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AOBA
APARTMENT AND OFFICE BUILDING ASSOCIATION OF METROPOLITAN WASHINGTON

June 15, 2020

By Electronic Filing

Brinda Westbrook-Sedgwick
Commission Secretary
D.C. Public Service Commission
1325 G Street, N.W., Suite 800
Washington, D.C. 20005

Re: **Formal Case No. 1115**
In the Matter of Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipe Replacement Plan

Formal Case No. 1142
In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.

Formal Case No. 1154
In the Matter of Application of Washington Gas Light Company for Approval of ProjectPipes 2 Plan

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing is the Direct Testimony of Bruce R. Oliver on behalf of the Apartment and Office Building Association of Metropolitan in the above-captioned proceeding.

If you have any questions, please contact me at ffrancis@aoba-metro.org or call me at (202) 296-3390 ext. 766. Thank you for your attention in this matter.

Sincerely,

Frann G. Francis

Frann G. Francis, Esq.

cc: All parties of record

CERTIFICATE OF SERVICE
Formal Case Nos. 1115, 1142 and 1154

I hereby certify on this 15th day of June, 2020 that the attached **Direct Testimony of Bruce Oliver** were filed electronically on behalf of the Apartment and Office Building Association of Metropolitan Washington in Formal Case Nos. 1115, 1142 and 1154 and copies were electronically delivered to the service list below:

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AOBA (A)

Before the

PUBLIC SERVICE COMMISSION
OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipe Replacement Plan	)))	**Formal Case No. 1115**
IN THE MATTER OF	)	
	)	
The Merger of AltaGas Ltd. and WGL Holdings, Inc.,	))	**Formal Case No. 1142**
IN THE MATTER OF	)	
	)	**Formal Case No. 1154**
Application of Washington Gas Light Company for Approval of ProjectPipes 2 Plan	))	

VOLUME I OF I: DIRECT TESTIMONY OF AOBA WITNESS
BRUCE R. OLIVER

June 15, 2020

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DIRECT TESTIMONY OF BRUCE R. OLIVER
DCPSC Formal Case No. 1115, 1142 and 1154

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DIRECT TESTIMONY OF BRUCE R. OLIVER
DCPSC Formal Case No. 1115, 1142 and 1154

LIST OF EXHIBITS AND ATTACHMENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I appear on behalf of the Apartment and Office Building Association of Metropolitan Washington (AOBA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony in this proceeding addresses issues relating to the Washington Gas Light Company ("Washington Gas," "WG" or "the Company")[1] request for

[1] AOBA believes that the distinctions between Washington Gas Light Company and its parent, WGL Holdings, Inc. are important to the Commission's considerations in this proceeding. To avoid confusing references to Washington Gas Light Company with references to its parent company any and all uses of the acronym "WGL" in this testimony will constitute references to WGL Holdings, Inc. Although the Commission and other parties have used the acronym "WGL" to reference Washington Gas Light Company, this testimony purposefully **avoids** using the acronym "WGL" to refer to Washington Gas Light

approval of a revised Accelerated Pipe Replacement Plan. This testimony also addresses issues relating to portions of the pre-filed Direct Testimony and Exhibits sponsored by Washington Gas witnesses Jacas and Stuber as well as the Supplemental Direct Testimonies and Exhibits of witnesses Jacas, Stuber, and Price.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I am an economist specializing in the areas of utility rates, energy, and regulatory policy matters. I have over 40 years of experience in the analysis of energy and utility policy issues. That experience includes employment in management positions in the rate departments of two major utilities (the Pacific Gas and Electric Company and the Potomac Electric Power Company), as well as service in management and senior staff positions for three consulting firms, Revilo Hill Associates, Inc., the Resource Dynamics Corporation, and ICF Incorporated.

As a consultant, I have served a diverse group of clients on issues encompassing a wide range of energy and utility related activities. My clients have included state regulatory commissions, utilities, state Attorneys General, state-funded consumer advocacy groups, municipal governments, hospitals and universities, federal agencies, commercial and industrial energy users, suppliers of equipment and services to utility markets, residential consumer intervenors, the Electric Power Research Institute (EPRI), and the World Bank. Projects for

Company and its regulated distribution utility operations. In fact, "Washington Gas" is listed as just one of four companies that operate under the entity referenced as "WGL."

those clients have included work on gas, electric, water, and wastewater utility regulatory proceedings, as well as analyses and forecasts of supply, demand, and prices for utility and non-utility energy markets. I have also assisted a number of commercial, institutional, and industrial energy users in the negotiation of a wide range of energy service contracts, including contracts for the procurement of competitive electricity and natural gas services.

To date, I have presented more than 400 separate pieces of testimony in over 300 proceedings before regulatory commissions in 25 jurisdictions. The regulatory jurisdictions in which I have testified include: the states of Pennsylvania, New York, New Jersey, Maryland, Delaware, Virginia, North Carolina, Rhode Island, Vermont, Connecticut, Massachusetts, Ohio, Illinois, Wisconsin, South Dakota, Arizona, New Mexico, Utah, and California, as well as the District of Columbia, Guam, the Virgin Islands, the City of Philadelphia, the Provence of Alberta, Canada, and the U.S. Federal Energy Regulatory Commission (FERC). My testimonies in those jurisdictions have addressed such topics as industry restructuring, utility mergers and acquisitions, divestiture of generation assets, sighting of energy facilities, utility revenue requirements, capital structure, costs of capital, cost of service allocations, rate design, rate unbundling, incentive rate-making, revenue decoupling, capacity expansion planning, asset management, outsourcing, demand-side management, energy conservation, contracts for non-tariff service provided to large energy users, natural gas purchasing practices, gas transportation service, natural gas processing, competitive bidding, economic development rates, load research, load forecasting, weather normalization, metering, fuel procurement, and fuel pricing issues. I have also testified before legislative committees in Virginia, Maryland, and the District of Columbia.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes, I have appeared before this Commission in a number of prior gas and electric rate proceedings. The prior WG proceedings before this Commission in which I have testified include: Formal Case Nos. 787, 840, 845, 890, 922, 934, 989, 1016, 1054, 1079, 1093, 1115, 1137 and 1142.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PROCEEDINGS IN OTHER JURISDICTIONS RELATING TO WASHINGTON GAS LIGHT COMPANY?

A. Yes, I have testified in numerous Washington Gas Light Company cases before the Maryland Public Service Commission (MDPSC) and the Virginia State Corporation Commission (VASSC). The Washington Gas Light Company proceedings in Maryland in which I have testified include: Case Nos. 7649, 8060, 8119, 8191, 8545, 8819, 8920 (Phases I and II), 8959, 8991, 9104 (Phases I and II), 9158, 9267, 9322, 9335, 9433, 9449, 9481 and 9605. The WG proceedings in Virginia in which I have submitted testimony include: Case Nos. PUE 830008, PUE 830029, PUE 880024, PUE 900016, PUE 910047, PUE 920041, PUE 940031, PUE 960296, PUE 980812, PUE 000584, PUE 2002-00364, PUE 2003-

00603, PUE 2005-00010, PUE 2006-00059 and PUE 2010-00139, and PUR 2018-00080.

Q. WERE THIS TESTIMONY AND ACCOMPANYING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

II. OVERVIEW AND SUMMARY

Q. WHAT IS YOUR OVERALL ASSESSMENT OF WG'S FILING IN THIS PROCEEDING?

A. As noted in the Direct Testimony of WG Witness Stuber, "*the overall Commission policy [is] to reduce risk and enhance safety through accelerated infrastructure replacement*."[2] Over the years of Washington Gas' Project Pipes 1 Plan, the Company has neither accelerated pipe replacement in the District of Columbia nor enhanced the safety of its District of Columbia distribution system. Rather, the number of miles of mains replaced on an annual basis has declined, and the numbers of **hazardous leaks** on the Company's distribution system in the District of Columbia have **increased significantly**. In fact, Washington Gas' Cast Iron main replacement record in the District since 2010 ranks as the **worst in the industry**. The only element of the Company's activities that has been

[2] WG Exhibit (B), the Direct Testimony of Witness Stuber, page 4, lines 11-13.

accelerated is its **cost recovery**. The Company has lost the entire concept of "normal" replacement activity, and it is falling further behind in its replacement of very old and increasing leak-prone pipes.[3] The Project Pipes 2 Plan that Washington Gas now offers does not remedy or seriously address the deficiencies in the Company's pipe replacement activities for the District of Columbia.

Despite WG's suggestions to the contrary, its District of Columbia distribution system has become demonstrably more leak prone and less safe. Over the period from 2010-2019, hazardous leaks per 100 miles of mains and hazardous leaks per 1,000 services on the Company's distribution system have both more than doubled. For WG's District of Columbia distribution mains, **hazardous** leaks have increased from 18.8 leaks per 100 miles of mains in 2010 to **41.8** hazardous leaks per 100 miles of mains in 2019 (i.e., an increase of 122%).[4] Hazardous service leaks in the District have increased from 2.2 per 1,000 services to 5.02 per thousand services (i.e., an increase of 131%).[5] This is not a system that is getting safer. In fact, twice in the last three years the Company's leak response requirements have necessitated Washington Gas declaring a

[3] WG's Depreciation Study in Formal Case No. 1162, Exhibit WG (F)-2, Statement E, page 31, indicates that the plant life expectations for the Company's Plastic mains have been shortened. This suggests that Washington Gas will have growing requirements in the coming years for more Plastic main replacement in addition to its substantial backlog of Cast Iron and Bare Steel main replacement requirements.

[4] Washington Gas Annual Reports to the Pipeline and Hazardous Materials Safety Administration ("PHMSA") for its District of Columbia distribution system for the years 2010 – 2019.

[5] Ibid.

"catastrophic event" to enable it to bring in resources from other utilities to assist its leak response and leak remediation efforts.

The characteristics of Washington Gas' District of Columbia distribution system are quite different from those of its Maryland and Virginia distribution systems. However, the Company continues to manage its pipe replacement activities as a single program with little sensitivity to the much greater age of its District of Columbia system and the much greater proportion of Cast Iron mains found in its DC distribution system.

The proverbial "*elephant in the room,*" that Washington Gas wants to ignore, is the amount of very old Cast Iron pipe that lies beneath the streets of the District and is becoming increasingly leak prone, and the extremely high cost of replacing such pipe. Washington Gas estimates that its costs for replacing Cast Iron mains equate to $1,602 per foot or nearly **$8.5 million per mile**.[6] Given that Washington Gas still has over 400 miles of Cast Iron mains in the District, replacement of all of those mains would require an investment of roughly **$3.3 billion** without any allowance for cost inflation over time. To put that in perspective, Washington Gas' total District of Columbia rate base as of December 31, 2019 was only about **$525 million**.[7] In other words, replacement of the approximately **one-third** of the Company's distribution system in the

[6] Exhibit WG (2A)-1, page 9 of 26, in this proceeding, presented in 2021 dollars. It should be noted that the Company's 2021 cost per mile for Cast Iron main replacements is nearly **10% higher** than the $1,457 dollars per foot that was presented in Exhibit WG (A)-2, page 6 of 26, filed with Witness Jacas Direct Testimony. This suggests that the Company's costs for Cast Iron main replacement are escalating at a rate **far in excess** of the general rate of inflation for all goods and services.

[7] Exhibit WG (D)-1 that accompanies the Direct Testimony of Washington Gas Witness Tuoriniemi in Formal Case No. 1162 (prior to ratemaking adjustments).

District that is still comprised of Cast Iron mains would require a total investment that is nearly **six times** the Company's current total rate base for the District. As I will document herein, the rate impacts of such replacements are substantial and must not be overlooked as they threaten the on-going economic viability of the Company's District of Columbia distribution system.

Much focus has been placed on the environmental impacts of increased leaks from Washington Gas' distribution system and the compatibility of such leaks with the attainment of the District's Energy and Environment goals. However, any long-term plan for Washington Gas must also address the affordability of the Company's gas distribution services in the District. The costs of maintaining the safety of Washington Gas' distribution system may have a much more dramatic impact on the future use of natural gas by residents and businesses in the District than environmental considerations. Overall, Washington Gas' has demonstrated that it cannot ensure the safety of its gas distribution system in the District of Columbia while keeping its rates for gas service in the District at affordable levels.

In the short-run this Commission must require Washington Gas to prioritize replacement of its most leak prone pipe based on Optimain scores, not on average leak rates by type of pipe which may disguise large amounts of highly leak prone Cast Iron pipe in the District. The Commission should also give priority to identification of a means of trimming the size of Washington Gas's system in the District and/or raising the safety of its DC distribution system to a more acceptable level while maintaining the affordability of any remaining service that is provided. In this context, the highest priority should be assigned to the development of a more sound business plan for Washington Gas' DC operations.

A. Summary of Findings

Q. PLEASE SUMMARIZE THE KEY ELEMENTS OF YOUR FINDINGS WITH RESPECT TO WG'S PROPOSALS IN THIS PROCEEDING.

A. Key findings of this testimony include the following:

- The numbers of **hazardous leaks** from mains and services in the District have both more than doubled between 2010 and 2019 despite the Commission's acceptance of Washington Gas' Project Pipe 1 plan.

- In 2019 Washington Gas' ratio of hazardous leaks per mile of mains in the District is the third highest level of leaks per mile of mains among all gas utility systems in the U.S. with more than 500 miles of mains and over 25,000 services.

- Since 2010 Washington Gas has replaced a significantly smaller percentage of its Cast Iron mains in the District than any other major gas utility in any other jurisdiction in the U.S. that had over 100 miles of Cast Iron mains installed in 2010.

- Washington Gas' claims that it has reduced Greenhouse Gas emissions in the District through its pipe replacement activities ignore the fact that the numbers of leaks on its system are growing faster than the Company's replacement of leak-prone pipe.

- Washington Gas' number of leaks per 100 miles of mains installed was the **third highest** in the industry in 2019 for systems with more than 500 total miles of mains.[8]

- Washington Gas' estimated costs for replacement of Cast Iron and Bare Steel mains in the District of Columbia are as much as **two to three times greater** than pipe replacement costs for gas distribution systems that serve other major cities in the eastern U.S.

- Based on Washington Gas' projected pipe replacement costs, the cost of replacing all of Washington Gas' Cast Iron and Bare Steel mains in the District is prohibitive, and more economic alternatives must be found if Washington Gas is to continue to provide service

[8] Only Keyspan Energy Delivery - New York City and ConEdison of New York had higher ratios of hazardous leaks per mile of mains installed in 2019.

to customers in the District who are currently fed from Cast Iron and Bare Steel mains.

- Even considering the relative size of Washington Gas' distribution system in the District of Columbia, the Company's proposed main replacements over the five years of its PIPES 2 plan are substantially smaller than the planned pipe replacement activity of other large Northeastern gas systems with large amounts of old Cast Iron Mains.

- Gas Service Standards are needed to: (1) ratchet downward the levels of hazardous leaks reported annually for the Company's District of Columbia distribution system; and (2) establish minimum annual levels of high risk pipe replacement.

- Washington Gas' budgeted costs for main replacements when viewed on the basis of dollars per mile or dollars per foot of main are sharply higher than those for other large Northeastern gas systems with significant amounts of old Cast Iron mains.

- At the rate of pipe replacement set forth for the Company's PIPES 2 Plan in Exhibit WG (2A)-1 it would take Washington Gas nearly

100 years to replace all of its targeted mains. Given that about 80% of WG's main miles targeted for replacement are Cast Iron Mains and that most of the Company's Cast Iron mains have already exceeded their expected useful lives, the proposed pace for main replacements, particularly for Cast Iron main replacements is not reasonable or realistic.

- There is an absence of reasonable ties between the Company's expected lives for distribution mains and Washington Gas' planning of main replacements.

- WG's proposed main replacements for the District under its PIPES 2 Plan pale in comparison to main replacement activity of other large gas systems that have significant mileage of Cast Iron and Bare Steel Mains on their systems.

B. <u>Summary of Recommendations</u>

Q. WHAT ARE YOUR RECOMMENDATIONS FOR COMMISSION ACTIONS WITH RESPECT TO WG'S FILINGS IN THIS PROCEEDING?

A. Based on the findings in this presentation, I urge the Commission to take the following actions:[9]

1. At this time the Commission should approve replacement of only the highest priority mains based on safety considerations.

2. The Commission should find Washington Gas' safety performance over the last decade, particularly with respect to the rising numbers of hazardous leaks on its District of Columbia distribution system unacceptable and that recent declines in miles of pipe replacement for very old and leak prone Cast Iron and Bare Steel mains are inconsistent with the efforts to ensure the safety of the District of Columbia distribution system.

3. The Commission should find Washington Gas' PIPES 2 Plan uneconomic and inadequately focused on improvements in the safety of the Washington Gas' DC distribution system.

4. The Commission should find that the numbers of services and miles of mains that Washington Gas proposes to replace over the next five years are not sufficient to keep pace with the aging of its

[9] Omission from this list of a recommendation presented elsewhere in this testimony is unintentional and does not diminish or negate the importance of such a recommendation.

existing distribution facilities and only serve to exacerbate backlog of pipe replacement requirements that Washington Gas currently faces in the District of Columbia.

5. As this Commission did with electric service following the derecho and other major storms early in the last decade, the Commission should set Gas Service Standards that require reduced numbers of hazardous leaks and completion of minimum annual levels of **high risk** pipe replacements, and if those standards are not met Washington Gas should be subject to significant financial penalties.

6. The Commission should immediately undertake an assessment of means for lowering the costs of pipe replacement and expanding the amount of pipe replaced in the District, or alternatively, identify means of reducing the scope of Washington Gas' distribution service operations in the District.

7. The Commission should find that, at the Company's estimates of costs for main replacement, large investments in the replacement of very old leak-prone mains in the District of Columbia are inconsistent with achievement of the District's energy and environmental

goals and represent a recipe for greater future Stranded Cost claims by Washington Gas.

8. The Commission should specifically reject Washington Gas' proposed Program 10 as the expenditures proposed under that program are only loosely tied to the replacement of high risk mains and services and the extent of overlaps between the pipe to be addressed by that program and by other Programs within the Company's PIPES 2 Plan are not clearly discernible.

9. The Commission should restrict Washington Gas from making dividend payments to its parent company, AltaGas, until it has met the equity funding requirements necessary to support at least its minimum annual pipe replacement requirements.

10. The Commission should establish **minimum** annual accelerated pipe replacement requirements designed to ensure greater annual progress toward the elimination of Cast Iron and Bare Steel mains.

11. The Commission should set caps on the costs per mile and cost per service that WG may recover through an accelerated cost recovery mechanism, as well as establish a policy that WG will only

be provided accelerated cost recovery for accelerated pipe replacement activity.

12. The Commission should require Washington Gas to file an annual Infrastructure, Safety and Reliability ("ISR") Plan for review by the parties and litigation before the Commission.

13. The Commission should provide a financial incentive for the Company to exceed its minimum annual pipe replacement requirements.

14. The Commission should establish "**normal**" pipe replacement requirements that are conceptually consistent with the plant life expectations used in the Company's depreciation studies. If WG fails to meet identified "normal" pipe replacement requirements in any given year, it should be subjected to financial penalties.

15. The Commission should require the development of a proxy group approach of eastern urban gas utilities to facilitate assessments of the reasonableness of WG's pipe replacement performance and costs.

III. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO WASHINGTON GAS' FILINGS IN THIS PROCEEDING ORGANIZED?

A. This discussion of issues is presented in three sections. **Section A** offers perspective on the status of WG's distribution system in the District of Columbia. **Section B** evaluates elements of WG's proposed PIPES 2 Plan. **Section C** examines potential alternatives for more safety focused and cost-effective efforts to address Washington Gas' DC distribution system leaks and alternatives to the Company's PIPES 2 Plan.

A. Perspective on the WG's Distribution System in the District

Q. HOW DOES THE COMPOSITION OF THE WASHINGTON GAS DISTRIBUTION SYSTEM IN THE DISTRICT DIFFER FROM THE COMPOSITION OF THE COMPANY'S DISTRIBUTION SYSTEMS IN MARYLAND AND VIRGINIA?

A. Exhibit AOBA (A)-1 indicates the distribution of mains by type that comprise the Company's distribution systems in the District of Columbia, Maryland and Virginia. As shown in that exhibit, Cast Iron mains accounted for **33.5%** of the total mains on the Company's DC distribution system in 2019. By comparison, only **0.7%** of WG's distribution mains in Maryland and **0.2%** of the Company's distribution mains in Virginia were Cast Iron mains. Further, Exhibit AOBA (A)-2 demonstrates that **31.9%** of the Company's current distribution mains in DC were installed prior to 1940 (i.e., more than 80 years ago), while the corresponding percentages for Maryland and Virginia are **1.0%** and **0.3%** respectively.

Q. IS THE COMPOSITION OF WASHINGTON GAS' DISTRIBUTION MAINS IN THE DISTRICT CLOSELY ALIGNED WITH THE OVERALL COMPOSITION OF MAINS FOR LARGE GAS SYSTEMS IN THE U.S.?

A. No, it does not. Washington Gas' 2019 Annual Report to PHMSA[10] indicates that its District of Columbia distribution system includes **33.5%** Cast Iron mains. That is the second highest percentage of Cast Iron Mains for all systems nationwide that had greater than 500 miles of mains and greater than 20,000 service lines installed in 2019. Only the Philadelphia Gas Works (a municipal utility) had a higher percentage of Cast Iron mains. The average percentage of Cast Iron mains for all 198 systems that had greater than 500 miles of mains and greater than 25,000 service lines installed in 2019 was 1.7%.[11] In 2019 Washington Gas' distribution systems in Maryland and Virginia and had 0.7% and 0.2% Cast Iron mains respectively.

WG's District of Columbia distribution system also had **31.9%** of its distribution mains installed prior to 1940. Again, that is the second highest percentage of mains installed pre-1940 (i.e., second only to the Philadelphia Gas Works). The industry average percentage of mains installed pre-1940 is only

[10] PHMSA is the Pipeline and Hazardous Materials Safety Administration, is an agency of the U.S. Department of Transportation whose responsibilities include gas pipeline safety.
[11] See Exhibit AOBA (A)-1.

2.9%. Similar, observations can be made with respect to mains installed pre-1970. The PHMSA data indicate that **56.6%** of the mains on WG's District of Columbia distribution system were installed prior to 1970. The comparable measures for WG's Maryland and Virginia systems were 30.3% and 24.5%. No matter how you slice it, the District's gas distribution system is a comparatively dated system with a very high percentage of very old Cast Iron mains.

Q. HAS THE COMPANY PROPERLY REFLECTED THE SIZE OF THE CAST IRON MAIN COMPONENT OF WASHINGTON GAS' DISTRICT OF COLUMBIA DISTRIBUTION SYSTEM AND THE GREATER OVERALL AGE OF MAINS IN THE DISTRICT IN THE COMPANY'S MAIN REPLACEMENT ACTIVITIES OVER THE LAST DECADE?

A. No. **Table 1** shows the percentage of Cast Iron mains replaced between 2010 and 2019 for older, primarily Northeastern, U.S. natural gas distribution systems with the **lowest percentages** of Cast Iron mains replaced. **Table 1 a**lso shows WG's percentages of Cast Iron mains replaced for DC, MD, and VA. Between 2010 and 2019 WG's Distribution system in the District of Columbia had by far the lowest percentage of Cast Iron mains replaced (i.e., **5.4%**). No gas distribution system with a total of more than 500 miles of mains installed, other than Washington Gas' DC distribution system, replaced less than 10% of its existing Cast Iron mains between 2010 and 2019. Most of the systems listed in **Table 1** replaced at least 20% of their mileage of Cast Iron over the same period. Only

Southern Connecticut Gas Co. at 12.2% of Cast Iron mains replaced and the Philadelphia Gas Works at 16.4% replaced less than 20% of their Cast Iron mains between 2010 and 2019. If Washington Gas' Cast Iron main replacement performance in the District of Columbia between 2010 and 2019 was ranked in terms of quartiles for the industry, it would be at the **worst end of the fourth quartile** for all U.S. natural gas systems with Cast Iron mains in 2019.

Table 1

Large Gas Utility Systems with Cast Iron Mains in 2010
With the Lowest Percentages of Cast Iron Mains Replaced by 2019

Respondent	Juris	Reported Miles Cast Iron Mains 2010	Reported Miles Cast Iron Mains 2019	Cast Iron Replaced Miles	Cast Iron Replaced %	2019 Total System Miles of Mains
Washington Gas Light Co	DC	428	405	23	**5.4%**	1,223
Washington Gas Light Co	VA	17	15	2	11.8%	6,440
Washington Gas Light Co	MD	75	44	31	41.3%	6,306
Washington Gas Light Co	Total	520	484	36	**10.8%**	13,969
Southern Connecticut Gas	CT	689	605	84	12.2%	2,471
Philadelphia Gas Works	PA	1,562	1,306	256	16.4%	3,041
Baltimore Gas & Electric	MD	1,349	1,068	281	20.8%	7,443
National Fuel Gas Dist.	PA	175	137	38	21.7%	4,843
Boston Gas Company	MA	2,167	1,676	491	22.7%	6,384
Public Service Elec & Gas	NJ	4,236	3,245	991	23.4%	18,003
Liberty Utilities	MA	134	99	35	26.1%	621
DTE Gas Company	MI	2,513	1,843	670	26.7%	20,078
Consolidated Edison	NY	1,318	958	360	27.3%	4,372
Connecticut Natural Gas	CT	385	274	111	28.8%	2,185
Keyspan Energy of NYC	NY	1,692	1,198	494	29.2%	4,158
NSTAR Gas Company	MA	423	297	126	29.8%	3,300
Peoples Gas Light & Coke	IL	286	195	91	31.8%	4,572
PECO Energy Co (Gas)	PA	799	529	170	32.5%	6,928
Colonial Gas Co. – Lowell	MA	122	81	41	33.6%	1,405
Yankee Gas Services Co	CT	446	283	163	36.5%	3,474
UGI Utilities Inc.	PA	387	242	145	37.5%	12,028
Niagara Mohawk Power	NY	639	317	322	50.4%	8,868

I also observed that although Washington Gas had only 75 miles of Cast Iron mains in its Maryland distribution system in 2010, it replaced 31 miles or 41.3% of those mains between 2010 and 2019. By comparison WG replaced only 23 miles of Cast Iron mains in the District over the same period despite the fact that it had 428 miles of Cast Iron mains in DC in 2010.

Q. ARE THERE OTHER FACTORS THAT DIFFERENTIATE WASHINGTON GAS' DC DISTRIBUTION SYSTEM FROM ITS MARYLAND AND VIRGINIA DISTRIBUTION SYSTEMS?

A. Yes. First, roughly 97% of the mains in WG's Maryland and Virginia distribution systems are Plastic or Protected Wrapped Steel. However, Plastic and Protected Wrapped Steel mains account for only about 60% of WG's gas main mileage in the District of Columbia. Second, Unprotected Bare Steel and Unprotected Wrapped Steel services account for over 13% of the total services on WG's distribution system in the District, but represent only 1.6% and 2.4% of WG's distribution systems in Virginia and Maryland, respectively.

Further, the density of the Company's distribution system in the District is significantly greater than the density of its Maryland and Virginia counterparts. In DC the Company has over 102 services per mile of mains. In Maryland, Washington Gas has only about 71 services per mile of mains, and in Virginia it currently has about 73 services per mile. The greater density of the District of Columbia distribution system influences the numbers of persons that are likely to be exposed to any given leak and with greater exposure to leaks, the risks of death, injury, and damage to property resulting from gas leaks increase.

Washington Gas' DC Distribution System also represents the fourth highest density of development in terms of services per mile for all large gas distribution systems. Only the Philadelphia Gas Works, Keyspan Energy Delivery of NYC, and Peoples Gas Light & Coke (which service Chicago, IL) have higher numbers of services per mile of mains. The average number of services per mile of mains for all large gas systems in the U.S. is just under 50 services per mile. WG's distribution system in the District has more than twice that density. Again, the comparatively high number of services per mile in the District amplifies the growing safety risks associated with WG's growing numbers of hazardous leaks in the District.

Q. CAN YOU PROVIDE FURTHER COMPARATIVE INFORMATION THAT WOULD SHED LIGHT ON WG'S CAST IRON MAIN REPLACEMENT ACTIVITIES IN THE DISTRICT OVER THE LAST DECADE?

A. Yes. Overall, approximately 150 of the 1,436 gas utility systems in the U.S. that filed annual reports with PHMSA in 2010 operated Cast Iron mains. Those 150 utilities had a total of 33,500 miles of Cast Iron gas mains in 2010. By the end of 2019, the total mileage of Cast Iron mains used by gas utilities in the U.S. had fallen to less than 20,600 miles (i.e., a **reduction of 38.5%**). At least 38, gas utilities totally eliminated their use of Cast Iron gas mains between 2010 and

2019. Many of those were comparatively small systems. However, as detailed in **Table 2**, below, among those gas systems that essentially eliminated all of their use of Cast Iron gas mains between 2010 and 2019 were nine large gas distribution systems, including South Jersey Gas Co. and New Jersey Natural Gas Co., (two utilities often included in proxy groups for Washington Gas).

Table 2

Large Gas Systems Substantially Eliminating Cast Iron Main Use between 2010 and 2019

Respondent	Juris	Reported Miles Cast Iron Mains 2010	Reported Miles Cast Iron Mains 2019	% Cast Iron Replaced	2019 Total System Miles of Mains
Duke Energy of Ohio	OH	269	0	100.0%	5,783
South Jersey Gas Co	NJ	250	1	99.6%	6,684
Centerpoint Energy	AR	183	0	100.0%	13,773
Centerpoint Energy	LA	183	0	100.0%	4,100
Kansas Gas Service	KS	125	0	100.0%	11,529
Rochester Gas & Electric	NY	80	0	100.0%	4,890
New Jersey Natural Gas	NJ	71	0	100.0%	7,342
Public Service Co of CO	CO	67	0	100.0%	22,633
Centerpoint Energy	MN	66	0	100.0%	14,113

Of all gas systems in the U.S. with Cast Iron mains in 2010, the only systems will lower percentages of Cast Iron mains replaced between 2010 and 2019 were six very small, mostly municipal, gas systems with limited Cast Iron main mileage. See **Table 3** below. No gas distribution system with a total of more than 500 miles of mains (of all types) installed, other than Washington Gas' District of Columbia distribution system, replaced less than 10% of its existing Cast Iron mains over the last 10 years.

Table 3

Small Gas Systems with No Cast Iron Mains Replaced
(2010 – 2019)

Respondent	Juris	Reported Miles Cast Iron Mains 2010	Reported Miles Cast Iron Mains 2019	% Cast Iron Replaced	2019 Total System Miles of Mains
Roanoke Utilities Board	AL	2	2	0.0%	57
Red Bay NG System	AL	4	4	0.0%	100
Pike County Power & Light	PA	7	7	0.0%	20
Fulton Gas System	KY	3	3	0.0%	143
City of Donaldsonville	LA	44	44	0.0%	59
City of Charlottesville	VA	1	1	0.0%	335

Q. HAS WG PERFORMED BETTER WITH RESPECT TO ITS REPLACEMENT OF BARE STEEL MAINS ON ITS DC DISTRIBUTION SYSTEM?

A. Not substantially better. Since 2010 Washington Gas has replaced only 6.5 miles of Bare Steel mains despite the Company's representation that Bare Steel mains have the highest average leak rate of any material type on its District of Columbia system. The 6.5 miles of Bare Steel mains replaced in the District since 2010 represent only **22.4%** of the 29 miles of Bare Steel mains the Company reported in 2010. By comparison, Washington Gas replaced 57 miles or 37.3% of its Bare Steel mains in Maryland, and 17 miles or 45.7% of its Bare Steel mains in Virginia since 2010.

Also, the 6.5 miles of Bare Steel mains that Washington Gas has replaced in DC since 2010 does not compare favorably with the performance of other large gas systems. On average, large gas systems in the U.S. replaced **35.7%** of their Cast Iron mains between 2010 and 2019. In other words, although WG exceeded the average large system replacement rate for Bare Steel mains between 2010 and 2019 in Maryland and Virginia, its replacement of Bare Steel mains in the District was significantly below the U.S. average for large gas systems. Moreover, the comparatively low rate of Bare Steel main replacements in the District seems to ignore the representation in Table 2 on page 16 of Exhibit Pepco (2A)-1 that the Company's computed average leak rate for Bare Steel mains in the District (i.e., 10.2 leaks per mile) or more than 4.5 times the average leak rate for all mains in the District.

Q. HAS WG PRIORITIZED ITS REPLACEMENT OF CAST IRON MAINS?

A. No. Although over 90% of the Company's 100 highest Optimain scores for main segments in the District are Cast Iron main segments, the Company's PIPES 2 Plan proposes to replace only 1.3 miles per year of the more than 400 miles of Cast Iron mains currently in place. In other words, at the end of the Company's PIPES 2 Plan Washington Gas will still have nearly 400 miles of Cast Iron mains in its DC distribution system. Nearly all of those mains will have been in place for more than 85 years. Much attention has been directed to the need for replacement of Cast Iron and Bare Steel mains. Yet, somehow Washington Gas seems to be working from the perspective that the lives of its existing Cast Iron mains in the District can be extended as many as **35 years** into the future without growing leaks and safety problems.

Q. HOW DOES WASHINGTON GAS' DISTRIBUTION SYSTEM IN THE DISTRICT OF COLUMBIA COMPARE WITH OTHER GAS UTILITIES IN TERMS OF HAZARDOUS LEAKS PER 100 MILES OF MAINS?

A. In 2019 only two gas systems with over 500 miles of mains had greater numbers of hazardous leaks per 100 miles of mains installed than Washington Gas' DC Distribution System. Those are both New York utilities: ConEdison of New York and Keyspan Energy Delivery NY City. **Table 4** shows the gas utility systems with the highest ratios of leaks and **hazardous leaks** per 100 miles of mains for 2019. The ratio 41.77 ratio of **hazardous leaks** per 100 miles of mains for Washington Gas' District of Columbia distribution system is more than **12 times greater** than the industry average of 3.26 leaks per 100 miles of mains. It should be noted that only Washington Gas' District of Columbia system, the two New York utilities referenced above, Boston Gas and the Philadelphia Gas Works have ratios of hazardous leaks per 100 miles of mains in excess of 15. It is also noteworthy that Washington Gas' jurisdictional distributions systems have leak rates per 100 miles of mains in the top ten for large gas systems in the U.S. Again, if hazardous leaks per 100 miles[12] was used as a metric for ranking the performance of the Washington Gas distribution system in the District of Columbia, the WG DC distribution system performance would be at the worst end of the fourth quartile.

[12] The choice of the denominator for this metric is somewhat arbitrary. It makes no substantive differences if leaks or hazardous leaks are measured per 100 miles of mains or per mile of mains as long as the same denominator is used consistently for all years and all systems that are compared.

Table 4

Large Gas Systems with Highest Ratios of Hazardous Leaks per 100 Miles of Mains Installed in 2019

		2019 Main Leaks		Leaks per 100 Miles	
Respondent	Juris	Total	Hazardous	Total	Hazardous
1. Keyspan Energy - NYC	NY	3,348	2,566	80.53	61.72
2. ConEdison of New York	NY	6,805	2,372	155.65	54.25
3. **Washington Gas Light**	**DC**	984	511	**80.44**	**41.77**
4. Boston Gas Co	MA	6,162	2,330	96.52	36.50
5. Philadelphia Gas Works	PA	2,779	905	91.39	29.76
6. Baltimore Gas & Electric	MD	3,088	1,105	41.49	14.85
7. **Washington Gas Light Co**	**MD**	1,564	801	24.80	12.70
8. Niagara Mohawk[13]	RI	982	378	30.74	11.83
9. NSTAR Gas Company	MA	694	317	21.03	9.61
10. **Washington Gas Light Co**	**VA**	1,061	529	16.48	8.21
All Respondents (1,405)		122,273	43,254	9.21	3.26
Large Systems (198)[14]		116,868	41,776	9.83	3.51

The Commission should take note of how deviant the worst gas systems are from the industry average and how quickly the ratios of hazardous leaks per 100 miles of mains decline as we move down the ranking.

At 41.77 hazardous leaks per 100 miles of mains for WG's gas mains in the District of Columbia, there is essentially a 40% chance that any main on the Company's system will experience a hazardous leak each year. However, if newer plastic and cathodically protected, coated steel mains are removed from

[13] Niagara Mohawk reporting for its Narragansett Electric Company – Gas Operations in Rhode Island. Both companies are subsidiaries of National Grid USA.

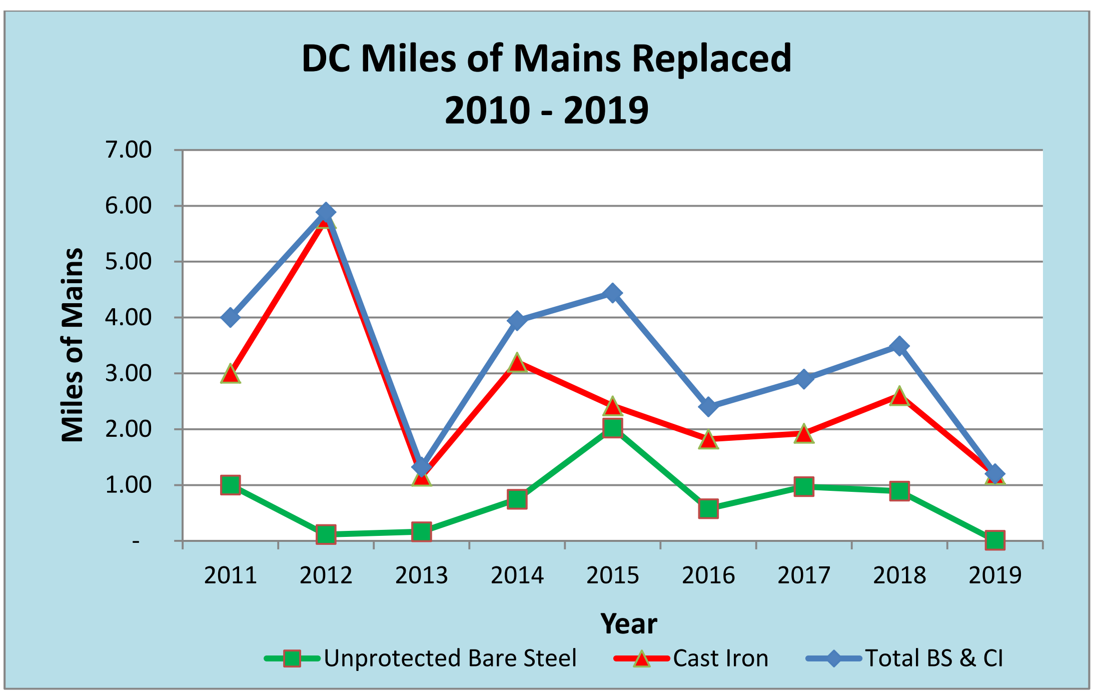
[14] Of 1,405 gas systems that filed Annual Reports to PHMSA for 2019, only 243 reported greater than 500 miles of mains installed and only 196 reported both greater than 500 miles of mains and greater than 25,000 services. For the purposes of this discussion, I have classified gas systems with greater than 500 miles of mains and greater than 25,000 services as "large systems."

that calculation, the likelihood of hazardous leaks on older gas mains in the Company's District of Columbia Distribution system rises dramatically.[15]

Q. ON WHAT INFORMATION DO YOU RELY TO IDENTIFY A DECLINE IN WG'S REPLACEMENT OF BARE STEEL AND CAST IRON MAINS?

A. Based on computed changes in the numbers of Cast Iron and Bare Steel Mains reported by WG in its Annual Reports to PHMSA for its District of Columbia distribution system, I have computed the year to year changes in the numbers of miles of main by type of main. Those results are shown graphically in Figure 1.

Figure 1



[15] Eliminating just those mains installed in the last 40 years from the calculation of leaks per 100 miles (under the assumption that newer mains are less likely to have leak problems), increases the leak ratio for the remaining mains on WG distribution system in the District to roughly 65% for the remaining mains.

As depicted above, the Company's replacements of Cast Iron and Bare Steel mains peaked in 2012 at less than six miles of main replacements, and they have not reached that level in any year since 2012. In 2019, WG's Cast Iron and Bare Steel main replacements in the District of Columbia fell to 1.2 miles. That is the lowest level since 2010, and it equates to only about 20% of the level achieved by the Company in 2012. At the rate of replacement achieved in 2012, Washington Gas would require another 72 years to replace all of its current Cast Iron and Bare Steel mains. At the Company's 2019 rate of Cast Iron and Bare Steel main replacements, Washington Gas would require over 350 years to complete the same task. Given that the vast majority of the Company's Cast Iron and Bare Steel mains are already more than 80 years old, these time frames for replacement of WG's remaining Cast Iron and Bare Steel mains would simply not be consistent with maintenance of system safety. The Company's recent main replacement activities are reflective of avoidance of this problem rather than a concerted effort to remedy the problem.

Q. WHAT EVIDENCE DO YOU HAVE THAT LEAKS ON THE WASHINGTON GAS DISTRIBUTION SYSTEM IN THE DISTRICT HAVE BEEN INCREASING?

A. The Annual Reports Washington Gas submits to PHMSA detail the leaks and hazardous leaks that the Company experiences each year on its District of Columbia distribution system by cause. Over the last ten years the annual numbers of leaks and hazardous leaks for both mains and services in the District have increased dramatically. **Figure 2** graphically depicts the increases in service and main leaks that have been experienced in the District for the years 2010 through 2019. **Figure 3** portrays the increases Washington Gas has experienced in terms of hazardous leaks on its DC distribution system over the same period. Hazardous leaks on both mains and services in the District have increased faster than total leaks. Total leaks on services have increased 66.4% while hazardous service leaks have increase **135.6%**. Likewise, WG has experienced a 95.2% increase in total leaks on mains while its hazardous main leaks in DC have increased **128.1%**. Moreover, these increases have been observed despite implementation of WG's PIPES 1 Plan during this period.

Figure 2

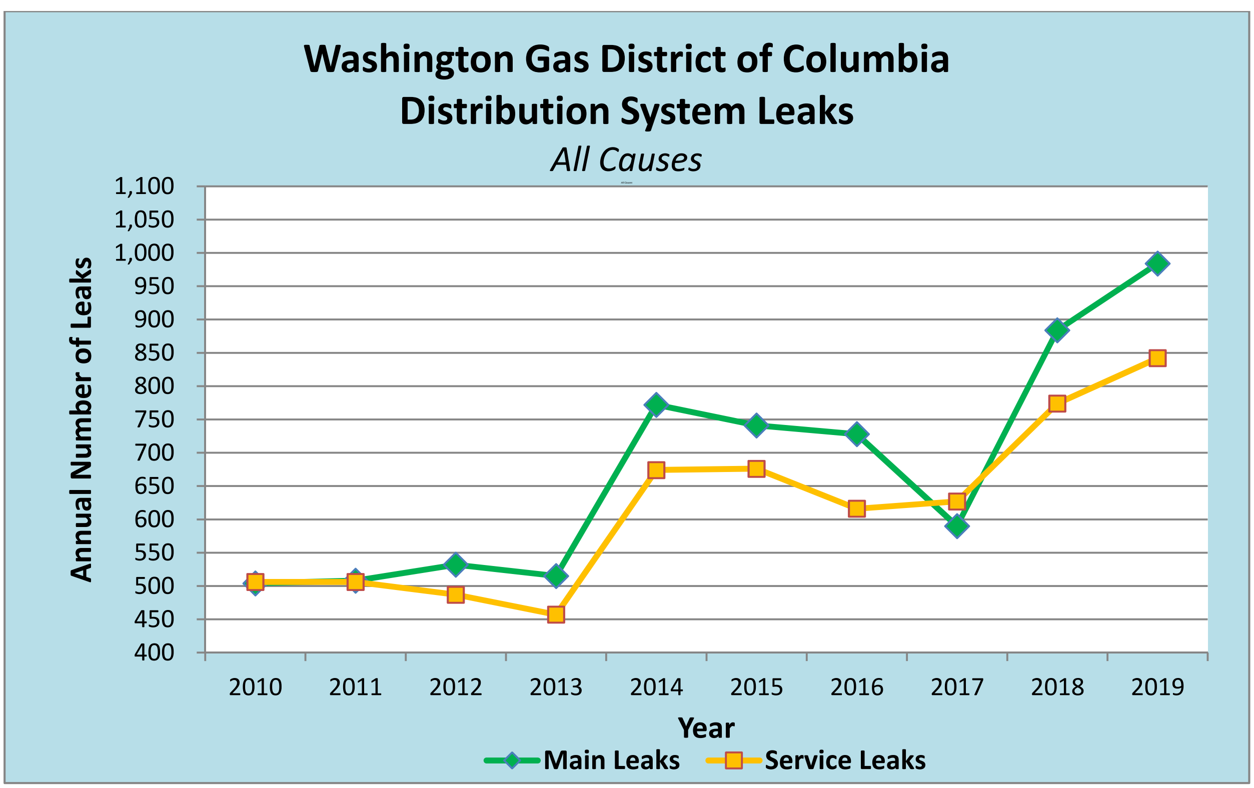
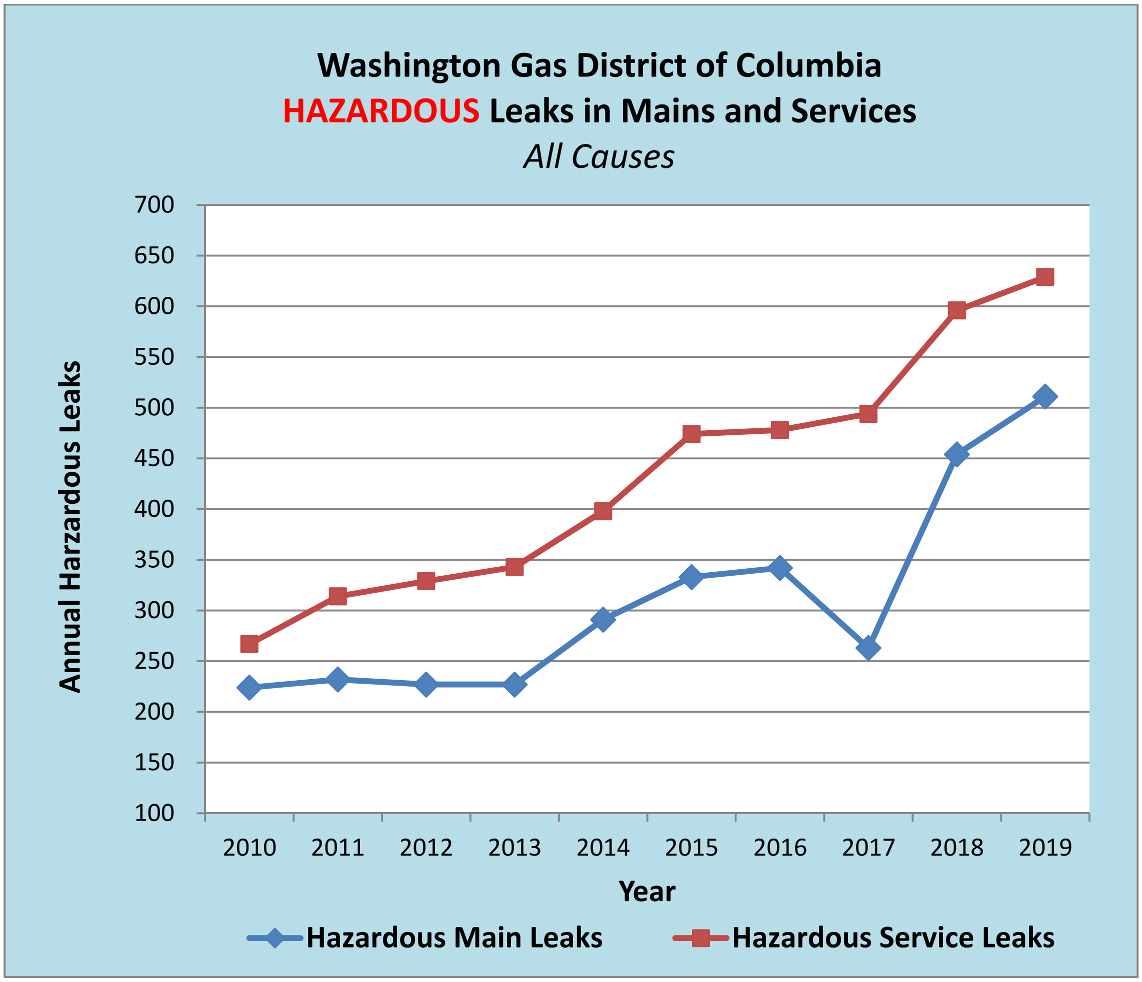


Figure 3



These increases are illustrative of the failure of the Company's PIPES 1 plan to improve the safety of its District of Columbia distribution system. These rather dramatic increases in leaks and hazardous leaks in the District of Columbia also raise important questions regarding the Company's claims of reductions in Greenhouse Gas emissions.

Q. DID LARGE GAS DISTRIBUTION SYSTEMS GENERALLY EXPERIENCE SIMILAR LARGE INCREASES IN LEAKS AND HAZARDOUS LEAKS ON THEIR DISTRIBUTION MAINS AND SERVICES OVER THE LAST DECADE?

A. No. For for the nearly 200 large distribution systems, for which data was examined, hazardous main leaks **increased** on average by **only 1.0%** between 2010 and 2019. Over the same period the average increase in hazardous service leaks was **increased 20.4%**. Both of these statistics are substantially lower than the increased experienced on the Washington Gas distribution system in DC. Moreover, total annual leaks on mains **declined** over that period by an average of **13.5%**, while total leaks on services **increased 28.0%**. Again, we find that Washington Gas' performance in the District of Columbia with respect to each of these measures has been substantially worse.

Exhibit AOBA (A)-3 compares the hazardous leaks and total leaks on mains and on services for selected large gas systems. The systems compared are predominantly systems from older systems in the Northeastern portion of the U.S. that tend to have greater amounts of very old mains and services. Included are data for systems that serve New York City, Boston, Philadelphia, and Pittsburgh, and Baltimore, as well as systems that serve a number of smaller eastern cities including Providence, RI; Rochester, NY; Richmond, VA; Cincinnati, OH; New Haven, CT; and Hartford, CT. Of the utilities listed, none matched or exceeded the percentage increases in hazardous leaks reported for by Washington Gas, and a number had significant reductions in both hazardous and total leaks between 2010 and 2019. The only utilities listed that reported significant increases in **hazardous leaks** for either or both mains or services were Keyspan Energy Delivery - NYC, Connecticut Natural Gas, Baltimore Gas & Electric, and Colonial Gas - Lowell, MA. Yet, none of those systems equaled or exceeded the percentage increases in hazardous leaks for the District of Columbia.

Importantly, Exhibit AOBA (A)-3 shows that 11 of the 27 systems listed achieved reductions in each of the reported categories of hazardous and total leaks. Moreover, 10 other systems achieved reductions in at least two of the four categories of leaks shown in Exhibit (AOGA (A)-3. This suggests that there should be little tolerance for a failure to reduce leaks on the Company's District of Columbia distribution system as we move forward in time.

Q. HOW DO MEASURES OF UNACCOUNTED FOR GAS RELATE TO WG'S LEAK PERFORMANCE IN THE DISTRICT?

A. Many factors can contribute to reported unaccounted gas volumes for a distribution system, however, there can be little doubt that increases in the numbers of distribution system leaks serve to amplify the amount of unaccounted gas reported for a distribution system. Overall for the 198 large gas systems identified from the PHMSA data, unaccounted gas declined between 2010 and 2019 from 1.39% to 1.03%. However, Washington Gas reported an increase in its Unaccounted Gas percentage from 3.32% in 2010 to **4.3%** in 2019. Again, the overall statistics for large gas systems differ markedly from those for Washington Gas. Washington Gas' 2019 Unaccounted Gas percentage is **more than four times** the average for all large gas systems. Thus, there is substantial evidence that Washington Gas' Greenhouse Gas ("GHG") emissions per mile of pipe are also significantly above the industry average.

Q. IS THERE ANY EVIDENCE THAT WASHINGTON GAS' PIPE REPLACEMENT ACTIVITIES IN THE DISTRICT TO DATE HAVE AMELIORATED ANNUAL GHG EMISSIONS FROM WG'S DISTRIBUTION SYSTEM IN THE DISTRICT?

A. No. Table 4 in Exhibit WG (2A)-1 offers projections of GHG emissions reductions from the Company's PIPES 2 Plan. Accepting **<u>arguendo</u>** the reasonableness of those estimates of future GHG emissions reductions, I still find no evidence that the Company has achieved, or will achieve, any **<u>net</u>** reduction in its annual contribution to GHG emissions. Replacing an average of about five miles of mains per year when the Company has over 400 miles of very old leak prone pipe in the District, cannot be expected to have an appreciable impact on overall GHG emissions. When consideration is given to the increasing annual numbers of leaks on the Company's DC distribution system, the net impacts of WG's limited annual pipe replacement on its overall annual GHG emissions is more likely negative (i.e., the Company's overall annual GHG emissions are increasing, not declining).

Q. CAN YOU ESTIMATE THE AMOUNT OF INCREASE IN GHG EMISSIONS THAT CAN BE ATTRIBUTED TO LEAKS ON THE COMPANY'S DC DISTRIBUTION SYSTEM?

A. Yes. The difference between WG's 2019 Unaccounted Gas percentage (i.e., 4.3%) and the average for all large gas distribution systems in the U.S. (i.e., 1.03%) is **3.27%**. Based on annual gas throughput of about 300 million therms,[16] I estimate that the leaks on WG's DC distribution system result in the Company's loss of approximately 10,000,000 therms of gas annually. That equates to approximately **53,000 metric tons of CO_2** of annual emissions.[17] That is more than **three times** the cumulative total GHG reduction for 2020-2025 that the Company estimates for its PIPES 2 programs. If the Company's Unaccounted Gas percentage remains at its 2019 level over the period 2020 – 2025, the increase in emissions due to leaks could be more than 15 times WG's estimated PIPES 2 Plan emissions reductions. If WG's system leaks and Unaccounted Gas percentage continue to increase, the Company's GHG emission would also increase further.

Q. HOW HAS WG'S SUBSTANTIAL BACKLOG OF PIPE REPLACEMENT REQUIREMENTS IMPACTED ITS OPERATING COSTS IN RECENT YEARS?

A. Washington Gas' operating costs for leak response and leak remediation activities have increased dramatically. Those dramatic increases in WG's costs

[16] See Exhibit WG (H)-1 in Formal Case No. 1162, Schedule C, page 1 of 2, line 20, column D.
[17] EPA: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references. A therm of natural gas yields 0.0053 metric tons of CO_2.

for leak response and leak remediation activities have strained the Company's cash-flow and drained financial resources that might have otherwise been available to support pipe replacement efforts. They have also limited the contractor resources that Washington Gas can dedicate to pipe replacement activities. In addition, growth in the numbers of leaks, particularly Grade 1 leaks, that WG has been required to address on an annual basis, the Company has been required to shift a significant portion of its contractor resources to leak remediation and away from pipe replacement activities.

In February and March of 2019, a spike in leak remediation activities required the Company to declare a "***catastrophic incident***" and bring in Mutual Aid support from other utilities. Moreover, the Company's need to invoke the "***catastrophic incident***" provisions of its current Labor Contract with the International Brotherhood of Teamsters, cause the Company to pay double-time wages to its own union workers for the duration of the emergency in addition to paying for increased costs for Mutual Aid resources.[18] This is the second time now three years that Washington Gas has had to rely on Mutual Aid to supplement its available in-house and contractor personnel to keep up with increasing levels of gas leaks. Reliance on such outside resources is rare in the gas industry, and under the Company's current labor contract with the Teamsters

[18] The Company's current contract with Teamsters Local 96 defines a "*catastrophic incident*" as: *"… any incident resulting in cessation or significant interruption of operations at one or more Company facilities or an incident resulting in the activation of 'mutual aid.'"* On or about February 14, 2019 Washington Gas activated "*mutual aid*" for the second time in the last two years. Under the provisions of Annex EF to the Company's current Labor Contract with the International Brotherhood of Teamsters, Local 96, Washington Gas is required to pay its union workers double-time pay for the duration of the period of that Mutual Aid resources are utilized.

Union it is also very expensive. As a result, the Company's leak response and leak remediation costs have grown dramatically.

B. Evaluation of WG's PIPES 2 Plan

Q. DOES THE COMPANY'S PIPES 2 PLAN ADEQUATELY EXPLAIN THE RELATIONSHIP BETWEEN ITS "NORMAL" (I.E., NON-ACCELERATED) PIPE REPLACEMENT ACTIVITY AND THE PROJECTS IT SEEKS TO INCLUDE IN ITS PIPES 2 PLAN?

A. No. As I have previously indicated herein, Washington Gas has a substantial backlog of pipe replacement requirements for its District of Columbia distribution system and its recent pipe replacement activity, even with an accelerated pipe replacement program, has fallen woefully short of providing a meaningful level of pipe replacement in the District. Over the last couple years, the Company has essentially performed no "normal" pipe replacement activity, and there is no evidence in the Company's PIPE 2 plan that it will complete any significant level of "normal" pipe replacements over the next five years. It is clear that Washington Gas believes that its Project PIPES plans are for accelerated cost recovery, not acceleration of the amount of pipe replaced.

Q. EXHIBIT (2A)-2, PAGE 4, PROVIDES WASHINGTON GAS' REPONSE TO ITEM 9 OF THE LIBERTY AUDIT REPORT RECOMMENDATIONS WHICH

CALL ON THE COMPANY TO RE-DEFINE "NORMAL" REPLACEMENT WORK. DOES THE COMPANY'S REPONSE TO THAT ITEM PROVIDE A MEANINGFUL RE-DEFINITION OF "NORMAL" REPLACEMENT ACTIVITY?

A. No. "Normal" replacement activity needs to be related to the Company's expectations regarding the useful lives of existing facilities. As assessed in the Company's depreciation studies,[19] Washington Gas periodically evaluates the expected lives of various elements of its distribution plan, including mains and services by material type, and assesses the time profile of expected retirements for those facilities for depreciation and financial planning purposes. A key part of those assessments is the application of "Iowa-type curves" to depict the time profile of expected plant retirements. Washington Gas "normal" replacement activities should reflect those anticipated profiles for the expected retirement of assets. I understand that actual retirements may vary from expectations. However, to the extent the variations become substantial, those variations need to be reflected in both the Company's pipe replacement planning and the Commission's ratemaking determinations.

The aging of facilities over time is not an unexpected phenomenon. The Company's current backlog of pipe replacement requirements emanates from the lack of a more disciplined approach to "normal' pipe replacement. Although the deferral of "normal" pipe replacement in prior periods may have helped to increase returns for shareholders, the Company is now in a position in which the

[19] See for example, Exhibit WG (F)-2 in Formal Case No. 1162 and Exhibit WG (H)-2 in Formal Case No. 1137.

impacts of past pipe replacement deferrals (i.e., rising leak rates) are now negatively impacting its ability to address both backlogged pipe replacement projects and “normal” replacement requirements. In other words, further deferral of “normal” pipe replacement activity is becoming the “norm,” and that simply further erodes system safety and further expands to the backlog of projects that will need to be addressed in future periods.

Q. IS WG’S STRUCTURING OF ITS PROJECT PIPES 2 PLAN INTO TEN PROGRAMS REASONABLE AND APPROPRIATE?

A. No. A plan with ten programs loses focus on the target which was, and should continue to be, system safety.

Q. SHOULD THE COMMISSION ACCEPT THE PROGRAM 10 EXPENDITURES PROPOSED IN WITNESS JACAS’ SUPPLEMENTAL DIRECT TESTIMONY, AS PART OF THE COMPANY’S ACCELERATED PIPE REPLACEMENT ACTIVITIES INCLUDED IN THE PIPES 2 PLAN?

A. No. The piping that Washington Gas would replace as part of the proposed Program 10 lacks necessary and appropriate attention to safety priorities. Witness Jacas argues that the Commission’s desire that high risk pipes be replaced proactively supports inclusion of Program 10 costs in the PIPES 2 Plan. However, the broad scope of WG’s proposed Program 10 is not consistent with that objective. Although Witness Jacas refers to the pipe that would be replaced as part of Program 10 as "*relatively higher risk pipe*," he provides no support for his assessment of the relative risk of the specific pipe segments that would be included in Program 10 pipe replacements. Rather, Witness Jacas' description of the categories of pipe WG would include in Program 10 (i.e., "bare steel, unprotected wrapped steel, vintage mechanically coupled wrapped steel, and cast iron mains including contingent main and affected services") is simply a reiteration of the categories of types of mains that would be addressed by other proposed programs. The Company offers little or no meaningful assessment of the interface between the work Washington Gas would perform for "others" and the pipe replacements it would otherwise be able to pursue under the other elements of its proposed PIPES 2 plan. The Company's distribution system in the District, with its greatly increased numbers of hazardous leaks, is not a position that allows for discretionary substitution of lower risk projects included in "Work Compelled by Other" for the replacement of higher risk pipe. Moreover, Washington Gas' past management of its pipe replacement activities leaves the District in the position where potential cost savings associated with coordinate work with other parties, while potentially attractive, must take a back seat to more pressing system safety considerations.

Q. HOW DO THE COSTS PER UNIT FOR MAIN AND SERVICE REPLACEMENTS IN WITNESS JACAS' EXHIBITS WG (A)-2 AND WG (2A)-1 COMPARE?

A. In Witness Jacas' Direct Exhibit (A)-2, the Company presented estimated costs per foot for main replacements in 2020 dollars. In his Supplemental Direct Exhibit (2A)-1, comparable estimates of main replacement costs per foot of main are set forth in 2021 dollars. That one year change increases each of WG's main replacement cost estimates by between 9.3% and 10.0%. Those are large one year increases that are at least three to five times greater than expected increases in the general level of cost inflation. See Exhibit AOBA (A)-4. For service replacements, WG's 2021 cost estimates per unit are increased more than 16% for Services replaced with mains, about 9% for services replaces without mains, and 3.9% for service change overs. All of these estimates of average costs per unit for service replacements again significantly exceed general cost inflation expectations.

On the basis of the cost data presented in Exhibit WG (A)-2, Washington Gas had a cost per foot for Cast Iron main replacements of $1,457. That equated to a cost of $7.7 million per mile in 2020 dollars. In Exhibit WG (2A)-1 the Company updates its cost per foot estimate for Cast Iron mains to $1,602 per foot or nearly **$8.5 million per mile** in 2021 dollars. Similarly, Washington Gas' updated costs for Bare Steel and Unprotected Wrapped Steel main replacements increase from $1,116 dollars per foot or $5.9 million per mile in 2020 dollars to $1,220 per foot or **$6.4 million per mile** in 2021 dollars. Even WG's costs for Vintage Mechanically Coupled mains increase from the equivalent of $3.8 million per mile in 2020 dollars to $ 4.2 million per mile in 2021 dollars. As I will discuss further in the next section of this testimony, these highly uneconomic levels of pipe replacement costs should cause the Commission to question the ability of Washington Gas to manage its pipe replacement activities in the District in a cost-effective manner.

Q. HOW DO WG'S COSTS PER FOR MAIN AND SERVICE REPLACEMENTS COMPARE WITH THOSE FOR OTHER GAS DISTRIBUTION UTILITIES?

A. Although directly comparable measures of pipe replacement costs are often not readily available, I do find evidence that the Costs per Mile for main replacement Washington Gas has presented in Exhibit WG (2A)-1 are substantially above the costs for Cast Iron pipe replacement reported by other gas utilities. Table 5 provides anecdotal evidence of the Cast Iron main replacement costs other large eastern systems have experienced. Some of this data is a few years old. For example, the most recent Philadelphia Gas Works data is for 2016. However, even making reasonable allowances for inflation, the reported costs per mile for Cast Iron main replacements are well below replacement costs per mile estimates in WG's PIPES 2 Plan.

Table 5
Cast Iron Main Replacement Cost Per Mile
For Comparable Urban Utilities

Gas Utility	Juris	Miles/Yr Replaced	Cost of Replacement	Cost Per Mile *(Millions)*
Philadelphia Gas Works	PA	31.5	$ 52,699,500	$1.673
Baltimore Gas & Electric	MD	62.0	$ 177,000,000	$2.529
Boston Gas Company	MA	91.0	$ 195,874,000	$2.152
Consolidated Edison	NY	85.0	$ 342,200,000	$4.026
Washington Gas (PIPES 2)[20]	DC	5.0		$8.459

Q. SHOULD THE COMMISSION ACCEPT WG'S INCLUSION OF TRANSMISSION PROJECTS WITHIN ITS PIPES 2 PROGRAM?

A. No. Washington Gas has provided no evidence of the extent to which its proposed Transmission Programs directly impact safety for the District of Columbia. The Company has failed to provide any demonstration that funds diverted from distribution system pipe replacement to the Company's proposed Transmission Programs would have greater impacts on safety than increased distribution pipe replacement spending. In the absence of such information the Commission lacks necessary foundation for assessing the comparative safety impacts of the proposed Transmission programs. In this context, the Commission should deny accelerated recovery of Transmission program costs at least until such time that the levels of hazardous leaks on the Company's distribution system in the District are substantially reduced. Accelerated cost recovery must

[20] The $1,602 cost per foot shown in Exhibit WG (2A)-1, page 9 of 25, multiplied by 5,280 feet per mile. WG's cost per foot for Bare Steel main replacement (i.e., $1,220) equates to $6,441,600 dollars per mile.

be focused on the replacement of high risk **distribution** mains and services to which residents and business in the District are more directly exposed.

Q. WHAT IS YOUR ASSESSMENT OF WASHINGTON GAS' PROPOSED PROGRAM 9, ADVANCED LEAK DETECTION?

A. Deployment of Advanced Leak Detection ("ADL") is clearly a step toward better understanding of the frequency and severity of leaks. It should also serve to improve the Company's assessment of pipe replacement priorities. As I have previously discussed, efforts to identify priorities based on average leak rates for various types of pipe can be greatly misleading. Advanced Leak Detection technology provides a means of improving the data and information used in the prioritization of pipe replacements. On that basis I strongly encourage the deployment of Advanced Leak Detection technology. However, Advanced Leak Detection does not in and of itself result in the replacement of high risk pipe. Rather, it is a tool that should be part of a well-managed utility's **on-going activities**. As indicated in Exhibit WG (2A)-1,[21] Washington Gas expects its use of ADL to endure at least 35 years. In that context, Advanced Leak Detection does not represent one-time, unusual, or temporary expenditures for which recovery through a rate ride is appropriate. With appropriate evidentiary support for the level of the Company's ADL expenditures, I would not oppose an

[21] Exhibit WG (2A)-1 attached to the Supplemental Direct Testimony of Witness Jacas, page 12 of 25.

amendment to the Company's filing in Formal Case No. 1162 for the inclusion of reasonable Advanced Leak Detection costs in base rates.

Q. HAS WASHINGTON GAS PRESENTED DATA, ANALYSES, OR STUDIES TO SUPPORT THE REASONABLENESS OF DELAYED REPLACEMENT OF ITS ALREADY VERY OLD CAST IRON MAINS?

A. No, it has not. The Company offers only a trivial amount of Cast Iron main replacement. Apparently Washington Gas assumes, without evidentiary support, that its further deferral of Cast Iron main replacement will have no appreciable impact on continued growth in the annual numbers of total leaks and hazardous leaks reported for its DC distribution system.

Q. WILL WASHINGTON GAS' PLANS FOR THE REPLACEMENT OF PIPE IN THE DISTRICT OF COLUMBIA IMPACT ITS REPORTED LEAKS?

A. Yes, but not in a positive direction. The Company's pipe replacement plans clearly influence the numbers of leaks experienced, but with Washington Gas proposing a level of pipe replacement in terms of miles per year that is well below the level necessary to keep up with on-going pipe replacement requirements, it cannot be assumed the Washington Gas' proposed PIPES 2 Plan will have any dampening effect on either total annual leaks or hazardous leaks for its District of Columbia distribution system.

Q. TABLE 2 ON PAGE 16 OF 25 IN EXHIBIT WG (2A)-1 SHOWS THE COMPANY'S DETERMINATION OF LEAKS PER MILE FOR DISTRIBUTION MAINS BY MATERIAL TYPE. DO YOU FIND RELIANCE ON THOSE AVERAGES AN APPROPRIATE APPROACH FOR DETERMINING PIPE REPLACEMENT PRIORITIES?

A. No, I do not. Such methods represent at best a crude approach to prioritization of main replacement projects. Reliance on such averages can hide variations in the actual leaks per mile for mains of the same material type and can lead to inappropriate conclusions regarding the relative levels of leaks on specific projects. When the Company has computed Optimain Scores to high risk mains, Optimain scores should provide greater insight regarding the relative risks associated with specific main segments than measures of average leaks per mile for all mains in a material type category.

The Commission should be particularly sensitive to the manner in which Washington Gas uses average measures of leaks per mile for a category such as Cast Iron mains. As I have previously noted, over 90 percent of WG's 100 highest Optimain scores for main segments on the Company's District of Columbia distribution system in 2019 (as well as in prior years) are for Cast Iron mains. Moreover, only one of the top 25 Optimain scores for main segments in DC was for a Bare Steel main. The others were all for Cast Iron main segments. Yet, through the use of average leak rates, the Company's methods would suggest that all Bare Steel mains are more risky than all Cast Iron mains. That simply is not true.

Q. CAN YOU ILLUSTRATE THE MANNER IN WHICH AVERAGES CAN DISGUISE LARGE VARIATIONS IN LEAKS PER MILE WITHIN A CLASS OF MAINS?

A. Yes. In 2019 Washington Gas had only 23 miles of Bare Steel distribution mains in the District of Columbia, but it had over 400 miles of Cast Iron distribution mains in the District. Thus, for each mile of Bare Steel mains, the Company had nearly 18 miles of Cast Iron mains. These large differences in the numbers of miles of pipe included in those categories amplify the potential that reliance on measures of average leaks per mile by material type will fail to provide for identification of substantial higher risk sub-categories within the much larger Cast Iron mains category.

The following provides an example, based on the data Witness Jacas has used to portray average leaks per mile for various types of mains which shows the manner in which averages can hide more extreme variations in leak rates. Witness Jacas shows an average of 10.2 leaks per mile for 23 miles of Bare Steel mains. He also shows an average leak rate of 4.6 leaks per mile for 410 miles[22] of Cast Iron Mains. However, there could be a significant subgroup of

[22] In his computation of average leaks per mile for Cast Iron main, Witness Jacas' footnote 7 on page 16 of WG Exhibit (2A)-1 uses a number of miles for Cast Iron mains for the denominator of his Cast Iron mains leaks per mile calculation that includes Reconditioned Cast Iron ("RCI") mains. The inclusion of Reconditioned Cast Iron mains for the purposes of his leaks per mile calculation is inappropriate. The

main segments within the of the Company's Cast Iron main inventory that has a significantly higher average level of leaks per mile than the Company reports for its Bare Steel mains. For example, the Cast Iron mains category could have a subset as large or larger than the Company's Bare Steel mains with a higher average leak rate than WG's Bare Steel mains in the District, but WG's use of averages for the material types would never identify that subset of cast iron mains or assign them appropriate priority.

Table 6

Example of Hidden Subgroups Within Leaks per Mile Averages

Category/Subset	**Miles of Mains**	**Leaks per Mile**	**Total Annual Leaks**
All Cast Iron Mains	405	4.6	1,863
Higher Risk Subset	50	**15.0**	750
Lower Risk Subset	150	2.0	300
All Others	205	4.0	813

Q. WHY WOULD THE COMPANY USE CATEGORY AVERAGES FOR LEAKS PER MILE IN PREFERENCE TO OPTIMAIN SCORES IN ITS PRIORTIZATION OF MAIN REPLACEMENT PROJECTS?

Reconditioning of Cast Iron mains yields different useful life and leak rate expectations for reconditioned mains than for mains that have not been reconditioned. As a result, Reconditioned Cast Iron mains are effectively newer and less leak prone than the vast majority of the Company's much older Cast Iron main inventory. By including RCI mains in his leak per mile calculations for Cast Iron mains, the average level of leaks for the Company's non-reconditioned cast iron mains is understated.

A. It appears that the Company has an economic bias against pursuing Cast Iron main replacements because due to its assessment that higher costs for replacing Cast Iron mains limit the number of projects or total miles of mains that it can afford to pursue in any given year. As a result, WG's approach to prioritizing main replacement projects allows economic considerations to override safety considerations. If Washington Gas is allowed to continue its prioritization of projects based on average leak per mile by material type, few, if any, high risk Cast Iron mains will be included among the projects that WG chooses to pursue, and many comparatively high priority Cast Iron main projects will be deferred.

C. <u>Pipe Replacement Policies and Alternatives</u>

Q. SHOULD THE COMMISSION APPROVE WASHINGTON GAS' PIPES II PLAN AS PRESENTED BY THE COMPANY?

A. No. The Company's plan is inordinately expensive for the limited amount of pipe replacement that is proposed, and it lacks adequate focus on the replacement of the Company's highest risk pipe. The PIPES 1 Plan has clearly fallen short in its efforts to improve the safety of gas service in the District of Columbia, and the Commission needs to re-examine the basic structure of Washington Gas' pipe replacement plans for the District. The Commission also needs to examine WG's PIPES 2 plan in the context of the pipe replacement programs that have been, or are being, pursued by other large northeast gas systems. Even adjusting for the relative size of WG's District of Columbia system, many large gas systems are pursuing substantially greater levels of pipe replacement than Washington Gas proposes for the District as part of its PIPES 2 Plan. Washington Gas must be required to achieve a level of annual pipe replacements for the District that is more in line with achieving a safe and well maintained gas system for the District as well as a sustainable level pipe replacement going forward.

Neither the scale of the Company's PIPES II Plan nor the costs of that Plan should be found reasonable by this Commission. The scope of WG's pipe replacement proposals is too small to address the substantial backlog of pipe replacement requirements that Washington Gas faces in the District, and the Company's estimated pipe replacement costs are prohibitively expensive. At nearly $8.5 million per mile for Cast Iron main replacements and $6.4 million per mile for Base Steel main replacements, WG's total costs for eliminating its inventory of very old and leak prone mains would require a total investment in 2021 dollars of $3.6 billion. That is the equivalent of nearly seven times WG's current distribution rate base of the District of Columbia.[23]

Q. IS THERE AN ALTERNATIVE FOMULATION OF THE COMPANY'S PIPES 2 PLAN PROPOSALS THAT YOU COULD SUPPORT?

A. Yes. There are two basic alternatives. One is to modify WG's pipe replacement plan to provide greater focus on safety and greater assurance of cost-effective

[23] See Exhibit WG ( )-1

completion of projects. The other approach is to begin the process of phasing-out elements of WG's distribution system in the District.

Q. HAVE OTHERS MADE RECOMMENDATIONS IN SUPPORT OF PHASING OUT GAS DISTRIBUTION UTILITY OPERATIONS AS AN ALTERNATIVE TO REPLACING AGING NATURAL GAS INFRASTRUCTURE?

A. Yes. A January 6, 2020 article, authored by the Rocky Mountain Institute ("RMI"), observed that there is a need to consider retiring aging natural gas infra-structure, and avoid costly infrastructure replacements. RMI suggests that through electrification impactful advances in clean energy development and car-bon and GHG emission mitigation can be achieved:

> The increased spending on America's aging gas infrastructure system calls into question the wisdom of doubling down on a fossil fuel delivery network that's becoming more expensive at the same time the need for climate action is becoming more urgent.
>
> Greater recognition of methane leakage has also drawn attention to the challenges of operating an aging system. Research released earlier this year found that in six major US cities—Washington, D.C.; Baltimore; Philadelphia; New York City; Providence; and Boston — methane leaks are more than twice US Environmental Protection Agency (EPA) estimates.
>
> Not only are main replacement and other gas system investments a significant financial burden that will take decades to complete, but doubling down on fossil fuel infrastructure is also entirely incom-patible with climate change goals.[24]

[24] Mike Henchen and Kiley Kroh, RMI, *A New Approach to America's Rapidly Aging Gas Infrastructure* (January 6, 2020), https://rmi.org/a-new-approach-to-americas-rapidly-aging-gas-infrastructure/.

Q. IS RMI ALONE IN ITS CONCERNS?

A. No. On February 11, 2020, the Sierra Club released a list of cities that have committed to ending natural gas use in new building construction.[25] Moreover, in a report on the need for a building electrification action plan to combat climate change, released in December 2019, among the Sierra Club's findings and recommendations in support of clean energy and mitigation of climate change are: (1) the need to phase out the use of natural gas; (2) acknowledge that renewable natural gas is not a viable alternative to electrification; and (3) adoption of policies to ensure electrification of buildings and incentives for the sale of electric appliances.[26]

Given the current status of Washington Gas' distribution system in the District of Columbia and the Company's estimated costs for replacing its existing Cast Iron and Bare Steel mains the RMI and Sierra Club positions warrant consideration.

Q. ARE THERE OTHER ALTERNATIVES TO WG'S PIPES 2 PLAN THAT WARRANT CONSIDERATION BY THE COMMISSION IN THIS PROCEEDING?

A. A brief review of pipe replacement programs in other Northeastern U.S. jurisdictions suggests some alternative program formulations that may be more

[25] Matt Gough, Sierra Club, *Forward-Looking Cities Lead the Way to a Gas-Free Future* (February 11, 2020), https://www.sierraclub.org/articles/2020/02/forward-looking-cities-lead-way-gas-free-future.

[26] Rachel Golden, Sierra Club, *Building Electrification Action Plan for Climate Leaders* (December 2019), https://www.sierraclub.org/sites/www.sierraclub.org/files/Building%20Electrification%20Action%20Plan%20for%20Climate%20Leaders.pdf.

successful than the Project PIPES program that Washington Gas seeks to continue. From those observations, the Commission is encouraged to consider and implement the following:

1. The need to establish minimum annual accelerated pipe replacement requirements designed to ensure greater annual progress toward the elimination of Cast Iron and Bare Steel mains.

2. The establishment of caps on the costs per mile and cost per service that WG may recover through an accelerated cost recovery mechanism, as well as a policy that WG will only be provided accelerated cost recovery for accelerated pipe replacement activity.

3. A requirement for Washington Gas to file an annual Infrastructure, Safety and Reliability ("ISR") Plan for review by the parties and litigation before the Commission.

4. The provision of a financial incentive for the Company to exceed its minimum annual pipe replacement requirements.

5. Establishment and annual update of detailed "normal" pipe replacement requirements that are conceptually consistent with the plant life expecta-

tions used in the Company's depreciation studies. Moreover, if WG fails to meet identified "normal" pipe replacement requirements in any given year it should be subjected to financial penalties.

6. Establishment of a proxy group approach to assessing the reasonableness of WG's pipe replacement performance and costs.

Q. HOW SHOULD MINIMUM ANNUAL ACCELERATED PIPE REPLACEMENT REQUIREMENTS BE DETERMINED FOR WASHINGTON GAS' DISTRICT OF COLUMBIA DISTRIBUTION SYSTEM?

A. Minimum annual accelerated pipe replacement requirements should ensure meaningful annual progress toward the elimination of very old Cast Iron and Bare Steel mains and improvement of the safety of WG's DC distribution system net reductions in the numbers of leaks, and particularly hazardous leaks, reported annually for that system. The average of 5 miles per year of accelerated main replacements that is proposed by the Company in its PIPES 2 Plan is woefully inadequate and well below the levels of pipe replacement being pursued by other large urban gas utilities in the mid-Atlantic and Northeastern regions of the U.S. Utilities in Philadelphia, Baltimore, New York, and Boston are all pursuing much greater levels of annual replacements for Cast Iron and Bare Steel mains that Washington Gas proposes to target in DC (even after adjustment for differences in the size of those systems).

Table 7 provides an illustration of the manner in which Minimum Annual Accelerated Main Replacement requirements could be determined.

Table 7

Determination of Minimum Annual Accelerated Pipe Replacement Requirements for WG's DC Distribution System

Utility	Juris	2019 Total Miles of Mains	Annual Miles Replaced	Adjusted Miles/Year for WG-DC[27]
Philadelphia Gas Works	PA	3,041	31.5	12.7
Baltimore Gas & Electric	MD	7,443	62.0	10.2
Boston Gas Company	MA	6,384	91.0	17.4
Consolidated Edison	NY	4,372	85.0	23.8
Average **(Minimum Requirement)**				**16.0**
Washington Gas Light	DC	1,223	5.0	

As this Commission did when it established EQSS for electric reliability, the required level of accelerated main replacement could start below the average shown computed in Table 7 and then ratchet the requirement upward on an annual basis until the targeted long-term minimum level is reached. For example, the Commission could start with a Year 1 requirement of 8.0 miles per year and then raise the minimum 2.0 miles per year until the minimum requirement reaches 16 miles per year.

Q. WHAT WOULD BE APPROPRIATE PIPE REPLACEMENT COST CAPS FOR WASHINGTON GAS' DC DISTRIBUTION SYSTEM?

[27] Adjusted Miles per Year computed by multiplying the utility's Annual Miles Replaced by the ratio of WG-DC Total Miles of Mains to the utility's Total Miles of Mains.

A. The costs caps established by the Commission need be set significantly below the costs estimates per unit of replacement (i.e., per foot or mile of main replaced and per unit of service replacement or change over) Washington Gas has presented in this proceeding.[28] But, the cost CAP should be consistent with other utilities main replacement cost experience. The range of costs for Cast Iron pipe replacement for gas distribution systems in other major eastern cities (shown in Table 5 on page 45 of this testimony) is from roughly $1.7 million per mile to about $4.0 million per mile. The average appears to be only about $2.6 million per mile. These costs are all at least two to three times lower than Washington Gas' estimated cost for Cast Iron main replacement in the District.

I also note a US Department of Energy report, titled "Natural Gas Infrastructure Modernization Programs at Local Distribution Companies - Key Issues and Considerations" which states:

> *LDCs seeking to replace older infrastructure can face high costs; the cost of replacing cast iron and unprotected steel mains can range from $1 million to $5 million per mile depending on location. Costs can be a significant challenge in particular for LDCs with large inventories of cast iron or unprotected steel pipe to be replaced.*[29]

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[28] If Washington Gas cannot work within the range of costs experienced by other urban gas utilities, then this Commission should require the Company to immediately identify, and contract with, a third party to oversee the Company's implementation of pipe replacement activities in the District and their costs.

[29] U.S. Department of Energy, "*Natural Gas Infrastructure Modernization Programs at Local Distribution Companies - Key Issues and Considerations.*" page 17 of 78, January 2017. Although this report was released in early 2017 and the data in the report pre-date the report's release, reasonable allowances for cost inflation to not approach the levels of costs for pipe replacement used by Washington Gas in this proceeding.

A cost cap should be set at a level that is more reflective of the experience of other urban gas utilities, and no costs in excess of 120% of an established cost cap should be provided accelerated costs recovery. However, costs more in excess of 120% of an established cost cap may be presented for consideration by the Commission in a subsequent base rate proceeding.

Q. PLEASE EXPLAIN THE ISR PROCESS THAT YOU ENVISION.

A. The envisioned ISR process is modeled, in part, from a process used for National Grid's Narragansett Electric Company – Gas Division in Rhode Island. The suggested process would require Washington Gas to identify and provide cost detail for each pipe replacement project it intends to pursue during the next planning year. Washington Gas would be required to include in its annual ISR filings leak data and other safety information to support the priority it assigns to each project, as well as a detailed assessment of the economics of pipe replacement versus abandonment of service for each project. Through this annual review process many of the problems in the PIPES 1 program identified through the Liberty Audit can be identified and resolved on a more "real time" basis, and cost factors leading to cost overruns can be addressed in a more timely manner.

All projects approved by the Commission as part of an ISR plan would be provided accelerated cost recovery through an ISR rider mechanism for costs up to 120% of the applicable cost caps. The ISR rider would be reconciled annually to reflect prudently incurred actual costs (within the established costs caps) and actual revenue recoveries.

Q. HOW SHOULD THE FINANCIAL INCENTIVES AND PENALTIES REFERENCE ABOVE BY STRUCTURED?

A. An approach that has been used in New York to provide a two basis point reward on its authorized ROE for each mile of mains completed within a calendar year that is excess of the Company's minimum main replacement requirement. However, I do not support an ROE-based approach to providing incentives because the realized incentive is not related to either the costs or the benefits of the incremental work completed. Rather, an ROE incentive is typically applied to the Company's total rate base of which the completed work may only represent only a small component.

The preferred alternative would allow the Company to recover a bonus (e.g., a five percent cost adder) in addition to its actual costs for each mile of pipe replacement completed within a calendar year that is: (a) in excess of the Company's established annual minimum main replacement requirement; and (b) completed within 120 percent of the cost cap per mile established for main replacement work. This alternative ensures more direct ties between the costs of a project and the incentive provided.

Q. WHAT SHOULD BE THE RELATIONSHIP BETWEEN "NORMAL PIPE REPLACEMENT" AND "ACCELERATED PIPE REPLACEMENTS" FOR WG'S DISTRICT OF COLUMBIA DISTRIBUTION SYSTEM?

A. With more than 1,200 miles of distribution mains in the District and expected lives for those facilities averaging less than 80 years, all other things being equal, simple math would suggest that Washington Gas should be replacing about 15 miles of mains per year as part of its "normal pipe replacement" activity. But Washington Gas has not achieved even anything approximating that normal level of pipe replacement in recent years. Rather, Washington Gas has developed a growing backlog of very old and increasingly leak prone mains, and it is now in a situation which it has neither the resources nor finances to support simultaneous efforts to address both backlogged and normal pipe replacement requirements. If the Company's provision of gas service in the District is to be continued over time, the Commission must mandate that Washington Gas find more economic approaches to lowering its pipe replacement costs and substantially reducing its backlog of pipe replacement projects.

Q. WHY DO YOU BELIEVE THAT THE ESTABLISHMENT OF A PROXY GROUP WOULD BE HELPFUL IN THE EVALUATION OF WG'S ON-GOING PIPE REPLACEMENT ACTIVITES?

A. Washington Gas is not the only gas distribution utility that has been faced with requirements for replacement of significant requirements for replacement of Cast

Iron and Bare Steel mains. Some gas utility systems have already eliminated substantial amounts of Cast Iron and Bare Steel mains remaining. Yet, Washington Gas' presentations in this proceeding are noticeably lacking in their references to and utilization of information regarding the experience of other utilities.

Washington Gas must not continue to operate in a vacuum. In my long experience with the Company in three jurisdictions, Washington Gas has generally appeared to have an aversion to comparisons of its operations, methods, and costs with those for other companies in the gas distribution industry. However, the Company's poor pipe replacement performance, dramatic increases in its number of hazardous leaks, and very high cost estimates for pipe replacements compel a need for broader view of the factors impeding WG's more timely replacement of greater amounts of high risk pipe.

Many other systems appear to have been more successful in the elimination of large amounts of old Cast Iron and Bare Steel mains, as well as reducing the numbers of leaks on their systems. Yet, WG has apparently found those tasks to be more challenging. With a number of other systems still having considerable miles of such mains to replace, more regular monitoring and evaluation of the experience of gas systems in other jurisdictions may help to answer question regarding how to influence the factors that have impeded WG's pipe replacement and efforts over the last decade.

The Washington Gas distribution system in the District is at a critical juncture, and weak oversight of the Company's pipe replacement activities during this period has the potential to burden the District with higher costs and growing safety concerns well into the future.[30] We cannot just sit back and accept Washington Gas' poor performance statistics and comparatively high pipe replacement costs and expect the situation to remedy itself. By tracking the pipe replacement costs and accomplishments of other large gas distribution systems, the hope is that the Company and the Commission will be provided greater perspective on these matters that will facilitate better management of these tasks and more informed regulatory policy decisions.

III. CONCLUSION

Q. DO YOU OFFER ANY CONCLUDING OBSERVATIONS?

A. Yes. The current approach to pipe replacement is not working and has not produced needes results for the District of Columbia. Over the period of WG's PIPES 1 Plan, Washington Gas replaced fewer miles of pipe, not more. As a result, the District now has one of the leakiest gas distribution systems in the U.S., and the Company's need to respond to growing numbers of leaks have increased its operating costs and reduced the resources available for needed pipe replacements. What started as a program for accelerated recovery of costs

[30] A particular concern for all parties should be the potential that expensive investments in long-lived gas distribution assets may soon become "stranded cost" burdens as environmental concerns increase and costs of gas distribution service continue to rise.

for **incremental** distribution system pipe replacement activity, has degenerated into a catch-all program for a much wider range of costs.

Clearly, accelerated cost recovery has not been the answer to Washington Gas' problems. The Company's levels of main replacement work are well below those for most other large gas distribution systems, and its costs for main replacement appear to be among the highest in the industry. A number of large gas distribution systems have either replaced most if not all of their very old Cast Iron and Bare Steel mains. Others are committed to aggressive programs to achieve similar results. However, Washington Gas is not among either of those groups. At the rate of Cast Iron main replacement actually achieved by Washington Gas over the last decade (i.e., an average of about 2.5 miles per year), the Company would need more than **160 years** to remove all of its existing Cast Iron and Bare Steel mains. Data from other gas systems strongly suggest that better results are achievable. But, the Company's PIPES 2 Plan does not begin to present a viable solution to legitimate safety and cost concerns. With the information presented herein regarding the state of Washington Gas' DC distribution system, further action by the Commission is required to ensure public safety in the District. The Company's leak problems will not be resolved without substantial changes in the Commission's approach to regulating WG's District of Columbia operations.

The Commission must take serious action to address the problems in Washington Gas' District of Columbia operations. When this Commission encountered unacceptable levels of electric system reliability in the first part of the last decade, it acted decisively to establish service quality standards and to compel annual tightening of reliability requirements. Comparable action with respect to Washington Gas' distribution system operations and costs is necessary at this time. Business as usual is not a viable option. Washington Gas status as one of the worst performers in the industry with respect to pipe replacement and hazardous gas leaks must be taken seriously by all parties. If Washington Gas cannot work within the range of costs experienced by other urban gas utilities, then this Commission should require the Company to immediately identify, and contract with, a third party to oversee the Company's implementation and cost of pipe replacement activities in the District.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. It does.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipe Replacement Plan	)	Formal Case No. 1115
IN THE MATTER OF The Merger of AltaGas Ltd. and WGL Holdings, Inc.,	)	Formal Case No. 1142
IN THE MATTER OF Application of Washington Gas Light Company for Approval of ProjectPipes 2 Plan	)	Formal Case No. 1154

DECLARATION OF BRUCE R. OLIVER

I, Bruce R. Oliver, do hereby declare under the penalty of perjury that I an authorized to make this Declaration on behalf of the Apartment and Office Building Association of Metropolitan Washington; that the foregoing testimony and exhibits were prepared by me or under my direction and supervision; and that the contents therein are true and correct to the best of my knowledge, information and belief.

Bruce R. Oliver /s/

Bruce R. Oliver

Dated: June 15, 2020

Washington Gas Light Company

Formal Case Nos. 1115, 1142, 1154

Composition of WG Distribution Mains by Jurisdiction

Based on Washington Gas 2019 Annual Reports to PHMSA for DC, MD and VA

	Miles of Mains Installed 2019			
	WG-WD	**WG-MD**	**WG-VA**	**WG Total**
Cast Iron 1/	404.92	43.79	14.22	462.93
Bare Steel				
Unprotected	22.51	95.31	20.65	138.47
Protected	-	-	-	-
Coated Steel				
Unprotected	55.66	65.78	153.24	274.68
Protected	319.30	2,278.35	1,861.33	4,458.98
Plastic	415.59	3,822.30	4,390.16	8,628.05
Other 2/	5.26	0.18	-	5.44
Total	1,223.24	6,305.71	6,439.60	13,968.55

	% of 2019 Mains by Material Type and Jurisdiction			
	WG-WD	**WG-MD**	**WG-VA**	**WG Total**
Cast Iron 1/	**33.1%**	0.7%	0.2%	3.3%
Bare Steel				
Unprotected	1.8%	1.5%	0.3%	1.0%
Protected	-	-	-	-
Coated Steel				
Unprotected	4.6%	1.0%	2.4%	2.0%
Protected	26.1%	36.1%	28.9%	31.9%
Plastic	34.0%	60.6%	68.2%	61.8%
Other 2/	0.0%	0.0%	0.0%	0.0%
Total	99.6%	100.0%	100.0%	100.0%

1/ Excludes Reconditioned Cast Iron Pipe installed in DC within the last five years.
2/ Includes 5.26 miles of Reconditioned Cast Iron mains in DC installed between 2015 and 2019. Also includes 0.18 miles of Ductile Iron reported for MD in 2019.

Washington Gas Light Company

Formal Case Nos. 1115, 1142, 1154

Age of WG Distribution Mains by Jurisdiction

Based on Washington Gas 2019 Annual Reports to PHMSA

	2019 Reported Total Miles of Mains			
	WG-DC	**WG-MD**	**WG-VA**	**WG Total**
Pre - 1940	**390.46**	**60.69**	**17.18**	**468.33**
1940 - 1949	48.13	82.05	50.96	181.14
1950 - 1959	132.60	608.48	591.76	1,332.84
Subtotal 1940 - 1959	180.73	690.53	642.72	1,513.98
1960 - 1969	121.85	1,161.95	914.62	2,198.42
1970 - 1979	90.79	537.69	441.10	1,069.58
Subtotal 1960 - 1979	212.64	1,699.64	1,355.72	3,268.00
1980 - 1989	109.93	681.24	848.03	1,639.20
1990 - 1999	153.57	1,383.96	1,641.42	3,178.95
Subtotal 1980 - 1999	263.50	2,065.20	2,489.45	4,818.15
2000 - 2009	**93.49**	**1,159.35**	**1,326.44**	**2,579.28**
2010 - 2019	**78.14**	**621.32**	**607.95**	**1,307.41**
Subtotal 2000 - 2019	171.63	1,780.67	1,934.39	3,886.69
Vintage Unknown	**4.27**	**9.02**	**0.14**	**13.43**
Total	**1,223.23**	**6,305.75**	**6,439.60**	**13,968.58**

	% of 2019 Mains by Vintage and Jurisdiction			
	WG-DC	**WG-MD**	**WG-VA**	**WG Total**
Pre - 1940	**31.9%**	1.0%	0.3%	3.4%
1940 - 1949	**3.9%**	1.3%	0.8%	1.3%
1950 - 1959	**10.8%**	9.6%	9.2%	9.5%
Subtotal 1940 - 1959	**14.8%**	11.0%	10.0%	10.8%
1960 - 1969	**10.0%**	18.4%	14.2%	15.7%
1970 - 1979	**7.4%**	8.5%	6.8%	7.7%
Subtotal 1960 - 1979	**17.4%**	27.0%	21.1%	23.4%
1980 - 1989	**9.0%**	10.8%	13.2%	11.7%
1990 - 1999	**12.6%**	21.9%	25.5%	22.8%
Subtotal 1980 - 1999	**21.5%**	32.8%	38.7%	34.5%
2000 - 2009	**7.6%**	18.4%	20.6%	18.5%
2010 - 2019	**6.4%**	9.9%	9.4%	9.4%
Subtotal 2000 - 2019	**14.0%**	28.2%	30.0%	27.8%
Vintage Unknown	**0.3%**	0.1%	0.0%	0.1%
Total	**100.0%**	100.0%	100.0%	100.0%

Washington Gas Light Company

Formal Case Nos. 1115, 1142, 1154

Composition of WG Distribution Services by Jurisdiction

Based on Washington Gas 2019 Annual Reports to PHMSA for DC, MD and VA

	Numbers of Services Installed 2019			
	WG-WD	**WG-MD**	**WG-VA**	**WG Total**
Bare Steel				
Unprotected	6,208	4,797	5,078	16,083
Protected	-	-	-	-
Coated Steel				
Unprotected	10,490	5,906	2,348	18,744
Protected	3,728	47,808	37,825	89,361
Plastic	94,022	364,278	405,844	864,144
Copper	9,825	22,025	19,324	51,174
Other	1,014	394	324	1,732
Total	125,287	445,208	470,743	1,041,238

	% of 2019 Services by Material Type and Jurisdiction			
	WG-WD	**WG-MD**	**WG-VA**	**WG Total**
Bare Steel				
Unprotected	5.0%	1.1%	1.1%	1.5%
Protected	-	-	-	-
Coated Steel				
Unprotected	8.4%	1.3%	0.5%	1.8%
Protected	3.0%	10.7%	8.0%	8.6%
Plastic	75.05%	81.8%	86.2%	83.0%
Copper	7.8%	4.9%	4.1%	4.9%
Other 2/	0.8%	0.1%	0.1%	0.2%
Total	100.0%	100.0%	100.0%	100.0%

1/ Excludes Reconditioned Cast Iron Pipe installed in DC within the last five years.
2/ Includes 5.26 miles of Reconditioned Cast Iron mains in the District of Columbia between 2015 and 2019. Also includes 0.18 miles of Ductile Iron reported for MD in 2019.

Washington Gas Light Company

Formal Case Nos. 1115, 1142, 1154

Age of WG Distribution Services by Jurisdiction

Based on Washington Gas 2019 Annual Reports to PHMSA

	2019 Reported Total Numbers of Services			
	WG-DC	**WG-MD**	**WG-VA**	**WG Total**
Pre - 1940	**3,738**	**473**	**254**	**4,465**
1940 - 1949	1,193	581	184	1,958
1950 - 1959	10,011	29,587	22,249	61,847
Subtotal 1940 - 1959	11,204	30,168	22,433	63,805
1960 - 1969	12,557	59,740	45,721	118,018
1970 - 1979	30,820	44,644	37,335	112,799
Subtotal 1960 - 1979	43,377	104,384	83,056	230,817
1980 - 1989	19,192	50,201	59,249	128,642
1990 - 1999	15,524	87,424	113,723	216,671
Subtotal 1980 - 1999	34,716	137,625	172,972	345,313
2000 - 2009	**14,653**	**95,097**	**109,135**	**218,885**
2010 - 2019	**16,296**	**76,440**	**82,175**	**174,911**
Subtotal 2000 - 2019	30,949	171,537	191,310	393,796
Vintage Unknown	**1,303**	**1,021**	**718**	**3,042**
Total	**125,287**	**445,208**	**470,743**	**1,041,238**

	% of 2019 Services by Vintage and Jurisdiction			
	WG-DC	**WG-MD**	**WG-VA**	**WG Total**
Pre - 1940	**3.0%**	0.1%	0.1%	0.4%
1940 - 1949	**1.0%**	0.1%	0.0%	0.2%
1950 - 1959	**8.0%**	6.6%	4.7%	5.9%
Subtotal 1940 - 1959	**8.9%**	6.8%	4.8%	6.1%
1960 - 1969	**10.0%**	13.4%	9.7%	11.3%
1970 - 1979	**24.6%**	10.0%	7.9%	10.8%
Subtotal 1960 - 1979	**34.6%**	23.4%	17.6%	22.2%
1980 - 1989	**15.3%**	11.3%	12.6%	12.4%
1990 - 1999	**12.4%**	19.6%	24.2%	20.8%
Subtotal 1980 - 1999	**27.7%**	30.9%	36.7%	33.2%
2000 - 2009	**11.7%**	21.4%	23.2%	21.0%
2010 - 2019	**13.0%**	17.2%	17.5%	16.8%
Subtotal 2000 - 2019	**24.7%**	38.5%	40.6%	37.8%
Vintage Unknown	**1.0%**	0.2%	0.2%	0.3%
Total	**100.0%**	100.0%	100.0%	100.0%

Washington Gas Light Company

DC PSC Formal Case Nos. 1115, 1142, 1154

Comparisons of Ten-Year Changes in Annual Numbers of Leaks for Large Gas Systems

Based on PHMSA Annual Report Data for 2010 - 2019

Ln No	ID No	Operator	Juris	2019 Miles of Mains	2019 Numbers of Services	Percent Increase in Reported Annual Leaks: Hazardous Leaks Mains	Hazardous Leaks Services	Total Annual Leaks Mains	Total Annual Leaks Services
1	22182	WASHINGTON GAS LIGHT CO	DC	1,223	125,287	**128.13%**	**135.58%**	**95.24%**	**66.40%**
2	1800	KEYSPAN ENERGY DELIVERY - NY CITY	NY	4,158	570,669	**79.06%**	**69.23%**	**66.07%**	**78.24%**
3	2700	CONNECTICUT NATURAL GAS CORP	CT	2,185	139,715	4.44%	31.61%	26.22%	**80.94%**
4	1088	BALTIMORE GAS & ELECTRIC CO	MD	7,443	543,565	44.07%	**96.39%**	-51.93%	**53.79%**
5	11856	COLONIAL GAS CO - LOWELL DIV	MA	1,405	77,855	**104.08%**	-23.89%	9.72%	-25.10%
6	2704	CONSOLIDATED EDISON CO OF NEW YORK	NY	4,372	376,306	2.42%	4.53%	40.80%	9.84%
7	15329	PEOPLES GAS LIGHT & COKE CO	IL	4,572	506,913	-21.83%	16.92%	-49.92%	**69.63%**
8	1209	COLUMBIA GAS OF MASSACHUSETTS	MA	4,996	276,935	-22.75%	15.52%	8.92%	1.27%
9	3240	DELMARVA POWER & LIGHT COMPANY	DE	2,114	130,265	7.53%	-10.94%	-3.23%	9.00%
10	11713	KEYSPAN ENERGY DELIVERY - LONG ISLANI	NY	8,309	555,519	-23.36%	-3.10%	11.41%	7.11%
11	4350	ELIZABETHTOWN GAS CO	NJ	3,234	229,886	-45.33%	40.58%	-51.93%	22.80%
12	1640	BOSTON GAS CO	MA	6,384	511,008	-15.79%	-12.74%	6.90%	-13.43%
13	18496	SOUTHERN CONNECTICUT GAS CO	CT	2,471	147,404	33.33%	-8.75%	-25.00%	-39.22%
14	24015	YANKEE GAS SERVICES CO	CT	3,474	163,607	-4.50%	-34.03%	38.94%	-40.13%
15	15350	PEOPLES NATURAL GAS COMPANY LLC	PA	10,387	621,616	-14.74%	-44.11%	41.04%	-36.61%
16	2364	DUKE ENERGY OHIO	OH	5,783	411,656	-32.35%	46.17%	-48.03%	-20.77%
17	15469	PHILADELPHIA GAS WORKS	PA	3,041	476,605	-43.30%	**-57.75%**	31.15%	-23.80%
18	17360	RICHMOND, CITY OF	VA	1,936	100,587	-38.18%	-30.11%	-37.43%	-3.41%
19	2600	COLUMBIA GAS OF PENNSYLVANIA	PA	7,656	433,668	-39.08%	-26.42%	-42.25%	-21.13%
20	13480	NIAGARA MOHAWK POWER CORP	NY	8,868	568,370	-13.23%	-34.88%	-47.51%	-41.83%
21	13480	NATIONAL GRID (NARRAGANSETT ELEC)*	RI	3,195	194,550	-42.11%	-40.37%	-47.51%	-23.73%
22	14330	ORANGE & ROCKLAND UTILITY INC	NY	1,870	106,197	**-59.09%**	-33.45%	-60.70%	-23.60%
23	2652	NSTAR GAS COMPANY	MA	3,300	206,765	-7.04%	**-56.57%**	**-53.33%**	**-64.15%**
24	15462	PECO ENERGY CO	PA	6,928	460,656	-31.48%	**-57.67%**	-34.55%	**-59.05%**
25	13299	NEW JERSEY NATURAL GAS CO	NJ	7,342	529,517	**-54.48%**	-45.97%	-43.73%	-40.29%
26	18440	SOUTH JERSEY GAS CO	NJ	6,684	322,000	**-70.34%**	-26.12%	-85.47%	-19.23%
27	17570	ROCHESTER GAS & ELECTRIC CORP	NY	4,890	282,347	-40.00%	**-72.22%**	**-88.80%**	**-84.50%**

* The Annual Report to PHMSA for Narragansett Electric Co's Rhode Island Gas Division was filed by a National Grid affiliate, Niagara Mohawk Power Corp.

Washington Gas Light Company

DC PSC Formal Case No. 1115, 1142, and 1154

Changes in WG Estimates of Pipe Replacement Costs per Unit

		Costs per Unit		Increase	
		Direct Exh WG (A)-2	**Suppl Exh WG (2A)-1**	**$**	**%**
		2020 Dollars	*2021 Dollars*		
Main Replacement Costs					
Program 1: Bare Steel Mains	$/ft	$ 1,116	$ 1,220	$ 104	9.3%
Program 2: Unprotect Wrapped Steel	$/ft	$ 1,116	$ 1,220	$ 104	9.3%
Program 3: Vintage Mech Coupled	$/ft	$ 725	$ 797	$ 72	9.9%
Program 4: Cast Iron Mains	$/ft	$ 1,457	$ 1,602	$ 145	10.0%
Service Replacement Costs					
Program 1: Bare Steel					
Service w/o Main		$ 21,172	$ 24,715	$ 3,543	16.7%
Service w/ Main		$ 7,349	$ 8,015	$ 666	9.1%
Change Over		$ 2,797	$ 2,907	$ 110	3.9%
Program 2: Unprotected Wrapped Steel					
Service w/o Main		$ 21,172	$ 24,715	$ 3,543	16.7%
Service w/ Main		$ 7,349	$ 8,015	$ 666	9.1%
Change Over		$ 2,797	$ 2,907	$ 110	3.9%
Program 3: Vintage Mech Coupled					
Service w/o Main		$ 21,172	$ 24,715	$ 3,543	16.7%
Service w/ Main		$ 7,349	$ 8,015	$ 666	9.1%
Change Over		$ 2,797	$ 2,907	$ 110	3.9%
Program 4: Cast Iron					
Service w/ Main		$ 8,492	$ 10,024	$ 1,532	18.0%
Change Over		$ 4,468	$ 4,645	$ 177	4.0%
Program 5: Copper Services		$ 21,172	$ 24,715	$ 3,543	16.7%
Program 8: Low Pressure Replacements					
Service w/ Main		$ 21,172	$ 24,715	$ 3,543	16.7%
Change Over		$ 2,797	$ 2,907	$ 110	3.9%

Washington Gas Light Company

FC 1115 and FC 1154

DC Cast Iron Main Replacement Costs

Cost per foot for Cast Iron Main Replacements (FC 1114, 1142 and 1154, Exh WG (A)-2, page 9 of 26)	$	1,602.00	
Feet per mile		5,280	
Cost per mile	$	8,458,560	
Remaining miles of Cast Iron Mains in DC (WG 2019 Annual Report to PHMSA for DC Distribution)		405	
Total CI Main Replacement Cost	$	3,425,716,800	
Required Annual Return on CI Mains Investment at **6.95% pre-tax Weighted Cost of Capital**	$	238,087,318	
Percent Equity in Capital Structure (FC 1162, WG Exh 2B-1, page 1)		52.10%	
Equity Investment	$	1,784,798,453	
Allowed ROE (Order No. 18712 in Formal Case No. 1137)		9.25%	
Required Annual pre-tax Equity Return	$	165,093,857	
Revenue Requirement for Equity Return	$	217,923,891	
Income Taxes on CI Main Investment Equity Return Requirements	$	52,830,034	
Conservative Estimate of Depreciation Expense (assumes an 80-year expected life for newly installed pipe without allowances for removal and salvage)	$	42,821,460	
Incremental Annual Revenue Requirement for CI main replacement Return & Taxes (without inflation)	$	333,738,812	
Current Total DC Customers (FC 1162 Exh WG (H)-1, Sch C, page 1 of 2, line 20, col. C)		163,362	
Estimated Percent of Current DC Mains that are Cast Iron Mains		33.12%	
Potential No. of lost customers if Cast Iron mains are not replaced		54,098	
Incremental Annual Cost per Customer (assuming no loss of customers)	**$**	**3,054.42**	
Incremental Annual Cost per Customer **Retained** by Replacing Cast Iron Mains	$	6,169.18	
Bill Impacts at Current Rates			
Average Annual Residential Bill, **including gas costs** (FC 1162 Exh WG (H)-1, Sch. C, page 1, line 3, Col I/Col C)	$	874.55	1/
Average Annual Residential **Distribution Bil**l (FC 1162 Exh WG (H)-1, Sch C, page 1, line 3, Col E/Col C)	**$**	**528.27**	1/
Bill Impacts at WG' Proposed Rates in FC 1162			
Average Annual Residential Bill, including gas costs (FC 1162 Exh WG (H)-1, Sch. C, page 1, line 3, Col J/Col C)	$	1,028.62	2/
Average Annual Residential Distribution Bill (FC 1162 Exh WG (H)-1, Sch C, page 1, line 3, Col F/Col C)	$	682.34	2/
Average Capital Expenditure per Customer Served from Cast Iron Mains	$	63,324.51	

1/ FC 1162, Lawson Direct, Exht WG (H)-1, Sch C, page 1, line 3, present rates.
2/ FC 1162, Lawson Direct, Exht WG (H)-1, Sch C, page 1, line 3, proposed rates.

Attachment A
Resume for Bruce R. Oliver
Formal Case Nos. 1115, 1142 & 1154

BRUCE R. OLIVER

Revilo Hill Associates, Inc.
7103 Laketree Drive
Fairfax Station, Virginia 22039
(703) 569-6480

EXPERIENCE

Over 40 years of experience specializing in the areas of utility rates, energy, and regulatory policy. Offers unusual depth and breadth in his understanding of energy and utility industries which leads to creative and effective resolution of rate issues. Has presented expert testimony in regulatory proceedings in more than 300 proceedings before regulatory commissions in 24 jurisdictions, and has served a diverse group of clients on issues encompassing a wide range of energy and utility-related activities. Assists clients in the assessment of competitive energy markets for retail services and in the negotiation of contracts for the purchase of such services. Clients have included commercial and industrial energy users, hospitals and universities, state regulatory commissions, utilities, consumer advocates, municipal governments, federal agencies, and suppliers of equipment and services to utility markets.

1985-Present — Revilo Hill Associates, Inc.
President and CEO

Directs the firm's consulting practice, with specialization in the areas of industrial economics, energy, utilities and regulatory policy. Provides expert testimony in regulatory proceedings. Assists individual commercial and institutional customers in the competitive procurement of energy services and resolution of utility service and billing issues. Regulatory work includes participation in electric, gas, water and sewer utility rate and policy matters, with particular specialization in the areas of utility costs of service, rate structure, rate of return, utility planning, and forecasting. Examples of recent projects include:

- Development and presentation of positions regarding the merits of various forms of alternative ratemaking including, but not limited to: multi-year rate plans; performance-based ratemaking concepts; and the merits of proposals for Performance Incentive Mechanisms.

- Assessment of a gas distribution utility's plans for accelerated replacement of aging and leak prone distribution mains by an LDC, as well as the impacts of rising leak rates the utility's gas system safety and rates distribution services.

- Negotiation of settlements to reflect the impacts of the Tax Cut and Jobs Act of 2017 in rates for certain electric and gas distribution utilities.

- Investigation of utility merger issues including ring-fencing, costs to achieve, estimated merger benefits, and allocation of merger benefits among customers for electric and gas utility mergers.

- Investigation of gas distribution utility system expansion proposals, tariff changes, and proposed ratemaking treatment of costs for gas expansion activities.

- Examination of utility proposals undergrounding overhead electric distribution facilities and the recovery of costs for undergrounding activities.

- Evaluation of utility proposals for the deployment of Advanced Metering Infrastructure (AMI) and the development of dynamic pricing rates to be implemented using AMI equipment.

- Detailed evaluation of a gas distribution utility's long-range gas supply planning, its evaluation of gas supply alternatives, and the prudence of gas its procurement decisions.

- Investigation of cost of service, rate design, tariff, forecasting and planning issues for island utilities in the U.S. Virgin Islands and Guam.

- Analysis of utility revenue decoupling proposals including assessment of the cost of service and rate impacts of such proposals and the development of appropriate tariff language for such proposals.

- Investigation of matters relating to a utility's outsourcing of significant components of its Administrative and General and Customer Service activities, including the merits of the proposed outsourcing arrangements and appropriate rate treatment of costs incurred to: select providers of outsourced services; negotiate contracts; and achieve the implementation of outsourcing arrangements.

- Strategic analysis and policy guidance for a major commercial consumer group in the development and presentation of positions before legislative and regulatory bodies regarding electric and gas regulatory issues.

- Development of Asset Management incentive programs for natural gas distribution utilities.

- Investigation and preparation of a report on the causes of large heating oil price increases for the Attorney General of a New England state.

- Participation as a member of a three-person panel hearing a gas marketer complaint of anti-competitive behavior by a local gas distribution utility in its provision of unbundled gas transportation services.

- Preparation of cost allocation studies and rate structure proposals for electric, gas, water and wastewater utility regulatory proceedings;

- Analysis of proposals for restructuring and the unbundling of rates for local gas distribution companies, and negotiated terms, conditions, and pricing for restructured utility services.

2000-Present AOBA Alliance, Inc.
Director and Chief Economist

Key technical advisor to one of the nation's largest and most successful customer-based energy aggregation programs. Assists non-residential customers in the Washington, D.C. area in the procurement of competitive retail energy services, including the evaluation and negotiation of contract terms for competitive electricity, natural gas, energy information services. Monitors energy markets and keeps participants informed regarding energy market developments and pricing trends. Focused primarily on the commercial building industry, the AOBA Alliance, Inc. serves more than 9,000 electric and natural gas accounts in twelve states and the District of Columbia. Those participants use over 3.0 billion kWh per year and over 660 MW of electrical peak load.

1981-85 Resource Dynamics Corporation
Principal and Vice President

Responsible for the firm's activities in the areas of energy pricing, utility rates and regulatory policy. Provided expert testimony before utility regulatory commissions on issues relating to costs of service, rate design, load management, load research, fuel price forecasting, utility costing analyses, and cost allocation methods. Evaluated utility fuel procurement practices, fuel price forecasts, and price forecasting methodologies. Contributed to modeling efforts relating to the estimation of national and regional electric utility load curves and coal market prices. Participated in the development handbooks for cogeneration feasibility assessment.

1980-81 Potomac Electric Power Company
Manager of Rate Research Department

Directed the development of all rate related programs. Supervised the costing, design and analysis of traditional and innovative rates (including time-of-use, load management and cogeneration tariffs). Also was responsible for corporate revenue forecasting activities, as well as the development of marginal and avoided cost studies.

1979-80 Pacific Gas and Electric Company
Rate Experimentation Supervisor

Responsible for design, implementation and analysis of innovative rate programs for both gas and electric service. Developed programs for curtailable service; cogeneration; conservation; residential load cycling; and commercial, industrial, and agricultural time-of- use rates. Directed analyses of time-of-use and lifeline price elasticities and development of marginal and avoided costing methods.

1973-79 ICF Incorporated
Project Manager

Specialized in energy policy and utility regulatory analyses. Performed detailed analysis of U.S. petroleum, natural gas, coal and electric utility industries. Provided expert testimony on utility rate issues. Designed experimental rates for federally funded time-of-use rate and load management programs in North Carolina. Provided technical support to the DOE Regulatory Intervention Program. Contributed to the design and development of the National Coal Model, and prepared forecasts of low sulfur fuel availability for utility markets.

1972-73 U.S. Cost-of-Living Council - Pay Board
Labor Economist

Served in the Office of the Chief Economist. Responsible for macroeconomic analyses of Board decisions, and for the development data systems to support assessments of the impacts of Board decisions and the reporting of aggregate statistics on wage increases granted by the Board.

<u>EDUCATION</u>

1972 M.A., Economics, Virginia Polytechnic Institute and State University

1970 B.A., Economics, Virginia Polytechnic Institute and State University

RATE CASE PARTICIPATION

Alberta, Canada

Canadian Western Natural Gas	1998 General Rate Application
NOVA Gas Transmission Ltd.	1995 GRA, Phase II
Canadian Western Natural Gas	Core Market Direct Purchase
Northwestern Utilities	Core Market Direct Purchase
TransAlta Utilities Corp.	Load Retention Rate Offering
Alberta Power Ltd.	1993 General Rate Application

Arizona

Southwest Gas Corporation	Docket No. U-1551-93-272
Sun City Water Company	Docket No. U-1656-91-134
Havasu Water Company	Docket No. U-2013-91-133
Arizona Water Company	Docket No. U-1445-91-227

California

Pacific Gas & Electric Company	Application No. 58089

Connecticut

Southern Connecticut Gas Company	Docket No. 89-09-06
Connecticut Light & Power Company	Docket No. 87-07-01

Delaware

Chesapeake Utilities Corporation	Docket No. 95 - 73
Delmarva Power & Light Company	Docket No. 94 - 141
Delmarva Power & Light Company	Docket No. 94 - 129
Delaware Electric Cooperative	Docket No. 94 - 100
Delmarva Power & Light Company	Docket No. 92 - 85
Delmarva Power & Light Company	Docket No. 92 - 71F
Delaware Electric Cooperative	Docket No. 91 - 37
Delmarva Power & Light Company	Docket No. 91 - 24
Delmarva Power & Light Company	Docket No. 91 - 20
Delmarva Power & Light Company	Docket No. 90 - 31
Delmarva Power & Light Company	Docket No. 90 - 21
Delmarva Power & Light Company	Docket No. 89 - 26
Chesapeake Utilities Corporation	Docket No. 88 - 39F
Delmarva Power & Light Company	Docket No. 88 - 34
Delmarva Power & Light Company	Docket No. 88 - 32, Phase 2
Delmarva Power & Light Company	Docket No. 88 - 32
Delaware Electric Cooperative	Docket No. 87 - 34, Phase 2
Delaware Electric Cooperative	Docket No. 87 - 34
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 5
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 4

Delmarva Power & Light Company	Docket No. 87 - 9, Phase 3
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 2
Delmarva Power & Light Company	Docket No. 87 - 9
Delmarva Power & Light Company	Docket No. 86 - 43
Delmarva Power & Light Company	Docket No. 86 - 24

District of Columbia

Potomac Electric Power Company	Formal Case No. 1156
Potomac Electric Power Company	Formal Case No. 1151
Potomac Electric Power Company	Formal Case No. 1150
Potomac Electric Power Company	Formal Case No. 1145
WGL – AltaGas Merger	Formal Case No. 1142
Potomac Electric Power Company	Formal Case No. 1139
Washington Gas Light Company	Formal Case No. 1137
Potomac Electric Power Company	Formal Case No. 1133
Potomac Electric Power Company	Formal Case No. 1130
Potomac Electric Power Company	Formal Case No. 1121
Exelon – Pepco Merger	Formal Case No. 1119
Potomac Electric Power Company	Formal Case No. 1116
Washington Gas Light Company	Formal Case No. 1115
Potomac Electric Power Company	Formal Case No. 1103
Washington Gas Light Company	Formal Case No. 1093
Potomac Electric Power Company	Formal Case No. 1087
Washington Gas Light Company	Formal Case No. 1079
Potomac Electric Power Company	Formal Case No. 1076
Potomac Electric Power Company	Formal Case No. 1056
Washington Gas Light Company	Formal Case No. 1054
Potomac Electric Power Company	Formal Case No. 1053, Phase II
Potomac Electric Power Company	Formal Case No. 1053
Washington Gas Light Company	Formal Case No. 1016
Potomac Electric Power/Conectiv Merger	Formal Case No. 1002
Washington Gas Light Company	Formal Case No. 989
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Formal Case No. 951
Potomac Electric Power Company	Formal Case No. 945
Potomac Electric Power Company	Formal Case No. 939
Washington Gas Light Company	Formal Case No. 934
Washington Gas Light Company	Formal Case No. 922
District of Columbia Natural Gas	Formal Case No. 890
Potomac Electric Power Company	Formal Case No. 889
Potomac Electric Power Company	Formal Case No. 869
District of Columbia Natural Gas	Formal Case No. 845
District of Columbia Natural Gas	Formal Case No. 840
Potomac Electric Power Company	Formal Case No. 834
Potomac Electric Power Company	Formal Case No. 813, Phase II
Potomac Electric Power Company	Formal Case No. 813

Washington Gas Light Company	Formal Case No. 787
Potomac Electric Power Company	Formal Case No. 785
Potomac Electric Power Company	Formal Case No. 759, Phases III
Potomac Electric Power Company	Formal Case No. 759, Phases II
Potomac Electric Power Company	Formal Case No. 759, Phases I
Potomac Electric Power Company	Formal Case No. 758

Guam

Guam Power Authority	Docket No. 11-090, Phase II
Guam Power Authority	Docket No. 11-090
Guam Power Authority	Docket No. 07-010
Guam Power Authority	Docket No. 98-002
Guam Power Authority	Docket No. 96-004
Guam Power Authority	Docket No. 95-001
Guam Power Authority	Docket No. 94-001
Guam Power Authority	Docket No. 92-002
Guam Power Authority	Docket No. 89-002 A,B,C

Illinois

Commonwealth Edison Company	Docket No. 86-0128

Maryland

Washington Gas Light Company	Case No. 9605
Potomac Electric Power Company	Case No. 9602
Washington Gas Light Company	Case No. 9481
WGL – AltaGas Merger	Case No. 9449
Potomac Electric Power Company	Case No. 9443
Washington Gas Light Company	Case No. 9433
Potomac Electric Power Company	Case No. 9418
Exelon – Pepco Merger	Case No. 9361
Potomac Electric Power Company	Case No. 9336
Washington Gas Light Company	Case No. 9335
Washington Gas Light Company	Case No. 9322
Potomac Electric Power Company	Case No. 9311
Potomac Electric Power Company	Case No. 9286
Washington Gas Light Company	Case No. 9267
Potomac Electric Power Company	Case No. 9217
Potomac Electric Power Company	Case No. 9207
Washington Gas Light Company	Case No. 9158
Washington Gas Light Company	Case No. 9104, Phase II
Washington Gas Light Company	Case No. 9104
Potomac Electric Power Company	Case No. 9092, Phase II
Potomac Electric Power Company	Case No. 9092
Standard Offer Service Docket	Case No. 9063
Standard Offer Service Docket	Case No. 9056

Standard Offer Service Docket	Case No. 9037
Potomac Electric Power Company	Case No. 8895
Washington Gas Light Company	Case No. 8991
Washington Gas Light Company	Case No. 8959
Washington Gas Light Company	Case No. 8920, Phase II
Washington Gas Light Company	Case No. 8920
Potomac Electric Power Company	Case No. 8895
Potomac Electric Power Company	Case No. 8890
Potomac Electric Power Company	Case No. 8791
Potomac Electric Power Company	Case No. 8773
Generic Electric Industry Restructuring	Case No. 8738
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 8725
Washington Gas Light Company	Case No. 8545
Potomac Electric Power Company	Case No. 8315
Potomac Electric Power Company	Case No. 8251
Maryland Natural Gas	Case No. 8191
Potomac Electric Power Company	Case No. 8162
Maryland Natural Gas	Case No. 8119
Potomac Electric Power Company	Case No. 8079
Baltimore Gas & Electric Company	Case No. 8070
Maryland Natural Gas	Case No. 8060
Potomac Electric Power Company	Case No. 7972
Potomac Electric Power Company	Case No. 7874
Washington Gas Light Company	Case No. 7649

Massachusetts

Investigation of Rate Structures to Promote Efficient Deployment of Demand Management	Docket No. 07-50

North Carolina

Generic Electric Load Management	Docket No. M100, Sub 78

New Jersey

Public Service Electric and Gas	Docket No. GT93060242
Public Service Electric and Gas	Docket No. ER91111698J
Elizabethtown Gas Company	Docket No. 8812-1231
Elizabethtown Gas Company	Docket No. 8612-1374
Public Service Electric and Gas	Docket No. 8512-1163
Jersey Central Power & Light	Docket No. 8511-1116
New Jersey Natural Gas Company	Docket No. 8510-974
South Jersey Gas Company	Docket No. 850-8858
Public Service Electric and Gas	Docket No. 850-2231
New Jersey Natural Gas Company	Docket No. 850-7732
South Jersey Gas Company	Docket No. 843-184, Phase II
Atlantic Electric Company	Docket No. 8310-883, Phase II

New Jersey Natural Gas Company	Docket No. 831-46
Public Service Electric and Gas	Docket No. 837-620
Public Service Electric and Gas	Docket No. 8210-869

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Gas Company of New Mexico	Case No. 2353
Gas Company of New Mexico	Case No. 2340
Gas Company of New Mexico	Case No. 2307
Gas Company of New Mexico	Case No. 2183
Gas Company of New Mexico	Case No. 2147 (Remand)
Gas Company of New Mexico	Case No. 2147
Gas Company of New Mexico	Case No. 2093

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Consolidated Edison Company	Docket No. 94-E-0334
Consolidated Edison Company	Docket No. 91-E-0462
Brooklyn Union Gas Company	Docket No. 90-G-0981

Ohio

Toledo Edison Company	Case No. 78-628-EL-FAC

Pennsylvania

PECO Energy Company	Docket No. R-20028394
PG Energy, Inc.	Docket No. R-00061365
Philadelphia Electric Company	Docket No. R-00970258
Mechanicsburg Water Company	Docket No. R-00922502
West Penn Power Company	Docket No. R-00922378
Pennsylvania Electric Company	Docket No. M-920312
North Penn Gas Company	Docket No. R-922276
Metropolitan Edison Company	Docket No. R-922314
York Water Company	Docket No. R-922168
Dauphin Consolidated Water Company	Docket No. R-921000
Pennsylvania Electric Company	Docket No. M-920312
Duquesne Light Company	Docket No. C-913424
Pennsylvania American Water Company	Docket No. R-911909
West Penn Power Company	Docket No. R-901609
Pennsylvania Gas & Water Co. Water Div.	Docket No. R-891209
Pennsylvania Power Company	Docket No. R-881112
Duquesne Light Company	Docket No. R-870651
Pennsylvania Electric Company	Docket No. R-870172
Metropolitan Edison Company	Docket No. R-870171
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Duquesne Light Company	Docket No. R-860378
Philadelphia Electric Company	Docket No. R-850290
Pennsylvania Power Company	Docket No. R-850267
Pennsylvania Power & Light Company	Docket No. R-850251

Philadelphia Electric Company	Docket No. R-850152
Western Pennsylvania Water Company	Docket No. R-850096
Pennsylvania Power Company	Docket No. R-842740
Pennsylvania Power & Light Company	Docket No. R-842651
Pennsylvania Electric Company	Docket No. R-832550
Metropolitan Edison Company	Docket No. R-832549
Duquesne Light Company	Docket No. R-842383
UGI Corporation-Gas Utility Division	Docket No. R-832331
Pennsylvania Power & Light Company	Docket No. I-830374
Pennsylvania Electric Company	Docket No. R-822250
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Pennsylvania Power & Light Company	Docket No. R-822169
Pennsylvania Gas & Water Co. - Water Div.	Docket No. R-822102
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Pennsylvania Gas & Water Co. - Gas Div.	Docket No. R-821961
Philadelphia Electric Company	Docket No. R-811626

Philadelphia, City of

Philadelphia Gas Works	1992 Rate Design Proceeding
Philadelphia Water Department	1992 Rate Increase Request
Philadelphia Gas Works	1990 Rate Increase Request
Philadelphia Water Department	1990 Rate Increase Request
Philadelphia Gas Works	1989 Proceeding
Philadelphia Gas Works	1988 Rate Increase Request
Philadelphia Gas Works	1987-88 Operating Budget
Philadelphia Gas Works	1986 Rate Increase Request
Philadelphia Water Department	1985 Rate Increase Request

Rhode Island – Public Utilities Commission

National Grid – Gas Long-Range Plan	Docket No. 4872
National Grid – Gas GCR	Docket No. 4846
National Grid – Gas DAC	Docket No. 4816
National Grid – Gas Annual ISR Filing	Docket No. 4781
National Grid – Gas Base Rates	Docket No. 4770
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National Grid – Electric Backup Service	Docket No. 4232
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Providence Gas Company	Docket No. 2374
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Valley Gas Company	Docket No. 2276
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Valley Gas Company	Docket No. 2138, Phase I
Providence Gas Company	Docket No. 2082
Providence Gas Company	Docket No. 2076
Providence Gas Company	Docket No. 2001, Phase II
Valley Gas Company	Docket No. 2038

Providence Gas Company	Docket No. 2001
Block Island Power Company	Docket No. 1998
Providence Gas Company	Docket No. 1971
Generic Gas Transportation	Docket No. 1951
Valley Gas Company	Docket No. 1736
Providence Gas Company	Docket No. 1723
Providence Gas Company	Docket No. 1673

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National Grid Acquisition of New England Gas Company's Rhode Island Assets	Docket No. D-06-13
Merger of Southern Union, Valley Gas Company And Bristol & Warren Gas Company	Docket No. D-00-02

South Dakota

Northern States Power Company	Docket No. F-3188

Utah

Dominion Energy Utah	Docket No. 19-057-02

Vermont

Department of Public Service	Docket No. 5378
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Washington Gas Light Company	Docket No. PUR 2018-00080
Virginia Electric Power Company	Docket No. PUE 2018-00042
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Virginia Electric Power Company	Docket No. PUE 2016-00021
Virginia Electric Power Company	Docket No. PUE 2016-00001
Virginia Electric Power Company	Docket No. PUE 2015-00027
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Virginia Electric Power Company	Docket No. PUE 2009-00019
Virginia Electric Power Company	Docket No. PUE 2009-00018
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Washington Gas Light Company	Docket No. PUE 940031
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Northern Virginia Natural Gas	Docket No. PUE 900016
Northern Virginia Natural Gas	Docket No. PUE 880024
Virginia Electric Power Company	Docket No. PUE 830029
Washington Gas Light Company	Docket No. PUE 830008

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Water and Power Authority – Electric Rates	Docket No. 612
Water and Power Authority – Water Rates	Docket No. 576
Water and Power Authority – Electric Rates	Docket No. 575
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Gas Transportation - Generic	Docket No. 05-GI-102

Federal Energy Regulatory Commission

Weaver's Cove Energy, LLC.	Docket No. CP04-36-000
Mill River Pipeline, LLC.	Docket No. CP04-41-000
Columbia Gulf Transmission Co.	Docket No. RP86-167-000
Columbia Gas Transmission Corp.	Docket No. RP86-168-000
Columbia Gulf Transmission Co.	Docket No. TC86-021-000

SELECTED REPORTS, PUBLICATIONS AND PRESENTATIONS

"Will Energy Market Developments Drive Government Policy or Will Government Policy Drive Energy Markets," Presentation to AOBA Utility Committee, June 27, 2013.

"Ratemaking for Recovery of Pipeline Safety Investments," Presentation to the National Association of Regulatory Utility Commissioners, February 6, 2013.

"In Comparatively Stable Energy Markets, Legislative and Regulatory Decisions Make Budgeting for Energy Services A Real Challenge," Presentation to AOBA Utility Committee, October 19, 2011.

"Energy Commodities Show Stability; Charges for Utility Services Rise," Presentation to AOBA Utility Committee, April 20, 2011.

"Budgeting for Utilities In the Face of Constantly Changing Rates," Presentation to AOBA Utility Committee, November 10, 2010.

"Electric Utilities Seek Increased Rates to Fund Large Construction Projects," Presentation to AOBA Utility Committee, October 7, 2009.

"Could You Soon Be Paying $1.00 per kWh for Peak Electricity Supply?" Presentation to AOBA Utility Committee, June 24, 2009.

"Energy Markets in a Tailspin," Presentation to AOBA Utility Committee, March 11, 2009.

"Energy price Outlook for 2009," Presentation to AOBA Utility Committee, December 10, 2008.

"Are You 'Going Green' or Going in the Red," Presentation to AOBA Utility Committee, June 18, 2008.

"Understanding Your Utility Costs and Your Competitive Service Options," Presentation to the Mid-Atlantic Hispanic Chamber of Commerce, July 10, 2006.

"Keeping Your Head Above Water In Volatile Electricity And Natural Gas Markets," Presentation to Legum & Norman Managed Condominiums, February 28, 2006.

"Surviving in Deregulated Energy Markets: *What You Don't Know Will Hurt You*!" Presentation to AOBA Legislative & Regulatory Seminar, May, 18, 2006.

"The Utility Market And Deregulation: *What's In It For You*? Presentation to the Montgomery County, Maryland, Apartment Assistance Program, September 29, 2005.

"Winds of Long-Term Change or Another Short-Term Market Distortion: Post-Katrina and Rita Energy Markets," Keynote Presentation to AOBA Leadership Conference, September 28, 2005.

"These Are Not Your Father's Energy Markets," Presentation to the Institute of Real Estate Management, March 8, 2005.

"Understanding Natural Gas Markets," Prepared for the AOBA Alliance, Inc., August 2004.

"Default Service: Protection or Problem," Prepared for the AOBA Alliance, Inc., April 2004.

<u>Assessment of Winter 2000 Heating Oil Price Increases for Rhode Island</u>, Report Prepared for the Rhode Island Department of Attorney General, September 2001 (with P. Roberti).

"Stranded Costs and Stranded Values," Presentation before the Virginia General Assembly, Joint Subcommittee on Electric Industry Restructuring, Task Force on Stranded and Transition Costs, May, 1998.

"Comments Regarding Restructuring of the Electric Industry in Maryland," Presentation before the Maryland Legislative Task Force on Electric Industry Restructuring, December 1997.

Electric Industry Restructuring And Competition In Virginia, Prepared for the Apartment and Office Building Association of Metropolitan Washington, September 1997.

"Assessment of the Proposed Pepco/BGE Merger," Presentation to the District of Columbia Community Forum on Merger Issues, December 1996.

Assessment of the Agreement Between Delmarva Power & Light Company and the Medical Center of Delaware for the Supply of Electrical Power, Prepared for the Delaware Public Service Commission, Docket No. 94-129, December 1994.

Assessment of the Agreement Between Delmarva Power & Light Company and Ciba-Geigy Corporation for the Supply of Limited Volume Natural Gas, Prepared for the Delaware Public Service Commission, Docket No. 94-141, November 1994.

Assessment of the Natural Gas Service Agreement Between Delmarva Power & Light Company and the Medical Center of Delaware, Prepared for the Delaware Public Service Commission, Docket No. 94-129, November 1994.

Lifeline Rates for Electric Service and Their Potential Application to the Guam Power Authority, Prepared for the Public Utilities Commission of Guam, December 1991.

Review of Additional Information Provided by Delmarva Power & Light Company Regarding the Costs of Gas Supply for Hay Road Combined Cycle Generation; prepared for the Delaware Public Service Commission, Docket No. 87-9, Phase V, June 1991.

Evaluation of Delmarva Power & Light Company's Proposed Near-Term Capacity Additions, prepared for the Delaware Public Service Commission, Docket No. 87-9, Phase V, August, 1990.

Evaluation and Recommendations: Delmarva Power & Light Company's Proposed Commercial and Industrial Indoor Lighting Pilot Program, Prepared for the Delaware Public Service Commission, Docket No. 87-9, Phase V, January, 1990.

Preliminary Evaluation of DP&L's Proposed Long Term Purchase of Capacity and Energy from Duquesne Light Company, Prepared for the Delaware Public Service Commission, Docket No. 87-9, Phase IV, January 1990.

Staff Review and Technical Assessment: Challenge 2000 Supply Side Plan, Prepared for the Delaware Public Service Commission, Docket No. 87-9, Phase II, October 1988 (with N.R. Friedman and J. Byrne).

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Evaluation of the Proposed Load Management Program and Accompanying New Rate Schedule R-LM, Prepared for the Delaware Public Service Commission, Docket No. 87-34, January 1988.

Staff Interim Report to the Hearing Examiner, Prepared for the Delaware Public Service Commission, Docket No. 87-9, January 1988, (with J. Byrne, D. Rich, & Y.D. Wang).

Report for the Attorney General of the State of New Mexico: In the Matter of the Application of Gas Company of New Mexico for a Variance to and a Change in General Order No. 44, February 1987 (with R. LeLash and G. Epler).

Determinants of Capital Costs for Coal-Fired Power Plants, prepared for U.S. Energy Information Administration, March 1985 (with J. P. Price and C. J. Koravik).

Trends in Electric Utility Load Duration Curves, prepared for U.S. Energy Information Administration, December 1984. (with J. P. Price)

"Potential 1984 Strike by United Mine Workers of America," Executive Briefing Paper, prepared for U.S. Energy Information Administration, Sept., 1984.

Coal Market Decision - Making: Description and Modeling Implications, prepared for the U.S. Energy Department Information Administration, May 1984 (with J. P. Price).

Power System Load Management Technologies, Energy Department Paper No. 11, World Bank, November 1983 (with J.P. Price).

"Excess Capacity in U.S. Electric Utilities," Geopolitics of Energy, Volume 5, Issue No. 9, September 1983.

Ohio Cogeneration Handbook, prepared for the Ohio Department of Energy, June 1982 (with N. R. Friedman and J. P. Price).

Cogeneration Engineering Handbook, prepared for the California Energy Commission. January 1982 (with N. R. Friedman and J. P. Price).

Third Annual Report: Time of Use Rates for Very Large Customers, Pacific Gas and Electric Company, March 1980 (with R. Levitan).

Residential Peak Load Reduction Program: Implementation Plan, Pacific Gas and Electric Company, January 1980.

"Marginal Cost Adjustment Mechanisms and Rate Design", paper presented to the California Marginal Cost Pricing Project, August 1979.

Effects of Time-of-Day Pricing Under Alternative Assumptions: Three Case Studies, prepared for the U.S. Department of Energy, 1979. (with R. Spann)

Long Run Incremental Cost Analysis and the Development of Time-of-Day Rates for Blue Ridge Electric Membership Corporation, prepared for the North Carolina Utilities Commission, January 1978.

Report on Federally Financed Time-of-Day Rate Experiments for Residential Electric Utility Customers, prepared for the U.S. General Accounting Office, November 1977.

An Empirical Evaluation of the Predatory Theory of Vertical Integration: The Case of Petroleum, (with E. Erickson and R. Spann) prepared for the American Petroleum Institute, October, 1977.

Electric Utility Coal Consumption and Generation Trends, 1976-1985, prepared for the Office of Coal, Federal Energy Administration, October 1976.

Methodology for Improving the Price Sensitivity of the PIES Oil and Gas Supply Curves, prepared for the Federal Energy Administration, February 1976.

Coal Demand for Electricity Generation 1975-1984, prepared for the Office of Coal, Federal Energy Administration, August 1975.

Tanker Requirements for U.S. Waterborne Oil Imports, prepared for the Federal Maritime Administration, September 1973 (with W. Stitt).

Attachment B
National Grid Rhode Island Annual ISR Filing for 2020
Formal Case Nos. 1115, 1142 & 1154

The Narragansett Electric Company
d/b/a National Grid

Gas Infrastructure, Safety, and Reliability Plan FY 2021 Proposal

Book 1 of 2

December 20, 2019

Docket No. 4996

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

nationalgrid

Raquel J. Webster
Senior Counsel

December 20, 2019

BY HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2020 Gas Infrastructure, Safety, and Reliability Plan Docket No. 4996

Dear Ms. Massaro:

In compliance with R.I. Gen. Laws § 39-1-27.7.1, I have enclosed 10 copies of National Grid's[1] proposed Gas Infrastructure, Safety, and Reliability (ISR) Plan (Gas ISR Plan or Plan) for fiscal year (FY) 2021. The Gas ISR Plan is designed to enhance the safety and reliability of National Grid's natural gas distribution system. As required by law, National Grid submitted the proposed Plan to the Division of Public Utilities and Carriers (Division) for review. The Division undertook a comprehensive review of the initial plan, which included issuing numerous informal and formal discovery requests to the Company, review of responses to those requests, discussions with Company representatives, and outside consultant review. After further discussions with the Company, the Division and the Company were able to mutually agree on the budget for the Plan. Based on its review of the initial Plan and discussions with the Company, the Division supports the Plan's budget and has indicated its general concurrence with the Plan, including the programs and projects outlined in the Plan. Consistent with prior Gas ISR filings, the Division will continue to review the Plan and its costs after filing.

The Gas ISR Plan is designed to protect and improve the gas delivery system through proactively replacing leak-prone pipe; upgrading the system's custody transfer stations, pressure regulating facilities, and peak shaving plants; responding to emergency leak situations; and addressing conflicts that arise out of state, municipal, and third-party construction projects. The Plan is intended to achieve these safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas distribution infrastructure and directly benefit all Rhode Island gas customers.

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[1] The Narragansett Electric Company d/b/a National Grid.

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

The Plan includes a description of the categories of work National Grid proposes to perform in FY 2021and the proposed targeted spending levels for each work category. In addition to the Plan, this filing includes the pre-filed direct testimony of four witnesses. Amy Smith introduces the Plan document and describes the program components of the Plan; Lee Gresham, JD, PhD provides testimony regarding the operation and maintenance (O&M) expenses associated with the Plan and, specifically, the Company's proposed Heat Decarbonization Assessment planned work. Melissa A. Little describes the revenue requirement for the Plan; and Ryan M. Scheib describes the calculation of the Gas ISR factors proposed in the Plan and provides the bill impacts from the proposed rate changes.

For the average residential heating customer using 845 therms annually, implementation of the proposed ISR factors for the period of April 1, 2020 through March 31, 2021 will result in an annual increase of $44.08, or 3.7 percent.

For the PUC's convenience, the Company has also included copies of its responses to Division Data Requests Set 1. In connection with the Data Requests, this filing contains a Motion for Protective Treatment of Confidential Information in accordance with 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential and privileged information in Attachment DIV 1-11. In compliance with Rule 1.3(H), National Grid has provided the PUC with one complete, unredacted copy of Attachment DIV 1-11 in an envelope marked, **"HIGHLY CONFIDENTIAL INFORMATION - DO NOT RELEASE!**

The Gas ISR Plan presents an opportunity to facilitate and encourage investment in National Grid's gas utility infrastructure and enhance National Grid's ability to provide safe, reliable, and efficient gas service to customers.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures
cc: Christy Hetherington, Esq.
Al Mancini, Division
John Bell, Division
Rod Walker, Division

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Fiscal Year 2021 Gas Infrastructure, Safety, and Reliability Plan	)	Docket No. 4996

NATIONAL GRID'S MOTION FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On December 20, 2019, National Grid submitted its Proposed Fiscal Year 2021 Gas Infrastructure, Safety, and Reliability Plan (Gas ISR or the Plan) with the PUC. For the PUC's convenience, the Company also included its responses to the Rhode Island Division of Public Utilities and Carriers' First Set of Data Requests regarding the Plan. In Data Request Division 1-11, the Division requested a copy of a study relating to the construction of an LNG tank in Cumberland, Rhode Island. In responding to Data Request Division 1-11, National Grid provided a copy of the requested study as Attachment Division 1-11. National Grid requests

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

confidential treatment of this study, which is highly confidential and proprietary because it contains commercially sensitive/trade secret information.

For the reasons described below, the Company requests that, pursuant to R.I. Gen. Laws § 38-2-2(4)(B) and Rule 1.3(H), the PUC afford confidential treatment to the confidential and proprietary information included in Attachment Division 1-11.

II. LEGAL STANDARD

Rule 1.3(H) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq*. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47. National Grid meets the first and second prongs of this test, which apply here.

III. BASIS FOR CONFIDENTIALITY

The information contained in Attachment DIV 1-11 should be protected from public disclosure because it contains commercially sensitive/trade secret information relating to the study performed in connection with the construction of an LNG tank in Cumberland, Rhode Island. National Grid does not ordinarily make such studies public, and disclosing such commercially sensitive and proprietary information to the public could harm the Company. Moreover, the PUC has previously recognized the proprietary nature of these types of studies.

Accordingly, National Grid respectfully requests that the PUC provide confidential treatment to the confidential study attached as Attachment Division 1-11.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

Raquel J. Webster, Esq. (#9064)
National Grid
40 Sylvan Road
Waltham, MA 02451
781-907-2121

Dated: December 20, 2019

Testimony of
Amy Smith

DIRECT TESTIMONY

OF

AMY SMITH

December 20, 2019

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Amy Smith. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

A. I am employed by National Grid USA Service Company, Inc. (Service Company) as the Director, New England Jurisdiction. I am the New England state jurisdictional lead for all gas system issues, including those related to the capital investment strategies for Narragansett Electric Company, d/b/a National Grid (National Grid or the Company). In my role, I work closely with the Rhode Island Jurisdictional President and Jurisdiction staff on all local gas issues related to the Rhode Island gas system in the Rhode Island service territory. My responsibilities include working with regulators on issues related to the gas system, developing strategies to support Company objectives regarding investment in the gas system, and providing testimony regarding capital investments in National Grid's gas system during state regulatory proceedings.

Q. Please describe your educational background and professional experience.

A. In 1982, I graduated from Simmons College with a Bachelor of Arts in Economics and Mathematics. In 1991, I joined Boston Gas Company (now National Grid) as an analyst in Gas Supply Planning. Since that time, I have held a variety of positions in Rates and

Regulation, Performance Measurement, Credit and Collections, Customer Regulatory Relations, Emergency Dispatch, Gas Resource Planning, Network Strategy, Construction, Gas Pipeline Safety and Compliance and Gas Investment, Resource and Rate Case Planning. I assumed my current position on April 1, 2019. In addition, from 1984 to 1989, I worked for the Massachusetts Department of Public Utilities (the Department).

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes. In 2019, I filed testimony with the PUC in support of the Company's Reconciliation of the FY 2019 Infrastructure, Safety, and Reliability Plan. In 2011 and 2012, I testified at the PUC in support of the Company's Gas Infrastructure, Safety, and Reliability Plans. In 2011, I testified at a technical session in support of the Company's first Gas ISR Plan and presented the Company's five-year capital plan along with an explanation of how the existing Accelerated Replacement Program (ARP) would be closed out and transitioned to the new Gas ISR Plan (Docket 4219). In 2012, I also testified at a technical session in support of the Company's Gas ISR Plan for FY 2013 and addressed regulatory reporting requirements. (Docket 4306).

In Massachusetts, before the Department of Public Utilities (the Department) and on behalf of Boston Gas Company (Boston Gas) and Colonial Gas Company (Colonial Gas), each d/b/a National Grid (collectively National Grid or the MA Companies), I have filed testimony and related exhibits in support of capital investment and gas safety and reliability proposals in the MA Companies' last two base rate increase proceedings, dockets D.P.U. 17-170 and D.P.U 10-55, respectively. I also filed testimony in support of the MA Companies' Targeted Infrastructure Replacement Factor filing in docket D.P.U. 11-36. In 2008, I testified at the Department regarding low-income credit and collections practices in docket D.P.U 08-4. In 2005, I testified at a technical session at the Department in support of the MA Companies' service quality performance in docket D.P.U. 04-116. I have also testified before the New Hampshire Public Utilities Commission.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's proposed FY 2021 Gas ISR Plan (Gas ISR Plan or Plan).[1] Through my testimony, I present the Company's Gas ISR Plan, which details the work the Company expects to complete under the Plan and the anticipated capital investments associated with that work. Company witness Lee

[1] The Company is required by statute to annually file an infrastructure, safety, and reliability spending plan with the PUC for review and approval. *See* R.I. Gen. Laws § 39-1-27.7.1(d). In addition to budgeted spending, the annual Gas ISR Plan must contain a reconcilable allowance for the Company's anticipated capital investments and other spending for the upcoming fiscal year. *See* R.I. Gen. Laws § 39-1-27.7.1(c)(2). For FY 2021, the Company's fiscal year is for the period of April 1, 2020 through March 31, 2021, so the Plan would be effective April 1, 2020.

Gresham, JD, PhD is providing testimony on the operation and maintenance (O&M) expenses associated with the Gas ISR Plan, specifically, the Company's proposed Heat Decarbonization Assessment planned work. Company Witness Melissa A. Little is providing testimony on the calculation of the revenue requirement associated with the Company's Plan, and Company Witness Ryan M. Scheib is providing testimony relative to (1) how the Company calculated the rate design for the ISR mechanism; (2) the calculation of the ISR factors; and (3) the customer bill impacts of the proposed ISR factors.

III. OVERVIEW

Q. How did the Company prepare the Gas ISR Plan?

A. The Company prepared the Gas ISR Plan and submitted it to the Rhode Island Division of Public Utilities and Carriers (Division) for review on September 29, 2019.[2] On November 7, 2019 and November 8, 2019, the Company met with the Division regarding the Plan and subsequently responded to informal discovery requests from the Division about various components of the Plan. On November 9, 2019, the Company conducted field visits with the Division to provide the Division with the opportunity to observe

[2] R.I. Gen. Laws § 39-1-27.7.1(d) requires that the Company and the Division work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which is then submitted to the PUC for review and approval within 90 days.

various capital projects that have been completed, are currently under construction, and/or are planned for future periods. On November 10, 2019, the Company conducted a site visit of the Northboro Massachusetts Gas Control Center with the Division to provide the Division with the opportunity to view capital improvement projects that have been completed and/or are planned for future periods, along with an overview of the Rhode Island gas transmission and distribution systems. The Company and the Division continued to collaborate regarding the proposed Plan on several occasions, including subsequent meetings on November 14, November 21, November 26, and December 5, 2019. The Company also responded to several formal and informal supplemental data requests from the Division. The Division has indicated general concurrence with the proposed Gas ISR Plan, including the programs and projects outlined in the Plan, and will continue to review the Plan and its costs after filing, consistent with prior Gas ISR Plan filings. Overall, the Gas ISR Plan will allow the Company to meet state and federal safety and reliability requirements, maintain its gas distribution system in a safe and reliable condition and assess the feasibility of several decarbonization methods for the gas system. The Plan has been developed to improve the safety and reliability of the Company's gas system for the immediate and long-term benefit of Rhode Island's natural gas customers.

Q. What is the Gas ISR Plan designed to accomplish?

A. The Gas ISR Plan is designed to establish a spending plan, together with a reconcilable allowance for the anticipated capital investments and other spending needed to maintain and upgrade the Company's gas delivery system, such as proactively replacing leak-prone gas mains; upgrading the system's plant, pressure regulating systems, and piping; responding to emergency leak situations; and addressing conflicts that arise out of public works projects. The Plan attempts to attain the Company's safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas pipeline infrastructure and directly benefit Rhode Island gas customers. The Company now submits the Plan to the PUC for review and approval in accordance with Rhode Island law.[3]

Q. Are you sponsoring any exhibits through your testimony?

A. Yes. The proposed Gas ISR Plan is attached as Exhibit 1 to my testimony. The Plan is organized as follows:

[3] *See* R.I. Gen. Laws § 39-1-27.7.1(d).

Section 1 – Introduction and Summary

Section 2 – Gas Capital Investment Plan (including major categories of work)

Section 3 – Revenue Requirement Calculation

Section 4 – Rate Design and Bill Impacts

Attachment 1 – 2018 System Integrity Report

My testimony focuses on Sections 1 and 2 of the Plan. As noted earlier, Mr. Gresham is sponsoring the O&M – Heat Decarbonization Assessment testimony included in Section 2 of the Plan; Ms. Little is sponsoring the revenue requirement calculation included in Section 3 of the Plan; and Mr. Scheib is sponsoring the rate design and bill impacts included in Section 4 of the Plan.

Q. What types of infrastructure, safety, and reliability work does the Gas ISR Plan include?

A. The Gas ISR Plan seeks not only to maintain the Company's distribution system, but also to proactively upgrade the system's condition to address problems before they arise. A safe and reliable gas delivery system in Rhode Island is essential to the health, safety, and well-being of its citizens, and for maintaining a healthy economy and continuing to attract new residents and businesses to Rhode Island. In 2008, the PUC embarked on a course of addressing Rhode Island's aging gas infrastructure with the establishment of the Accelerated Replacement Plan. The Company filed its first Gas ISR Plan on December 20, 2010 for FY 2012. In addition to the type of infrastructure, safety, and reliability work performed under the Accelerated Replacement Plan, the Gas ISR Plan contains spending related to safety and reliability for Public Works, Mandated programs, and Reliability programs, including Gas Expansion. Included in the Plan document is a description of the Company's proposed budget for capital investment and associated O&M expenses for FY 2021 and a capital forecast for FY 2022 through FY 2025. As agreed with the Division in the FY 2020 ISR Plan, given the magnitude of the scope and cost for the Southern Rhode Island Gas Expansion Project (Southern RI Gas Expansion), the Company will continue to manage any deviations from the FY 2021 Southern RI Gas Expansion Project budget separately from the overall Discretionary budget under the Plan. If deviations do occur with the Southern RI Gas Expansion Project, the Company will neither advance nor delay other Discretionary work to compensate for those changes in FY 2021 costs. This year's Plan also includes a section describing the history and effectiveness of the Gas ISR Plan and a copy of the most recent System Integrity Report, as ordered by the PUC in Docket No. 4781. Additionally, the Plan provides funding, as O&M, for Heat Decarbonization Assessments; testimony for this category is provided by Lee Gresham.

IV. CAPITAL INVESTMENT PLAN

Q. What levels of spending are proposed in the Gas ISR Plan?

A. For FY 2021, the Company proposes to invest a total of $199.61 million, including $39.30 million for Non-Discretionary capital expenditures; $144.79 million for Discretionary capital expenditures, which includes $40.46 million for the Southern RI Gas Expansion Project; $1.52 million for PE Stamps; $13.01 million for incremental curb to curb paving costs estimated in accordance with the new RI paving law; and $1.00 million of O&M spending to begin assessing capital investment options for heat decarbonization. The incremental paving costs include $2.61 million for incremental paving specific to the Southern RI Gas Expansion Project. The Plan is broken down into categories of Non-Discretionary, Discretionary, O&M, and Incremental Costs, each of which contain programs designed to maintain the safety and reliability of the Company's gas delivery infrastructure. Non-Discretionary programs include work required by legal, regulatory code, and/or agreement, or a result of damage or failure, with limited exceptions. Discretionary programs are not required by legal, regulatory code, and/or agreement, with limited exceptions. The O&M expenses are also discretionary but are categorized separately because they are not capital expenses. The Incremental Costs are broken out separately for tracking purposes, but they support work in both the Non-Discretionary and Discretionary categories.

Q. What levels of spending is the Company proposing for Non-Discretionary programs?

A. For each Non-Discretionary program category in the Gas ISR Plan, the Company proposes the following levels of spending:

- $17.37 million net investment for Public Works programs, including $18.77 million in capital spend and $1.40 million in reimbursements;
- $21.68 million for Mandated Programs (i.e., Corrosion, Purchase Meter Replacements, Reactive Leaks (Cast Iron Joint Encapsulation/Service Replacement), Service Replacement (Reactive) – Non-Leak/Other, Main Replacement (Reactive) – Maintenance (including Water Intrusion), Transmission Station Integrity; and
- $0.25 million for Damage/Failure programs.

Q. What levels of spending is the Company proposing for Discretionary programs?

A. For each Discretionary program category in the Gas ISR Plan, the Company proposes the following levels of spending:

- $67.73 million for the Proactive Main Replacement program (i.e., Proactive Main Replacement, Large Diameter, and Atwells Avenue project);
- $0.35 million for the new Proactive Service Replacement program;
- $36.25 million for Gas System Reliability, including work relative to Gas System Control, System Automation, Heater Program, Pressure Regulating Facilities, Allens Avenue Multi Station Rebuild, Valve Installation Replacement, Take Station Refurbishment, Gas System Reliability Enhancement, Instrumentation and Regulation – Reactive, Distribution

Station Over Pressure Protection, Liquefied Natural Gas (LNG) facilities, Replace Pipe on Bridges, Access Protection Remediation, and Tools and Equipment; and

- $40.46 million for the Southern Rhode Island Gas Expansion Project (Southern RI Gas Expansion).

Q. What level of spending is the Company proposing for the O&M Expenses category?

A. For the O&M Expenses category in the Gas ISR Plan, the Company proposes the following levels of spending:

- $1.00 million for Heat Decarbonization Assessments.

Q. What levels of spending is the Company proposing for the Incremental Costs category?

A. For the Incremental Costs category in the Gas ISR Plan, the Company proposes the following levels of spending:

- $1.52 million for Professional Engineer (PE) Stamps;
- $13.01 million for Incremental Curb to Curb Paving Costs, including Southern RI Gas Expansion and All Other ISR Work.

The Company will continue to file quarterly reports with the Division and PUC detailing the progress of its Gas ISR Plan programs for FY 2021.

Q. The Company has included $1.52 million for PE Stamps in response to the new Rhode Island statutory requirements regarding review and approval of certain work by a Professional Engineer. How did you arrive at that estimate?

A. The Company based its estimate on its experience with similar requirements in Massachusetts, using the work types and volumes proposed in the FY 2021 RI Gas ISR Plan.

Q. Do you anticipate any variance from the proposed estimate of PE Stamp costs?

A. Actual costs may vary based on the individual characteristics and complexity of each job, and whether any changes to a job occur after the job has started, such as change in scope or field conditions that require a PE to update and approve revised plans.

Q. Explain why the company has included incremental curb to curb paving costs in this plan.

A. In the Summer of 2019, the Governor signed the new Rhode Island Utility Fair Share Roadway Repair Act into law. The Act requires public utilities or utility facilities to repave and repair roadways that they alter or excavate from curb to curb or as required in accordance with state or municipal utility permit requirements. Historically, the Company's typical area of pavement restoration for work in roadways has been isolated to the side of the street where the work occurred, an approximately 8-11 feet width off the curb and the length of the trench. The Company estimates that the new paving law will result in $13.01 million in incremental paving costs for FY 2021, which includes $2.61 million for incremental paving costs for the Southern Rhode Island Gas Expansion Project (Southern RI Gas Expansion Project) and $10.40 million for all other ISR work. The Company has included the estimated incremental paving costs in the FY 2021 Gas ISR plan because they will be costs incurred in direct relation to the capital investment work contained in the Gas ISR.

Q. The Company has included $13.01 million for incremental curb to curb paving costs including the Southern RI Gas Expansion project and all other ISR Work. Please explain how this cost was estimated.

A. The incremental curb to curb paving cost estimate of $13.01 million is comprised of three cost categories: Main Installation for $5.60 million; Patches for $4.80 million; and the Southern RI Gas Expansion Project for $2.61 million. A summary of the total estimate for the FY 2021 Gas ISR Incremental Curb to Curb Paving Costs is presented in the table below. For the Main Installation incremental cost estimate, the Company estimated the current final restoration paving width to be 10.28 feet or 6,033 square yards of paving per mile and the average curb to curb restoration will be 26 feet or 15,253 square yards per mile. Based on a cost per square yard of $12.50 for the current average paving, the cost per mile is approximately $0.08 million. When the final restoration width is extended to curb-to-curb, the Company anticipates additional costs of approximately 20% will be incurred for incremental work such as driveway aprons, line striping, drainage, sewer, intersection sensors and other miscellaneous work. Therefore, the estimated cost per mile for curb to curb restoration is $0.23 million per mile, resulting in an incremental cost per mile of $0.15 million to extend paving to curb to curb. After deducting the estimated miles that are already paved curb to curb and included in the average width of 10.28 feet, the Company estimates the incremental cost of paving curb to curb will be $5.60 million.

For final restoration patches, the Company estimates that 3,429 ISR patches will be completed in FY 2021. The cost of a standard patch is approximately $1,400. The Company estimates that for 50% of the patches, the state and municipal permits will require patch areas that are larger than a current standard patch. The Company anticipates those patch widths will be extended to curb to center line and curb to curb and therefore the average patch cost is anticipated to be $2,800 per patch, resulting in an incremental cost per patch of $1,400 or $4.80 million for all final restoration patches.

For the Southern RI Gas Expansion project, the incremental paving costs of $2.57 million reflect the cost of extending the width of the final restoration paving and the cost of complying with new Rhode Island Department of Transportation (RIDOT) concrete base restoration guidelines.

FY 2021
Incremental Curb to Curb Paving Costs
Main Installation, Patches, and Southern RI Gas Expansion Project

Planned Main Installation Paving Miles	42.3

*Note that minus the ~14% which is already paved curb to curb, this number is effectively approximately 36.5 miles

Main Installation Paving	**Sq Yards/ Mile**	**Cost/ Sq Yd**	**Added Costs %***	**Cost/Mile**	**Total Cost for 42.92 Miles**	**Budget**
Minimum 8ft Restoration	4,693	$ 12.50		$ 58,663	$ 2,480,837	
Average 10.28ft Restoration	6,033	$ 12.50		$ 75,410	$ 3,189,089	
Curb to Curb 26 ft Restoration	15,253	$ 12.50	20%	$ 228,800	$ 9,675,952	
Curb to Curb minus Average = Incremental Cost/mile				$ 153,390	$ 6,486,863	
Deduct ~14% for roads already paved curb to curb					$ 890,889	
Total Incremental Cost for curb to curb main installation paving					$ 5,595,974	**$ 5,596,000**

*Added Costs for paving curb to curb such as driveway aprons, striping, drainage, sewer, intersection sensors, etc.

Planned ISR Patches	3,429

Patching Paving Costs	**Average Cost/Patch**	**Total Cost for 3,429 Patches**	**Budget**
Standard	$ 1,400	$ 4,800,600	
Mix of curb to curb and curb to center @ 50% adoption rate	$ 2,800	$ 9,601,200	
"Curb to Curb" minus Standard = Incremental Cost/Patch	$ 1,400	$ 4,800,600	**$ 4,801,000**

Southern RI Gas Expansion Incremental Paving Costs	**Incremental Paving Cost**	**Budget**
Main Installation*	$ 2,565,078	$ 2,565,000
Other Investment - MOP Increase from 150 to 200 psi	$ 49,000	$ 49,000
Total Incremental Southern RI Gas Expansion Paving Costs	$ 2,614,078	**$ 2,614,000**

*Cost also includes impact of new RIDOT concrete restoration guidelines

FY 2021 Gas ISR Incremental Paving Costs by Category	**Incremental Paving Cost**	**Budget**
Main Installation - 44.43 miles	$ 5,595,974	$ 5,596,000
Patches - 3,429 @ 50% (mix curb to curb and curb to center)	$ 4,800,600	$ 4,801,000
Southern RI Gas Expansion	$ 2,614,078	$ 2,614,000
Total FY 2021 ISR Incremental Paving Costs	**$ 13,010,652**	**$ 13,011,000**

Q. How does the Company plan to treat the replacement of leak-prone pipe in Rhode Island in FY 2021?

A. To continue to provide safe and reliable gas service to its Rhode Island customers, the Company is proposing to abandon approximately 62 miles and rehabilitate approximately 1 mile of leak-prone pipe in FY 2021, which is an increase of 1 abandonment mile compared to the FY 2020 ISR Plan and keeps pace with the 20-year Proactive Main Replacement program. The Large Diameter program accounts for approximately 1 mile of rehabilitation by utilizing sealing and lining techniques. The Atwells Avenue Main Replacement project is contributing approximately 0.6 miles to the abandonment total. The Public Works program is contributing 13 miles to the abandonment total. The Proactive Main Replacement – Leak Prone Pipe program is contributing approximately 47.4 miles to the abandonment total. The Company is proposing FY 2021 spending of $67.73 million for the Proactive Main Replacement program, which includes $5.08 million for the Atwells Avenue project, and $17.37 million for the Public Works program. The value of and need for targeted spending on the replacement of leak-prone gas main is well-documented and is only increasing in importance as these facilities continue to age. The 20-year Proactive Main Replacement program and corresponding five-year plan call for the abandonment of 70 miles of leak-prone pipe per year from FY 2022 to 2025. The Company is currently assessing the feasibility of increasing the abandonment target by 8 miles from FY 2021 to FY 2022 and beyond.

Q. What is the difference between installation miles and abandonment miles in relation to the replacement of leak-prone pipe?

A. Installation miles represent the units of new main that are required to be connected to the distribution system. Thus, installation miles represent the main driver for unit costs when combined with service relays and tie overs. Abandonment miles represent the total of the old leak-prone pipe that is retired or disconnected from the distribution system. In some instances, the existence of parallel leak-prone main provides the Company with the opportunity to install a single section of new main to abandon two sections of existing leak-prone main; the current FY 2021 workplan contains approximately 3.9 miles of parallel main to be abandoned (the FY 2020 workplan originally contained 3.0 miles of parallel main). This will result in annual leak-prone pipe replacement program targets where total abandonment miles exceed total installation miles.

Q. How do the FY 2021 leak-prone pipe replacement programs compare to the FY 2020 programs?

A. The Public Works program abandonment and installation miles will remain the same at 13 miles. The table below provides a comparison of the Main Replacement – Leak Prone Pipe program between FY 2020 and FY 2021, including the estimated cost per mile for installed and abandoned main in urban, suburban, and rural areas. This table excludes the Large Diameter program and the costs for the Atwells Avenue Main Replacement program because the nature of those programs are not suitable for year-over-year comparison. The average installation cost per mile for work in rural locations is estimated to increase from $0.86 million in FY 2020 to $0.97 million in FY 2021. The average installation cost per mile for work in suburban locations is estimated to increase from $1.13 million in FY 2020 to $1.24 million in FY 2021. The average installation cost per mile for work in urban locations is estimated to decrease from $1.83 million in FY 2020 to $1.77 million in FY 2021 because the FY 2021 plan contains a slightly higher volume of replacements that are changing from low-pressure to high-pressure and calls for the installation of 2-inch and 4-inch main instead of 6-inch and 8-inch main which results in a cost savings per mile.

FY 2020 (Plan as of 12/19/2018)				
	Installation Miles	Abandonment Miles	Installation Cost/Mile	Abandonment Cost/Mile
Rural	5.9	6.6	$0.86M	$0.76M
Suburban	18.4	20.1	$1.13M	$1.04M
Urban	17.1	20.3	$1.83M	$1.54M
Total	41.3	47.0	$1.38M	$1.22M

FY 2021 (Plan as of 12/18/2019)				
	Installation Miles	Abandonment Miles	Installation Cost/Mile	Abandonment Cost/Mile
Rural	4.0	4.6	$0.97M	$0.84M
Suburban	21.9	23.6	$1.24M	$1.15M
Urban	16.4	19.2	$1.77M	$1.51M
Total	42.3	47.4	$1.42M	$1.27M

Q. Have the Company's efforts at replacing leak-prone pipe been effective?

A. Yes. When the ISR program was first implemented in FY 2012, approximately 48 percent of the Company's gas distribution system in Rhode Island was comprised of leak-prone pipe. Through the FY 2019 Gas ISR Plan, the Company has abandoned a total of 445 miles of leak-prone pipe, which has contributed to an estimated reduction of 1,235 gas leaks. An important system performance indicator regarding the effectiveness of the Company's leak-prone pipe abandonment program is the number of leak receipts. Since 2008, the Company has seen an overall downward trend on leak receipts, which indicates that the ISR program and former Accelerated Replacement Program have contributed to this result. More details regarding the effectiveness of the Gas ISR Plan are provided in the Company's most recent System Integrity Report (2018), which is included as an attachment to the Plan.

Q. Has the Company made any modifications in the Plan related to the replacement of leak-prone pipe?

A. Yes. The Company will continue its renewed Large Diameter Program, where there is an inventory of 37 miles of leak-prone pipe greater than 12-inches in diameter. The Company forecasts that this program will result in an underspend in FY 2020 because the Company was unable to complete planned segments of work in Providence due to permitting issues. Therefore, the delayed work has been deferred until FY 2021. For 2021 the Company proposes to spend $3.40 million to address approximately 1 mile of large diameter main through lining or sealing techniques. The Company originally put this program on hold in FY 2019 to mitigate the impact of the Special Projects that needed to be funded in that Plan, but the need to replace the large diameter inventory necessitated the inclusion of the program in FY 2020 and again in FY 2021.

In addition, the FY 2021 Plan continues to include the Atwells Avenue Main Replacement project, which will be year two of a three-year project. In the 2017-2018 winter period, the Company experienced four main breaks on Atwells Avenue in Providence on 12-inch low pressure cast iron main installed in the 1870s. This main is located in one of the busiest streets within Providence, with a heavy concentration of restaurants. Upon completion of an integrity analysis, the Company deemed it necessary to abandon over 1 mile of cast iron main and replace it with over 1 mile (5,505 feet) of high-density polyethylene (HDPE) plastic pipe between FY 2020 and FY 2022. The project is broken into 4 segments; 1A – 1,565 feet; 1B – 1,565 feet; 2 – 965 feet; and 3 – 1,410 feet. In FY 2020, the Company is addressing the highest risk segment, Segment 2. In mid-September 2019, the City of Providence granted the Company a permit to begin that work. Due to the later than anticipated field work start date, the Company was unable to accelerate the Segment 1A work into FY 2020 and Segment 1A is now part of the FY 2021 workplan. The $5.08 million budget in FY 2021 includes the completion of Segments 1A and 1B and the engineering and design work in preparation of Segment 3, which is scheduled to be completed in FY 2022. The final restoration work associated with Segment 2 is anticipated to be completed in FY 2020. The final restoration work associated with Segments 1A and 1B, along with the field work for Segment 3 are scheduled to be completed as part of the estimated FY 2022 budget of $5.19 million. The total estimated cost for the Atwells Avenue main replacement project is approximately $11.63 million, although the estimate is subject to change.

Q. What is the Southern Rhode Island Gas Expansion Project?

A. As was detailed in the FY 2020 Gas ISR, the Company has identified a need and has begun to build in increased capacity in the Southern Rhode Island service territory. The more than 30,000 customers in the Company's Southern Rhode Island service territory are served by almost 600 miles of distribution infrastructure, including approximately 77 miles of distribution main operating at pressures of 99 psig and above (the Southern Rhode Island Distribution Mains). As of 2018, growth forecasts indicated the maximum vaporization capacity at the Exeter LNG facility would be exceeded by calendar year 2019. This could have resulted in approximately 3,750 customers with below minimum pressures and them being at risk of losing service. In addition, several regulator station inlet pressures are predicted to fall below the minimum threshold, which would cause problems on the downstream pressure systems if the regulator stations cannot maintain their outlet set pressure. Increasing capacity in Southern Rhode Island mitigates the risk of customers in the region losing service in the event of an outage at the Exeter LNG facility. Moreover, many commercial customers seeking to expand existing and new operations in the Southern Rhode Island region, such as in and around Quonset Point, cannot be served without this project. Without this project, the Company may have needed to impose a moratorium on all new gas service requests, as well as requests for expansion of existing gas service, to prevent service interruptions to existing customers. To address these capacity issues, in FY 2020, the Company began construction on a project to reinforce the Southern Rhode Island Distribution Mains by installing approximately five miles of new 20-inch steel distribution main parallel to the existing 12-inch distribution main located beneath Route 2 (a Rhode Island Department of Transportation right-of-way) through the towns of Warwick, West Warwick, and East Greenwich. The parallel distribution main is being constructed to be in-line inspected, initially operated at 99 psig, and designed for a maximum allowable operating pressure (MAOP) of 200 psig to meet future demand. The new distribution main will be placed in-service in phases between FY 2020 and FY 2022, with normal operation at 99 psig and the potential to operate at 200 psig after a district regulator station is installed in the future near South Road in East Greenwich. This project will also require work on existing regulator and take stations from FY 2021 through FY 2023. Based on current forecasts, each segment will add immediate growth capacity. Once all of the segments are completed, the Company expects that approximately 1,100 dekatherms per hour of additional capacity will be available. The installation of a second distribution main will also improve the reliability of the Company's gas distribution system in the area by decreasing the Company's dependence on pressure support from the Exeter LNG facility and by introducing redundancy that reduces the risk associated with a distribution main being out of service.

Q. What is the cost and scope of work for the Southern Rhode Island Project?

A. Between FY 2020 and FY 2024, the Company estimates that it will spend a total of $125.53 million for the Southern Rhode Island Project, which includes $3.54 million for incremental curb to curb paving along with costs associated with new RIDOT concrete base restoration guidelines. The work is comprised of main installation, regulation station investment, and other upgrades and investment. For the main installation portion of the Southern Rhode Island Project, the Company plans to install a total of 5 miles (26,625 feet) of new 20-inch steel distribution main. Between FY 2020 and FY 2023, the total estimated cost for the main installation work is currently $96.79 million, based on a completed design and an 80 percent level of confidence based on identified risks and future unknown risks, which includes incremental paving costs of $3.49 million. Factors contributing to the 80 percent project confidence level include the known increase of contractor pricing for the awarded phase two and three contracts versus the original estimates, assumptions around the increased presence of ledge based on phase one field conditions, changes to the RI paving law, new RIDOT concrete base restoration guidelines, permitting and work hour restrictions, requirements for night work, and handling of contaminated soil and ground water. For FY 2021, the Company expects to spend a total of $41.36 million for the main installation work, which includes incremental paving costs of $2.57 million.

In FY 2021, the Company plans to continue preparation work, such as planning, engineering, and site planning, for regulator stations associated with the Southern Rhode Island Project. Between FY 2021 and FY 2023, the Company plans to upgrade the Cranston Take Station and the Cowesett Regulator Station. The total estimated cost for the FY 2020 through FY 2024 regulator station work is currently $17.58 million. Additional funding of $5.79 million is included for a planned new regulator station located at the southern end of the main installation to reduce the system pressure from a MAOP of 200 psig to 99 psig before feeding back into the distribution system, with the majority of construction planned for FY 2023.

Other upgrades and investment for the Southern Rhode Island Project include the installation of a launcher and receiver to support in-line inspections of the 200 psig main, material testing to support the maximum operating pressure (MOP) increase from 150 psig to 200 psig for 5.2 miles (27,578 feet) of existing main in Cranston and West Warwick, and the installation of a remote operating valve (ROV). The total estimated cost for the FY 2020 through FY 2023 other upgrades and investment work is currently $11.16 million, which includes incremental paving costs of $0.05 million related roadway patches for the MOP increase. For FY 2020, the Company estimates that it will spend $3.55 million for the material testing. For FY 2021, the Company estimates that it will spend $0.98 million to complete the remainder of the material testing, which includes incremental paving costs of $0.05 million. All other work in this category is planned to occur in FY 2022 and FY 2023. The estimates related to the FY 2022 and FY 2023 work are considered preliminary and will be updated as part of the Company's FY 2022 Gas ISR Plan.

Q. Is the Company including any proposed operation and maintenance (O&M) expense in the FY 2021 Gas ISR Plan, as it has in prior Plans?

A. Yes. In prior years, the Company has included O&M expenses associated with supporting the ISR Plan. In FY 2021, the Plan includes $1.00 million of O&M expenses to support the Heat Decarbonization Assessment category. The testimony of Lee Gresham, JD, PhD provides further detail regarding the planned work for that category.

Q. Does the FY 2021 Gas ISR Plan fulfill the statutory requirements for the safety and reliability of the Company's gas distribution system in Rhode Island?

A. Yes. The FY 2021 Gas ISR Plan establishes the capital investment in Rhode Island that is necessary to meet the needs of the Company's customers, together with a spending and work plan to maintain the overall safety and reliability of the Company's Rhode Island gas distribution system.

V. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

Exhibit 1
Gas ISR FY2021

The Narragansett Electric Company
d/b/a National Grid

FY 2021 Gas Infrastructure, Safety, and Reliability Plan Proposal

December 20, 2019

Submitted to:
Rhode Island Public Utilities Commission

nationalgrid

Section 1
Introduction

Section 1
Introduction and Summary
FY 2021 Proposal

Introduction and Summary
FY 2021 Proposal

In consultation with the Rhode Island Division of Public Utilities and Carriers (Division), National Grid[1] has developed the following proposed fiscal year (FY) 2021[2] gas infrastructure, safety, and reliability (ISR) plan (Gas ISR Plan or Plan) in compliance with R.I. Gen. Laws § 39-1-27.7.1 (Revenue Decoupling Law), which provides for the filing of "[a]n annual gas infrastructure, safety and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[3] The proposed Gas ISR Plan addresses capital spending on gas infrastructure and other costs related to maintaining the safety and reliability of the Company's gas distribution system. Through the Plan, the Company will maintain and upgrade its gas delivery system by proactively replacing leak-prone pipe; upgrading the gas delivery system's custody transfer stations, pressure regulating facilities, and peak shaving plants; responding to emergency leak situations; addressing infrastructure conflicts that arise out of state, municipal, and third-party construction projects. The Company will also begin assessing capital investment options for heat decarbonization. The Plan intends to attain these safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas pipeline infrastructure, promote

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

[2] FY 2021 is defined as the 12 months ending March 31, 2021.

[3] R.I. Gen. Laws § 39-1-27.7.1(c)(2).

efficiency in the management and operation of the gas distribution system, and directly benefit Rhode Island gas customers. The Company now submits the Plan to the Rhode Island Public Utilities Commission (PUC) for review and approval.[4]

This Introduction and Summary presents (1) a history of the Gas ISR program in Rhode Island and a statement regarding how the ISR program has contributed to safety and reliability; (2) an overview of the proposed FY 2021 Plan for the statutory categories of costs; (3) the resulting FY 2021 revenue requirement associated with the proposed Plan; and (4) the rate design based upon that revenue requirement and estimated typical bill impacts resulting from the rate design.

The Gas ISR Plan describes the Company's safety and reliability activities and the multi-year plan upon which the FY 2021 Plan is based. The Plan also addresses capital investment in utility infrastructure for the upcoming fiscal year. The Plan itemizes the recommended work activities by general category and provides budgets for capital investment and associated operation and maintenance (O&M) expenses.

As envisioned in the Revenue Decoupling Law, after the end of the fiscal year, the Company will true up the Gas ISR Plan's budgeted levels to its actual investment and expenditures and reconcile the revenue requirement associated with the actual investment and expenditures with the revenue billed from the rate[2] adjustments implemented at the beginning of each fiscal year. The Company will continue to file quarterly reports with the Division and PUC

[4] In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the Company and the Division must work together over the course of 60 days in an attempt to reach an agreement on a proposed Plan, which must then be submitted to the Public Utilities Commission (PUC) for review and approval within 90 days.

concerning the progress of its Gas ISR programs. In addition, when the Company makes its reconciliation and rate adjustment filing described below, the Company will file an annual report on the prior fiscal year's activities. In implementing an ISR plan in any fiscal year, the circumstances encountered during the year may require reasonable deviations from the original ISR plan. In such cases, the Company will include in its quarterly reports an explanation of any significant deviations.

In the Summer of 2019, the Governor signed the new Rhode Island Utility Fair Share Roadway Repair Act into law. The Act requires public utilities or utility facilities to repave and repair roadways that they alter or excavate from curb to curb or as required in accordance with state or municipal utility permit requirements. Historically, the Company's typical area of pavement restoration for work in roadways has been isolated to the side of the street where the work occurred, an approximately 8-11 feet width off the curb and the length of the trench. The Company estimates that the new paving law will result in $13.01 million in incremental paving costs for FY 2021, which includes $2.61 million for incremental paving costs for the Southern Rhode Island Gas Expansion Project (Southern RI Gas Expansion Project) and $10.40 million for all other ISR work. Details of the incremental paving costs are detailed below. Estimated paving incremental costs are not included in each category, but rather, are shown in a separate line item against which the Company will track actual incremental paving costs associated with the new law.

The FY 2021 level of capital and related O&M spending provided in the Gas ISR Plan to maintain the safety and reliability of the Company's gas delivery infrastructure is $199.61 million. As described in more detail below, this amount includes $40.46 million to continue the

Southern RI Gas Expansion Project, which the Company manages as a distinct spending portfolio, $2.61 million for incremental curb to curb paving costs for that project, $10.40 million in incremental curb to curb paving costs for all other ISR work, $1.52 million to implement new statutory requirements to have natural gas infrastructure design plans and specifications approved by a Rhode Island registered Professional Engineer (PE Stamp) when the work could pose a material risk to public safety, and $144.63 million for the rest of the Plan. .

A description of the Company's proposed capital investment plan for FY 2021 is provided in Section 2. The revenue requirement description and calculations are contained in Section 3. A description of the rate design and bill impacts are provided in Section 4.

History of the ISR Plan

The Rhode Island natural gas distribution system is one of the oldest in the United States and includes a large proportion of leak-prone and deteriorating infrastructure installed, in some instances, more than 100 years ago. The Company, which owns and operates the gas distribution system, has an obligation to provide safe and reliable service to customers in compliance with applicable state and federal pipeline safety statutes and regulations. However, the challenge of meeting this obligation is amplified on the portions of the distribution system containing leak-prone pipe, which consists of unprotected steel, cast iron and wrought iron, and vintage Aldyl-A and Polybutylene plastic pipe.

In accordance with the Revenue Decoupling Law, the Company filed its first Gas ISR plan on December 20, 2010 for FY 2012. The ISR program replaced the Accelerated Replacement Program (ARP), which began as part of the Company's 2008 rate case in

Docket No. 3943. The ARP targeted the replacement of cast iron and non-cathodically protected steel mains and non-cathodically protected steel inside services. The ISR program expanded on the ARP through inclusion of other capital programs related to safety and reliability for public works, mandated programs, and reliability. From FY 2012 to FY 2019, the Company has invested a total of $661 million through the Gas ISR program. This includes a total of $416 million that targeted the replacement of leak-prone pipe through the Company's Proactive Main Replacement and Public Works programs. When the ISR program was first implemented, approximately 48 percent of the Company's gas distribution system in Rhode Island was comprised of leak-prone pipe. The table below highlights a total of 445 miles of leak-prone pipe abandoned through the FY 2019 ISR Plan that has contributed to an estimated reduction of 1,235 leaks.

Description	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	Total
Total ISR Abandonment Miles	46	47	53	55	59	63	62	60	445
Gas Leaks Eliminated	191	186	140	121	150	109	178	160	1,235

To monitor its system performance, the Company prepares an annual System Integrity Report. A copy of the most recent System Integrity Report (2018) is provided as Schedule 1 at the end of the Plan. The System Integrity Report provides historical data on leak receipts, leak repairs, open leaks, and inventory of mains and services. Additional data is provided around material type for each of the listed categories. The Company considers leak receipts to be an important system performance indicator regarding the effectiveness of its leak-prone pipe abandonment program. Since 2008, the Company has seen an overall downward trend on leak receipts, which would indicate that the ISR and ARP programs have contributed to this result.

Notably, variability in year-to-year annual leaks per mile will occur. Contributing factors include weather, public awareness, and overall system deterioration rates.

Section 2: Gas Capital Investment Plan

The Company's proposed gas capital investment plan set forth in Section 2 summarizes the Company's planned capital investments in terms of the following key Discretionary[5] and Non-Discretionary[6] categories, Incremental Costs, and Operation and Maintenance Expenses:

Non-Discretionary:

A. Public Works
B. Mandated Programs
C. Damage/Failure

Discretionary:

A. Proactive Main Replacement
B. Proactive Service Replacement
C. Heat Decarbonization
D. Gas System Reliability
E. Southern RI Gas Expansion

Incremental Costs:

A. Professional Engineering Stamps
B. Curb to Curb Paving - all ISR Work (excluding Southern RI Gas Expansion)
C. Curb to Curb Paving - Southern RI Gas Expansion

Operation and Maintenance Expenses:

A. Heat Decarbonization

[5] Discretionary programs are not required by legal, regulatory code, or agreement, or a result of damage or failure, with limited exceptions.

[6] Non-Discretionary programs include projects that are required by legal, regulatory code, and/or agreement, or which are the result of damage or failure, with limited exceptions.

Section 2 itemizes the proposed activities by sub-categories and provides budgets for each sub-category. The Company has included its capital budget, identified the relevant projects that would be part of the Gas ISR Plan, and provided its rationale for the need for and benefit of performing such work to provide safe and reliable service to its customers. The Company has also provided a five-year capital plan to provide a longer-term approach to infrastructure, safety, and reliability and to demonstrate how the FY 2021 Plan would be incorporated into that longer-term planning approach.

The Company's FY 2021 Plan includes the elimination or rehabilitation of a total of approximately 63 miles of leak-prone pipe (approximately 48 miles of proactive main replacement, 1 mile of rehabilitation work, 13 miles of public works replacement, and 1 mile of reinforcement work). This resulting abandonment target of approximately 62 miles for FY 2021 is an increase of 1 mile compared to the FY 2020 ISR Plan and keeps pace with the 20-year Proactive Main Replacement program. The Company has increased the Proactive Main Replacement program cast iron abandonment percentage from 60 percent to 61 percent. Cast iron represents 63 percent of the Company's total leak-prone pipe inventory.

The FY 2021 Gas ISR Plan also includes a category for Gas Expansion, namely, to reinforce the distribution mains in Southern Rhode Island (the Southern RI Gas Expansion Project). As noted in the FY 2020 Gas ISR Plan, the Southern RI Gas Expansion Project presents unique challenges for the Company with managing the Plan due to its size, cost, and complexity. As part of the execution of the Southern RI Gas Expansion Project, the forecasted spend in FY 2021, and in future fiscal years, may change as risks occur and/or cost savings are achieved. If the Southern Rhode Island Project is managed with the overall Discretionary portfolio, any changes may result in the need to advance or delay several projects, especially if the variance is significant. Instead, the Company will continue to manage the Southern RI Gas Expansion Project as a distinct portfolio of spend and not advance or delay other projects if over- or under-spend occurs on the Southern RI Gas Expansion Project.

Section 3: Revenue Requirement

The Company has provided a calculation of the cumulative revenue requirement resulting from the proposed FY 2021 capital investment plan. Section 3 of the Plan contains a description of the revenue requirement model for FY 2021 and an illustrative calculation for FY 2022. This calculation would form the basis for the Plan rate adjustment, which would become effective April 1, 2020 upon PUC approval. As provided in Section 3 of the Plan, in accordance with the Company's gas tariff, RIPUC NG-GAS No. 101, Section 3, Schedule A, Item No. 3.3, the Company will reconcile this rate adjustment as part of its annual Distribution Adjustment Charge filing. The pre-tax rate of return on rate base is the rate of return approved by the PUC in the Amended Settlement Agreement in the Company's most recent general rate case, Docket No. 4770. In the future, the pre-tax rate of return would change to reflect changes to the rate of return approved by the PUC in future rate case proceedings. Any change in the rate of return would be applicable on a prospective basis, effective at the time of the change.

Section 4: Rate Design

For purposes of rate design, the revenue requirement associated with the capital investment is allocated to rate classes based upon the most recent rate base allocator approved in the Amended Settlement Agreement in Docket No. 4770. For each rate class, the allocated revenue requirement is divided by the applicable fiscal year forecasted therm deliveries to arrive at a per-therm factor unique to each rate class.

The estimated typical bill impacts associated with the rate design and bill impacts are provided in Section 4. Including the $1.52 million cost associated with PE Stamps, and the incremental $13.01 million cost associated with the new RI curb to curb paving law, the bill impact of the Gas ISR Plan for the average Residential Heating customer for the period April 1, 2020 through March 31, 2021 would be an annual increase of $44.08, or 3.7 percent, from last year's bills. Excluding the incremental $13.01 million for paving costs, the bill impact would be an annual increase of $41.46, or 3.4%, from last year's bills.

Attachment 1

The 2018 System Integrity Report is included as an attachment to this report.

Please see Attachment 1

2018 SYSTEM INTEGRITY REPORT

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Enterprise
Gas Distribution Systems
Trend-Based Integrity Analysis

RI

Gas Distribution Engineering
Gas Asset Management– Gas Process & Engineering

Saadat Khan (631) 710-3510 Director – Gas Distribution Engineering
Leomary Bader (781) 907-2785 Manager – Gas Distribution Engineering
Aamir Khizar (631) 770-3511 Senior Engineer – Gas Distribution Engineering
Yan Wang-jiang (781) 907-2241 Engineer – Gas Distribution Engineering
Kevin Lim (315) 428-6399 Engineer – Gas Distribution Engineering
Jim MacMartin (315) 428-5054 Engineer – Gas Distribution Engineering
Kevin Peters (631) 770-3438 Engineer – Gas Distribution Engineering
Prathiba Seetharam (516) 448-8673 Engineer – Gas Distribution Engineering
Madeline Blaisdell (781) 907-4164 Assoc. Engineer – Gas Distribution Engineering

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2018 SYSTEM INTEGRITY REPORT

Overall Regional Gas Distribution Integrity Assessment Summary

2018 SYSTEM INTEGRITY REPORT

Overall Regional Distribution Integrity Assessment Summary

Distribution Engineering has reviewed all of the findings in the annual Trend-Based Distribution System Integrity Analysis (*System Integrity Report*) in accordance with our Distribution Integrity Management Plan (DIMP), and finds that leak receipts have decreased slightly for MA. NYS and RI have experienced only slight increases in the amount of leak receipts despite an elevated number of Heating Degree Days which is a testament to the effectiveness of the accelerated LPP replacement program in identifying the correct LLP for replacement. There are no immediate causes for concern that would warrant changes to DIMP. Any anomalies found were either explained as non-systemic or set up for continued research and/or monitoring. These will be explained in notes to this report. CI main break rates have increased in every region which has been attributed to a combination of an elevated number of Heating Degree Days as well as milder average temperatures which resulted in a higher number of freeze-thaw cycles.

Below is a summary of the individual key integrity measure results for Rhode Island.

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2018 System Integrity Report Summary

REGIONS / ITEMS	RI
• Leak Receipts	Slight Increase
• Workable Leak Backlog	Increase
• LPP Main and Service Inventories	Decrease
• Overall Main Leak Rate	Slight Increase
• Cast Iron Main Break Rate	Increase
• Steel Main Corrosion Leak Rate	No Change
• Service Leak Rate	Decrease

Increase Slight Increase No Change Decrease

2018 SYSTEM INTEGRITY REPORT

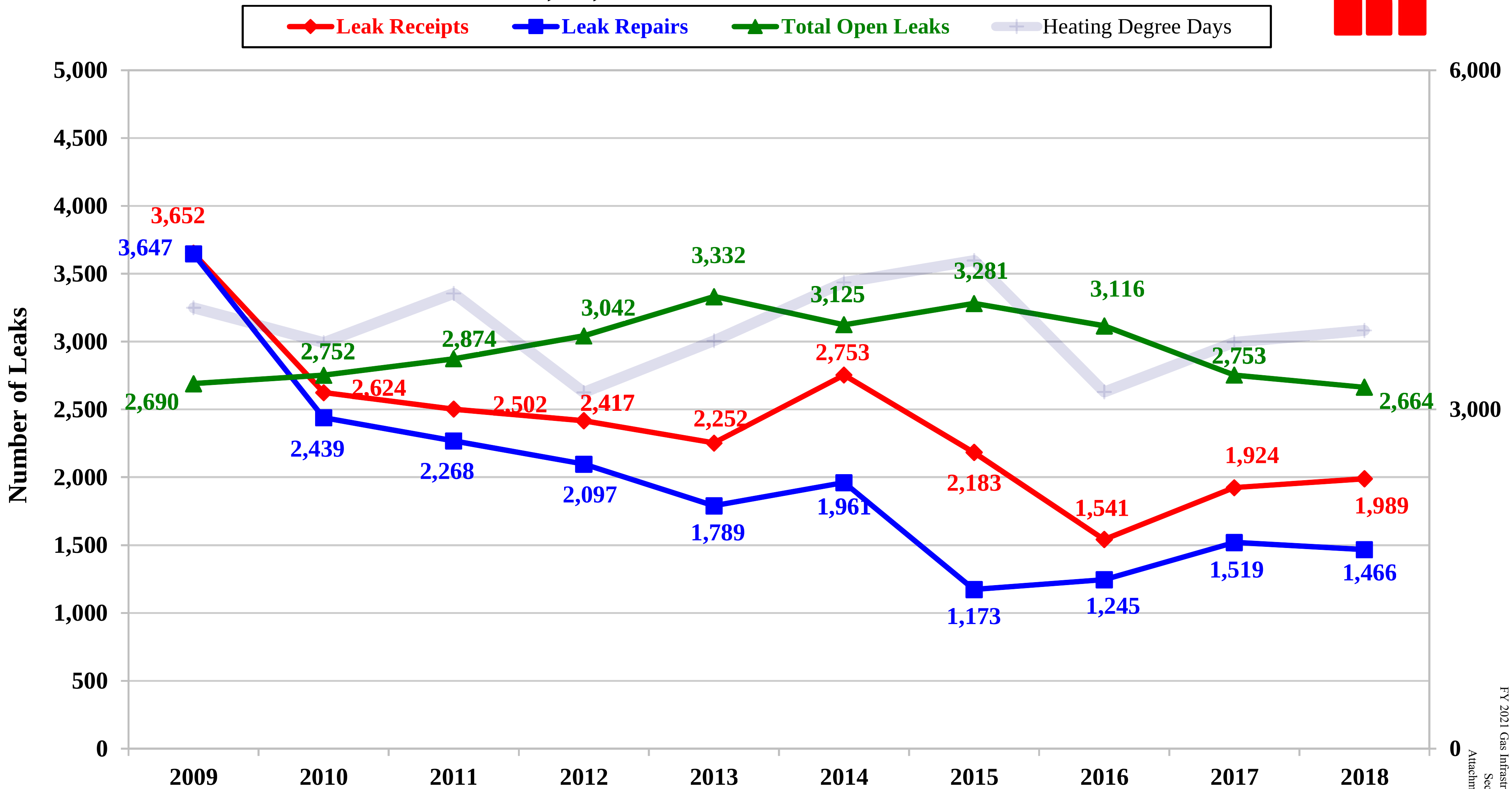
LEAK RECEIPTS, REPAIRS AND BACKLOG BY HDD TREND (Main & Service)

NOTE: Heating Degree Day (HDD)

2018 SYSTEM INTEGRITY REPORT

TOTAL LEAK RECEIPTS, REPAIRS & BACKLOG RI

INCLUDES ALL TYPE 1, 2A, 2 and 3 LEAKS DISCOVERED - EXCLUDING DAMAGES



Leak Receipts and Repairs and Backlog:

2018 RI Leak Repairs = 2018 RI Leak Receipts = 2018 RI Leak Backlogs =

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2018 SYSTEM INTEGRITY REPORT

Overall Regional Distribution Integrity Assessment Summary

Rhode Island (RI)

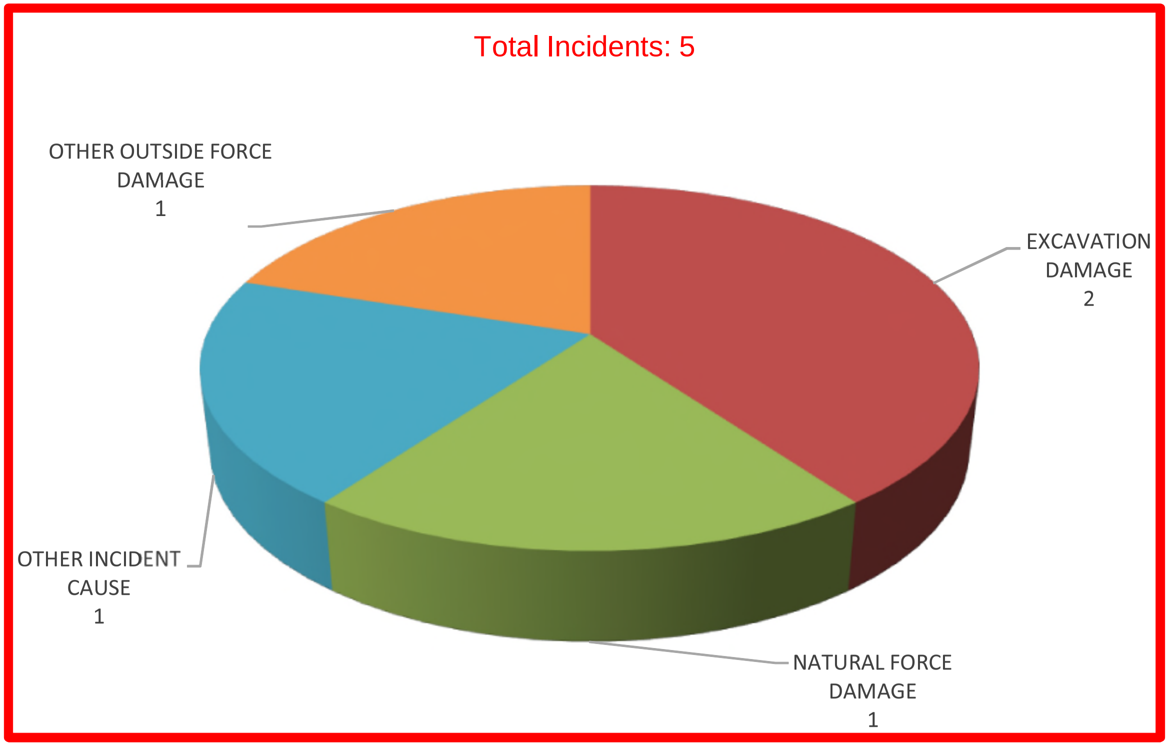
- Leak receipts increased.
- Workable leak backlog decreased.
- Leak prone main and service inventories continue to decline steadily.
- Overall main leak rate increased. Steel main corrosion rate decreased and Cast Iron main break rate increased.
- Service leak rate decreased.

PHMSA Reported Incidents

2018 SYSTEM INTEGRITY REPORT

RI

PHMSA Reported Incidents



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2018 SYSTEM INTEGRITY REPORT

LEAK MANAGEMENT ANALYSIS

(Mains & Services)

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2018 SYSTEM INTEGRITY REPORT

2018 LEAK RECEIPTS

RI

1,989 Leak Receipts

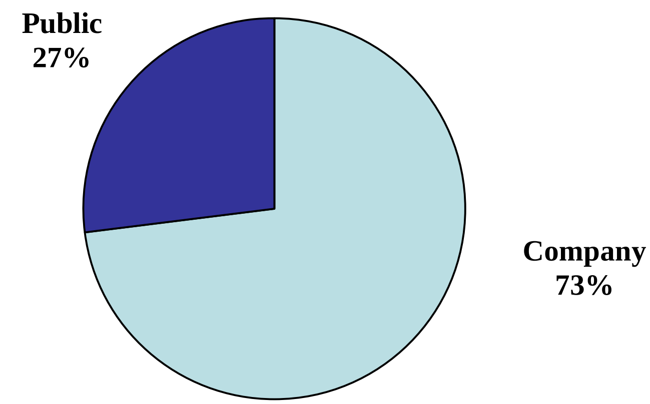
3,201 miles of Main
197,147 #'s of Services
(2,483 miles)

5,684 total miles of pipe

0.35 Leak Receipts per Mile of Pipe

2018 LEAK RECEIPTS BY DISCOVERY SOURCE

RI



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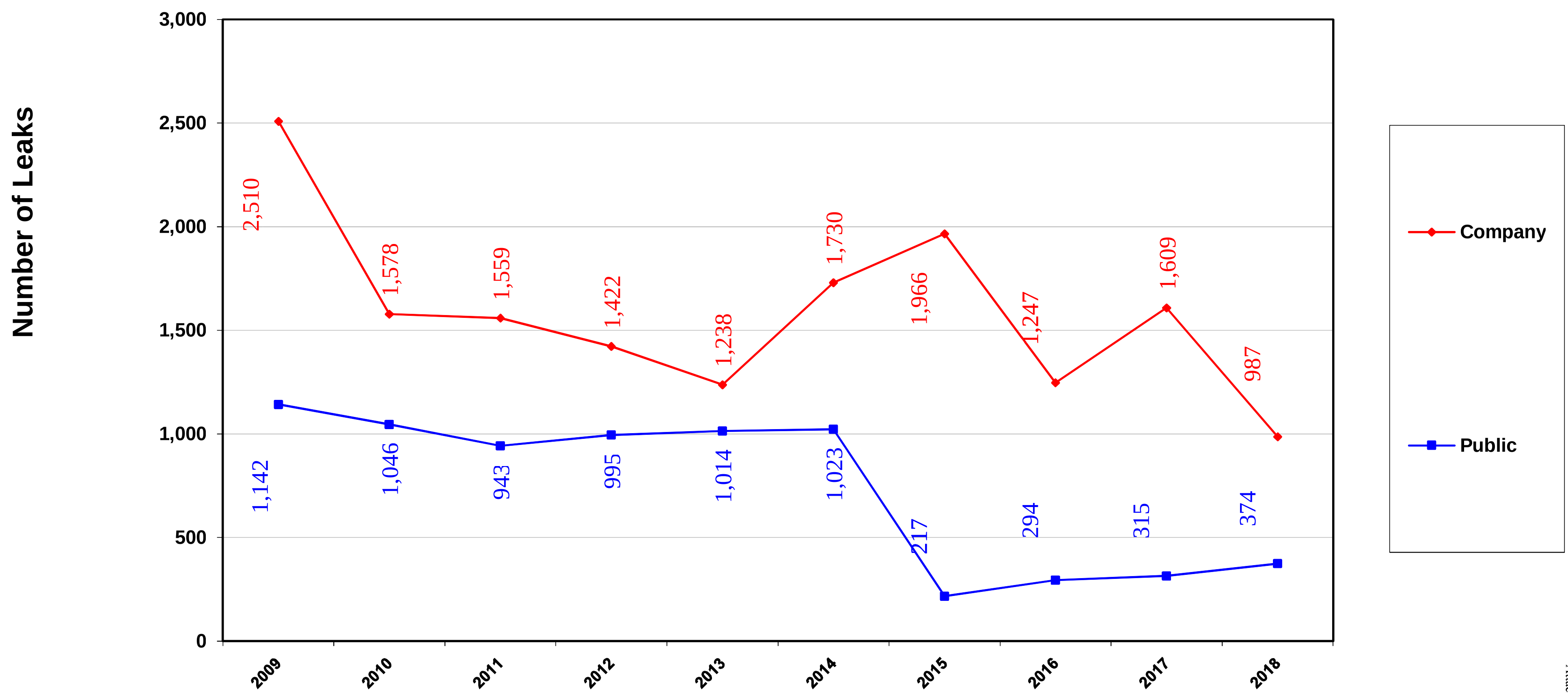
2018 SYSTEM INTEGRITY REPORT

RI

2009 - 2018 LEAK RECEIPTS

By Discovery Source (Excluding Damages)

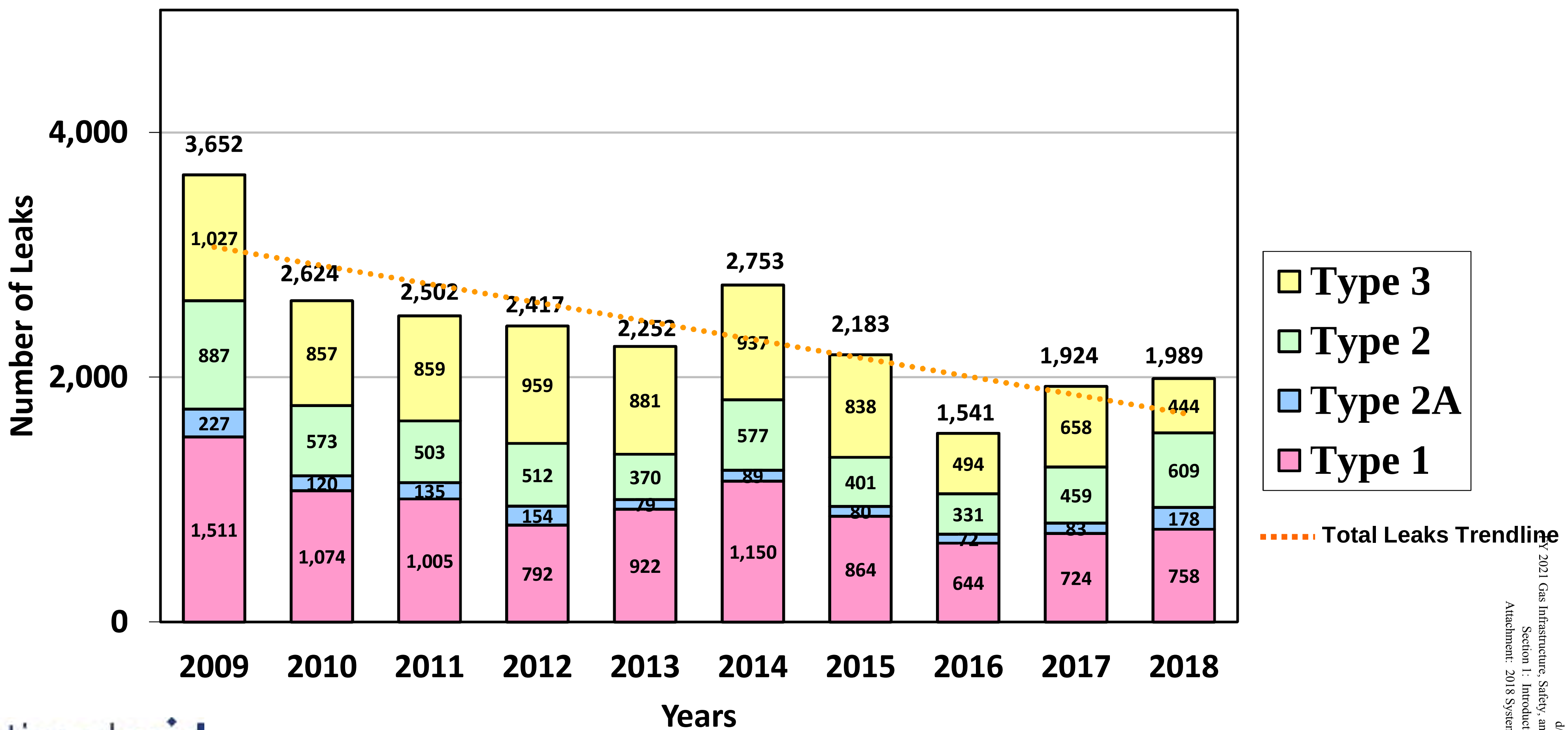


2018 SYSTEM INTEGRITY REPORT

RI

LEAK RECEIPTS
By ORIGINAL Type

(Excluding Damages)



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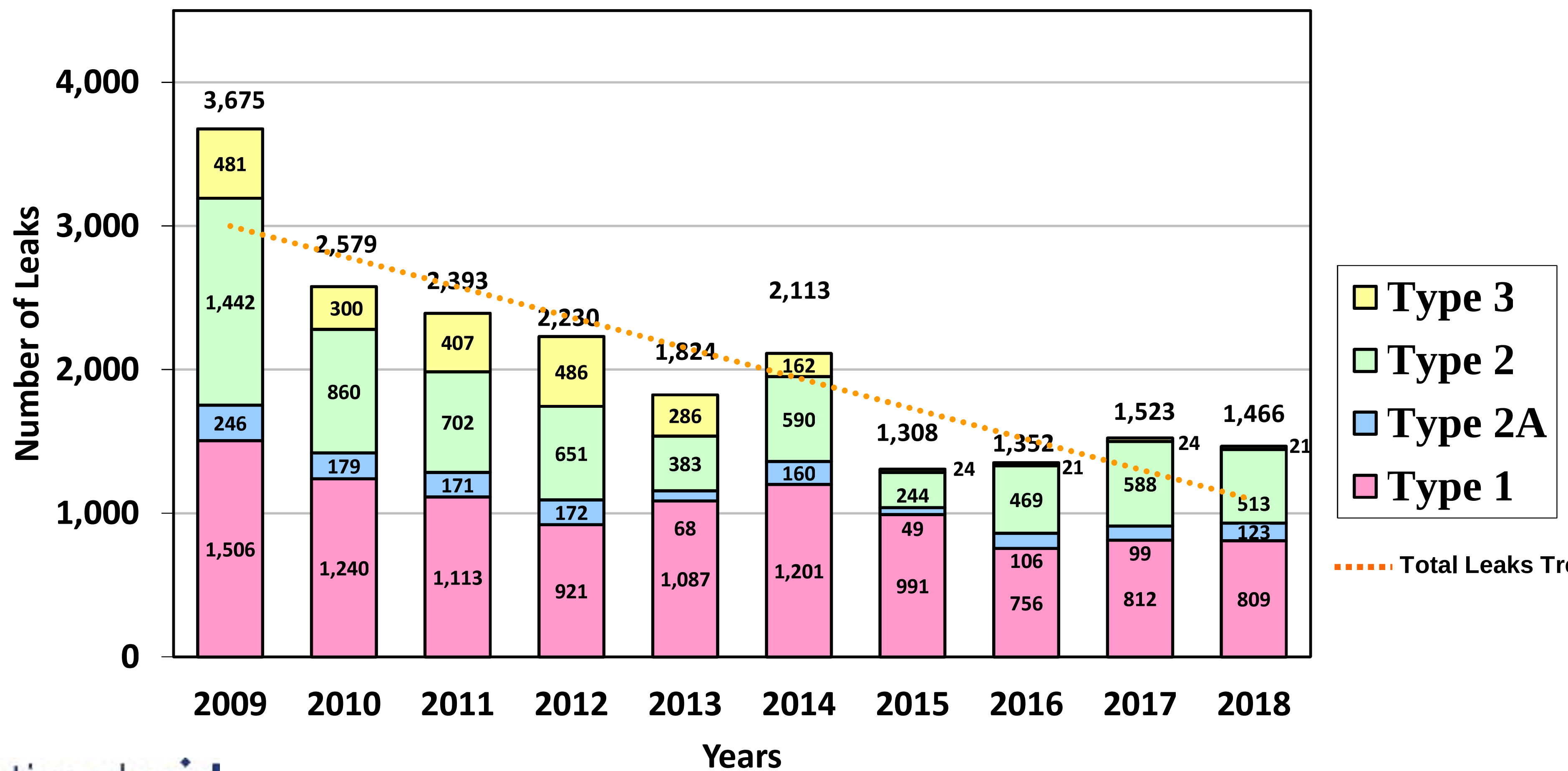
2018 SYSTEM INTEGRITY REPORT

RI

LEAKS REPAIRED
By REPAIRED Type

(Including Damages)



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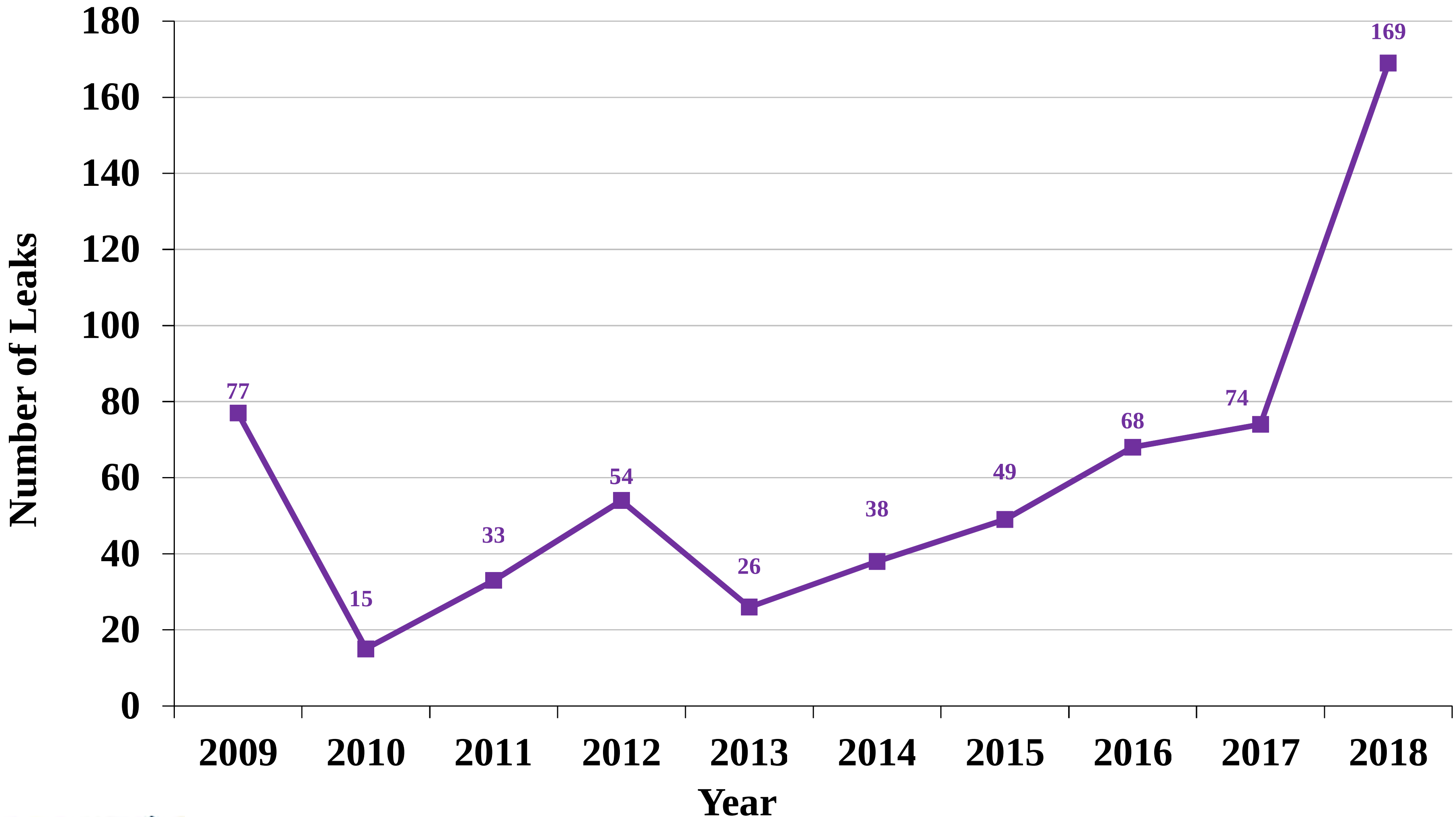
2018 SYSTEM INTEGRITY REPORT

RI

YEAR-END WORKABLE LEAK BACKLOGS

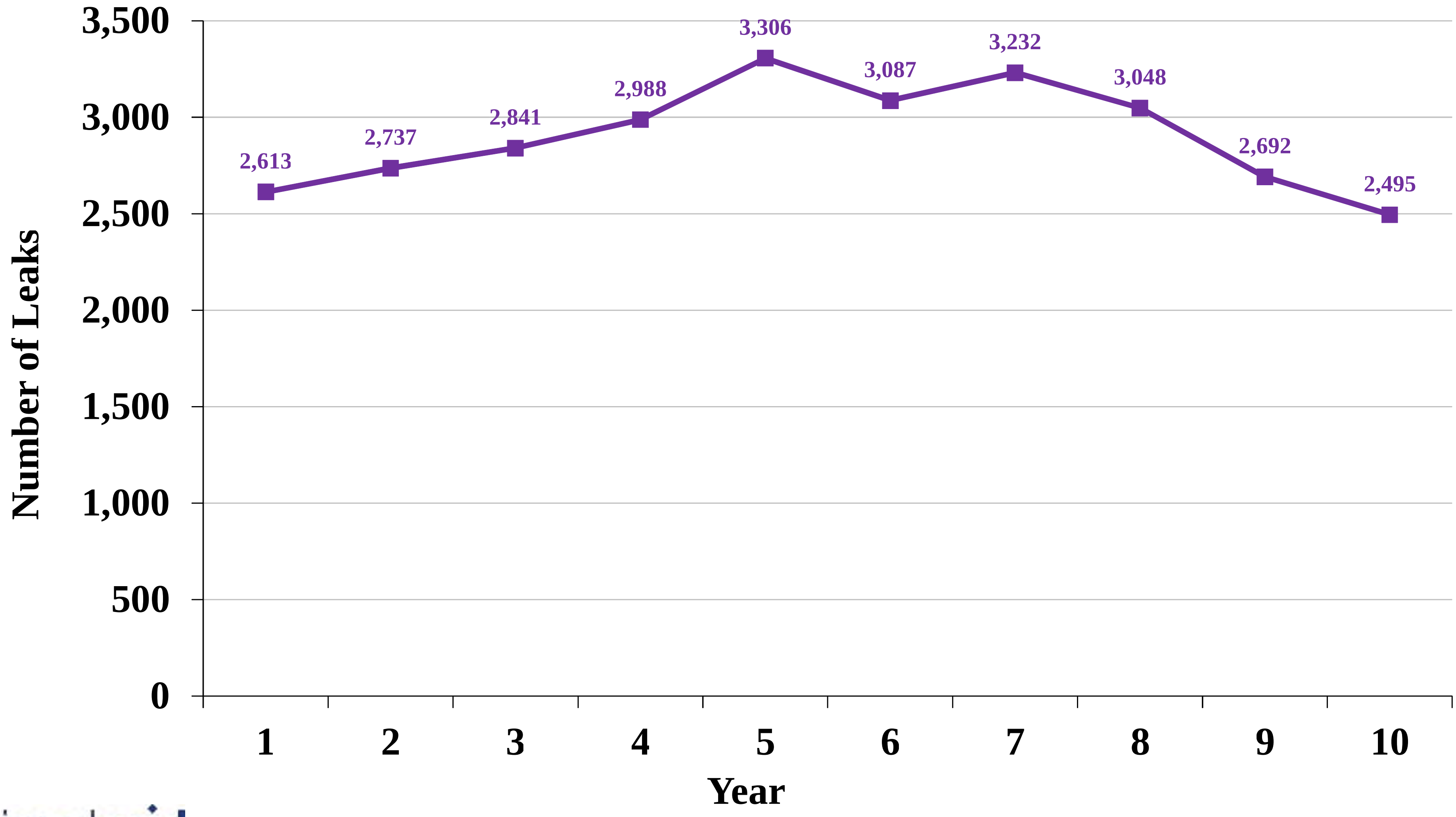


Note: 2018 experienced an increase in the backlog due to implementation of the Work Continuation Plan.

2018 SYSTEM INTEGRITY REPORT

RI

YEAR-END OPEN TYPE 3



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2018 SYSTEM INTEGRITY REPORT

MAIN INVENTORY ANALYSIS

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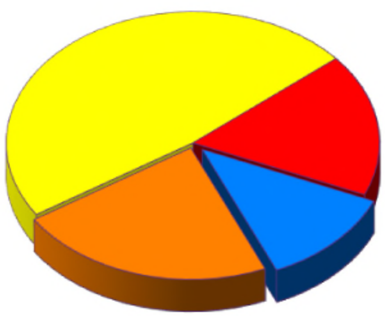
2018 SYSTEM INTEGRITY REPORT

MAIN INVENTORY

Rhode Island

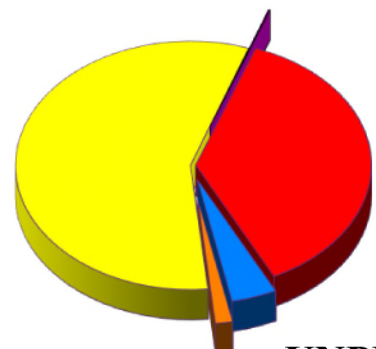
3,201 MILES



2018 PHMSA Average

124 Companies with 2,000+ miles

8,600 MILES



2018 SYSTEM INTEGRITY REPORT

NATIONAL GRID MAIN REPLACEMENT

Rate Case Supported "Leak-Prone" Main Replacement Levels

Region	2018 Total Main (Miles)	2018 Leak Prone Main (Miles)	Leaks/Miles of Total Main (Repair rate)	Leaks/Miles of Leak Prone Main (Repair rate)	(5)2018 Annual "Planned" Replacement (Miles)	Planned Replacement % of Leak prone system	(5)2018 Annual "Actual" Replacement (Miles)	Actual Replacement % of Leak prone system	(5)2019 Annual "Planned" Replacement (Miles)	Years to LPP Main Elimination based on "Current" annual plan
RI	3,187	1,086	0.32	0.81	60.0	5.5%	67.5	6.2%	55.0	15

Note:
1. Leaks per mile of total main excludes Excavation leaks.
2. Leaks per mile of Leak-Prone main (LPP) excludes Excavation leaks and Plastic leaks.
3. Leak-Prone Pipe = Unprotected steel (Bare & Coated) + CI/WI + Aldyl-A (MD, 1985 and prior) + Other.
4. Miles of Leak-Prone main replaced includes all Proactive programs (Main Replacement program & System Reinforcement) and all Reactive programs (Public Works, Water Intrusion & Leak/reactive).
5. Annual planned and actual replacement miles are CY.
6. Data sources are 2016, 2017, 2018 US Gas Leak Prone Pipe Replacement Programs monthly reports from Gas Resource Management CMS.

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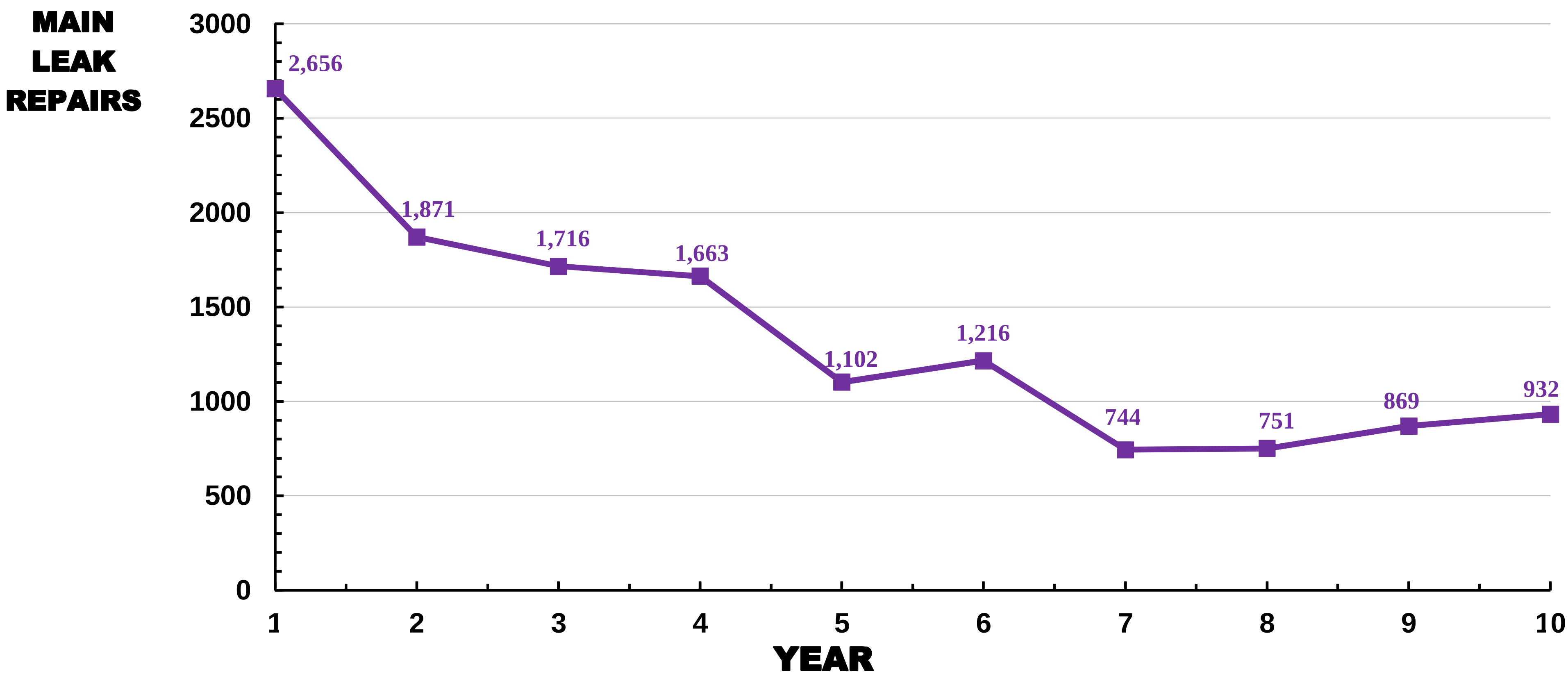
MAIN LEAK REPAIR ANALYSIS

2018 SYSTEM INTEGRITY REPORT

TOTAL MAIN LEAK REPAIRS

INCLUDING Damages



NOTE: Cast Iron Leaks Count Total Individual Joint Repairs

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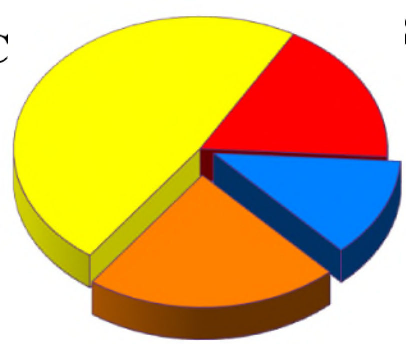
2018 SYSTEM INTEGRITY REPORT

RI

TOTAL MAIN INVENTORY COMPARED TO LEAK REPAIRS

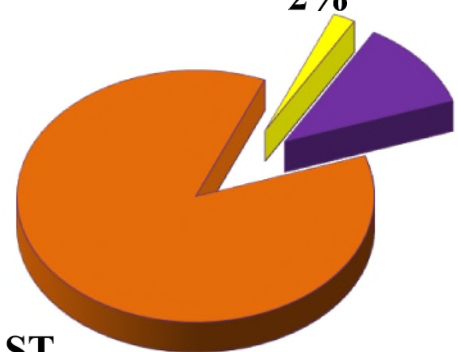
TOTAL MAIN INVENTORY BY MATERIAL

3,201 MILES



TOTAL MAIN LEAK REPAIRS BY MATERIAL

929 LEAKS (including damages)



NOTE: (*) CI Leaks include Other material Leaks.
Each Repair is Counted as an Individual Leak.

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2018 SYSTEM INTEGRITY REPORT

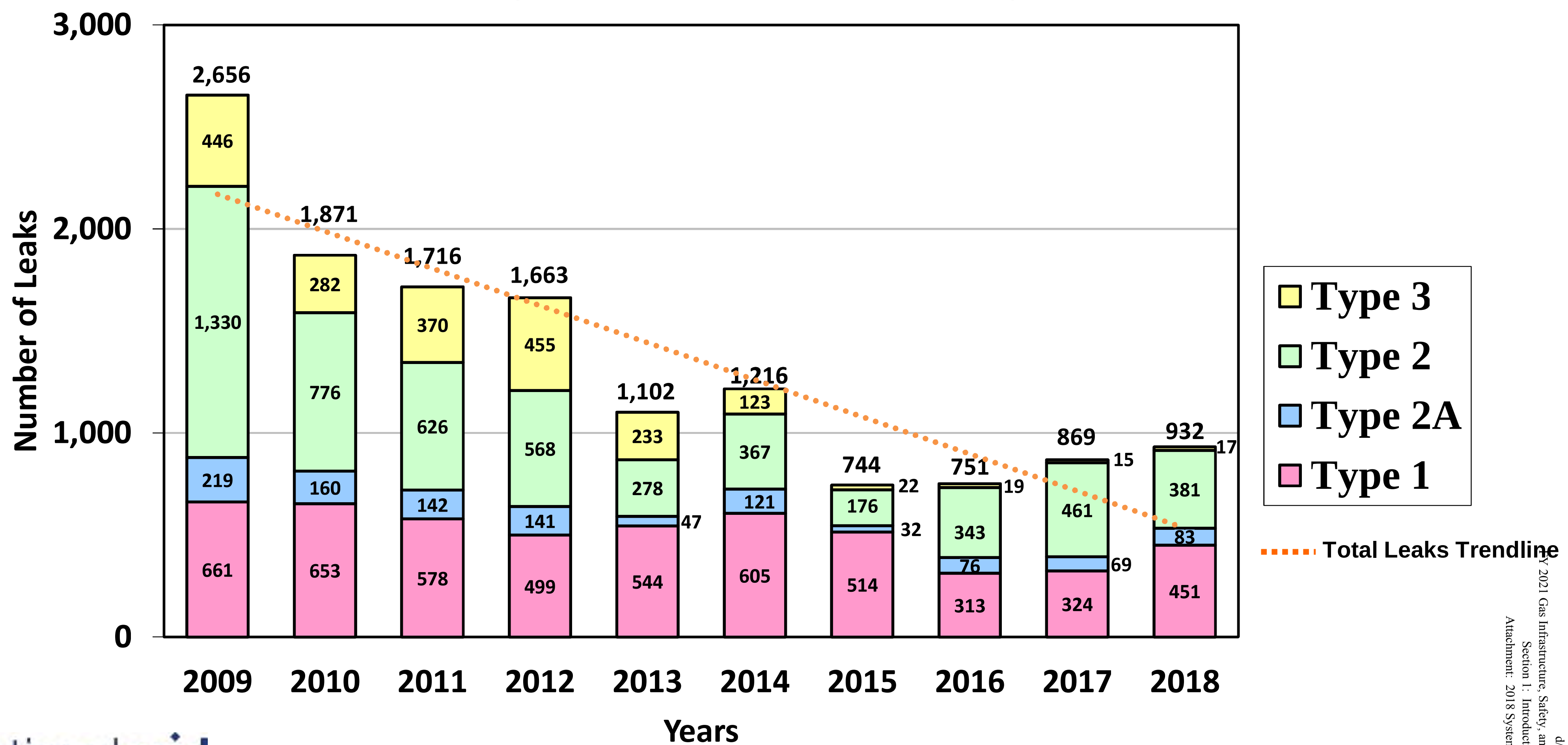
RI

LEAKS REPAIRED

By Type

MAIN

(Including Damages)



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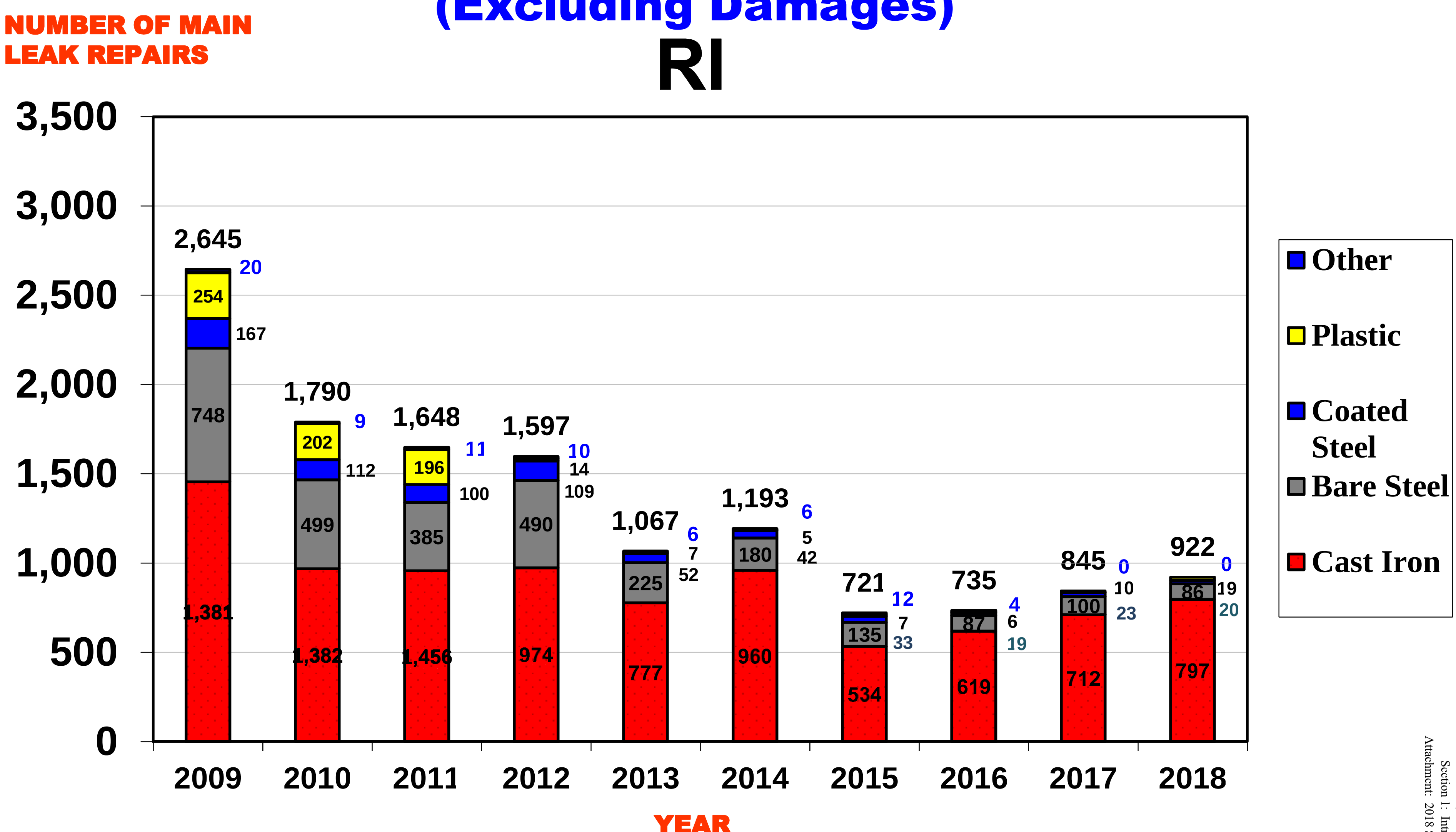
2018 SYSTEM INTEGRITY REPORT

2009 - 2018 MAIN LEAK REPAIRS

All Main Leak Repairs by Material (Excluding Damages)

RI



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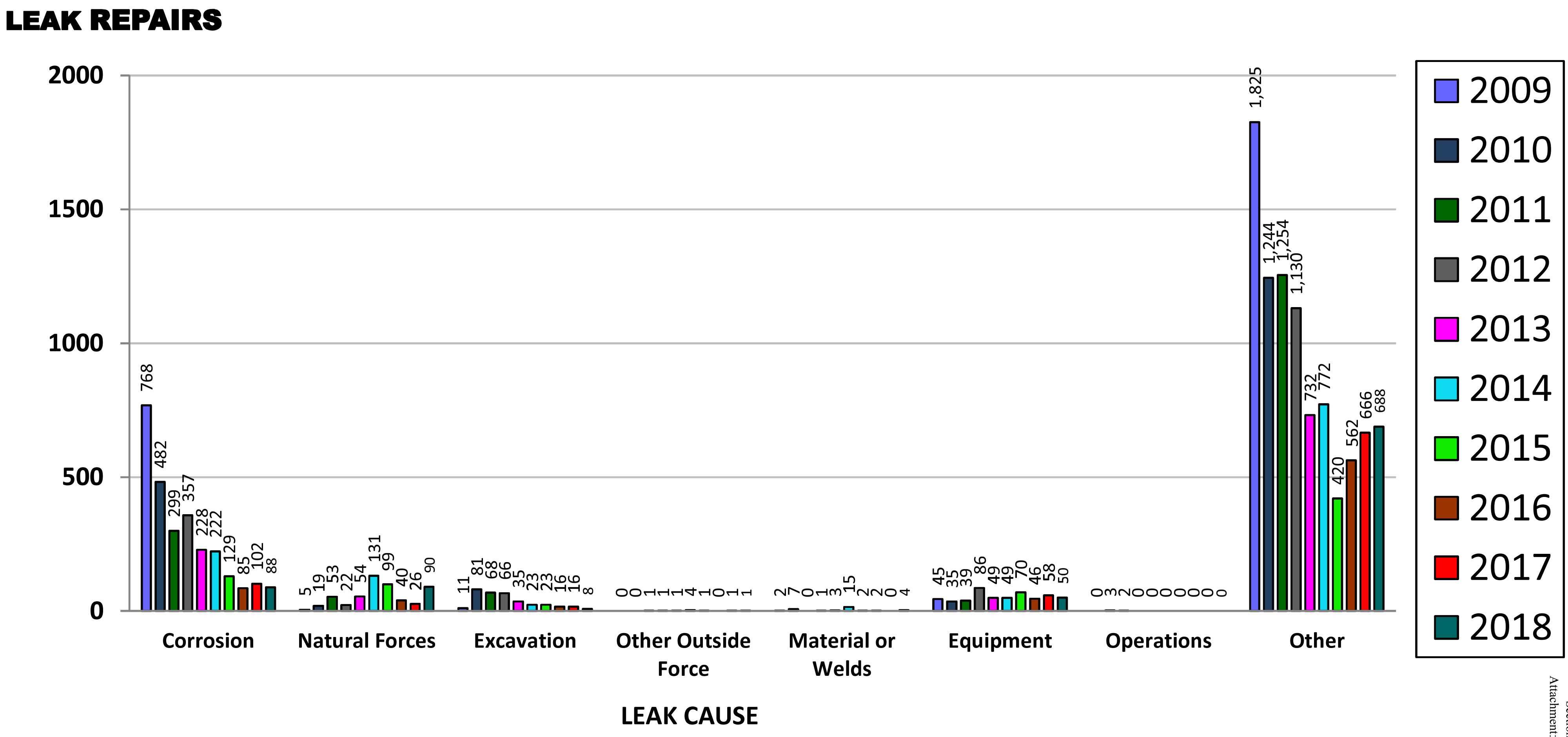
2018 SYSTEM INTEGRITY REPORT

RI

MAIN LEAKS REPAIRED

COMPARISON BY LEAK CAUSES



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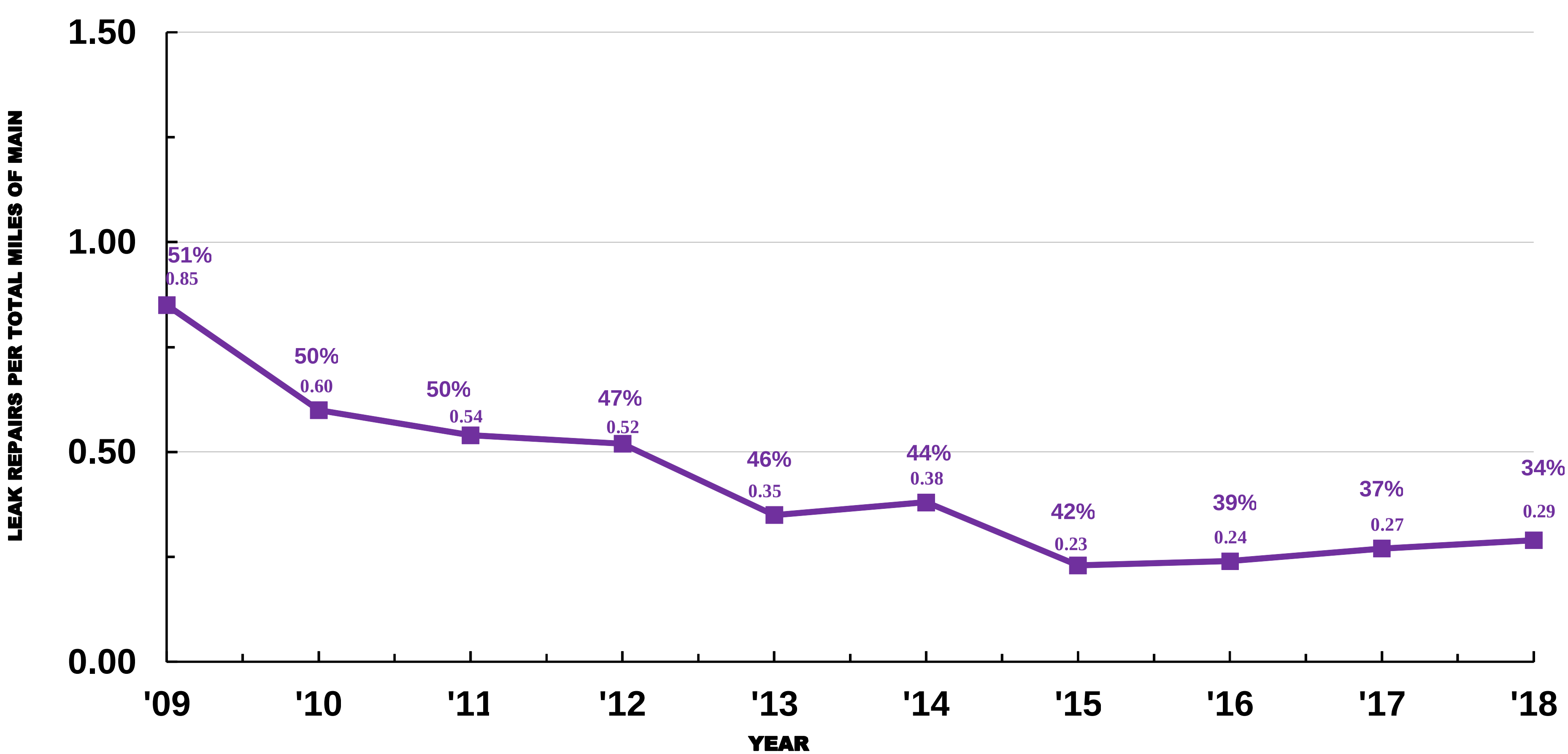
2018 SYSTEM INTEGRITY REPORT
TOTAL MAIN LEAK "RATES"

INCLUDING Damages

PERCENTAGES SHOWN ARE PERCENT OF LEAK-PRONE PIPE



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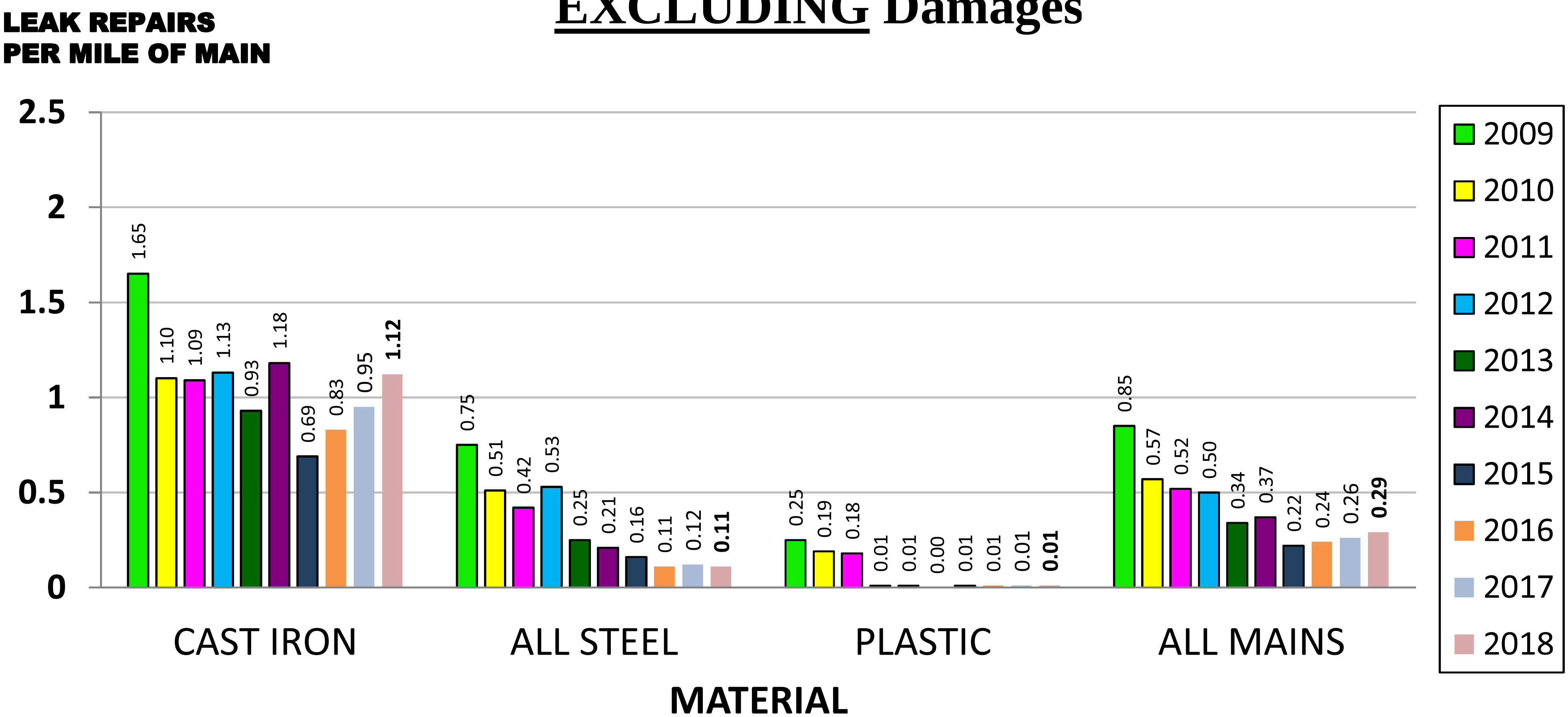
2018 SYSTEM INTEGRITY REPORT

RI

MAIN LEAK "RATES"

COMPARISON BY MATERIAL

EXCLUDING Damages

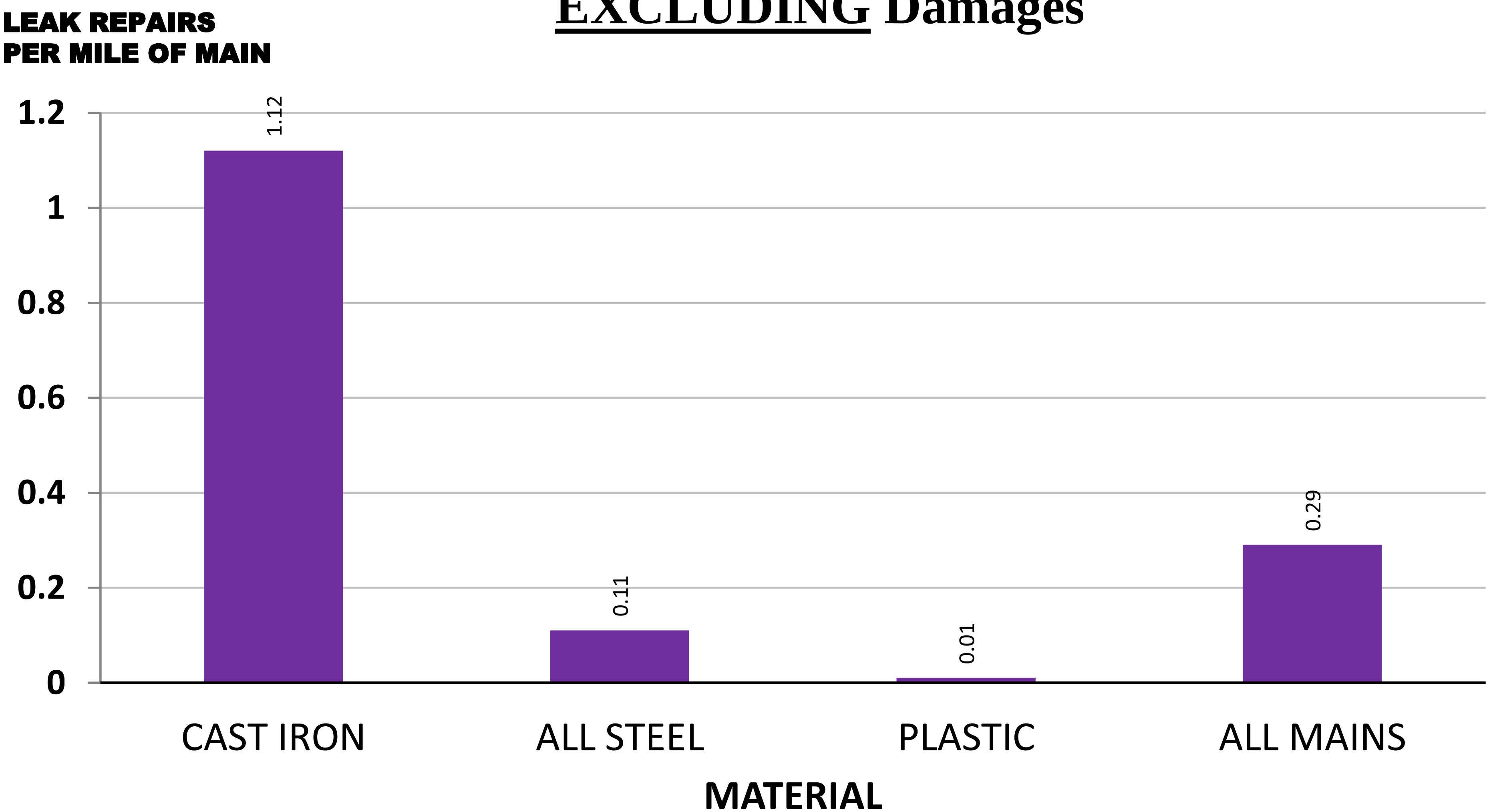


COUNTING EACH INDIVIDUAL REPAIR AS A LEAK

2018 SYSTEM INTEGRITY REPORT

RI

MAIN LEAK "RATES"
COMPARISON BY MATERIAL
EXCLUDING Damages



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2018 SYSTEM INTEGRITY REPORT

A CLOSER LOOK AT CAST IRON MAINS

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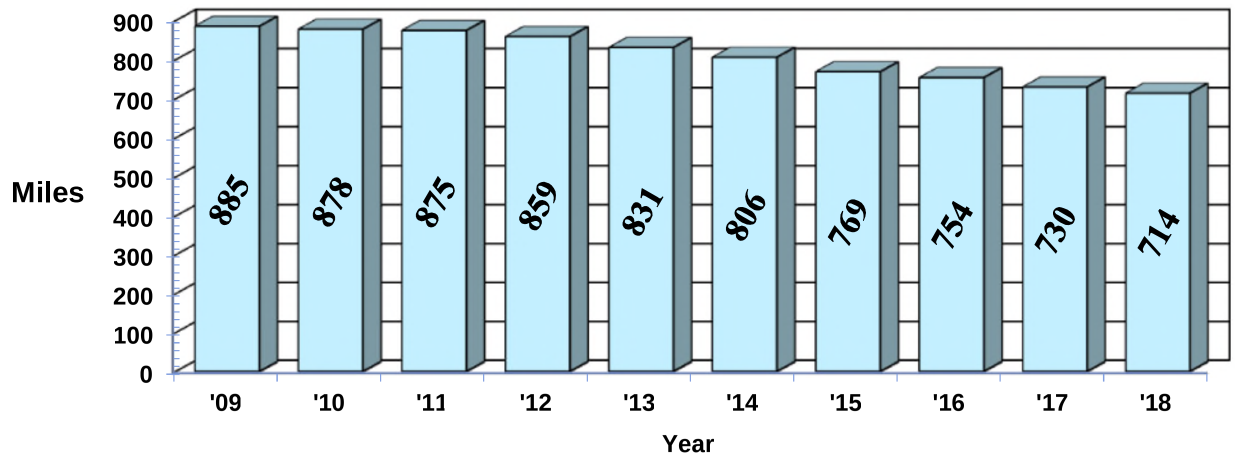
2018 SYSTEM INTEGRITY REPORT

RI

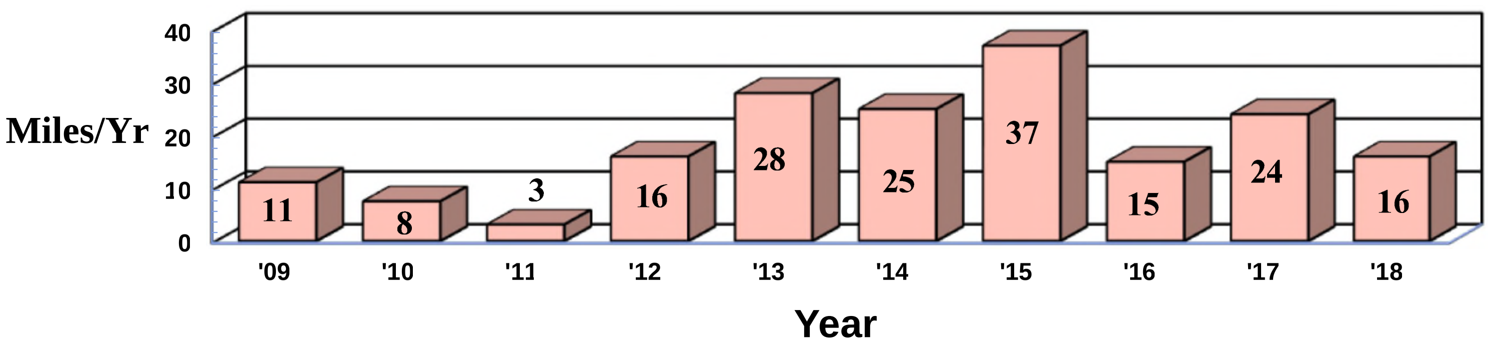
DOT-Reported Pipe Inventories

CAST IRON MAIN INVENTORY



CAST IRON ATTRITION RATE

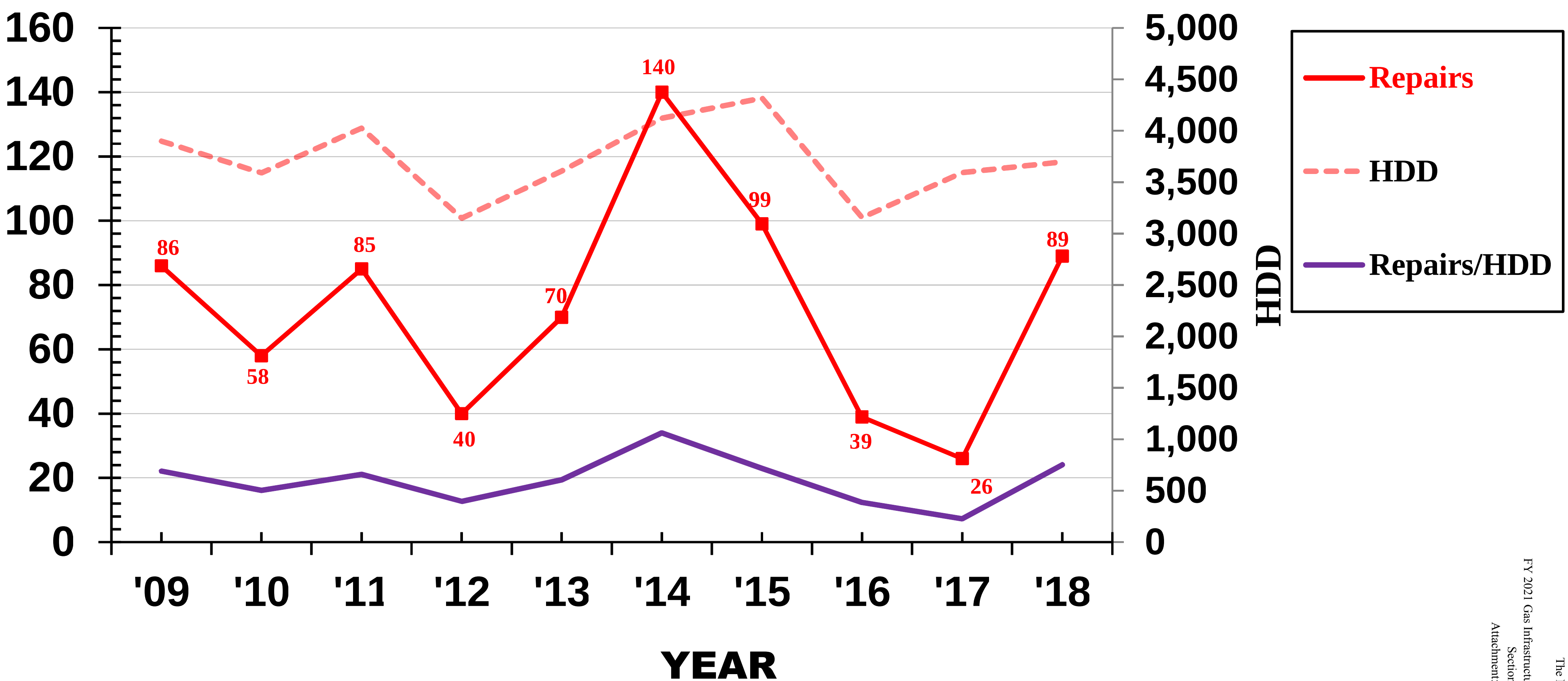
Avg 10-Yr Attrition Rate: 18.27 Miles/Year (2.56%)



2018 SYSTEM INTEGRITY REPORT

RI BREAKS

TOTAL CAST IRON MAIN BREAKS - HDD



Repairs/HDD is Multiplied by 1,000

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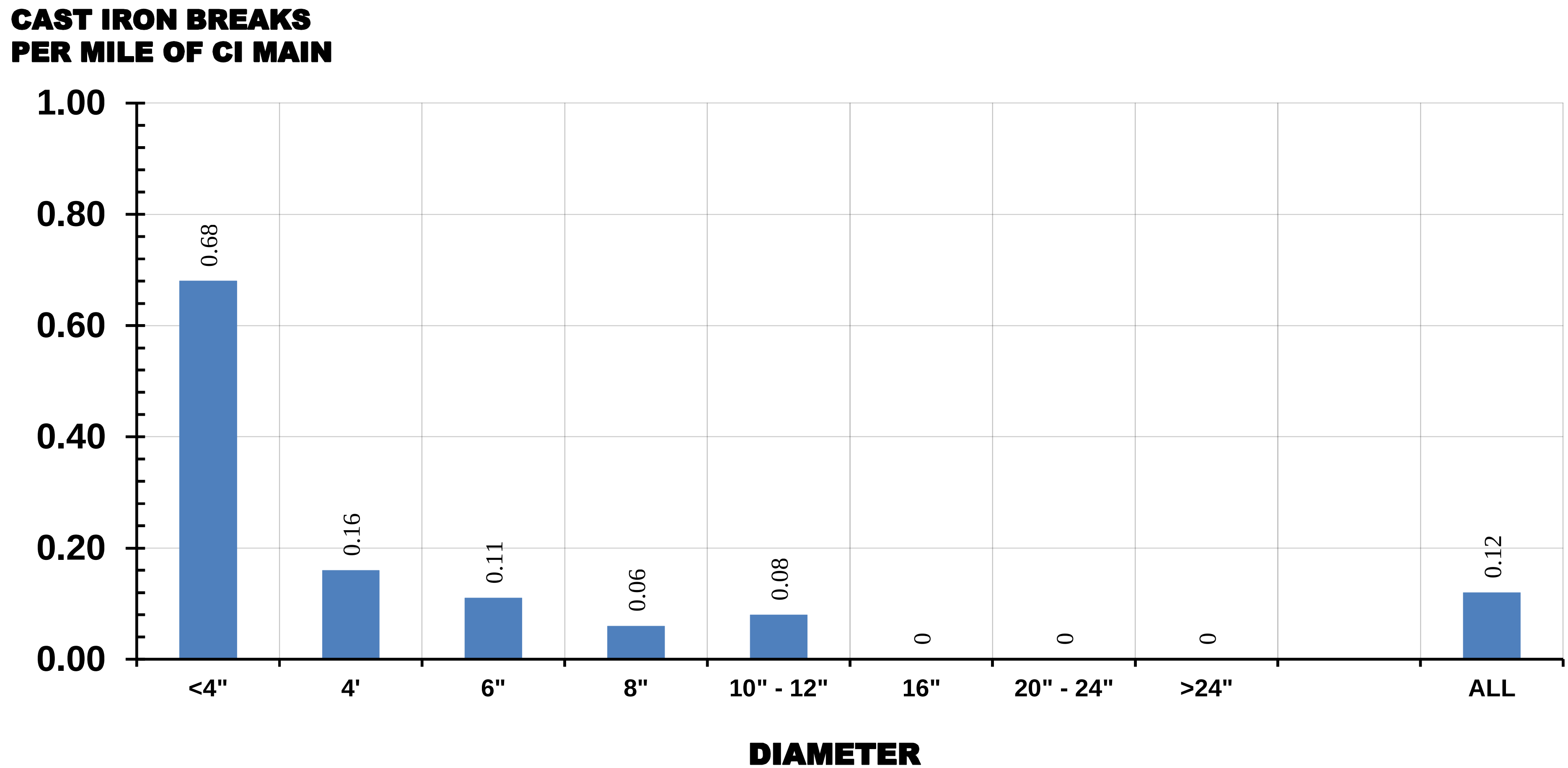
2018 SYSTEM INTEGRITY REPORT

CAST IRON MAIN BREAK "RATES"

"RI" COMPARISON BY DIAMETER



Size	CI Inventory 2017	CI Inventory 2018
< 4"	5 mi	5 mi
4"	281 mi	272 mi

Size	CI Inventory 2017	CI Inventory 2018
6"	303 mi	296 mi
8"	31 mi	31 mi

Size	CI Inventory 2017	CI Inventory 2018
10" - 12"	71 mi	71 mi
16"	17 mi	17 mi

Size	CI Inventory 2017	CI Inventory 2018
20" - 24"	13 mi	13 mi
24"	5 mi	5 mi

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2018 SYSTEM INTEGRITY REPORT

A CLOSER LOOK AT STEEL MAINS

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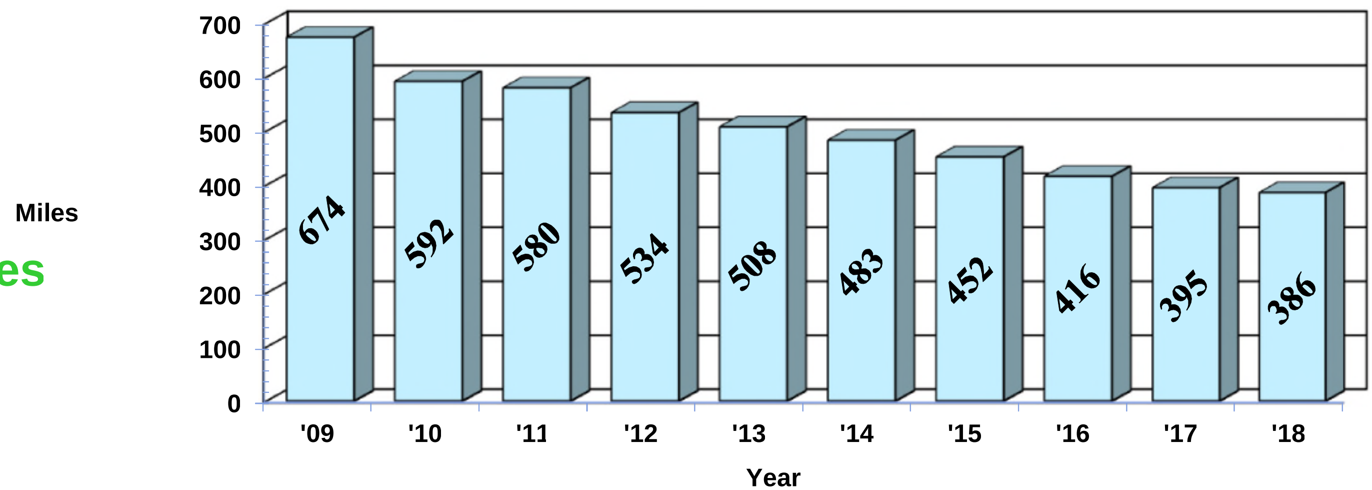
2018 SYSTEM INTEGRITY REPORT

RI

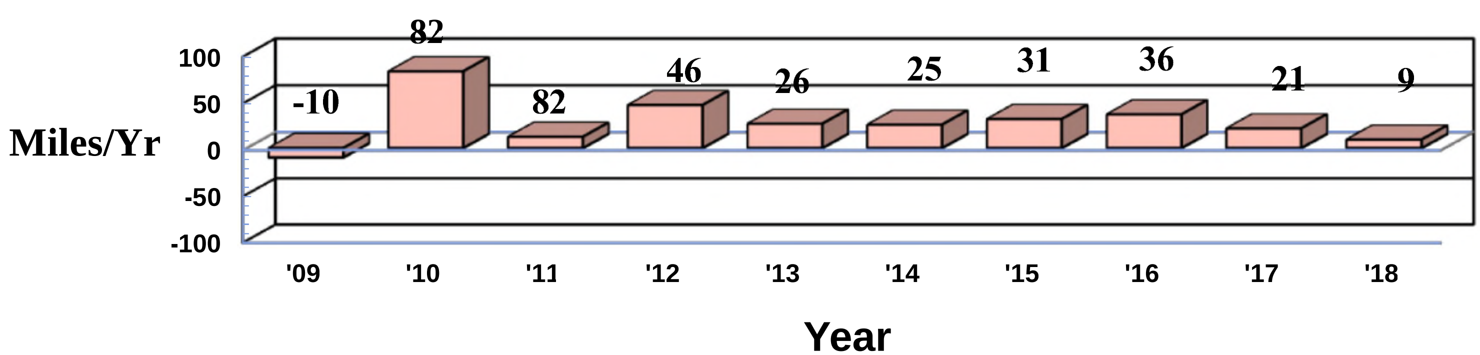
UNPROTECTED STEEL MAIN INVENTORY

DOT-Reported Pipe Inventories



UNPROTECTED STEEL ATTRITION RATE

Avg 10 -Yr Attrition Rate: 27.79 Miles/Year (7.20%)



NOTE: In RI, Attrition is due to both replacement and "added" cathodic protection.

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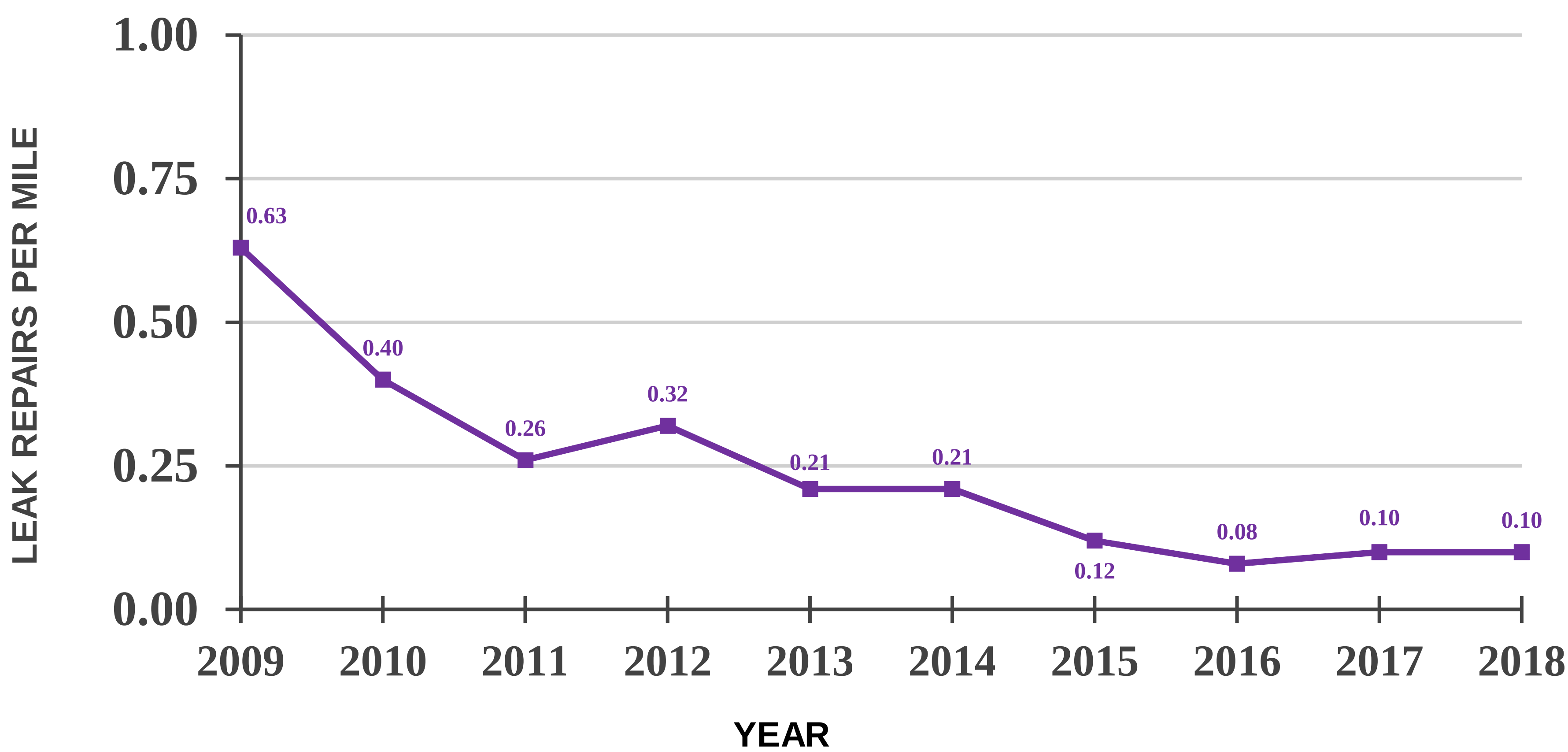
2018 SYSTEM INTEGRITY REPORT

MAIN CORROSION LEAK "RATES"

CORROSION Leak Repairs Per Mile of "TOTAL" Steel

INCLUDES **ALL** CORROSION LEAKS, REGARDLESS OF MAIN MATERIAL



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2018 SYSTEM INTEGRITY REPORT

SERVICE INVENTORY ANALYSIS

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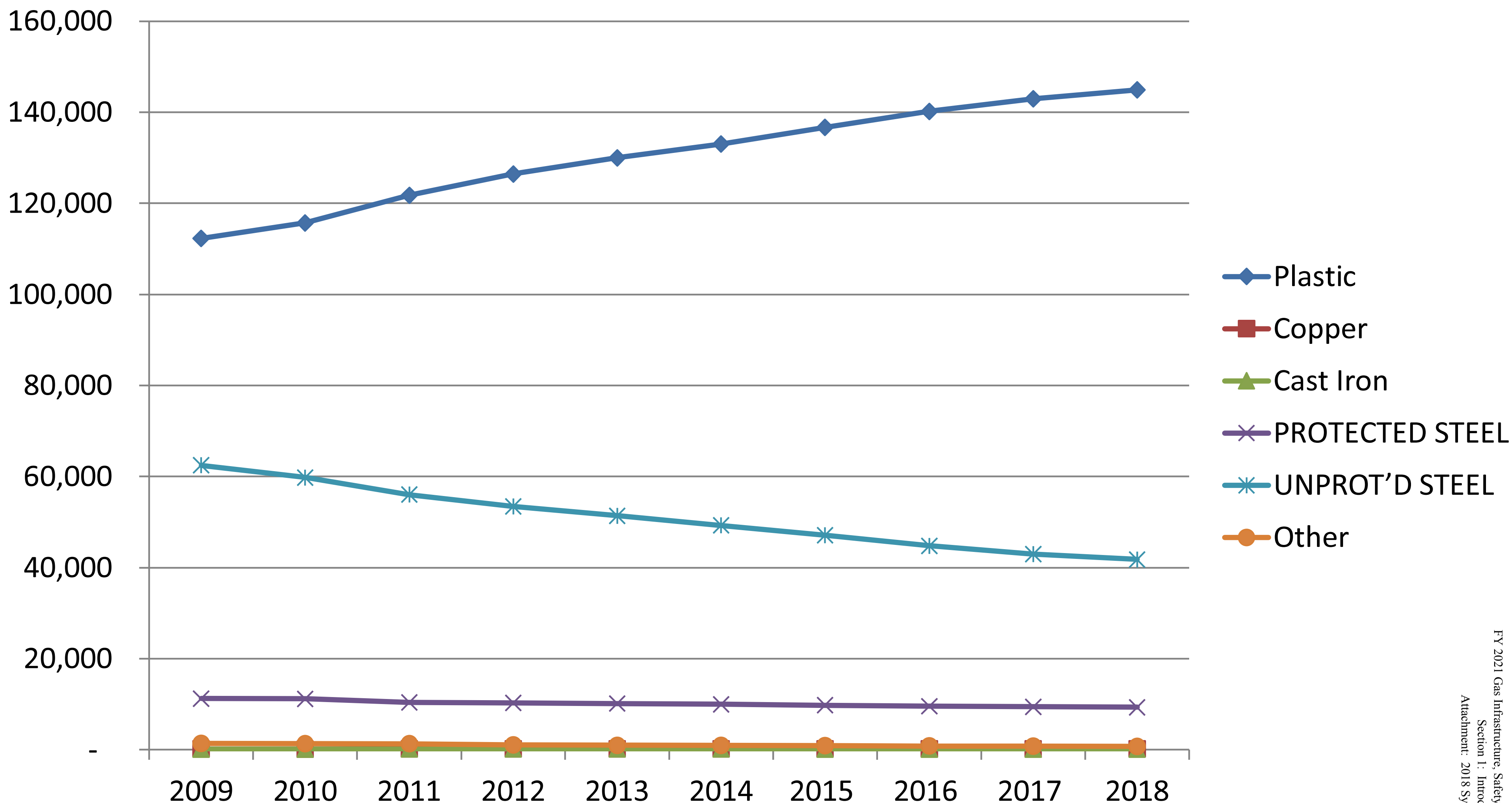
2018 SYSTEM INTEGRITY REPORT

RI

SERVICE INVENTORY TREND



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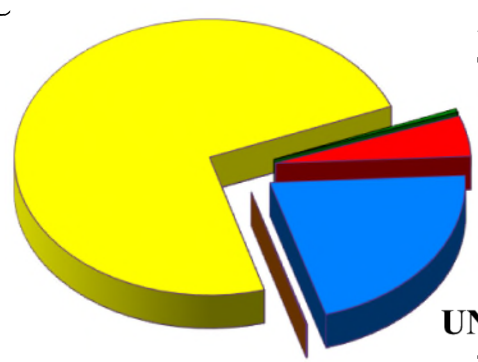
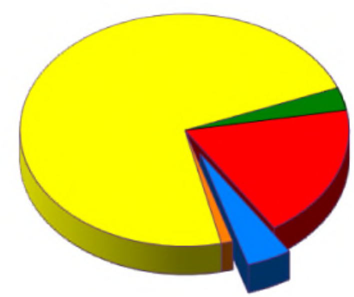
2018 SYSTEM INTEGRITY REPORT
SERVICE INVENTORY

RI
197,147 SERVICES



PHMSA Average
479,894 SERVICES



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2018 SYSTEM INTEGRITY REPORT

SERVICE LEAK REPAIR ANALYSIS

NOTE: Above Ground Leaks, which are included in the DOT Reports (beginning in 2012), are excluded from this report in order to maintain the integrity of our trend analyses for distribution (not CMS) piping.

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2018 SYSTEM INTEGRITY REPORT

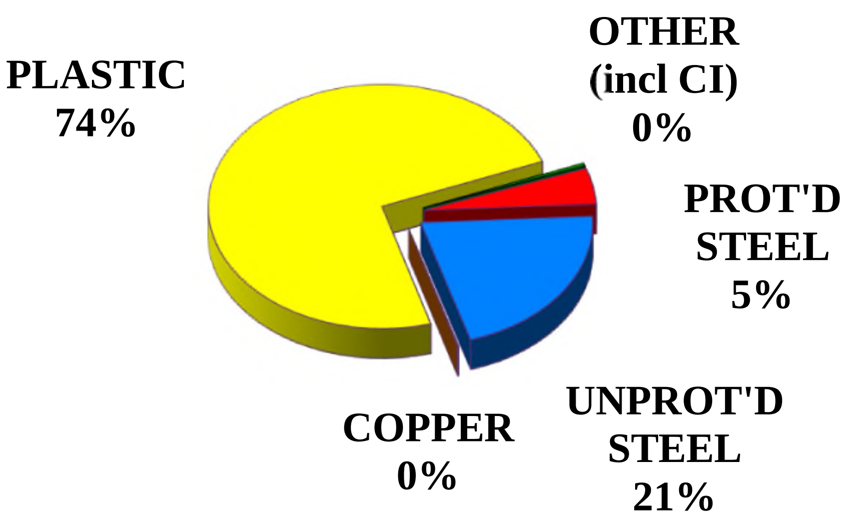
RI

TOTAL SERVICE LEAK REPAIRS

INCLUDING Damages

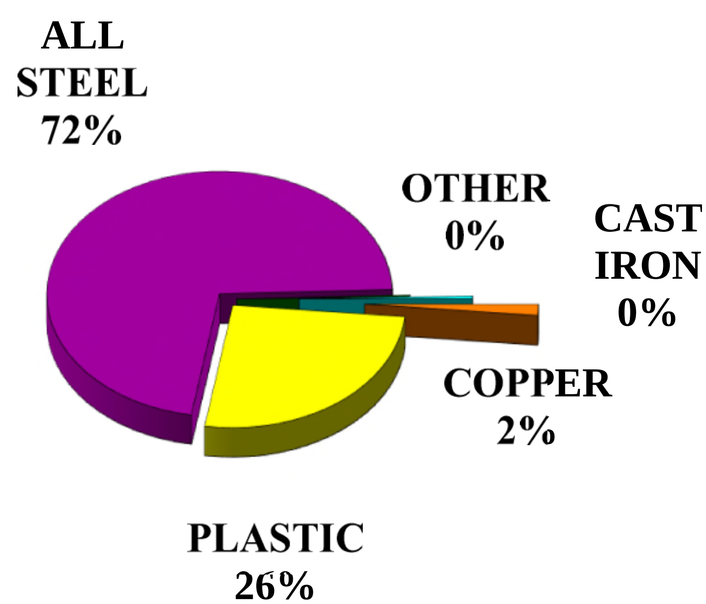
TOTAL SERVICE INVENTORY
BY MATERIAL

197,147 SERVICES



TOTAL SERVICE LEAK REPAIRS
BY MATERIAL

534 LEAKS



IMPORTANT: *Service Repairs are identified by the service material. This is not necessarily the material that leaked. For example - a leak caused by corrosion of a steel valve or fitting on a plastic service is shown as a plastic service leak.*

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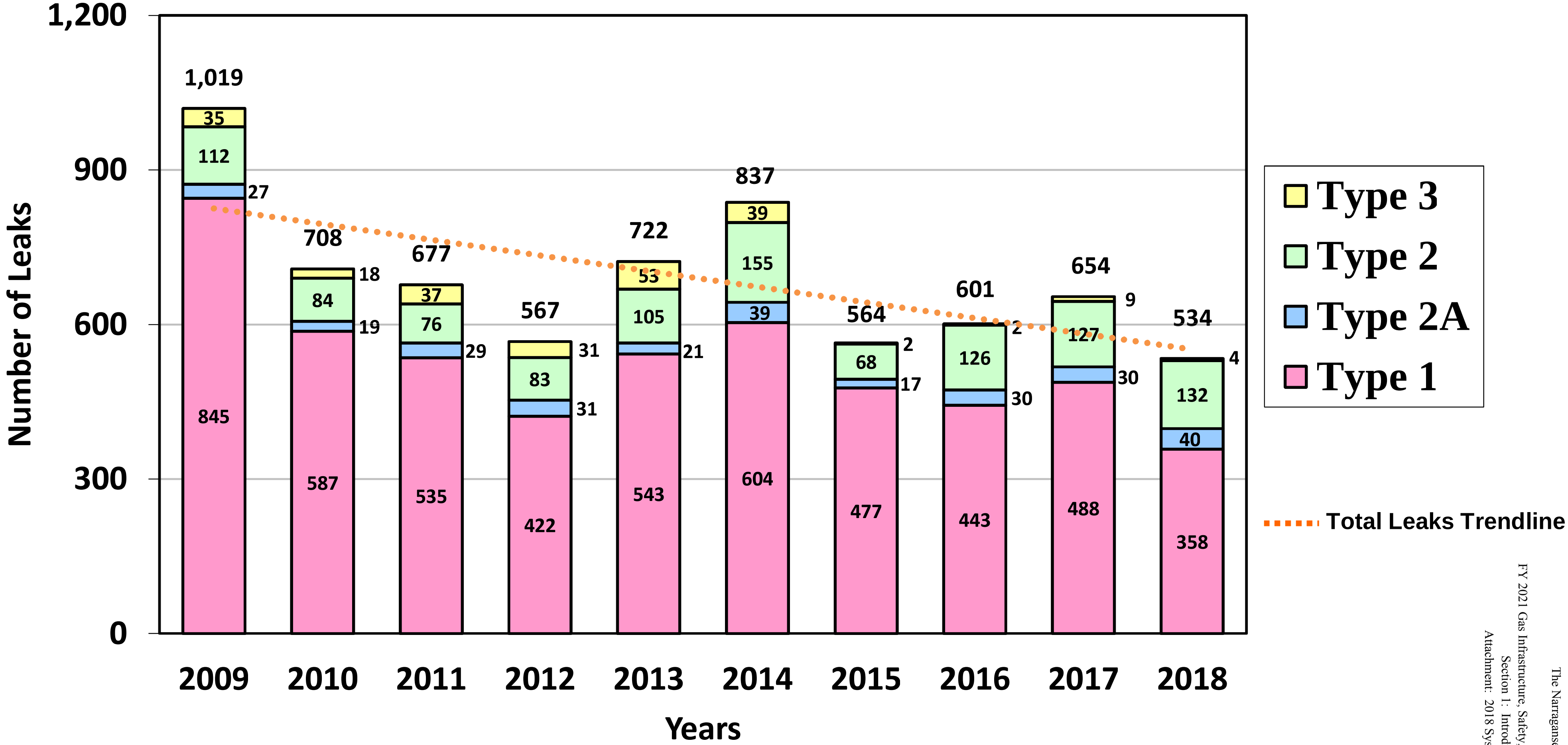
2018 SYSTEM INTEGRITY REPORT

RI

LEAKS REPAIRED By REPAIRED Type (Including Damages)

SERVICE



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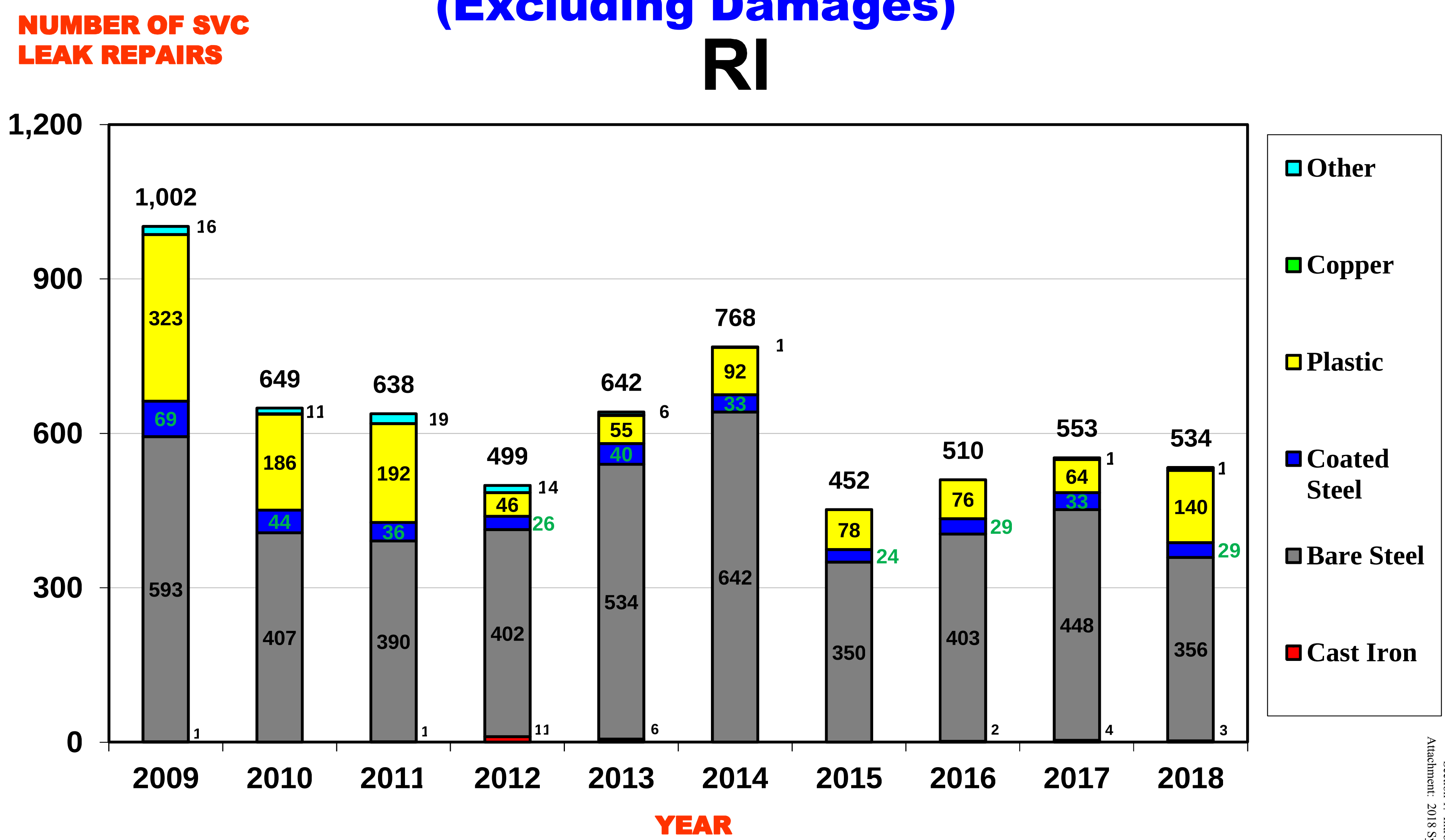
2018 SYSTEM INTEGRITY REPORT
2009 - 2018 SERVICE LEAK REPAIRS
All Service Leak Repairs by Material (Excluding Damages)
RI



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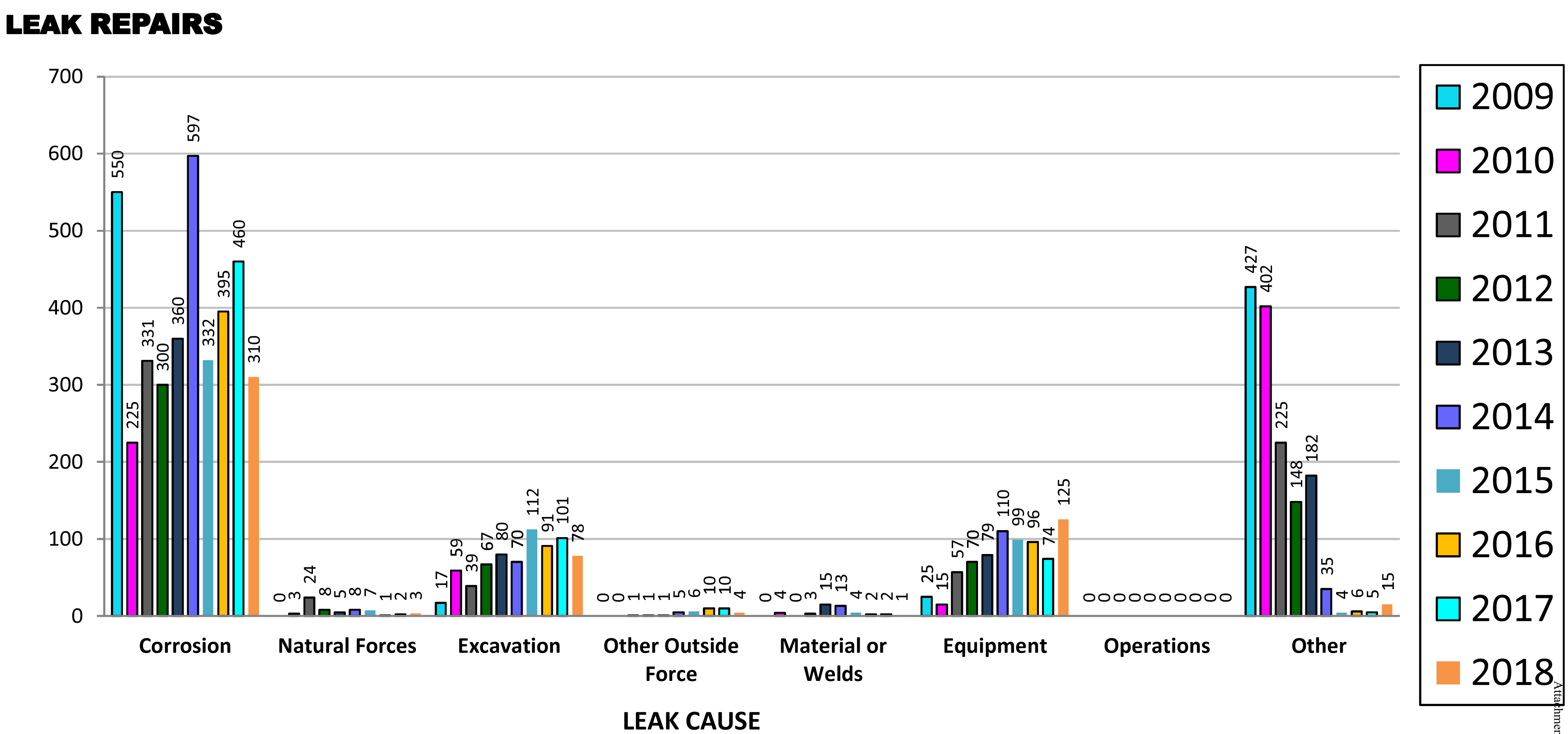
2018 SYSTEM INTEGRITY REPORT

RI

SERVICE LEAKS REPAIRED

COMPARISON BY LEAK CAUSES



COUNTING EACH INDIVIDUAL REPAIR AS A LEAK

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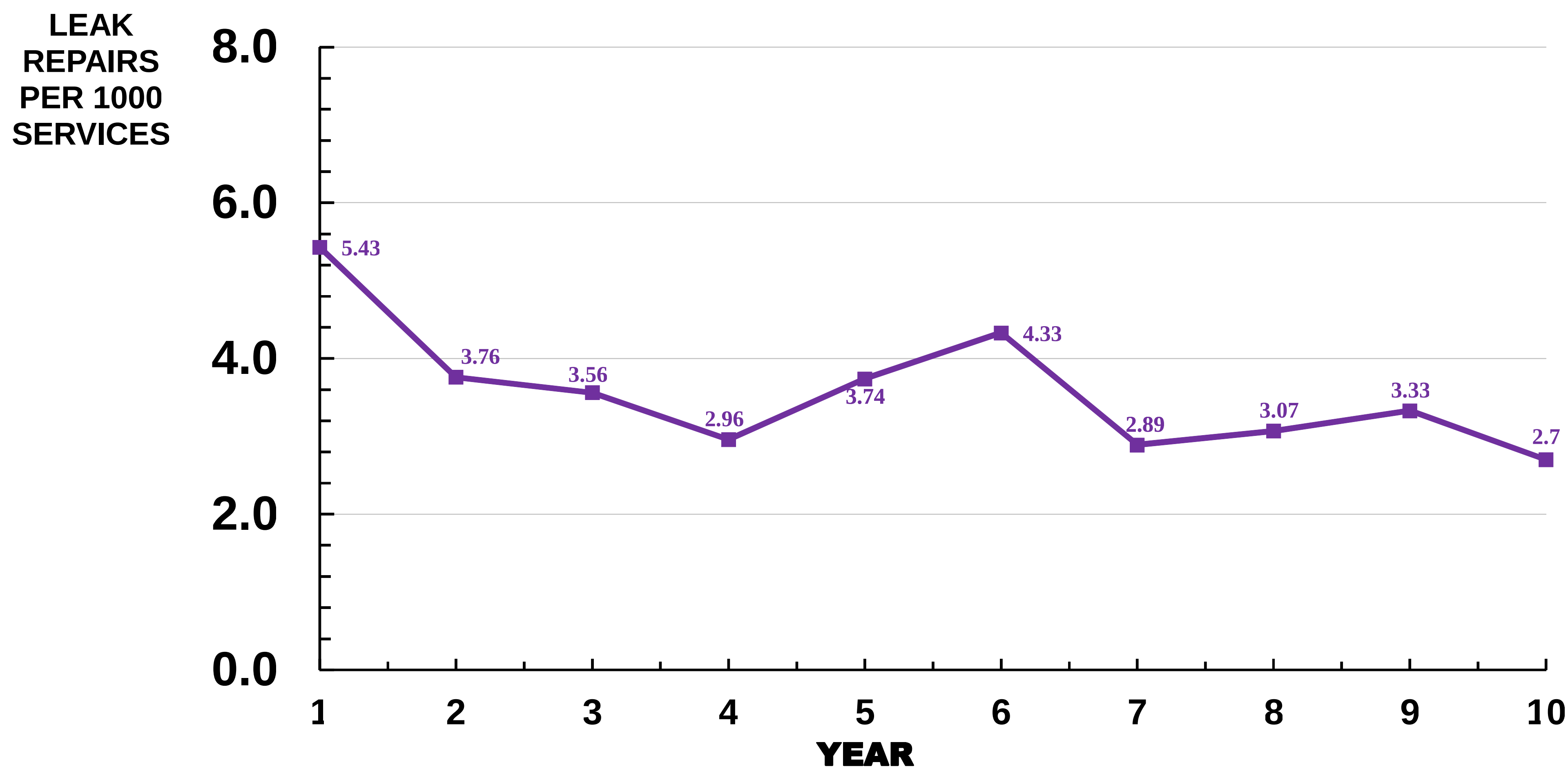
2018 SYSTEM INTEGRITY REPORT

TOTAL SERVICE LEAK "RATES"

INCLUDING Damages



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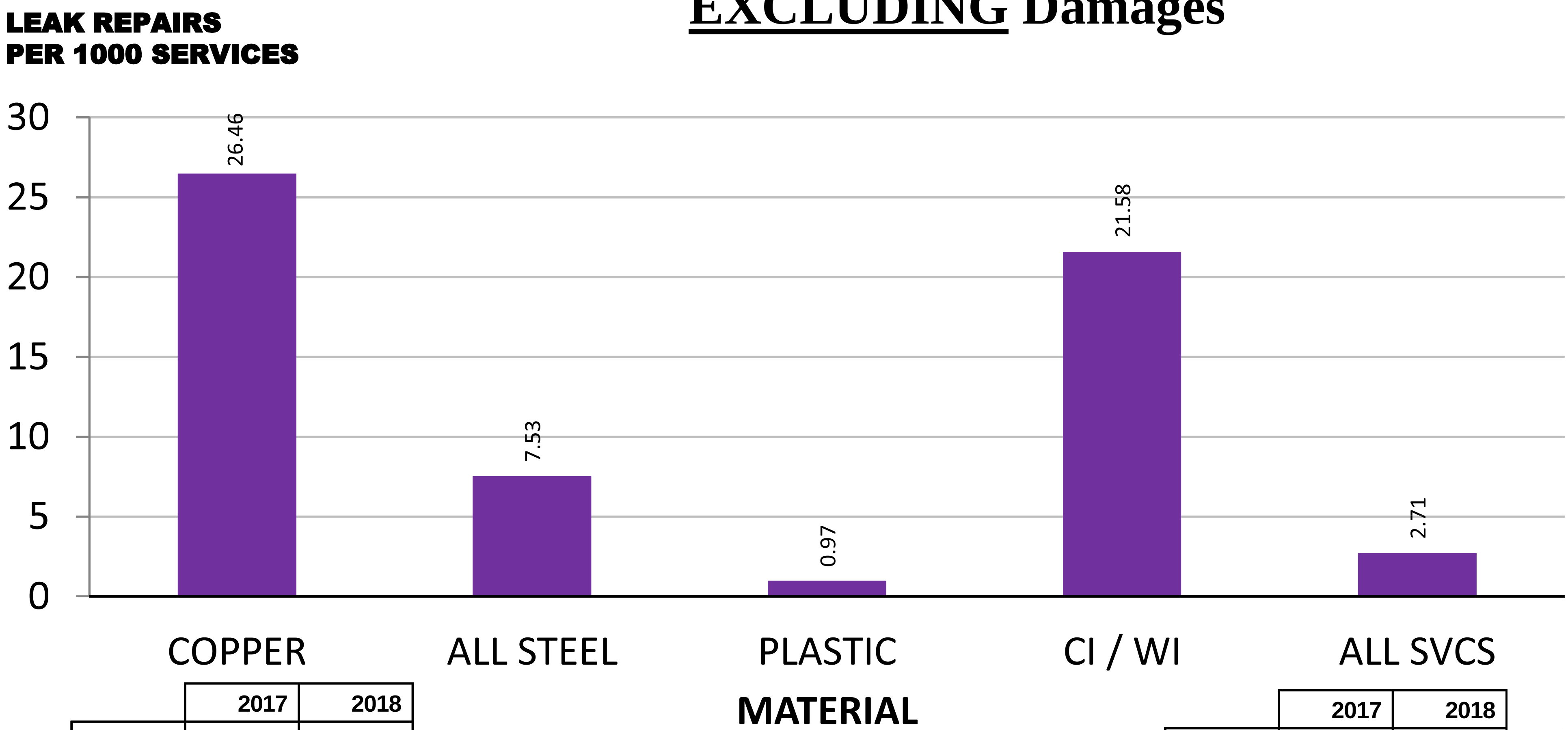
2018 SYSTEM INTEGRITY REPORT

RI

SERVICE LEAK "RATES"

COMPARISON BY MATERIAL

EXCLUDING Damages



	2017	2018
Plastic	142,956	144,929

	2017	2018
Copper	192	189

	2017	2018
Cast Iron	129	127

	2017	2018
Total Steel	52,425	51,127

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COUNTING EACH INDIVIDUAL REPAIR AS A LEAK

2018 SYSTEM INTEGRITY REPORT

2017/2018 DISTRIBUTION DOT REPORT DATA COMPARISONS

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2018 SYSTEM INTEGRITY REPORT

	General Data Correction	LPP					
	Explanation Needed	1,100	Main	1,140	Main		
	Discussed & Approved	42,109	Service	43,290	Service		
2017 - 2018 DOT Comparisons		RI					
		2018		2017		Delta(18-17)	%
Main Inventory	Cast Iron	700	miles	730	miles	-29	-4.0%
	Reconditioned Cast Iron	0	miles	0	miles	+0	N/A
	Plastic	1,539	miles	1,476	miles	+63	4.3%
	UP Bare Steel	199	miles	224	miles	-25	-11.2%
	UP Coated Steel	187	miles	171	miles	+16	9.4%
	Total UP Steel	386	miles	395	miles	-9	-2.3%
	CP Bare Steel	0	miles	0	miles	+0	N/A
	CP Coated Steel	562	miles	590	miles	-27	-4.6%
	Total CP Steel	562	miles	590	miles	-27	-4.6%
	Other	0	miles	0	miles	+0	0.0%
	Ductile Iron	14	miles	16	miles	-2	-12.6%
	TOTAL MAIN	**3,201**	**miles**	**3,205**	**miles**	**-4**	**-0.1%**
Main Leaks	Corrosion	102	repairs	102	repairs	+0	0.0%
	Natural Forces	94	repairs	26	repairs	+68	261.5%
	Excavation	12	repairs	16	repairs	-4	-25.0%
	Other Outside Force	1	repairs	1	repairs	+0	0.0%
	Material or Welds	5	repairs	0	repairs	+5	N/A
	Equipment	57	repairs	58	repairs	-1	-1.7%
	Operations	0	repairs	0	repairs	+0	N/A
	Other	756	repairs	666	repairs	+90	13.5%
	TOTAL MAIN LEAKS	**1,027**	**repairs**	**869**	**repairs**	**+158**	**18.2%**
Service Inventory	Copper	189	svcs	192	svcs	-3	-1.6%
	Plastic	144,929	svcs	142,956	svcs	+1973	1.4%
	UP Bare Steel	33,726	svcs	34,701	svcs	-975	-2.8%
	UP Coated Steel	8,067	svcs	8,268	svcs	-201	-2.4%
	Total UP Steel	41,793	svcs	42,969	svcs	-1176	-2.7%
	CP Bare Steel	0	svcs	0	svcs	+0	N/A
	CP Coated Steel	9,334	svcs	9,456	svcs	-122	-1.3%
	Total CP Steel	9,334	svcs	9,456	svcs	-122	-1.3%
	Other	763	svcs	803	svcs	-40	-5.0%
	Cast Iron / Wrought Iron	127	svcs	129	svcs	-2	-1.6%
	TOTAL SERVICES	**197,135**	**svcs**	**196,505**	**svcs**	+630	**0.3%**
Service Leaks Excluding Above Ground Leaks	Corrosion	333	repairs	460	repairs	-127	-27.6%
	Natural Forces	3	repairs	2	repairs	+1	50.0%
	Excavation	88	repairs	101	repairs	-13	-12.9%
	Other Outside Force	5	repairs	10	repairs	-5	-50.0%
	Material or Welds	2	repairs	2	repairs	+0	0.0%
	Equipment	135	repairs	74	repairs	+61	82.4%
	Operations	0	repairs	0	repairs	+0	N/A
	Other	20	repairs	5	repairs	+15	300.0%
	TOTAL SVC LEAKS	**586**	**repairs**	**654**	**repairs**	**-68**	**-10.4%**
Service Leaks Including Above Ground Leaks	Corrosion	333	repairs	460	repairs	-127	-27.6%
	Natural Forces	3	repairs	2	repairs	+1	50.0%
	Excavation	88	repairs	101	repairs	-13	-12.9%
	Other Outside Force	7	repairs	13	repairs	-6	-46.2%
	Material or Welds	2	repairs	2	repairs	+0	0.0%
	Equipment	135	repairs	74	repairs	+61	82.4%
	Operations	0	repairs	0	repairs	+0	N/A
	Other	20	repairs	5	repairs	+15	300.0%
	TOTAL SVC LEAKS	**588**	**repairs**	**657**	**repairs**	**-69**	**-10.5%**
Total Leak Repairs (Main & Service) Excluding Above Ground Leak		1,613	repairs	1,523	repairs	+90	5.9%
Total Leak Repairs (Main & Service) Including Above Ground Leak		1,615	repairs	1,526	repairs	+89	5.8%
Workable Backlog As of 12/31		169	leaks	74	leaks	+95	128.4%
UFG (Net)		2.5%		2.2%		0.30%	13.6%
Average Service Length (Ft)		66.5	ft	66.5	ft	+0	0.0%

Data Shown Includes Filed Revisions

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2018 SYSTEM INTEGRITY REPORT

NATIONAL GRID-US
2018 GAS DISTRIBUTION
SYSTEM STATISTICS

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2018 SYSTEM INTEGRITY REPORT

2018 GAS DISTRIBUTION SYSTEM STATISTICS

STATE	LEGACY	Miles of Main	# of Services	Avg Service Length (ft/svc)	Miles of Services	TOTAL Distribution Pipeline	Residential Customers	Commercial and Industrial Customers	TOTAL Customers	Sendout (MDT)	Sendout (MDT)/ HDD
		2018 PIPELINE / CUSTOMER / SENDOUT STATISTICS									
	NYC	4,156	569,988	45	4,858	9,014	1,194,771	73,018	1,267,789	206,995	59
	LI	8,253	550,950	65	6,783	15,036	540,268	62,489	602,757	108,941	31
	UPSTATE	8,820	566,339	73	7,819	16,639	576,024	47,688	623,712	173,868	38
ALL NEW YORK STATE		***21,229***	***1,687,277***	***60.9***	***19,460***	***40,689***	***2,311,063***	***183,195***	***2,494,258***	***489,804***	***42***
	BGC/EGC	7,240	563,962	49.0	5,232	12,472	655,202	59,871	715,073	126,715	33
	CCC/CLW	3,890	197,420	73.9	2,765	6,655	191,725	19,336	211,061	27,389	7
	RI	3,201	197,147	66.5	2,483	5,684	246,215	25,576	271,791	43,889	12
NEW ENGLAND		***14,331***	***958,529***	***57.7***	***10,480***	***24,811***	***1,093,141***	***104,784***	***1,197,925***	***197,993***	***17***
TOTAL NGRID-US		**35,560**	**2,645,806**	**59.7**	**29,939**	**65,499**	**3,404,205**	**287,978**	**3,692,183**	**687,797**	**30**

CAUTION:

This chart is for comparative-illustrative purposes only. The data is not audited & many assumption have been made.

Inventory data is from the Annual DOT/PHMSA Distribution Reports.

Customer data is from the Gas Customer Data base- Active Gas Accounts

Sendout data is from the sendouts for the 12-month period used to calculate UFG for the DOT Reports.

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2018 SYSTEM INTEGRITY REPORT

2018 GAS DISTRIBUTION SYSTEM STATISTICS

STATE	LEGACY	PERCENTAGES OF NGRID-US SYSTEM					ASSET RATIOS			GAS CONSUMPTION RATIOS			
		% of Main	% of Services	% of Distrib-ution Pipeline	% of Custo-mers	% of Sendout	Service Density (Svcs / Mile Main)	Meter Density (Custo-mers / Service)	Customer Density (Customers / Mile Total Pipeline)	Main Capacities Used (Sendout MDT / Mile Main)	Service Capacities Used (Sendout MDT/ Service)	Pipeline Capacities Used (Sendout MDT / Mile Total Pipe)	Customer Usage (Sendout MDT / Customer)
	NYC	11.7%	21.5%	13.8%	34.3%	30.1%	137	2.2	140.6	49.81	0.36	22.96	0.163
	LI	23.2%	20.8%	23.0%	16.3%	15.8%	67	1.1	40.1	13.20	0.20	7.25	0.181
	UPSTATE	24.8%	21.4%	25.4%	16.9%	25.3%	64	1.1	37.5	19.71	0.31	10.45	0.279
ALL NEW YORK STATE		***59.7%***	***63.8%***	***62.1%***	***67.6%***	***71.2%***	***79***	***1.5***	***61.3***	***23.07***	***0.29***	***12.04***	***0.196***
	BGC/EGC	20.4%	21.3%	19.0%	19.4%	18.4%	78	1.3	57.3	17.50	0.22	10.16	0.177
	CCC/CLW	10.9%	7.5%	10.2%	5.7%	4.0%	51	1.1	31.7	7.04	0.14	4.12	0.130
	RI	9.0%	7.5%	8.7%	7.4%	6.4%	62	1.4	47.8	13.71	0.22	7.72	0.161
NEW ENGLAND		***40.3%***	***36.2%***	***37.9%***	***32.4%***	***28.8%***	***67***	***1.2***	***48.3***	***13.82***	***0.21***	***7.98***	***0.165***
TOTAL NGRID-US		**100%**	**100%**	**100%**	**100%**	**100%**	**74**	**1.4**	**56.4**	**19.34**	**0.26**	**10.50**	**0.186**

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2018 SYSTEM INTEGRITY REPORT

SEPARATE LEAK-PRONE PIPE ANALYSIS

STATE	LEGACY	2018 LEAK-PRONE PIPE INVENTORY						LEAK-PRONE PIPE %'s		
		Leak - Prone Main (miles)	% of TOTAL Main	Leak - Prone Services (#)	% of TOTAL Services	Miles of Leak - Prone Services	TOTAL Leak - Prone Pipe (in miles)	% of NG-US Leak - Prone Main (miles)	% of NG-US Leak - Prone Services (#)	% of NG-US TOTAL Leak - Prone Pipe
	NYC	1,565	37.7%	129,761	22.8%	1,106	2,671	16.7%	25.6%	17.8%
	LI	3,075	37.3%	79,730	14.5%	982	4,057	32.8%	15.7%	27.0%
	UPSTATE	566	6.4%	136,519	24.1%	1,885	2,451	6.0%	26.9%	16.3%
ALL NEW YORK STATE		***5,206***	***24.5%***	***346,010***	***20.5%***	***3,972***	***9,178***	***55.5%***	***68.3%***	***61.1%***
	BGC/EGC	2,896	40.0%	110,902	19.7%	1,029	3,925	30.8%	21.9%	26.1%
	CCC/CLW	186	4.8%	7,787	3.9%	109	295	2.0%	1.5%	2.0%
	RI	1,100	34.4%	42,121	21.4%	531	1,631	11.7%	8.3%	10.8%
NEW ENGLAND		***4,182***	***29.2%***	***160,810***	***16.8%***	***1,669***	***5,851***	***44.5%***	***31.7%***	***38.9%***
TOTAL NGRID-US		**9,388**	**26.4%**	**506,820**	**19.2%**	**5,641**	**15,029**	**100%**	**100%**	**100%**

NOTES:
Leak-Prone Main includes Cast Iron/Wrought Iron, Unprotected Steel , Aldyl-A and Other Material.
Leak-Prone Service includes Cast Iron/Wrought Iron, Copper and Unprotected Steel.

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2018 SYSTEM INTEGRITY REPORT

LEAK AND REPAIR ANALYSIS

STATE	LEGACY	2018 LEAK DATA				LEAK RATE RATIOS					
		TOTAL Leak Receipts (Main & Service)	TOTAL Leak Repairs (Main & Service)	Year-End Workable Leak Backlog	TOTAL Repairs + Workable Leaks	TOTAL Leak Receipts / Mile TOTAL Pipe	TOTAL Leak Receipts / Mile Leak-Prone Pipe	TOTAL Leak Repairs / Mile TOTAL Pipe	TOTAL Leak Repairs / Mile Leak-Prone Pipe	Repairs + Workables / Mile TOTAL Pipe	Repairs + Workable / Mile Leak-Prone Pipe
	NYC	4,171	4,813	10	4,823	0.5	1.6	0.5	1.8	0.5	1.8
	LI	3,452	3,214	-	3,214	0.2	0.9	0.2	0.8	0.2	0.8
	UPSTATE	1,549	1,355	-	1,355	0.1	0.6	0.1	0.6	0.1	0.6
ALL NEW YORK STATE		***9,172***	***9,382***	***10***	***9,392***	***0.2***	***1.0***	***0.2***	***1.0***	***0.2***	***1.0***
	BGC/EGC	6,951	6,645	1,397	8,042	0.6	1.8	0.5	1.7	0.6	2.0
	CCC/CLW	707	869	17	886	0.1	2.4	0.1	2.9	0.1	3.0
	RI	1,989	1,466	169	1,635	0.3	1.2	0.3	0.9	0.3	1.0
NEW ENGLAND		***9,647***	***8,980***	***1,583***	***10,563***	***0.4***	***1.6***	***0.4***	***1.5***	***0.4***	***1.8***
TOTAL NGRID-US		**18,819**	**18,362**	**1,593**	**19,955**	**0.3**	**1.3**	**0.3**	**1.2**	**0.3**	**1.3**

NOTES:
TOTAL Leak Receipts (Main & Service) data excludes Excavation Leaks.
TOTAL Leak Repairs (Main & Service) data includes Excavation Leaks.
TOTAL Leak Repairs (Main & Service) data excludes Above Ground Leaks.

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2018 SYSTEM INTEGRITY REPORT

2018 SYSTEM INTEGRITY REPORT ANALYSIS (FINDINGS AND EXPLANATIONS)

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2018 SYSTEM INTEGRITY REPORT

ANALYSIS OF FINDINGS AND EXPLANATIONS

FINDING 2:

RI

Total leak receipts have increased by 3% (65) in 2018 compared to 2017.

MAIN – Leak repairs have increased by 7% (63) in 2018 compared to 2017. Total Cast Iron Joint leaks comprise 74% of all main leaks.

SERVICE – Leak repairs have decreased by 18% (120) compared to 2017. Corrosion leaks comprise 44% of all service leaks.

TOTAL – Gas leak repairs decreased by 3% (53) in 2018.

2018 SYSTEM INTEGRITY REPORT

LPP Replacement Projection

NE - Leak Prone Pipe Replacement

		CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	CY21	CY22	CY23	CY24	CY25
RI	All Programs	54.3	44.0	28.8	56.0	62.7	63.3	67.0	55	55	70	70	70	70	70
	Proactive	50.0	39.9	23.0	50.3	51.0	48.3	51.2	42	42	49	49	53	54	59

Cast Iron/Unprotected Steel Ratio

NE - Cast Iron / Unprotected Steel

Calendar Years		2015	2016	2017	2018
RI	Cast Iron	29.4	19.8	24.7	28.3
	Unp. Steel	39.5	41.0	28.5	39.2

2018 SYSTEM INTEGRITY REPORT

2018 METER STATISTICS

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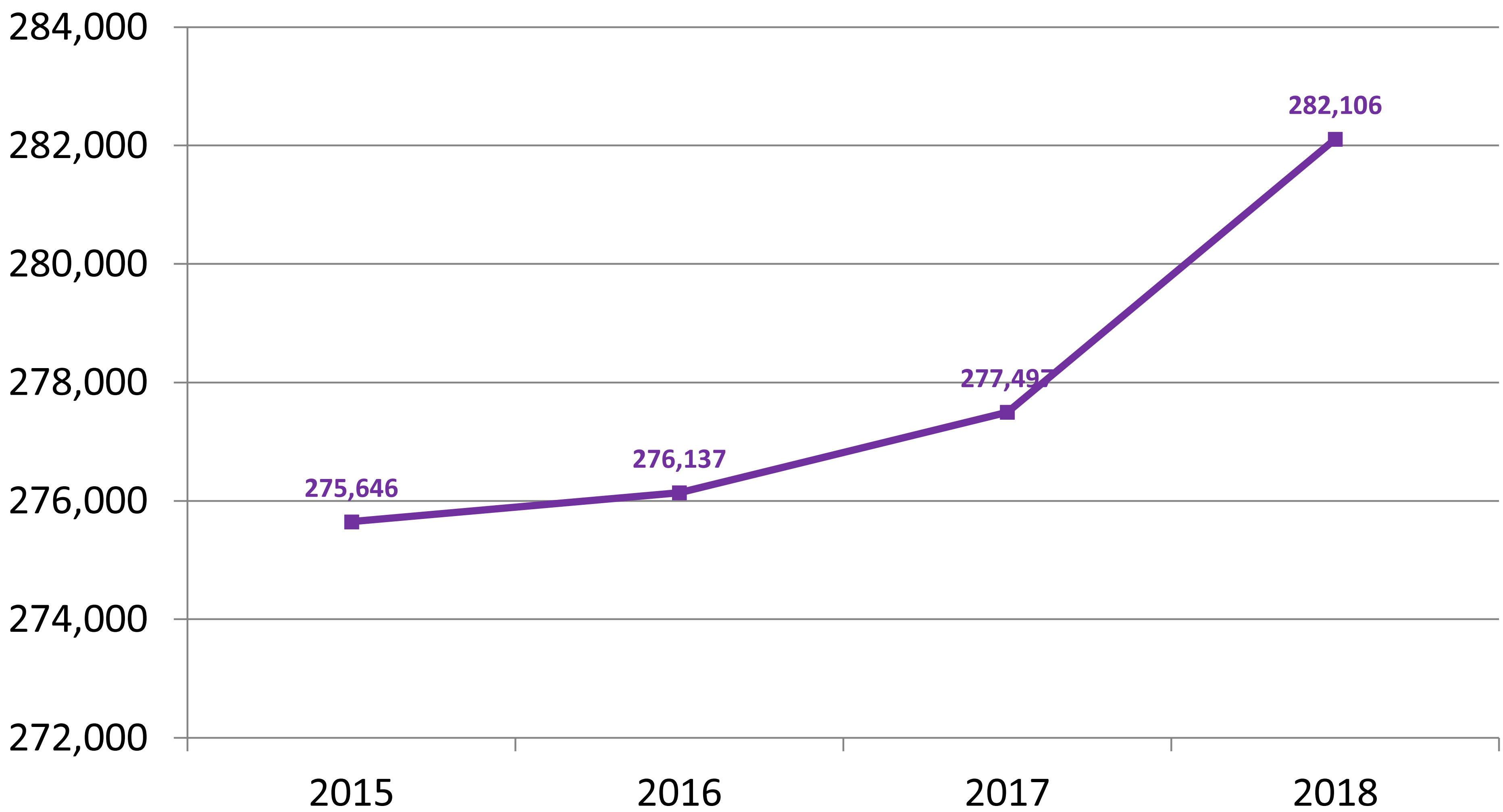
2018 SYSTEM INTEGRITY REPORT

RI

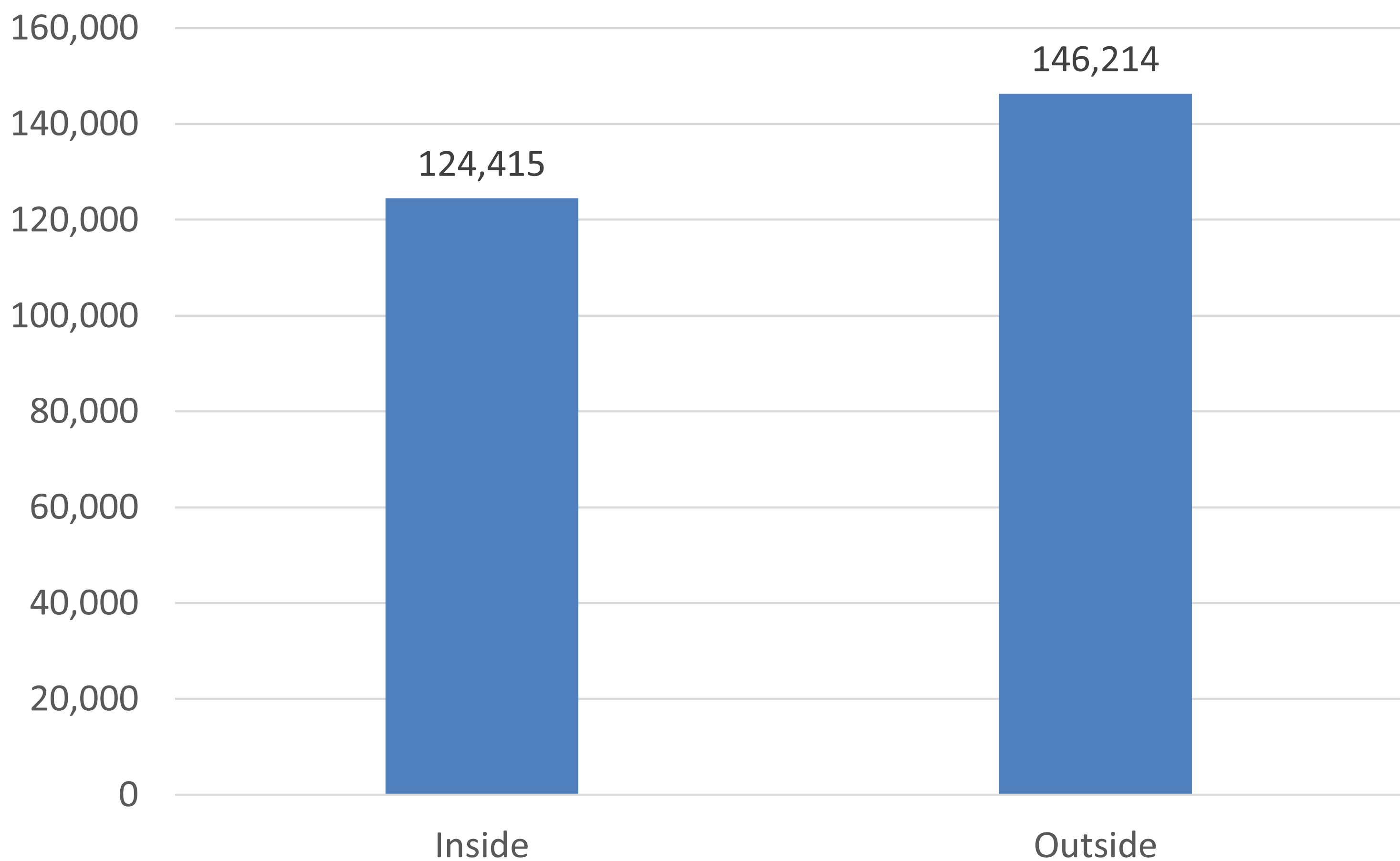
Meter Population



2018 SYSTEM INTEGRITY REPORT

RI

Meter Population Inside VS Outside



Note: Based upon readily available exports in July 2019.

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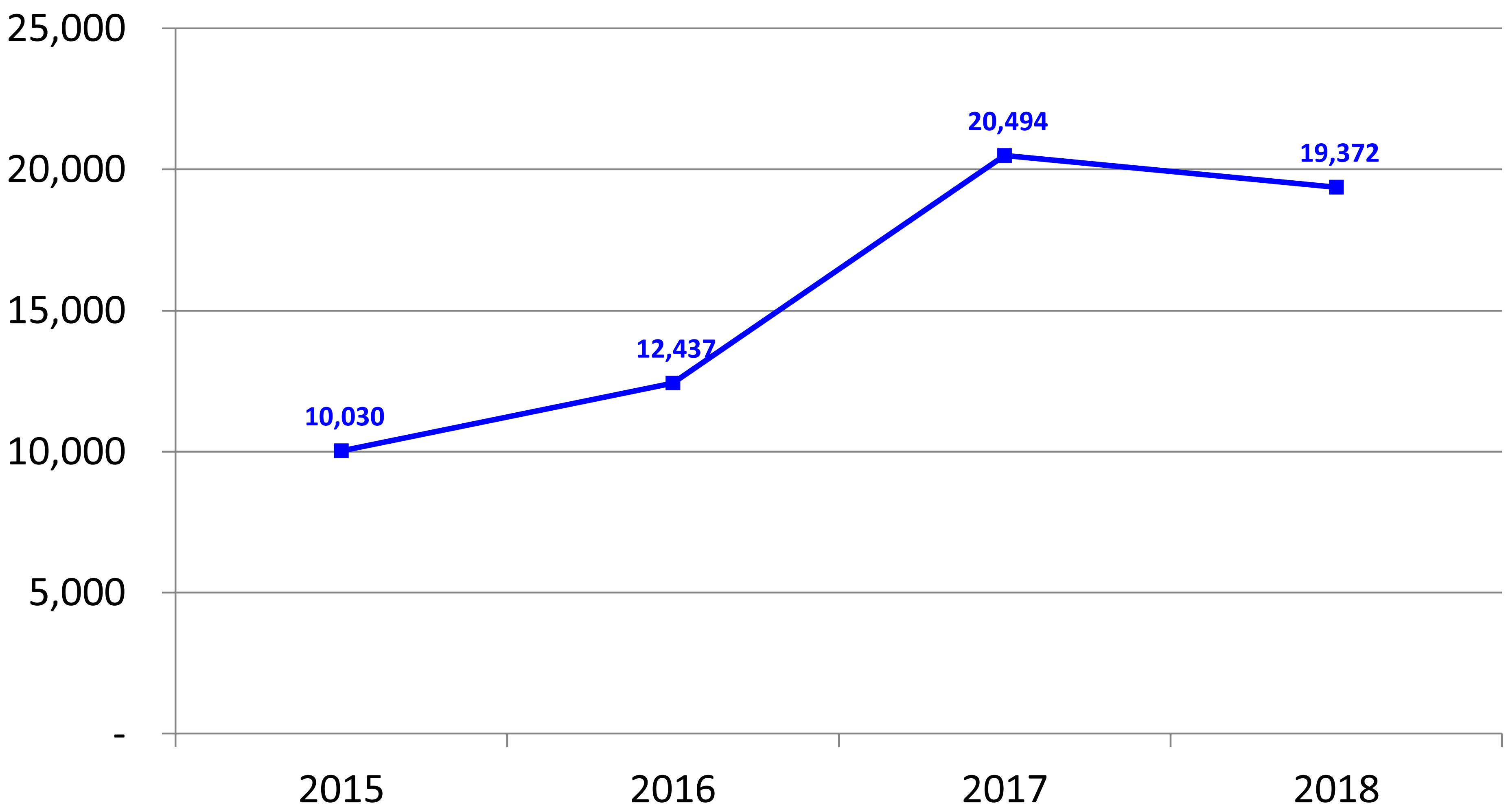
2018 SYSTEM INTEGRITY REPORT

RI

Meter Changes



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Section 2
Gas Capital Investment

Section 2

Gas Capital Investment Plan
FY 2021 Proposal

Gas Capital Investment Plan
FY 2021 Proposal

Background

The Company developed its proposed capital investment plan to meet its obligation to provide safe, reliable, and efficient gas distribution service for customers at reasonable costs.[7] The Gas ISR Plan includes capital investment spending needed to meet state and federal regulatory requirements applicable to the Company's gas system and to maintain its distribution infrastructure in a safe and reliable condition. To address the replacement of leak-prone pipe, the Plan includes infrastructure, safety, and reliability work for cast-iron and non-cathodically protected steel mains. The Plan also contains capital spending related to safety and reliability for public works projects, mandated programs, and gas reliability, including gas expansion in Southern Rhode Island. Additionally, the plan includes O&M spending to begin assessing capital investment options for heat decarbonization.

Consistent with the goals of the Revenue Decoupling Law, in order to continue to provide safe and reliable gas delivery service to Rhode Island customers, it is critical that the Company remain vigilant with respect to investing in its infrastructure and have appropriate and timely cost recovery. To that end, the Company's proposed Plan identifies the capital spending investment that it expects to complete in FY 2021. At the end of this section, Table 1 contains a description of the proposed budget for the FY 2021 Plan; Table 2 contains a proposed five-year

[7] The Company delivers natural gas to approximately 272,000 Rhode Island residential and commercial and industrial customers in 32 cities and towns in Rhode Island. To provide this service, the Company owns and maintains approximately 3,200 miles of gas mains and approximately 197,000 gas services.

spending forecast for FY 2021 through FY 2025; and Table 3 contains actual spending based on the prior five-year period, FY 2015 through FY 2019. In FY 2021, the Company proposes to invest a total of $199.61 million of ISR investments[8] to be included in the FY 2021 Gas ISR recovery mechanism. This amount includes the following: $39.30 million for Non-Discretionary capital expenditures; $144.79 million for Discretionary capital expenditures, which includes $40.46 million for the Southern RI Gas Expansion Project; $1.52 million for PE Stamps; $13.01 million for incremental curb to curb paving costs estimated in accordance with the new RI paving law; and $1.00 million of O&M spending to begin assessing capital investment options for heat decarbonization. The incremental paving costs include $2.61 million for incremental paving specific to the Southern RI Gas Expansion Project.

As set forth in Table 1 at the end of this section, the Company proposes the following levels of spending for each category of programs contained in the $199.61 million that the Company proposes in the FY 2021 Gas ISR Plan:

Non-Discretionary:

- $17.37 million net investment for Public Works programs, including $18.77 million in capital spend and $1.40 million in reimbursements;
- $21.68 million for Mandated Programs (i.e., Corrosion, Purchase Meter Replacements, Reactive Leaks (Cast Iron Joint Encapsulation/Service Replacement), Service Replacement (Reactive) – Non-Leak/Other, Main Replacement (Reactive) – Maintenance (including Water Intrusion), Transmission Station Integrity; and
- $0.25 million for Damage/Failure programs.

[8] For FY 2021, the Company plans to spend $232.84 million of total capital investment. Of that total amount, $33.23 million is associated with projected growth and other non-ISR spending, which is not included for recovery in the FY 2020 Gas ISR Plan.

Discretionary:

- $67.73 million for the Proactive Main Replacement program (i.e., Proactive Main Replacement, Large Diameter, and Atwells Avenue project);
- $0.35 million for the new Proactive Service Replacement program;
- $40.40 million for Gas System Reliability, including work relative to Gas System Control, System Automation, Heater Program, Pressure Regulating Facilities, Allens Avenue Multi Station Rebuild, Valve Installation Replacement, Take Station Refurbishment, Gas System Reliability Enhancement, Instrumentation and Regulation – Reactive, Distribution Station Over Pressure Protection, Liquefied Natural Gas (LNG) facilities, Replace Pipe on Bridges, Access Protection Remediation, and Tools and Equipment; and
- $40.46 million for the Southern Rhode Island Gas Expansion Project (Southern RI Gas Expansion).

Incremental Costs:

- $1.52 million for PE Stamps.
- $13.01 million for Incremental Curb to Curb Paving Costs, including Southern RI Gas Expansion and All Other ISR Work.

Operation and Maintenance Expenses:

- $1.00 million for Heat Decarbonization Assessment

Incremental Costs: Curb to Curb Paving

The Rhode Island Utility Fair Share Roadway Repair Act was enacted into state law on July 15, 2019. The Act require public utilities or utility facilities to repave and repair roadways which have been altered or excavated by the Utility from curb line to curb line or as required in accordance with the state or municipal utility permit requirements. The new law is immediately applicable to all work on state roadways, and within municipalities as they see fit to adopt within their permits. To date, 5 of the 38 municipalities in Rhode Island[9] have adopted curb to curb restoration requirements. The Company anticipates that most municipalities will adopt the requirements before the start of the Company's FY 2021 construction season in April 2020. The new curb to curb paving restoration requirement will significantly impact the costs of gas capital construction projects and gas maintenance work in RI.

The Company has estimated the cost of complying with the law for all work other than the Southern RI project using the following assumptions and assuming the incremental paving will be required for 100% of miles installed and for 50% of patch restorations associated with ISR work. After subtracting the average cost of prior paving requirements, the Company estimates incremental costs of $5.60 million associated with restoring approximately 42.3[10] miles of trenches following main work, $4.80 million associated with restoring 3,429 patches associated with ISR work, and $2.61 million associated with road restoration for the Southern RI project.

[9] 32 municipalities have gas services.
[10] Approximately 14% of final restoration is already included in the average restoration costs, so the incremental restoration mileage is effectively approximately 36.5 miles.

A summary of the total estimate for the FY 2021 Gas ISR Incremental Curb to Curb Paving Costs is presented in the table below.

FY 2021
Incremental Curb to Curb Paving Costs
Main Installation, Patches, and Southern RI Gas Expansion Project

Planned Main Installation Paving Miles	42.3

*Note that minus the ~14% which is already paved curb to curb, this number is effectively approximately 36.5 miles

Main Installation Paving	**Sq Yards/ Mile**	**Cost/ Sq Yd**	**Added Costs %***	**Cost/Mile**	**Total Cost for 42.92 Miles**	**Budget**
Minimum 8ft Restoration	4,693	$ 12.50		$ 58,663	$ 2,480,837	
Average 10.28ft Restoration	6,033	$ 12.50		$ 75,410	$ 3,189,089	
Curb to Curb 26 ft Restoration	15,253	$ 12.50	20%	$ 228,800	$ 9,675,952	
Curb to Curb minus Average = Incremental Cost/mile				$ 153,390	$ 6,486,863	
Deduct ~14% for roads already paved curb to curb					$ 890,889	
Total Incremental Cost for curb to curb main installation paving					$ 5,595,974	**$ 5,596,000**

*Added Costs for paving curb to curb such as driveway aprons, striping, drainage, sewer, intersection sensors, etc.

Planned ISR Patches	3,429

Patching Paving Costs	**Average Cost/Patch**	**Total Cost for 3,429 Patches**	**Budget**
Standard	$ 1,400	$ 4,800,600	
Mix of curb to curb and curb to center @ 50% adoption rate	$ 2,800	$ 9,601,200	
"Curb to Curb" minus Standard = Incremental Cost/Patch	$ 1,400	$ 4,800,600	**$ 4,801,000**

Southern RI Gas Expansion Incremental Paving Costs	**Incremental Paving Cost**	**Budget**
Main Installation*	$ 2,565,078	$ 2,565,000
Other Investment - MOP Increase from 150 to 200 psi	$ 49,000	$ 49,000
Total Incremental Southern RI Gas Expansion Paving Costs	$ 2,614,078	**$ 2,614,000**

*Cost also includes impact of new RIDOT concrete restoration guidelines

FY 2021 Gas ISR Incremental Paving Costs by Category	**Incremental Paving Cost**	**Budget**
Main Installation - 44.43 miles	$ 5,595,974	$ 5,596,000
Patches - 3,429 @ 50% (mix curb to curb and curb to center)	$ 4,800,600	$ 4,801,000
Southern RI Gas Expansion	$ 2,614,078	$ 2,614,000
Total FY 2021 ISR Incremental Paving Costs	**$ 13,010,652**	**$ 13,011,000**

Description of Programs and Projects

The Non-Discretionary and Discretionary programs are described in detail below.

Non-Discretionary Work:

A. Public Works

The purpose of the Public Works program is to address existing gas infrastructure conflicts, as appropriate, and to improve the safety and reliability of the Company's natural gas distribution system in conjunction with municipal reconstruction and water and sewer projects, which provide significant incremental benefits to customers and communities. Municipal and water and sewer work affords the Company an opportunity to replace additional leak-prone pipe and reduce paving costs by coordinating the Company's gas main replacement work with planned third-party construction projects, while also benefitting customers and communities by improving service delivery and minimizing construction impacts and inconvenience. The Company has an ongoing plan to replace targeted gas mains on a risk-based approach. Coordinating the Company's Integrity programs with planned municipal and water and sewer projects has yielded increased system reliability, system integrity, and optimized capital spending. Although one of the primary purposes of Public Works spending is to address direct conflicts between planned third-party projects and existing gas infrastructure, Public Works spending provides the additional opportunity to coordinate other system improvement work, such as the replacement of leak-prone pipe, system reliability upgrades, elimination of redundant main, and regulator station upgrades.

The Company will manage multiple projects to address the dynamic nature of the Public Works process through effective liaison activity. Although municipal schedules and plans change largely due to funding, other factors also contribute to the scheduling of these projects (e.g., political demand and maintenance). Changes in municipal projects can and do create additional work in developing and coordinating the Company's planning and budgeting processes. Using the Company's five-year work planning process, the Company can provide some flexibility in scheduling, coordinating, and engineering projects in concert with municipal public works initiatives. For FY 2021, the Plan includes $17.37 million in spending under the Public Works category, which includes $18.77 million in capital spend and $1.40 million that is anticipated to be reimbursed under agreements with third parties. Overall, the Public Works budget provides for the installation of 13 miles of gas main, mainly resulting from the replacement and abandonment of 13 miles of leak-prone gas main, consisting of cast iron and unprotected steel main. Please note that the costs in this category do not include any incremental cost associated with complying with the new RI paving law. Please note that the Company's calculation of estimated incremental paving costs excludes public works miles since the municipality or the state is typically responsible for final paving restoration when the Company completes its work in conjunction with public works projects. Additionally, the costs in this category do not include the estimated incremental cost of $0.46 million associated with complying with the new PE Stamp statutory requirements. The PE Stamp costs will be tracked as a separate line item.

B. Mandated Programs

Spending for Mandated Programs falls into the following six categories: (1) Corrosion, (2) Purchase Meter Replacement, (3) Reactive Leaks (4) Reactive Service Replacement - Non-leak/Other, (5) Reactive Main Replacement-Maintenance, and (6) Transmission Station Integrity.

1. Corrosion

Cathodic protection effectively extends the service life of buried steel facilities (as compared to unprotected buried steel facilities) and can prolong replacement by 20 years or more. In 1971, the Code of Federal Regulations, Part 192, was amended to require the cathodic protection of all new buried steel gas facilities. Protection is accomplished in part through ensuring proper coating by establishing proper conditions on pipe segments through installation of rectifiers, anodes, insulators, and test stations. In addition, the Corrosion program includes control line work at existing regulator stations and cathodic protection upgrades. For FY 2021, the Company proposes to spend $1.17 million on this program. Please note that the costs in this category do not include the estimated incremental cost of $0.04 million associated with complying with the new PE Stamp statutory requirements. The PE Stamp costs will be tracked as a separate line item.

2. Purchase Meter Replacement

Capital costs for the Purchase Meter Replacement program are required for the procurement of replacement meters. For FY 2021, the Company proposes to purchase 22,000 meters. The meter replacements are part of a multi-year plan and 22,000 meters represents approximately 7.8 percent of the existing meter population in Rhode Island, at a cost of $4.85 million.

3. **Reactive Leaks**

This category provides funding for the leak sealing of cast iron bell joints that are discovered during proactive leak surveys, public odor calls, or other activities. In addition, it provides funding for remediating leaking gas services through insertion, replacement, and/or abandonment of the services. For FY 2021, the Company proposes to spend $12.28 million for this work.

4. **Reactive Service Replacement - Non-leak/Other**

This program contains the capital costs for service relocations, meter protection, service abandonments, and the installation of curb valves. In FY 2021, the Company will continue the agreement with the Division to expand curb valve installations to properties inaccessible for inside inspection. Installation of curb valves provides additional public safety benefits and complements efforts in place aimed at improving collection and meter reading opportunities particularly in situations where the Company has encountered difficulty gaining access to meters. For FY 2021, the Company proposes to spend $2.10 million for this program.

5. **Reactive Main Replacement – Maintenance**

This category of work consists of emergency main replacements or modifications because of leaks or other unplanned events where main conditions dictate immediate replacement and/or gas facilities are subject to water intrusion or exposure and require remedy. Over the past several years, the Company has received minimal requests in this category, primarily because the Company's increased Proactive Main Replacement program work has reduced the need for reactive work through construction of a more resilient system. The Company proposes to spend $0.68 million in this area.

6. Transmission Station Integrity

The Transmission Station Integrity program is a new ISR program for FY 2021 that is a continuation of a rate base- funded program[11], for $0.31 million per year. This program began several years ago and has primarily consisted of in-depth compliance records and documentation reviews of pressure regulating facilities. The primary purpose of the Transmission Station Integrity program is to meet the recent United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) code requirements, issued on October 1, 2019 and which will be effective on July 1, 2020. The PHSMA code requirements ensure that pipelines, including those associated with transmission stations, are safe, reliable, and fit for service. The next stage of this multi-year program includes retesting, and, where necessary, replacing equipment, prioritized by a standard risk-based evaluation that will not meet the incoming PHSMA documentation requirements. Of the 24 Transmission Stations on the Company's system, 12 are in scope for re-testing and/or replacing equipment. In FY 2021, the Company proposes to spend $0.61 million in this category, and the activities primarily consist of project development, engineering, and procuring long lead materials for the identified

[11] See RIPUC Docket No. 4770, November 27, 2017 Initial Filing, Book 4 at Bates Page 55, Line 17 and Bates Page 58, Line 8; August 16, 2018 Compliance Filing Book 2 on Bates Page 204, Line 3; and Compliance Attachment 2, Schedule 38, Page 6.

capital replacement projects. The Company expects that construction will begin in FY 2022.

Please note that the costs in the Mandated categories do not include the estimated incremental cost associated with complying with either the new RI paving law or the new PE Stamp statutory requirements, where applicable. Instead, these costs will be tracked as separate line items. In total, the Gas ISR Plan for FY 2021 contains $21.68 million for all categories of Mandated work.

C. <u>Damage/Failure Program</u>

The Company proposes to include funding for safety and reliability projects associated with remediation of damage or failure occurrences. Damage or failure projects are initiated in response to events outside the Company's control that require immediate action. The Company proposes a FY 2021 budget of $0.25 million for such work.

In total, for FY 2021, the Gas ISR Plan contains $39.30 million for Non-Discretionary work.

Discretionary Work:

A. <u>Proactive Main Replacement Program</u>

The value of and need for targeted spending on the replacement of leak-prone gas main is well-documented and has been accepted by the PUC and Division. For FY 2021, the Company forecasts spending $67.73 million on its Proactive Main Replacement and Rehabilitation programs, which will address approximately 49 miles of leak-prone gas main (approximately 48 miles of proactive main replacement including Atwells Avenue and approximately 1 mile of rehabilitation work) and approximately 3,387 service relays, inserts, or tie-ins. Please note that the costs in this category do not include the estimated incremental cost associated with complying with the new RI paving law, with the exception of the Atwells Avenue project, which already assumed curb to curb paving in the cost estimates. The incremental paving costs incurred in the proactive main replacement program will be tracked as a separate line item. Additionally, the costs in this category do not include the estimated incremental cost of $0.80 million associated with complying with the new PE Stamp statutory requirements. The PE Stamp costs will be tracked as a separate line item.

1. **<u>Proactive Main Replacement (<16-inch)</u>**

The Proactive Main Replacement (<16-inch) program consists of the installation of approximately 42.3 miles and the abandonment of approximately 47.4 miles of cast iron and unprotected steel main with a diameter of less than 16 inches, and the renewal, abandonment, or tie-over of existing services. The average installation cost per mile for work in rural locations is estimated to increase from $0.86 million in FY 2020 to $0.97 million in FY 2021. The average installation cost per mile for work in suburban locations is estimated to increase from $1.13 million in FY 2020 to $1.24 million in FY 2021. The average installation cost per mile for work in urban locations is estimated to decrease from $1.83 million in FY 2020 to $1.77 million in FY 2021 because the FY 2021 plan contains a slightly higher volume of replacements that are changing from low-pressure to high-pressure and calls for the installation of 2-inch and 4-inch main instead of 6-inch and 8-inch main which results in a cost savings per mile. The table below provides a comparison of the Main Replacement – Leak Prone Pipe program between FY 2020 and FY 2021, including the estimated cost per mile for installed and abandoned main in urban, suburban, and rural areas. This table excludes the Large Diameter program and the costs for the Atwells Avenue Main Replacement program because the nature of those programs are not suitable for year-over-year comparison

FY 2020 (Plan as of 12/19/2018)				
	Installation Miles	Abandonment Miles	Installation Cost/Mile	Abandonment Cost/Mile
Rural	5.9	6.6	$0.86M	$0.76M
Suburban	18.4	20.1	$1.13M	$1.04M
Urban	17.1	20.3	$1.83M	$1.54M
Total	41.3	47.0	$1.38M	$1.22M
FY 2021 (Plan as of 12/18/2019)				
	Installation Miles	Abandonment Miles	Installation Cost/Mile	Abandonment Cost/Mile
Rural	4.0	4.6	$0.97M	$0.84M
Suburban	21.9	23.6	$1.24M	$1.15M
Urban	16.4	19.2	$1.77M	$1.51M
Total	42.3	47.4	$1.42M	$1.27M

The overall Proactive Main Replacement program costs have increased over the past several years, in part because the proportion of cast iron gas mains that the Company is replacing has increased. Moreover, the costs for replacement of cast iron main is typically greater than unprotected bare steel due to several key factors, including the following: (1) cast iron is predominant on low and intermediate pressure systems consisting of larger diameter mains; and (2) cast iron facilities are typically centralized in urban areas where costs are driven by higher customer density, greater underground congestion (e.g., excavation), and increased restoration and traffic control. In FY 2021, the Company is increasing the cast iron abandonment percentage to 61 percent of total leak-prone pipe inventory, which is a 1 percent increase from the FY 2020 Plan. Cast iron represents 64 percent of the Company's total leak-prone main inventory in Rhode Island. The Company has analyzed historic costs and has developed budget projections based on project specific main replacement candidates identified for completion in the program. For FY 2021, the Company proposes to spend $59.25 million on the Proactive Main Replacement (<16-inch) program.

2. **Proactive Large Diameter Program (>=16-inch)**

The Company operates approximately 37 miles of large diameter (greater than or equal to 16-inches) leak-prone gas mains. The Proactive Large Diameter Program consists of rehabilitating large diameter leak-prone pipe through the implementation of a sealing and lining program. For FY 2021, the Company proposes to spend a total of $3.40 million on this program to address approximately one mile of large diameter leak-prone pipe. This includes lining 2,600 feet of cast iron main of 16-inches or more. In addition, the Company will seal 2,500 feet of 16-inch cast iron main. Lining and sealing are cost-effective alternatives for remediating large diameter leak-prone pipe. Additional benefits of this program include minimization of impact to customers and communities, a shortened construction period, and use of existing space in areas with significant underground utility congestion. All of this work is located in Providence.

3. **Proactive - Atwells Avenue Main Replacement**

In the 2017-2018 winter period, the Company experienced four main breaks on Atwells Avenue in Providence on 12-inch low pressure cast iron main installed in the 1870s. This main is located in one of the busiest streets in Providence, with a heavy concentration of restaurants. Upon completion of an integrity analysis, the Company concluded that it was necessary to abandon over one mile of cast iron main and replace it with over one mile (5,505 feet) of high-density polyethylene (HDPE) plastic pipe between FY 2020 and FY 2022. The project is broken into 4 segments; 1A – 1,565 feet; 1B – 1,565 feet; 2 – 965 feet; and 3 – 1,410 feet. In FY 2020, the Company is addressing the highest risk segment, Segment 2. In mid-September 2019, the City of Providence granted the Company a permit to begin that work. Due to the later than anticipated field work start date, the Company was unable to accelerate the Segment 1A work into FY 2020, and Segment 1A is now part of the FY 2021 workplan. The $5.08 million budget in FY 2021 includes the completion of Segments 1A and 1B (approximately 0.6 miles of installation and abandonment of leak-prone gas main) and the engineering and design work in preparation of Segment 3, which is scheduled to be completed in FY 2022. The Company anticipates that the final restoration work associated with Segment 2 will be completed in FY 2020. The final restoration work associated with Segments 1A and 1B, along with the field work for Segment 3, are scheduled to be completed as part of the estimated FY 2022 budget of $5.19 million. The total estimated cost for the Atwells Avenue main replacement project is approximately $11.63 million, although the estimate is subject to change.

B. Proactive Service Replacement Program

National Grid has identified 700 isolated leak prone services that will not be replaced as part of the Proactive Main Replacement Program because they are located on mains that are not leak prone. The Company will replace 100 services each year for the next seven years. The annual cost of the Proactive Service Replacement Program is $0.35 million. Please note that the costs in this category do not include the estimated incremental cost associated with complying with the new RI paving law. Those costs, explained above, will be tracked as a separate line item.

C. Reliability

Reliability spending includes 14 programs to address gas control and system automation, heating, pressure regulation, take stations, valve installation/replacement, gas network reliability and resiliency, distribution station over pressure protection, LNG facilities, replacement pipe on bridges, access protection remediation, and capital tools and equipment. The FY 2021 Gas ISR Plan contains $36.25 million in spending for Gas System Reliability. The costs in this category do not include any incremental cost associated with complying with the new RI paving law, and no costs have been built into the incremental paving cost estimate because the volume of paving associated with reliability work is limited. Any incremental paving costs incurred will be tracked as a separate line item in the Company's quarterly reports. Additionally, the costs in the Reliability categories do not include the estimated incremental cost of $0.23 million associated with complying with the new PE Stamp statutory requirements. The PE Stamp costs will be tracked as a separate line item. Of the $36.25 million budget, $20.66 million are costs specifically related to ensuring the Resiliency of the Company's gas distribution system. These programs are designed to enhance the Company's ability to ensure the system is able to perform on the coldest days of the year or in the event of an incident that impacts delivery of gas supply to the Rhode Island system. Resiliency Programs are also designed to enhance the Company's ability to respond to emergencies and to minimize impacts to the system and our customers in the event of a supply interruption or other incidents that require interrupting gas service. A summary of each major program is provided below. Resiliency programs are identified in each category. The table below summarizes the programs that support Resiliency.

	FY 2021 Reliability Totals	FY 2021 Resiliency Subcategory	Resiliency Sub-Categories
Reliability Categories			
Gas System Control	$118		
System Automation	$1,252	$1,252	System Automation, Remote Operation from Gas Control
Heater Program	$2,961		
Pressure Regulating Facilities	$7,849	$7,849	Including second bypass valve installations
Allens Ave Multi Station Rebuild	$6,200		
Take Stations Rebuild	$995	$995	Take Station Refurbishments
Valve Installation/Replacement (incl Storm Hardening & Aquidneck Isl)	$676	$498	Valve Installation - Newport and Middletown
Gas System Reliability - Gas Planning	$2,371		
I&R - Reactive	$1,392		
Distribution Station Over Pressure Protection	$3,636	$3,636	Distribution Station Over Pressure Protection
LNG	$6,433	$6,433	Exeter, Cumberland, Support for Aquidneck Island
Replace Pipe on Bridges	$1,500		
Access Protection Remediation	$260		
Tools & Equipment	$603		
Reliability & Resiliency Totals	**$36,246**	**$20,663**	

1. <u>Gas System Control</u>

Under the Gas System Control – Training Simulator project, the Company's Gas Control and Critical Network Infrastructure personnel will use funding of $0.12 million to purchase, design and implement a real-time system modeled simulator for the training of new and in place Operators. Under the Federal Control Room Management Regulations CFR 192.631, pipeline operators are required to incorporate the use of either table-top scenario or simulator based technology in the training of the Gas System Operators. Currently, the Company relies on paper based tabletop scenarios. The enhanced use of simulator based training for Operators will allow real time system based training to occur in response to normal, abnormal and emergency operating conditions and provide real time feedback in real world systems. This will allow Gas System Operators to recognize, react, and determine the correctness of their actions in real time to optimize gas system performance and to prevent real life emergency situations from occurring.

2. <u>Valve Installation / Replacement</u>

Valves are used to sectionalize portions of the gas network to support both planned and unplanned field activities. Replacement of inoperable valves is necessary to ensure the Company's continued ability to effectively isolate portions of the distribution system. New valve installations are also occasionally needed to provide the capability to reduce the size of an isolation area where existing valves would result in broader shutdown than desired. For FY 2021, the Company has budgeted $0.68 million for valve work, with approximately $0.50 million for valves in Newport and Middletown. The new valve installations in Newport and Middletown support Resiliency.

3. <u>System Automation</u>

The primary purpose of the System Automation program is to meet the United States Department of Transportation code requirements under 49 C.F.R. Part 192, Docket ID PHMSA 2007-27954, which were issued on December 3, 2009. These code provisions contain the following pipeline safety requirements: (a) control room management/human factors, (b) modernization of the Company's system data and telemetry recording, and (c) increasing the level of system automation and control. The overall System Automation program will increase the safety, reliability, and efficiency of the gas system and, by extension, the level of service the Company provides to its customers.

The Company's ability to provide safe and reliable service is governed to a large extent by the Company's ability to maintain adequate pressure in its gas mains. To accomplish this task, the Company has approximately 196 gas pressure regulator stations disbursed throughout its Rhode Island gas service territory. Although a portion of these regulator stations have full system telemetry and control capability, additional stations require the installation of new telemetry equipment and FY 2021 will be a continuation of the process to equip more stations. In addition to monitoring and controlling the regulator stations, the Company must also monitor system end points to ensure that adequate system pressures are being maintained in remote areas under a variety of operating conditions. For FY 2021, the Company is proposing to spend $1.25 million for its System Automation program, all of which supports Resiliency. The Company's FY 2021 work will provide alternating current power, telemetry, and/or remote control to approximately 25 locations.

4. <u>Heater Program</u>

The Heater installation program provides for the installation and replacement of gas system heaters, which are operated to ensure proper conditioning and control of gas temperatures at key Company facilities. Work for the project identified in this program began in FY 2018, materials are being purchased in FY 2020, and the Company plans to commence construction of the new heaters at the Company's Cranston gate station during FY 2021, which was deferred from FY 2020 due in part to higher than anticipated contractor bids. The Company will spend $2.96 million for the construction phase of this work, along with smaller heater upgrades at other locations, during FY 2021.

5. **Pressure Regulating Facilities**

The Company's pressure regulating facilities have been designed to reliably control gas distribution system pressures and maintain continuity of supply during normal and critical gas demand periods. Each regulator station has specific requirements for flows and pressures based on the anticipated needs of the station. A facility includes both pressure-regulating piping and equipment and control lines, but it may also include a heater or a scrubber. The Company has instituted a program that provides for condition-based assessments of all regulator stations. Accepted engineering guidelines provide for design, planning, and operation of these gas distribution facilities. Applicable state and federal codes are followed to help ensure safe and continuous supply of natural gas to the Company's customers and the communities it serves. The FY 2021 Plan includes enhancements in response to regulator station work prioritized through condition-based assessments, which include, in part, station accessibility, pipe condition (i.e., corrosion), water intrusion, redundancy, station isolation, and common mode failure. In FY 2021, work is planned at eight regulator stations, which includes locations in East Providence, Providence, Newport, Pawtucket, Warwick, and West Warwick. Additionally, work will be done to install a second bypass valve at nine stations to prevent a failure of a single bypass valve resulting in over pressurization, of which, three stations are located in Middletown and four stations are located in Newport. The Company plans to spend $7.85 million for this category during FY 2021, all of which support Resiliency.

6. **Allens Avenue Multi Station Rebuild Project**

The Allens Avenue Multi Station Rebuild project is a multi-year project designed to replace or retire eight existing pressure regulating facilities at the Company's major gas interchange in Providence. Four of the existing regulator stations that feed the 99 pounds per square inch gauge (psig) distribution system will be replaced by, and consolidated into, a single new station, with that portion of work scheduled to begin in October 2019 and completed by the end of FY 2021. An additional three regulator stations feeding various distribution systems at other pressures will be relocated off-property, which will help enable abandonment of additional leak-prone pipe and is planned to begin in FY 2021. An eighth station will be retired by integrating the downstream system with an existing distribution network during the project. The new facilities on the site are designed with storm hardening protections to ensure safe and continued operation in the event of adverse weather impacts and flooding. The scope of work also includes the abandonment and/or removal of obsolete pipe and equipment in support of the safety and reliability of the Company's distribution system at this location. A component of the Allens Avenue Project is an LNG send-out line with an estimated cost of $1.30 million. This work was originally scheduled to be completed in FY 2021, will now be moved up to FY 2020. Advancing this work will help accelerate the project timeline and reduce the

FY 2021 budget requirement. Incorporating that change, in FY 2021, the Company plans to spend $6.20 million to relocate and commission three regulator stations and complete additional pipework associated with the new 99 psig regulator station.

7. <u>Take Station Refurbishments</u>

The Take Station Refurbishment program will address required modifications to the Company's custody transfer stations. Projects include installation of third layer of over pressure protection with remote operation capability at multiple stations, design costs for future station construction, and control line replacement work. The remote operated valves will be installed at high pressure connection points and will support the ability to shorten response time in the event of a major gas release. The Company plans to spend $1.00 million for this program during FY 2021. Take station refurbishments are designed to support Resiliency.

8. <u>Gas System Reliability – Gas Planning Program</u>

The Gas Planning program identifies projects that support system reliability through standardization and simplification of system operations (e.g., system up-ratings and de-ratings and regulator elimination), integration of systems (e.g., tie-ins), and new supply sources (e.g., take stations). The FY 2021 budget includes funding for the initial phase of a multi-year project designed to eliminate a single-feed system and engineering costs to address enhancements to the Cumberland Take Station on Scott Road. Funding is also included for the project closeout costs for the Wood at Woodlawn regulator station in

Bristol, which is being completed to move a regulator station out of flood plain area. For FY 2021, the Company proposes to spend approximately $2.37 million for this program.

9. <u>Instrumentation and Regulation (I&R) Reactive Program</u>

The I&R Reactive program is established to address capital project requirements over and above the Pressure Regulation capital budget. Projects range from instrumentation replacement due to failure; replacement of obsolete/unreliable equipment, such as regulators, pilots, boilers, heat exchangers, odorant equipment, and station valves; and replacement of building roofs or doors due to deterioration. New additions to the program for FY 2021 include the installation of override pilots to protect the system in case of control line damage or failure, as was the case recently with a gas system outside of Rhode Island. For FY 2021, the Company proposes to spend $1.39 million for this program.

10. <u>Distribution Station Over Pressure Protection</u>

The Distribution Station Over Pressure Protection program is new for FY 2021 and has been implemented to address risks for over pressurization incidents at pressure regulating facilities throughout the system. Actions planned for this program include work to relocate and provide additional protections for regulator sensing and control lines to protect from third-party damage, installation of additional control equipment to ensure safe and reliable regulator operation in the event of control line damage, and installation of new relief valves on the system to ensure that potential abnormal operating conditions at regulator stations do not result in over pressurization scenarios. For FY 2021, the Company proposes to spend $3.64 million for this program which supports Resiliency.

11. <u>LNG</u>

The LNG program is established to address specific and blanket capital project requirements to support the Company's LNG operations. This program includes $5.42 million of funding for specific projects associated with the Exeter LNG facility, including the purchase of, and preparation for the installation of, two new boil-off compressors which will replace two compressors that were originally commissioned in the early 1970's, installation of an automated emergency shutdown system and associated upgrades to the fire alarm system, preparation for the installation of a high expansion foam system, and the purchase of critical spares for items that aren't readily available (i.e. long lead times). Additional funding of $0.57 million is associated with the blanket program for the Exeter LNG plant, which is aligned with recent historical experience for this facility. Funding also includes $0.25 million for engineering and infrastructure costs associated with peak shaving requirements for Aquidneck Island. Finally, funding also includes $0.20 for a Cumberland Tank Replacement feasibility study. For FY 2021, the Company plans to spend $6.43 million for the LNG program, all of which supports Resiliency.

12. <u>Replace Pipe on Bridges</u>

In FY 2021, the Company expects to spend $1.50 million for project planning, engineering, and long-lead materials in preparation for the replacement of main on the

Goat Island bridge in Newport. The Rhode Island Department is Transportation (RIDOT) is currently planning a project to repair or replace the bridge, with construction anticipated to begin in FY 2022.

13. Access Protection Remediation

The Access Protection Remediation program is designed to reduce the risk of public injury by restricting and/or deterring public access to the Company's elevated gas facilities. In FY 2021, the Company expects to spend $0.26 million for the identification and execution of projects for this program.

14. Capital Tools and Equipment

This category includes tools and equipment required to support the performance of work contained in the Gas ISR Plan and to provide for the safety and reliability of the gas distribution system. The Company will spend $0.60 million on capital tools and equipment during FY 2021.

D. Gas Expansion – Southern Rhode Island Project

As was detailed in the FY 2020 Gas ISR, the Company has identified a need and has begun to build in increased capacity in the Southern Rhode Island service territory. The more than 30,000 customers in the Company's Southern Rhode Island service territory are served by almost 600 miles of distribution infrastructure, including approximately 77 miles of distribution main operating at pressures of 99 psig and above (the Southern Rhode Island Distribution Mains). As of 2018, growth forecasts indicated the maximum vaporization capacity at the Exeter

LNG facility would be exceeded by calendar year 2019. This could have resulted in approximately 3,750 customers with below minimum pressures and them being at risk of losing service. In addition, several regulator station inlet pressures are predicted to fall below the minimum threshold, which would cause problems on the downstream pressure systems if the regulator stations cannot maintain their outlet set pressure. Increasing capacity in Southern Rhode Island mitigates the risk of customers in the region losing service in the event of an outage at the Exeter LNG facility. Moreover, many commercial customers seeking to expand existing and new operations in the Southern Rhode Island region, such as in and around Quonset Point, cannot be served without this project. Without this project, the Company may have needed to impose a moratorium on all new gas service requests, as well as requests for expansion of existing gas service, to prevent service interruptions to existing customers.

To address these capacity issues, in FY 2020, the Company began construction on a project to reinforce the Southern Rhode Island Distribution Mains by installing approximately five miles of new 20-inch steel distribution main parallel to the existing 12-inch distribution main located beneath Route 2 (a Rhode Island Department of Transportation right-of-way) through the towns of Warwick, West Warwick, and East Greenwich. The parallel distribution main is being constructed to be in-line inspected, initially operated at 99 psig, and designed for a maximum allowable operating pressure (MAOP) of 200 psig to meet future demand. The new distribution main will be placed in-service in phases between FY 2020 and FY 2022, with normal operation at 99 psig and the potential to operate at 200 psig after a district regulator station is installed in the future near South Road in East Greenwich. This project will also require work on existing regulator and take stations from FY 2021 through FY 2023. Based on current forecasts, each segment will add immediate growth capacity. Once all of the segments are completed, the Company expects that approximately 1,100 dekatherms per hour of additional capacity will be available. The installation of a second distribution main will also improve the reliability of the Company's gas distribution system in the area by decreasing the Company's dependence on pressure support from the Exeter LNG facility and by introducing redundancy that reduces the risk associated with a distribution main being out of service.

Between FY 2020 and FY 2024, the Company estimates that it will spend a total of $125.53 million for the Southern Rhode Island Project, which includes $3.54 million for incremental curb to curb paving along with costs associated with new RIDOT concrete base restoration guidelines. The work is comprised of main installation, regulation station investment, and other upgrades and investment. For the main installation portion of the Southern Rhode Island Project, the Company plans to install a total of 5 miles (26,625 feet) of new 20-inch steel distribution main. Between FY 2020 and FY 2023, the total estimated cost for the main installation work is currently $96.79 million, based on a completed design and an 80 percent level of confidence based on identified risks and future unknown risks, which includes incremental paving costs of $3.49 million. Factors contributing to the 80 percent project confidence level include the known increase of contractor pricing for the awarded phase 2 & 3 contracts versus the original estimates, assumptions around the increased presence of ledge based on phase 1 field conditions, changes to the RI paving law, new RIDOT concrete base restoration guidelines, permitting and work hour restrictions, requirements for night work, and handling of contaminated soil and ground water. For FY 2021, the Company expects to spend a total of $41.36 million for the main installation work, which includes incremental paving costs of $2.57 million.

In FY 2021, the Company plans to continue preparation work, such as planning, engineering, and site planning, for regulator stations associated with the Southern Rhode Island Project. Between FY 2021 and FY 2023, the Company plans to upgrade the Cranston Take Station and the Cowesett Regulator Station. The total estimated cost for the FY 2020 through FY 2024 regulator station work is currently $17.58 million. Funding of $5.79 million is included for a planned new regulator station located at the southern end of the main installation to reduce the system pressure from a MAOP of 200 psig to 99 psig before feeding back into the distribution system, with the majority of construction planned for FY 2023.

Other upgrades and investment for the Southern Rhode Island Project include the installation of a launcher and receiver to support in-line inspections of the 200 psig main, material testing to support the maximum operating pressure (MOP) increase from 150 psig to 200 psig for 5.2 miles (27,578 feet) of existing main in Cranston and West Warwick, and the installation of a remote operating valve (ROV). The total estimated cost for the FY 2020 through FY 2023 other upgrades and investment work is currently $11.16 million, which includes incremental paving costs of $0.05 million related roadway patches for the MOP increase. For FY 2020, the Company estimates it will spend $3.55 million for the material testing. For FY 2021, the Company estimates it will spend $0.98 million to complete the remainder of the material testing, which includes incremental paving costs of $0.05 million. All other work in this category is planned to occur in FY 2022 and FY 2023. The estimates related to the FY 2022 and FY 2023 work are considered preliminary and will be updated as part of the Company's FY 2022 Gas ISR Plan.

A summary of the total estimate for the Southern Rhode Island Project is presented in the table below.

Southern RI Gas Expansion Spending Forecast

Description	Units	FY 2020 Forecast	FY 2021	FY 2022	FY 2023	FY 2024	Total in FY21 ISR
Main Installation:							
Phase 1	12,625	$ 39,922,433					$ 39,922,433
Phase 2	11,050		$ 38,798,000				$ 38,798,000
Phase 3	2,950			$ 13,982,000			$ 13,982,000
Project Closeout					$ 600,000	$ -	$ 600,000
Subtotal Main Installation	26,625	$ 39,922,433	$ 38,798,000	$ 13,982,000	$ 600,000	$ -	$ 93,302,433
Incremental curb to curb paving*		$ -	$ 2,565,000	$ 926,000	$ -	$ -	$ 3,491,000
Total Main Installation	**26,625**	**$ 39,922,433**	**$ 41,363,000**	**$ 14,908,000**	**$ 600,000**	**$ -**	**$ 96,793,433**
*Cost also includes impact of new RIDOT concrete restoration guidelines							
Regulator Station Investment:							
Cranston Take Station Upgrades		$ 75,000	$ 175,000	$ 9,754,000	$ 100,000	$ -	$ 10,104,000
Cowesett Regulator Station Upgrades		$ 75,000	$ 175,000	$ 1,337,000	$ 100,000	$ -	$ 1,687,000
New Regulator Station		$ 50,000	$ 380,000	$ 100,000	$ 5,205,000	$ 50,000	$ 5,785,000
Total - Regulator Station Investment		**$ 200,000**	**$ 730,000**	**$ 11,191,000**	**$ 5,405,000**	**$ 50,000**	**$ 17,576,000**
Other Upgrades/Investment:							
Launcher/Receiver		$ -	$ -	$ -	$ 5,698,000	$ -	$ 5,698,000
MOP Increase from 150 to 200 psi		$ 3,554,654	$ 932,000	$ 50,000	$ -	$ -	$ 4,536,654
Installation of ROV				$ 873,000	$ -	$ -	$ 873,000
Subtotal - Other Investment		$ 3,554,654	$ 932,000	$ 923,000	$ 5,698,000		$ 11,107,654
Incremental curb to curb paving		$ -	$ 49,000	$ -	$ -	$ -	$ 49,000
Total - Other Investment		**$ 3,554,654**	**$ 981,000**	**$ 923,000**	**$ 5,698,000**	**$ -**	**$ 11,156,654**
Subtotal Southern RI Gas Expansion Project (Excluding Incremental Curb to Curb Paving)		$ 43,677,087	$ 40,460,000	$ 26,096,000	$ 11,703,000	$ 50,000	$ 121,986,087
Total Incremental curb to curb paving		$ -	$ 2,614,000	$ 926,000	$ -	$ -	$ 3,540,000
Total Southern RI Gas Expansion Project		**$ 43,677,087**	**$ 43,074,000**	**$ 27,022,000**	**$ 11,703,000**	**$ 50,000**	**$ 125,526,087**

For FY 2021, the Company estimates it will spend a total of $43.07 million for the Southern Rhode Island Project. This includes $41.36 million for the installation of 2.1 miles (11,050 feet) of gas main, $0.73 million related to regulator stations, and $0.98 million to complete the final portion of the material testing required to increase the maximum operating pressure from 150 psig to 200 psig for the 5.2 miles (27,578 feet) of existing main in Cranston and West Warwick.

Excluding the Gas Expansion category, the proposed Gas ISR Plan contains $104.33 million in spending for Discretionary work in FY 2021. Including the Gas Expansion category, the proposed Plan contains a total of $144.79 million in spending for Discretionary work.

O&M Expenses:

A. <u>Heat Decarbonization</u>

National Grid recognizes and supports Rhode Island's need to ensure energy reliability and facilitate the transition towards a low-carbon future and away from the high-carbon, delivered fuels that currently supply roughly 40% of the State's heading needs. The Company believes that the best approach for Rhode Island is a technology-neutral approach, and that a balanced mix of strategic electrification, decarbonized gas, and energy efficiency will play a material role in achieving these objectives. National Grid can help identify and provide greater insights into the actions Rhode Island can take over the next decade to address heating sector reliability and emissions and which types of actions should be undertaken at pilot versus commercial scale.

For instance, geothermal heat pumps are highly efficient and can meet whole-home heating and cooling needs. For delivered fuel customers outside of the natural gas network, geothermal is an opportunity to convert to a cleaner heating system. However, the high cost of these systems a lack of public awareness has stifled widescale adoption of this technology. The Company believes that utility involvement can help address both barriers and encourage geothermal heat pump adoption growth.

The Company is proposing a top-down technical and market feasibility analysis of ground source heat pumps, evaluating inclusion of the heating loop in rate base. A two-phased assessment, as it is envisioned, will focus on utility applications at the edge of the gas network (i.e., communities currently seeking gas connections) and how the customer interacts with the technology from a business perspective. This assessment will help inform the Company's future geothermal capital plans.

Phase 1 aims to provide:

- A high-level, techno-economic assessment of geothermal with ground source heat pumps,
- An evaluation of land availability and limitations on the use thereof, and
- Identification of site selection criteria.

Phase 1 will be used to understand the potential for geothermal heat pumps to contribute to heating sector emissions reductions in Rhode Island and inform supporting strategy. It is anticipated the Company will perform the assessment in-house. Phase 2 will focus on identifying suitable sites for utility owned geothermal heat pump systems. This will be accomplished through a market analysis that identifies specific candidate sites, utility business models, and customer offerings, as well as assesses scalability. Due to limited internal resources, the Company anticipates retaining consulting services to assist with Phase 2.

For those customers for whom electrification is impracticable due to economic and / or technical constraints, the Company sees the opportunity to drive the decarbonization of the gas network through renewable natural gas (RNG) and potentially hydrogen blending. RNG presents an extraordinary opportunity to decarbonize the heating sector and leverage existing assets for a more affordable outcome. Integrating RNG converts the existing gas network into a clean energy distribution system that delivers low- or zero-carbon fuel to customers. We believe that decarbonizing the gas and electric networks in parallel can reduce the cost of achieving deep decarbonization goals. Integrating RNG will allow customers to reduce their carbon footprint, without having to replace equipment or undertake deep renovations, minimizing disruption and upfront capital costs for our customers.

The objective of this project is to understand the potential near-and long-term gas demand in Rhode Island that can be served by RNG. To accomplish this, the Company proposes a bottom-up RNG (including hydrogen) economic potential assessment. Specifically, the Company proposes estimating the potential amount of near and long-term non-electric gas demand in Rhode Island that can be served by RNG based on available feedstocks, load forecasts, and expected renewable generation buildout and dedicated RNG / hydrogen project-specific renewables projects. The most granular, site-specific assessment will be focused on landfill gas given facilities have been operating at scale worldwide for decades. Emerging sources and technologies used to produce RNG (municipal solid waste, food waste) and hydrogen (via electrolyzers) will also be evaluated for near-, mid-, and long-term feasibility. This insight will be used to identify opportunities for utility-led capital programs and projects that provide or integrate low-carbon energy supply, such as:

- Identify and evaluate specific locations for RNG interconnections and potential partners to develop RNG facilities.

- Evaluate locations for future use as a closed-loop hydrogen injection site. The Company would determine if hydrogen can safely be introduced into our system in subsequent years.
- Evaluating locations for use as a future RNG injection site. Engineering work will allow us to ascertain an appropriate and beneficial location to build a hydrogen injection site in the State. The work will provide the Company with a more complete understanding of the application of hydrogen technology in our system. The money requested could be utilized to develop a building site plan for a future electrolyzer, potentially aimed at meeting supply constraints in a specific area, and which could blend 2-3% hydrogen into the system (further allowing us to address potential leak and pipe embrittlement concerns).

Five-Year Gas ISR Investment Plan

As of December 31, 2018, approximately 1,150 miles, or 36 percent, of the 3,201 miles in the Company's gas distribution system in Rhode Island is made up of leak-prone pipe. The 1,150 miles of leak-prone pipe are comprised of 386 miles of unprotected steel, 715 miles of cast iron and wrought iron gas main, and 50 miles of vintage Aldyl-A and Polybutylene plastic. The Company plans to eliminate or rehabilitate all leak-prone pipe within the next 16 years.

The Company's proposed five-year Gas ISR investment plan is provided in Table 2 below. Table 2 contains the approved FY 2020 Plan spending, along with spending projected within each of the primary categories for the period FY 2020 through FY 2024.

The Company's prior five-year Gas ISR investment plan actual spend is provided in Table 3 below.

Table 1
Narragansett Gas
FY 2021
($000)

Categories	Budget	Leak-Prone Pipe Abandonment Miles	Main Replacement Installation Miles
NON-DISCRETIONARY			
Public Works			
CSC/Public Works - Non-Reimbursable	$17,368		
CSC/Public Works - Reimbursable	$1,403		
CSC/Public Works - Reimbursements	($1,403)		
Public Works Total	**$17,368**	**13.0**	**13.0**
Mandated Programs			
Corrosion	$1,166		
Purchase Meters (Replacements)	$4,852		
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	$12,280		
Service Replacements (Reactive) - Non-Leaks/Other	$2,096		
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	$680		
Transmission Station Integrity	$610		
Mandated Total	**$21,684**		
Damage / Failure (Reactive)			
Damage / Failure (Reactive)	**$249**		
NON-DISCRETIONARY TOTAL	**$39,301**		
DISCRETIONARY			
Proactive Main Replacement			
Main Replacement (Proactive) - Leak Prone Pipe	$59,250	47.4	42.3
Main Replacement (Proactive) - Large Diameter LPCI Program	$3,398		
Atwells Avenue	$5,081	0.6	0.6
Proactive Main Replacement Total	**$67,729**	**48.0**	**42.9**
Proactive Service Replacement			
Proactive Service Replacement Total	**$350**		
Reliability			
Gas System Control	$118		
System Automation	$1,252		
Heater Installation Program	$2,961		
Pressure Regulating Facilities	$7,849		
Allens Ave Multi Station Rebuild	$6,200		
Take Station Refurbishment	$995		
Valve Installation/Replacement (incl Storm Hardening & Middletown/Newport)	$676		
Gas System Reliability	$2,371		
I&R - Reactive	$1,392		
Distribution Station Over Pressure Protection	$3,636		
LNG	$6,433		
Replace Pipe on Bridges	$1,500		
Access Protection Remediation	$260		
Tools & Equipment	$603		
Reliability Total	**$36,246**		
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$104,325**		
Southern RI Gas Expansion Project	$40,460		
DISCRETIONARY TOTAL (With Gas Expansion)	**$144,785**		
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$143,626**		
CAPITAL ISR TOTAL (With Gas Expansion) Amount does not include incremental paving associated with new RI Paving Law, PE Stamps, or O&M	**$184,086**	**61.0**	**55.9**
Incremental Costs			
PE Stamps	$1,515		
Incremental Paving - Main Installation	$5,596		
Incremental Paving - Patches	$4,801		
Incremental Paving - Southern RI Gas Expansion	$2,614		
Incremental Costs Total	**$14,526**		
CAPITAL ISR TOTAL **(with Gas Expansion, PE Stamps, and Incremental Paving)**	**$198,612**		
O&M - Heat Decarbonization			
O&M - Heat Decarbonization Total	**$1,000**		
ISR GRAND TOTAL **(with Gas Expansion, PE Stamps, Incremental Paving, and O&M)**	**$199,612**	**61.0**	**55.9**

*Total miles of abandonment will be 62 miles. 1 mile will come from Reinforcement work.

Table 2
RI Gas ISR Spending Forecast
($000)

Investment Categories	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
NON-DISCRETIONARY					
Public Works	$17,368	$17,851	$18,172	$18,815	$20,624
Mandated Programs	$21,684	$27,218	$27,477	$36,431	$40,915
Damage / Failure (Reactive)	$249	$248	$245	$247	$285
Special Projects	$0	$0	$0	$0	$0
NON-DISCRETIONARY TOTAL	**$39,301**	**$45,318**	**$45,894**	**$55,493**	**$61,824**
DISCRETIONARY					
Proactive Main Replacement	$67,729	$74,149	$69,780	$76,185	$76,286
Proactive Service Replacement	$350	$350	$350	$350	$350
Reliability	$36,246	$36,514	$75,774	$73,783	$42,352
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$104,325**	**$111,013**	**$145,904**	**$150,318**	**$118,988**
Southern RI Gas Expansion Project	$40,460	$26,096	$11,703	$50	$0
DISCRETIONARY TOTAL (With Gas Expansion)	**$144,785**	**$137,109**	**$157,607**	**$150,368**	**$118,988**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$143,626**	**$156,330**	**$191,798**	**$205,811**	**$180,811**
CAPITAL ISR TOTAL (With Gas Expansion) Amount does not include incremental paving costs associated with new RI Paving Law, PE Stamps, or O&M	**$184,086**	**$182,426**	**$203,501**	**$205,861**	**$180,811**
INCREMENTAL COSTS					
PE Stamps	$1,515	$1,560	$1,607	$1,655	$1,705
Incremental Paving - Main Installation	$5,596	$5,764	$5,937	$6,115	$6,298
Incremental Paving - Patches	$4,801	$4,945	$5,093	$5,246	$5,404
Incremental Paving - Southern RI Gas Expansion	$2,614	$926	$0	$0	$0
INCREMENTAL COSTS TOTAL	$14,526	$13,195	$12,637	$13,017	$13,407
CAPITAL ISR Total (With Gas Expansion, PE Stamps, and Incremental Paving)	**$198,612**	**$195,622**	**$216,139**	**$218,878**	**$194,218**
O&M - HEAT DECARBONIZATION*					
O&M - Heat Decarbonization Total	**$1,000**	**$0**	**$0**	**$0**	**$0**
ISR GRAND TOTAL (with Gas Expansion, PE Stamps, and Incremental Paving)	**$199,612**	**$195,622**	**$216,139**	**$218,878**	**$194,218**

*Heat Decarbonization FY22-25: Future years are TBD and will be proposed in the FY22 ISR based on outcomes of feasibility studies in FY21.

Table 3

RI Gas ISR Historical Spend
($000)

Investment Categories	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
	Actual	**Actual**	**Actual**	**Actual**	**Actual**
NON-DISCRETIONARY					
Public Works	$ 7,207	$ 7,732	$ 8,597	$ 14,590	$ 13,575
Mandated Programs	$ 15,415	$ 16,861	$ 16,370	$ 22,110	$ 18,868
Damage / Failure (Reactive)	$ -	$ -	$ -	$ 1,610	$ -
Special Projects	$ -	$ -	$ 5,020	$ 1,780	$ 8,486
NON-DISCRETIONARY TOTAL	**$ 22,622**	**$ 24,592**	**$ 29,987**	**$ 40,080**	**$ 40,928**
DISCRETIONARY					
Proactive Main Replacement	$ 40,904	$ 58,386	$ 48,872	$ 51,210	$ 52,629
Proactice Main Replacement - Large Diameter LPCI Program	$ -	$ -	$ -	$ 1,180	$ -
Atwells Avenue	$ -	$ -	$ -	$ -	$ -
Service Replacement - Proactive	$ 1,121	$ 1,789	$ -	$ -	$ -
Reliability	$ 8,968	$ 7,914	$ 8,403	$ 13,950	$ 10,290
Special Projects	$ 3,728	$ 1,188	$ -	$ -	$ -
DISCRETIONARY TOTAL	**$ 54,721**	**$ 69,277**	**$ 57,275**	**$ 66,330**	**$ 62,918**
Base ISR Capital Total (Excluding Growth)	**$ 77,343**	**$ 93,869**	**$ 87,262**	**$ 106,410**	**$ 103,846**
O&M Total	$ 503	$ 464	$ 488	$ 560	$ 179
GAS ISR TOTAL	**$ 77,846**	**$ 94,333**	**$ 87,750**	**$ 106,970**	**$ 104,025**

Section 3
Revenue Requirement

Section 3
Revenue Requirement
FY 2021 Proposal

Revenue Requirement
FY 2021 Proposal

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Gas ISR Plan for the fiscal year ended March 31, 2021.

As shown on Attachment 1, Page 1, Column (b), the Company's FY 2021 Gas ISR Plan cumulative revenue requirement totals $22,354,740. The revenue requirement consists of the following elements: (1) operation and maintenance (O&M) expenses of $1,000,000 associated with heat decarbonization; (2) the revenue requirement of $7,636,309 on FY 2021 proposed non-growth ISR capital investment of $198,612,000, as calculated on Attachment 1, Page 12; (3) the FY 2021 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through FY 2020 totaling $9,007,264, as summarized on Attachment 1, Page 1; and (4) property tax expenses of $4,711,167, as shown on Attachment 1, Page 20, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770. Importantly, the incremental capital investment for the FY 2021 ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4770 for FY 2018 through FY 2021. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan).

For illustration purposes only, Attachment 1, Page 1, Column (c) provides the FY 2022 revenue requirement for the respective vintage year capital investments. Notably, these amounts will be trued up to actual investment activity after the conclusion of the fiscal year, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2021 Gas ISR Plan revenue requirement includes $1,000,000 of operation and maintenance expenses as shown on Page 1, Line 1, associated with heat decarbonization. These proposed operation and maintenance expenses are discussed in Section 2 of this Plan.

Gas Infrastructure Investment

Incremental Capital Investment

As noted above, Attachment 1, Page 12 calculates the revenue requirement of incremental capital investment associated with the Company's FY 2021 Gas ISR Plan, that is, gas infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment, including cost of removal, was obtained from Table 1 in Section 2 of the Plan. The FY 2021 revenue requirement also includes the incremental capital investment associated with the Company's actual ISR capital investments from FY 2018 through FY 2019 and FY 2020 ISR Plan, excluding investments reflected in rate base in Docket No. 4770.

Attachment 1, Page 15 calculates the incremental FY 2018 through FY 2021 ISR capital investment and the related incremental cost of removal, incremental retirements, and incremental net operating loss (NOL) position for the FY 2021 ISR revenue requirement. The calculations on Page 15 compare ISR-eligible capital investment, cost of removal, retirements, and net NOL position for FY 2018 through FY 2021 to the corresponding amounts reflected in rate base in Docket No. 4770.

Incremental Capital Investment Calculation

The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with plant additions incurred to expand its gas infrastructure and improve the reliability and safety of its gas facilities. When new base rates are implemented, as was the case in Docket No. 4770, the Company no longer recovers costs for pre-rate case ISR plant additions through a separate ISR factor. Instead, such costs are recovered through base rates, and the underlying ISR plant additions become a component of base distribution rate base from that point forward. The forecast used to develop rate base in the distribution rate case included ISR plant additions levels for FY 2018, FY 2019, and five months of FY 2020 (using the level of plant additions approved in the FY 2018 Gas ISR Plan as a proxy for FY 2019 and FY 2020). The effective date of new rates in Docket No. 4770 was September 1, 2018. Therefore, recovery of the approved FY 2012 through FY 2017 ISR revenue requirement through the ISR factor ended on August 31, 2018, and all future recovery of those ISR plant additions will be through the Company's base rates.

As a result of the implementation of new base rates pursuant to Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR plant additions were rolled into base rates effective at that date. The FY 2021 revenue requirement for incremental FY 2018, FY 2019, and FY 2020 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's rate base in Docket 4770. These incremental fiscal year vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved Amended Settlement Agreement in Docket No. 4770. The current filing is based on the actual ISR investment made during the Company's fiscal years ended March 31, 2018 and 2019 and estimated ISR investment levels for the Company's fiscal years ended March 31, 2020 and 2021, and which are incremental to the levels reflected in rate base in the Company's last base rate case (Docket No. 4770).

Gas Infrastructure Revenue Requirement

The revenue requirement calculation on incremental gas infrastructure investment for vintage year FY 2021 is shown on Attachment 1, Page 12. The revenue requirement calculation incorporates the incremental Gas ISR Plan capital investment, cost of removal, and retirements, which are the basis for determining the two components of the revenue requirement: (1) the return on investment (i.e., average Plan rate base at the weighted average cost of capital) and (2) depreciation expense. The calculation on Page 12 begins with the determination of the depreciable net incremental capital that will be included in the Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in the Plan rate base in determining depreciation expense. Retirements, however, do not affect rate base, as both plant-in-service and the depreciation reserve are reduced by the installed value of the plant being retired and, therefore, have no impact on net plant. Incremental book depreciation expense on Line 12 is computed based on the net depreciable additions from Line 3 at the 2.99 percent composite depreciation rate approved in Docket No. 4770, and as shown on Line 9. The Company has assumed a half-year convention for the year of installation. Unlike retirements, cost of removal affects rate base, but not depreciation expense. Consequently, the cost of removal, as shown on Line 7, is combined with the incremental depreciable amount from Line 6 (vintage year ISR Plan allowable capital additions, less non-general plant depreciation expense included in base distribution rates) to arrive at the incremental investment on Line 8 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 8 and accumulated depreciation on current vintage year investment and accumulated deferred tax reserves as shown on Lines 13 and 18, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 14 through 18, equals the difference between book depreciation and tax depreciation on the capital investment, multiplied by the effective tax rate, net of any tax net operating loss (NOL) or NOL utilization. The calculation of tax depreciation is described below. The average rate base before deferred tax proration adjustment is shown on Line 23. This amount then nets with the deferred tax proration adjustment on Line 24 to derive the average ISR rate base on Line 25. This average rate base is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4770, as shown on Line 26, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 27. Incremental depreciation expense is added to this amount on Line 28. The sum of these amounts reflects the annual revenue requirement associated with the capital investment portion of the Plan on Line 29, which is carried forward to Page 1 as part of the total Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018 through FY 2020 incremental Plan capital investment are shown on Pages 2, 5 and 8, respectively. These capital investment revenue requirement amounts are added to the total property tax recovery on Page 1, Line 8 and the operation and maintenance expense on Page 1, Line 1 to derive the total FY 2021 Gas ISR Plan revenue requirement of $22,354,740, as shown on Page 1, Line 10.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2021 is provided on Attachment 1, Page 13. The tax depreciation amount assumes that a portion of the capital investment, as shown on Lines 1 through 3, will be eligible for immediate deduction on the Company's fiscal year federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[1] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation, as shown on Page 13, Lines 4 through 12 for FY 2021. During 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the 2010 Tax Act), which provided for an extension of bonus depreciation. Specifically, the

[1] In 2009, the Internal Revenue Service (IRS) issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. Since that time, the Company has taken a capital repairs deduction on all subsequent fiscal year tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the Gas ISR Plan.

2010 Tax Act provided for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 31, 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013, and then extended further through December 31, 2017 via the Protecting Americans From Tax Hikes (PATH) Act. As noted in the Company's previous Gas ISR filings, the Tax Cuts and Jobs Act of 2017 (the 2017 Tax Act) went into effect on December 22, 2017. The 2017 Tax Act has many elements, but two particular aspects have an impact on the Gas ISR revenue requirement. The first is the reduction of the federal income tax rate from 35 percent to 21 percent commencing January 1, 2018. The second 2017 Tax Act element affecting the Gas ISR revenue requirement is changes to the bonus depreciation rules eliminating bonus depreciation for certain capital investments, including ISR-eligible investments, effective September 28, 2017. However, property acquired prior to September 28, 2017 and placed in service in tax years beginning after December 31, 2017 is allowed bonus depreciation. The Company's original interpretation of the 2017 Tax Act was that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company has revised its estimate of FY 2019 and FY 2020 bonus depreciation. The Company's FY 2021 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2021 investment.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a

§481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal (COR). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100% deductible. The vintage FY 2018 through FY 2021 tax depreciation calculations in this filing include an additional tax deduction related to this change in accounting issue. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and cost of removal. These annual total tax depreciation amounts are carried forward to Line 10 of Page 12 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2018, FY 2019 and FY 2020 on Pages 3, 6 and 9, respectively.

The Company continues to monitor for new guidance pertaining to the 2017 Tax Act and any resulting impacts to its pending rate requests. The Company will file its FY 2019 tax return in December 2019. At that time, the Company will evaluate whether any revisions are required to its calculation of accumulated deferred income taxes included in rate base in the FY 2019, FY 2020, and FY 2021 vintage revenue requirement calculations in this docket. If so, the Company will supplement this filing with a revised FY 2021 revenue requirement calculation.

Federal Net Operating Loss

Tax NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. Tax NOLs do not mean that the Company is suffering losses in its financial statements. Instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the Internal Revenue Code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return. However, such costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions have exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2018, with the exception of FY 2011 and FY 2017. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies the NOLs against taxable income in the future.

As a result of the 2017 Tax Act, the Company originally did not expect to generate new NOLs in FY 2018 and anticipates it will begin to utilize prior years' NOLs in FY 2019. Estimated NOL utilization is included in base rates in Docket No. 4770. Therefore, the calculation of accumulated deferred income taxes in this filing includes only the incremental amount of forecasted NOL utilization in FY 2021, which is the fiscal year the benefit would be reflected in the Company's federal income tax return.

NOL utilization is an increase to the Company's accumulated deferred income taxes. Accumulated deferred income taxes, which equal the difference between book depreciation and tax depreciation on ISR capital investment, multiplied by the effective tax rate, are included as a credit or reduction in the calculation of rate base.

Accumulated Deferred Income Tax Proration Adjustment

The Gas ISR Plan includes a proration calculation with respect to the accumulated deferred income tax (ADIT) balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(l)-1(h)(6). This regulation sets forth normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing which includes capital expenditures, book depreciation expense, and ADIT related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the ADIT balances are in rate base. This filing includes FY 2018, FY 2019, FY 2020, and FY 2021 proration calculations at Attachment 1, on Pages 4, 7, 10 and 14, respectively, the effects of which are included in each year's respective revenue requirement.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is set forth on Attachment 1, Pages 19 and 20. The method used to recover property tax expense under the Gas ISR Plan was modified by the Amended Settlement Agreement in Docket No. 4323 and continued by the Amended Settlement Agreement in Docket No. 4770. In determining the base on which property tax expense is calculated for purposes of the Plan revenue requirement, the Company includes an amount equal to the base rate allowance for depreciation expense and depreciation expense on incremental Plan plant additions in the accumulated reserve for depreciation that is deducted from plant-in-service. The Property Tax Recovery Adjustment also includes the impact of any changes in the Company's effective property tax rates on base rate embedded property, plus cumulative Plan net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery formula. This provision of the Amended Settlement Agreement in Docket No. 4323 took effect for Plan property tax recovery periods subsequent to the end of the rate year for that docket, or January 31, 2014, and has been continued by the Amended Settlement Agreement in Docket No. 4770. The FY 2021 revenue requirement includes $4,711,167 for the Net Property Tax Recovery Adjustment.

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Operation and Maintenance Expenses			
1	Forecasted Gas Infrastructure, Safety, and Reliability O&M Expenses	$0	$1,000,000	$0
	Capital Investment:			
2	Actual Revenue Requirement on FY 2018 Incremental Capital Included in ISR Rate Base	$663,731	$676,445	$690,881
3	Actual Revenue Requirement on FY 2019 Incremental Capital Included in ISR Rate Base	($666,404)	($1,002,387)	($1,003,034)
4	Forecasted Revenue Requirement on FY 2020 Capital Included in ISR Rate Base	$4,123,711	$9,333,206	$9,082,041
5	Forecasted Revenue Requirement on FY 2021 Capital Included in ISR Rate Base		$7,636,309	$15,098,354
6	Total Capital Investment Revenue Requirement	$4,121,038	$16,643,573	$23,868,242
7	FY 2020 Property Tax Recovery Adjustment	$2,353,682		
8	FY 2021 Property Tax Recovery Adjustment		$4,711,167	
9	Total Capital Investment Component of Revenue Requirement	**$6,474,720**	**$21,354,740**	**$23,868,242**
10	Total Fiscal Year Revenue Requirement	**$6,474,720**	**$22,354,740**	**$23,868,242**
11	Incremental Fiscal Year Rate Adjustment		**$15,880,020**	

Column Notes:
(a) RIPUC Docket No. 4916, Revised Section 3, Attachment 1R, Page 1 of 19

Line Notes for Columns (b) and (c):
1 Section 2, Table 1
2 Page 2 of 22, Line 30, Col. (d) and Col. (e)
3 Page 5 of 22, Line 29, Col. (c), and Col. (d)
4 Page 8 of 22, Line 29, Col. (b), and Col. (c)
5 Page 12 of 22, Line 29, Col. (a), and Col. (b)
6 Sum of Lines 2 through Line 5
8 Line 63, Column (k) × 1,000
9 Sum of Line 6 through Line 8
10 Line 1 + Line 9
11 Line 10 Col (b) - Line 10 Col (a)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Computation of Revenue Requirement on FY 2018 Actual Incremental Gas Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)
	Depreciable Net Capital Included in ISR Rate Base							
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 15 of 22 , Line 3 ,Col (a)		$4,632,718	$0	$0	$0	$0
2	Retirements	Page 15 of 22 , Line 9 ,Col (a)		$12,059,428	$0	$0	$0	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line		($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)
	Change in Net Capital Included in ISR Rate Base							
4	Capital Included in ISR Rate Base	Line 1		$4,632,718	$0	$0	$0	$0
5	Depreciation Expense			$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718
7	Cost of Removal	Page 15 of 22 , Line 6 ,Col (a)		$1,941,168	$1,941,168	$1,941,168	$1,941,168	$1,941,168
8	**Net Plant Amount**	**Line 6 + Line7**		**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**
	Deferred Tax Calculation:							
9	Composite Book Depreciation Rate		1/	3.38%	3.15%	2.99%	2.99%	2.99%
10	Tax Depreciation	Year 1=Page 3 of 22, Line 24, Col (a); then = Page 3 of 22, Col (d)		$7,820,728	$21,720	$20,089	$18,585	$17,189
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$7,820,728	$7,842,448	$7,862,538	$7,881,123	$7,898,312
12	Book Depreciation	Year 1= Line 3 × Line 9 × 50%; then = Line 3 × Line 9		($125,511)	($234,127)	($222,059)	($222,059)	($222,059)
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		($125,511)	($359,638)	($581,697)	($803,756)	($1,025,814)
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$7,946,239	$8,202,087	$8,444,235	$8,684,878	$8,924,126
15	Effective Tax Rate		2/	21.00%	21.00%	21.00%	21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$1,668,710	$1,722,438	$1,773,289	$1,823,824	$1,874,066
17	Less: FY 2018 Federal NOL	-Page 21 of 22, Line 10, Col (e)		($6,051,855)	($6,051,855)	($6,051,855)	($6,051,855)	($6,051,855)
18	Excess Deferred Tax	(Line 14 × 31.55% blended FY18 tax rate) - Line 16; then = Prior Year Line 18	3/	$838,328	$838,328	$838,328	$838,328	$838,328
19	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17 + Line 18		($3,544,817)	($3,491,089)	($3,440,238)	($3,389,703)	($3,339,461)
	ISR Rate Base Calculation:							
20	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886
21	Accumulated Depreciation	- Line 13		$125,511	$359,638	$581,697	$803,756	$1,025,814
22	Deferred Tax Reserve	- Line 19		$3,544,817	$3,491,089	$3,440,238	$3,389,703	$3,339,461
23	Year End Rate Base before Deferred Tax Proration	Sum of Lines 20 through 22		$10,244,214	$10,424,613	$10,595,821	$10,767,344	$10,939,161
	Revenue Requirement Calculation:							
24	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = 0; then Average of (Prior + Current Year Line 23)					$10,681,583	$10,853,253
25	Proration Adjustment	Year 1 and 2 =0; then = Page 4 of 22, Line 41, Col (j), Col (k) and Col (l)					$2,169	$2,157
26	Average ISR Rate Base after Deferred Tax Proration	Line 24 + Line 25					$10,683,752	$10,855,409
27	Pre-Tax ROR	Page 22 of 22, Line 30, Column (e)					8.41%	8.41%
28	Return and Taxes	Line 26 × Line 27					$898,504	$912,940
29	Book Depreciation	Year 1 = N/A; then = Line 12					($222,059)	($222,059)
30	**Annual Revenue Requirement**	**Sum of Lines 28 through 29**		**N/A**	**N/A**	**N/A**	**$676,445**	**$690,881**

1/ 3.38%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.38% × 5 /12 + 2.99% × 7 / 12
2/ The Federal Income Tax rate changed from 35% to 21% on Janurary 1, 2018 per the Tax Cuts and Jobs Act of 2017

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 2 of 22, Line 1		$4,632,718	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.43%				
3	Capital Repairs Deduction	Line 1 × Line 2		$3,957,731	MACRS basis:		$300,875	
							Annual	Cumulative
					Fiscal Year			
4	Bonus Depreciation				2018	3.75%	$11,283	$7,820,728
5	Plant Additions	Line 1		$4,632,718	2019	7.22%	$21,720	$7,842,448
6	Less Capital Repairs Deduction	Line 3		$3,957,731	2020	6.68%	$20,089	$7,862,538
7	Plant Additions Net of Capital Repairs Deduction	Line 5 - Line 6		$674,987	2021	6.18%	$18,585	$7,881,123
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	2022	5.71%	$17,189	$7,898,312
9	Plant Eligible for Bonus Depreciation	Line 7 × Line 8		$674,987	2023	5.29%	$15,901	$7,914,213
10	Bonus depreciation 100% category	100% × 15.86%	2/	15.86%	2024	4.89%	$14,707	$7,928,920
11	Bonus depreciation 50% category	50% × 58.05%	2/	29.03%	2025	4.52%	$13,606	$7,942,525
12	Bonus depreciation 40% category	40% × 26.35%	2/	10.54%	2026	4.46%	$13,425	$7,955,950
13	Bonus Depreciation Rate (October 2017 - March 2018)	1 × 50% × 0%	2/	0.00%	2027	4.46%	$13,422	$7,969,372
14	Total Bonus Depreciation Rate	Line 10 + Line 11 + Line 12 + Line 13		55.43%	2028	4.46%	$13,425	$7,982,797
15	Bonus Depreciation	Line 9 × Line 14		$374,112	2029	4.46%	$13,422	$7,996,219
					2030	4.46%	$13,425	$8,009,644
	Remaining Tax Depreciation				2031	4.46%	$13,422	$8,023,066
16	Plant Additions	Line 1		$4,632,718	2032	4.46%	$13,425	$8,036,491
17	Less Capital Repairs Deduction	Line 3		$3,957,731	2033	4.46%	$13,422	$8,049,913
18	Less Bonus Depreciation	Line 15		$374,112	2034	4.46%	$13,425	$8,063,338
19	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 16 - Line 17 - Line 18		$300,875	2035	4.46%	$13,422	$8,076,761
20	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	2036	4.46%	$13,425	$8,090,186
21	Remaining Tax Depreciation	Line 19 × Line 20		$11,283	2037	4.46%	$13,422	$8,103,608
					2038	2.23%	$6,713	$8,110,320
22	FY18 tax (gain)/loss on retirements	Per Tax Department	3/	$1,536,434		100.00%	$300,875	
23	Cost of Removal	Page 2 of 22, Line 7		$1,941,168				
24	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 21, 22 & 23		$7,820,728				

1/ Capital Repairs percentage is based on the actual results of the FY 2018 tax return.
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2018 tax return
3/ Actual Loss for FY2018

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**			(a) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 4 Col (a); then = Page 2 of 22 , Line 12 ,Col (d) and Col (e)		($222,059)	($222,059)	($222,059)
2	Bonus Depreciation			$0	$0	$0
3	Remaining MACRS Tax Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 4 Col (a); then = -Page 3 of 22, Col (d)		($20,089)	($18,585)	($17,189)
4	FY18 tax (gain)/loss on retirements			$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($242,148)	($240,644)	($239,248)
6	Effective Tax Rate			21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($50,851)	($50,535)	($50,242)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction					
9	Cost of Removal					
10	Book/Tax Depreciation Timing Difference at 3/31/2017					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10				
12	Effective Tax Rate					
13	Deferred Tax Reserve	Line 11 × Line 12				
14	Total Deferred Tax Reserve	Line 7 + Line 13		($50,851)	($50,535)	($50,242)
15	Net Operating Loss			$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($50,851)	($50,535)	($50,242)
	Allocation of FY 2018 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($242,148)	($240,644)	($239,248)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($242,148)	($240,644)	($239,248)
20	Total FY 2018 Federal NOL			$0	$0	$0
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$0	$0	$0
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20		$0	$0	$0
23	Effective Tax Rate			21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23		$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($50,851)	($50,535)	($50,242)
		(h)	(i)	(j)	(k)	(l)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY20	FY21	FY22
26	April	30	91.78%	($3,889)	($3,865)	($3,843)
27	May	31	83.29%	($3,529)	($3,507)	($3,487)
28	June	30	75.07%	($3,181)	($3,161)	($3,143)
29	July	31	66.58%	($2,821)	($2,804)	($2,787)
30	August	31	58.08%	($2,461)	($2,446)	($2,432)
31	September	30	49.86%	($2,113)	($2,100)	($2,088)
32	October	31	41.37%	($1,753)	($1,742)	($1,732)
33	November	30	33.15%	($1,405)	($1,396)	($1,388)
34	December	31	24.66%	($1,045)	($1,038)	($1,032)
35	January	31	16.16%	($685)	($681)	($677)
36	February	28	8.49%	($360)	($358)	($356)
37	March	31	0.00%	$0	$0	$0
38	Total	365		($23,243)	($23,098)	($22,964)
39	Deferred Tax Without Proration	Line 25		($50,851)	($50,535)	($50,242)
40	Average Deferred Tax without Proration	Line 39 × 50%		($25,426)	($25,268)	($25,121)
41	Proration Adjustment	Line 38 - Line 40		$2,183	$2,169	$2,157

Column Notes:
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) through (l) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Computation of Revenue Requirement on FY 2019 Actual Incremental Gas Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)
	Depreciable Net Capital Included in ISR Rate Base						
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 15 of 22 , Line 3 ,Col (b)		($914,000)	$0	$0	$0
2	Retirements	Page 15 of 22 , Line 9 ,Col (b)		($1,368,021)	$0	$0	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$454,021	$454,021	$454,021	$454,021
	Change in Net Capital Included in ISR Rate Base						
4	Capital Included in ISR Rate Base	Line 1		($914,000)	$0	$0	$0
5	Depreciation Expense			$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		($914,000)	($914,000)	($914,000)	($914,000)
7	Cost of Removal	Page 15 of 22 , Line 6 ,Col (b)		$5,626,564	$5,626,564	$5,626,564	$5,626,564
8	**Net Plant Amount**	**Line 6 + Line 7**		**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**
	Deferred Tax Calculation:						
9	Composite Book Depreciation Rate	As Approved in RIPUC Docket No. 4323 & 4770	1/	3.15%	2.99%	2.99%	2.99%
10	Tax Depreciation	Year 1 = Page 6 of 22, Line 21, Col (a); then = Page 6 of 22, Col (d)		$5,166,399	($16,141)	($14,929)	($13,811)
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$5,166,399	$5,150,257	$5,135,328	$5,121,517
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50%; then = Line 3 × Line 9		$7,157	$13,575	$13,575	$13,575
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$7,157	$20,732	$34,307	$47,883
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$5,159,242	$5,129,525	$5,101,021	$5,073,634
15	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$1,083,441	$1,077,200	$1,071,214	$1,065,463
17	Add: FY 2019 Federal NOL incremental utilization	Page 15 of 22, Line 12, Col (b)		$15,690,984	$15,690,984	$15,690,984	$15,690,984
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$16,774,424	$16,768,184	$16,762,198	$16,756,447
	ISR Rate Base Calculation:						
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$4,712,564	$4,712,564	$4,712,564	$4,712,564
20	Accumulated Depreciation	- Line 13		($7,157)	($20,732)	($34,307)	($47,883)
21	Deferred Tax Reserve	- Line 18		($16,774,424)	($16,768,184)	($16,762,198)	($16,756,447)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		($12,069,018)	($12,076,353)	($12,083,942)	($12,091,766)
	Revenue Requirement Calculation:						
23	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 22 ÷ 2; then = (Prior Year Line 22 + Current Year Line 22) ÷ 2				($12,080,147)	($12,087,854)
24	Proration Adjustment	Year 1 =0; then = Page 7 of 22, Line 41, Col (j), Col (k) and Col (l)				($257)	($247)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24				($12,080,404)	($12,088,101)
26	Pre-Tax ROR	Page 22 of 22, Line 30, Column (e)				8.41%	8.41%
27	Return and Taxes	Line 25 × Line 26				($1,015,962)	($1,016,609)
28	Book Depreciation	Line 12				$13,575	$13,575
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**N/A**	**N/A**	**($1,002,387)**	**($1,003,034)**

1/ 3.38%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.38% × 5 /12 + 2.99% × 7 / 12

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Tax Depreciation and Repairs Deduction on FY 2019 Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 5 of 22, Line 1		($914,000)	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	71.49%				
3	Capital Repairs Deduction	Line 1 × Line 2		($653,419)	MACRS basis:		($223,592)	
							Annual	Cumulative
					Fiscal Year			
	Bonus Depreciation				2019	3.75%	($8,385)	$5,166,399
4	Plant Additions	Line 1		($914,000)	2020	7.22%	($16,141)	$5,150,257
5	Less Capital Repairs Deduction	Line 3		($653,419)	2021	6.68%	($14,929)	$5,135,328
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		($260,581)	2022	6.18%	($13,811)	$5,121,517
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	2023	5.71%	($12,774)	$5,108,743
8	Plant Eligible for Bonus Depreciation	Line 6 × Line 7		($260,581)	2024	5.29%	($11,817)	$5,096,926
9	Bonus Depreciation Rate (30% Eligible)	1 × 30% × 11.65%		3.50%	2025	4.89%	($10,929)	$5,085,997
10	Bonus Depreciation Rate (40% Eligible)	1 × 40% × 26.75%		10.70%	2026	4.52%	($10,111)	$5,075,886
11	Total Bonus Depreciation Rate	Line 9 + Line 10		14.20%	2027	4.46%	($9,977)	$5,065,910
12	Bonus Depreciation	Line 8 × Line 11		($36,989)	2028	4.46%	($9,974)	$5,055,935
					2029	4.46%	($9,977)	$5,045,958
	Remaining Tax Depreciation				2030	4.46%	($9,974)	$5,035,984
13	Plant Additions	Line 1		($914,000)	2031	4.46%	($9,977)	$5,026,007
14	Less Capital Repairs Deduction	Line 3		($653,419)	2032	4.46%	($9,974)	$5,016,033
15	Less Bonus Depreciation	Line 12		($36,989)	2033	4.46%	($9,977)	$5,006,056
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		($223,592)	2034	4.46%	($9,974)	$4,996,082
17	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	2035	4.46%	($9,977)	$4,986,105
18	Remaining Tax Depreciation	Line 16 × Line 17		($8,385)	2036	4.46%	($9,974)	$4,976,131
					2037	4.46%	($9,977)	$4,966,154
19	FY19 tax (gain)/loss on retirements	Per Tax Department	2/	$238,628	2038	4.46%	($9,974)	$4,956,180
20	Cost of Removal	Page 5 of 22, Line 7		$5,626,564	2039	2.23%	($4,988)	$4,951,191
						100.00%	($223,592)	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19 & 20		$5,166,399				

1/ Capital Repairs percentage is based on a three-year average of FYs 2014, 2015 and 2016 capital repairs rates.
2/ Actual Loss for FY2019

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		(a) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 7 Col (a); then = Page 5 of 22 , Line 12 ,Col (c) and Col (d)	$162,791	$13,575	$13,575
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 7 Col (a); then = - Page 6 of 22, Col (d)	($156,315)	$14,929	$13,811
4	FY19 tax (gain)/loss on retirements		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$6,476	$28,504	$27,386
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$1,360	$5,986	$5,751
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2019				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21%	21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$1,360	$5,986	$5,751
15	Net Operating Loss		$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$1,360	$5,986	$5,751
	Allocation of FY 2019 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$6,476	$28,504	$27,386
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$6,476	$28,504	$27,386
20	Total FY 2019 Federal NOL		$0	$0	$0
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0	$0
22	Allocated FY 2019 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$1,360	$5,986	$5,751

Line No.	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY20	(k) FY21	(l) FY22
26	April	30	91.78%	$104	$458	$440
27	May	31	83.29%	$94	$415	$399
28	June	30	75.07%	$85	$374	$360
29	July	31	66.58%	$75	$332	$319
30	August	31	58.08%	$66	$290	$278
31	September	30	49.86%	$57	$249	$239
32	October	31	41.37%	$47	$206	$198
33	November	30	33.15%	$38	$165	$159
34	December	31	24.66%	$28	$123	$118
35	January	31	16.16%	$18	$81	$77
36	February	28	8.49%	$10	$42	$41
37	March	31	0.00%	$0	$0	$0
38	Total	365		$622	$2,736	$2,629
39	Deferred Tax Without Proration	Line 25		$1,360	$5,986	$5,751
40	Average Deferred Tax without Proration	Line 39 × 50%		$680	$2,993	$2,876
41	Proration Adjustment	Line 38 - Line 40		($58)	($257)	($247)

lumn Notes:
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) through (l) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Computation of Revenue Requirement on FY 2020 Forecasted Incremental Gas Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Depreciable Net Capital Included in ISR Rate Base					
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 15 of 22 , Line 3 ,Col (c)		$115,727,842	$0	$0
2	Retirements	Page 15 of 22 , Line 9 ,Col (c)	1/	$10,634,425	$0	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$105,093,417	$105,093,417	$105,093,417
	Change in Net Capital Included in ISR Rate Base					
4	Capital Included in ISR Rate Base	Line 1		$115,727,842	$0	$0
5	Depreciation Expense	Page 18 of 22, Line 72(c)		$23,534,853	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$92,192,989	$92,192,989	$92,192,989
7	Cost of Removal	Page 15 of 22 , Line 6 ,Col (c)		$4,804,530	$4,804,530	$4,804,530
8	**Net Plant Amount**	**Line 6 + Line 7**		**$96,997,519**	**$96,997,519**	**$96,997,519**
	Deferred Tax Calculation:					
9	Composite Book Depreciation Rate	Page 16 of 22, Line 86(e)	1/	2.99%	2.99%	2.99%
10	Tax Depreciation	Year 1 =Page 9 of 22, Line 21, Col (a); then =Page 9 of 22, Col (d)		$88,746,670	$2,485,973	$2,299,327
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$88,746,670	$91,232,643	$93,531,971
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$1,571,147	$3,142,293	$3,142,293
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$1,571,147	$4,713,440	$7,855,733
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$87,175,524	$86,519,204	$85,676,238
15	Effective Tax Rate			21.00%	21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$18,306,860	$18,169,033	$17,992,010
17	Add: FY 2020 Federal NOL utilization	Page 15 of 22, Line 12, Col (c)		$1,997,796	$1,997,796	$1,997,796
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$20,304,656	$20,166,829	$19,989,806
	ISR Rate Base Calculation:					
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$96,997,519	$96,997,519	$96,997,519
20	Accumulated Depreciation	- Line 13		($1,571,147)	($4,713,440)	($7,855,733)
21	Deferred Tax Reserve	- Line 18		($20,304,656)	($20,166,829)	($19,989,806)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		$75,121,716	$72,117,250	$69,151,980
	Revenue Requirement Calculation:					
23	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Line 22 × Page 11 of 22, Line 16; then = Average of (Prior Year Line 22 + Current Year Line 22/2)			$73,619,483	$70,634,615
24	Proration Adjustment	Page 10 of 22, Line 41, Cols (j), (k) and (l)			($5,774)	($7,416)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24			$73,613,709	$70,627,199
26	Pre-Tax ROR	Page 22 of 22, Line 30, Column (e)			8.41%	8.41%
27	Return and Taxes	Line 25 × Line 26			$6,190,913	$5,939,747
28	Book Depreciation	Line 12			$3,142,293	$3,142,293
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**N/A**	**$9,333,206**	**$9,082,041**

1/ 2.99%, Composite Book Depreciation Rate of Distirbution Plant approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Tax Depreciation and Repairs Deduction on FY 2020 Incremental Capital Investments

Line No.				Fiscal Year 2020 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 8 of 22, Line 1		$115,727,842
2	Capital Repairs Deduction Rate	Per Tax Department	1/	68.90%
3	Capital Repairs Deduction	Line 1 × Line 2		$79,736,483
	Bonus Depreciation			
4	Plant Additions	Line 1		$115,727,842
5	Less Capital Repairs Deduction	Line 3		$79,736,483
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$35,991,359
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
8	Plant Eligible for Bonus Depreciation	Line 6 × Line 7		$35,991,359
9	Bonus Depreciation Rate 30%	14.4% × 30%		4.32%
10	Bonus Depreciation Rate 0%			0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10		4.32%
12	Bonus Depreciation	Line 8 × Line 11		$1,554,827
	Remaining Tax Depreciation			
13	Plant Additions	Line 1		$115,727,842
14	Less Capital Repairs Deduction	Line 3		$79,736,483
15	Less Bonus Depreciation	Line 12		$1,554,827
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$34,436,532
17	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%
18	Remaining Tax Depreciation	Line 16 × Line 17		$1,291,370
19	FY20 tax (gain)/loss on retirements	Per Tax Department	2/	$1,359,460
20	Cost of Removal	Page 8 of 22, Line 7		$4,804,530
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19 & 20		$88,746,670

20 Year MACRS Depreciation

MACRS basis: $34,436,532

(b) Fiscal Year	(c)	(d) Annual	(e) Cumulative
2020	3.75%	$1,291,370	$88,746,670
2021	7.22%	$2,485,973	$91,232,643
2022	6.68%	$2,299,327	$93,531,971
2023	6.18%	$2,127,145	$95,659,115
2024	5.71%	$1,967,359	$97,626,474
2025	5.29%	$1,819,971	$99,446,445
2026	4.89%	$1,683,258	$101,129,703
2027	4.52%	$1,557,220	$102,686,923
2028	4.46%	$1,536,558	$104,223,481
2029	4.46%	$1,536,214	$105,759,694
2030	4.46%	$1,536,558	$107,296,252
2031	4.46%	$1,536,214	$108,832,466
2032	4.46%	$1,536,558	$110,369,024
2033	4.46%	$1,536,214	$111,905,238
2034	4.46%	$1,536,558	$113,441,796
2035	4.46%	$1,536,214	$114,978,010
2036	4.46%	$1,536,558	$116,514,568
2037	4.46%	$1,536,214	$118,050,781
2038	4.46%	$1,536,558	$119,587,339
2039	4.46%	$1,536,214	$121,123,553
2040	2.23%	$768,279	$121,891,832
	100.00%	$34,436,532	

1/ FY 2020 estimated capital repair deduction is based on FY 2018 estimate
2/ FY 2020 estimated tax loss on retirements is based on FY 2018 estimate

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investments

Line No.	**Deferred Tax Subject to Proration**		(a) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = Page 8 of 22 , Line 12 Col (b) and Col (c)	$1,571,147	$3,142,293	$3,142,293
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = Page 9 of 22, Col (d)	($1,349,676)	($2,485,973)	($2,299,327)
4	FY20 tax (gain)/loss on retirements	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0	($1,359,460)	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,137,989)	$656,320	$842,966
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	($238,978)	$137,827	$177,023
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0	($79,736,483)		
9	Cost of Removal	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0	($4,804,530)		
10	Book/Tax Depreciation Timing Difference at 3/31/2020				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($84,541,013)		
12	Effective Tax Rate		21%		
13	Deferred Tax Reserve	Line 11 × Line 12	($17,753,613)		
14	Total Deferred Tax Reserve	Line 7 + Line 13	($17,992,590)	$137,827	$177,023
15	Net Operating Loss				
16	Net Deferred Tax Reserve	Line 14 + Line 15	($17,992,590)	$137,827	$177,023
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	($1,137,989)	$656,320	$842,966
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($84,541,013)	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($85,679,002)	$656,320	$842,966
20	Total FY 2020 Federal NOL	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0	($9,513,316)		
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	($9,386,960)		
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	($126,356)		
23	Effective Tax Rate		21%		
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	($26,535)		
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($265,512)	$137,827	$177,023

	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY20	(k) FY21	(l) FY22
26	April	30	91.80%	($10,772)	$10,544	$13,543
27	May	31	83.33%	($9,779)	$9,571	$12,293
28	June	30	75.14%	($8,817)	$8,630	$11,084
29	July	31	66.67%	($7,823)	$7,657	$9,835
30	August	31	58.20%	($6,829)	$6,684	$8,585
31	September	30	50.00%	($14,774)	$5,743	$7,376
32	October	31	41.53%	($12,272)	$4,770	$6,126
33	November	30	33.33%	($9,850)	$3,829	$4,917
34	December	31	24.86%	($7,347)	$2,856	$3,668
35	January	31	16.39%	($4,844)	$1,883	$2,418
36	February	29	8.47%	($2,503)	$973	$1,249
37	March	31	0.00%	$0	$0	$0
38	Total	366		($95,609)	$63,139	$81,095
39	Deferred Tax Without Proration	Line 25		($265,512)	$137,827	$177,023
40	Average Deferred Tax without Proration	Year 1: Line 39 × Page 11 of 22, Line 16; then = Line 39 × 0.5		($106,789)	$68,914	$88,511
41	Proration Adjustment	Line 38 - Line 40		$11,181	($5,774)	($7,416)

Column Notes:
(i) Sum of remaining days in the year (Col (h)) divided by 365
(j) Current Year Line 25 × Page 11 of 22, Col (f) × Current Month Col (i)
(k) & (l) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
ISR Additions April through August 2020

Line No.	Month No.	Month	FY 2020 ISR Additions (a)	In Rates (b)	Not In Rates (c) = (a) - (b)	Weight for Days (d)	Weighted Average (e) = (d) × (c)	Weight for Investment (f)=(c)÷Total(c)
1								
2	1	Apr-19	$12,879,299	$7,764,750	$5,114,549	0.958	$4,901,443	4.42%
3	2	May-19	$12,879,299	$7,764,750	$5,114,549	0.875	$4,475,231	4.42%
4	3	Jun-19	$12,879,299	$7,764,750	$5,114,549	0.792	$4,049,018	4.42%
5	4	Jul-19	$12,879,299	$7,764,750	$5,114,549	0.708	$3,622,806	4.42%
6	5	Aug-19	$12,879,299	$7,764,750	$5,114,549	0.625	$3,196,593	4.42%
7	6	Sep-19	$12,879,299	$0	$12,879,299	0.542	$6,976,287	11.13%
8	7	Oct-19	$12,879,299	$0	$12,879,299	0.458	$5,903,012	11.13%
9	8	Nov-19	$12,879,299	$0	$12,879,299	0.375	$4,829,737	11.13%
10	9	Dec-19	$12,879,299	$0	$12,879,299	0.292	$3,756,462	11.13%
11	10	Jan-20	$12,879,299	$0	$12,879,299	0.208	$2,683,187	11.13%
12	11	Feb-20	$12,879,299	$0	$12,879,299	0.125	$1,609,912	11.13%
13	12	Mar-20	$12,879,299	$0	$12,879,299	0.042	$536,637	11.13%
14	Total		$154,551,592	$38,823,750	$115,727,842		$46,540,327	100.00%
15	**Total Additions September 2019 through March 2020**				**$90,155,095**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**						**40.22%**	

Column (a)=Page 15 of 22 , Line 1 ,Col (c)
Column (b)=Page 15 of 22 , Line 2 ,Col (c)
Column (d) = (12.5 - Month No.) ÷ 12
Line 15 = Sum of Lines 7(c) through 13(c)
Line 16 = Line 14(e)/Line 14(c)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Computation of Revenue Requirement on FY 2021 Forecasted Incremental Gas Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)
	Depreciable Net Capital Included in ISR Rate Base				
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 15 of 22 , Line 3 ,Col (d)		$179,664,487	$0
2	Retirements	Page 15 of 22 , Line 9 ,Col (d)	1/	$23,555,235	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$156,109,252	$156,109,252
	Change in Net Capital Included in ISR Rate Base				
4	Capital Included in ISR Rate Base	Line 1		$179,664,487	$0
5	Depreciation Expense	Page 18 of 22, Line 78(c)		$40,700,587	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$138,963,900	$138,963,900
7	Cost of Removal	Page 15 of 22 , Line 6 ,Col (d)		$17,833,998	$17,833,998
8	**Net Plant Amount**	**Line 6 + Line 7**		**$156,797,898**	**$156,797,898**
	Deferred Tax Calculation:				
9	Composite Book Depreciation Rate	Page 16 of 22, Line 86(e)	1/	2.99%	2.99%
10	Tax Depreciation	Year 1 =Page 13 of 22, Line 21, Col (a); then = Page 13 of 22, Col (d)		$173,600,482	$1,909,181
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$173,600,482	$175,509,663
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$2,333,833	$4,667,667
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$2,333,833	$7,001,500
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$171,266,649	$168,508,163
15	Effective Tax Rate			21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$35,965,996	$35,386,714
17	Add: FY 2021 Federal NOL utilization	Page 15 of 22 , Line 12 ,Col (d)		($7,598,182)	($7,598,182)
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$28,367,814	$27,788,532
	ISR Rate Base Calculation:				
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$156,797,898	$156,797,898
20	Accumulated Depreciation	- Line 13		($2,333,833)	($7,001,500)
21	Deferred Tax Reserve	- Line 18		($28,367,814)	($27,788,532)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		$126,096,251	$122,007,866
	Revenue Requirement Calculation:				
23	Average Rate Base befor Deferred Tax Proration Adjustment	Year 1 = Current Year Line 22 ÷ 2; then = (Prior Year Line 22 + Current Year Line 22) ÷ 2		$63,048,125	$124,052,059
24	Proration Adjustment	Page 14 of 22, Line 41, Col (j) and Col (k)		$1,527	($24,864)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24		$63,049,652	$124,027,195
26	Pre-Tax ROR	Page 22 of 22, Line 30, Column (e)		8.41%	8.41%
27	Return and Taxes	Line 25 × Line 26		$5,302,476	$10,430,687
28	Book Depreciation	Line 12		$2,333,833	$4,667,667
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**$7,636,309**	**$15,098,354**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 12 of 22, Line 1		$179,664,487	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.28%				
3	Capital Repairs Deduction	Line 1 × Line 2		$153,217,875	MACRS basis:		$26,446,612	
							Annual	Cumulative
					Fiscal Year			
	Bonus Depreciation				2021	3.75%	$991,748	$173,600,482
4	Plant Additions	Line 1		$179,664,487	2022	7.22%	$1,909,181	$175,509,663
5	Less Capital Repairs Deduction	Line 3		$153,217,875	2023	6.68%	$1,765,840	$177,275,503
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$26,446,612	2024	6.18%	$1,633,607	$178,909,110
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2025	5.71%	$1,510,895	$180,420,005
8	Plant Eligible for Bonus Depreciation	Line 6 × Line 7		$0	2026	5.29%	$1,397,703	$181,817,709
9	Bonus Depreciation Rate ()	Per Tax Department		0.00%	2027	4.89%	$1,292,710	$183,110,419
10	Bonus Depreciation Rate ()	Per Tax Department		0.00%	2028	4.52%	$1,195,916	$184,306,335
11	Total Bonus Depreciation Rate	Line 9 + Line 10		0.00%	2029	4.46%	$1,180,048	$185,486,383
12	Bonus Depreciation	Line 8 × Line 11		$0	2030	4.46%	$1,179,783	$186,666,166
					2031	4.46%	$1,180,048	$187,846,214
	Remaining Tax Depreciation				2032	4.46%	$1,179,783	$189,025,997
13	Plant Additions	Line 1		$179,664,487	2033	4.46%	$1,180,048	$190,206,045
14	Less Capital Repairs Deduction	Line 3		$153,217,875	2034	4.46%	$1,179,783	$191,385,828
15	Less Bonus Depreciation	Line 12		$0	2035	4.46%	$1,180,048	$192,565,876
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$26,446,612	2036	4.46%	$1,179,783	$193,745,660
17	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	2037	4.46%	$1,180,048	$194,925,707
18	Remaining Tax Depreciation	Line 16 × Line 17		$991,748	2038	4.46%	$1,179,783	$196,105,491
					2039	4.46%	$1,180,048	$197,285,539
19	FY21 tax (gain)/loss on retirements	Per Tax Department	2/	1,556,861	2040	4.46%	$1,179,783	$198,465,322
20	Cost of Removal	Page 12 of 22, Line 7		$17,833,998	2041	2.23%	$590,024	$199,055,346
						100.00%	$26,446,612	
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19 & 20		$173,600,482				

1/ Capital Repairs percentage is based on a three-year average of FYs 2017, 2018 and 2019 capital repairs rates.
2/ FY 2021 estimated tax loss on retirements is tax department estimate

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investments

Line No.	**Deferred Tax Subject to Proration**			(a) FY21	(b) FY22
1	Book Depreciation	Page 12 of 22 , Line 12 ,Col (a), Col (b) and Col		$2,333,833	$4,667,667
2	Bonus Depreciation	Page 13 of 22 , Line 12 ,Col (a)		$0	$0
3	Remaining MACRS Tax Depreciation	Year 1= - Page 13 of 22, Line 18, Col (a); then = - Page 13 of 22, Col (d)		($991,748)	($1,909,181)
4	FY21 tax (gain)/loss on retirements	Page 13 of 22 , Line 19 ,Col (a)		($1,556,861)	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($214,776)	$2,758,486
6	Effective Tax Rate			21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($45,103)	$579,282
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Page 13 of 22 , Line 3 ,Col (a)		($153,217,875)	
9	Cost of Removal	Page 12 of 22 , Line 7 ,Col (a)		($17,833,998)	
10	Book/Tax Depreciation Timing Difference at 3/31/2021				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		($171,051,873)	
12	Effective Tax Rate			21%	
13	Deferred Tax Reserve	Line 11 × Line 12		($35,920,893)	
14	Total Deferred Tax Reserve	Line 7 + Line 13		($35,965,996)	$579,282
15	Net Operating Loss	- Page 12 of 22 , Line 17 ,Col (a)		$7,598,182	
16	Net Deferred Tax Reserve	Line 14 + Line 15		($28,367,814)	$579,282
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($214,776)	$2,758,486
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		($171,051,873)	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($171,266,649)	$2,758,486
20	Total FY 2021 Federal NOL	- Page 12 of 22 , Line 17 ,Col (a)÷21%		$36,181,820	
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$36,136,447	
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20		$45,374	
23	Effective Tax Rate			21%	
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23		$9,528	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($35,574)	$579,282
		(h)	(i)	(j)	(k)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY21	FY22
26	April	30	91.78%	($2,721)	$44,306
27	May	31	83.29%	($2,469)	$40,206
28	June	30	75.07%	($2,225)	$36,238
29	July	31	66.58%	($1,974)	$32,138
30	August	31	58.08%	($1,722)	$28,038
31	September	30	49.86%	($1,478)	$24,071
32	October	31	41.37%	($1,226)	$19,971
33	November	30	33.15%	($983)	$16,003
34	December	31	24.66%	($731)	$11,903
35	January	31	16.16%	($479)	$7,803
36	February	28	8.49%	($252)	$4,100
37	March	31	0.00%	$0	$0
38	Total	365		($16,260)	$264,777
39	Deferred Tax Without Proration	Line 25		($35,574)	$579,282
40	Average Deferred Tax without Proration	Line 39 × 0.5		($17,787)	$289,641
41	Proration Adjustment	Line 38 - Line 40		$1,527	($24,864)

Column Notes:
(i) Sum of remaining days in the year (Col (h)) divided by 365
(j) & (k) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
FY 2018 - FY 2021 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2018 (a)	Actual Fiscal Year 2019 (b)	Plan Fiscal Year 2020 (c)	Plan Fiscal Year 2021 (d)
	Capital Investment					
1	ISR-eligible Capital Investment	Col (a)=Docket No. 4678 FY18 Reconciliation Filing; Col (b)=Docket No. 4781 FY19 Reconciliation Filing; Col (c)=Docket No. 4916 FY20 Plan Filing; Col(d)=Section 2, Table 1	$97,809,718	$92,263,000	$154,551,592	$179,664,487
2	ISR-eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770 Schedule MAL-11-Gas Page 5, Col (a)=Lines 1(a) + 1(b); Col(b)=Lines 1(c) + 1(d); Col(c)= Line 1(e)	$93,177,000	$93,177,000	$38,823,750	$0
3	Incremental ISR Capital Investment	Line 1 - Line 2	$4,632,718	($914,000)	$115,727,842	$179,664,487
	Cost of Removal					
4	ISR-eligible Cost of Removal	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY20 Plan Filing; Col(d)=Section 2, Table 1	$8,603,224	$11,583,085	$7,910,408	$18,947,513
5	ISR-eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L23+L42×7÷12+Docket 4678 Page 2, Line 7x3÷12; Col(b)=[P1]L42×5÷12+[P2]L18×7÷12; Col (c)=[P2]L18×5÷12+L39×7÷12; Col (d) = [P2] L39×5÷12+L60×7÷12	$6,662,056	$5,956,522	$3,105,878	$1,113,515
6	Incremental Cost of Removal	Line 4 - Line 5	$1,941,168	$5,626,564	$4,804,530	$17,833,998
	Retirements					
7	ISR-eligible Retirements	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY20 Plan Filing; Col(d)=FY21 Planned Investment x 3-year average actual retirement rate FY17 - FY19	$24,056,661	$6,531,844	$14,753,610	$25,032,040
8	ISR-eligible Retirements per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L24+L43×7÷12+ Docket 4678 Page 2, Line 2x3÷12; Col(b)=[P1]L43×5÷12+[P2]L19×7÷12 Col (c)=[P2]L19×5÷12+L40×7÷12; Col (d) = [P2]L40×5÷12+L61×7÷12	$11,997,233	$7,899,865	$4,119,186	$1,476,805
9	Incremental Retirements	Line 7 - Line 8	$12,059,428	($1,368,021)	$10,634,425	$23,555,235
	(NOL)/ NOL Utilitization					
10	ISR (NOL)/NOL Utilization Per ISR	Page 21 of 22, Line 10	($6,051,855)	$16,495,753	$5,060,855	$0
11	ISR NOL Utilization Per Docket 4770	Schedule 11-Gas Page 11, Docket No. 4770: Col (a)= L40×5÷12; Col (b) = L40×5÷12+L48×7÷12; Col (c) = P11,L48×5÷12+P12,L39×7÷12; Col (d) = P12,L39×5÷12+P12,L49×7÷12	$0	$804,769	$3,063,059	$7,598,182
12	Incremental (NOL)/NOL Utilization	Line 10 - Line 11	($6,051,855)	$15,690,984	$1,997,796	($7,598,182)

Note: The FY21 non-growth ISR capital investment of $198,612,000 is the sum of Line 1 and Line 4.

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense per Rate Case RIPUC Docket No. 4770

Line	Account No.	Account Title	Test Year June 30, 2017 1/ (a)	ARO Adjustment (b)	Adjustments June 30, 2017 (c)	Adjusted Balance (d) = (a) + (b) + (c)	Proposed Rate (e)	Depreciation Expense (f) = (d) x (e)
		Intangible Plant						
1	302.00	Franchises And Consents	$213,499	$0	$0	$213,499	0.00%	$0
2	303.00	Misc. Intangible Plant	$25,427	$0	$0	$25,427	0.00%	$0
3	303.01	Misc. Int Cap Software	$19,833,570	$0	$9,991,374	$29,824,944	0.00%	$0
4								
5		Total Intangible Plant	$20,072,496	$0	$9,991,374	$30,063,870		$0
6								
7		Production Plant						
8								
9	304.00	Production Land Land Rights	$364,912	$0	$0	$364,912	0.00%	$0
10	305.00	Prod. Structures & Improvements	$2,693,397	$0	$0	$2,693,397	15.05%	$405,356
11	307.00	Production Other Power	$46,159	$0	$0	$46,159	7.16%	$3,305
12	311.00	Production LNG Equipme	$3,167,445	$0	$0	$3,167,445	11.40%	$361,089
13	320.00	Prod. Other Equipment	$1,106,368	$0	$0	$1,106,368	6.69%	$74,016
14								
15		Total Production Plant	$7,378,281	$0	$0	$7,378,281		$843,766
16								
17		Storage Plant						
18								
19	360.00	Stor Land & Land Rights	$261,151	$0	$0	$261,151	0.00%	$0
20	361.03	Storage Structures Improvements	$3,385,049	$0	$0	$3,385,049	0.99%	$33,512
21	362.04	Storage Gas Holders	$4,606,338	$0	$0	$4,606,338	0.04%	$1,843
22	363.00	Stor. Purification Equipment	$13,891,210	$0	$0	$13,891,210	3.37%	$468,134
23								
24		Total Storage Plant	$22,143,748	$0	$0	$22,143,748		$503,488
25								
26		Distribution Plant						
27								
28	374.00	Dist. Land & Land Rights	$956,717	$0	$0	$956,717	0.00%	$0
29	375.00	Gas Dist Station Structure	$10,642,632	$0	$0	$10,642,632	1.15%	$122,390
30	376.00	Distribution Mains	$46,080,760	$0	$0	$46,080,760	3.61%	$1,663,515
31	376.03	Dist. River Crossing Main	$695,165	$0	$0	$695,165	3.61%	$25,095
32	376.04	Mains - Steel And Other - Sl	$4,190	$0	$0	$4,190	0.00%	$0
33	376.06	Dist. District Regulator	$14,213,837	$0	$0	$14,213,837	3.61%	$513,120
34	376.11	Gas Mains Steel	$57,759,572	$0	$0	$57,759,572	3.31%	$1,908,954
35	376.12	Gas Mains Plastic	$382,797,443	$0	$0	$382,797,443	2.70%	$10,316,391
36	376.13	Gas Mains Cast Iron	$5,556,209	$0	$0	$5,556,209	8.39%	$465,888
37	376.14	Gas Mains Valves	$222,104	$0	$0	$222,104	3.61%	$8,018
38	376.15	Propane Lines	$0	$0	$0	$0	3.61%	$0
39	376.16	Dist. Cathodic Protect	$1,569,576	$0	$0	$1,569,576	3.61%	$56,662
40	376.17	Dist. Joint Seals	$63,067,055	$0	$0	$63,067,055	4.63%	$2,920,005
41	377.00	T&D Compressor Sta Equipment	$248,656	$0	$0	$248,656	1.07%	$2,661
42	377.62	1/ 5360-Tanks ARO	$299	($299)	$0	$0	0.00%	$0
43	378.10	Gas Measur & Reg Sta Equipment	$19,586,255	$0	$0	$19,586,255	2.08%	$407,394
44	378.55	Gas M&Reg Sta Eqp RTU	$372,772	$0	$0	$372,772	6.35%	$23,671
45	379.00	Dist. Measur. Reg. Gs	$11,033,164	$0	$0	$11,033,164	2.22%	$244,936
46	379.01	Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586	0.00%	$0
47	380.00	Gas Services All Sizes	$331,205,854	$0	$0	$331,205,854	3.05%	$10,101,779
48	381.10	Sml Meter& Reg Bare Co	$26,829,565	$0	$0	$26,829,565	1.76%	$472,200
49	381.30	Lrg Meter& Reg Bare Co	$15,779,214	$0	$0	$15,779,214	1.76%	$277,714
50	381.40	Meters	$9,332,227	$0	$0	$9,332,227	0.96%	$89,589
51	382.00	Meter Installations	$675,201	$0	$0	$675,201	3.66%	$24,712
52	382.20	Sml Meter& Reg Installation	$43,145,998	$0	$0	$43,145,998	3.66%	$1,579,144
53	382.30	Lrg Meter&Reg Installation	$2,524,025	$0	$0	$2,524,025	3.66%	$92,379
54	383.00	Dist. House Regulators	$937,222	$0	$0	$937,222	0.67%	$6,279
55	384.00	T&D Gas Reg Installs	$1,216,551	$0	$0	$1,216,551	1.56%	$18,978
56	385.00	Industrial Measuring And Regulating Station Equipment	$540,187	$0	$0	$540,187	4.18%	$22,580
57	385.01	Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921	0.00%	$0
58	386.00	Other Property On Customer Premises	$271,765	$0	$0	$271,765	0.23%	$625
59	386.02	Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131	0.00%	$0
60	387.00	Dist. Other Equipment	$930,079	$0	$0	$930,079	2.15%	$19,997
61	388.00	1/ ARO	$5,736,827	($5,736,827)	$0	$0	0.00%	$0
62								
63		Total Distribution Plant	$1,055,696,761	($5,737,126)	$0	$1,049,959,635	2.99%	$31,384,677
64								
65		General Plant						
66								
67	389.01	General Plant Land Lan	$285,357	$0	$0	$285,357	0.00%	$0
68	390.00	Structures And Improvements	$7,094,532	$0	$0	$7,094,532	3.12%	$221,349
69	391.01	Gas Office Furniture & Fixture	$274,719	$0	$0	$274,719	6.67%	$18,324
70	394.00	General Plant Tools Shop (Fully Dep)	$26,487	$0	$0	$26,487	0.00%	$0
71	394.00	General Plant Tools Shop	$5,513,613	$0	$0	$5,513,613	5.00%	$275,681
72	395.00	General Plant Laboratory	$221,565	$0	$0	$221,565	6.67%	$14,778
73	397.30	Communication Radio Site Specific	$387,650	$0	$0	$387,650	5.00%	$19,383
74	397.42	Communication Equip Tel Site	$63,481	$0	$0	$63,481	20.00%	$12,696
75	398.10	Miscellaneous Equipment (Fully Dep)	$1,341,386	$0	$0	$1,341,386	0.00%	$0
76	398.10	Miscellaneous Equipment	$2,789,499	$0	$0	$2,789,499	6.67%	$186,060
77	399.10	1/ ARO	$342,146	($342,146)	$0	$0	0.00%	$0
78								
79		Total General Plant	$18,340,436	($342,146)	$0	$17,998,289	4.16%	$748,271
80								
81		Grand Total - All Categories	$1,123,631,722	($6,079,273)	$9,991,374	$1,127,543,823	3.05%	$33,480,202
82							2.97%	
83		Other Utility Plant Assets						
84			Line 63		Total Distribution Plant	$1,049,959,635	2.99%	$31,384,677
85			Line 73 + Line 74		Communication Equipment	$451,132	7.11%	$32,079
86					Total ISR Tangible Plant	$1,050,410,767	2.99%	$31,416,756
					Non ISR Assets	$77,133,057		

Lines 1 through 81 - per RIPUC Docket No. 4770 Compliance filing dated August 16, 2018 , Compliance Attachment 2, Schedule 6-GAS, Pages 3 & 4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No	Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
				(a)	(b)	(c)
1	Total Company Rate Year Depreciation		Sum of Page 2, Line 16 and Line 17	$39,136,909		
2	Total Company Test Year Depreciation		Per Company Books	$33,311,851		
3	Less: Reserve adjustments		Page 4, Line 29, Col (b) + Col (c)	($15,649)		
4	Adjusted Total Company Test Year Depreciation Expense		Line 2 + Line 3	$33,296,202		
5	Depreciation Expense Adjustmen		Line 1 - Line 4	$5,840,707		
6						
7				Per Book		
8	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount		
9	Total Gas Utility Plant 06/30/17		Page 4, Line 27, Col (d)	$1,405,994,678	($77,133,057)	$1,328,861,622
10	Less Non Depreciable Plant		Sum of Page 3, Line 5, Col (d) and Page 4, Line 25, Col (e)	($308,514,725)		($308,514,725)
11	Depreciable Utility Plant 06/30/17		Line 9 + Line 10	$1,097,479,953	($77,133,057)	$1,020,346,897
12						
13	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-GAS, Page 3, Line 4	$19,592,266		$19,592,266
14	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 13 x Retirement Rate	($1,345,989)		($1,345,989)
15	Depreciable Utility Plant 08/31/17		Line 11 + Line 13 + Line 14	$1,115,726,231	($77,133,057)	$1,020,346,897
16						
17	Average Depreciable Plant for Year Ended 08/31/17		(Line 11 + Line 15)/2	$1,106,603,092		$1,106,603,092
18						
19	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		
20						
21	Book Depreciation Reserve 06/30/17		Page 5, Line 72, Col (d)	$357,576,825		$357,576,825
22	Plus: Book Depreciation Expense		Line 17 x Line 19	$6,233,864		$6,233,864
23	Less: Net Cost of Removal/(Salvage)	2/	Line 13 x Cost of Removal Rate	($1,014,879)		($1,014,879)
24	Less: Retired Plant		Line 14	($1,345,989)		($1,345,989)
25	Book Depreciation Reserve 08/31/17		Sum of Line 21 through Line 24	$361,449,821		
26						
27	Depreciation Expense 12 Months Ended 08/31/18					
28	Total Utility Plant 08/31/17		Line 9 + Line 13 + Line 14	$1,424,240,956	($77,133,057)	$1,347,107,900
29	Less Non Depreciable Plant		Line 10	($308,514,725)		($308,514,725)
30	Depreciable Utility Plant 08/31/17		Line 28 + Line 29	$1,115,726,231		$1,038,593,175
31						
32	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-GAS, Page 3, Line 11	$115,710,016		$115,710,016
33	Less: Plant Retired in 12 Months Ended 08/31/18		Line 32 x Retirement rate	($7,949,278)		($7,949,278)
34	Depreciable Utility Plant 08/31/18		Sum of Line 30 through Line 33	$1,223,486,969		$1,146,353,912
35						
36	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 30 + Line 34)/2	$1,169,606,600		$1,092,473,543
37						
38	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		3.38%
39						
40	Book Depreciation Reserve 08/31/17		Line 25	$361,449,821		
41	Plus: Book Depreciation 08/31/18		Line 36 x Line 38	$39,532,703		$36,925,606
42	Less: Net Cost of Removal/(Salvage)		Line 32 x Cost of Removal Rate	($5,993,779)		
43	Less: Retired Plant		Line 33	($7,949,278)		
44	Book Depreciation Reserve 08/31/18		Sum of Line 40 through Line 43	$387,039,467		

