023,000	2,357,185.28	0.24%	0.55%	1.00%	1.37%	1.78%	2.51%	2.67%

[1]All customers assumed to receive BGSS supply

[2]Total percent change may not tie to the cumulative percent due to rounding

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE NEXT PHASE OF THE GAS SYSTEM MODERNIZATION PROGRAM AND ASSOCIATED COST RECOVERY MECHANISM ("GSMP III")

Notice of Filing and Notice of Public Hearings | BPU Docket No.: GR________

TAKE NOTICE that, on March 1, 2023, Public Service Electric and Gas Company ("Public Service", "PSE&G", or "Company") filed a petition and supporting documentation with the New Jersey Board of Public Utilities ("Board" or "BPU"). The Company is seeking Board approval to implement and administer an extension to PSE&G's Gas System Modernization Program ("GSMP III" or "Program") and to approve an associated cost recovery mechanism.

PSE&G seeks Board approval to invest approximately $2.54 billion in Program investments across its gas service territory over three (3) years with cost recovery based upon the Board's Infrastructure Investment Program ("IIP") rules and consistent with the same approach being used for the Company's Energy Strong II and IAP programs. The implementation of the GSMP III Program proposes to replace cast iron ("CI") mains and unprotected steel ("US") mains and services; address the abandonment of district regulators associated with this cast iron and unprotected steel plant; rehabilitate large diameter elevated pressure cast iron ("EPCI"); upgrade utilization pressure cast iron ("UPCI") portions of the system to EPCI; replace limited amounts of protected steel and plastic mains; and relocate inside meter sets. The Program will result in the replacement of approximately 380 miles of main annually, for a total of 1,140 miles of replacement main. The proposed replacement miles include 810 miles of UPCI mains, 50 miles of EPCI mains, 200 miles of US mains and 80 miles of cathodically-protected steel and plastic mains. Additionally, the proposed Program would result in the abandonment of approximately 210 district regulators, the replacement of approximately 92,100 US services and the relocation of approximately 49,200 inside meter sets to the outside. Finally, the program will include the installation of a one megawatt power-to-gas facility that will serve a portion of the Central 60 psig gas distribution system with a blended supply of up to 2% of clean hydrogen and the installation of a facility that will allow the injection of RNG created from landfill gas into the Central 35 psig gas distribution system.

In conjunction with the implementation of the Program, PSE&G will seek Board approval to recover the revenue increases associated with the capital investment costs of the GSMP III. While the Company is not seeking an increase at this time, PSE&G is seeking authority to recover a return on and return of its investments through semi-annual adjustments to its IIP charges beginning on December 1, 2024. The Company estimates that the rate change would increase rates by approximately $22.99 million. This rate change is only an estimate at this time and is subject to change.

For illustrative purposes, the December 1, 2024 estimated GSMP III rate components of IIP charges including New Jersey Sales and Use Tax (SUT) for residential Rate Schedule RSG is shown in Table #1. Table #2 provides customers with the approximate effect of the proposed change in the GSMP III component of IIP charges relating to the Program, if approved by the Board, effective December 1, 2024. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Under the Company's proposal, a typical residential gas heating customer using 172 therms per month during the winter months and 1,040 therms on an annual basis would see an initial increase in the annual bill from $1,170.82 to $1,183.52, or $12.70 or approximately 1.08%. The approximate effect of the proposed GSMP III component of IIP charge on typical gas residential monthly bills, if approved by the Board, is illustrated in Table #3.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential gas heating customer using 1,040 therms annually would be: $12.70 or approximately 1.08% effective 12/1/2024; $16.36 or approximately 1.40% effective 6/1/2025; $23.62 or approximately 2.02% effective 12/1/2025; $20.06 or approximately 1.71% effective 6/1/2026; $21.64 or approximately 1.85% effective 12/1/2026; $22.62 or approximately 1.93% effective 6/1/2027; and $4.86 or approximately 0.42% effective 12/1/2027.

Tables #4 & #5 provide customers with the estimated incremental and cumulative rate impacts of the Program to typical and class average customers for each Rate Class. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of the Company's Petition may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A. 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

The Petition is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings.

PLEASE TAKE FURTHER NOTICE that due to the COVID-19 pandemic, virtual public hearings are scheduled on the following date and times so that members of the public may present their views on the Petition at the virtual public hearing as noted below.

Information provided at the public hearings will become part of the record and considered by the Board.

VIRTUAL PUBLIC HEARINGS
Date: tbd
Times: tbd
Join: Join Zoom Meeting
https://pseg.zoom.us/j/92846158128?pwd=czBtZHE5ZTh1Z1FveGlmSVg0R1NuQT09#success

Go To www.Zoom.com and choose "Join a Meeting" at the top of the web page. When prompted, use Meeting number 928 4615 8128 to access the meeting.

-or-

Join by phone (toll-free):
Dial In: (888) 475-4499
Meeting ID: 928 4615 8128
When prompted, enter the Meeting ID number to access the meeting.

Representatives from the Company, Board Staff, and the New Jersey Division of Rate Counsel will participate in the virtual public hearings. Members of the public are invited to participate by utilizing the link or the dial-in number set forth above and may express their views on the Petition. All comments will be made a part of the final record of the proceeding and will be considered by the Board.

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters and/or listening assistance, 48 hours prior to the above hearings to the Acting Board Secretary at board.secretary@bpu.nj.gov.

