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Rhode Island Energy™
a PPL company

February 29, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-49-NG – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Gas Infrastructure, Safety, and Reliability Plan
<u>Responses to PUC Data Requests – Set 10</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy, I have enclosed the Company's responses to the Public Utilities Commission's ("PUC") Tenth Set of Data Requests in the above-referenced matter.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket No. 23-49-NG Service List

PUC 10-1
Investor Materials

Request:

Please provide any investor presentation materials that were used by PPL in its latest Q4 Earnings call. Please also provide a copy of the transcript.

Response:

Please see Attachment PUC 10-1-1 for the presentation that was used by PPL Corporation at its fourth quarter 2023 earnings call held on February 16, 2024. Please see Attachment PUC 10-1-2 for the transcript of the PPL Corporation fourth quarter 2023 earnings call.

Prepared by or under the supervision of: Katherine Hearns

PPL CORPORATION

4th Quarter 2023 Investor Update

February 16, 2024

Cautionary Statements and Factors That May Affect Future Results

Statements made in this presentation about future operating results or other future events are forward-looking statements under the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from the forward-looking statements. A discussion of some of the factors that could cause actual results or events to vary is contained in the Appendix of this presentation and in PPL's SEC filings.

Management utilizes non-GAAP financial measures such as "earnings from ongoing operations" or "ongoing earnings" in this presentation. For additional information on non-GAAP financial measures and reconciliations to the appropriate GAAP measure, refer to the Appendix of this presentation and PPL's SEC filings.

Business Update

Vince Sorgi
President & Chief Executive Officer

4TH QUARTER 2023
INVESTOR UPDATE

February 16, 2024

2023 Review: Challenges Met, Promises Kept

Executed our strategy and achieved each priority set for the year

✓ **Delivered electricity and natural gas safely and reliably to our more than 3.5 million customers**
- Achieved first quartile T&D reliability and first decile generation fleet performance [(1)(2)]

✓ **Exceeded the midpoint of our 2023 earnings forecast**
- Achieved 2023 ongoing earnings of $1.60 per share → 8.1% growth from pro forma 2022 earnings per share [(3)]
- Offset over $0.10 per share impact compared to plan from mild weather and storms

✓ **Executed $2.4 billion capital investment plan**

✓ **Exceeded our $50 - $60 million O&M savings target for 2023**
- Achieved $75 million in savings from 2021 baseline

✓ **Achieved constructive outcomes in key regulatory proceedings**
- Approval of majority of Kentucky generation replacement plan
- Approval of our first ISR filing and Advanced Meter plan (AMF) in Rhode Island

✓ **Completed key milestones in integration of Rhode Island Energy**
- Remain on track to exit Transition Service Agreements (TSAs) with National Grid in mid-2024
- Four major IT transition plans completed as scheduled in 2023

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Reliability performance based on System Average Interruption Frequency Index (SAIFI). The average number of interruptions that a customer experiences over a specific period for each customer served.
(2) Generation performance based on Equivalent Forced Outage Rate (EFOR). Represents the number of hours a unit is forced offline, compared to the number of hours a unit is running.
(3) Refers to 2022 pro forma earnings that reflected a full year of earnings contributions from Rhode Island Energy (RIE). RIE was acquired by PPL in May 2022.

Forward Outlook Remains Strong

Business plan update extends growth targets through 2027

- **Announced 2024 EPS forecast range of $1.63 - $1.75 per share with a midpoint of $1.69 per share**
  - Midpoint reflects 7.0% growth from midpoint of 2023 ongoing EPS target, in line with targeted growth rate
  - Announces 7.3% increase to quarterly common stock dividend to $0.2575 per share
- **Extended 6% - 8% annual EPS and dividend growth targets through at least 2027 (previously 2026)**
  - Growth targets based off the midpoint of PPL's 2024 forecast range
- **Increased capital plan to $14.3 billion for 2024 - 2027 (vs. $11.9 billion 2023 - 2026)**
  - Rate base growth increases to 6.3% over plan period (vs. 5.6% in prior plan period)
- **Maintained strong credit metrics with no equity needs through at least 2027**
  - Continue to project 16% - 18% FFO/CFO to debt and holding company debt below 25% of total debt
- **Included at least $175 million of O&M savings by 2026**
  - Remain on track to deliver $120 - $130 million of O&M savings by end of 2024; $150M by 2025
- **No anticipated base rate case filings in 2024 in Pennsylvania, Kentucky, or Rhode Island**

Our Strategy: Creating Utilities of the Future

Focused on delivering value for BOTH customers AND shareowners

- **Enhance reliability and resiliency of our electric and gas networks through innovation and strategic investments**
- **Advance a cleaner energy transition affordably and reliably for our customers**
- **Deliver operational efficiencies to support the clean energy transition and customer affordability**
- **Explore opportunities to build scale through economic development and customer growth**
- **Empower customers through digital solutions and better customer service**

The Right Strategy for a Changing Energy Landscape

Focused on supporting the growth and decarbonization of our economy

The U.S. has set a goal of **net-zero CO_2 emissions by 2050**

Achieving this will require **economy-wide decarbonization,** resulting in a projected **2-3X increase** in electricity demand

We will need to **reliably meet this demand** while **retiring aging fossil-fueled plants**

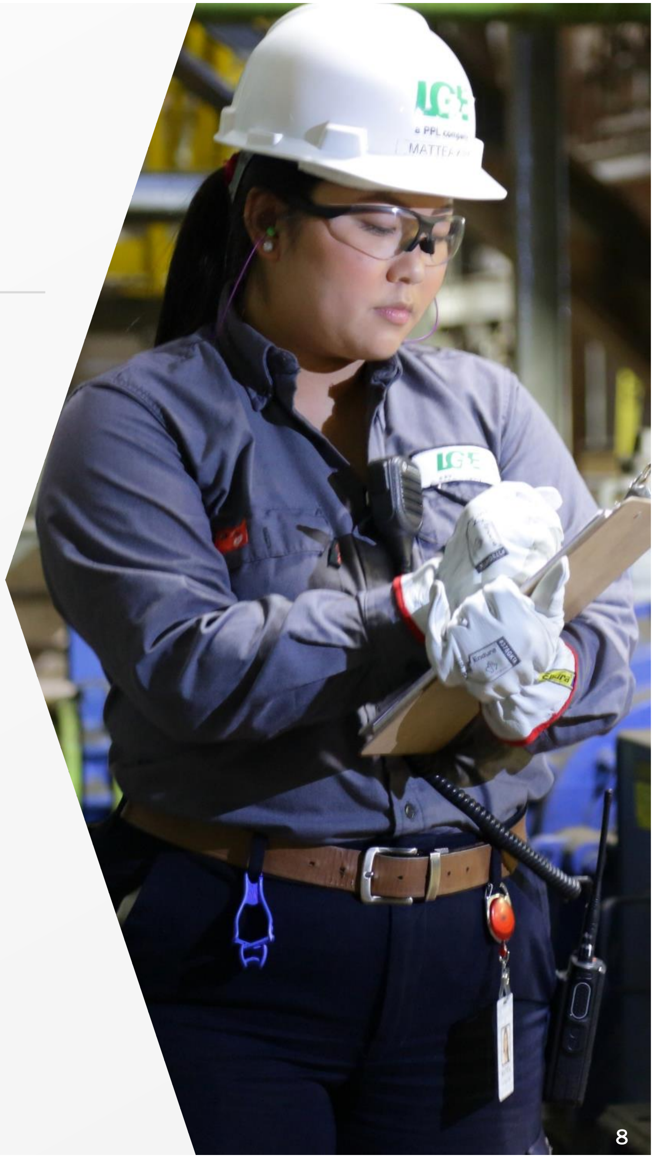
Success will require **faster commercialization** of new technology than we've ever achieved

Our "Utility of the Future" strategy positions PPL as a leader in our sector to deliver value for stakeholders

2024 Outlook and Priorities

Continue to deliver on PPL's vision, mission, and strategy

- Continue to execute our strategy to build the "Utilities of the Future" and enhance value for all stakeholders
- Achieve at least the midpoint of the 2024 earnings forecast range of $1.69 per share, aligned with the midpoint of our annual 6% to 8% earnings per share growth target
- Execute $3.1 billion capital expenditure plan to enable the delivery of safe, reliable and affordable energy to our customers and advance the Grid for the clean energy transition
- Deliver our O&M savings targets of $120 - $130 million through smart grids, process automation, centralization efforts, and asset optimization
- Complete our integration of Rhode Island Energy and exit TSAs with National Grid



Financial Update

Joe Bergstein
Executive Vice President & Chief Financial Officer

4TH QUARTER 2023
INVESTOR UPDATE

February 16, 2024

Financial Overview

Overview of 4th Quarter Financial Results

(Earnings per share)

	Q4 2023	Q4 2022
Reported Earnings (GAAP)	$0.15	$0.26
Less: Special Items	($0.25)	($0.02)
Ongoing Earnings	$0.40	$0.28
PA Regulated	$0.20	$0.16
KY Regulated [(1)]	$0.17	$0.11
RI Regulated	$0.05	$0.03
Corp. and Other [(1)]	($0.02)	($0.02)

Overview of Annual Financial Results

(Earnings per share)

	2023	2022
Reported Earnings (GAAP)	$1.00	$1.02
Less: Special Items	($0.60)	($0.39)
Ongoing Earnings	$1.60	$1.41
PA Regulated	$0.74	$0.70
KY Regulated [(1)]	$0.77	$0.76
RI Regulated	$0.20	$0.08
Corp. and Other [(1)]	($0.11)	($0.13)

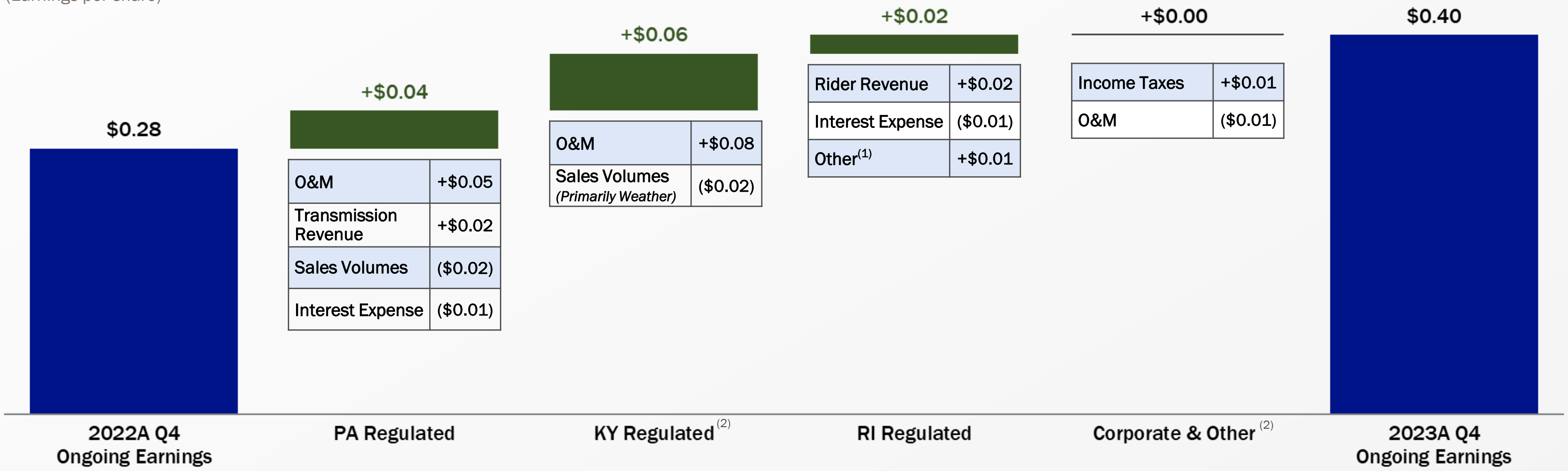
Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Kentucky holding company costs for intercompany financing activity are now presented in Corporate and Other beginning on January 1, 2023. Prior periods have been adjusted to reflect this change.

Review of 4th Quarter Financial Results

Ongoing Earnings Walk: Q4 2023 vs. Q4 2022

(Earnings per share)



Segment	PA Regulated	KY Regulated	RI Regulated	Corp. & Other	Total PPL
Q4 2023 Ongoing EPS	$0.20	$0.17	$0.05	($0.02)	$0.40

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

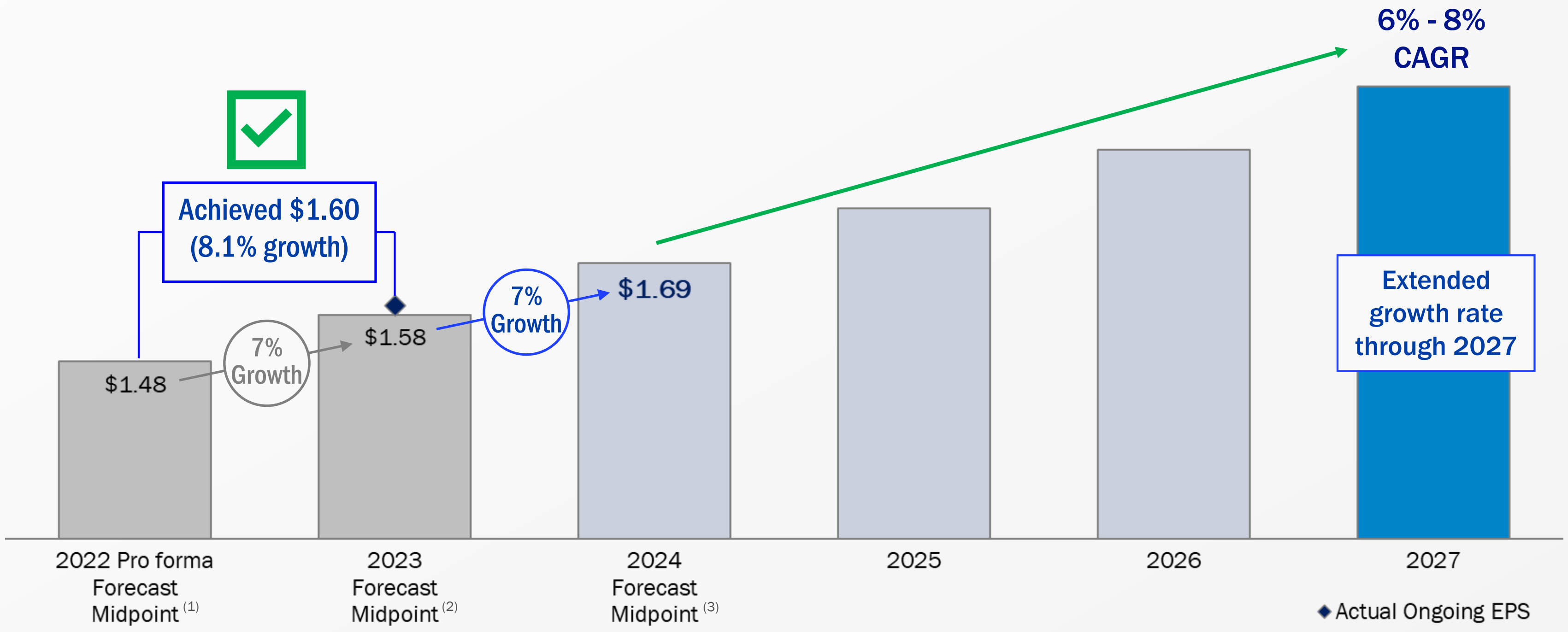
(1) Reflects factors that were not individually significant.

(2) Kentucky holding company costs for intercompany financing activity are now presented in Corporate and Other beginning on January 1, 2023. Prior periods have been adjusted to reflect this change.

Delivering Strong, Sustainable Growth

Exceeded midpoint of growth target in 2023; extended growth through 2027

(Earnings per share)

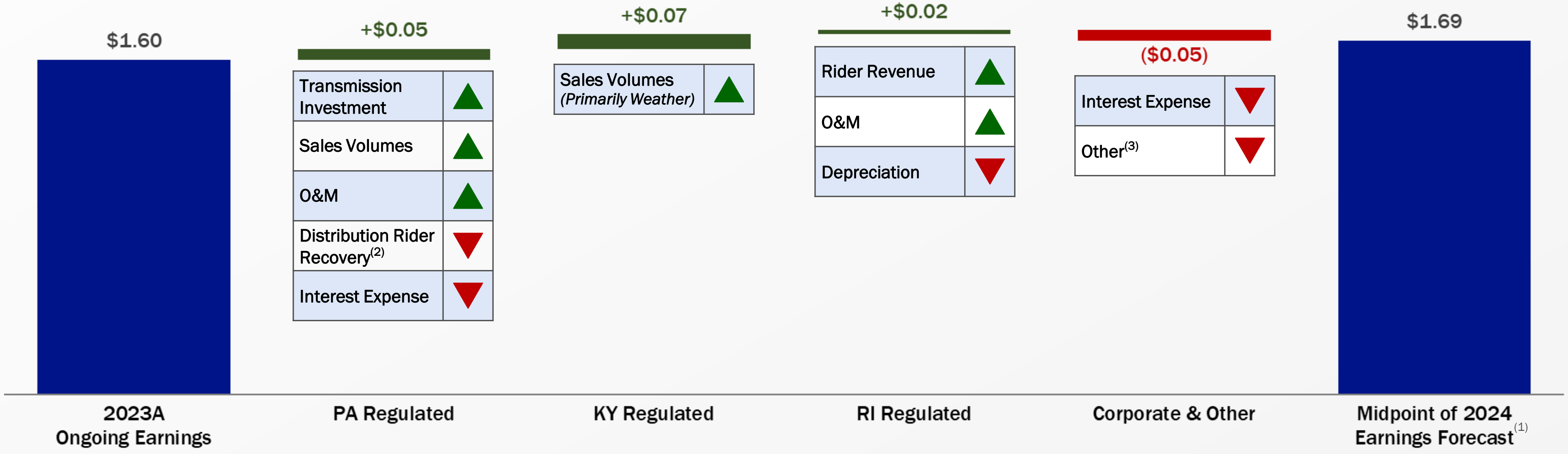


(1) Represents the midpoint of PPL's 2022 pro forma forecast range of $1.40 to $1.55 per share, reflecting a full year of earnings contributions from Rhode Island Energy (RIE). RIE was acquired by PPL in May 2022.
(2) Represents the midpoint of PPL's 2023 forecast range of $1.50 - $1.65 per share.
(3) Represents the midpoint of PPL's 2024 forecast range of $1.63 - $1.75 per share.

Walk to Midpoint of 2024 Earnings Forecast

Projected drivers of annual ongoing EPS change: 2023A to 2024 forecast midpoint

(Earnings per share)



Segment	PA Regulated	KY Regulated	RI Regulated	Corp. & Other	Total PPL
2024 EPS Forecast[1]	$0.79	$0.84	$0.22	($0.16)	$1.69

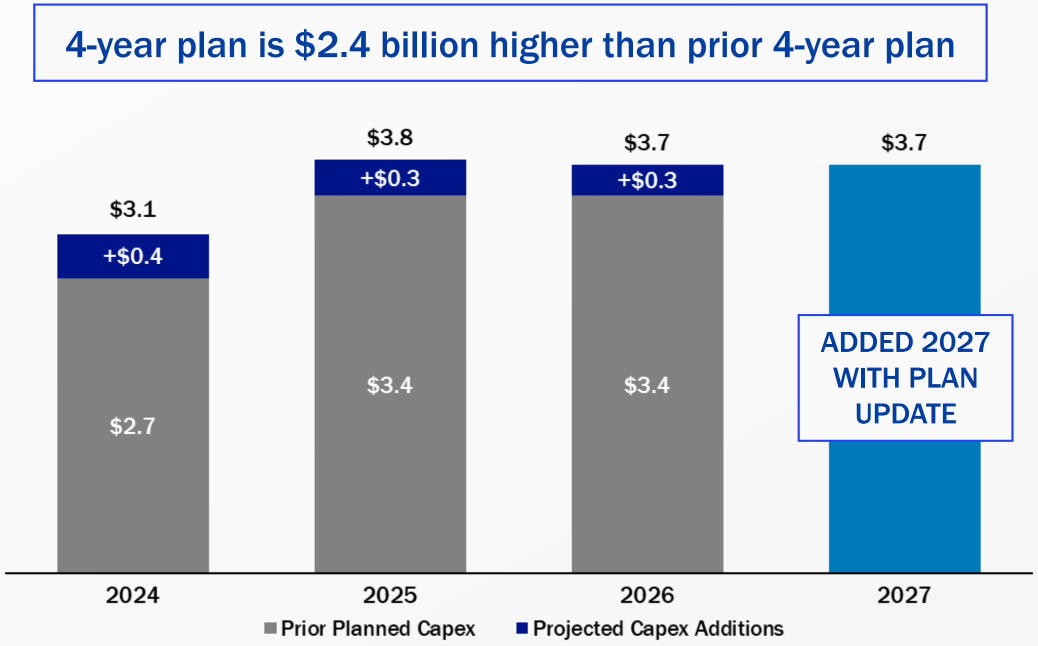
Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Represents the midpoint of PPL's 2024 earnings forecast range of $1.63 - $1.75 per share.
(2) Distribution System Improvement Charge, or DSIC mechanism, is an alternative ratemaking mechanism providing more timely recovery of long-term infrastructure investments between rate cases.
(3) Reflects factors that were not individually significant.

2024 – 2027 Capital Investment Plan

$14.3 billion of projected capital investments that deliver value for customers

($ in billions)



Notable Plan Updates:

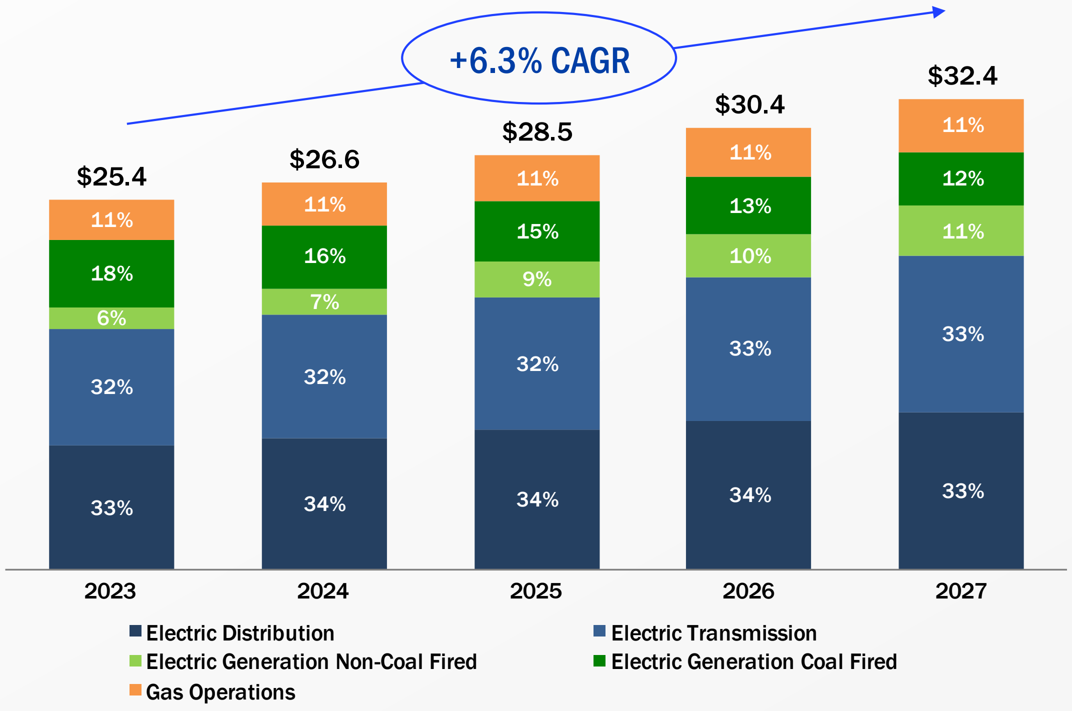
- **Approximately $1 billion increase in 2024 – 2026 period, compared to prior capital plan**
  - Primarily related to electric T&D investments in Pennsylvania and Kentucky
- **Update includes $3.7 billion of projected investment needs in 2027**
  - Investments to replace aging infrastructure, increase resiliency, and execute generation replacement plan in Kentucky

Note: Totals may not sum due to rounding.

Rate Base CAGR Increased to 6.3% Through 2027

Projected Annual Rate Base Growth (2023 – 2027)[(1)]

(Year-end rate base, $ in billions)



- Rate base growth increases to 6.3% over plan vs. 5.6% in prior plan period
- Two-thirds of rate base relates to investments in electric transmission and distribution infrastructure
- Percentage of rate base related to coal generation declines to below 12% by 2027

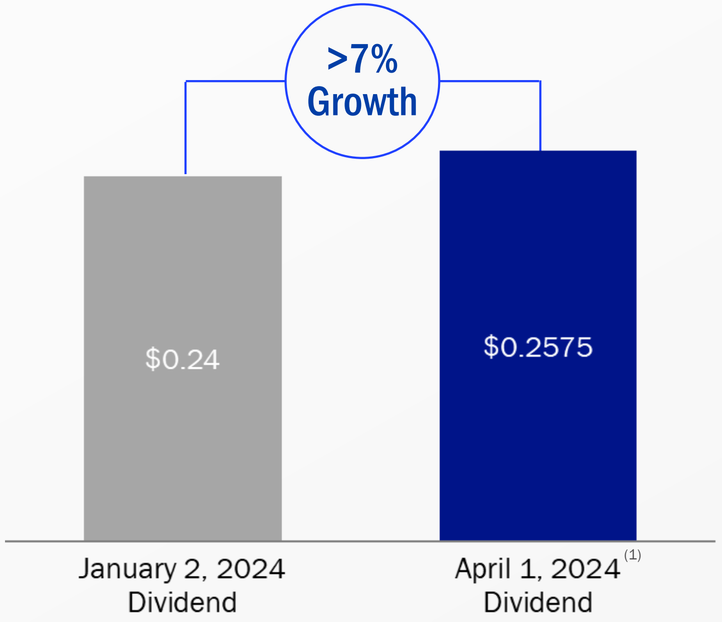
Note: Totals may not sum due to rounding.

(1) Rhode Island rate base excludes acquisition-related adjustments for non-earning assets.

Increasing Quarterly Dividend In Line with EPS Growth

Quarterly dividend increased to $0.2575 per share

(Dividends per share)



- **Announced 7.3% increase to PPL's quarterly dividend to $0.2575 per share (from $0.24)**
  - Annualized dividend now $1.03 per share[2]
- **Payable April 1, 2024 to shareowners of record as of March 8, 2024**
- **Future dividend growth projected to continue to grow in line with projected earnings growth[2]**
  - Targeted dividend payout of 60% – 65%
- **Supports total return proposition of 9% - 12%[3]**

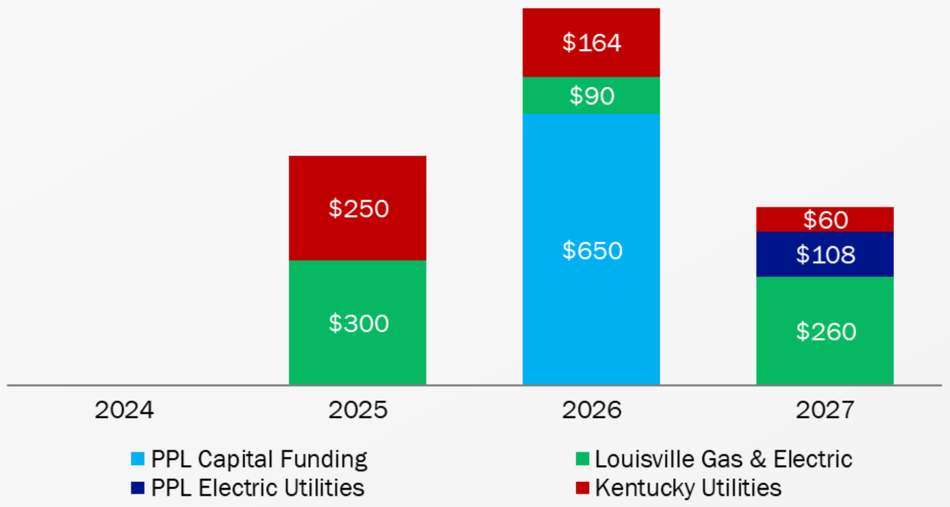
(1) Based on February 16, 2024, dividend declaration by Board of Directors.
(2) Subject to Board of Directors approval.
(3) Total return reflects PPL's targeted EPS growth rate plus dividend yield based on targeted annualized dividend and PPL's closing share price as of February 14, 2024.

Credit and Financing Plan Update

Plan maintains strong credit metrics without the need for equity issuances

- **Updated plan supports credit metric targets**
  - 16% - 18% FFO/CFO to debt throughout plan
  - Holding company debt projected to remain less than 25% of total debt
- **Manageable debt maturity stack**
  - No maturities in 2024 and $550 million in 2025
  - Limited floating rate debt exposure (less than 5% of total long-term debt)
- **No equity issuances needed through at least 2027**
- **Executing 2024 Financing Plan:**
  - Issued $650 million of 10-year First Mortgage Bonds at PPL Electric Utilities in January at 4.85%
  - Expect our first debt issuance at Rhode Island Energy since PPL's acquisition

PPL's Debt Maturity Outlook
($ in millions)



Closing Remarks

Vince Sorgi
President & Chief Executive Officer

4TH QUARTER 2023
INVESTOR UPDATE

February 16, 2024

PPL Investment Highlights

A total return proposition of 9% - 12%[1]

Large-cap, regulated U.S. utility operating in constructive regulatory jurisdictions

- Principal electric/gas utilities serving Kentucky, Pennsylvania, and Rhode Island
- Highlighted by future test years in each jurisdiction, FERC formula rates and real-time recovery mechanisms

Visible and predictable 6% - 8% annual EPS and dividend growth[2]

- $14.3B capital investment plan, driving average annual rate base growth of 6.3% through 2027
- Targeted annual O&M savings of at least $175M by 2026

Premier balance sheet supports organic growth and provides financial flexibility

- Top-tier credit ratings among peers: Baa1 rating at Moody's and A- rating at S&P
- Targeting 16% - 18% FFO/CFO to Debt and no equity issuances needed through at least 2027

Compelling opportunity to transition existing coal fleet to cleaner energy resources[3]

- Committed to net-zero carbon emissions by 2050[4]
- Rate base from coal generation declines to less than 12% by 2027

(1) Total return reflects PPL's targeted EPS growth rate plus dividend yield based on targeted annualized dividend and PPL's closing share price as of February 14, 2024.
(2) Refers to PPL's projected earnings per share growth from 2024 to 2027 and targeted dividend per share growth in line with EPS.
(3) PPL is economically transitioning coal-fired generation and has committed to not burn coal by 2050 unless it can be mitigated with carbon dioxide removal technologies.
(4) PPL is committed to a reasoned and deliberate glidepath to net-zero carbon emissions by 2050; ensuring safety, reliability and affordability remain intact during the transition.

Quarterly Supplemental Information

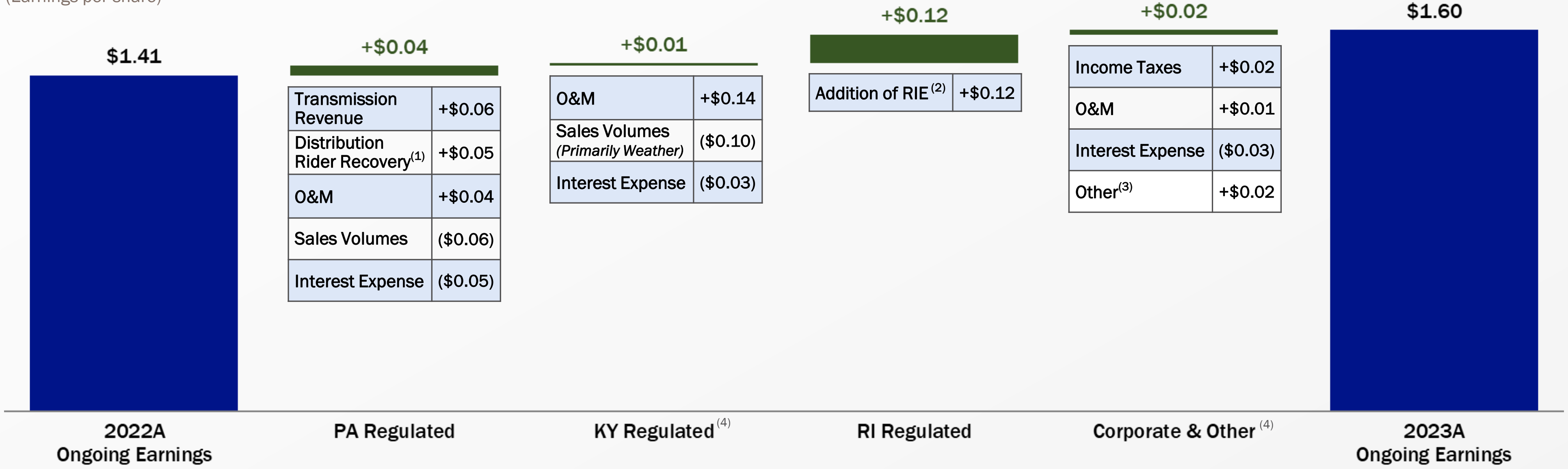
4TH QUARTER 2023
INVESTOR UPDATE

February 16, 2024

Review of 2023 Financial Results

Ongoing Earnings Walk: 2023 vs. 2022

(Earnings per share)



Segment	PA Regulated	KY Regulated	RI Regulated	Corp. & Other	Total PPL
2023 Ongoing EPS	$0.74	$0.77	$0.20	($0.11)	$1.60

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Distribution System Improvement Charge, or DSIC mechanism, is an alternative ratemaking mechanism providing more timely recovery of long-term infrastructure investments between rate cases.
(2) RIE – Rhode Island Energy.
(3) Reflects factors that were not individually significant.
(4) Kentucky holding company costs for intercompany financing activity are now presented in Corporate and Other beginning on January 1, 2023. Prior periods have been adjusted to reflect this change.

Electricity Sales Volumes

2023 retail sales vs. 2022 retail sales by operating segment[1]

(GWh)	Weather-Normalized Electricity Sales Volume						Actual Electricity Sales Volume			Annual EPS Sensitivity
Pennsylvania	Three Months Ended Dec. 31,			Trailing Twelve Months Ended Dec. 31,			Three Months Ended Dec. 31,			Per 1% Change In Total Load
	2023	2022	% Change	2023	2022	% Change	2023	2022	% Change	
Residential	3,656	3,736	(2.2%)	14,418	14,816	(2.7%)	3,509	3,723	(5.7%)	**+/- $0.005 - $0.01**
Commercial[2]	3,273	3,319	(1.4%)	13,663	13,923	(1.9%)	3,256	3,310	(1.6%)	
Industrial	2,022	2,138	(5.4%)	8,380	8,563	(2.1%)	2,022	2,138	(5.4%)	
Other	22	22	NM*	75	76	NM*	22	24	NM*	
Total	**8,973**	**9,216**	**(2.6%)**	**36,536**	**37,379**	**(2.3%)**	**8,810**	**9,195**	**(4.2%)**	
Kentucky	Three Months Ended Dec. 31,			Trailing Twelve Months Ended Dec. 31,			Three Months Ended Dec. 31,			Per 1% Change In Total Load
	2023	2022	% Change	2023	2022	% Change	2023	2022	% Change	
Residential	2,439	2,454	(0.6%)	10,533	10,588	(0.5%)	2,304	2,459	(6.3%)	**+/- $0.01 - $0.02**
Commercial	1,785	1,786	(0.1%)	7,591	7,682	(1.2%)	1,754	1,788	(1.9%)	
Industrial	2,065	2,065	0.0%	8,469	8,670	(2.3%)	2,065	2,065	0.0%	
Other	624	612	NM*	2,651	2,669	NM*	615	614	NM*	
Total	**6,913**	**6,917**	**(0.0%)**	**29,244**	**29,609**	**(1.2%)**	**6,739**	**6,926**	**(2.7%)**	

*NM: Not Meaningful
Note: Totals may not sum due to rounding.
(1) Excludes Rhode Island Energy's sales volumes as its revenue is decoupled.
(2) 2022 sales volumes were adjusted to reflect a correction to a customer account.

Capital Expenditure Plan

($ in millions)

	2024	2025	2026	2027	4-Year Total
Pennsylvania					
Electric Distribution	$500	$425	$400	$425	$1,750
Electric Transmission	$675	$800	$825	$725	$3,025
Pennsylvania Total	**$1,175**	**$1,225**	**$1,225**	**$1,150**	**$4,775**
Kentucky					
Electric Distribution	$325	$400	$400	$350	$1,475
Electric Transmission	$125	$175	$300	$350	$950
Electric Generation Non-Coal Fired	$425	$675	$550	$650	$2,300
Electric Generation Coal Fired	$200	$175	$175	$150	$700
Gas Operations	$75	$125	$100	$125	$425
Other	$125	$125	$100	$175	$525
Kentucky Total	**$1,275**	**$1,675**	**$1,625**	**$1,800**	**$6,375**
Rhode Island					
Electric Distribution	$250	$300	$275	$225	$1,050
Electric Transmission	$200	$300	$300	$250	$1,050
Gas Operations	$225	$250	$275	$275	$1,025
Rhode Island Total	**$675**	**$850**	**$850**	**$750**	**$3,125**
Total Utility Capex	**$3,125**	**$3,750**	**$3,700**	**$3,700**	**$14,275**

Projected Rate Base (Year-End)

ppl

(Year-end rate base, $ in billions)

	2023	2024	2025	2026	2027
Pennsylvania					
Electric Distribution	$4.3	$4.6	$4.7	$4.9	$5.0
Electric Transmission	$5.5	$5.8	$6.1	$6.6	$6.9
Pennsylvania Total	**$9.8**	**$10.3**	**$10.9**	**$11.4**	**$11.9**
Kentucky					
Electric Distribution	$3.0	$3.2	$3.5	$3.8	$4.0
Electric Transmission	$1.6	$1.7	$1.9	$2.1	$2.4
Electric Generation Non-Coal Fired	$1.5	$1.9	$2.5	$2.9	$3.5
Electric Generation Coal Fired	$4.6	$4.4	$4.2	$4.0	$3.7
Gas Operations	$1.2	$1.3	$1.4	$1.5	$1.6
Kentucky Total	**$11.9**	**$12.4**	**$13.4**	**$14.2**	**$15.1**
Rhode Island (1)					
Electric Distribution	$1.2	$1.3	$1.4	$1.6	$1.8
Electric Transmission	$1.0	$1.0	$1.1	$1.3	$1.5
Gas Operations	$1.5	$1.6	$1.8	$1.9	$2.1
Rhode Island Total	**$3.7**	**$3.9**	**$4.3**	**$4.8**	**$5.4**
Total Rate Base	**$25.4**	**$26.6**	**$28.5**	**$30.4**	**$32.4**

Note: Totals may not sum due to rounding.
(1) Rhode Island rate base excludes acquisition-related adjustments for non-earning assets.

Debt Maturities

($ in millions)

	2024	2025	2026	2027	2028	2029+	Total
PPL Capital Funding	$0	$0	$650	$0	$1,000	$1,396	$3,046
PPL Electric Utilities	$0	$0	$0	$108	$0	$4,541	$4,649
Louisville Gas & Electric(1)	$0	$300	$90	$260	$0	$1,839	$2,489
Kentucky Utilities(1)	$0	$250	$164	$60	$0	$2,615	$3,089
Rhode Island Energy(2)	$1	$1	$0	$0	$350	$1,150	$1,502
Total Debt Maturities(3)	**$1**	**$551**	**$904**	**$428**	**$1,350**	**$11,541**	**$14,775**

Note: As of December 31, 2023. Totals may not sum due to rounding.

(1) Amounts reflect the timing of any put option on municipal bonds that may be put by the holders before the bonds' final maturities.
(2) Amounts reflect sinking fund payments that are due annually until the bond's final maturity.
(3) Does not reflect unamortized debt issuance costs and unamortized premiums (discounts) totaling ($163 million).

Liquidity Profile

($ in millions)

Entity	Facility	Expiration Date	Capacity	Borrowed	LCs & CP Issued[(1)(2)]	Unused Capacity
PPL Capital Funding	Syndicated Credit Facility[(3)]	Dec-2027	$1,250	$0	$390	$860
	Bilateral Credit Facility	Mar-2024	$100	$0	$0	$100
	Uncommitted Credit Facility	Mar-2024	$100	$0	$13	$87
	Subtotal		$1,450	$0	$403	$1,047
PPL Electric Utilities	Syndicated Credit Facility	Dec-2027	$650	$0	$511	$139
Louisville Gas & Electric	Syndicated Credit Facility	Dec-2027	$500	$0	$0	$500
Kentucky Utilities	Syndicated Credit Facility	Dec-2027	$400	$0	$93	$307
Total PPL Credit Facilities			**$3,000**	**$0**	**$1,007**	**$1,993**

Note: As of December 31, 2023. Totals may not sum due to rounding.

(1) Letters of Credit (LCs) and Commercial Paper (CP).
(2) Commercial paper issued reflects the undiscounted face value of the issuance.
(3) Includes a $250 million borrowing sublimit for RIE and a $1 billion sublimit for PPL Capital Funding. At December 31, 2023, PPL Capital Funding had $365 million of commercial paper outstanding and RIE had $25 million of commercial paper outstanding. On January 5, 2024, the borrowing sublimits under the facility were reallocated to $400 million at RIE and $850 million at PPL Capital Funding.

PPL's Credit Ratings

PPL Corporation

Credit Rating	S&P	Moody's
Secured	NR	NR
Unsecured	NR	NR
Long-term Issuer	A-	Baa1
Outlook	Stable	Stable

PPL Capital Funding

Credit Rating	S&P	Moody's
Secured	NR	NR
Unsecured	BBB+	Baa1
Long-term Issuer	A-	NR
Outlook	Stable	Stable

Rhode Island Energy

Credit Rating	S&P	Moody's
Secured	A	NR
Unsecured	A-	A3
Long-term Issuer	A-	A3
Outlook	Stable	Stable

LG&E and KU

Credit Rating	S&P	Moody's
Secured	A	A1
Unsecured	NR	NR
Long-term Issuer	A-	A3
Outlook	Stable	Stable

PPL Electric Utilities

Credit Rating	S&P	Moody's
Secured	A+	A1
Unsecured	NR	NR
Long-term Issuer	A	A3
Outlook	Stable	Stable

Note: As of December 31, 2023.

Pennsylvania Regulatory Overview

PPL Electric Utilities

Key Attributes

2023 Rate Base	
Year-End Rate Base ($B)	$9.8
% of Total PPL Rate Base	38%
Allowed ROE	
Electric Transmission	10.0% + adders(1)
Electric Distribution	(2)
Capital Structure (2023)	
Equity	56%
Debt	44%
Last Base Rate Case (rates effective date)	1/1/2016
Test Year	Forward Test Year

Constructive Features Mitigating Regulatory Lag

- ✓ FERC Formula Transmission Rates
- ✓ Distribution System Improvement Charge (DSIC)
  - An alternative ratemaking mechanism providing more-timely cost recovery of qualifying distribution system capital expenditures
- ✓ Pass through of energy purchases
- ✓ Smart Meter Rider
- ✓ Storm Cost Recovery
- ✓ Alternative Ratemaking(3)
  - In Pennsylvania, there are various mechanisms available including: decoupling mechanisms, performance-based rates, formula rates, and multi-year rate plans

(1) Adders include 50-basis points for RTO membership and incremental returns for certain projects.
(2) Last Pennsylvania distribution base rate case was effective 1/1/2016 with an un-disclosed ROE.
(3) Alternative ratemaking is available for next distribution base rate case.

Kentucky Regulatory Overview

Louisville Gas & Electric and Kentucky Utilities

Key Attributes

2023 Rate Base	
Year-End Rate Base ($B)	$11.9
% of Total PPL Rate Base	47%
Allowed ROE	
Base	9.425%
ECR & GLT Mechanisms	9.35%
Capital Structure (2023)	
Equity	53%
Debt	47%
Last Base Rate Case (rates effective date)	7/1/2021
Test Year	Forward Test Year

Constructive Features Mitigating Regulatory Lag

- ✓ Environmental Cost Recovery (ECR) Surcharge
  - Provides near real-time recovery for approved environmental projects related to coal-fired generation
- ✓ Gas Line Tracker (GLT)
  - Approved mechanism for LG&E's recovery of certain costs associated with gas transmission lines, gas service lines, and leak mitigation
- ✓ Demand-Side Management (DSM) Cost Recovery
  - Provides recovery of energy efficiency programs
- ✓ Retired Asset Recovery (RAR) Rider (1)
  - Provides recovery of and return on remaining net book value at time of retirement, with recovery over 10 years from retirement date
- ✓ Fuel Adjustment Clause (FAC)
  - Pass through of costs of fuel and energy purchases
- ✓ Gas Supply Clause (GSC)
  - Pass through of costs of natural gas supply

(1) Retired Asset Recovery Rider applies to the generating plants of LG&E and KU.

Rhode Island Regulatory Overview

Rhode Island Energy

Key Attributes

2023 Rate Base	
Year-End Rate Base ($B)	$3.7
% of Total PPL Rate Base	15%
Allowed ROE	
Electric Transmission	10.57% + adders(1)
Electric Distribution	9.275%(2)
Gas Distribution	9.275%(2)
Capital Structure (2023)	
Equity	51%
Debt	49%
Last Base Rate Case (rates effective date)	9/1/2018
Test Year	Multi-year(3)

Constructive Features Mitigating Regulatory Lag

- ✓ Multi-year rate plans for electric and gas distribution
- ✓ Infrastructure, Safety, and Reliability (ISR) tracker
  - Annual recovery mechanism for certain capital and O&M costs for electric and gas distribution projects filed with the RIPUC
- ✓ Performance-based incentive revenues
  - Includes electric system performance, energy efficiency, natural gas optimization, and renewables incentives
- ✓ Revenue decoupling
- ✓ Storm cost recovery
- ✓ Pension expense tracker
- ✓ Energy Efficiency tracker
- ✓ FERC Formula Transmission Rates

(1) Reflects base allowed ROE. Rhode Island Energy receives a 50-basis point RTO adder and additional project adder mechanisms that may increase the allowed ROE up to 11.74%.
(2) Reflects base allowed ROE. Rhode Island Energy can earn higher returns than the base allowed ROE through incentive mechanisms and efficiencies that are supported by customer sharing mechanisms. Earnings sharing with customers of 50% when earned ROE is between 9.275% and 10.275% and increases to 75% sharing for customers when earned ROE exceeds 10.275%.
(3) Based on regulatory framework established in 2018, which included a multi-year framework for Rhode Island Energy electric and gas base rates based on a historical test year with the ability to forecast certain O&M categories for future years. All other O&M expenses are increased by inflation each year. Includes annual rate reconciliation mechanism that incorporates allowance for anticipated capital investments.

Appendix

4TH QUARTER 2023
INVESTOR UPDATE

February 16, 2024

Reconciliation of Segment Reported Earnings to Earnings From Ongoing Operations – Current Year

After-Tax (Unaudited) ($ in millions)	Three Months Ended December 31, 2023 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	Twelve Months Ended December 31, 2023 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings [1]	$ 120	$ 135	$ 26	$ (168)	$ 113	$ 552	$ 519	$ 96	$ (427)	$ 740
Less: Special Items (expense) benefit:										
Talen litigation costs, net of tax of $24, $26 [2]	-	-	-	(93)	(93)	-	-	-	(99)	(99)
Strategic corporate initiatives, net of tax of $0, $1, $0, $1, $3 [3]	-	(1)	-	(3)	(4)	(1)	(2)	-	(10)	(13)
Acquisition integration, net of tax of $2, $16, $14, $58 [4]	-	-	(10)	(59)	(69)	-	-	(56)	(218)	(274)
PA tax rate change	-	(1)	-	-	(1)	-	-	-	-	-
Sale of Safari Holdings, net of tax of ($1), $0 [5]	-	-	-	(1)	(1)	-	-	-	(4)	(4)
PPL Electric billing issue, net of tax of $4, $10 [6]	-	(9)	-	-	(9)	-	(24)	-	-	(24)
FERC transmission credit refund, net of tax of $0, $2 [7]	(1)	-	-	-	(1)	(6)	-	-	-	(6)
Unbilled revenue estimate adjustment, net of tax of $2, $2 [8]	(5)	-	-	-	(5)	(5)	-	-	-	(5)
Other non-recurring charges, net of tax of $1, $1, $0 [9]	-	(3)	-	-	(3)	-	(3)	-	(15)	(18)
Total Special Items	(6)	(14)	(10)	(156)	(186)	(12)	(29)	(56)	(346)	(443)
Earnings from Ongoing Operations	$ 126	$ 149	$ 36	$ (12)	$ 299	$ 564	$ 548	$ 152	$ (81)	$ 1,183

After-Tax (Unaudited) (per share – diluted)	Three Months Ended December 31, 2023 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	Twelve Months Ended December 31, 2023 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings [1]	$ 0.16	$ 0.18	$ 0.04	$ (0.23)	$ 0.15	$ 0.75	$ 0.70	$ 0.13	$ (0.58)	$ 1.00
Less: Special Items (expense) benefit:										
Talen litigation costs [2]	-	-	-	(0.13)	(0.13)	-	-	-	(0.13)	(0.13)
Strategic corporate initiatives [3]	-	-	-	-	-	-	-	-	(0.01)	(0.01)
Acquisition integration [4]	-	-	(0.01)	(0.08)	(0.09)	-	-	(0.07)	(0.30)	(0.37)
Sale of Safari Holdings [5]	-	-	-	-	-	-	-	-	(0.01)	(0.01)
PPL Electric billing issue [6]	-	(0.02)	-	-	(0.02)	-	(0.04)	-	-	(0.04)
FERC transmission credit refund [7]	-	-	-	-	-	(0.01)	-	-	-	(0.01)
Unbilled revenue estimate adjustment [8]	(0.01)	-	-	-	(0.01)	(0.01)	-	-	-	(0.01)
Other non-recurring charges [9]	-	-	-	-	-	-	-	-	(0.02)	(0.02)
Total Special Items	(0.01)	(0.02)	(0.01)	(0.21)	(0.25)	(0.02)	(0.04)	(0.07)	(0.47)	(0.60)
Earnings from Ongoing Operations	$ 0.17	$ 0.20	$ 0.05	$ (0.02)	$ 0.40	$ 0.77	$ 0.74	$ 0.20	$ (0.11)	$ 1.60

(1) Reported Earnings represents Net Income.
(2) Represents a settlement agreement with Talen Montana, LLC and affiliated entities and other litigation costs.
(3) Represents costs primarily related to PPL's centralization efforts and other strategic efforts.
(4) Primarily integration and related costs associated with the acquisition of Rhode Island Energy.
(5) Primarily final closing and other related adjustments for the sale of Safari Holdings, LLC.
(6) Certain expenses related to billing issues.
(7) Prior period impact related to a FERC refund order.
(8) Prior period impact of a methodology change in determining unbilled revenues.
(9) PA Reg. includes certain expenses associated with a litigation settlement. Corp. & Other primarily includes certain expenses related to distributed energy investments.

Reconciliation of Segment Reported Earnings to Earnings From Ongoing Operations – Prior Year

After-Tax (Unaudited)	**Three Months Ended December 31, 2022**						**Twelve Months Ended December 31, 2022**					
($ in millions)	**KY Reg.**	**PA Reg.**	**RI Reg.**	**Corp. & Other**	**Disc. Ops.[7]**	**Total**	**KY Reg.**	**PA Reg.**	**RI Reg.**	**Corp. & Other**	**Disc. Ops.[7]**	**Total**
Reported Earnings[1]	$ 84	$ 115	$ 11	$ (62)	$ 42	$ 190	$ 549	$ 525	$ (44)	$ (316)	$ 42	$ 756
Less: Special Items (expense) benefit:												
Income (Loss) from Discontinued Operations	-	-	-	-	42	42	-	-	-	-	42	42
Talen litigation costs, net of tax of $1, $0 [2]	-	-	-	(4)	-	(4)	-	-	-	1	-	1
Strategic corporate initiatives, net of tax of $3, $4 [3]	-	-	-	-	-	-	(8)	-	-	(15)	-	(23)
Acquisition integration, net of tax of $4, $11, $28, $39 [4]	-	-	(17)	(44)	-	(61)	-	-	(109)	(148)	-	(257)
PA tax rate change [5]	-	-	-	1	-	1	-	9	-	(4)	-	5
Sale of Safari Holdings, net of tax of ($3), $16 [6]	-	-	-	3	-	3	-	-	-	(53)	-	(53)
Total Special Items	-	-	(17)	(44)	42	(19)	(8)	9	(109)	(219)	42	(285)
Earnings from Ongoing Operations	$ 84	$ 115	$ 28	$ (18)	$ -	$ 209	$ 557	$ 516	$ 65	$ (97)	$ -	$ 1,041

After-Tax (Unaudited)	**Three Months Ended December 31, 2022**						**Twelve Months Ended December 31, 2022**					
(per share – diluted)	**KY Reg.**	**PA Reg.**	**RI Reg.**	**Corp. & Other**	**Disc. Ops.[7]**	**Total**	**KY Reg.**	**PA Reg.**	**RI Reg.**	**Corp. & Other**	**Disc. Ops.[7]**	**Total**
Reported Earnings[1]	$ 0.11	$ 0.16	$ 0.01	$ (0.08)	$ 0.06	$ 0.26	$ 0.75	$ 0.71	$ (0.06)	$ (0.44)	$ 0.06	$ 1.02
Less: Special Items (expense) benefit:												
Income (Loss) from Discontinued Operations	-	-	-	-	0.06	0.06	-	-	-	-	0.06	0.06
Talen litigation costs [2]	-	-	-	(0.01)	-	(0.01)	-	-	-	-	-	-
Strategic corporate initiatives [3]	-	-	-	-	-	-	(0.01)	-	-	(0.02)	-	(0.03)
Acquisition integration [4]	-	-	(0.02)	(0.06)	-	(0.08)	-	-	(0.14)	(0.20)	-	(0.34)
PA tax rate change [5]	-	-	-	-	-	-	-	0.01	-	(0.01)	-	-
Sale of Safari Holdings [6]	-	-	-	0.01	-	0.01	-	-	-	(0.08)	-	(0.08)
Total Special Items	-	-	(0.02)	(0.06)	0.06	(0.02)	(0.01)	0.01	(0.14)	(0.31)	0.06	(0.39)
Earnings from Ongoing Operations	$ 0.11	$ 0.16	$ 0.03	$ (0.02)	$ -	$ 0.28	$ 0.76	$ 0.70	$ 0.08	$ (0.13)	$ -	$ 1.41

(1) Reported Earnings represents Net Income.
(2) PPL incurred legal expenses related to litigation with Talen Montana, LLC and affiliated entities. Twelve months ended December 31, 2022, also includes insurance reimbursements received related to this litigation.
(3) Represents costs primarily related to the acquisition of Rhode Island Energy and PPL's corporate centralization efforts.
(4) Primarily includes integration and related costs associated with the acquisition of Rhode Island Energy. Twelve months ended December 31, 2022, also includes costs for certain commitments made during the acquisition process.
(5) Impact of Pennsylvania state tax reform.
(6) Primarily includes the estimated loss on the sale of Safari Holdings, LLC at December 31, 2022.
(7) Tax benefit due to the provision to final 2021 tax return adjustments, primarily related to the discontinued U.K. utility business.

Forward-Looking Information Statement

Statements contained in this presentation, including statements with respect to future earnings, cash flows, dividends, financing, regulation and corporate strategy, including the anticipated acquisition of Narragansett from National Grid, and its impact on PPL Corporation, are “forward-looking statements” within the meaning of the federal securities laws. Although PPL Corporation believes that the expectations and assumptions reflected in these forward-looking statements are reasonable, these statements are subject to a number of risks and uncertainties, and actual results may differ materially from the results discussed in the statements. The following are among the important factors that could cause actual results to differ materially from the forward-looking statements: asset or business acquisitions and dispositions, including the expected acquisition of Narragansett Electric, and our ability to realize expected benefits from them; pandemic health events or other catastrophic events, including severe weather, and their effect on financial markets, economic conditions, supply chains and our businesses; the outcome of rate cases or other cost recovery or revenue proceedings; the direct and indirect effects on PPL or its subsidiaries or business systems of cyber-based intrusion or threat of cyberattacks; capital market and economic conditions, including interest rates and inflation, and decisions regarding capital structure; market demand for energy in our service territories; weather conditions affecting customer energy usage and operating costs; the effect of any business or industry restructuring; the profitability and liquidity of PPL Corporation and its subsidiaries; new accounting requirements or new interpretations or applications of existing requirements; operating performance of our facilities; the length of scheduled and unscheduled outages at our generating plants; environmental conditions and requirements, and the related costs of compliance; system conditions and operating costs; development of new projects, markets and technologies; performance of new ventures; receipt of necessary government permits and approvals; the impact of state, federal or foreign investigations applicable to PPL Corporation and its subsidiaries; the outcome of litigation involving PPL Corporation and its subsidiaries; stock price performance; the market prices of debt and equity securities and the impact on pension income and resultant cash funding requirements for defined benefit pension plans; the securities and credit ratings of PPL Corporation and its subsidiaries; changes in political, regulatory or economic conditions in states, regions or countries where PPL Corporation or its subsidiaries conduct business, including any potential effects of threatened or actual cyberattack, terrorism, or war or other hostilities; new state, federal or applicable foreign legislation or regulatory developments, including new tax legislation; and the commitments and liabilities of PPL Corporation and its subsidiaries. Any such forward-looking statements should be considered in light of such important factors and in conjunction with factors and other matters discussed in PPL Corporation's Form 10-K and other reports on file with the Securities and Exchange Commission.

Definitions of Non-GAAP Financial Measures

Management utilizes "Earnings from Ongoing Operations" or "Ongoing Earnings" as a non-GAAP financial measure that should not be considered as an alternative to net income, an indicator of operating performance determined in accordance with GAAP. PPL believes that Earnings from Ongoing Operations is useful and meaningful to investors because it provides management's view of PPL's earnings performance as another criterion in making investment decisions. In addition, PPL's management uses Earnings from Ongoing Operations in measuring achievement of certain corporate performance goals, including targets for certain executive incentive compensation. Other companies may use different measures to present financial performance.

Earnings from Ongoing Operations is adjusted for the impact of special items. Special items are presented in the financial tables on an after-tax basis with the related income taxes on special items separately disclosed. Income taxes on special items, when applicable, are calculated based on the statutory tax rate of the entity where the activity is recorded. Special items may include items such as:

- Gains and losses on sales of assets not in the ordinary course of business.
- Impairment charges.
- Significant workforce reduction and other restructuring effects.
- Acquisition and divestiture-related adjustments.
- Significant losses on early extinguishment of debt.
- Other charges or credits that are, in management's view, non-recurring or otherwise not reflective of the company's ongoing operations.

Event Name: PPL Corporation 4th Quarter 2023 Earnings
Event Date: Friday, February 16, 2024, 11:00 AM ET

Officers and Speakers
Andy Ludwig; Vice President, Investor Relations
Vince Sorgi; President and Chief Executive Officer
Joe Bergstein; Chief Financial Officer

Analysts
Shar Pourreza; Guggenheim Partners
Durgesh Chopra; Evercore ISI
Angie Storozynski; Seaport
Paul Zimbardo; Bank of America
Anthony Crowdell; Mizuho
David Paz; Wolfe Research

Presentation

Operator: Good day, and welcome to the PPL Corporation Fourth Quarter 2023 Earnings Conference Call.

[Operator Instructions]

Please note this event is being recorded.

I would now like to turn the conference over to Andy Ludwig, Vice President, Investor Relations. Please go ahead.

Andy Ludwig: Good morning, everyone, and thank you for joining the PPL Corporation conference call on fourth quarter and full year 2023 financial results. We have provided slides for this presentation on the Investors section of our website.

We'll begin today's call with updates from Vince Sorgi, PPL President and CEO; and Joe Bergstein, Chief Financial Officer, and conclude with a Q&A session following our prepared remarks.

Before we get started, I'll draw your attention to Slide 2 and a brief cautionary statement. Our presentation today contains forward-looking statements about future operating results or other future events. Actual results may differ materially from these forward-looking statements. Please refer to the appendix of this presentation and PPL's SEC filings for a discussion of some of the factors that could cause actual results to differ from the forward-looking statements.

We will also refer to non-GAAP measures, including earnings from ongoing operations or ongoing earnings, on this call. For reconciliations to the comparable GAAP measures, please refer to the appendix.

I will now turn the call over to Vince.

Vince Sorgi: Thank you, Andy, and good morning, everyone. Welcome to our fourth quarter and year end investor update. I'm excited for today's call, as we closed out 2023 in strong fashion and our future continues to look very bright, and I look forward to highlighting why that is on today's call.

Turning to Slide 4. I'm very proud of what our PPL team was able to accomplish in 2023. In short, it was a year of challenges met and promises kept. Most importantly, we delivered electricity and natural gas safely and reliably to our more than 3.5 million customers. This included top-quartile T&D reliability at each of our utilities, including record liability for our companies in Kentucky and Rhode Island, and top-decile performance in Pennsylvania. Our generation reliability in Kentucky was among the very best in the nation. We achieved all this despite heightened storm activity in each of our service territories.

At the same time, and despite over $0.10-per-share impact from mild weather and storms, we delivered on every one of our financial commitments to our shareowners. Namely, we achieved ongoing earnings of $1.60 per share, exceeding the midpoint of our ongoing earnings forecast by $0.02, and delivering over 8% growth from pro forma of 2022. We achieved this through our strong focus on operational efficiency and outperformance and key areas that Joe will cover in his financial review. We also executed $2.4 billion in planned capital spend on time and on budget to advance a reliable, resilient, affordable and cleaner energy future. We exceeded our annual O&M savings target for 2023 through our strong enterprise-wide focus on technology and business transformation, achieving $75 million in savings from our 2021 baseline, reinforcing our continuous improvement mindset and putting us solidly on track to deliver our targeted $175 million in O&M savings by 2026.

These operational and financial achievements were matched by strong results elsewhere in the business that position us for future success. Underpinned by sound planning and effective management of regulatory proceedings, we secured constructive regulatory outcomes in Kentucky and Rhode Island. in Kentucky, we secured approval for about $2 billion in generation replacement investments as part of our CPCN process that concluded in November of last year. The KPSC's decision ensures that we can continue to meet our customers' future energy needs safely, reliably and affordably, while advancing a cleaner energy mix in the state.

And in Rhode Island, we secured approval of our first infrastructure safety and reliability plans since acquiring Rhode Island Energy. In addition, we received a green light to deploy advanced metering functionality across Rhode Island as we lay a foundation for a smarter, more resilient, more reliable and more dynamic electric grid capable of supporting the state's leading climate goals. Finally, we continued to provide a smooth and seamless transition to PPL ownership for our Rhode Island Energy stakeholders, completing all planned 2023 integration milestones and keeping us on track to exit our remaining transition service agreements with National Grid in mid-2024. These achievements are a direct result of our focus on execution, our disciplined investment strategy, our ability to adjust when challenges arise, our experienced leadership team and clarity of purpose across PPL as we pursue our Utility of the Future strategy.

Looking ahead, we recognize we still have room to improve as we pursue our vision to be the best utility company in the U.S. And in 2024, we're determined to make continued progress as we seek to maximize long-term value for both our customers and shareowners.

Turning to Slide 5. Today we announced the results of our updated business plan, which extends our projected growth outlook through at least 2027. In connection with this update, today we announced our 2024 ongoing earnings forecast range of $1.63 to $1.75 per share. The midpoint of this range, $1.69 per share, represents 7% growth from our 2023 ongoing earnings-per-share target, consistent with our long-term growth targets.

In addition, today we announced a quarterly common stock dividend of $0.2575 per share. This represents a 7.3% increase from the current quarterly dividend of $0.24 per share and aligns with our commitment to dividend growth in line with our EPS growth targets. We've extended our 6% to 8% annual EPS and dividend growth targets through at least 2017 based of the midpoint of our 2024 earnings forecast range.

In addition to today's updated growth forecast, our updated capital plan includes $14.3 billion from 2024 to 2027 to strengthen grid reliability and resiliency and advance a cleaner energy mix without compromising on affordability. The new plan is expected to drive average annual rate base growth of 6.3% through 2027, up from the prior growth rate of 5.6%. We plan to fund these additional investments supported by our exceptional balance sheet, as our credit metrics remain well within our targets through the plan period without the need for equity issuances through at least 2027.

As I highlighted in my recap of 2023, we've made outstanding progress toward our multiyear target of at least $175 million in annual O&M savings by 2026. Based on the progress we made last year, we remain solidly on track to deliver our 2024 targeted savings of $120 million to $130 million.

In terms of rate case timing in the plan, we do not anticipate any base rate case filings in 2024 in Pennsylvania, Kentucky or Rhode Island. Looking beyond 2024, our current projections would have us filing a base rate case a bit sooner in Kentucky than previously anticipated due to several factors, including the CPCN decision and additional capital investment needs on the T&D side of the business. Currently we believe the earliest we would file a rate case in Kentucky will be in the first half of 2025.

For Rhode Island, the earliest we would file is late 2025, which is consistent with the prior plan.

Finally, in Pennsylvania, recall that we have not been in for a base rate case since 2015 and we have no plans to go in again before 2026 at the earliest. The DSIC mechanism in Pennsylvania has operated as designed to support long-term infrastructure investment between rate cases. We do see an increased need to invest more to improve reliability on the distribution system and filed with the Pennsylvania PUC a request to modify our long-term infrastructure improvement plan, or LTIIP, which includes an increase in planned DSIC-eligible investment over a five-year period. We are considering filing a waiver request with the Pennsylvania PUC in the near future, requesting modifications to the DSIC mechanism to support accelerated replacement of aging infrastructure. As always, our focus is on maintaining affordability for our customers, and we will continue to evaluate the need for future rate cases based on a variety of factors, including capital plans, interest rates, market conditions and regulatory lag.

Turning to Slide 6. Our updated plan and business outlook supports our Utility of the Future strategy, which is core to everything we do. What does that mean to us? It means updating our design criteria and continuing to harden our transmission and distribution systems to protect against climate change and keep our systems and data secure against cyberthreats. It means expanding our industry-leading use of technology, including smart grids, automation, data analytics, AI and technologies that haven't even been invented yet, to build a self-healing grid. It means investing in R&D to drive innovation to advanced technologies that can be scaled safely, reliably and affordably, to meet our customers' evolving energy needs and to actually achieve net zero, like the carbon capture project that was awarded a $72-million DOE grant at our Cane Run combined-cycle plant in Kentucky.

At the same time, it means expanding transmission and incorporating grid-enhancing technologies to connect more renewables and improve reliability for our customers; advancing a cleaner generation mix while keeping energy safe, reliable and affordable; expanding our ability to reliably manage two-way power flows on the distribution network as we connect significantly more distributed energy; driving operational efficiencies to support an affordable clean energy transition; partnering with our customers and state and local officials to enable growth and economic development in our communities; and lastly, expanding self-service options for our customers using digital tools to enhance the customer experience.

Turning to Slide 7. As you can hear, creating the utilities of the future requires change across our entire business, and it requires significant investments to support a net zero economy. The industry and others are projecting a 200% to 300% increase in electricity demand, which will require additions of reliable generation unless we see unprecedented amounts of energy conservation. At the same time, aging fossil fuel plants in this country are being retired very rapidly, without replacements of reliable, dispatchable generation capacity, and considering that fossil fuel generation represents more than 50% of our total capacity in the U.S., that presents a potentially major problem if this transition is not managed appropriately.

The math simply doesn't add up, when we don't have proven, scalable technology currently available to actually achieve net-zero carbon emissions that customers can afford. Most technologies used in our industry took 40 years to commercialize from the demonstration phase. We need to cut that time frame in half, at least, to meet net zero by 2050 targets, especially as we think about the big four new potential technologies: nuclear SMRs, carbon capture and sequestration, long-duration energy storage and hydrogen.

In the meantime, we need to leverage commercially viable resources that exist today to reduce our carbon footprint while maintaining reliability. Those that are dispatchable, can ramp up and down quickly and are vital to balancing the gaps left on the system by intermittent renewables. That is why natural gas generation is the key to achieving deep decarbonization in this country, and it actually allows us to deploy more renewables than we would otherwise be able to do, because of the reliability benefits of natural gas.

In a nutshell, this is what makes the energy transition such a challenge: being able to deliver the clean energy future in a way that maintains reliability and affordability for our customers. However, with every challenge brings opportunity, and that's why we know our Utility of the Future strategy is the right approach for this dynamic energy landscape. It's why our generation transition plan in Kentucky is reasoned and deliberate and ensures we can maintain the reliability and resiliency our customers and public officials demand. We actually need to figure out a way to do the same in de-regulated markets like PJM and ISO New England, and it's why becoming more efficient is such a critical component of our strategy, because for every dollar of O&M we can take out of the business, we can spend $8 on capital without impacting the customer bill. The energy transition simply won't happen if customers cannot afford it. This is how we will achieve our long-term vision and how we intend the enhance the value we deliver for all stakeholders. It requires us to lead from the front, and that is exactly what we have been doing and what we will continue to do in 2024 and beyond.

Turning to Slide 8 and our priorities for 2024. In addition to advancing our Utility of the Future strategy, our 2024 priorities also include achieving at least the midpoint of our earnings-per-share forecast; executing $3.1 billion in infrastructure investments to maintain safe, reliable and affordable energy for our customers and modernize the grid; delivering on our 2024 O&M savings targets as we deploy scalable technologies across our portfolio, take advantage of economies of scale created by our centralization efforts, and continue to leverage data analytics to reduce costs and optimize asset planning and maintenance. Finally, we need to complete our integration of Rhode Island Energy and exit all remaining transition service agreements with National Grid.

Bottom line: We're eager to showcase PPL's strengths once again in 2024 and we are poised to lead on these very significant issues facing our industry. We have tremendous conviction in our strategy and business plan, and in our ability to execute them both, and we look forward to once again delivering on our commitments to customers and shareowners.

That concludes my business and strategic update. I'll now turn the call over to Joe for the financial update.

Joe Bergstein: Thank you, Vince, and good morning, everyone. Let's turn to Slide 10.

PPL's fourth quarter GAAP earnings were $0.15 per share, compared to $0.26 per share in Q4 2022. We recorded special items of $0.25 per share during the fourth quarter, primarily due to a settlement agreement with Talen Energy Corporation, as well as integration and related expenses associated with the acquisition of Rhode Island Energy. Adjusting for these special items, fourth quarter earnings from ongoing operations were $0.40 per share, an improvement of $0.12 per share compared to Q4 2022. The primary drivers of this increase were returns on capital investments and lower O&M expenses, partially offset by lower sales volumes, primarily due to the continued mild weather experienced in the fourth quarter of 2023. In total, weather was a $0.02-per-share drag on our Q4 results compared to our plan.

On an annual basis, our 2023 GAAP earnings were $1 per share. Adjusting for $0.60 per share of special items recorded throughout the year, our 2023 ongoing earnings were $1.60 per share. This compares to $1.41 per share of ongoing earnings for 2022, or a 13% increase from those prior year results, and as Vince noted, we delivered our earnings target for 2023, exceeding the $1.58-per-share midpoint of our earnings forecast. Our teams did a fantastic job of executing our plan while remaining steadfast on achieving our financial goals, which enabled us to offset the adverse impacts of significant unfavorable weather and storm activity while maintaining reliability for our customers. 2023 demonstrated our ability to deal with adversity and still achieve our commitments to both customers and shareowners, adding to our confidence in our ability to achieve our earnings targets.

Turning to the ongoing segment drivers for the fourth quarter on Slide 11. Our Pennsylvania regulated segment results increased by $0.04 per share compared to the same period a year ago. The increase was primarily driven by lower O&M and higher transition revenue, partially offset by lower sales volumes and higher interest expense. Our Kentucky segment results increased by $0.06 per share compared to the fourth quarter of 2022. The improvements in Kentucky's results were primarily driven by lower O&M expense, partially offset by lower sales volumes due to the mild weather. Our Rhode Island segment results increased by $0.02 per share. This increase was primarily driven by higher rider revenue from capital investments, partially offset by higher interest expense. Finally, results at Corporate and Other were flat compared to the prior period, primarily due to lower income taxes, offset by higher O&M expense.

Moving to Slide 12. 2023 was a pivotal year for PPL following our strategic repositioning, which we completed in 2022. Heading into the year, we set our 2023 earnings forecast range with a midpoint of $1.58 per share, representing 7% growth from the 2022 pro forma midpoint of $1.48 per share, which reflected a full year of earnings from Rhode Island Energy, and for the second consecutive year, we outperformed our own targets, beating our earnings forecast by $0.02 and achieving over 8% growth for the 2022 pro forma forecast midpoint. This was a significant achievement given the abnormally mild weather and storms we experienced, which impacted results by more than $0.10 per share.

And as I've said numerous times over the past year, we were confident that our team would overcome those challenges and deliver on our commitments to both our customers and shareowners. This included several areas of excellent execution and constructive regulatory mechanisms, including prudent management of costs without sacrificing reliability, recovery of critical infrastructure investments in PA through the DSIC mechanism; outperformance and integration of Rhode Island Energy; and optimization of our financing plan.

Looking at 2024, the midpoint of our earnings forecast range is $1.69 per share, which again represents 7% earnings growth from the midpoint of our 2023 forecast. Since we initially communicated our earnings growth targets to investors, we remain on that consistent trajectory while extending that growth further into the future, and we've done that again today, with our extension of the 6% to 8% growth targets to 2027, supported by an updated capital investment plan, which I'll discuss in more detail in a couple of slides.

Moving to Slide 13. On this slide, we've provided a walk from our 2023 actual results of $1.60 per share to the midpoint of our 2024 forecast, highlighting the projected drivers of the year-over-year increase by segment. Our Pennsylvania segment results are expected to increase by $0.05 per share in 2024, primarily due to returns on additional capital investments in transmission, higher sales volume and lower O&M, partially offset by less distribution and rider recovery and higher interest expense. We project our Kentucky segment results to increase by $0.07 per share in 2024, primarily driven by higher sales volumes due to the expected return to normal weather. Our Rhode Island segment results are expected to increase by $0.02 per share in 2024, compared to our 2023 results. This is primarily due to higher capital investment rider revenue and lower O&M, partially offset by higher depreciation expense. Finally, we project our Corporate and Other results to decrease by $0.05 per share in 2024, primarily due to higher interest expense and other factors that are not individually significant.

Turning to Slide 14. Over the next four years, we have planned capital investments of $14.3 billion focused on delivering superior service and enhancing the overall customer experience while maintaining an affordable price. This includes advancing industry-leading grid modernization, expanding and hardening our transmission networks, improving the safety of our natural gas networks, and implementing our approved generation replacement plan in Kentucky. This plan represents a $2.4-billion increase in capital investments compared to the prior four-year plan.

Approximately $1 billion of that increase is expected to occur in the 2024 to 2026 period. Most of that increase is projected to be in Pennsylvania and Kentucky, as we continue to modernize our electric transmission and distribution systems and enhance reliability and resiliency.

We continue to expect significant investment needs into the end of this decade, as reflected on our 2027 forecast. This includes nearly $1.2 billion in Pennsylvania, of which approximately 65% is transmission investment under FERC formula rates; $1.8 billion of investment in Kentucky, primarily related to further enhancements on the electric and gas T&D systems; and to execute our generation replacement plan. And it includes over $700 million of investment in Rhode Island as we continue to prepare the grid for significant levels of clean energy resources and as we enhance resiliency against increasingly severe storms while continuing our focus to maintain a safe and reliable gas network by replacing leak-prone pipe.

Turning to Slide 15. These additional capital investments are projected to lead to annual rate base growth of 6.3% from 2023 to 2027. This compares to annual rate base growth of 5.6% in our prior plan period from 2022 to 2026. As you can see in the chart, two thirds of our rate base relates to investments in our electric T&D networks, given the significant needs as we strengthened and modernized the grid.

Importantly, while we project our total rate base to grow, rate base related to coal generation continues to decline from 2023 to 2027. In fact, the percentage of our total rate base related to coal generation is expected to be less than 12% by the end of 2027, down from about 18% today, and based on this trajectory, we expect this to continue to decline and be under 10% by the end of the decade.

In summary, the result of our updated plan narrows the gap between our projected rate base growth and earnings growth targets as investment needs continue to increase with the evolving energy landscape. As such, we continue to be very focused on affordability and maximizing every dollar we spend. Our earnings growth in the near term continues to be driven by the combination of rate base growth and operating efficiencies that we believe maximizes value for both customers and shareowners.

Moving to Slide 16. Today we announced an increase in our quarterly cash dividend to $0.2575 per share. This results in an annualized dividend of $1.03 per share, compared to our prior annualized dividend of $0.96 per share. This 7.3% increase aligns with our projected 2024 forecasted earnings growth and long-term EPS growth targets. We continue to expect future dividend growth to align with our earnings growth targets. The updated dividend remains within our targeted dividend payout range of 60% to 65% based on the midpoint of our 2024 earnings forecast. The combination of PPL's EPS growth and dividend yields provides investors with an attractive total return proposition in the range of 9% to 12%.

Moving to an update on PPL's credit and our financing plan for 2024 on Slide 17. We continue to believe that having one of the sector's strongest balance sheets is a clear strategic advantage that provides the company with significant financial flexibility. Our updated business plan maintains strong credit metrics throughout. This includes maintaining a 16% to 18% FFO to debt ratio and a holding company to total debt ratio below 25%. We have limited near-term refinancing risk, with zero maturities in 2024 and only $550 million of total maturities in 2025, and we continue to maintain limited floating rate debt exposure, mitigating volatility in our plan. We also continue to be uniquely positioned to continue to fund our growth without the need for equity throughout our updated planning period, which is now extended through 2027.

As investors think about our financing plan for 2024, they should expect our activity to be primarily focused on funding our utility capital plans with operating company debt. We've already executed a portion of this plan with our $650-million PPL Electric Utilities deal in January, which was executed at attractive pricing. We're also planning to be in the market for Rhode Island, with our first debt offering since the acquisition. We have no current plans for debt issuances in Kentucky or at PPL Capital Funding this year, but that is an area we'll continue to evaluate opportunistically in connection with market conditions and our strong financial position.

In closing, I'm extremely pleased with our financial position and outlook to execute our updated plan. This concludes my prepared remarks; I'll now turn the call back over to Vince.

Vince Sorgi: Thank you, Joe. As I mentioned earlier, this is a pivotal time for our industry; a time that requires us to lead with strength. There is no shortage of challenges facing our industry in being able to deliver the clean energy transition safely, reliably and affordably for our customers.

This is what gets me out of bed every morning, and why I'm so excited to be a part of this industry at this moment in time. I'm convinced we have the right strategy for the right time; a strategy that prioritizes efficiency and affordability, built on our core strengths, and will maximize long-term value for customers and shareowners alike. We are well positioned to continue our competitive and predictable long-term earnings growth of 6% to 8% a year. We've established a de-risked and disciplined business plan that advances a safe, reliable, affordable and sustainable energy future while providing investors with an attractive return proposition. And finally, we have an experienced leadership team that is 100% committed to delivering on these objectives and backed by a dedicated team of 6,500 strong across PPL.

With that, operator, let's open it up for questions.

Questions & Answers

Operator: [Operator Instructions]

The first question today comes from Shar Pourreza with Guggenheim Partners.

Shar Pourreza: So just on the transmission side, I see you've added a couple hundred million to the Pennsylvania plan; how much of that is tied to the recent RTEP Window 3 awards? And the reason why I'm asking is we've seen some significant increases in transmission needs and transfer capability across utilities in eastern PJM and EMaC, so just trying to get a sense for what has started to trickle into your plan versus incremental. Thanks.

Joe Bergstein: Yes. Hey, Shar, it's Joe. About half of that increase is driven by what you're describing and what we were awarded in that recent PJM window.

Shar Pourreza: Got it, perfect. And then just coming back to the Kentucky spend, the CPCN process obviously had deferred but not quite closed the door to the second CCGT; is that something that you could revisit? And could the spend start to land in the outer years of the latest plan? Just kind of trying to get a sense for the next incremental focus. Thanks.

Vince Sorgi: Yes. To your point, Shar, the order suggested that we should come back with another CPCN filing with an in-service date for that second CCGT in 2030. And so we would plan on doing that in a couple years' time, start to prepare for that. And obviously we'll be updating that as we go through the IRP process this year, looking at load and generation economics and all that. So the first point is really the updated IRP that we'll file this year, and then ultimately that'll feed into a CPCN filing to be -- to establish plant service in 2030.

Shar Pourreza: Perfect. That's all the questions I had. Congrats, Vince, on the execution; it's pretty notable. Appreciate it.

Vince Sorgi: Thanks, Shar. Appreciate it.

Operator: The next question comes from Durgesh Chopra with Evercore ISI.

Durgesh Chopra: I just had a question on Pennsylvania. Maybe just -- can you elaborate on what you plan to do, or any color you can share on the DSIC itself? The reason why I ask is the -- your peer water utility in the state, their rate case is drawing a lot of attention; there are new commissioners at the commission; so just -- maybe just talk to the regulatory environment in the state? And then what -- if you could share any color on what you might try to do with the DSIC mechanism, that would be great. Thank you.

Vince Sorgi: Sure. So maybe a precursor to the DSIC waiver is really the LTIIP process that we have in the state, Durgesh. In mid-January, we filed a petition with the commission to modify our LTIIP, which covers the period -- that's the long-term infrastructure improvement plan that covers the period from January 1 of 2023 to 12/31/27, so we're already a year into this current LTIIP plan. We did file for some significant adjustments to that plan, which the LTIIP is really the precursor for the types of projects that would then be eligible to flow through the DSIC mechanism.

We're proposing to increase that LTIIP plan from about $500 million to about $800 million. We're including a new project, or a new program, for predictive failure technology. We've been doing a lot of testing on some new devices that we can put on the grid that actually enable us to identify failing equipment before it actually fails and causes an outage. So we have some money in there that we want to include. We're also looking at just other distribution reliability projects; our reliability, very strong in Pennsylvania, being led by our transmission results there. We need to continue to improve our distribution reliability. So additional money in there for that, and then of course we have the approved projects through the IIJA process that we also updated the LTIIP for.

So the parties have 30 days to file comments on our LTIIP filing, and those comments are actually due today, so we'll want to review those comments before we file for the DSIC waiver request. We have notified the PUC of our intention to file that waiver request, and we'd expect to file that relatively soon, Durgesh. At this point, the request -- we're still working on it -- will likely be in the form of a higher cap on the DSIC.

Operator: The next question comes from Angie Storozynski with Seaport.

Angie Storozynski: So I -- it's a bit of an unfair question, I will admit; so we're waiting to see this potential large data center to be developed next to -- or directly next to the Susquehanna nuclear plant, which is obviously your service territory and your former asset, so I'm just wondering -- so if that were to happen, if we were to have this almost 1,000 megawatts data center, what type of investments would that require from you guys, from a T&D perspective? And is it already embedded in your plan?

Vince Sorgi: Yes, so let me talk about, maybe, data centers more broadly. You're referring to one that's specifically related or will be tied to the Susquehanna nuclear plant, so most of that activity is really between Talen and the data center entity, although we are working with Talen to ensure that the reliability of power supply is there for that center. So some incremental work there, Angie.

What I would say, though, more broadly, beyond that specific instance, is we've really started to see some data center activity both in Pennsylvania and Kentucky, with some very large load requirements. Again, 1-gig-size projects, some smaller than that, but we are seeing some 1-gig projects as well. And in our territories, we have some -- a number of positive attributes that these data centers are looking for. Not only is our reliability very strong in the top-quartile, top-decile range, especially in our transmission side of the business, which is where these generally are pulling their power from -- the reliability there is extremely high -- we also have relatively inexpensive land, and an abundance of that land, in both of our jurisdictions in PA and Kentucky.

And then in Pennsylvania in particular we have a decent amount of capacity on the transmission network that we could add this load without a lot of investment, that still is incredibly beneficial for our customers because that will still lower the overall cost and bill for our retail customers, the more and more load that we can connect to the transmission network. And that, of course, we're close to New England and the Mid-Atlantic region, especially, as you think about Pennsylvania, so there's a number of things in our territories that make this attractive, and of course, in Kentucky, we have relatively cheap power prices.

So, very active in working with the data center companies. We haven't included these in our load forecast at this point. We will do that at the appropriate time, if and when we close these deals with these folks, but I would just say at this point, a lot of activity going on with the data centers, as you're hearing with some of our peers as well.

Angie Storozynski: And can I ask about Kentucky? So you mentioned that the grid is getting tighter from the power supply perspective. I mean, one, does it make you sort of reassess your plans for retirements of coal plants and/or additions of new gas plants in the state? And also, how do those data center providers actually look at thermal power from gas and coal versus, I don't know, nuclear or renewables? Does that matter? Do they really care about the carbon footprint or emissions or is it mostly the total cost and how cheap the power is?

Vince Sorgi: Yes, for the most part, what we're seeing, Angie, is reliability, and reliability of power. I think you're right; there are some data center companies that also want to ensure that that power is coming from green energy sources, like what we're seeing up in Susquehanna, as you mentioned earlier, but for the most part, it's about reliability and the cost of that power, because obviously these are huge costs for these data centers, is the cost of the electricity itself, so.

To your point, we don't have as much capacity in Kentucky as we do up here in Pennsylvania, and so we would expect there to be incremental investment needed to support data centers in Kentucky, perhaps more so than we would need, at least in the near term, in Pennsylvania.

Certainly this will feed into, as I was mentioning before, into our IRP process as we look at our load growth, as we think about our generation replacement strategy. A little too early, I would say, to say we need to modify our current thinking on that, but clearly, if some of these large centers hit, we're going to have to factor that into the IRP and then ultimately into that CPCN request a couple of years from now.

Operator: The next question comes from Paul Zimbardo with Bank of America.

Paul Zimbardo: First one: On the O&M targets -- and please correct me if I'm wrong -- it looks like you've reaffirmed them all but exceeded the 2023 target by around $20 million. I'm just -- what would -- and I know the targets are "at least." What would you need to see to increase those targets? And what drove that initial outperformance versus target?

Joe Bergstein: Yes, sure. Hey, Paul. It's Joe. So first, focusing on what drove the outperformance in 2023 is, as we noted, we achieved $75 million in savings compared to the $50-million to $60-million target that we had coming into the year. It was really driven by acceleration of some of the initiatives from 2024. When we started the [TMO] process, we have initiative owners for all of these projects that will deliver these savings, and we've set milestones and KPIs for all of them. And so what we saw bringing that rigor to the process has actually allowed us to accelerate in some areas, which gives us confidence in our achieving the $120 million to $130 million next year and the $175 million overall.

As we talked about, and as Vince talked about in his remarks, focused on the Utility of the Future and ensuring affordability for customers is key, and so from that perspective, we'll continue to look to get more efficient as we go through the plan, but where we are today is we're still holding that $175 million, at least $175 million, as we said. What I can say is the growth that we're talking about here, and expanding that in 2027, doesn't rely on further efficiencies, so to the extent that we're successful in identifying more, that would be upside to the current plan.

Paul Zimbardo: Okay, great. Very clear. And then on the rate case timing strategy, I know Vince listed a bunch of factors, but one of them wasn't about how rate cases go for peers. Just curious; how important is that as you think through the process, how the -- especially in Pennsylvania, just given a lot of the rate cases, as Durgesh was mentioning? How important is that to kind of assess your own plan?

Vince Sorgi: Yes. Well, clearly, because we have no rate cases in 2024 across the board, we're able to assess the regulatory environment and the outcomes that our peers are getting. As we know, not every company gets the same outcome, even under the same jurisdiction, so it wouldn't totally impact our decision, but clearly it's something that we will keep an eye on and feed into our decision making. And again, the fact that we don't have anything for, certainly, the rest of this year, and likely the first one will be down in Kentucky sometime in 2025, feeling pretty good about our timing that we have in the plan right now.

Operator: [Operator Instructions]

The next question comes from Anthony Crowdell with Mizuho.

Anthony Crowdell: Just a couple quick ones. One, to follow up from Angie's question, what's this load growth forecast you're assuming for '24?

Joe Bergstein: Hi, Anthony. It's Joe. We're assuming 50 basis point load growth throughout our planning horizon.

Anthony Crowdell: Great. And then if I could jump on a Durgesh question, in Pennsylvania, you're filing the DSIC, and I think you're looking to raise the cap -- you talked about it. Just curious -- again, I'm not saying that it's -- I'm here to say it doesn't get approved, but if you don't get approval, does that increase of the frequency of the rate filing, or do you believe you have other offsets that you could still stay out in Pennsylvania a little longer?

Vince Sorgi: Yes, it's the latter, Anthony. We have some modest value in the plan coming from the DSIC filing. I think the real benefit is it would enable to stay out longer in Pennsylvania and make the investments that we had talked about, but yes, to your point, if for some reason that request does not get approved, we're comfortable we can manage that and still maintain the growth targets that we've talked about.

Anthony Crowdell: Great. And then just lastly, on Slide 17, I appreciate the detail on the -- you don't have any near-term financing. Just in 2026, you see the capital funding; you also have the electric utility funding there. On those maturities, do you think you'll retire those vehicles, those financing vehicles, or do you think you just roll over that? I'm just curious on what your plan is on those financing vehicles.

Joe Bergstein: Yes, Anthony, we'll have to assess that as we get closer. Obviously where interest rates are will play a big role in what we do there, so I think it's a little early to tell on how we'll treat those. Our assumption is that we refi them and hold them.

Operator: The next question comes from David Paz with Wolfe.

David Paz: Just actually following up on a previous question, the FFO to debt in particular, where are you in that 16% to 18% currently? And where -- how does that -- what's the profile of that over the course of your plan?

Joe Bergstein: Yes. I would just say we're comfortably in that 16% to 18% range. We, in the early part of the plan, we continued to have integration costs for Rhode Island that obviously are -- impact the credit metric, and those roll away, and then you see the CapEx increase later in the plan. So we feel really good about where we are within that range and kind of operate comfortably around the midpoint.

David Paz: Okay, thank you. And then just -- I don't know if you touched on this, but what are your opportunities, or what opportunities do you see from the pending offshore wind solicitations? More transmission? What do you have in your plan, if anything? Just any color you can provide, that would be great.

Vince Sorgi: Sure. So a couple opportunities there. Obviously we have the RFP that we've issued in Rhode Island. We are not the owners of that, but we would be the offtaker of that generation. And so to your point, we do have, in the plan, the transmission required to -- the enhancements to the transmission grid to handle that offshore wind load.

We have talked in the past about our -- a joint venture with WindGrid to potentially provide wet transmission solutions more broadly up in Rhode Island -- or New England, that we would partner with them on, where we would not own the turbine, the wind turbine generation, but we would build out a mesh network of sorts to lower the overall cost of the transmission buildout, as we think about upwards of 30 gigs of offshore wind over the next, say, decade being built out up there.

That opportunity will highly depend on where the U.S. Treasury ultimately comes out on their implementation provisions for the IRA. So we are monitoring those regulations very closely. The initial regs that came out from the treasury, we think, were in error in proposing that the regulations would limit the eligibility of the ITC credit for that wet transmission only if that transmission is owned by the same taxpayer that owns the wind turbines themselves. That limitation, if the final rules come out that way, would unnecessarily raise the cost of the offshore wind industry, which we know is quite challenged. And so we continue to engage with the administration and other policy makers to try to improve that final regulation and expand it to all taxpayers, not just ones that own the turbines, and to try to bring the overall cost of offshore wind down so that we can get this very important clean energy source kind of up and running in the U.S. But I can't give you any assurance in terms of what that final rule is going to say.

I can say we don't have any of that upside potential in our business plan. It's not in our growth projections at all at this point. I would say it kind of hinges on this, and then the states really coming together up there and partnering on this broader solution, which we believe will certainly bring the cost of offshore wind down.

Operator: This concludes our question-and-answer session. I would like to turn the conference back over to Vince Sorgi for any closing remarks.

Vince Sorgi: Just want to say thanks for joining us. Again, strong end to 2023; really looking forward to 2024 and beyond. Spent quite a bit of time talking about the Utility of the Future strategy; we do think that's an area that differentiates us from our peers, as well as the strength of our balance sheet and our overall dividend policy where we're growing the dividend in line with earnings.

So just appreciate everybody for calling us, or for joining us, and look forward to providing updates as we go through the year. Thanks so much.

Operator: The conference has now concluded. Thank you for attending today's presentation. You may now disconnect.

PUC 10-2
Southern Rhode Island Expansion Project

Request:

Please provide the original budget estimate upon which the Company was basing its investment plan for the Southern Rhode Island Expansion Project when the expansion project was first included in the Company's ISR filing seeking inclusion of the project in the ISR.

Response:

The total original cost estimate for the entire Southern Rhode Island Gas Expansion ("Southern RI Gas Expansion") Project was $112.37 million.

The Southern Rhode Island Gas Expansion was first included as an ISR project in the Company's fiscal year ("FY") 2020 Gas ISR Proposal in Docket No. 4916, which was submitted on December 20, 2018. Prior to that filing and during FY 2019, the Company initially spent $2.39 million on the Southern RI Gas Expansion. In its FY 2020 ISR proposal, the Company stated that between FY2020 and FY2022, the Company estimated it would spend another $109.98 million to complete the project, resulting in a total cost estimate of $112.37 million.

PUC 10-3
Southern Rhode Island Expansion Project

Request:

Please provide the budget estimate developed by the Company after engineering design work was completed on the Southern Rhode Island Expansion Project, including a breakdown of components upon which the estimate was based.

Response:

The estimated spend on components of the Southern Rhode Island Growth Project are as follows:

- Maximum Allowable Operating Pressure (MAOP) Line Increase: $4.057M
- Main Installation: $ 96.792M
- Regulator Station Installation at Quaker At Cowesett: $4.240M
- Take Station Rebuild Laten Knight: $6.840M
- New Regulator Station for Southern RI Growth Project: $6.830M (currently in engineering design)

PUC 10-4
Southern Rhode Island Expansion Project

Request:

Please provide a schedule showing actual expenditures against annual budgets for the Rhode Island Expansion Project from project inception through forecasted spending in FY 2024. For each year, please provide a breakdown by component. Please also include a forecast of expenditures through project completion.

Response:

Please see Attachment PUC 10-4 for the requested information.

Attachment PUC 10-4

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
	$ Millions	**FY2019**		**FY2020**		**FY2021**		**FY2022**		**FY2023**		**FY2024**		**FY2025**	**FY2026**	**FY2027**	**FY2028**	**Lifetime**
Line	**Description**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**	**Proposed Budget**	**Forecast**	**Forecast**	**Forecast**	**Total Lifetime Forecast**
1	**Main Installation**	**$ 2.39**	**$ -**	**$ 40.18**	**$ 39.92**	**$ 40.57**	**$ 41.36**	**$ 13.53**	**$ 14.91**	**$ 0.52**	**$ 0.60**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 97.18**
	Regulator Station Investments:																	
2	Cranston Take Station Upgrades (aka Laten Knight)					$ 0.13	$ 0.20			$ 0.72		$ 1.68	$ 3.00	$ 4.00	$ 0.05			$ 6.59
3	Cowesett Regulator Station Upgrades					$ 0.32	$ 0.63	$ 1.26	$ 2.95	$ 2.82	$ 5.79	$ 0.05	$ 0.08	$ 0.01				$ 4.46
4	New Regulator Station					$ 0.01	$ 0.38						$ 0.63	$ 0.05	$ 3.45	$ 3.27	$ 0.05	$ 6.83
5	**Total - Regulator Station Investments**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.46**	**$ 1.21**	**$ 1.26**	**$ 2.95**	**$ 3.54**	**$ 5.79**	**$ 1.73**	**$ 3.70**	**$ 4.06**	**$ 3.50**	**$ 3.27**	**$ 0.05**	**$ 17.88**
6	**Other Upgrades/Investments: MOP Increase from 150 to 200 psi**	**$ -**	**$ -**	**$ 2.55**	**$ 4.54**	**$ 0.73**	**$ 0.50**	**$ 0.16**	**$ 1.58**	**$ 0.00**	**$ 0.40**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3.44**
7	**Annual Totals**	**$ 2.39**	**$ -**	**$ 42.73**	**$ 44.46**	**$ 41.76**	**$ 43.07**	**$ 14.95**	**$ 19.44**	**$ 4.06**	**$ 6.79**	**$ 1.73**	**$ 3.70**	**$ 4.06**	**$ 3.50**	**$ 3.27**	**$ 0.05**	**$ 118.50**

Note for New Regulator Station: on 2/1/24 the Company determined that this New Regulator Station would need to be an 8" above ground station and three (3) possible locations are being investigated. An easement will be needed and the Company is currently working thru the easement process. For this response the Company updated the FY2026 forecast from $0.45M to $3.45M and the FY2027 forecast from $1.27M to $3.27M and the FY2028 forecast has remained at $0.05M for project closeout. The Company will also update its internal 5-year investment plan with this updated information.

PUC 10-5
Southern Rhode Island Expansion Project

Request:

Please provide copies of all the relevant sanction papers relating to the Southern Rhode Island Expansion Project, including those approved when the Company was owned by National Grid.

Response:

Please see the table, below for a list of the sanction papers relating to the Southern Rhode Island Expansion Project and Attachment PUC 10-5-1 through Attachment PUC 10-5-12 for copies of the sanction papers.

Attachment	Sanction Paper Name	Investment Plan Name	Funding Project Number	Sanction Amount (+/-10%)	Type of Sanction	Date of Sanction Request
Attachment PUC 10-5-01	USSC-18-243 FY19 Annual Project Development - RI Gas	Gas System Reinforcement - Quaker Lane	C079252	$ 1,300,000	Project Development	6/26/2018
Attachment PUC 10-5-02	USSC-18-243- v2 FY19 Annual Project Development - RI Gas	Gas System Reinforcement - Quaker Lane (Material Purchase Commitment)	C079252	$ 6,000,000	Project Development	11/16/2018
Attachment PUC 10-5-03	USSC-19- 089 FY20 Annual Project Development - Narragansett Electric Co	Southern RI Station Upgrades	C082302	$ 400,000	Project Development	2/19/2019
Attachment PUC 10-5-03	USSC-19- 089 FY20 Annual Project Development - Narragansett Electric Co	Southern RI New Regulator Station	C081906	$ 100,000	Project Development	2/19/2019
Attachment PUC 10-5-03	USSC-19- 089 FY20 Annual Project Development - Narragansett Electric Co	MOP Increase from 150 to 200 PSI	C081907	$ 200,000	Project Development	2/19/2019
Attachment PUC 10-5-04	USSC-19- 089 v2 FY20 Annual Project Development - RI Resanction	Southern RI Station Upgrades	C082302	$ 491,000	Project Development	5/28/2019
Attachment PUC 10-5-04	USSC-19- 089 v2 FY20 Annual Project Development - RI Resanction	Southern RI New Regulator Station	C081906	$ 491,000	Project Development	5/28/2019
Attachment PUC 10-5-04	USSC-19- 089 v2 FY20 Annual Project Development - RI Resanction	MOP Increase from 150 to 200 PSI	C081907	$ 3,550,000	Project Development	5/28/2019
Attachment PUC 10-5-05	USSC-20-146 FY21 PD Sanction RI	Cowesett Reg Station	C085181	$ -	Project Development	3/19/2020
Attachment PUC 10-5-05	USSC-20-146 FY21 PD Sanction RI	Cranston Take Station	C082302	$ -	Project Development	3/19/2020
Attachment PUC 10-5-05	USSC-20-146 FY21 PD Sanction RI	GrowthPoint – Return of Cranston Line to 200 psig MOP	C081907	$ -	Project Development	3/19/2020
Attachment PUC 10-5-06	USSC-21-102 FY22 Project Development Sanction RI	Gas Planning - LTRI - Growthpoint - New Regulator Station	C082302	$ 250,000	Project Development	3/2/2021
Attachment PUC 10-5-06	USSC-21-102 FY22 Project Development Sanction RI	Gas Planning - LTRI - Growthpoint - New Regulator Station Near Cowesett	C082302	$ 250,000	Project Development	3/2/2021
Attachment PUC 10-5-06	USSC-21-102 FY22 Project Development Sanction RI	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	C085181	$ 500,000	Project Development	3/2/2021
Attachment PUC 10-5-06	USSC-21-102 FY22 Project Development Sanction RI	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cranston	C082302	$ 200,000	Project Development	3/2/2021
Attachment PUC 10-5-07	RIEG 23-004 Cranston Reg. Station Upgrades - Growthpoint	Gas Planning - Cranston Reg. Station Upgrades - Growthpoint - C082302 aka Latent Knight Gate Station	C082302	$ 6,840,000	Full	3/24/2023
Attachment PUC 10-5-08	USSC-21-008 GrowthPoint – Cranston Line MOP increase to 200 psig	Gas Planning - Growthpoint - C081907 - MOP Increase	C081907	$ 4,057,000	Full	1/19/2021
Attachment PUC 10-5-09	RIEG 23-103 (C) - Cranston Line MOP increase to 200 psig	Gas Planning - Growthpoint - C081907 - MOP Increase	C081907	$ 3,288,323	Closure	5/23/2023
Attachment PUC 10-5-10	USSC-19-001 Southern RI Growth Reinf Quaker Ln	Gas Planning - Growthpoint - C079252 - Main Installation	C079252	$ 73,908,000	Full	1/30/2019
Attachment PUC 10-5-11	USSC-19-001V2 Southern RI Growth REinforcement - Quaker Ln	Gas Planning - Growthpoint - C079252 - Main Installation	C079252	$ 96,792,000	Resanction	1/27/2020
Attachment PUC 10-5-12	USSC-21-285 LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	Gas Planning - Cowesett Reg. Station - Growthpoint - C085181	C085181	$ 4,240,000	Full	7/27/2021

Prepared by or under the supervision of: Phil LaFond and Tom Mulkeen

Short Form Sanction Paper

Title:	FY19 Annual Project Development – RI Gas	**Sanction Paper #:**	USSC-18-243
Project #:	Many – See Summary of Projects	**Sanction Type:**	Sanction
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	06/26/2018
Author:	William Foley	**Sponsor:**	John Stavrakas, VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	William Foley

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction in the amount $1.643M with a tolerance of +/- 10% for the purposes of fiscal year 2019 (FY19) Stage 4.3 Project Development, which includes the purchase of long lead materials, the pursuit of permitting and land rights, and all other preliminary engineering activities.

This sanction amount is $1.643M broken down into:
$ 1.643M Capex
$ 0.000M Opex
$ 0.000M Removal

This project has undergone a Capital Efficiency Review with the following determination:

Specific capital efficiencies will be identified in the individual project sanctions after the activities in Stage 4.3 Develop & Sanction have been performed. Those activities are described in Section 2.1.

1.2 Project Summary

Project Development activities are required for projects in FY19 to support the existing Narragansett Electric Company Investment Plan. The initial list of projects to be developed during FY19 are outlined in Section 3.1, Summary of Projects. Project Development activities are required for complex capital projects under the new Capital Delivery Process Model.

2 Project Detail

Short Form Sanction Paper

2.1 Background

2.1 Background

The Company has developed a standardized process for developing and delivering complex projects. In accordance with the Company's Capital Delivery Initiative, below is a list of the common activities that are authorized to take place, as needed, this fiscal year (FY):

- Assemble a cross functional project team to assist in the development of projects to define and approve specific scope;
- Conduct site specific investigative work (i.e. test holes, borings, vegetation evaluation, soil samples, etc.);
- Pursue permitting and land rights;
- Perform preliminary engineering and other related tasks;
- Procure materials (e.g. heaters, etc.);
- Develop the Project Execution Plan (PEP) which includes items above as well as:
    - detailed cost estimate
    - risk register & mitigation plan
    - baseline schedule
    - resource strategy for final design and or project execution
    - contract strategy;
- PEP approval meeting;
- Complete Project Book 4.3 and Gate C Checklist;
- Gate C Approval Meeting

2.2 Alternatives

Each project listed in Section 3.1 is nearing the end of a Stage 4.2 Options Analysis. The full list of project alternatives will be discussed during the individual project sanctions at the end of Stage 4.3. For the purposes of this group project sanction, the alternatives are listed below:

Alternative 1: Process partial sanction papers on an individual project basis to obtain enough Delegation of Authority (DOA) to progress the project through final design.

This alternative was not chosen because approving these development costs in one sanction is more efficient than going through multiple individual partial sanctions.

2.3 Investment Recovery

Investment recovery will be through standard rate recovery mechanisms for each project.

Short Form Sanction Paper

2.3.1 Customer Impact

The first full year revenue requirement, for each of the projects listed in Section 3.1, will be determined during the individual project sanctions.

3 Related Projects, Scoring, Budgets

3.1 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
CRCC204	Gas	CI Lining - Lining	0.170
C080795	Gas	Holder 19 Rebuild	0.047
C080782	Gas	LNG - Exeter ESD System	0.116
C080783	Gas	LNG - Exeter Hi Ex Foam System	0.010
C079252	Gas	Gas System Reinforcement - Quaker Lane	1.300
		Total	1.643

3.2 Associated Projects

N/A

3.3 Prior Sanctioning History

N/A

3.4 Category

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ○ Policy- Driven ○ Justified NPV ⊙ Other	A new Complex Capital Delivery Process has been established and approved to standardize the process for delivering projects in accordance with the Business Management Systems.

Short Form Sanction Paper

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3.5 Asset Management Risk Score

Asset Management Risk Score: 35

Primary Risk Score Driver: (Policy Driven Projects Only)

○ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

⦿ Mixed

3.6 Complexity Level

○ High Complexity ⦿ Medium Complexity ○ Low Complexity ○ N/A

Complexity Score: 21

3.7 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
June 2019	Project Closure Sanction

4 <u>Financial</u>

4.1 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY19-FY23 Gas Capital Plan	○ Yes ⦿ No	⦿ Over ○ Under ○ NA	$1.643M

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4.1.1 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

4.2 CIAC / Reimbursement

N/A

4.3 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend	Prior Yrs	Current Planning Horizon ($M) Yr. 1 2018/19	Yr. 2 2019/20	Yr. 3 2020/21	Yr. 4 2021/22	Yr. 5 2022/23	Yr. 6 + 2023/24	Total
CRCC204	CI Lining - Lining	Est Lvl (e.g. +/- 10%)	CapEx	-	0.170	-	-	-	-	-	0.170
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.170	-	-	-	-	-	0.170
C080795	Holder 19 Rebuild	Est Lvl (e.g. +/- 10%)	CapEx	-	0.047	-	-	-	-	-	0.047
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.047	-	-	-	-	-	0.047
C080782	LNG - Exeter ESD System	Est Lvl (e.g. +/- 10%)	CapEx	-	0.116	-	-	-	-	-	0.116
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.116	-	-	-	-	-	0.116
C080783	LNG - Exeter Hi Ex Foam System	Est Lvl (e.g. +/- 10%)	CapEx	-	0.010	-	-	-	-	-	0.010
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.010	-	-	-	-	-	0.010
C079252	Gas System Reinforcement - Quaker Lane	Est Lvl (e.g. +/- 10%)	CapEx	-	1.300	-	-	-	-	-	1.300
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	1.300	-	-	-	-	-	1.300
Total Project Sanction			CapEx	-	1.643	-	-	-	-	-	1.643
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	1.643	-	-	-	-	-	1.643

4.4 Project Budget Summary Table

Short Form Sanction Paper nationalgrid

Project Costs per Business Plan

$M		Current Planning Horizon ($M) Yr. 1 2018/19	Yr. 2 2019/20	Yr. 3 2020/21	Yr. 4 2021/22	Yr. 5 2022/23	Yr. 6 + 2023/24	Total
CapEx		1.300	0.000	0.000	0.000	0.000	0.000	1.300
OpEx		0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal		0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan		1.300	0.000	0.000	0.000	0.000	0.000	1.300

Variance **(Business Plan-Project Estimate)**

$M		Current Planning Horizon ($M) Yr. 1 2018/19	Yr. 2 2019/20	Yr. 3 2020/21	Yr. 4 2021/22	Yr. 5 2022/23	Yr. 6 + 2023/24	Total
CapEx		(0.343)	0.000	0.000	0.000	0.000	0.000	(0.343)
OpEx		0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal		0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan		(0.343)	0.000	0.000	0.000	0.000	0.000	(0.343)

5 Key Milestones

Milestone	Target Date: (Month/Year)
Project Sanction	June 2018
Completion	May 2019
Project Closure Paper	June 2019

6 Climate Change

N/A - Impact to climate will be determined during each individual full project sanction.

7 Statements of Support

7.1.1 Supporters

The supporters listed have aligned their part of the business to support the development of these projects.

Role	Individual	Responsibilities
Investment Planner	Phillip Quan	Endorses relative to 5-year business plan or emergent work
Resource Planning	Laeyeng Hunt	Endorses Resources, cost estimate, schedule, and

		Portfolio Alignment
Project Management	Bradley Wheeler	Endorses Resources, cost estimate, schedule
Project Controls & Estimation	Michael Chin	Endorses Cost Estimate

7.1.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Reviewer List	**Individual**
Finance	Felicia Midkiff
Regulatory	Ed Turieo
Jurisdictional Delegate	John Currie
Procurement	Diego Chevere
Control Center	Paul Loiacono

7.1.3 List References

N/A

Short Form Sanction Paper nationalgrid

8 Decisions

I:

(a) APPROVE this paper and the investment of $1.643M and a tolerance of +/-10%

(b) NOTE that William Foley is the Project Manager and has the approved financial delegation.

Signature......D. H. Campbell......Date 7/3/18.....
David H. Campbell, Vice President ServCo Business Partnering, USSC Chair

Short Form Sanction Paper

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9 Other Appendices

Re-sanction Request

nationalgrid

Title:	FY19 Annual Project Development – RI Gas	**Sanction Paper #:**	USSC-18-243 v2
Project #:	See Below – Summary of Projects	**Sanction Type:**	Re-sanction
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	11/6/2018
Author:	William Foley	**Sponsor:**	John Stavrakas, VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	William Foley

1 *Executive Summary*

This paper requests re-sanction of the FY19 Annual Project Development – RI Gas blanket in the amount of $6.343M with a tolerance of +/- 10% for the purposes of purchase of long lead materials, the pursuit of permitting and land rights, and all other preliminary engineering activities.

This re-sanction amount is $6.343M broken down into:
$6.343M Capex
$0.000M Opex
$0.000M Removal

Note the originally requested sanction amount of $1.643M

2 *Resanction Details*

2.1 Project Summary

Project Development activities are required for projects in FY19 to support the existing The Narragansett Electric Company Investment Plan. The initial projects to be developed during FY19 are outlined in Section 2.2, Summary of Projects. Project Development activities are required for complex capital projects under the new Capital Delivery Process Model.

nationalgrid

Re-sanction Request

2.2 Summary of Projects

Project Number	Project Type (Elect only)	Project Title	Material Purchase	FY19 Project Development	Estimate Amount ($M)
CRCC204	Project type	CI Lining - Lining	0.000	0.000	0.170
C080795	Project type	Proj Name	0.000	0.000	0.047
C080782	Project type	LNG - Exeter High Ex Foam System	0.000	0.000	0.116
C080783	Project type	LNG - Exeter Hi Ex Foam System	0.000	0.000	0.010
C079252	Project type	Gas System Reinforcement - Quaker Lane	4.195	1.805	6.000
			Total		6.343

2.3 Prior Sanctioning History

Describe previous sanctions for the projects included in the scope of this paper (Newest to Oldest).

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Sanction Type	Sanction Paper #	Potential Investment Tolerance
6/26/2018	USSC	$1.643M	$1.643M	Sanction	USSC-18-243	+/- 10%

Over / Under Expenditure Analysis

Summary Analysis ($M)	Capex	Opex	Removal	Total
Resanction Amount	6.343	0.000	0.000	6.343
Latest Approval	1.643	0.000	0.000	1.643
Change*	4.700	0.000	0.000	4.700

Change = (Re-sanction – Amount Latest Approval)

2.4 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY19-FY23 Gas Capital Plan	○ Yes ⦿ No	⦿ Over ○ Under ○ N/A	6.343M

2.5 If cost > approved Business Plan how will this be funded?

Re-sanction Request

Re-allocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

2.6 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	Current Planning Horizon Yr. 1 2018/19	Yr. 2 2019/20	Yr. 3 2020/21	Yr. 4 2021/22	Yr. 5 2022/23	Yr. 6 + 2023/24	Total
CRCC204	CI Lining - Lining	10	CapEx	0.000	0.170	0.000	0.000	0.000	0.000	0.000	0.170
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.170	0.000	0.000	0.000	0.000	0.000	0.170
C080795	Proj Name	Holder 19 Rebuild	CapEx	0.000	0.047	0.000	0.000	0.000	0.000	0.000	0.047
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.047	0.000	0.000	0.000	0.000	0.000	0.047
C080782	LNG - Exeter High Ex Foam System	Est Lvl (e.g. +/- 10%)	CapEx	0.000	0.116	0.000	0.000	0.000	0.000	0.000	0.116
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.116	0.000	0.000	0.000	0.000	0.000	0.116
C080783	LNG - Exeter Hi Ex Foam System	Est Lvl (e.g. +/- 10%)	CapEx	0.000	0.010	0.000	0.000	0.000	0.000	0.000	0.010
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.010	0.000	0.000	0.000	0.000	0.000	0.010
C079252	Gas System Reinforcement - Quaker Lane	Est Lvl (e.g. +/- 10%)	CapEx	0.000	1.805	4.195	0.000	0.000	0.000	0.000	6.000
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	1.805	4.195	0.000	0.000	0.000	0.000	6.000
Total Project Sanction			CapEx	0.000	2.148	4.195	0.000	0.000	0.000	0.000	6.343
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	2.148	4.195	0.000	0.000	0.000	0.000	6.343

Re-sanction Request

nationalgrid

2.7 Project Budget Summary Table

Project Costs per Business Plan

		Current Planning Horizon ($M)						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
CapEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Variance **(Business Plan-Project Estimate)**

		Current Planning Horizon ($M)						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
CapEx	0.000	(6.343)	0.000	0.000	0.000	0.000	0.000	(6.343)
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	(6.343)	0.000	0.000	0.000	0.000	0.000	(6.343)

2.8 Drivers

2.8.1 Detailed Analysis Table

Detail Analysis	Over/Under Expenditure?	Amount (M's)
Material purchase commitment for Quaker Lane Reinforcement	☒ Over ☐ Under	5.643

2.8.2 Explanation of Key Variations

In order to meet the Company's anticipated construction timeline for the Quaker Lane Reinforcement (also known as Southern Rhode Island Gas Expansion) project, National Grid must commit to purchase approximately 12,000 linear feet of 20-inch steel pipe for delivery in early FY20. Additionally, valves, fittings, remote operated valves, and other miscellaneous material must be committed to in FY19. No additional costs will be incurred in FY19, however the Company is seeking the authorization to commit to the material purchase for FY20. The Company expects to submit the southern Rhode Island Gas Expansion project for a Project Sanction in early 2019.

2.9 Key Milestones

Milestone	Target Date: (Month/Year)
Project Sanction	June 2018
Re-sanction	November 2018
Project Closure Sanction	May 2019

2.10 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
May 2019	Project Closure Sanction

3 *Statements of Support*

3.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities
Investment Planner	Phillip Quan	Endorses relative to 5-year business plan or emergent work
Resource Planning	Laeyeng Hunt	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Bradley Wheeler	Endorses Resources, cost estimate, schedule
Project Controls & Estimation	Michael Chin	Endorses Cost Estimate

3.2 Reviewers

The reviewers have provided feedback on the content/language of the paper

Function	Individual
Finance	Felicia Midkiff
Regulatory	Ed Turieo
Jurisdictional Delegate	John Currie
Procurement	Diego Chevere
Control Center	Paul Loiacono

Re-sanction Request

Decisions

I:

(a) APPROVE this paper and the investment of $6.343M and a tolerance of +/-10%

(b) NOTE that William Foley is the Project Manager and has the approved financial delegation.

Signature……………Ch Vu……………Date……4/6/18……

David H. Campbell, Vice President ServCo Business Partnering, USSC Chair

Re-sanction Request

nationalgrid

4 Appendices

N/A

Short Form Sanction Paper

Title:	FY20 Annual Project Development – Narragansett Electric Co	**Sanction Paper #:**	USSC-19-089
Project #:	See Below – Summary of Projects	**Sanction Type:**	Sanction
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	2/19/2019
Author:	William Foley	**Sponsor:**	John Stavrakas, VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	William Foley

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction in the amount $2.972M for multiple projects with a tolerance of +/- 10% for the purposes of fiscal year 2020 (FY20) Stage 4.3 Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development of Stage 4.3 projects.

This sanction amount is $2.972M broken down into:
$2.972M Capex
$0.000M Opex
$0.000M Removal

This project has undergone a Capital Efficiency Review with the following determination:

Specific capital efficiencies will be identified in the individual project sanctions upon the completion of project scope development.

1.2 Project Summary

Project Development activities are required for projects in FY20 to support the existing Narragansett Electric Company Investment Plan. The initial list of projects to be developed during FY20 are outlined in Section 3.1, Summary of Projects. Stage 4.3 activities are required for these complex capital projects under the Capital Delivery Process Model.

Short Form Sanction Paper

2 Project Detail

2.1 Background

The Company has developed a standardized process for developing and delivering complex projects. In accordance with the Company's Capital Delivery Initiative, below is a list of the common activities that are authorized to take place, as needed, this fiscal year (FY):

- Assemble a cross functional project team to assist in the development of projects to define and approve specific scope;
- Conduct site specific investigative work (i.e. test holes, borings, vegetation evaluation, soil samples, etc.);
- Pursue permitting and land rights;
- Perform preliminary engineering and other related tasks;
- Procure materials (e.g. heater, etc.);
- Develop the Project Execution Plan (PEP) which includes items above as well as:
    - detailed cost estimate
    - risk register & mitigation plan
    - baseline schedule
    - resource strategy for final design and or project execution
    - contract strategy;
- PEP approval meeting;
- Complete Project Book 4.3 and Gate C Checklist;
- Gate C Approval Meeting

2.2 Drivers

N/A

2.3 Project Description

N/A

2.4 Benefits

The investment is expected to result in savings associated with robust vetting of project details to meet Asset Management needs. Project Development ensures representation from all necessary stakeholders and sign off on final scope before individual project sanctioning.

Additionally, Project Development activities reduces future budgetary risk. Project Development creates a Risk Register to identify and quantify project risk. The output of 4.3 is a risk-assessed, detailed estimate used for individual project sanctioning.

Any project-level benefits will be identified during the individual project sanctions.

2.5 *Business & Customer Issues*

N/A

2.6 *Alternatives*

Each project listed in Section 3.1 will have progressed through Stage 4.2 Options Analysis and these individual project options will be discussed during the individual full project sanctions at the end of Stage 4.3. For the purposes of this group project development, the alternatives are listed below:

Alternative 1: Process partial sanction papers on an individual project basis to obtain enough Delegation of Authority (DOA) to progress the project through final design.

This alternative was not chosen because approving these development costs in one sanction is more efficient than going through multiple individual partial sanctions.

2.7 *Investment Recovery*

Investment recovery will be through standard rate recovery mechanisms for each project.

2.7.1 Customer Impact

The first full year revenue requirement, for each of the projects listed in Section 3.1, will be determined during the individual project sanctions.

3 <u>Related Projects, Scoring, Budgets</u>

3.1 *Summary of Projects*

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Project Number	Project Title	Estimate Amount ($M)
C081157	Atwells Avenue	0.200
C078561	Allens Ave Seawall	1.000
C082835	LNG - Old Mill Lane Permanent Portable Site	0.200
C080795	Holder 19 Rebuild	0.300
C080782	LNG - Exeter AESD System	0.472
C072346	Kenyon Indistries	0.100
C082302	Southern RI Station Upgrades	0.400
C081906	Southern RI New Regulator Station	0.100
C081907	MOP Increase from 150 to 200 PSI	0.200
	TOTAL	2.972

3.2 *Associated Projects*

N/A

3.3 *Prior Sanctioning History*

N/A

3.4 *Category*

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ○ Policy- Driven ○ Justified NPV ⦿ Other	The Capital Delivery Initiative has been established and approved to standardize the process for delivering projects in accordance with the Business Management Systems.

3.5 *Asset Management Risk Score*

Asset Management Risk Score: 35

Primary Risk Score Driver: (Policy Driven Projects Only)

○ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven ● Mixed

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3.6 _Complexity Level_

○ High Complexity ⦿ Medium Complexity ○ Low Complexity ○ N/A

Complexity Score: 21

3.7 _Next Planned Sanction Review_

Date (Month/Year)	Purpose of Sanction Review
June 2020	Project Closure Sanction

4 _Financial_

4.1 _Business Plan_

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY20-24 Gas Capital Plan	⦿ Yes ○ No	○ Over ○ Under ⦿ NA	$0.000

4.1.1 If cost > approved Business Plan how will this be funded?

4.2 _CIAC / Reimbursement_

N/A

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Short Form Sanction Paper

4.3 *Cost Summary Table*

Project Number	Project Title	Project Estimate Level (%)	Spend	Prior Yrs	Current Planning Horizon ($M) Yr. 1 2019/20	Yr. 2 2020/21	Yr. 3 2021/22	Yr. 4 2022/23	Yr. 5 2023/24	Yr. 6 + 2024/25	Total
C081157	Atwells Avenue	+/-10%	CapEx	-	0.200	-	-	-	-	-	0.200
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.200	-	-	-	-	-	0.200
C078561	Allens Ave Seawall	+/-10%	CapEx	-	1.000	-	-	-	-	-	1.000
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	1.000	-	-	-	-	-	1.000
C082835	LNG - Old Mill Lane Permanent Portable Site	+/-10%	CapEx	-	0.200	-	-	-	-	-	0.200
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.200	-	-	-	-	-	0.200
C080795	Holder 19 Rebuild	+/-10%	CapEx	-	0.300	-	-	-	-	-	0.300
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.300	-	-	-	-	-	0.300
C080782	LNG - Exeter AESD System	+/-10%	CapEx	-	0.472	-	-	-	-	-	0.472
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.472	-	-	-	-	-	0.472
C072346	Kenyon Indistries	+/-10%	CapEx	-	0.100	-	-	-	-	-	0.100
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.100	-	-	-	-	-	0.100
C082302	Southern RI Station Upgrades	+/-10%	CapEx	-	0.400	-	-	-	-	-	0.400
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.400	-	-	-	-	-	0.400
C081906	Southern RI New Regulator Station	+/-10%	CapEx	-	0.100	-	-	-	-	-	0.100
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.100	-	-	-	-	-	0.100
C081907	MOP Increase from 150 to 200 PSI	+/-10%	CapEx	-	0.200	-	-	-	-	-	0.200
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	0.200	-	-	-	-	-	0.200
Total Project Sanction			CapEx	-	2.972	-	-	-	-	-	2.972
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	2.972	-	-	-	-	-	2.972

Short Form Sanction Paper nationalgrid

4.4 ***Project Budget Summary Table***

Project Costs per Business Plan

		Current Planning Horizon ($M)						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
CapEx	0.000	2.972	0.000	0.000	0.000	0.000	0.000	2.972
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	2.972	0.000	0.000	0.000	0.000	0.000	2.972

Variance (Business Plan-Project Estimate)

		Current Planning Horizon ($M)						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
CapEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

5 ***Key Milestones***

Milestone	Target Date: (Month/Year)
Project Sanction	February 2019
Start Preliminary Engineering	April 2019
Preliminary Engineering Complete	March 2020
Project Closure Sanction	June 2020

6 ***Climate Change***

N/A

Impact to climate will be determined during each individual project sanction.

7 ***Statements of Support***

7.1.1 *Supporters*

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities
Investment Planner	Quan, Philip	Endorses relative to 5-year business plan or emergent work
Resource Planning	Millen, John	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Wheeler, Bradley	Endorses Resources, cost estimate, schedule
LNG	Sullivan, Kathleen	Endorses scope, design, conformance with design standards for LNG projects.
Gas Project Estimation	Duffy, John	Endorses Cost Estimate

7.1.2 *Reviewers*

The reviewers have provided feedback on the content/language of the paper.

Function	Individual
Finance	Attard, Jason
Regulator	Turieo, Ed
Jurisdictional Delegate	Currie, John
Procurement	Chevere, Diego
Control Center	Loiacono, Paul

7.1.3 *List References*

N/A

Short Form Sanction Paper

8 Decisions

I:

(a) APPROVE this paper and the investment of $2.972M and a tolerance of +/-10%

(b) NOTE that William Foley is the Project Manager and has the approved financial delegation.

Signature........DLH Campbell...................Date..3/13/19...
David H. Campbell, Vice President ServCo Business Partnering, USSC Chair

Short Form Sanction Paper

9 Other Appendices

9.1 *Sanction Request Breakdown by Project*

N/A

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Resanction: US Sanction Paper

Title:	FY20 Annual Project Development – RI Resanction	Sanction Paper #:	USSC-19-089 v2
Project #:	Multiple - see below- Summary of Projects	Sanction Type:	Resanction
Operating Company:	The Narragansett Electric Co.	Date of Request:	5/28/2019
Author:	Foley, William	Sponsor:	Bennett, Thomas E. VP Gas Asset Mgmt
Utility Service:	Gas	Project Manager:	Foley, William

Executive Summary

This paper requests Resanction of Multiple - see below- Summary of Projects in the amount of $6.804M with a tolerance of +/-10% for the purposes of fiscal year 2020 (FY20) Stage 4.3 Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development of Stage 4.3 projects..

This sanction amount is $6.804M broken down into:

$6.804M Capex
$0.000M Opex
$0.000M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

Note the originally requested sanction amount of $2.972M.

Project Summary

Project Development activities are required for projects in FY20 to support the existing Narragansett Electric Company Investment Plan. The initial list of projects to be developed during FY20 are outlined in Section 3.1, Summary of Projects. Stage 4.3 activities are required for these complex capital projects under the Capital Delivery Process Model.

Related Projects, Scoring and Budget

Summary of Projects

Project Number	*Project Type* (Elec only)	*Project Title*	*Estimate Amount($M)*

C081157	Atwells Avenue	0.300
C078561	Allens Ave Seawall	1.000
C082835	LNG - Old Mill Lane Permanent Portable Site	0.200
C080795	Holder 19 Rebuild	0.300
C080782	LNG - Exeter AESD System	0.472
C082302	Southern RI Station Upgrades	0.491
C081906	Southern RI New Regulator Station	0.491
C081907	MOP Increase from 150 to 200 PSI	3.550
	Total:	6.804

Prior Sanctioning History

Date	*Governance Body*	*Sanctioned Amount*	*Potential Project Investment*	*Sanction Type*	*Sanction Paper*	*Potential Investment Tolerance*
2/19/2019	USSC	$2.972	$2.972	Sanction	USSC-019-089	10%

Over / Under Expenditure Analysis

Summary Analysis	Capex	Opex	Removal	Total
Resanction Amount	6.804	0.000	0.000	6.804
Latest Approval	2.972	0.000	0.000	2.972
Change	3.832	0.000	0.000	3.832

Key Milestones

Milestone	*Date (Month / Year)*
Project Sanction	February, 2019
Start Preliminary Engineering	April, 2019
Re-sanction	May, 2019
Preliminary Engineering Complete	March, 2020
Project Closure Sanction	June, 2020

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
June, 2020	Closure

Business Plan

Business Plan Name & Period	*Project Included in approved Business Plan?*	*Over / Under Business Plan*	*Project Cost relative to approved Business Plan ($M)*

FY20-24 Gas Capital Plan	(●) Yes ( ) No	(●) Over ( ) Under ( ) N/A	(3.832)

If Cost > Approved

if costs > approved Business Plan how will this be funded?

Re-Allocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

Drivers

The list of projects contained in this document are part of the FY20 Rhode Island ISR filing. Completion of the development of these projects is required to maintain our safety and reliability targets in the Rhode Island Jurisdiction.

Detailed Analysis Table

Detail Analysis	*Over/Under Expenditure?*	*Amount (M's)*
Additional activities performed during 4.3	(●) Over ( ) Under	3.868

Explanation of Key Variations

Three key projects are driving the variation -- MOP Increase from 150 to 200 PSI, Southern RI New Regulator Station, and Southern RI Station Upgrades. In all three cases, activities that were initially expected to occur after Final Sanction have been accelerated in order to further develop the project prior to a project level sanction. These activities include test holes, material verification and inspection, and survey work.

Cost Summary Table

Project Number	C081157	Project Title	Atwells Avenue	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.300	0.000	0.000	0.000	0.000	0.000	0.300
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.300	0.000	0.000	0.000	0.000	0.000	0.300

Project Number	C078561	Project Title	Allens Ave Seawall	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000

Project Number	C082835	Project Title	LNG - Old Mill Lane Permanent Portable Site	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200

Project Number	C080795	Project Title	Holder 19 Rebuild	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.300	0.000	0.000	0.000	0.000	0.000	0.300
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.300	0.000	0.000	0.000	0.000	0.000	0.300

Project Number	C080782	Project Title	LNG - Exeter AESD System	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.472	0.000	0.000	0.000	0.000	0.000	0.472
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.472	0.000	0.000	0.000	0.000	0.000	0.472

Project Number	C082302	Project Title	Southern RI Station Upgrades	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.491	0.000	0.000	0.000	0.000	0.000	0.491
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.491	0.000	0.000	0.000	0.000	0.000	0.491

Project Number	C081906	Project Title	Southern RI New Regulator Station	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	0.491	0.000	0.000	0.000	0.000	0.000	0.491
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.491	0.000	0.000	0.000	0.000	0.000	0.491

Project Number	C081907	Project Title	MOP Increase from 150 to 200 PSI	Project Estimate Level	+/-10 %

Spend	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	3.550	0.000	0.000	0.000	0.000	0.000	3.550
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	3.550	0.000	0.000	0.000	0.000	0.000	3.550

Total Project Sanction								
Capex	0.000	6.804	0.000	0.000	0.000	0.000	0.000	6.804
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	6.804	0.000	0.000	0.000	0.000	0.000	6.804

Project Costs per Business Plan

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	2.972	0.000	0.000	0.000	0.000	0.000	2.972
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	2.972	0.000	0.000	0.000	0.000	0.000	2.972

Variance

$M	Prior Yrs	Yr 1 2020	Yr 2 2021	Yr 3 2022	Yr 4 2023	Yr 5 2024	Yr 6 2025	Total
Capex	0.000	(3.832)	0.000	0.000	0.000	0.000	0.000	(3.832)
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	(3.832)	0.000	0.000	0.000	0.000	0.000	(3.832)

Statement of Support

Department	*Individual*	*Responsibilities*
Investment Planner	Quan, Philip	Endorses relative to 5-year business plan or emergent work
Resource Planning	Hunt, Laeyeng	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule
Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers	
Function	***Individual***
Finance	Attard, Jason V.
Regulatory	Turieo, Edward
Jurisdictional Delegate	Smith, Amy S.
Procurement	Chevere, Diego
Control Center	Loiacono, Paul A.

Decisions

I:

(a) APPROVE the investment of $6.804M and a tolerance of +/-10% for fiscal year 2020 (FY20) Stage 4.3 Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development of Stage 4.3 projects..

(b) NOTED that Foley, William has the approved financial delegation

Signature DHCampbell

Date 7/19/19

David H. Campbell, Vice President US Treasury, USSC Chair

Appendix

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Project Development: US Sanction Paper

Title:	FY21 PD Sanction - RI	Sanction Paper #:	USSC-20-146
Project #: C55 Invst Code:	Multiple Projects Various	Sanction Type:	Project Development
Operating Company:	The Narragansett Electric Company	Date of Request:	3/19/2020
Author:	Foley, William	Sponsor(s):	Bennett, Thomas E. VP Gas Asset Mgmt
Utility Service:	Gas	Project Manager:	Foley, William

Executive Summary

This paper requests Project Development of Multiple Projects in the amount of $7.240M with a tolerance of +/-10% for the purposes of fiscal year 2021 (FY21) Stage 4.3 Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development of Stage 4.3 projects.

This sanction amount is $7.240M broken down into:
$7.240M Capex
$0.000M Opex
$0.000M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

Specific capital efficiencies will be identified in the individual project sanctions upon the completion of project scope development.

Project Summary

Project Development activities are required for projects in FY21 to support the existing Narragansett Electric Company Investment Plan. The initial list of projects to be developed during FY21 are outlined in the Cost Summary Table. Stage 4.3 activities are required for these complex capital projects under the Network Development Process Model.

Background

The Company has developed a standardized process for developing and delivering complex projects. In accordance with the Company's Capital Delivery Initiative, below is a list of the common activities that are authorized to take place, as needed, this fiscal year (FY):

- Assemble a cross functional project team to assist in the development of projects to define and

approve specific scope
- Conduct site specific investigative work (i.e. test holes, borings, vegetation evaluation, soil samples, etc.);
- Pursue permitting and land rights;
- Perform preliminary engineering and other related tasks;
- Procure Materials
- Develop Project Execution Plan (PEP) which includes items above as well as:
  - Detailed cost estimate
  - Risk register and mitigation plan
  - Baseline schedule
  - Resource strategy for final design and project execution
  - Contract strategy
- PEP approval meeting
- Complete Project Book 4.3 and Gate C Checklist
- Gate C Approval Meeting

Project Description

Upon Gate B approval, projects included in the paper will proceed with individual development activities as outlined above.

Summary of Benefits

A single authorization for projects in development provides the flexibility to quickly move projects forward into preliminary engineering and respond to work plan needs over the course of the fiscal year.

Business and Customer Issues

There are no significant business or customer issues beyond what has been described elsewhere.
Due to the current COVID-19 Pandemic, National Grid's ability to deliver this project/program/blanket may be at risk. We will continue to evaluate based on rapidly evolving conditions and take appropriate actions as needed.

Drivers:

Each project listed in in summary of projects will have progressed through Needs Case and Options Analysis and the individual project drivers will be discussed during the individual full project sanctions at the end of Development.

Alternatives

Number	*Title*
1	Process partial sanction papers on an individual project basis to obtain enough Delegation of Authority (DOA) to progress the project through final design. This alternative was not chosen because approving these development costs in one sanction is more efficient than going through multiple individual partial sanctions.

Related Projects, Scoring and Budget

Summary of Projects

Project Number	*Proj. Type* (Elec only)	*Project Title*	*PS&I Transfer*	*Material Purchase*	*FY21 Project Development*	*Estimate Amount*

C085231	Heater Installation Program - Dey St GS	0.000	0.225	0.225
C078561	Allens Ave Seawall	0.000	1.000	1.000
C084666	LNG - Cumberland Tank Replacement	0.000	0.190	0.190
C080782	LNG - Exeter AESD System	0.000	0.285	2.850
C079870	LNG - Exeter Boiloff Compressor 2 Upgrade	1.500	0.400	1.900
C083909	LNG - Exeter Fire Alarm Upgrade	0.000	0.475	0.475
C080783	LNG - Exeter High Ex Foam System	0.000	0.350	0.350
C085232	Heater Installation Program - Smithfield GS	0.000	0.000	0.000
C085181	Cowesett Reg Station	0.000	0.000	0.000
C082302	Cranston Take Station	0.000	0.000	0.000
C081907	GrowthPoint – Return of Cranston Line to 200 psig MOP	0.000	0.000	0.000
C081906	Reg Station/Launcher-Receiver/Install ROV	0.000	0.000	0.000
C078188	CI Lining – Blackstone St, PVD	0.000	0.250	0.250
C078189	Petteys Av, PVD (WO 90000184270)	0.000	0.000	0.000
C078190	Russell St, PVD (WO 90000184267)	0.000	0.000	0.000
			Total	7.240

Associated Projects - N/A

Prior Sanctioning History - N/A

Key Milestones

Milestone	*Date (Month / Year)*
Sanction	March, 2020
Start Preliminary Engineering	April, 2020
Preliminary Engineering Complete	March, 2021
Project Closure Sanction	July, 2021

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review

July, 2021	Closure

Category

Category

- (●) Mandatory
- ( ) Policy-Driven
- ( ) Justified NPV

Reference to Mandate, Policy, or NPV

Capital Project Development costs may support the delivery of projects from all capital categories

Asset Management Risk Score: 35

PRIMARY RISK SCORE DRIVER

( ) Reliability ( ) Environment ( ) Health & Safety ( ) Not Policy Driven
(●) Mixed

Complexity Level: 21

( ) High Complexity (●) Medium Complexity ( ) Low Complexity ( ) N/A

Net Zero

Contribution to National Grid's 2050 80% emissions reduction target:	(●) Neutral	( ) Positive	( ) Negative
Impact on adaptability of network for future climate change:	(●) Neutral	( ) Positive	( ) Negative
Qualifies for Green Financing:	( ) Yes	( ) No	(●) N/A

Investment Recovery and Customer Impact

Investment Recovery

Investment recovery will be through standard rate recovery mechanisms for each project.

Customer Impact

The first full year revenue requirement for each of the projects below will be determined during the individual project sanctions.

Business Plan

Business Plan Name & Period (BP 19)	***Project Included in approved Business Plan?***	***(Over) / Under Business Plan***	***Project Cost relative to approved Business Plan ($M)***
FY21 - FY25 Gas Capital Plan	(●) Yes ( ) No	( ) Over ( ) Under (●) N/A	0.000

If Cost > Approved

if costs > approved Business Plan how will this be funded?

N/A

Cost Summary Table

Project Number	C085231	Project Title	Heater Installation Program - Dey St GS	Project Estimate Level	+/-10%			
Spend	**Prior Yrs**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**Total**
Capex	0.000	0.225	0.000	0.000	0.000	0.000	0.000	0.225
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.225	0.000	0.000	0.000	0.000	0.000	0.225

Project Number	C078561	Project Title	Allens Ave Seawall	Project Estimate Level	+/-10%			
Spend	**Prior Yrs**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**Total**
Capex	0.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000

Project Number	C084666	Project Title	LNG - Cumberland Tank Replacement	Project Estimate Level	+/-10%			
Spend	**Prior Yrs**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**Total**
Capex	0.000	0.190	0.000	0.000	0.000	0.000	0.000	0.190
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.190	0.000	0.000	0.000	0.000	0.000	0.190

Project Number	C080782	Project Title	LNG - Exeter AESD System	Project Estimate Level	+/-10%			
Spend	**Prior Yrs**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**Total**
Capex	0.000	2.850	0.000	0.000	0.000	0.000	0.000	2.850
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	2.850	0.000	0.000	0.000	0.000	0.000	2.850

Project Number	C079870	Project Title	LNG - Exeter Boiloff Compressor 2 Upgrade	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	1.900	0.000	0.000	0.000	0.000	0.000	1.900
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	1.900	0.000	0.000	0.000	0.000	0.000	1.900

Project Number	C083909	Project Title	LNG - Exeter Fire Alarm Upgrade	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.475	0.000	0.000	0.000	0.000	0.000	0.475
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.475	0.000	0.000	0.000	0.000	0.000	0.475

Project Number	C080783	Project Title	LNG - Exeter High Ex Foam System	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.350	0.000	0.000	0.000	0.000	0.000	0.350
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.350	0.000	0.000	0.000	0.000	0.000	0.350

Project Number	C085232	Project Title	Heater Installation Program - Smithfield GS	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C085181	Project Title	Cowesett Reg Station	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C082302	Project Title	Cranston Take Station	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C081907	Project Title	GrowthPoint – Return of Cranston Line to 200 psig MOP	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C081906	Project Title	Reg Station/Launcher-Receiver/Install ROV	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C078188	Project Title	CI Lining – Blackstone St, PVD	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250

Project Number	C078189	Project Title	Petteys Av, PVD (WO 90000184270)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total

Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Project Number	C078190	Project Title	Russell St, PVD (WO 90000184267)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Total Project Sanction

Capex	0.000	7.240	0.000	0.000	0.000	0.000	0.000	7.240
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	7.240	0.000	0.000	0.000	0.000	0.000	7.240

Project Costs per Business Plan

$M	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	7.240	0.000	0.000	0.000	0.000	0.000	7.240
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	7.240	0.000	0.000	0.000	0.000	0.000	7.240

Variance

$M	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Statement of Support

Department	***Individual***	***Responsibilities***
Investment Planner	Eddleston, Stephanie	Endorses relative to 5-year business plan or emergent work
Resource Planning	LaFond, Phil	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule
Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers

Function	***Individual***
Finance	McConnachie, Christopher / Pfeifer, Carson
Regulatory	Azarcon, Carolyn
Jurisdictional Delegate	Schmid, Randy
Procurement	Chevere, Diego
Control Center	Loiacono, Paul J.

Decisions

I:

(a) APPROVE the investment of $7.240M and a tolerance of +/-10% for fiscal year 2021 (FY21) Stage 4.3 Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development of Stage 4.3 projects.

(b) NOTED that Foley, William has the approved financial delegation

DocuSigned by:
Signature Christine McClure
957B264AFE26466...

Date 4/28/2020

Christine McClure, Vice President, Finance Business Partner Service Company, USSC Chair

Appendix

N/A

nationalgrid

Project Development: US Sanction Paper

Title:	FY22 Project Development Sanction - RI	Sanction Paper #:	USSC-21-102
Project #: C55 Invst Code:	Multiple Projects (see below) Multiple	Sanction Type:	Project Development
Operating Company:	The Narragansett Electric Company	Date of Request:	3/2/2021
Author:	Foley, William	Sponsor(s):	Bennett, Thomas E. VP Gas Asset Mgmt
Utility Service:	Gas	Project Manager:	Foley, William

Executive Summary

This paper requests Project Development of Multiple Projects (see below) in the amount of $7.900M with a tolerance of +/-10% for the purposes of fiscal year 2022 (FY22) Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development Network Development Process projects.

This sanction amount is $7.900M broken down into:

$7.900M Capex
$0.000M Opex
$0.000M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

Specific capital efficiencies will be identified in the individual project sanctions upon the completion of project scope development.

Project Summary

Project Development activities are required for projects in FY22 to support the existing Narragansett Electric Company Investment Plan. The initial list of projects to be developed during FY22 are outlined in Section 3.1, Summary of Projects. Stage 4.3 activities are required for these complex capital projects under the Network Development Process.

Background

The Company has developed a standardized process for developing and delivering complex projects. In accordance with the Company's Capital Delivery Initiative, below is a list of the common activities that are authorized to take place, as needed, this fiscal year (FY):

- Assemble a cross functional project team to assist in the development of projects to define and approve specific scope
- Conduct site specific investigative work (i.e. test holes, borings, vegetation evaluation, soil samples,

etc.);
- Pursue permitting and land rights;
- Perform preliminary engineering and other related tasks;
- Procure Materials
- Develop Project Execution Plan (PEP) which includes items above as well as:
  - Detailed cost estimate
  - Risk register and mitigation plan
  - Baseline schedule
  - Resource strategy for final design and project execution
  - Contract strategy
- PEP approval meeting
- Complete Project Book 4.3 and Gate C Checklist
- Gate C Approval Meeting

Project Description

Upon Gate B approval, projects included in the paper will proceed with individual development activities as outlined above.

Summary of Benefits

The investment is expected to result in savings associated with robust vetting of project details to meet Asset Management needs. Project Development ensures representation from all necessary stakeholders and sign off on final scope before individual project sanctioning.

Additionally, Project Development activities reduces future budgetary risk. Project Development creates a Risk Register to identify and quantify project risk. The output of 4.3 is a risk-assessed, detailed estimate used for individual project sanctioning.

Business and Customer Issues

Due to the COVID-19 pandemic, the Company's ability to deliver this project/program/blanket may be at risk. The project(s) within this paper as well as the entire jurisdictional portfolio will continue to be evaluated each month through the Company's current control procedures and, if necessary, special actions will be taken to reevaluate their viability for the current fiscal year.