1/	3 year average retirement over plant addition in service FY 15 ~ FY17	6.87%	Retirements
2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17	5.18%	COR

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No		Description		Reference	Amount (a)	Less non-ISR eligible Plant (b)	ISR Amount (c)
1		Rate Year Depreciation Expense 12 Months Ended 08/31/19:					
2		Total Utility Plant 08/31/18		Page 1, Line 28 + Line 32 + Line 33	$1,532,001,694	($77,133,057)	$1,454,868,637
3		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,223,486,969		$1,146,353,912
5							
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-GAS, Page 3, Line 35	$114,477,000	($1,348,000)	$113,129,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($7,864,570)	$92,608	($7,771,962)
8							
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,330,099,399	($78,388,449)	$1,251,710,950
10							
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,276,793,184		$1,199,032,431
12							
13		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
14							
15		Book Depreciation Reserve 08/31/18		Page 1, Line 44	$387,039,467		$0
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$38,950,409		$35,851,070
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($5,929,909)		$0
19		Less: Retired Plant		Line 7	($7,864,570)		$0
20		Book Depreciation Reserve 08/31/1		Sum of Line 15 through Line 1	$412,381,898		$36,037,570
21							
22		Rate Year Depreciation Expense 12 Months Ended 08/31/20:					
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$1,638,614,124	($78,388,449)	$1,560,225,675
24		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
25		Depreciable Utility Plant 08/31/1		Line 23 + Line 24	$1,330,099,399		$1,251,710,950
26							
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-GAS, Page 5, Line 11(i)	$21,017,630	($750,000)	$20,267,630
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($1,443,911)	$51,525	($1,392,386)
29							$0
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,349,673,118	($79,086,924)	$1,270,586,194
31							
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,339,886,258		$1,261,148,572
33							
34		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
35							
36		Book Depreciation Reserve 08/31/20		Line 20	$412,381,898		$0
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$40,875,154		$37,708,342
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($1,088,713)		$0
40		Less: Retired Plant		Line 28	($1,443,911)		$0
41		Book Depreciation Reserve 08/31/2		Sum of Line 36 through Line 4	$450,910,927		$37,894,842
42							
43		Rate Year Depreciation Expense 12 Months Ended 08/31/21:					
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$1,658,187,843	($79,086,924)	$1,579,100,919
45		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,349,673,118		$1,270,586,194
47							
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-GAS, Page 5, Line 11(l)	$21,838,436	($750,000)	$21,088,436
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($1,500,301)	$51,525	($1,448,776)
50							
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,370,011,253	($79,785,399)	$1,290,225,854
52							
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,359,842,185		$1,280,406,024
54							
55		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
56							
57		Book Depreciation Reserve 08/31/20		Line 41	$450,910,927		$0
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$41,483,938		$38,284,140
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($1,131,231)		$0
61		Less: Retired Plant		Line 49	($1,500,301)		$0
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$489,949,834		$38,470,640
63							
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		0.0687	Retirements		
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		0.0518	COR		
66							
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)			$41,061,654
68		Less: General Plant Depreciation (assuming add=retirement)		Page 10, Line 79(f)			($748,271)
69		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
70		Total					$40,345,462
71		7 Months					x7/12
72		FY 2020 Depreciation Expense					$23,534,853
73							
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)			$41,670,438
75		Less: General Plant Depreciation		Page 10, Line 79(f)			($748,271)
76		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
77		Total					$40,954,247
78		FY 2021 Depreciation Expense		5 Months of RY 2 and 7 Months of RY 3			$40,700,587

The Narragansett Electric Company
d/b/a National Grid
FY 2021 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2019
1	Plant In Service	$1,195,705	$92,263	$24,845	$117,108		($6,844)		$1,305,969
2	Accumulated Depr	$414,713				$40,858	($6,844)	($6,123)	$442,604
3	Net Plant	$780,992							$863,364
4	Property Tax Expense	$22,678							$23,283
5	Effective Prop tax Rate	2.90%							2.70%
		End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2020
6	Plant In Service	$1,305,969	$154,552	$19,341	$173,893		($14,754)		$1,465,108
7	Accumulated Depr	$442,604				$41,650	($14,754)	($7,910)	$461,590
8	Net Plant	$863,364							$1,003,518
9	Property Tax Expense	$23,283							$28,640
10	Effective Prop tax Rate	2.70%							2.85%
		End of FY 2020	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2021
11	Plant In Service	$1,465,108	$179,664	$24,845	$204,509		($25,032)		$1,644,585
12	Accumulated Depr	$461,590				$46,790	($25,032)	($18,948)	$464,401
13	Net Plant	$1,003,518							$1,180,184
14	Property Tax Expense	$28,640							$31,827
15	Effective Prop tax Rate	2.85%							2.70%

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2018				Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 month						
16	Incremental ISR Additions		$97,810				$92,263					
17	Book Depreciation: base allowance on ISR eligible plant		($24,356)				($24,356)					
18	Book Depreciation: current year ISR additions		($1,246)				($1,449)					
19	COR		$8,603				$11,583					
20	Net Plant Additions		$80,811				$78,041					
21	RY Effective Tax Rate		3.06%				3.06%					
22	ISR Property Tax Recovery on FY 2014 vintage investment			$194		5 month	1.27%	$76				
23	ISR Property Tax Recovery on FY 2015 vintage investment			$1,311				$508				
24	ISR Property Tax Recovery on FY 2016 vintage investment			$1,819				$709				
25	ISR Property Tax Recovery on FY 2017 vintage investment			$1,799				$714				
26	ISR Property Tax Recovery on FY 2018 vintage investment			$2,469				$989				
27	ISR Property Tax Recovery on FY 2019 vintage investment							$993				
28	Total Property Tax due to ISR			$7,592				$3,989				
29	ISR Year Effective Tax Rate	2.90%				2.70%						
30	RY Effective Tax Rate	3.06%	-0.15%			3.06%	-0.36%					
31	RY Effective Tax Rate 5 mos for FY 2019		-0.15%			5 month	-0.15%					
32	RY Net Plant times 5 m 7 month	$458,057	* -0.15%	($694)		$458,057	* -0.15%	($684)				
33	FY 2014 Net Adds time 7 month	$6,343	* -0.15%	($10)		$5,950	* -0.15%	($9)				
34	FY 2015 Net Adds time 7 month	$42,913	* -0.15%	($65)		$39,920	* -0.15%	($60)				
35	FY 2016 Net Adds times ISR Year Effective Tax	$59,527	* -0.15%	($90)		$55,693	* -0.15%	($83)				
36	FY 2017 Net Adds times ISR Year Effective Tax	$58,883	* -0.15%	($89)		$56,076	* -0.15%	($84)				
37	FY 2018 Net Adds times ISR Year Effective Tax	$80,810	* -0.15%	($122)		$77,664	* -0.15%	($116)				
38	FY 2019 Net Adds times ISR Year Effective Tax rate					$78,041	* -0.15%	($117)				
39	Total Property Tax due to rate differential			($1,071)				($1,152)				
40	Total ISR Property Tax Recovery			$6,521				$2,837				

The Narragansett Electric Company
d/b/a National Grid
FY 2021 ISR Property Tax Recovery Adjustment

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2019		7 months		Cumulative Increm. ISR Prop. Tax for FY2020				Cumulative Increm. ISR Prop. Tax for FY2021		
41	Incremental ISR Additions		($914)				$115,728				$179,664	
42	Book Depreciation: base allowance on ISR eligible plant		$0				$0				$0	
43	Book Depreciation: current year ISR additions		($7)				($1,571)				($2,334)	
44	COR		$5,627				$4,805				$17,834	
45	Net Plant Additions		$4,705				$118,961				$195,165	
46												
47	RY Effective Tax Rate		2.92%				2.96%				3.02%	
48	Property Tax Recovery on Growth and non-ISR 7 mos		1.70%	$0				($604)				($1,249)
49	ISR Property Tax Recovery on FY 2018 Net Incremental			$118				$212				$223
50	ISR Property Tax Recovery on FY 2019 Net Incremental			$80				$139				$141
51	ISR Property Tax Recovery on FY 2020 Net Incremental							$3,518				$3,499
52	ISR Property Tax Recovery on FY 2021 vintage investment											$5,896
53	ISR Year Effective Tax Rate	2.70%				2.85%				2.70%		
54	RY Effective Tax Rate	2.92%	-0.22%			2.96%	-0.10%			3.02%	-0.32%	
55	RY Effective Tax Rate 7 mos for FY 2019		-0.13% 7 mos				-0.10%				-0.32%	
56	RY Net Plant times Rate 7 month	$919,892 * -0.13%		($1,203)		$908,586 * -0.1%		($939)		$889,353 * -0.32%		($2,886)
57	Growth and non-ISR Incremental times rate difference			$0		($20,407) * -0.1%		$21		($41,336) * -0.32%		$134
58	FY 2018 Net Incremental times rate difference	$6,934 * -0.13%		($9)		$7,156 * -0.1%		($7)		$7,378 * -0.32%		($24)
59	FY 2019 Net Incremental times rate difference	$4,705 * -0.13%		($6)		$4,692 * -0.1%		($5)		$4,678 * -0.32%		($15)
60	FY 2020 Net Incremental times rate difference					$118,961 * -0.1%		($123)		$115,819 * -0.32%		($376)
61	FY 2021 Net Adds times rate difference									$195,165 * -0.32%		($633)
62	Total Property Tax due to rate differential			($1,218)				($1,053)				($3,800)
63	Total ISR Property Tax Recovery			($1,138)				$2,212				$4,711

Line Notes	
1(a) - 5(h)	Docket No. 4781 Attachment MAL-2, Page 10 of 13, 1(a) to 5(h)
6(a) - 10(a)	Per Line 1(h) ~ 5(h)
6(b)	Page 15 of 22 , Line 1 ,Col (c)÷1000
6(c)	Docket No. 4916, Revised Section 3, Att. 1R, P.15, L.7(c)
6(d)	Line 6(b) + Line 6(c)
6(f)	Page 15 of 22 , Line 7 ,Col (c)÷1000
6(h)	Line 6(a) + (d) + (f)
7(e)	Page 18 of 22 , (Line 16 + Line 17 ,Col (a))×5÷12 + Page 18 of 22 , (Line 37 + Line 38 ,Col (a))×7÷12 + (Page 2 of 22 , Line 3, Col (a) + Page 5 of 22 , Line 3, Col (a))÷1000 * 3.05% + Page 8 of 22 , Line 3, Col (a)×0.5×3.05%÷1000
7(f)	=6(f)
7(g)	Page 15 of 22 , Line 4 ,Col (c)÷1000
7(h)	Line 7(a) + (e) + (f) + (g)
8(h)	Line 6(h) - 7(h)
9(h)	Docket No. 4916, Revised Section 3, Att. 1R, P.15, L.10(h)
10(h)	Line 9(h) ÷ 8(h)
11(a) - 15(a)	Per Line 6(h) ~ 10(h)
11(b)	Page 15 of 22 , Line 1 ,Col (d)÷1000
11(c)	Line 1(c) - Estimated based on FY2019 actual non-ISR addition
11(d)	Line 11(b) + Line 11(c)
11(f)	Page 15 of 22 , Line 7 ,Col (d)÷1000
11(h)	Line 11(a) + (d) + (f)
12(e)	Page 18 of 22 , (Line 37 + Line 38 ,Col (a))×5÷12 + Page 18 of 22 , (Line 58 + Line 59 ,Col (a))×7÷12 + (Page 2 of 22 , Line 3, Col (a) + Page 5 of 22 , Line 3, Col (a) + Page 8 of 22 , Line 3, Col (a))÷1000 * 3.05% + Page 12 of 22 , Line 3, Col (a)×0.5×3.05%÷1000
12(f)	=11(f)
12(g)	- Page 15 of 22 , Line 4 ,Col (d)÷1000
12(h)	Line 12(a) + (e) + (f) + (g)
13(h)	Line 11(h) - 12(h)
14(h)	Line 13(h) x 15(h)

Line Notes	
15(h)	Line 10(a) - Estimated based on FY2019 actual property rate
16(a) - 40(g)	Docket No. 4781 Attachment MAL-1, Page 29 of 35, 82(e) to 107(k)
41(a) - 63(c)	Docket No. 4781 Attachment MAL-2, Page 11 of 13, 31(a) to 50(c)
41(f)	Page 8 of 22, Line 4(a)÷1000
42(f)	FY20 depreciation is reflected in the NBV at 56(e)
43(f)	- Page 8 of 22, Line 12(a)÷1000
44(f)	Page 8 of 22, Line 7(a)÷1000
45(f)	Sum of Lines 41(f) through 44(f)
47(f)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷ 56(e)
48(g)	Line 47(f) x Line 57(e)
49(g)	Line 47(f) x Line 58(e)
50(g)	Line 47(f) × 59(e)
51(g)	Line 47(f) × 60(e)
53(e)	=10(h)
54(e)	=47(f)
54(f)	53(e) -54(e)
55(f)	=54(f)
56(e)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: 56(a) × 5÷12 + (Sch 6-G, P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)) × 7÷12000
56(g)	56(e) ×55(f)
57(e)	= - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5, L3(e)+L3(g)+L7(e)+L7(g)
57(g)	57(e) ×55(f)
58(e)	Line 58(a) - Page 2 of 22, Line 12(c))÷1000
58(g)	=58(e) ×55(f)
59(e)	Line 59(a) - Page 5 of 22, Line 12(b))÷1000
59(g)	=59(e) ×55(f)
60(e)	=45(f)
60(g)	=60(e) ×55(f)
62(g)	sum of 56(g) through 61(g)
63(g)	sum of 48(g) through 51(g) + 62(g)

Line Notes	
41(j)	Page 12 of 22, Line 4(a) ÷1000
42(j)	FY21 depreciation is reflected in the NBV at 56(i)
43(j)	- Page 12 of 22, Line 12(a) ÷1000
44(j)	Page 12 of 22, Line 7(a) ÷1000
45(j)	Sum of Lines 41(j) through 44(j)
47(j)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷ 56(i)
48(k)	Line 47(j) x Line 57(i)
49(k)	Line 47(j) x Line 58(i)
50(k)	Line 47(j) x Line 59(i)
51(k)	Line 47(j) x Line 60(i)
52(k)	Line 47(j) x Line 61(i)
53(i)	=15(h)
54(i)	=47(j)
54(j)	53(i)-54(i)
55(j)	=54(j)
56(i)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att.1, Sch 6-G: (P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)) × 5÷12000+(P2, L51 - L62 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)- L1(i)) × 7÷12000
56(k)	56(i)×55(j)
57(i)	= - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5, L3(h)+L3(j)+L7(h)+L7(j)
57(k)	57(i)×55(j)
58(i)	Line 58(e) - Page 2 of 22, Line 12(d))÷1000
58(k)	=58(i)×55(j)
59(i)	Line 59(e) - Page 5 of 22, Line 12(c))÷1000
59(k)	=59(i)×55(j)
60(i)	Line 60(e) - Page 8 of 22, Line 5(a)÷1000
60(k)	=60(i)×55(j)
61(i)	45(j)
61(k)	=61(i)×55(j)
62(k)	sum of 56(k) through 61(k)
63(k)	sum of 48(k) through 52(k) + 62(k)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Test Year July 2016 - June 2017			Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020
1	Total Base Rate Plant DIT Provision		$29,439,421			$5,223,437	$20,453,237	$16,078,372	$5,085,206
2	Excess DIT amortization					$0	$0	($1,470,238)	($1,470,238)
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2018	FY 2019	FY 2020	FY 2021
3	Total Base Rate Plant DIT Provision					$24,514,347	$17,043,594	$8,195,454	$5,167,632
4	Incremental FY 18	$2,507,039	$2,560,766	$1,773,289	$1,823,824	$2,507,039	$53,728	($787,477)	$50,535
5	Incremental FY 19	$0	$1,083,441	$1,077,200	$1,071,214	$0	$1,083,441	($6,240)	($5,986)
6	Incremental FY 20	$0	$0	$18,306,860	$18,169,033	$0	$0	$18,306,860	($137,827)
7	Incremental FY 21				$35,965,996				$35,965,996
8	TOTAL Plant DIT Provision	$2,507,039	$3,644,207	$21,157,350	$57,030,068	$27,021,386	$18,180,762	$25,708,596	$41,040,350
9	NOL (Utilization)					$6,051,855	($16,495,753)	($5,060,855)	$0
10	Lesser of NOL or DIT Provision					$6,051,855	($16,495,753)	($5,060,855)	$0

Line Notes:

1(e) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 3 plus Line 4
1(f) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 7
1(g) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 50
1(h) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 41
1 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 51
2 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 52

3 Col (e) = Line 1(b) × 25% + Line 1(e) + Line 1(f) × 7/12; Col (f) = Line 1(f) × 5/12 + Line 1(g) × 7/12 + Line (2(f) x 5/12 + Line 2(g) × 7/12;

4(a)-7(d) Cumulative DIT plus Deferred Income Tax (Page 2, Line 16 + Line 18; Page 5, Line 16; Page 8, Line 16; Page 12, Line 16)
4(e)-7(h) Year over year change in cumulative DIT shown in Cols (a) through (d)
8 Sum of Lines 3 through 7
9 Col (e)(f) = Docket No. 4781 FY19 ISR Rec, Att. MAL-2, P.6, L.10; Col (g)= Docket no. 4916, R.S. 3, Att. 1R, P.11, L.10(c); Col(h) = Per Tax Department
10 Lesser of Line 8 or Line 9

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement
Calculation of Weighted Average Cost of Capital

Line No.						
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		(a)	(b)	(c)	(d)	(e)
3		Ratio	Rate	Weighted Rate	Taxes	Return
4	Long Term Debt	49.95%	5.70%	2.85%		2.85%
5	Short Term Debt	0.76%	0.80%	0.01%		0.01%
6	Preferred Stock	0.15%	4.50%	0.01%		0.01%
7	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
8		100.00%		7.54%	2.51%	10.05%
9						
10	(d) - Column (c) x 35% divided by (1 - 35%)					
11						
12						
13	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
14		(a)	(b)	(c)	(d)	(e)
15		Ratio	Rate	Weighted Rate	Taxes	Return
16	Long Term Debt	49.95%	5.70%	2.85%		2.85%
17	Short Term Debt	0.76%	0.80%	0.01%		0.01%
18	Preferred Stock	0.15%	4.50%	0.01%		0.01%
19	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
20		100.00%		7.54%	1.24%	8.78%
21	(d) - Column (c) x 21% divided by (1 - 21%)					
22						
23	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
24		(a)	(b)	(c)	(d)	(e)
25		Ratio	Rate	Weighted Rate	Taxes	Return
26	Long Term Debt	48.35%	4.98%	2.41%		2.41%
27	Short Term Debt	0.60%	1.76%	0.01%		0.01%
28	Preferred Stock	0.10%	4.50%	0.00%		0.00%
29	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
30		100.00%		7.15%	1.26%	8.41%
31	(d) - Column (c) x 21% divided by (1 - 21%)					
32						
33	FY18 Blended Rate			Line 8(e) × 75% + Line 20(e) × 25%		9.73%
34						
35	FY19 Blended Rate			Line 20 x 5 ÷ 12 + Line 30 x 7 ÷ 12		8.56%

Section 4
Rate Design &
Bill Impacts

Section 4
Rate Design and Bill Impacts
FY 2021 Proposal

Rate Design and Bill Impacts
FY 2021 Proposal

Like the revenue requirement, the proposed Gas ISR Plan rate design for FY 2021 is designed to recover incremental capital investment in excess of capital investment that has been reflected in the rate base in the Company's last general rate case in Docket No. 4770, as well as incremental O&M described in Section 2 and the property tax described in Section 3. For purposes of rate design, the revenue requirement associated with cumulative capital investment and property tax recovery is allocated to rate classes based upon a rate base allocator derived from the approved Allocated Cost of Service Study (ACOSS) included in the Amended Settlement Agreement in Docket No. 4770. The incremental O&M expense associated with the Heat Decarbonization Assessment has been allocated to all rate classes on a per-unit basis.

The throughput for the April 2020 through March 2021 period is from the Company's most recent forecast filed in the Company's Gas Cost Recovery filing in Docket No. 4963. Attachment 1 of this section provides the proposed ISR factors by rate class. Attachment 2 of this section provides the Plan's bill impacts[1] associated with the rate design in Attachment 1 by rate class. For the average Residential Heating customer using 845 therms per year, the cumulative impact of the FY 2021 Gas ISR Plan will represent an annual increase of $44.08, or 3.7 percent, from last year's bills.

[1] Bill impacts are provided using rates approved and currently in effect as of November 1, 2019.

	FY 2021 Revenue Requirement	Rate Class	Rate Base Allocator (%)	Allocation to Rate Class ($)	Throughput (dth)	CapEx Factor (dth)	CapEx Factor (therm)	O&M Allocation (therm)	Total ISR Factor (therm)	Uncollectible %	ISR Factor (therm)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
(1)	$21,354,740										
(2)	$1,000,000										
(3)		Res-NH	2.55%	$544,546	355,432	$1.5320	$0.1532	$0.0023	$0.1555	1.91%	$0.1585
(4)		Res-H	64.04%	$13,675,576	20,002,161	$0.6837	$0.0683	$0.0023	$0.0706	1.91%	$0.0719
(5)		Small	8.04%	$1,716,921	2,595,305	$0.6615	$0.0661	$0.0023	$0.0684	1.91%	$0.0697
(6)		Medium	12.23%	$2,611,685	6,151,694	$0.4245	$0.0424	$0.0023	$0.0447	1.91%	$0.0455
(7)		Large LL	5.57%	$1,189,459	2,930,300	$0.4059	$0.0405	$0.0023	$0.0428	1.91%	$0.0436
(8)		Large HL	2.25%	$480,482	1,564,868	$0.3070	$0.0307	$0.0023	$0.0330	1.91%	$0.0336
(9)		XL-LL	0.97%	$207,141	1,399,020	$0.1480	$0.0148	$0.0023	$0.0171	1.91%	$0.0174
(10)		XL-HL	4.35%	$928,931	6,711,586	$0.1384	$0.0138	$0.0023	$0.0161	1.91%	$0.0164
(11)		Total	100.00%	$21,354,740	41,710,367						

(a) Line 1: Proposed Capital Revenue Requirement & Forecasted Annual Property Tax Recovery Mechanism (Section 3, Attachment 1, Page 1, Line 10)
(a) Line 2: Proposed O&M (Section 3, Attachment 1, Page 1, Line 1)
(c) Docket 4770, RI 2017 Rate Case, Compliance Attachment 14, Schedule 2, Page 1 & 2, Line 15 (Rate Class divided by Total Company)
(d) Column (a) Line 1 * Column (c)
(e) Page 2, Column (m), Line 9
(f) Column (d) / Column (e), truncated to 4 decimal places
(g) Column (d) / (Column (e)*10), truncated to 4 decimal places
(h) Column (a) Line 2 / (Column (e) Line 11 * 10)
(i) Column (g) + Column (h)
(j) Docket 4770, RI 2017 Rate Case, Compliance Attachment 2, Schedule 22, Page 7, Line 15
(k) Column (i) / (1- Column (j)), truncated to 4 decimal places

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4996
Gas Infrastructure, Safety, and Reliability Plan FY 2021
Section 4: Attachment 1
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Forecasted Throughput April 2020 - March 2021

		Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Res-NH	38,776	23,141	16,991	13,192	12,870	12,955	17,210	29,318	41,316	50,599	54,760	44,305	355,432
(2)	Res-H	2,286,040	846,216	583,887	459,638	438,537	451,733	606,383	1,449,079	2,589,846	3,492,100	3,909,276	2,889,426	20,002,161
(3)	Small	322,732	146,582	69,771	51,967	51,719	54,435	46,321	164,007	327,130	443,028	543,243	374,371	2,595,305
(4)	Medium	695,442	386,939	274,477	199,940	188,417	185,696	221,094	460,376	722,500	931,426	1,071,317	814,070	6,151,694
(5)	Large LL	357,960	172,909	80,276	52,887	43,431	45,226	95,592	247,043	377,861	498,681	524,468	433,965	2,930,300
(6)	Large HL	141,189	111,789	106,220	91,875	91,003	103,985	106,623	127,141	161,974	178,099	195,202	149,769	1,564,868
(7)	X-Large LL	148,254	54,282	35,290	28,734	25,089	29,879	83,202	153,666	176,075	238,687	214,498	211,365	1,399,020
(8)	X-Large HL	532,906	493,776	501,198	491,138	501,539	535,334	555,401	580,109	622,822	677,322	653,010	567,030	6,711,586
(9)		4,523,300	2,235,634	1,668,110	1,389,371	1,352,605	1,419,243	1,731,827	3,210,737	5,019,522	6,509,942	7,165,776	5,484,300	41,710,367

Source: Company Forecast

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4996
Gas Infrastructure, Safety, and Reliability Plan FY 2021
Section 4: Attachment 1
Page 2 of 2

National Grid - RI Gas
Infrastructure, Safety, and Reliability (ISR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

(1)						Difference due to:					
(2)	Annual	Proposed	Current				DAC				
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(4)											
(5)	548	$872.94	$844.37	$28.57	3.4%	$0.00	$0.00	$27.71	$0.00	$0.00	$0.86
(6)	608	$948.53	$916.82	$31.71	3.5%	$0.00	$0.00	$30.76	$0.00	$0.00	$0.95
(7)	667	$1,022.80	$988.00	$34.79	3.5%	$0.00	$0.00	$33.75	$0.00	$0.00	$1.04
(8)	726	$1,097.10	$1,059.22	$37.88	3.6%	$0.00	$0.00	$36.74	$0.00	$0.00	$1.14
(9)	785	$1,171.34	$1,130.37	$40.97	3.6%	$0.00	$0.00	$39.74	$0.00	$0.00	$1.23
(10)	845	$1,246.89	$1,202.81	$44.08	3.7%	$0.00	$0.00	$42.76	$0.00	$0.00	$1.32
(11)	905	$1,322.45	$1,275.24	$47.22	3.7%	$0.00	$0.00	$45.80	$0.00	$0.00	$1.42
(12)	964	$1,396.64	$1,346.37	$50.27	3.7%	$0.00	$0.00	$48.76	$0.00	$0.00	$1.51
(13)	1,023	$1,470.93	$1,417.57	$53.36	3.8%	$0.00	$0.00	$51.76	$0.00	$0.00	$1.60
(14)	1,082	$1,545.25	$1,488.80	$56.45	3.8%	$0.00	$0.00	$54.76	$0.00	$0.00	$1.69
(15)	1,142	$1,620.83	$1,561.25	$59.58	3.8%	$0.00	$0.00	$57.79	$0.00	$0.00	$1.79

Residential Heating Low Income:

(16)						Difference due to:						
(17)	Annual	Proposed	Current				Low Income	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$648.78	$627.36	$21.43	3.4%	$0.00	($6.93)	$0.00	$27.71	$0.00	$0.00	$0.64
(21)	608	$704.82	$681.03	$23.78	3.5%	$0.00	($7.69)	$0.00	$30.76	$0.00	$0.00	$0.71
(22)	667	$759.88	$733.78	$26.10	3.6%	$0.00	($8.44)	$0.00	$33.75	$0.00	$0.00	$0.78
(23)	726	$814.96	$786.55	$28.41	3.6%	$0.00	($9.18)	$0.00	$36.74	$0.00	$0.00	$0.85
(24)	785	$870.00	$839.28	$30.73	3.7%	$0.00	($9.94)	$0.00	$39.74	$0.00	$0.00	$0.92
(25)	845	$926.02	$892.95	$33.06	3.7%	$0.00	($10.69)	$0.00	$42.76	$0.00	$0.00	$0.99
(26)	905	$982.04	$946.63	$35.41	3.7%	$0.00	($11.45)	$0.00	$45.80	$0.00	$0.00	$1.06
(27)	964	$1,037.03	$999.33	$37.70	3.8%	$0.00	($12.19)	$0.00	$48.76	$0.00	$0.00	$1.13
(28)	1,023	$1,092.10	$1,052.08	$40.02	3.8%	$0.00	($12.94)	$0.00	$51.76	$0.00	$0.00	$1.20
(29)	1,082	$1,147.22	$1,104.88	$42.34	3.8%	$0.00	($13.69)	$0.00	$54.76	$0.00	$0.00	$1.27
(30)	1,142	$1,203.26	$1,158.58	$44.68	3.9%	$0.00	($14.45)	$0.00	$57.79	$0.00	$0.00	$1.34

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2019

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4996
Gas Infrastructure, Safety, and Reliability Plan FY 2021
Section 4: Attachment 2
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National Grid - RI Gas
Infrastructure, Safety, and Reliability (ISR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

							Difference due to:				
(31)							DAC				
(32)	Annual	Proposed	Current								
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$378.01	$362.07	$15.94	4.4%	$0.00	$0.00	$15.46	$0.00	$0.00	$0.48
(36)	158	$396.94	$379.46	$17.48	4.6%	$0.00	$0.00	$16.96	$0.00	$0.00	$0.52
(37)	172	$415.93	$396.86	$19.06	4.8%	$0.00	$0.00	$18.49	$0.00	$0.00	$0.57
(38)	189	$438.96	$418.00	$20.96	5.0%	$0.00	$0.00	$20.33	$0.00	$0.00	$0.63
(39)	202	$456.53	$434.16	$22.37	5.2%	$0.00	$0.00	$21.70	$0.00	$0.00	$0.67
(40)	220	$480.88	$456.50	$24.38	5.3%	$0.00	$0.00	$23.65	$0.00	$0.00	$0.73
(41)	238	$505.31	$478.92	$26.39	5.5%	$0.00	$0.00	$25.60	$0.00	$0.00	$0.79
(42)	251	$522.92	$495.09	$27.82	5.6%	$0.00	$0.00	$26.99	$0.00	$0.00	$0.83
(43)	268	$545.85	$516.15	$29.70	5.8%	$0.00	$0.00	$28.81	$0.00	$0.00	$0.89
(44)	282	$564.82	$533.56	$31.26	5.9%	$0.00	$0.00	$30.32	$0.00	$0.00	$0.94
(45)	297	$585.13	$552.21	$32.92	6.0%	$0.00	$0.00	$31.93	$0.00	$0.00	$0.99

Residential Non-Heating Low Income:

								Difference due to:				
(46)							Low Income	DAC				
(47)	Annual	Proposed	Current									
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$281.96	$270.00	$11.95	4.4%	$0.00	($3.86)	$0.00	$15.46	$0.00	$0.00	$0.36
(51)	158	$296.02	$282.90	$13.11	4.6%	$0.00	($4.24)	$0.00	$16.96	$0.00	$0.00	$0.39
(52)	172	$310.09	$295.79	$14.30	4.8%	$0.00	($4.62)	$0.00	$18.49	$0.00	$0.00	$0.43
(53)	189	$327.17	$311.45	$15.72	5.0%	$0.00	($5.08)	$0.00	$20.33	$0.00	$0.00	$0.47
(54)	202	$340.21	$323.43	$16.78	5.2%	$0.00	($5.43)	$0.00	$21.70	$0.00	$0.00	$0.50
(55)	220	$358.29	$340.00	$18.29	5.4%	$0.00	($5.91)	$0.00	$23.65	$0.00	$0.00	$0.55
(56)	238	$376.40	$356.61	$19.79	5.6%	$0.00	($6.40)	$0.00	$25.60	$0.00	$0.00	$0.59
(57)	251	$389.47	$368.60	$20.87	5.7%	$0.00	($6.75)	$0.00	$26.99	$0.00	$0.00	$0.63
(58)	268	$406.50	$384.22	$22.28	5.8%	$0.00	($7.20)	$0.00	$28.81	$0.00	$0.00	$0.67
(59)	282	$420.58	$397.14	$23.44	5.9%	$0.00	($7.58)	$0.00	$30.32	$0.00	$0.00	$0.70
(60)	297	$435.64	$410.95	$24.69	6.0%	$0.00	($7.98)	$0.00	$31.93	$0.00	$0.00	$0.74

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2019

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Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

(61)						Difference due to:					
(62)	Annual	Proposed	Current				DAC				
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)											
(65)	830	$1,278.57	$1,236.91	$41.66	3.4%	$0.00	$0.00	$40.41	$0.00	$0.00	$1.25
(66)	919	$1,381.36	$1,335.24	$46.12	3.5%	$0.00	$0.00	$44.74	$0.00	$0.00	$1.38
(67)	1,010	$1,486.57	$1,435.89	$50.68	3.5%	$0.00	$0.00	$49.16	$0.00	$0.00	$1.52
(68)	1,099	$1,589.41	$1,534.28	$55.13	3.6%	$0.00	$0.00	$53.48	$0.00	$0.00	$1.65
(69)	1,187	$1,691.17	$1,631.59	$59.59	3.7%	$0.00	$0.00	$57.80	$0.00	$0.00	$1.79
(70)	1,277	$1,795.21	$1,731.10	$64.10	3.7%	$0.00	$0.00	$62.18	$0.00	$0.00	$1.92
(71)	1,367	$1,899.22	$1,830.62	$68.60	3.7%	$0.00	$0.00	$66.54	$0.00	$0.00	$2.06
(72)	1,456	$2,002.09	$1,929.01	$73.08	3.8%	$0.00	$0.00	$70.89	$0.00	$0.00	$2.19
(73)	1,544	$2,103.86	$2,026.37	$77.49	3.8%	$0.00	$0.00	$75.17	$0.00	$0.00	$2.32
(74)	1,635	$2,209.06	$2,126.98	$82.08	3.9%	$0.00	$0.00	$79.62	$0.00	$0.00	$2.46
(75)	1,725	$2,313.02	$2,226.44	$86.58	3.9%	$0.00	$0.00	$83.98	$0.00	$0.00	$2.60

C & I Medium:

(76)						Difference due to:					
(77)	Annual	Proposed	Current				DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)											
(80)	6,907	$7,811.84	$7,586.12	$225.72	3.0%	$0.00	$0.00	$218.95	$0.00	$0.00	$6.77
(81)	7,650	$8,538.12	$8,288.09	$250.03	3.0%	$0.00	$0.00	$242.53	$0.00	$0.00	$7.50
(82)	8,391	$9,262.02	$8,987.78	$274.24	3.1%	$0.00	$0.00	$266.01	$0.00	$0.00	$8.23
(83)	9,136	$9,990.10	$9,691.48	$298.62	3.1%	$0.00	$0.00	$289.66	$0.00	$0.00	$8.96
(84)	9,880	$10,717.26	$10,394.38	$322.88	3.1%	$0.00	$0.00	$313.19	$0.00	$0.00	$9.69
(85)	10,623	$11,443.56	$11,096.39	$347.16	3.1%	$0.00	$0.00	$336.75	$0.00	$0.00	$10.41
(86)	11,366	$12,169.85	$11,798.42	$371.43	3.1%	$0.00	$0.00	$360.29	$0.00	$0.00	$11.14
(87)	12,111	$12,897.89	$12,502.07	$395.81	3.2%	$0.00	$0.00	$383.94	$0.00	$0.00	$11.87
(88)	12,855	$13,625.10	$13,205.00	$420.10	3.2%	$0.00	$0.00	$407.50	$0.00	$0.00	$12.60
(89)	13,596	$14,348.99	$13,904.68	$444.31	3.2%	$0.00	$0.00	$430.98	$0.00	$0.00	$13.33
(90)	14,340	$15,076.17	$14,607.54	$468.63	3.2%	$0.00	$0.00	$454.57	$0.00	$0.00	$14.06

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2019

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Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(91)						Difference due to:					
(92)											
(93)											
(94)											
(95)	37,587	$41,006.17	$39,828.18	$1,177.99	3.0%	$0.00	$0.00	$1,142.65	$0.00	$0.00	$35.34
(96)	41,634	$45,153.51	$43,848.69	$1,304.81	3.0%	$0.00	$0.00	$1,265.67	$0.00	$0.00	$39.14
(97)	45,683	$49,303.33	$47,871.63	$1,431.70	3.0%	$0.00	$0.00	$1,388.75	$0.00	$0.00	$42.95
(98)	49,731	$53,452.23	$51,893.64	$1,558.59	3.0%	$0.00	$0.00	$1,511.83	$0.00	$0.00	$46.76
(99)	53,777	$57,598.64	$55,913.25	$1,685.39	3.0%	$0.00	$0.00	$1,634.83	$0.00	$0.00	$50.56
(100)	57,825	$61,747.53	$59,935.28	$1,812.25	3.0%	$0.00	$0.00	$1,757.88	$0.00	$0.00	$54.37
(101)	61,873	$65,896.44	$63,957.34	$1,939.10	3.0%	$0.00	$0.00	$1,880.93	$0.00	$0.00	$58.17
(102)	65,920	$70,043.76	$67,977.83	$2,065.93	3.0%	$0.00	$0.00	$2,003.95	$0.00	$0.00	$61.98
(103)	69,967	$74,191.72	$71,998.95	$2,192.77	3.0%	$0.00	$0.00	$2,126.99	$0.00	$0.00	$65.78
(104)	74,016	$78,341.57	$76,021.91	$2,319.66	3.1%	$0.00	$0.00	$2,250.07	$0.00	$0.00	$69.59
(105)	78,063	$82,488.90	$80,042.40	$2,446.49	3.1%	$0.00	$0.00	$2,373.10	$0.00	$0.00	$73.39

C & I HLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(106)						Difference due to:					
(107)											
(108)											
(109)											
(110)	41,956	$37,503.56	$36,599.56	$904.00	2.5%	$0.00	$0.00	$876.88	$0.00	$0.00	$27.12
(111)	46,471	$41,272.26	$40,270.98	$1,001.28	2.5%	$0.00	$0.00	$971.24	$0.00	$0.00	$30.04
(112)	50,991	$45,044.67	$43,946.01	$1,098.66	2.5%	$0.00	$0.00	$1,065.70	$0.00	$0.00	$32.96
(113)	55,507	$48,814.17	$47,618.20	$1,195.97	2.5%	$0.00	$0.00	$1,160.09	$0.00	$0.00	$35.88
(114)	60,028	$52,587.30	$51,293.91	$1,293.39	2.5%	$0.00	$0.00	$1,254.59	$0.00	$0.00	$38.80
(115)	64,545	$56,357.48	$54,966.78	$1,390.70	2.5%	$0.00	$0.00	$1,348.98	$0.00	$0.00	$41.72
(116)	69,062	$60,127.68	$58,639.63	$1,488.05	2.5%	$0.00	$0.00	$1,443.41	$0.00	$0.00	$44.64
(117)	73,583	$63,900.84	$62,315.37	$1,585.46	2.5%	$0.00	$0.00	$1,537.90	$0.00	$0.00	$47.56
(118)	78,099	$67,670.30	$65,987.53	$1,682.77	2.6%	$0.00	$0.00	$1,632.29	$0.00	$0.00	$50.48
(119)	82,619	$71,442.70	$69,662.55	$1,780.15	2.6%	$0.00	$0.00	$1,726.75	$0.00	$0.00	$53.40
(120)	87,137	$75,214.53	$73,337.06	$1,877.47	2.6%	$0.00	$0.00	$1,821.15	$0.00	$0.00	$56.32

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2019

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Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

							Difference due to:					
(121)								DAC				
(122)	Annual	Proposed	Current									
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(124)												
(125)	233,835	$187,007.42	$184,042.28	$2,965.13	1.6%	$0.00	$0.00	$2,876.18	$0.00	$0.00	$88.95	
(126)	259,019	$206,480.60	$203,196.14	$3,284.45	1.6%	$0.00	$0.00	$3,185.92	$0.00	$0.00	$98.53	
(127)	284,197	$225,949.76	$222,346.03	$3,603.73	1.6%	$0.00	$0.00	$3,495.62	$0.00	$0.00	$108.11	
(128)	309,381	$245,422.89	$241,499.81	$3,923.08	1.6%	$0.00	$0.00	$3,805.39	$0.00	$0.00	$117.69	
(129)	334,562	$264,894.11	$260,651.73	$4,242.38	1.6%	$0.00	$0.00	$4,115.11	$0.00	$0.00	$127.27	
(130)	359,745	$284,366.65	$279,804.92	$4,561.73	1.6%	$0.00	$0.00	$4,424.88	$0.00	$0.00	$136.85	
(131)	384,928	$303,839.12	$298,958.07	$4,881.05	1.6%	$0.00	$0.00	$4,734.62	$0.00	$0.00	$146.43	
(132)	410,110	$323,310.94	$318,110.56	$5,200.37	1.6%	$0.00	$0.00	$5,044.36	$0.00	$0.00	$156.01	
(133)	435,293	$342,783.46	$337,263.77	$5,519.69	1.6%	$0.00	$0.00	$5,354.10	$0.00	$0.00	$165.59	
(134)	460,471	$362,252.58	$356,413.62	$5,838.96	1.6%	$0.00	$0.00	$5,663.79	$0.00	$0.00	$175.17	
(135)	485,655	$381,725.76	$375,567.46	$6,158.30	1.6%	$0.00	$0.00	$5,973.55	$0.00	$0.00	$184.75	

C & I HLF Extra-Large:

							Difference due to:					
(136)								DAC				
(137)	Annual	Proposed	Current									
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(139)												
(140)	486,528	$334,216.43	$328,197.51	$6,018.92	1.8%	$0.00	$0.00	$5,838.35	$0.00	$0.00	$180.57	
(141)	538,924	$369,542.49	$362,875.41	$6,667.08	1.8%	$0.00	$0.00	$6,467.07	$0.00	$0.00	$200.01	
(142)	591,320	$404,867.74	$397,552.44	$7,315.30	1.8%	$0.00	$0.00	$7,095.84	$0.00	$0.00	$219.46	
(143)	643,718	$440,195.02	$432,231.46	$7,963.56	1.8%	$0.00	$0.00	$7,724.65	$0.00	$0.00	$238.91	
(144)	696,109	$475,517.27	$466,905.58	$8,611.69	1.8%	$0.00	$0.00	$8,353.34	$0.00	$0.00	$258.35	
(145)	748,506	$510,843.92	$501,584.08	$9,259.85	1.8%	$0.00	$0.00	$8,982.05	$0.00	$0.00	$277.80	
(146)	800,903	$546,170.56	$536,262.47	$9,908.09	1.8%	$0.00	$0.00	$9,610.85	$0.00	$0.00	$297.24	
(147)	853,294	$581,492.85	$570,936.62	$10,556.23	1.8%	$0.00	$0.00	$10,239.54	$0.00	$0.00	$316.69	
(148)	905,692	$616,820.13	$605,615.69	$11,204.44	1.9%	$0.00	$0.00	$10,868.31	$0.00	$0.00	$336.13	
(149)	958,088	$652,145.37	$640,292.73	$11,852.64	1.9%	$0.00	$0.00	$11,497.06	$0.00	$0.00	$355.58	
(150)	1,010,485	$687,472.01	$674,971.15	$12,500.86	1.9%	$0.00	$0.00	$12,125.83	$0.00	$0.00	$375.03	

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2019

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**Testimony of
Lee Gresham**

DIRECT TESTIMONY

OF

LEE GRESHAM, JD, PhD

December 20, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Lee Gresham. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

A. I am employed by National Grid USA Service Company, Inc. as a Lead Analyst in Regulatory and Customer Strategy. I am the Rhode Island jurisdictional lead for heat decarbonization matters for the gas division of The Narragansett Electric Company d/b/a National Grid (Company), including those related to the Company's capital investment strategy. In my role, I work closely with the Rhode Island Jurisdictional President and jurisdictional staff on all local issues related to the Company's Rhode Island heat decarbonization efforts. My responsibilities also include working with Rhode Island regulators on issues related to decarbonizing the gas system, developing strategies to support Company objectives regarding decarbonization-related investments in the gas system and providing testimony regarding capital investments that enable National Grid to decarbonize its gas distribution network.

Q. Please describe your educational background and professional experience.

A. I graduated from the College of the Holy Cross with a Bachelor of Arts degree in

Psychology and concentration in Pre-Medicine in 1999. In 2007, I graduated from Vermont Law School with a Juris Doctorate degree. And in 2010, I received a Doctor of Philosophy degree in Engineering and Public Policy from Carnegie Mellon University.

From 2010 to 2011, I was a Post-Doctoral Fellow with the Carbon Capture and Sequestration Regulatory Institute. I worked as a Senior Consultant at SAIC's Energy, Environment, and Infrastructure division from 2011 to 2012. From 2012 to 2018, I held roles of increasing responsibility as an Associate with The Brattle Group in the firm's utility practice.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's proposed Heat Decarbonization Assessment (or Assessment) filed as part of the FY 2021 Gas

Infrastructure, Safety, and Reliability Plan (Gas ISR Plan or Plan).[1] Through my testimony, I present the Company's Gas ISR Heat Decarbonization Assessment, which details the work the Company expects to complete and the anticipated capital investments associated with that work. Company Witness Melissa A. Little is providing testimony on the calculation of the revenue requirement associated with the Company's Plan, and Company Witness Ryan M. Scheib is providing testimony relative to (1) how the Company calculated the rate design for the ISR mechanism; (2) the calculation of the ISR factors; and (3) the customer bill impacts of the proposed ISR factors.

III. <u>OVERVIEW</u>

Q. How did the Company prepare the Gas ISR Heat Decarbonization Assessment proposal?

A. The Company prepared the Gas ISR Heat Decarbonization Assessment and submitted it to the Rhode Island Division of Public Utilities and Carriers (Division) for review on September 29, 2019.[2] On October 7, 2019, the Company met with the Division regarding the proposal and subsequently responded to discovery requests from the Division about

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[1] The Company is required by statute to annually file an infrastructure, safety, and reliability spending plan with the PUC for review and approval. *See* R.I. Gen. Laws § 39-1-27.7.1(d). In addition to budgeted spending, the annual Gas ISR Plan must contain a reconcilable allowance for the Company's anticipated capital investments and other spending for the upcoming fiscal year. *See* R.I. Gen. Laws § 39-1-27.7.1(c)(2). For FY 2021, the Company's fiscal year is for the period of April 1, 2020 through March 31, 2021, so the Plan would be effective April 1, 2020.

[2] R.I. Gen. Laws § 39-1-27.7.1(d) requires that the Company and the Division work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which is then submitted to the PUC for review and approval within 90 days.

various components of the Assessment. The Company and the Division continued to collaborate regarding the proposed Assessment, including a discussion on December 6, 2019. The Division has indicated general concurrence with the proposal, including the analyses and projects outlined therein, and will continue to review the Assessment and its costs after filing, consistent with prior Gas ISR Plan filings. Overall, the Heat Decarbonization Assessment will enable the Company to meet state and federal safety and reliability requirements and maintain its gas distribution system in a safe and reliable condition, all while pursuing deep greenhouse gas emissions reductions. The proposed Assessment has been developed to address decarbonization as well as safety and reliability improvements of the Company's gas system for the immediate and long-term benefit of Rhode Island customers. Addressing heating sector emissions in Rhode Island is fundamental to achieving the state's climate targets. Decarbonizing heat will require transformative changes to energy supply and customer energy use.

Q. What is the Gas ISR Plan's Heat Decarbonization Assessment designed to accomplish?

A. The objective for the Heat Decarbonization Assessment is to evaluate the potential to continue to safely and reliably operate and maintain Rhode Island gas pipeline infrastructure while taking meaningful steps towards decarbonizing the gas network and providing customers with clean and affordable heating solutions. This assessment will help inform the Company's future geothermal and renewable natural gas (RNG) capital plans.

Q. Are you sponsoring any exhibits through your testimony?

A. Yes. The proposed Gas ISR Plan is attached as Exhibit 1 to my testimony. The Plan is organized as follows:

Section 2 – Heat Decarbonization

Section 3 – Revenue Requirement Calculation

Section 4 – Rate Design and Bill Impacts

My testimony focuses on Section 2 of the Proposal. As noted earlier, Melissa A. Little is sponsoring the revenue requirement calculation included in Section 3 of the Proposal, and Ryan M. Scheib is sponsoring the rate design and bill impacts included in Section 4 of the Proposal.

Q. Please describe the proposed Geothermal Assessment and Objectives.

A. Geothermal (or ground source) heat pumps are highly efficient and can meet whole-home heating and cooling needs. For delivered fuel customers outside of the natural gas network, geothermal is an opportunity to convert to a cleaner heating system. However, the high cost of these systems and a lack of public awareness has stifled widescale adoption of this technology. The Company believes that utility involvement can help address both barriers and encourage geothermal heat pump adoption growth.

The Company is proposing a top-down technical and market feasibility analysis of ground source heat pumps, evaluating inclusion of the heating loop in rate base. A heating loop is the below-ground portion of a geothermal system used to extract or dissipate heat. A two-phased assessment, as it is envisioned, will focus on utility applications at the edge of the gas network (i.e., communities currently seeking gas connections) and how the customer interacts with the technology from a business perspective. This assessment will help inform the Company's future geothermal capital plans.

Phase 1 aims to provide:

- A high-level, techno-economic assessment of geothermal with ground source heat pumps;
- An evaluation of land availability and limitations on the use thereof; and
- Identification of site selection criteria.

Phase 1 will be used to understand the potential for geothermal heat pumps to contribute to heating sector emissions reductions in Rhode Island and inform supporting strategy. The Company anticipates that it will perform the assessment in-house. Phase 2 will focus on identifying suitable sites for utility-owned geothermal heat pump systems. This will be accomplished through a market analysis that identifies specific candidate sites, utility business models, and customer offerings, as well as assesses scalability. Due to limited internal resources, the Company anticipates retaining consulting services to assist with Phase 2.

Q. How will the results of the assessment be used or applied?

A. If a site or sites are found to be viable, the results will be used to inform a future ISR request for investment in a geothermal capital program.

Q. Please describe what specifically you are referring to with respect to the term "Renewable Natural Gas."

A. RNG is a term generally used to describe pipeline compatible gaseous fuel derived from biomass or other renewable sources that has lower lifecycle CO_2e emissions than geological natural gas. RNG feedstocks include manure, food waste, wastewater treatment plants, or other biomass sources, often using an anaerobic digester. With recent advancements to lower the cost of gasification technology, feedstocks with lower moisture content can also be used to produce RNG (e.g., municipal solid waste or agricultural residues). Furthermore, with new technological innovations, production of RNG is moving beyond biomass to include renewable electricity, often referred to as power-to-gas or P2G. This concept includes either adding hydrogen to the existing gas system (i.e., hydrogen blending) or producing synthetic methane by combining hydrogen and carbon dioxide. Collectively, RNG offers new ways to decarbonize the gas network by reducing the carbon footprint of the fuel supply in a manner similar to the way solar and wind technology reduce the carbon footprint of electricity.

Q. Please describe the proposed Renewable Natural Gas Assessment and Objectives.

A. Renewable natural gas (RNG) presents an extraordinary opportunity to decarbonize the heating sector and leverage existing assets for a more affordable outcome. Integrating RNG converts the existing gas network into a clean energy distribution system that delivers low- or zero-carbon fuel to customers. We believe that decarbonizing the gas and electric networks in parallel can reduce the cost of achieving deep decarbonization goals. Integrating RNG will allow customers to reduce their carbon footprint, without having to replace end-use equipment or undertake deep renovations, minimizing disruption and upfront capital costs for our customers.

The objective of this project is to understand the potential near-and long-term gas demand in Rhode Island that can be served by RNG. To accomplish this, the Company proposes a bottom-up RNG (including Hydrogen) economic potential assessment. Specifically, the Company proposes estimating the potential amount of near- and long-term non-electric gas demand in Rhode Island that can be served by RNG based on available feedstocks, load forecasts, and expected renewable generation buildout and dedicated RNG / Hydrogen project-specific renewables projects. The most granular, site-specific assessment will be focused on landfill gas given facilities have been operating at scale worldwide for decades including the Staten Island Landfill facility that has been injecting into National Grid's gas network since the 1980's.3 Emerging sources and technologies used to produce RNG (municipal solid waste, food waste) and Hydrogen (via electrolyzers) will also be evaluated for near-, mid-, and long-term feasibility. This insight will be used to identify opportunities for utility-led capital programs and projects that provide or integrate low-carbon energy supply, such as:

- Identify and evaluate specific locations for traditional RNG interconnections, such as landfill gas-based, and potential partners to develop RNG facilities.
- Evaluating locations for use as a future hydrogen injection site. Engineering work will allow us to ascertain an appropriate and beneficial location to build a hydrogen injection site in the State. The work will provide the Company with a more complete understanding of the application of hydrogen technology in our system. The money requested could be utilized to develop a building site plan for a future electrolyzer, potentially aimed at meeting supply constraints in a specific area, and which could blend 2-3% hydrogen into the system (further allowing us to address potential leak and pipe embrittlement concerns). Along with the work supported by the RNG Assessment the Company will simultaneously outline how to safely blend hydrogen into the gas network in a separate, but related effort.

3 https://www.epa.gov/lmop/lmop-national-map

Q. How does the Company plan to involve the Division, Office of Energy Resources, and other stakeholders and keep them apprised of progress while the assessments are being conducted?

A. The Company will work collaboratively with Rhode Island stakeholders while conducting the assessment. Incorporating the perspective of the Division, the Office of Energy Resources, and other stakeholders will be critical to performing an accurate and actionable assessment. The Company also proposes to develop an Advisory Committee to provide technical and policy expertise and guidance with respect to the assessments. The Advisory Committee will meet at regular intervals throughout the project to review assumptions, results, and deliverables.

IV. CAPITAL INVESTMENT PLAN

Q. What levels of spending are proposed in the Gas ISR Plan's Heat Decarbonization Proposal?

A. For FY 2021, the Company proposes to invest a total of $1 million in Heat Decarbonization assessments, allocated equally between the Geothermal and RNG proposals.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY

OF

MELISSA A. LITTLE

December 20, 2019

Table of Contents

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is Melissa A. Little, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position at National Grid and your responsibilities within that position.

A. I am a Director for New England Revenue Requirements in the Regulation and Pricing department of National Grid USA Service Company, Inc. (Service Company). The Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA (National Grid). My current duties include revenue requirement responsibilities for National Grid's gas and electric distribution activities in New England, including the gas operations of The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company).

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Science degree in Accounting Information Systems from Bentley College (now Bentley University). In September 2000, I joined PricewaterhouseCoopers LLP in Boston, Massachusetts, where I worked as an associate in the Assurance practice. In November 2004, I joined National Grid in the Service Company as an Analyst in the General Accounting group. After the merger of National

Grid and KeySpan in 2007, I joined the Regulation and Pricing department as a Senior Analyst in the Regulatory Accounting function, also supporting the Niagara Mohawk Power Corporation Revenue Requirement team. I was promoted to Lead Specialist in July 2011 and moved to the New England Revenue Requirement team. In August 2017, I was promoted to my current position.

Q. Have you previously filed testimony or testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes. Among other testimony, I testified in support of the Company's revenue requirement (1) for Narragansett, in the 2017 general rate case filing in Docket No. 4770; (2) for Narragansett Gas, in the Gas ISR Plan and reconciliation filings for FY 2016 in Docket No. 4540, FY 2017 in Docket No. 4590, and FY 2018 in Docket No. 4678, and FY 2019 in Docket No. 4781, and the Gas ISR Plan filing for FY 2020 in Docket No. 4916; and (3) for Narragansett Electric, in the Fiscal Year (FY) 2018 Electric Infrastructure, Safety, and Reliability (ISR) Plan and reconciliation filing in Docket No. 4682, and FY 2019 in Docket No. 4783, and the Electric ISR Plan filing for FY 2020 in Docket No. 4915.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 3 of the FY 2021 Gas ISR Plan (Gas ISR Plan or Plan), which describes the calculation of the Company's revenue requirement for FY 2021 in Attachment 1 of that section. The revenue requirement is based on the FY 2021 Gas ISR Plan capital investment described in the testimony of Company Witness Amy Smith.

II. GAS ISR PLAN REVENUE REQUIREMENT

Q. Please summarize the revenue requirement for the Company's FY 2021 Gas ISR Plan.

A. As demonstrated in Attachment 1, Page 1, Column (b), the Company's FY 2021 Gas ISR Plan revenue requirement amounts to $22,354,740, or an incremental $15,880,020 over the amount currently being billed for the Gas ISR Plan. The Plan's revenue requirement consists of the following elements: (1) operation and maintenance (O&M) expenses of $1,000,000 associated with heat decarbonization; (2) the revenue requirement of $7,636,309 comprised of the Company's return, taxes, and depreciation expense associated with FY 2021 proposed non-growth ISR incremental capital investment in gas utility infrastructure of $198,612,000, as calculated on Attachment 1, Page 12; (3) the FY 2021 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through FY 2020 totaling $9,007,264; and (4) FY 2021 property tax expense of $4,711,167, as shown on Attachment 1 at Page 20, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770.

Importantly, the incremental capital investment for the FY 2021 ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4770 for FY 2012 through FY 2021. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan).

The FY 2021 Gas ISR Plan includes Operation & Maintenance (O&M) expense of $1,000,000 associated with heat decarbonization assessments as described in the testimony of Company Witness Lee Gresham.

For illustration purposes only, Attachment 1, Page 1, Column (c) provides the FY 2022 revenue requirement for the respective vintage year capital investments. Notably, these amounts will be trued up to actual investment activity after the conclusion of the fiscal year, with rate adjustments for the revenue requirement differences incorporated in future ISR filings. A detailed description of the calculation of the Company's revenue requirement for FY 2021 is provided in Section 3 of the Gas ISR Plan.

Q. Did the Company calculate the FY 2021 Gas ISR Plan revenue requirement in the same fashion as calculated in the previous ISR factor submissions?

A. Yes, with the exception of the bonus depreciation assumptions used in the calculation of tax depreciation on FY 2019 and FY 2020 capital investment. As stated in Section 3 of the Plan, the Company's original interpretation of the 2017 Tax Cut and Jobs Act (2017 Tax Act) was that no federal tax deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company has revised its estimate of FY 2019 and FY 2020 bonus depreciation. The Company's FY 2021 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2021 investment.

Q. Does the Company plan to update the FY 2021 Gas ISR Plan revenue requirement calculation subsequent to the date of this filing?

A. Yes. The Company will file its FY 2019 federal income tax return in December 2019, coincident with the submission of this filing. The Company will compare the results of the actual FY 2019 federal tax return with the FY 2019 tax assumptions used to calculate deferred federal income taxes included in incremental rate base in the FY 2019, FY 2020 and FY 2021 vintage revenue requirement calculations and assess any impact to the FY 2021 Gas ISR Plan revenue requirement. The Company will then file a revised FY 2021 Gas ISR Plan revenue requirement prior to the hearing in this docket, which will quantify the impact of any revisions to accumulated deferred income taxes on the FY 2021 Gas ISR Plan revenue requirement, including any further implications of the Tax Act.

III. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY

OF

RYAN M. SCHEIB

December 20, 2019

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I. INTRODUCTION

Q. Please state your names and business address.

A. My name is Ryan M. Scheib and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am an Analyst in the New England Gas Pricing group employed by National Grid USA Service Company, Inc. In this position, I am responsible for the preparing and submitting various regulatory filings with the Rhode Island Public Utilities Commission (PUC) on behalf of The Narragansett Electric Company d/b/a National Grid (the Company).

Q. Please provide your educational background and professional experience.

I received a Bachelor of Science in Finance from the University of Delaware in 2016.

In 2016, I joined National Grid as an Associate Analyst in the New England Gas Pricing group. In 2018, I was promoted to Analyst supporting the Company.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. Yes, I have testified before the PUC in the Company's Distribution Adjustment Charge filing in October 2019, RIPUC Docket No. 4955.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 4 of the Fiscal Year (FY) 2021 Gas Infrastructure, Safety, and Reliability (ISR) Plan (Gas ISR Plan or Plan), which describes the calculation of the proposed FY 2021 ISR factors and the customer bill impacts of the proposed ISR factors.

II. <u>RATE DESIGN</u>

Q. Please summarize the rate design used to develop the ISR factors presented as part of this filing.

A. Like the revenue requirement, the proposed Gas ISR Plan rate design for FY 2021 is based on the revenue requirement of incremental capital investment in excess of capital investment that has been reflected in rate base in the Company's most recent general rate case in Docket No. 4770, as well as incremental Operations and Maintenance (O&M) expense associated with the Heat Decarbonization Assessment as described in Section 2 of the ISR Plan and a property tax expense as described in Section 3 of the ISR Plan. The Company has allocated the revenue requirement associated with the capital investment to each rate class based on the rate base allocator approved by the PUC in the Amended Settlement Agreement in Docket No. 4770. However, to recover the proposed incremental O&M expense associated with the Heat Decarbonization Assessment, the Company calculated a uniform per-unit factor for each rate class. The Company also utilized the most recently available forecasted throughput for the period April 2020 through March 2021 that had been developed for the Company's 2019-20 Gas Cost Recovery filing in Docket No. 4963. That data was compiled by rate class and summarized as set forth in Section 4, Attachment 1, Page 2 of the proposed Gas ISR Plan. As shown in Section 4, Attachment 1, Page 1, the Company divided the allocated rate class revenue requirement, as multiplied by the rate base allocation, by the forecasted throughput for each rate class to develop separate ISR capital factors per rate class on a per-therm basis. Finally, the Company divided the total incremental O&M expense of $1,000,000 by the total forecasted throughput for all rate classes to derive the O&M factor for all rate classes on a per therm basis. The Company then adjusted each rate class' ISR factor (capital and O&M factors) to reflect the 1.91 percent uncollectible factor from the Amended Settlement Agreement in Docket No. 4770.

III. <u>ISR FACTORS</u>

Q. What are the ISR factors proposed by the Company?

A. The ISR factors proposed by the Company are shown in the table below and in the Gas ISR Plan at Section 4, Attachment 1.

Table 3-1 FY 2021 ISR Factors Per Rate Class

Rate Class	ISR Rate ($/therm)
Res-Non-Heating	$0.1585
Res-Heating	$0.0719
Small C&I	$0.0697
Medium C&I	$0.0455
Large LL	$0.0436
Large HL	$0.0336
XL-LL	$0.0174
XL-HL	$0.0164

*Rates include uncollectible allowance.

The same factors noted above for Residential Heating and Residential Non-Heating customers would also apply to each of the Low-Income rate classes.

IV. BILL IMPACTS

Q. What is the impact of the proposed ISR factors on customers' bills?

A. For the average Residential Heating customer using 845 therms annually, the proposed FY 2021 ISR factors will result in an annual bill increase of $44.08, or 3.7 percent,[1] as shown in the proposed Gas ISR Plan at Section 4, Attachment 2. The annual impact of the proposed ISR factors for all rate classes is set forth in Section 4 (Rate Design and Bill Impacts) of the Plan.

[1] Please note that the bill impact includes the Rhode Island Gross Earnings Tax of three percent.

Q. Does this conclude your testimony?

A. Yes.