The Board will also accept written and/or electronic comments. While all comments will be given equal consideration and will be made part of the final record of this proceeding, the preferred method of transmittal is via the Board's Public Document Search Tool (https://publicaccess.bpu.state.nj.us/) by searching for the specific docket numbers listed above, and then posting the comment by utilizing the "Post Comments" button. Emailed comments may be filed with the Acting Board Secretary in PDF or Word format, to board.secretary@bpu.nj.gov.

Written comments may be submitted to the Acting Board Secretary, Carmen D. Diaz, at the Board of Public Utilities, 44 South Clinton Avenue, 1st Floor, P.O. Box 350, Trenton, New Jersey 08625-0350. All mailed or emailed comments should include the name of the Petition and the docket number.

All comments are considered "public documents" for purposes of the State's Open Public Records Act. Commenters may identify information that they seek to keep confidential by submitting them in accordance with the confidentiality procedures set forth in N.J.A.C. 14:1-12.3.

Table #1 GSMP III RATE COMPONENTS of IIP Charges For Residential RSG Customers Rates if Effective December 1, 2024				
			IIP Charges	
			Charges in Effect March 1, 2023 Including SUT	Estimated Charges Including SUT
RSG	Service Charge	per month	$0.00	$0.00
	Distribution Charge	$/Therm	$0.000000	$0.012235
	Off-Peak Use	$/Therm	$0.000000	$0.006118
	Basic Gas Supply Service-RSG (BGSS-RSG)	$/Therm	$0.000000	-$0.000071

Table #2 Proposed Percentage Change in Revenue By Customer Class For Gas Service For Rates if Effective December 1, 2024		
	Rate Class	Percent Change
Residential Service	RSG	1.10 %
General Service	GSG	0.64 %
Large Volume Service	LVG	0.37 %
Street Lighting Service	SLG	0.05 %
Firm Transportation Gas Service	TSG-F	0.14 %
Non-Firm Transportation Gas Service	TSG-NF	0.16 %
Cogeneration Interruptible Service	CIG	0.22 %
Contract Services	CSG	0.18 %
Overall		0.76 %

The percent increases noted above are based upon March 1, 2023 Delivery Rates, the applicable Basic Gas Supply Service (BGSS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

Table #3
Residential Gas Service For Rates if Effective December 1, 2024

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
170	25	$34.40	$34.71	$0.31	0.90 %
340	50	60.21	60.81	0.60	1.00
610	100	112.92	114.13	1.21	1.07
1,040	172	188.02	190.12	2.10	1.12
1,210	200	217.20	219.63	2.43	1.12
1,816	300	321.48	325.13	3.65	1.14

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect March 1, 2023 , and assumes that the customer receives commodity service from Public Service.

(2) Same as (1) except includes change for GSMP III Rate Adjustment.

Table #4
Gas Service
Incremental Annual Percent Change
From Current Typical Annual Bill
Rates Effective March 1, 2023
Including Forecasted Gas/Benefit Sales

Rate Class	Forecasted % Increase 12/1/2024	Forecasted % Increase 6/1/2025	Forecasted % Increase 12/1/2025	Forecasted % Increase 6/1/2026	Forecasted % Increase 12/1/2026	Forecasted % Increase 6/1/2027	Forecasted % Increase 12/1/2027
RSG	1.08%	1.40%	2.02%	1.71%	1.85%	1.93%	0.42%
GSG	0.71%	0.92%	1.35%	1.13%	1.23%	2.19%	0.48%
LVG	0.38%	0.49%	0.71%	0.60%	0.64%	1.13%	0.26%
TSG-F	0.15%	0.19%	0.27%	0.22%	0.24%	0.42%	0.09%
TSG-NF	0.24%	0.31%	0.45%	0.38%	0.41%	0.73%	0.16%
CIG	0.24%	0.31%	0.44%	0.38%	0.41%	0.73%	0.16%

The percent increases noted above are based upon Delivery Rates in effect March 1, 2023, and the applicable Basic Gas Supply Service (BGSS) charges and assumes customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

Table #5
Gas Service
Cumulative Annual Percent Change
From Current Typical Annual Bill
Rates Effective March 1, 2023
Including Forecasted Gas/Benefit Sales

Rate Class	Forecasted % Increase 12/1/2024	Forecasted % Increase 6/1/2025	Forecasted % Increase 12/1/2025	Forecasted % Increase 6/1/2026	Forecasted % Increase 12/1/2026	Forecasted % Increase 6/1/2027	Forecasted % Increase 12/1/2027
RSG	1.08%	2.48%	4.50%	6.21%	8.06%	9.99%	10.41%
GSG	0.71%	1.64%	2.98%	4.12%	5.34%	7.54%	8.01%
LVG	0.38%	0.87%	1.59%	2.19%	2.83%	3.96%	4.21%
TSG-F	0.15%	0.33%	0.60%	0.82%	1.05%	1.47%	1.56%
TSG-NF	0.24%	0.55%	0.99%	1.37%	1.78%	2.51%	2.67%
CIG	0.24%	0.55%	1.00%	1.37%	1.78%	2.51%	2.67%

The percent increases noted above are based upon Delivery Rates in effect March 1, 2023, and the applicable Basic Gas Supply Service (BGSS) charges and assumes customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY