nationalgrid

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Senior Counsel

August 27, 2021

BY ELECTRONIC MAIL

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

RE: Docket 5165 - 2021 Distribution Adjustment Charge (DAC)
<u>Responses to PUC Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of National Grid, [1] I have enclosed an electronic copy of the Company's responses to the Public Utilities Commission's First Set of Data Requests in the above-referenced matter.[2]

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

Very truly yours,

Raquel J. Webster

Enclosure

cc: Docket 5165 Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division
Jerome Mierzwa, Division's Consultant

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

[2] Per practice during the COVID-19 emergency period, the Company is providing a PDF version this report. The Company will provide the Commission Clerk with five (5) hard copies and, if needed, additional hard copies of this report upon request.

PUC 1-1

Request:

When was the last time that the Company funded a project with funds from the AGT fund? Is there any reason why the Commission should not eliminate the tariff provision and AGT factor?

Response:

The Company funded its last two disbursements from the AGT fund in August of 2018.

The Company recommends not eliminating the AGT factor provision of the Distribution Adjustment Clause of the Company's tariff because the Company believes that subtle changes to the parameters of the program would allow for more commercial and industrial customers to benefit from program as advanced future gas technologies become more readily available and more cost-effective.

Prepared by or under the supervision of: David Moreira

PUC 1-2

Request:

On page 19, line 3 of Mr. Scheib's testimony, should the factor be ($0.0003) indicating a credit rather than $0.0003 indicating a charge?

Response:

Page 19, line 3 of Mr. Scheib's testimony should read: "This amount is then divided by the forecasted throughput of 40,273,298 dth and divided by 10, resulting in a Storm Net Revenue credit factor of $0.0003 per therm for the 12 months beginning November 1, 2021."

Schedule RMS-1 presents all of the proposed components of the DAC included in the initial filing, with the Storm Net Revenue Factor being a credit.

Prepared by or under the supervision of: Ryan Scheib

PUC 1-3

Request:

Referring to Mr. Oliveira's and Mr. Allen's joint testimony on page 6, please explain what contributed to the $3,617,675 under-recovery of pension expensive.

Response:

Prorated rate allowances determined in Docket No. 4770 (effective September 2018) reflect census data, claims experience, demographic and economic assumptions included in fiscal year ended March 31, 2018 actuarial calculations. However, FY 2021 actual pension expense reflects updated census data, claims experience, demographic and economic assumptions included in fiscal year ended March 31, 2020 actuarial calculations.

Specifically, since March 31, 2020 was just a few weeks into the COVID crisis, market conditions unfavorably impacted FY 2021 expense in several ways that were outside the Company's control as further highlighted in Mr. Oliveira's and Mr. Allen's joint testimony on pages 6 through 8.

Overall, there were unfavorable factors caused by the economic turmoil of the prevailing COVID crisis as of March 31, 2020, such as significant declines in the market value of assets and long-term capital market outlook uncertainty that caused the actual FY 2021 pension expense to be higher than the estimated expense applied in Docket No. 4770. These unfavorable factors drove the FY 2021 under-recovery of pension expense.

Prepared by or under the supervision of: James Allen

PUC 1-4

Request:

In Ms. Smith's and Mr. Kocon's testimony on page 5 regarding the ISR reconciliation, they indicated that the primary driver of the under-spending was the COVID 19 pandemic. Please specify the details of what caused the under-spending, i.e., access to customer premises, less employees to perform the work, etc.

Response:

The Company provides program specific details in its FY 2021 Gas ISR Plan Annual Reconciliation filing in Attachment ASNK-1. Specifically:

Public Works Program
The Pandemic impacted the Company's ability to complete meter service work associated with the Public Works jobs because this type of work is customer facing and typically includes relighting equipment and appliances inside buildings after the transfer to the new service line and meter set has been completed. Thus, the limitations on meter service work impacted the Company's ability to abandon the forecasted miles for leak-prone pipe. See Annual Reconciliation Filing Attachment ASNK-1, p. 26.

Transmission Station Integrity Program
The Company completed lower volumes of work than planned for the Transmission Station Integrity program due to the pausing of the associated physical records review at Company locations. The Company restricted access to its locations to essential workers due to the Pandemic. See Annual Reconciliation Filing Attachment ASNK-1, pp. 26-28.

Proactive Main Replacement Program
As noted above in the Public Works section, the Pandemic impacted the Company's ability to complete portions of the meter service work associated with main replacement work since this work required entry into customers premises to transfer services to the new main and complete associated meter work. This ultimately prevented the Company from abandoning some segments of the existing main that were still providing service to customers. See Annual Reconciliation Filing Attachment ASNK-1, p. 29

Cast Iron Sealing Robot (CISBOT) projects were deferred for FY 2021 due to the Pandemic based on the Company's ability to complete the associated service work. The Cast Iron Lining (CI Lining) projects also experienced delays due to the Pandemic due to the Company's ability to complete the associated service work. Additionally, the lining project planned for Blackstone Street in Providence was deferred to eliminate potential impact to hospitals in the project area during the Pandemic; his deferral also contributed to the FY 2021 underspend. See Annual Reconciliation Filing Attachment ASNK-1, p. 32

Reliability Programs
The primary driver in all underspent Reliability categories is work delays due to the Pandemic, either due to travel restrictions or availability of crews to perform work due to illness or quarantine. The details for each program with Pandemic related delays are described below. See Annual Reconciliation Filing Attachment ASNK-1, pp. 33 to 35.

LNG
The LNG category was underspent due primarily to Pandemic-related travel restrictions that prohibited interstate travel or imposed quarantine requirements for Company personnel and contractors caused delays on the Exeter LNG project sub-categories and ultimately caused a portion of FY2021 planned work to be deferred until FY 2022.

Pressure Regulating Facilities
The delays in the Pressure Regulating Facilities category work were due primarily work delays in Q1 of the fiscal year as the Company implemented changes in work practices in the early months of the Pandemic and to crew availability which was impacted by Pandemic related absence due to sickness and quarantine requirements.

Distribution Station Over Pressure Protection
The delays in this category were due primarily work delays in Q1 of the fiscal year as the Company implemented changes in work practices in the early months of the Pandemic and to crew availability which was impacted by Pandemic related absence due to sickness and quarantine requirements.

PUC 1-5

Request:

Please explain why if work could not be done in other programs, the Southern Rhode Island Gas Expansion Program had an over-budget variance.

Response:

The Southern Rhode Island Gas Expansion Project did not have an over-budget variance. The Southern RI Gas Expansion Project had an underspending variance of $1.32 million in FY 2021. The Annual Reconciliation Filing Attachment ASNK-1, pp. 37-40 contains a full description of the variance drivers by each category. The underspending, including incremental paving, consists of the following variances by each Southern RI category.

Categories ($000)	**Budget**	**Total ISR Actual Spend**	**Variance**
Southern RI Gas Expansion Project			
Pipeline - Core Budget	*$38,798*		
Pipeline - Incremental Paving Budget	*$2,564*		
Pipeline - Total Budget	**$41,362**	**$40,568**	**($794)**
Other Upgrades/Investments - Core Budget	*$451*		
Other Upgrades/Investments - Incremental Paving Budget	*$50*		
Other Upgrades/Investments - Total Budget	**$501**	**$725**	**$224**
Regulator Station Investment - Total Budget	**$1,211**	**$462**	**($749)**
Southern RI Gas Expansion Project Total (including incremental paving budgets)	**$43,074**	**$41,755**	**($1,319)**

Please note that Table A and Table B of the Annual Reconciliation Filing, pp. 42 and 43 show the core spending of the Southern Rhode Island Gas Expansion Program is over spent by $1.295M. It also shows that Incremental Paving – Southern RI Gas Expansion budget is under spent by $2.614M. The chart above provides a clearer format of the total budget to actual spending for the total Southern Rhode Island Gas Expansion Program because all paving costs, including incremental paving, were tracked directly in the program work orders and not a separate incremental paving work order. Therefore, the Actual spending amount shown for the Southern Rhode Island Gas Expansion Program in both Table A and Table B includes the cost of all paving incurred for the project, including Incremental Paving.

Prepared by or under the supervision of: Amy Smith

PUC 1-5, page 2

Also, please note that the variance of $0.84M under spent listed on page 18 for the Pipeline portion of the work in the Pre-filed Direct Testimony of Amy Smith and Nathan Kocon is incorrect. The $0.05M budget for Other Upgrades/Investments – Incremental Paving was inadvertently factored into the $0.84M calculation. The correct variance is $0.79M under spent, which is correctly stated in The Annual Reconciliation Filing Attachment ASNK-1, p. 37.

The Pre-filed Direct Testimony of Amy Smith and Nathan Kocon should have stated:

Q. Please explain the under-budget variance of $0.79 million for Pipeline on the Southern Rhode Island Gas Expansion Project in FY 2021.

A. For FY 2021, the Company spent approximately $40.57 million for Construction – Pipeline compared to an annual budget of $41.36 million (including $2.56 million for incremental paving), resulting in a variance of $0.79 million less than budget.

National Grid did not experience the same issues in other ISR categories due to work delays resulting from the Pandemic. The driver of the delays for the other programs varied and were due to one or more of a variety of factors, including interstate travel restrictions, crew availability due to illness or quarantine requirements, or suspension of work that required entry into customer premises.

Please see the Company's response to PUC Data Request 1-4 for an explanation of why certain programs were impacted by the Pandemic. The Southern Rhode Island Gas Expansion Program did not experience any of the Pandemic-related issues listed above due to the specific nature of the work, which did not require entry into customer premises and due to the availability of sufficient contractor crews assigned to the project.

PUC 1-6

Request:

Could the lower number of reactive leaks and services referred to on page 9 of Ms. Smith's and Mr. Kocon's testimony be attributed to the fact that the Company has been actively replacing leak-prone pipes and services? And if so, please detail.

Response:

There are various factors that may have influenced the decrease of reactive leaks and reactive service replacements:

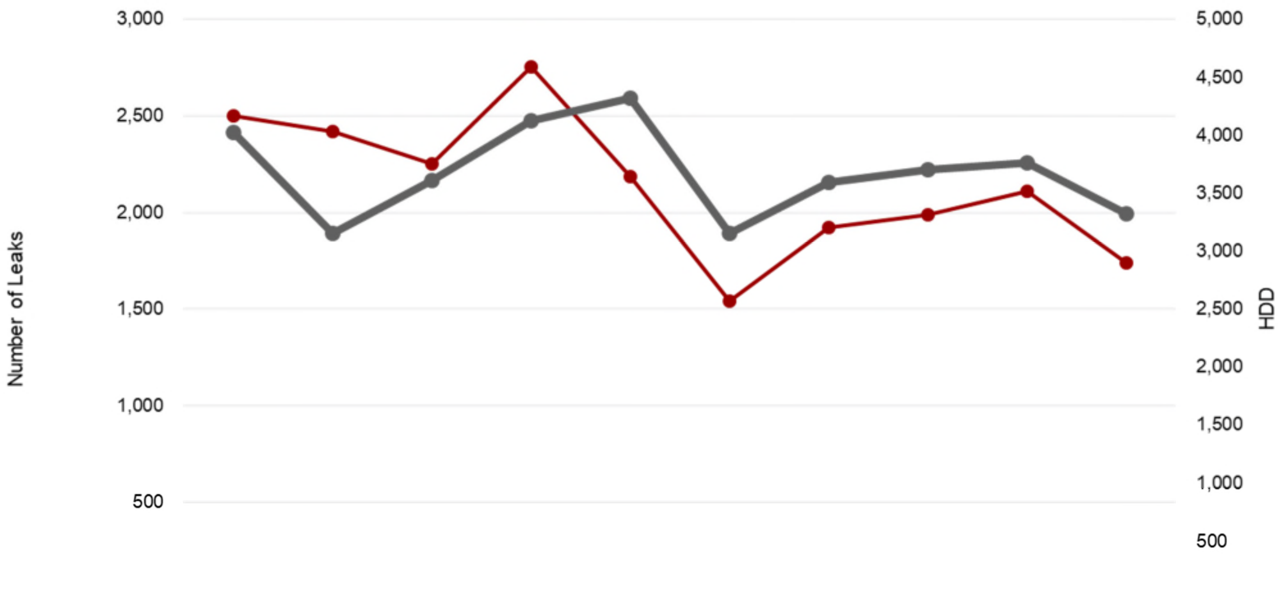
1. **Weather**
   In the winter of 2020, the region experienced the highest temperatures since 2016. Figure 1 below shows the 10-year trend of leak receipts vs. Heating Degree Days (HDD). As the graph illustrates, there is a direct correlation between the weather and the reactive leaks/leak receipts trends.

2. **Main Replacement Program**
   The Company prioritizes main replacements based on leak activities and other risk factors as specified in the Company's procedure ENG04030: Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement (please refer to Attachment PUC 1-6). The leak reduction may be attributed to the replacement of the leakiest segments.

<u>PUC 1-6, page 2</u>

Figure 1:

Leak Received vs Heating Degree Days
(Excluding Excavation Damages)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Leak Receipts	2,502	2,417	2,252	2,753	2,183	1,541	1,924	1,989	2,107	1,738
HDD	4,026	3,151	3,608	4,123	4,318	3,156	3,593	3,699	3,757	3,319

Prepared by or under the supervision of: Amy Smith

Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement ENG04030

1. Purpose

This procedure describes and details the identification, evaluation, and prioritization of distribution main segments for replacement, and prescribes methods to be used for corrective action.

Potential areas of active corrosion are identified using leakage surveys in conjunction with an analysis of the corrosion and leak history records.

2. Responsibilities

Distribution Engineering or designee shall be responsible to:

- Gather and evaluate gas facility and leak data, and determine required calculations.
- Determine qualification and prioritization procedure and remedial action for active corrosion, non-active continuing corrosion, and other systemic integrity issues.
- Identifying main segments for replacement and prioritizing them according to this procedure.

Corrosion Engineering or designee shall be responsible for:

- Evaluation and Reclassification of Pre-1971 Gas Piping with Cathodic Protection (CP)

  .

3. Personal & Process Safety

All required PPE shall be worn or utilized in accordance with the current National Grid Safety Policy when performing tasks associated with this document.

4. Operator Qualification Required Tasks [Qualified or Directed & Observed]

None

5. Content

5.1 Identification of Main Segments for Replacement

a. Main segment candidates are identified through four avenues:

   1) Field Requests, which will be reviewed throughout the year.
   2) Mains located in Public Improvement Job Areas, which will also be reviewed throughout the year, as requested by Field Operations and/or Public Works employees.
   3) Annual screenings by Main and Service Engineering, as deemed appropriate. Screenings will vary among the regions, based on the data and tools available for the systems.
   4) Lab failure analysis reports reviewed by Distribution Engineering for systemic issues.

b. All identified main segment candidates shall be evaluated and prioritized by Distribution Engineering in accordance with the criteria set forth in this procedure. Minimum segment lengths for screening and engineering review will vary among the regions; however, no Engineering review is required for replacements up to 300 feet. Segments identified by Distribution Engineering for systemic integrity issues will be replaced and prioritized as determined appropriate.

c. Where possible, the system should be upgraded to high pressure while retiring low pressure mains.

d. Leak prone pipe replacement includes replacement of associated leak prone services listed below:

   1) All steel services except large diameter, industrial and commercial services with Cathodic Protection

      **Note: Services that cannot be relayed should be transferred and follow corrosion policies. A test station sketch should be sent to corrosion department.

   2) Plastic

      i. Pre-1985: Aldyl-A (usually pink or grey)

      ii. Pre-1974: HDPE (black)

      Note: Please send the removed portion of some services installed prior to 1974 to Material lab in Hicksville, NY to verify integrity performance

      iii. Polybutylene (PB) - (tan or yellow)

   3) Copper

   4) Cast Iron

   5) Wrought Iron

e. All identified main segment candidates shall be reviewed by Distribution Engineering with the Corrosion Engineering to ensure that none of the job or part of the job is pre 1971 protected main.

5.2 Evaluation/Prioritization of Steel Main Segments for Replacement

a. Data Collection - Minimum Data Required:

   1) All Repaired Corrosion Leaks on Main Segment for the last 10 years

   2) All repaired corrosion leaks on services for last 10 years. (In order to consider service leaks in main prioritization calculation, there should be main leaks)

   3) All Open Leaks that are believed to be on the actual Main Segment

b. For all applicable leaks, the following data is required:

   1) Leak Number

   2) Date (date found for open leaks, date repaired for repaired leaks)

   3) Leak Class (original class for open leaks, repaired class for repaired leaks)

   4) For repaired leaks, the following additional data is also required:

      i. Number of Clamps Installed to Repair and specific clamp locations

      ii. Condition of Main When Repaired

      iii. Address Based Leak Location

      iv. Length of segment exhibiting significant leak activity (i.e. from first leak to last leak).

      v. Building Types in Area of Main Segment (None, Single Family Houses, Small Buildings, Public Buildings)

c. Calculate a main deterioration factor ("D") using the formula:

$D = N \times 500 / L_{(calc)}$

Where:

$L_{(calc)}$ = Length of Segment exhibiting significant leak activity (i.e. first leak to last leak) or 500 ft whichever is larger. However, if the total length of the segment considered for replacement is less than 500 ft, Lcalc shall be the length of the main considered,

The segment length used in calculations is not necessarily the total length being considered for replacement. "L" should be determined by the evaluating engineer as the length of the segment exhibiting significant leak activity. In no case should the length used for calculations extend beyond the locations of the leaks).

and

N = Repair Factor (within the defined "L_{calc}").

1) If the leak was repaired with 1 clamp, by another method, is still open, or associated service corrosion leak repair, N=1
2) If the leak was repaired with 2-3 clamps, N=2
3) If the leak was repaired with 4-5 clamps, N=3
4) If the leak was repaired with 6-7 clamps, N=4
5) If the leak was repaired with >7 clamps, N=5
6) If the leak was repaired by replacing a section of a pipe less than 10', N=7 and N=9 for replacement pipe 10' or greater

THE SUM OF ALL THE "N"s FOR EACH LEAK IS PLUGGED INTO THE FORMULA

This method estimates the deterioration according to the actual number of physical repairs and normalizes it for the length of the segment.

d. Calculate an incident probability factor ("P") using the formula:

$P = \{[(\text{\# Class1 Leaks}/0.5) + (\text{\# Class2A Leaks}/1.5) + (\text{\# Class2 Leaks}/2) + (\text{\# Class3 Leaks}/3)] \times 500\} / L_{(calc)}$

This method estimates public safety incident probability by weighting each leak based on how far the gas migrated toward buildings, again normalized according to the segment length. (Note – If leak class is unknown, Class 2A will be assumed).

e. Calculate a risk factor ("R") using the formula:

$R = P \times C$

Where:

P = Probability Factor Calculated in previous step.
C = Consequence Factor

1) If there are no buildings in the area, C = 0

2) If there are only single family homes, C = 1
3) If there are small buildings (multi-family, strip mall, etc), C = 1.2
4) If there are public buildings (school, church, hospital, etc) C = 1.5

This is the standard Risk Analysis calculation where Risk is defined as the product of the likelihood of an event and the potential consequence of that event. Consequences increase with building size and number of people affected.

f. Calculate the preliminary prioritization factor ("Pr") using the formula:

$$Pr = D + R + IM$$

Where:

D = Deterioration Factor Calculated in "c".
R = Risk Factor Calculated in "e".
IM = DIMP factor as found in National Grid's Distribution Integrity Management Program (DIMP) listed in attachment 1

The prioritization calculation considers both the deterioration of the main and the risk to public safety.

IM factor is applied to help accelerate the attrition of mains which belong to an asset group,known to have a higher likelihood of incident or is of a high relative risk.

g. The following adjustments may be needed:

1) Before making a final determination and prioritization of a main segment replacement, the details of the job are reviewed and "engineering judgment" is applied where appropriate. This application may result in the following types of adjustments:
   i. Changing the priority of the job
   ii. Increasing or decreasing the job length/scope
   iii. Breaking the job into smaller segments
   iv. Merging several segments into one job
2) These adjustments may be made based on the following types of information, if available and applicable:
   i. Analysis of the age of the leaks and any increasing frequency of leak occurrences
   ii. Pipe vintage and service insert activity associated with the main
   iii. Service leaks at the main connection due to corrosion
   iv. Adjustments based on very long or very short segments
   v. Observed pipe condition from leak repair data
   vi. Observed pipe condition from recent field exposure
   vii. Clustering of repairs and/or clamps along the segment
   viii. Other replacement jobs in the vicinity
   ix. Cathodic protection systems in place

x. Specific locations of intersections, fittings, material transitions, diameter transitions, etc.
xi. Customer complaints, Executive complaints, Regulatory Agency complaints
xii. Corporate good will
xiii. Unusual hazards or exposure in the area
xiv. Proximity to gas regulating equipment
xv. Proximity to transmission main
xvi. Unusual difficulty or expense of repairs
xvii. Main location
xviii. Identification of outdated construction methods or problematic materials or fittings
xix. Depth of cover and soil conditions
xx. High open leak counts
xxi. Water intrusion or other geographic considerations
xxii. Any special or unusual conditions or considerations identified by Field Operations
xxiii. Any other safety, integrity, operational or economic factors that are available and deemed appropriate

Segments that qualify based on their preliminary prioritization calculation may not be disqualified by adjustments.

h. Qualification of job for replacement:

1) Jobs will be approved and prioritized based on the calculated Prioritization Factor “Pr” and applied adjustments. Enough jobs should be approved to accommodate the replacement levels determined by the model(s) in use at the time.

Some jobs will be mandatory to replace.

2) In general, a condition of “Active Corrosion” will be determined when the preliminary Prioritization Factor (“Pr”) calculation is greater than 20 (Pr > 20).
3) Any unprotected steel main identified as Active Corrosion must have cathodic protection engineered and installed within one year or be replaced within two years in NY and three years in MA - unless extenuating circumstances make it unfeasible to do so, in which case, other appropriate mitigative measures are to be taken (Conduct a leakage survey of the segment once a year as a minimum).
4) Any cathodically protected main containing “Active Corrosion” must be brought up to acceptable cathodic protection within one year or replaced within two years in NY and three years in MA - unless extenuating circumstances make it unfeasible to do so (An example of such a circumstance may be when a street is under guarantee or a moratorium from excavation), in which case, other appropriate mitigative measures are to be taken. (Conduct a leakage survey of the segment once a year as a minimum).
5) Use the following labels for each job to provide a macro view as to the type of work to be performed throughout the year.

i. A "TS 300" label is associated with any steel job with a preliminary Prioritization Factor ("Pr") calculation of greater than 20 (Pr > 20), known as "Active Corrosion".
ii. A TS 900 label is given to any job which has received additional points from Public Works considerations (as described below).
iii. A TS 800 label is given to the remainder of the jobs.

i. Impact Identification:
1) Every approved job should be processed through the Strategic Asset and System Planning and Corrosion Engineering for:
i. Sizing (determining the appropriate replacement material and diameter).
ii. Determining if the replacement will have any impact on existing cathodic protection systems.
iii. Determining if abandonment is an appropriate option over replacement.
iv. Determining if a system uprating is an appropriate option as part of the replacement.

5.3 Evaluation/prioritization of cast iron main segments for replacement

a. Cast Iron Main Segments will be evaluated in a similar manner as Steel Main segments, where the Prioritization factor will be the sum of the Deterioration Factor, Risk factor and DIMP factor (Pr = D + R + IM).

b. Candidates are reviewed based primarily on breakage and/or graphitization history; and all segments that contain 1or more breaks and/or graphitization repairs must be reviewed.

c. If the candidate segment has had 2 or more breaks and/or graphitization repairs within 400 ft. and the MAOP is greater than six inches of water column – the segment has automatic approval for replacement. The Prioritization score will automatically be set at 21()

d. If the candidate segment doesn't have at least 2 breaks and/or graphitization repairs or if the pressure is six inches of water column– approval will be based on the Prioritization calculation
i. If "Pr" is greater than 20 (Pr > 20), replacement will be required (however, a cast iron segment is not deemed active corrosion)
ii. If "Pr" is less than or equal to 20 (Pr ≤ 20), prioritize and replace according to resources and replacement level recommendations

e. The Repair Factor "N" (as defined 5.2 – c for steel evaluation), will be assigned for each leak, as follows:

1) For cast iron – main breaks, graphitization (corrosion of cast iron) and joint leak repairs are examined.
i. If the leak is still open or associated service corrosion leak repair, N = 1
ii. If the leak was repaired only by joint sealing, N = 0.5
iii. If the leak was a break, crack or graphitization, N = 3

f. Engineering judgment should also be applied to both the prioritization and determination of the segment length to be replaced based on the pressure, diameter, dates of failures, surrounding areas, etc.

5.4 Evaluation/prioritization of plastic main segments for replacement

a. Vintage Plastic Main Segments shall be evaluated by Distribution Engineering based on Lab Failure Analysis Reports that are reviewed for systemic issues.

I. If Distribution Engineering determines that a systemic issue exists in a specific main segment due to improper fusion or other construction defects, the entire affected section of main will be forwarded to Main and Service Replacement Group for prioritization and expedited replacement.

b. Plastic Main Segments (including non-vintage plastic) will be evaluated in a similar manner as Steel Main segments, where the Prioritization factor will be the sum of the Deterioration Factor, Risk factor and DIMP factor (Pr = D + R + IM).

c. For plastic pipe segments in “b”, above, the following criteria shall apply:

1) For plastic – previous squeeze-offs, point loading failures (e.g. – rock impingement) and material defects (e.g. – cracking) and construction defect failures (e.g. – butt fusion joint) are examined.

Where:

N = Repair Factor (within the defined “L”)

i. If the leak is still open, N = 1
ii. If the leak was the result of an improper squeeze-off, N = 2 x (the number known squeeze-offs on ALDYL-A pre 1985 pipe)
iii. If the leak was the result of a point loading failure, N = 2
iv. If the leak was a the result of a construction defect or material defect, N = 3

5.5 Evaluation and Reclassification of Pre-1971 Gas Piping with Cathodic Protection

a. The following factors should be considered in evaluating and reclassify Pre-DOT CP pipe:

1) The Corrosion Engineering department shall identify inadequately protected sections of mains and services on the basis of;

i. Frequently failed readings in the last 5 years
ii. Failed readings despite additional anode installation
iii. Unusually low resistance or high current demand as determined by Corrosion Control
iv. Excessive Coating degradation determined by integrity assessments
v. High corrosion leak activity
vi. Any other unusual or abnormal condition determined by Corrosion Control

2) The section identified in section 1 above shall be removed from the CP monitoring program. The Electronic Monitoring Database and the Corrosion Control section folders shall be updated accordingly. In PCS, the section shall be marked as “inactive” and a statement that the section has been removed from the CP monitoring program along with an effective date with explanation of reclassification will be provided in the permanent remarks section. Reclassified pipe will be marked as “removed from CP” where Electronic Monitoring Database is available.

3) Once the section is removed from the CP monitoring program, it shall be treated as unprotected coated/bare main. Mapping (in NY) or Corrosion Control (in NE) will be notified to remove the Corrosion Control section number or the CP designation from electronic mapping records.

4) Every six months, the Corrosion Engineering department will run a report listing which sections of pipe have been reclassified from CP to unprotected coated/bare main. The Corrosion Engineering department will check this list against Corrosion Control mapping records to ensure consistency. This list will be sent to the Distribution Engineering.

b. The following steps are used to evaluate and reclassify Pre-DOT CP pipe when Distribution Engineering or field employees identify inadequacies:

1) Distribution Engineeringshall consult with the Corrosion Engineering department to evaluate the effectiveness of the cathodic protection on the section identified. Corrosion Engineering department will evaluate the section of main based on section 1 above.

i. Distribution Engineering shall incorporate the reclassified unprotected coated/bare main section into the LPP main replacement program on the basis of priority.

5.6 Reinforcements, Jobs in public works areas or storm hardening

a. Additional adjustments may be applied for candidate segments in public works areas, flood zones or for which reinforcement opportunities have been identified - by the addition of a Public Works (PW) and/or Reinforcement (RI) and/or storm hardening factor to the Prioritization calculation:

$$Pr = D + R + IM + PW + RI + SH$$

1) For Road Resurfacing, PW = 2.4
2) For Road Reconstruction, PW = 4.2
3) For Size-Pressure Upgrade Reinforcement, RI = 2.5
4) For 100-yr FEMA defined flood zone, SH = 2
5) For 500-yr FEMA defined flood zone, SH = 1

These factors are applied because of potential cost savings in combining main replacements with other work, as well as anticipated avoidance of performing work on protected streets that were recently improved.

6. Knowledge Base & References (Click here)

Knowledge Base		References
1 - Compliance History	5 - Job Aid	1 - Regulatory – Codes
2 - Data Capture	6 - Learning & Development	2 - Technical Documents
3 - Definitions	7 - Standard Drawings	3 - Tools Catalog
4 - Document History	8 - Tools & Equipment	

7. Attachments

Attachment 1: DIMP Factor

PUC 1-7

Request:

Please provide more detail on the Pandemic-related travel restrictions noted on page 14 of Ms. Smith's and Mr. Kocon's testimony that was as indicated to be a primary driver of under-spending in the LNG category of Reliability programs.

Response:

At various stages during the Pandemic, site access to our LNG facilities was restricted to operations personnel and contractors performing emergency and/or regulatory required tasks. At times, our consultants that were awarded the Exeter LNG projects encountered internal travel restrictions, which prevented them from performing site visits.

PUC 1-8

Request:

Please describe in detail what the $0.14 million was spent on in the Aquidneck Island Long-Term Capacity options category referred to on page 16 of Ms. Smith's and Mr. Kocon's testimony. Please identify how much has been spent in FY 2022 on the Aquidneck Island Long-Term Capacity options and detail what the spending was for.

Response:

The Company started work in FY 2021 and continued work in FY 2022 that will inform the Company's decision on the final infrastructure solution for Aquidneck Island in FY 2022. The detail is provided for each component of work for the potential solutions.

In Table 1-8-1, the Company provides detail regarding what the $0.14 million was spent on in FY 2021. To date, the Company has spent approximately $0.187 million in FY 2022. Detail regarding this spending is included in Table 1-8-2. The information on the work performed for each category is also included in the paragraphs following the tables.

TABLE 1-8-1

	FY 2021				
Description	**Through December 2021**	**Jan-2021**	**Feb-2021**	**Mar-2021**	**FY 2021 Actuals**
Portable LNG Equipment & Site Prep:					
Internal Labor (Project Development, Engineering, Environmental & Legal)	$ 3,278	$ 10,752	$ 13,857	$ 21,423	**$ 49,310**
Internal Labor (Process Safety Facility Siting)	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Navy-Owned Properties - Environmental Feasibility Study	$ -	$ 9,894	$ -	$ -	**$ 9,894**
LNG & Site Preparation - Navy-Owned Properties - Civil Site Surveying	$ -	$ -	$ -	$ 32,000	**$ 32,000**
LNG & Site Preparation - Navy-Owned Properties - Civil Engineering	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Navy-Owned Properties - Environmental Engineering	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Equipment Procurement	$ -	$ -	$ -	$ -	**$ -**
Total - Portable LNG Equipment & Site Prep	**$ 3,278**	**$ 20,646**	**$ 13,857**	**$ 53,423**	**$ 91,204**
Main Installation:					
Internal Labor (Project Development, Engineering, Environmental & Legal)	$ -	$ -	$ -	$ -	**$ -**
Tank Farm 3 to 99 psig System - Civil Surveying	$ -	$ -	$ -	$ -	**$ -**
Tank Farm 3 to 99 psig System - Navy-Owned Properties - Environmental Engineering	$ -	$ -	$ -	$ -	**$ -**
Tank Farm 3 to 99 psig System - Main Installation Engineering	$ -	$ -	$ -	$ -	**$ -**
Total Main Installation	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
New Regulator Station:					
New Regulator Station	$ -	$ -	$ -	$ -	**$ -**
Total - New Regulator Station Investment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
LNG Barge Interconnect Land to Marine Main:					
Internal Labor (Project Development, Engineering)	$ -	$ 3,033	$ 3,908	$ 6,043	**$ 12,984**
LNG Barge Interconnect Land to Marine Main - Feasibility Study	$ -	$ -	$ 18,070	$ 18,070	**$ 36,140**
LNG Barge Interconnect Land to Marine Main - Conceptual Scope & Estimate	$ -	$ -	$ -	$ -	**$ -**
Total - LNG Barge Interconnect Land to Marine Main Investment	**$ -**	**$ 3,033**	**$ 21,978**	**$ 24,113**	**$ 49,124**
Total Aquidneck Island Portable LNG Site Relocation Investment	**$ 3,278**	**$ 23,678**	**$ 35,836**	**$ 77,536**	**$ 140,328**

Prepared by or under the supervision of: Faye Brown

PUC 1-8, page 2

TABLE 1-8-2

	FY 2022				
Description	**Apr-2021**	**May-2021**	**Jun-2021**	**Jul-2021**	**FY 2022 YTD**
Portable LNG Equipment & Site Prep:					
Internal Labor (Project Development, Engineering, Environmental & Legal)	$ 9,746	$ 16,276	$ 4,925	$ 16,099	**$ 47,046**
Internal Labor (Process Safety Facility Siting)	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Navy-Owned Properties - Environmental Feasibility Study	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Navy-Owned Properties - Civil Site Surveying	$ -	$ 65,500	$ -	$ -	**$ 65,500**
LNG & Site Preparation - Navy-Owned Properties - Civil Engineering	$ -	$ -	$ -	$ -	**$ -**
LNG & Site Preparation - Navy-Owned Properties - Environmental Engineering	$ -	$ 4,437	$ -	$ 32,337	**$ 36,774**
LNG & Site Preparation - Equipment Procurement	$ -	$ -	$ -	$ -	**$ -**
Total - Portable LNG Equipment & Site Prep	**$ 9,746**	**$ 86,213**	**$ 4,925**	**$ 48,436**	**$ 149,320**
Main Installation:					
Internal Labor (Project Development, Engineering, Environmental & Legal)	$ -	$ 960	$ -	$ 4,742	**$ 5,702**
Tank Farm 3 to 99 psig System - Civil Surveying	$ -	$ -	$ -	$ -	**$ -**
Tank Farm 3 to 99 psig System - Navy-Owned Properties - Environmental Engineering	$ -	$ 3,067	$ -	$ 17,232	**$ 20,299**
Tank Farm 3 to 99 psig System - Main Installation Engineering	$ -	$ -	$ -	$ -	**$ -**
Total Main Installation	**$ -**	**$ 4,027**	**$ -**	**$ 21,974**	**$ 26,001**
New Regulator Station:					
New Regulator Station	$ -	$ -	$ -	$ -	**$ -**
Total - New Regulator Station Investment	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
LNG Barge Interconnect Land to Marine Main:					
Internal Labor (Project Development, Engineering)	$ 2,749	$ -	$ -	$ -	**$ 2,749**
LNG Barge Interconnect Land to Marine Main - Feasibility Study	$ 6,776	$ -	$ -	$ 2,259	**$ 9,035**
LNG Barge Interconnect Land to Marine Main - Conceptual Scope & Estimate	$ -	$ -	$ -	$ -	**$ -**
Total - LNG Barge Interconnect Land to Marine Main Investment	**$ 9,525**	**$ -**	**$ -**	**$ 2,259**	**$ 11,784**
Total Aquidneck Island Portable LNG Site Relocation Investment	**$ 19,271**	**$ 90,241**	**$ 4,925**	**$ 72,669**	**$ 187,105**

Portable LNG Equipment & Site Prep

The Company contracted with WSP USA (WSP), an engineering firm, to perform the civil site survey work for the three potential Navy-owned parcels; Tank Farm 3, located in Portsmouth; and Tank Farm 5 and the Former Navy Transfer Station, both located in Middletown. The civil site survey work consists of an aerial survey to collect current data of the parcels, digitizing the aerial survey results and a ground survey to gather information needed for civil site engineering. The engineering firm started this work, with the aerial survey complete in January 2021 and the ground survey work starting soon after. The work was complete in April 2021. In late January 2021, the Navy informed the Company that Tank Farm 5 is no longer available for consideration. The Company spent \$0.032 million in FY 2021 and \$0.066 million to date in FY 2022 for in progress costs associated with this work. The Company anticipates that it will receive remaining invoices within the next couple of months.

The Company contracted GZA GeoEnvironmental, Inc. (GZA), an engineering firm, to conduct a desktop environmental feasibility study for the three potential Navy-owned parcels, mentioned in the above paragraph. GZA completed this work in January 2021. GZA provided a white paper with the results, information needed to progress environmental engineering and next steps. For FY 2021, the \$0.099 million spent is for costs associated with this work.

The Company further contracted with GZA to provide environmental engineering to perform an environmental site assessment necessary for preparing an Environmental Conditions of Property (ECoP) Report on both the Former Transfer Yard Site and the Former Tank Farm No. 3 Site and evaluating and delineating wetlands on both the Former Transfer Yard Site and the Former Tank Farm No. 3 Site. This work started in April 2021 and the draft report was received in August 2021. For FY 2022, the \$0.037 million spent to date is for costs associated with work.

In addition to vendor costs, the Company spent \$0.049 million in FY 2021 and \$0.047 million to date in FY 2022 on internal labor and Company overheads in support of the work detailed above.

Main Installation

The Company also contracted WSP to perform the work civil site survey for the main installation route options. The aerial survey, mentioned in the above section, captured the data for the main route options. The ground survey started in February 2021 and the work was completed in July 2021. The Company anticipates that it will receive invoices for this work within the next couple of months.

The Company also contracted with GZA to provide environmental engineering to perform an environmental site assessment necessary for preparing an ECoP Report and evaluating and delineating wetlands along the extent of the main installation route options. This work started in April 2021 and the draft report was received in August 2021. For FY 2022, the $0.02 million spent to date is for costs associated with work.

In addition to vendor costs, the Company spent $0.06 million in FY 2022 to date on internal labor and Company overheads in support of the work detailed above.

LNG Barge Interconnect Land to Marine Main

The Company contracted with BL Companies, Inc. (BL Companies), an engineering firm, to perform a feasibility study for the land to marine main for an LNG Barge interconnect into the Company's 99 psig distribution system. BL Companies started this work in January 2021 and completed work in April 2021. The Company spent $0.036 million in FY 2021 and $0.009 million in FY 2022 for costs associated with this work.

In addition to vendor costs, the Company spent $0.013 million in FY 2021 and $0.003 million to date in FY 2022 on internal labor and Company overheads in support of the work detailed above.

PUC 1-9

Request:

Please explain why only $0.15 million of the $0.20 million authorized was spent on the Cumberland LNG tank replacement project as referred to on page 16 of Ms. Smith's and Mr. Kocon's testimony?

Response:

Prior to FY2021, it was determined that a feasibility study was needed to further evaluate building a new storage tank at the Cumberland LNG Facility. During FY2021, a preliminary exclusion zone study was conducted for the proposed conceptual layout to identify mitigation measures for siting design spills that would need to be considered in future development stages of the project. Since the number of vapor dispersion modelling iterations were unknown at the start of the study, it was initially estimated for this study to cost $0.20 million.

The actual cost of these efforts were $0.05 million less than anticipated.

Prepared by or under the supervision of: Steven Cardoso

PUC 1-10

Request:

Referring to page 20 of Ms. Smith's and Mr. Kocon's testimony, what was the basis of the decision to defer the field work for the Cowesett Regulator Station until 2023?

Response:

The basis of the decision to defer the field work for the Cowesett Regulator Station until 2023 (FY 2023, CY 2022 construction season) was due to revisions in the scope of work. When the project team started the engineering work in June 2020 (FY 2021), the initial phases of the engineering work resulted in expanded scope. The expanded scope identified the need for field investigation work. The field investigation work was performed in late fall 2020 (FY 2021). The revised timeline was necessary to complete the engineering work for the expanded scope after the field investigation was complete and prepare for construction. Therefore, the project team made the decision to defer the field work until June 2022 (FY 2023).

PUC 1-11

Request:

In addition to Ms. Smith and Mr. Kocon (page 21), Ms. Little (page 16) also indicates that the in-service revenue requirement methodology eliminates the potential for a double count of capital in-service in future ISR reconciliation filings. Has there been a double count previously and is so how was it resolved? How would the Company be able to determine if there was one unless it was looking specifically for it?

Response:

The Company's reference to double counts was specific to the risks associated from converting from one capital eligibility method to another. The Company is not aware of prior instances of double counts regarding costs included in the ISR.

The reference to eliminating the potential for a double count was specifically associated with the method selected to adopt the capital in-service approach. In other instances where in-service is the requirement for rate recovery, the Company would normally rely on a PowerPlan annual plant additions report to identify assets that are eligible for recovery. Removing the March 31, 2021 CWIP balances (for all historical ISR years) from the FY 2021 plant additions as part of the FY 2021 reconciliation allows for the use of the annual plant additions reporting method, starting in FY 2022, without risk of double count. Had the Company not proposed to reduce the FY 2021 Gas ISR investment by the amount of pre-FY 2021 spending residing in CWIP, the Company would be in a situation where every project placed in-service in FY 2022 and beyond would need to be analyzed to determine when the spending on that project occurred. Any spending incurred on or prior to March 31, 2021 would need to be reviewed for potential recovery in prior years, while spending after that date would be included. There are frequent occurrences of projects with spending spanning one or more years, which would result in situations where only a portion of a project would be eligible for recovery in future filings.

The Company concluded that the added level of complexity might create a risk of a double count if any spending that was already captured under the capital spending method was not properly excluded. This risk is avoided by removing the March 31, 2021 CWIP from the FY 2021 additions.

Prepared by or under the supervision of: John Currie