Drivers:

Each project listed in in summary of projects will have progressed through Needs Case and Options Analysis and the individual project drivers will be discussed during the individual full project sanctions at the end of Development.

Alternatives

Number	***Title***
1	Process partial sanction papers on an individual project basis to obtain enough Delegation of Authority (DOA) to progress the project through final design. This alternative was not chosen because approving these development costs in one sanction is more efficient than going through multiple individual partial sanctions. (Not Recommended)

Related Projects, Scoring and Budget

Summary of Projects

Project Number	***Proj. Type*** (Elec only)	***Project Title***	***PS&I Transfer***	***Material Purchase***	***FY22 Project Development***	***Estimate Amount***

C078188	CI Lining - 5212-Blackstone St, Lining – PVD	0.000	0.025	0.225	0.250
C078189	CI Lining - 5213-Petteys St, Lining – PVD	0.000	0.025	0.125	0.150
C078190	CI Lining - 5214-Russell St, Lining – PVD	0.000	0.025	0.125	0.150
C082302	Gas Planning - LTRI - Growthpoint - New Regulator Station	0.000	0.000	0.250	0.250
C082302	Gas Planning - LTRI - Growthpoint - New Regulator Station Near Cowesett	0.000	0.000	0.250	0.250
C085181	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	0.000	0.000	0.500	0.500
C082302	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cranston	0.000	0.000	0.200	0.200
C081906	Gas Planning - Reg Station/Launcher - Receiver/Install ROV	0.000	0.000	0.500	0.500
C086394	Gas Planning - Aquidneck Island Portable LNG Relocation - New Regulator Station (Old Mil Lane)	0.000	0.000	0.200	0.200
C086393	Gas Planning - Aquidneck Island Portable LNG Relocation - Main Installation (Old Mill Lane)	0.000	0.000	0.500	0.500
C086399	Gas Planning - Aquidneck Island Portable LNG Relocation - Portable LNG Equipment & Site Prep (Old Mill Lane)	0.000	0.000	1.500	1.500
C085232	Heater Installation Program - Smithfield GS	0.000	0.000	0.250	0.250
C084666	LNG - Cumberland Tank Replacement	0.000	0.000	0.500	0.500
C080782	LNG - Exeter AESD System	0.000	0.100	0.250	0.350
C079870	LNG - Exeter Boiloff Compressor 2 Upgrade	0.000	1.000	0.300	1.300

C079174	Transmission Station Integrity -Scott Road Take Station (Cumberland)	0.000	0.000	0.500	0.500
C080783	LNG - Exeter Hi Ex Foam System	0.000	0.200	0.350	0.550
				Total	7.900

Associated Projects - N/A

Prior Sanctioning History - N/A

Key Milestones

Milestone	***Date (Month / Year)***
Project Development Sanction	March 2021
Start Preliminary Engineering	April 2021
Preliminary Engineering Complete	March 2022
Project Closure Sanction	July 2022

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
July 2022	Closure

Category

Category	Reference to Mandate, Policy, or NPV
○ Mandatory ○ Policy-Driven ○ Justified NPV	Capital Project Development costs may support the delivery of projects from all capital categories.

Asset Management Risk Score: 35

PRIMARY RISK SCORE DRIVER

○ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven
◉ Mixed

Complexity Level: 21

○ High Complexity ◉ Medium Complexity ○ Low Complexity ○ N/A

Net Zero

Contribution to National Grid's 2050 80% emissions reduction target:	◉ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	◉ Neutral	○ Positive	○ Negative

Qualifies for Green Financing: ○ Yes ○ No ◉ N/A

Note: Impact to climate will be determined during each individual project sanction.

Investment Recovery and Customer Impact

Investment Recovery

Recovery will occur at the time of the next rate case for any operating company receiving allocations of these costs.

Customer Impact

The first full year revenue requirement for each of the projects below will be determined during the individual project sanctions.

Business Plan

Business Plan Name & Period (BP 20)	***Project Included in approved Business Plan?***	***(Over) / Under Business Plan***	***Project Cost relative to approved Business Plan ($M)***
FY22 - FY26 Gas Capital Plan	◉ Yes ○ No	○ Over ○ Under ◉ N/A	0.000

If Cost > Approved

if costs > approved Business Plan how will this be funded?

N/A

Cost Summary Table

Project Number	C078188	Project Title	CI Lining - 5212- Blackstone St, Lining – PVD	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250

Project Number	C078189	Project Title	CI Lining - 5213- Petteys St, Lining – PVD	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.150	0.000	0.000	0.000	0.000	0.000	0.150
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total								

	0.000	0.150	0.000	0.000	0.000	0.000	0.000	0.150

Project Number	C078190	Project Title	CI Lining - 5214- Russell St, Lining – PVD	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.150	0.000	0.000	0.000	0.000	0.000	0.150
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.150	0.000	0.000	0.000	0.000	0.000	0.150

Project Number	C082302	Project Title	Gas Planning - LTRI - Growthpoint - New Regulator Station	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250

Project Number	C082302	Project Title	Gas Planning - LTRI - Growthpoint - New Regulator Station Near Cowesett	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250

Project Number	C085181	Project Title	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500

Project Number	C082302	Project Title	Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cranston	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200

Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200

Project Number	C081906	Project Title	Gas Planning - Reg Station/Launcher - Receiver/Install ROV	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500

Project Number	C086394	Project Title	Gas Planning - Aquidneck Island Portable LNG Relocation - New Regulator Station (Old Mil Lane)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.200	0.000	0.000	0.000	0.000	0.000	0.200

Project Number	C086393	Project Title	Gas Planning - Aquidneck Island Portable LNG Relocation - Main Installation (Old Mill Lane)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500

Project Number	C086399	Project Title	Gas Planning - Aquidneck Island Portable LNG Relocation - Portable LNG Equipment & Site Prep (Old Mill Lane)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	1.500	0.000	0.000	0.000	0.000	0.000	1.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	1.500	0.000	0.000	0.000	0.000	0.000	1.500

Project Number	C085232	Project Title	Heater Installation Program - Smithfield GS	Project Estimate Level	+/-10%

		FY	FY	FY	FY	FY	FY	

Spend	Prior Yrs	2022	2023	2024	2025	2026	2027	Total
Capex	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.250	0.000	0.000	0.000	0.000	0.000	0.250

Project Number	C084666	Project Title	LNG - Cumberland Tank Replacement	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500

Project Number	C080782	Project Title	LNG - Exeter AESD System	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.350	0.000	0.000	0.000	0.000	0.000	0.350
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.350	0.000	0.000	0.000	0.000	0.000	0.350

Project Number	C079870	Project Title	LNG - Exeter Boiloff Compressor 2 Upgrade	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	1.300	0.000	0.000	0.000	0.000	0.000	1.300
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	1.300	0.000	0.000	0.000	0.000	0.000	1.300

Project Number	C079174	Project Title	Transmission Station Integrity -Scott Road Take Station (Cumberland)	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.500	0.000	0.000	0.000	0.000	0.000	0.500

Project Project Project

Number	C080783	Title	LNG - Exeter Hi Ex Foam System	Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.550	0.000	0.000	0.000	0.000	0.000	0.550
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.550	0.000	0.000	0.000	0.000	0.000	0.550

Total Project Sanction

Capex	0.000	7.900	0.000	0.000	0.000	0.000	0.000	7.900
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	7.900	0.000	0.000	0.000	0.000	0.000	7.900

Project Costs per Business Plan

$M	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	7.900	0.000	0.000	0.000	0.000	0.000	7.900
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	7.900	0.000	0.000	0.000	0.000	0.000	7.900

Variance

$M	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Statement of Support

Department	***Individual***	***Responsibilities***
Investment Planner	Eddleston, Stephanie	Endorses relative to 5-year business plan or emergent work
Resource Planning	LaFond, Phil	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule

Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers

Function	***Individual***
Finance	McConnachie, Christopher / Pfeifer, Carson
Regulatory	Azarcon, Carolyn; Long, James
Jurisdictional Delegate	Schmid, Randy
Procurement	Chevere, Diego
Control Center	Loiacono, Paul J.

Decisions

I:

(a) APPROVE the investment of $7.900M and a tolerance of +/-10% for fiscal year 2022 (FY22) Project Development, which includes preliminary engineering activities, permitting, pursuit of land rights, long lead materials, and all other activities related to the design and development Network Development Process projects.

(b) NOTED that Foley, William has the approved financial delegation

DocuSigned by:
Mike Gillespie
09F411044CFF47A...

Signature ______________________________

3/5/2021

Date ______________________________

Michael Gillespie, Vice President, Head of Finance Business Partnering, USSC Chair

Appendix

Project
CI Lining - 5212- Blackstone St, Lining – PVD
CI Lining - 5213- Petteys St, Lining – PVD
CI Lining - 5214- Russell St, Lining – PVD
LNG - Cumberland Tank Replacement
LNG - Exeter AESD System
LNG - Exeter Boiloff Compressor 2 Upgrade
Gas Planning - LTRI - Growthpoint - New Regulator Station Near Cowesett
Gas Planning - LTRI - Growthpoint - Regulator Station Upgrades - Cowesett
Gas Planning - Reg Station/Launcher -Receiver/Install ROV
Gas Planning - Aquidneck Island Portable LNG Relocation - New Regulator Station (Old Mil Lane)
Gas Planning - Aquidneck Island Portable LNG Relocation - Main Installation (Old Mill Lane)
Gas Planning - Aquidneck Island Portable LNG Relocation - Portable LNG Equipment & Site Prep (Old Mill Lane)
Heater Installation Program - Smithfield GS
Transmission Station Integrity -Scott Road Take Station (Cumberland)
LNG - Exeter Hi Ex Foam System

Sanction Paper RIE Gas 23-004

Title:	Cranston Reg. Station Upgrades - Growthpoint	**Version**	V [1.0]
Super Project #:	C082302	**Sanction Type:**	Full Sanction
Utility Service:	Gas	**Date of Request:**	3/24/2023
Author:	Mitchell Lonergan	**Sponsor:**	Tom Mulkeen
Project/Program Manager:		Andrew Hogan	

1 Project Overview

Summary of Driver

As a part of the Southern Rhode Island Growth Reinforcement project, it is expected that the existing station will see a significant increase in peak flows over the next 5 years. This project will enable increased flows and gas velocities.

Project Scope

Project scope is to remove the existing regulator runs and existing regulator portion of the existing building. Install new full width pre-fab building extension. Install two new regulator runs featuring a 12" Mooney Flowgrid control, a 8" Becker actuated ball valve Monitor, and 8" Becker actuated super monitor. Build new 200# outlet for the station and tie into the existing Kinder Morgan pipeline. Install new United Concrete DAC/GC building. Build new access road with proper storm water management system.

Primary Alternative

Refurbish Existing Regulator Run and Piping. This option would seek to rebuild the existing regulator runs in place, attempting to fit the regulator runs in the existing footprint. This option does not address all the risks present at this facility, including not addressing abutter noise complaint, which are exacerbated by the expected increase in flow from the expansion made possible by the GrowthPoint project, it is not the most viable option.
(Not Recommended)

The Total Cost forecasted for this project is $6,840,000.

Note: After careful consideration of multiple bids, this project was awarded to Ferreira Construction Company. Figures include the winning project bid of $2.3 million.

2 Project Driver

June 2017 forecasted flows and increase of Maximum Operating Pressure (MOP) from 150 psig to 200 psig through Cranston Take Station (67 Laten Knight Rd, Cranston) triggered a thorough review of the existing assets. The review was required to ensure the increase in gas flows, outlet pressures and velocities are mitigated to maintain safe levels and minimize noise through equipment. In addition, material verification was performed at the station. Upgrades and replacements were anticipated for the pressure regulating equipment and associated inlet and outlet piping.

Meeting the system capacity requirements for Southern Rhode Island in the June 2017 forecast and continuing to maintain minimum system pressures. The June 2017 forecast was used to justify the project need for the RI ISR and RI EFSB application. Each year, the current forecast is reviewed to ensure the project schedule is meeting system capacity requirements. The current forecast was reviewed and confirmed that proposed schedule meets need.

3 Project Scope (Preferred Alternative)

Refurbish Existing Regulator Run and Piping. This option would seek to rebuild the existing regulator runs in place, attempting to fit the regulator runs in the existing footprint. One benefit for this option would be to not require moving the inlet and outlet headers and therefore, negating the need for any building modifications. As there is limited linear space, it would be unlikely that this option could address the additional risks at this facility. It would not include installation of strainer equipment on the runs, installation of three independent layers of pressure control on each run, and full independent isolation capabilities for each run.

4 Project Alternative Review

Refurbish Existing Regulator Run and Piping. This option would seek to rebuild the existing regulator runs in place, attempting to fit the regulator runs in the existing footprint. One benefit for this option would be to not require moving the inlet and outlet headers and therefore negating the need for any building modifications. As there is limited linear space, it would be unlikely that this option could address the additional risks at this facility. It would not include installation of strainer equipment on the runs, installation of three independent layers of pressure control on each run, and full independent isolation capabilities for each run. As this option does not address all the risks present at this facility, including not addressing abutter noise complaint, which are exacerbated by the expected increase in flow from the expansion made possible by the GrowthPoint project, it is not the most viable option. (Not Recommended)

5 Summary of Benefits (Gas)

The key driver for this project is asset condition and reliability. Additional customer benefits include reinforcement, load relief, and safety. The station upgrades help to meet the system capacity requirements for Southern Rhode Island in the June 2017 forecast and continue to maintain minimum system pressures. Increased flows exacerbate the risk due to in increased gas velocities and continued reliance on a single run regulator station poses an additional reliability and redundancy risk.

Sanction Paper RIE Gas 23-004

6 Cost Summary ($'s M)

Super Proj #	Title		Prior Years	FY23	FY24	FY25	FY26	**Totals**
C082302	Cranston Reg. Station Upgrades Growthpoint	Cap Ex	0.690	0.800	1.500	3.750	0.100	**6.840**
		Op Ex	0.0	0.0	0.0	0.0	0.0	**0.0**
		Removal	0.0	0.0	0.0	0.0	0.0	**0.0**
		Total	**0.690**	**0.800**	**1.500**	**3.750**	**0.100**	**6.840**

7 Supporters

Department	Yes	N/A
Portfolio/ISR Management	☒	☐
Resource Planning	☒	☐
Project Management	☒	☐
Asset Management/Planning	☐	☒
Substation Engineering and Design	☐	☒
Protection Engineering	☐	☒
Distribution Design	☐	☒
Transmission Line Design	☐	☒
Control Center	☐	☒
Operations	☒	☐
Finance	☒	☐
Regulatory	☐	☒

8 Decision

Laeyeng Hunt, Director of Engineering, approved the investment of $6,840,000 (+10%) for the Cranston Regulator Station Upgrade - Growthpoint project.

X Laeyeng Hunt

Laeyeng Hunt
Director of Engineering

Date Mar 28, 2023

Laeyeng Hunt
Director of Engineering

9 Appendices

N/A

RIEG 23-004 Cranston Reg Station Upgrades - Growthpoint

Final Audit Report 2023-03-28

Created:	2023-03-28
By:	Madison Lema (Madison.Lema@nationalgrid.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAAn4BTfXDNDsxOWM83XaDbBgyWcWh1TFQL

"RIEG 23-004 Cranston Reg Station Upgrades - Growthpoint" History

Document created by Madison Lema (Madison.Lema@nationalgrid.com)
2023-03-28 - 4:48:16 PM GMT

Document emailed to lhhunt@ng.rienergy.com for signature
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2023-03-28 - 5:42:41 PM GMT

Signer lhhunt@ng.rienergy.com entered name at signing as Laeyeng Hunt
2023-03-28 - 5:44:09 PM GMT

Document e-signed by Laeyeng Hunt (lhhunt@ng.rienergy.com)
Signature Date: 2023-03-28 - 5:44:11 PM GMT - Time Source: server

Agreement completed.
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nationalgrid

Short: US Sanction Paper

Title:	GrowthPoint – Cranston Line MOP increase to 200 psig	Sanction Paper #:	USSC-21-008
Project #: C55 Invst Code:	C081907 5360020412	Sanction Type:	Sanction
Operating Company:	The Narragansett Electric Company	Date of Request:	1/19/2021
Author:	Przybysz, Agnieszka	Sponsor(s):	Bennett, Thomas E. VP Gas Asset Mgmt
Utility Service:	Gas	Project Manager:	Hogan, Andrew

Executive Summary

This paper requests Sanction of C081907 in the amount of $4.057M with a tolerance of +/-10% for the purposes of final design and execution; indicating that the baseline cost, scope and schedule as described herein has been approved through the Wholesale Network Process.

This sanction amount is $4.057M broken down into:
- $4.057M Capex
- $0.000M Opex
- $0.000M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

This project has been evaluated for capital efficiencies, which are reflected in the sanction amount. The project will continue to be evaluated for any procurement or construction efficiency opportunities upon its release for construction.

Project Summary

To utilize the maximum benefit for Southern Rhode Island from the new Southern Rhode Island Gas Expansion Project, the Cranston Take Station (a.k.a. Laten Knight) delivery pressure must be increased from 150 psig to 200 psig. This requires the pressure increase on existing Cranston Line.

Background

The existing Cranston Line has an Maximum Allowable Operating Pressure (MAOP) of 200 psig, but a current Maximum Operating Pressure (MOP) of 150 psig. Currently, this pipeline is in the voluntary IMP Program, due to this the asset owner Gas Transmission Engineering (GTE) recommended material verification for the line prior to increasing the MOP to 150 psig.

Project Description

Cranston Line is a gas pipeline running between the Cranston Take Station (a.k.a. Laten Knight) in Cranston

and Cowesett Regulator Station in West Warwick. Currently this pipeline has Maximum Operating Pressure (MOP) of 150 psi, Maximum Allowable Operating Pressure (MAOP) of Cranston Line is 200 psi.
The scope of this project is to perform pressure increase. Pressure increase procedure will be performed in increments, 4 increments are expected, equal to 25% of needed increase (ie. 50 psig increase at 12.5 psig steps). Leak survey will be completed after each increase. Per Gas Transmission (GTE) recommendation if leak is detected repair is required before next increment. Repairs will be completed by resources and under budget of Field Operation group. Before the start of the pressure increase procedure I&R will install pilots at Cranston Take Station.

Material Verification In-Situ in support of pressure increase was completed during project development. 22 excavations/test sites were completed along Cranston Line, on the Gas Transmission Engineering (GTE) asset. 13 test sites were completed on above and below grade pipes at Cranston Take Station and 8 test sites at Cowesett Regulator Station, all on the Pressure Regulation Engineering (PRE) assets. Inspection reports and data were reviewed by the asset owners. Gas Transmission and Pressure Regulation Engineering support the pressure increase to 200 PSIG based on the results of the investigation. Copies of the inspection reports are included in the work package, and with Gas Transmission and Pressure Regulation Engineering.

Summary of Benefits

Project, together with Southern Rhode Island Reinforcement project, allows National Grid to continue to maintain minimum required pressures to local customers to meet forecasted growth and improve gas system delivery.

Business and Customer Issues

Due to the COVID-19 pandemic, the Company's ability to deliver this project/program/blanket may be at risk. The project(s) within this paper as well as the entire jurisdictional portfolio will continue to be evaluated each month through the Company's current control procedures and, if necessary, special actions will be taken to reevaluate their viability for the current fiscal year.

Drivers:

Project supports meeting the system capacity requirements for Southern Rhode Island in the June 2017 forecast and continuing to maintain minimum system pressures.

Forecasted local customer growth is expected to exceed capacity of Southern Rhode Island Distribution System which could result in pressures to local customers falling below minimum in Southern Rhode Island service territory. Growth forecasts in 2018 predicted approximately 3,750 local customers could lose service on peak days by Winter 2022/2023.

The Southern Rhode Island Gas Expansion Project, in progress since 2019, will install approximately 5.1 miles of natural gas distribution main along Route 2 in Warwick, West Warwick, and East Greenwich, south from the Cowesett Regulator Station. This main is designed for a maximum allowable operating pressure (MAOP) of 200 psig but will initially operate at 99 psig. The Cranston Line Maximum Operating Pressure (MOP) increase is required to ensure sufficient inlet pressure for Cowesett regulator station and future new regulators, when the new main will be operated at the 200 psig MOP.

Alternatives

Number	*Title*
1	Do Nothing and Keep MOP at 150 psig - Does not meet project need and Company does not gain full capacity of new main installation. This is not recommended.
2	Return MOP to 200 psig without Material Verification - Since the pipeline segments are part of our voluntary Integrity Management Program (IMP), this option would be inconsistent with our current policies. This is not recommended.
3	

	Main Replacement – The scope and project duration of this option would not meet the need to return the MOP to 200 psig. The high level estimate for the relay of approximately 28,000 feet of 200 psig MAOP high pressure distribution main is over $100 Mil, which is not in the Capital Plan. It would be a challenge to add to the plan, along with the new high pressure distribution main installed for GrowthPoint. The project duration would take approximately 4 years to complete. This scope would also require approval by the RI EFSB, which application preparation and approval would take over one year. Although an aggressive construction schedule is feasible, the Company does not have the budget or resources to support. This is not recommended.
4	Material Verification – Fit For Service in support of Pressure Increase - This option is more complex and will require significantly more internal and external resources, a design drawing for each excavation and extended construction duration. The extended duration may not meet the need of the growth forecast for the region. This is not recommended.
5	In Line Inspection in support of Pressure Increase – Pipeline consists of multiple diameters, which require to have multiple size inspection tools, use of temporary launchers and receivers at each transition point. Although this option is feasible, this effort does not yield the same level of data needed to build the asset record for this pipeline. This is not recommended.

Related Projects, Scoring and Budget

Summary of Projects

Project Number	***Project Type*** (Elec only)	***Project Title***	***Estimate Amount($M)***
C081907		GrowthPoint –Cranston Line to 200 psig MOP	4.057
		Total:	4.057

Associated Projects

Project Number	***Project Title***	***Estimate Amount ($M)***
C079252	Southern Rhode Island Gas Expansion Project	96.792
		96.792

Prior Sanctioning History

Date	***Governance Body***	***Sanctioned Amount***	***Potential Project Investment***	***Sanction Type***	***Sanction Paper***	***Potential Investment Tolerance***
3/19/2020	USSC	$0.710M	$4.537M	Project Development	USSC-20-146	+/-10%
5/28/2019	USSC	$3.550M	$4.537M	Project Development	USSC-19-089 v2	+/-10%
2/19/2019	USSC	$0.200M	$4.537M	Project Development	USSC-19-089	+/-10%

Key Milestones

Milestone	***Date (Month / Year)***
Project Development Sanction	February 2019
Project Development Sanction	May 2019
Project Development Sanction	February 2020

Gate C - Approval to Begin Engineering & Design	December 2020
Sanction	January 2021
Gate C1 - Approval to Progress to Field Execution	February 2021
Construction Start	June 2021
Construction Complete / Ready for Load / Use	September 2021
Gate D - Approval to Progress to Closeout	January 2022
Project Closure Sanction	August 2022

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
August 2022	Closure

Category

Category	Reference to Mandate, Policy, or NPV
(●) Mandatory ( ) Policy-Driven ( ) Justified NPV	Federal Code 49 CFR 192.623 and RI Division of Public Utilities and Carriers' Standards for Gas Utilities, 815-RICR-20-00-1, Section 1.5.B.,require minimum pressures to be maintained in the gas system. National Grid has established system minimum pressures to be maintained for all pressure levels.

Asset Management Risk Score: 35

PRIMARY RISK SCORE DRIVER

( ) Reliability ( ) Environment ( ) Health & Safety (●) Not Policy Driven

Complexity Level: 23

( ) High Complexity (●) Medium Complexity ( ) Low Complexity ( ) N/A

Net Zero

Contribution to National Grid's 2050 80% emissions reduction target:	(●) Neutral	( ) Positive	( ) Negative
Impact on adaptability of network for future climate change:	(●) Neutral	( ) Positive	( ) Negative
Qualifies for Green Financing:	( ) Yes	( ) No	(●) N/A

Investment Recovery and Customer Impact

Investment Recovery

Investment recovery will be through standard rate recovery mechanisms.

Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $0.8297M.

Business Plan

Business Plan Name & Period (BP 19)	*Project Included in approved Business Plan?*	*(Over) / Under Business Plan*	*Project Cost relative to approved Business Plan ($M)*
FY21 - FY25 Gas Capital Plan	◉ Yes ○ No	○ Over ◉ Under ○ N/A	0.114

If Cost > Approved

if costs > approved Business Plan how will this be funded?

Reallocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

Cost Summary Table

Project Number	C081907	Project Title	GrowthPoint –Cranston Line to 200 psig MOP	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	2.431	0.710	0.870	0.046	0.000	0.000	0.000	4.057
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	2.431	0.710	0.870	0.046	0.000	0.000	0.000	4.057

Total Project Sanction								
Capex	2.431	0.710	0.870	0.046	0.000	0.000	0.000	4.057
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	2.431	0.710	0.870	0.046	0.000	0.000	0.000	4.057

Project Costs per Business Plan

$M	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	2.431	0.710	0.930	0.100	0.000	0.000	0.000	4.171
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	2.431	0.710	0.930	0.100	0.000	0.000	0.000	4.171

Variance

		FY	FY	FY	FY	FY	FY	

$M	Prior Yrs	2021	2022	2023	2024	2025	2026	Total
Capex	0.000	0.000	0.060	0.054	0.000	0.000	0.000	0.114
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	0.000	0.060	0.054	0.000	0.000	0.000	0.114

Statement of Support

Department	***Individual***	***Responsibilities***
Investment Planner	Eddleston, Stephanie	Endorses relative to 5-year business plan or emergent work
Resource Planning	LaFond, Phil	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule
Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers

Function	***Individual***
Finance	McConnachie, Christopher / Pfeifer, Carson
Regulatory	Azarcon, Carolyn; Long, James
Jurisdictional Delegate	Schmid, Randy
Procurement	Chevere, Diego
Control Center	Loiacono, Paul J.

Decisions

I:

(a) APPROVE the investment of $4.057M and a tolerance of +/-10% for final design and execution; indicating that the baseline cost, scope and schedule as described herein has been approved through the Wholesale Network Process.

(b) NOTED that Hogan, Andrew has the approved financial delegation

DocuSigned by:

Signature _____ Mike Gillespie _____________________________
09F411044CFF47A...

Date 1/25/2021 _____________________________

Michael Gillespie, Vice President, Head of Finance Business Partnering, USSC Chair

Appendix

N/A

Sanction Closure Paper – RIE Gas 23-103

Title:	GrowthPoint – Cranston Line MOP increase to 200 psig	**Version**	V [1.0]
Super Project #:	C081907	**Sanction Type:**	Closure
Utility Service:	Gas	**Date of Request:**	May 23, 2023
Author:	Tom Mulkeen	**Sponsor:**	Tom Mulkeen
Project/Program Manager:		Andrew Hogan	

1 ***Project Overview***

This paper is presented to close the project Growthpoint – Cranston Line MOP Increase to 200 psig. The total spend was $3,288.323. The sanctioned amount for this project (USSC-21-008) was $4,057,000. This project was $768,677 (20%) under budget.

The final spend amount is broken down into:
($'s Millions)

Spend Type	FY - 2019	FY - 2020	FY - 2021	FY - 2022	FY - 2023	Total
CAPEX	0.006	2.401	0.686	0.158	0.0	3.252
OPEX	0.0	0.001	0.0	0.0	0.0	0.002
REMOVAL	0.0	0.024	0.011	0.0	0.0	0.035
TOTAL	0.006	2.425	0.697	0.158	0.0	3.288

2 ***Project Driver***

Forecasted local customer growth is expected to exceed capacity of Southern Rhode Island Distribution System which could result in pressures to local customers falling below minimum in Southern Rhode Island service territory. Growth forecasts in 2018 predicted approximately 3,750 local customers could lose service on peak days by Winter 2022/2023.

The Southern Rhode Island Gas Expansion Project, in progress since 2019, will install approximately 5.1 miles of natural gas distribution main along Route 2 in Warwick, West Warwick, and East Greenwich, south from the Cowesett Regulator Station. This main is designed for a maximum allowable operating pressure (MAOP) of 200 psig but will initially operate at 99 psig. The Cranston Line Maximum Operating Pressure (MOP) increase is required to ensure sufficient inlet pressure for Cowesett regulator station and future new regulators, when the new main will be operated at the 200 psig MOP.

The existing Cranston Line has a Maximum Allowable Operating Pressure (MAOP) of 200 psig, but a current Maximum Operating Pressure (MOP) of 150 psig. Currently, this pipeline is in the voluntary IMP Program. Due to this the asset owner, Gas Transmission Engineering (GTE), recommended material verification for the line prior to increasing the MOP from 150 psig.

To utilize the maximum benefit for Southern Rhode Island from the new Southern Rhode Island Gas Expansion Project, the Cranston Take Station (a.k.a. Laten Knight) delivery pressure must be increased from150 psig to 200 psig. This requires the pressure increase on existing Cranston Line.

Sanction Closure Paper – RIE Gas 23-103

This project supports meeting the system capacity requirements for Southern Rhode Island in the June 2017 forecast and continuing to maintain minimum system pressures.

3 Related Projects

($'S Millions)

Sanction Paper	Investment Name	DOA	Spending from Inception thru 3/31/2023	Frcst Lifetime Spend	(Over)/Under DOA (w/o thrshld)
RIEG 23-004	Gas Planning - Cranston Reg. Station Upgrades - Growthpoint - C082302	6.8	1.3	8.2	(1.4)
RIEG 23-103 (C),	Gas Planning - Growthpoint - C081907 - MOP Increase	4.1	3.3	3.3	0.8
USSC-19-001	Gas Planning - Growthpoint - C079252 - Main Installation	96.8	97.7	97.7	(0.9)
USSC-21-285	Gas Planning - Cowesett Reg. Station - Growthpoint - C085181	4.2	4.0	4.1	0.2
	Gas Planning - New Reg. Station Near Cowesett - Growthpoint - C081906	2.5	0.0	1.4	1.1
	CRA-LatenKnightRd-RCV-RIS-334 (C079173 - WO 90000187922)	2.5	0.0	0.2	2.3
USSC 19-086 v2	CRA-LATEN KNIGHT GS-REPL HTR-RIS334 (C077172 -WO 90000181511) *	4.1	4.2	0.0	4.1
	TOTAL GROWTHPOINT RELATED PROJECTS	**121.0**	**110.5**	**114.8**	**6.2**

* Originally known as Cranston Gate Station Heater Project - Needs Closure paper

4 Final Outcome

The MOP was increased to formally established MAOP of 200 psi. Pressure was successfully increased in four stages (25% per stage) with a leak survey completed after each stage. No leaks found during each pressure increase stage. One major obstacle is the typical duration of increasing the pressure per stage then scheduling a leak survey crew. The project team recognized this challenge bringing I&R, CMS, and Project Management together. We scheduled far in advance a CMS crew to be present during each pressure increase to then perform the leak survey. This process was completed in one week rather than as many as four.

5 Project Scope (Preferred Alternative)

Cranston Line is a gas pipeline running between the Cranston Take Station (a.k.a. Laten Knight) in Cranston and Cowesett Regulator Station in West Warwick. Currently this pipeline has Maximum Operating Pressure (MOP) of 150 psi, Maximum Allowable Operating Pressure (MAOP) of Cranston Line is 200 psi. The scope of this project is to perform pressure increase. Pressure increase procedure will be performed in increments, 4 increments are expected, equal to 25% of needed increase (ie. 50 psig increase at 12.5 psig steps). Leak survey will be completed after each increase. Per Gas Transmission (GTE) recommendation if leak is detected repair is required before next increment. Repairs will be completed by resources and under budget of Field Operation group. Before the start of the pressure increase procedure I&R will install pilots at Cranston Take Station.

Material Verification In-Situ in support of pressure increase was completed during project development. 22 excavations/test sites were completed along Cranston Line, on the Gas Transmission Engineering (GTE) asset. 13 test sites were completed on above and below grade pipes at Cranston Take Station and 8 test sites at Cowesett Regulator Station, all on the Pressure Regulation Engineering (PRE) assets. Inspection reports and data were reviewed by the asset owners. Gas Transmission and Pressure Regulation Engineering support the pressure increase to 200 PSIG based on the results of the investigation. Copies of the inspection reports are included in the work package, and with Gas Transmission and Pressure Regulation Engineering.

6 ***Project Alternative Review***

1. Do Nothing and Keep MOP at 150 psig - Does not meet project need and Company does not gain full capacity of new main installation. This is not recommended.

2. Return MOP to 200 psig without Material Verification - Since the pipeline segments are part of our voluntary Integrity Management Program (IMP), this option would be inconsistent with our current policies. This is not recommended.

3. Main Replacement – The scope and project duration of this option would not meet the need to return the MOP to 200 psig. The high level estimate for the relay of approximately 28,000 feet of 200 psig MAOP high pressure distribution main is over $100 Mil, which is not in the Capital Plan. It would be a challenge to add to the plan, along with the new high pressure distribution main installed for GrowthPoint. The project duration would take approximately 4 years to complete. This scope would also require approval by the RI EFSB, which application preparation and approval would take over one year. Although an aggressive construction schedule is feasible, the Company does not have the budget or resources to support. This is not recommended.

4. Material Verification – Fit For Service in support of Pressure Increase - This option is more complex and will require significantly more internal and external resources, a design drawing for each excavation and extended construction duration. The extended duration may not meet the need of the growth forecast for the region. This is not recommended.

5. In Line Inspection in support of Pressure Increase – Pipeline consists of multiple diameters, which require to have multiple size inspection tools, use of temporary launchers and receivers at each transition point. Although this option is feasible, this effort does not yield the same level of data needed to build the asset record for this pipeline. This is not recommended.

7 ***Summary of Benefits***

Project, together with Southern Rhode Island Reinforcement project, allows Rhode Island Energy to continue to maintain minimum required pressures to local customers to meet forecasted growth and improve gas system delivery; increasing safety and reliability within the Southern Rhode Island Reinforcement footprint.

Sanction Closure Paper – RIE Gas 23-103

8 Supporters

Department	Yes	N/A
Portfolio/ISR Management	☒	☐
Resource Planning	☒	☐
Project Management	☒	☐
Asset Management/Planning	☒	☐
Portfolio/ISR Management	☒	☐
Substation Engineering and Design	☐	☒
Protection Engineering	☐	☒
Distribution Design	☐	☒
Transmission Line Design	☐	☒
Control Center	☐	☒
Operations	☒	☐
Finance	☒	☐
Regulatory	☒	☐

9 Decision

Laeyeng Hunt, Director of Engineering, approved the investment of $3,288.323 (+10%) for the GrowthPoint – Cranston Line MOP increase to 200 psig for the period of FY 2019 thru 2022.

Signature Laeyeng H Hunt
Laeyeng H Hunt (May 23, 2023 14:01 EDT)

Date May 23, 2023

Laeyeng Hunt
Director of Engineering

10 Appendices

None

RIEG 23-103 (C) Growthpont MOP Increase

Final Audit Report 2023-05-23

Created:	2023-05-23
By:	Randy Schmid (Randy.Schmid@nationalgrid.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAA6jlp53xy09MkZe7APY6VYZpmFftfzn0c

"RIEG 23-103 (C) Growthpont MOP Increase" History

Document created by Randy Schmid (Randy.Schmid@nationalgrid.com)
2023-05-23 - 1:45:30 PM GMT- IP address: 136.226.73.103

Document emailed to lhhunt@ng.rienergy.com for signature
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Signer lhhunt@ng.rienergy.com entered name at signing as Laeyeng H Hunt
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Document e-signed by Laeyeng H Hunt (lhhunt@ng.rienergy.com)
Signature Date: 2023-05-23 - 6:01:24 PM GMT - Time Source: server- IP address: 98.110.146.102

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US Sanction Paper

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Title:	Southern RI Growth Reinforcement-Quaker Ln	**Sanction Paper #:**	USSC-19-001
Project #:	C079252	**Sanction Type:**	Sanction
Operating Company:	The Narragansett Electric Co.	**Date of Request:**	1/30/2019
Author:	Agnieszka Przybysz	**Sponsor:**	John Stavrakas, VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	Andrew Hogan

1 ***Executive Summary***

1.1 ***Sanctioning Summary***

This paper requests sanction of project C079252 in the amount of $77.786M with a tolerance of +/- 10% for the purposes of Engineering, Materials Procurement, Full implementation, and any other activities related to the design and construction of the project.

This sanction amount is $77.786M broken down into:
$77.786M Capex
$0.000M Opex
$0.000M Removal

This project has undergone a Capital Efficiency Review with the following determination:

This project has been evaluated for capital efficiencies, which are reflected in the sanction amount. The project will continue to be evaluated for any procurement or construction efficiency opportunities upon its release for construction.

1.2 ***Project Summary***

This project seeks to fund the installation of approximately 5.1 miles of transmission main on The Narragansett Electric Company's natural gas system in Warwick, West Warwick and East Greenwich, located south of the Cranston Take Station. The scope of work includes installation of new 20 inch steel transmission main designed for a maximum allowable operating pressure (MAOP) of 200 psig and constructed to be in-line inspected (ILI). The new main installation begins in Quaker Lane, West Warwick near Regulator Station #133 at the intersection of Cowesset Road and continues south through South Country Trail, East Greenwich. The project is segmented into three phases, each temporarily connected to the existing distribution system at a maximum operating pressure (MOP) of 99 psig. Once all phases are installed and the associated projects are completed, the pressure will be increased to a MOP of 200 psig.

US Sanction Paper

This project sanction request is comprised of only the 5.1 miles of transmission main work. Work regarding regulator stations and existing facilities will both be addressed under separate project sanctions.

1.3 *Summary of Projects*

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
C079252	Reliability	Southern RI Growth Reinf- Quaker Ln	77.786
		Total	77.786

1.4 *Associated Projects*

Project Number	Project Title	Estimate Amount ($M)
C081906	GrowthPoint – Regulator Station	11.483
C081907	GrowthPoint – Existing Facilities	17.201
	Total	28.684

1.5 *Prior Sanctioning History*

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Sanction Type	Potential Investment Tolerance
11/6/18	USSC	$5.300M	N/A Note 1	Project Development Re-Sanction	+/-10%
6/26/18	USSC	$1.300M	N/A Note 1	Project Development Sanction	+/-10%

Note 1: Project scope was developed under the annual project development sanction process.

1.6 *Next Planned Sanction Review*

Date (Month/Year)	Purpose of Sanction Review
June 2022	Project Closure Sanction

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US Sanction Paper

1.7 *Category*

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ⦿ Policy- Driven ○ Justified NPV ○ Other	Federal Code 49 CFR 192.623 and RI Division of Public Utilities and Carriers' Standards for Gas Utilities, 815-RICR-20-00-1, Section 1.5.B.,require minimum pressures to be maintained in the gas system. National Grid has established system minimum pressures to be maintained for all pressure levels.

1.8 *Asset Management Risk Score*

Asset Management Risk Score: _35____

Primary Risk Score Driver: (Policy Driven Projects Only)

○ Reliability ○ Environment ⦿ Health & Safety ○ Not Policy Driven

1.9 *Complexity Level*

⦿ High Complexity ○ Medium Complexity ○ Low Complexity ○ N/A

Complexity Score: _28____

1.10 *Process Hazard Assessment*

A Process Hazard Assessment (PHA) is required for this project:

⦿ Yes ○ No

US Sanction Paper

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1.11 *Business Plan*

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY19-23 Gas Capital Plan	⦿ Yes ○ No	⦿ Over ○ Under ○ NA	$75.741M

1.12 *If cost > approved Business Plan how will this be funded?*

Re-allocation of funds within the portfolio has been managed by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements. In particular, the project is included in the FY20-29 Gas Capital Plan at the sanctioned amount.

1.13 *Current Planning Horizon*

		Current Planning Horizon						
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
CapEx	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786

1.14 *Key Milestones*

Milestone	Target Date: (Month/Year)
Project Development Sanction	June 2018
Project Development Re-Sanction	November 2018
Gate C – Approval of Project Execution Plan	November 2018
Project Sanction	January 2019
Gate C1 – Approval to Progress to Field Execution	February 2019
Construction Start	April 2019
Construction Complete - CC	November 2021
Gate D – Approval to Progess to Closeout	January 2022
Gate E – Approval to Close Project	June 2022
Project Closure Sanction	June 2022

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US Sanction Paper

1.15 *Resources, Operations and Procurement*

Resource Sourcing			
Engineering & Design Resources to be provided	☑ Internal	☑ Contractor	
Construction/Implementation Resources to be provided	☑ Internal	☑ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	○ Red	○ Amber	⦿ Green
Availability of external resources to deliver project:	○ Red	○ Amber	⦿ Green
Operational Impact			
Outage impact on network system:	○ Red	○ Amber	⦿ Green
Procurement Impact			
Procurement impact on network system:	○ Red	○ Amber	⦿ Green

1.16 *Key Issues (include mitigation of Red or Amber Resources)*

Please see Section 3.8 Execution Risk Appraisal addressing key issues.

1.17 *Climate Change*

Contribution to National Grid's 2050 80% emissions reduction target:	⦿ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	⦿ Neutral	○ Positive	○ Negative

1.18 *List References*

1	US Enterprise Wide 5-Year Distribution System Reinforcement & Reliability Plan

US Sanction Paper

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2 *Decisions*

The Senior Executive Sanctioning Committee (SESC) at a meeting held on January 30, 2019:

(a) APPROVED this paper and the investment of $73.908M and a tolerance of +/- 10%

(b) NOTED that Andrew Hogan is the Project Manager and has the approved financial delegation.

Signature..Date. 1/30/19
Margaret Smyth
US Chief Financial Officer
Chair, Senior Executive Sanctioning Committee

US Sanction Paper

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3 Sanction Paper Detail

Title:	Southern RI Growth Reinf-Quaker Ln	**Sanction Paper #:**	USSC-19-001
Project #:	C079252	**Sanction Type:**	Sanction
Operating Company:	Nantucket Electric Co.	**Date of Request:**	1/30/2019
Author:	Agnieszka Przybysz	**Sponsor:**	John Stavrakas, VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	Andrew Hogan

3.1 Background

As part of the Company's resource portfolio, Long Term Planning and Operations Engineering, in coordination with Sales, Project Engineering, and Project Management, developed this project to increase system capacity for forecasted growth, and improve system reliability. This project increases capacity needed for the forecasted growth by installing a 20-inch distribution main in parallel to the existing distribution main and improves system reliability by decreasing the Company's dependence on pressure support from the Exeter LNG facility and reducing the risks associated with loss of one of the distribution mains in this area. Further, this Project addresses system capacity issues on the 99 psig feeder system that currently limit regional targeted growth projects on downstream distribution systems reviewed by Operations Engineering as gas capacity requests. The gas capacity request process is designed to identify reinforcements that address local or regional issues restricting growth for an individual customer. Gas capacity request reinforcements do not provide additional capacity to the system and cannot be expected to accommodate future growth. Therefore, this project is needed as a gas system reinforcement project.

The Southern Rhode Island service territory is defined as the area supplied south of the Cranston Take Station, which includes the cities, towns and villages of Warwick, West Warwick, East Greenwich, Coventry, Cranston, Exeter, Kingston, Narragansett, North Kingstown, South Kingstown, Scituate, Wakefield, West Greenwich and West Kingston. Nine district regulator stations feed off the single-feed 200 psig to 99 psig regulator station at Cowesett Road in Warwick, RI. This service territory includes approximately 77 miles of distribution mains rated to operate at or above 99 psig (the "Southern RI Distribution Mains").

The 99 psig system of the Southern RI Distribution Mains is presently operating at maximum capacity and utilizes pressure support from the Exeter LNG facility for average daily temperatures 30 degrees Fahrenheit and colder. Beginning in winter

2017-18, growth forecasts exceeded redundant vaporization capacity from the Exeter LNG facility. If growth continues as forecasted, it is possible that gas pressures will fall below minimum, resulting in a risk of loss of service to customers during periods of peak winter demand.

When developing the Gas System Reinforcement and Reliability Programs, Long Term Planning uses an in-depth analysis of customer growth to the zone/zip code level based on zone growth factors (percentages) provided by the Forecasting and Analytics group. Long Term Planning uses this forecasted growth to calculate a growth factor (percentage) for each zip code. These zip code growth factors are then used to allocate the overall customer growth forecasted for Rhode Island to the validated Synergi network analysis computer models. The result of this methodology is that some zip codes show positive growth while others may show negative growth. By better simulating where the customer growth is expected to occur, the overall accuracy of the reinforcement projects that must be constructed in order to support each region's average annual system growth are identified. These projects are designed to maintain minimum system design pressures during periods of peak demand, (i.e. design weather conditions), thus ensuring continuous service to all customers on the network in compliance with Federal and State Codes. The peak demand for a given territory is based on the same forecast that is filed annually with the RI Public Utilities Commission ("PUC") and used to develop the gas supply portfolio. The System Reinforcement program is a critical component for enabling gas supply to be delivered to Firm customers. Design weather conditions have been established for Rhode Island as -3°F (68 Heating Degree Days).

3.2 *Drivers*

This project is needed to maintain continuous service to all customers on the Southern Rhode Island service territory distribution network during periods of peak demand (i.e., design weather conditions) while increasing capacity in an area that is currently constrained. The results of the growth analysis (described in Section 3.1 above) performed on the gas distribution network predicts that for the 2022/23 winter, using the current Gas Supply send-out forecast, approximately 3,750 customers could experience below minimum design pressures and be at risk of losing service if design conditions were experienced. The estimated restoration cost (i.e., relight, plus claims) for such an event is approximately $6.5M, based on an estimated $1,750 per customer. The estimated restoration cost does not include other significant costs, such as business interruption costs and other customer and societal costs that result from loss of natural gas service when gas is needed most. To avoid this situation, without this project the Company may need 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.

The Company's service territory around the Southern RI Distribution Mains is unique because there are fewer interstate pipelines than other areas. Thus, the Company relies on LNG for pressure support at warmer temperatures as compared with other parts of its service territory, which traditionally rely on LNG for peak shaving on design days. The additional capacity from the project should reduce reliance on the Exeter LNG facility for pressure support. As each phase of this project is completed, unsold capacity could be considered as a reduction in dependence at the Exeter LNG facility because the need for pressure support would be reduced.

3.3 *Project Description*

The Southern Rhode Island Reinforcement Project includes the design, procurement, construction, testing and completion of the project. This is a multi-stage project designed to cost-effectively reinforce and improve the reliability of the system and increase capacity in the currently constrained Southern Rhode Island area. The scope of work includes the installation of the new 20 inch steel main designed for a MAOP of 200 psig and constructed to be ILI.

This project will install approximately 28,500 feet (approximately 5.1 miles) of 20 inch 200 psig transmission main from the existing 200 psig main near Regulator Station RIS-133 located at Cowesset Road, Warwick and continues south through South Country Trail, East Greenwich. It will be activated in-service in phases with normal operation at 99 psig, up until a new 200 psig to 99 psig district regulator station is installed in East Greenwich when the main will be uprated to normal operation at 200 psig.

As noted earlier, this project sanction request is comprised of only the 5.1 miles of transmission main work. Work regarding regulator stations and existing facilities will both be addressed under separate project sanctions.

3.4 *Benefits Summary*

The benefit of installing this reinforcement is to allow for continued growth in the Southern Rhode Island service territory, and to maintain adequate system pressure, above minimum design, to prevent the loss of service to customers. Without the project, if growth continues as expected, by the 2022/2023 winter, the Company may need to impose a moratorium on new service connections or else up to 3,750 customers could see below minimum pressures and would be at risk of losing service. In addition, several regulator station inlet pressures are predicted to fall below minimum, which would cause problems on the downstream pressure systems if the stations cannot maintain their outlet set pressure. The Project is being developed to address several issues, including (1) maintaining minimum code required pressures, especially in light of forecasted growth; (2) increasing gas system reliability; and (3) reducing reliance on the Exeter LNG facility for pressure support.

3.5 *Business and Customer Issues*

There are no significant business or customer issues beyond what has been described elsewhere.

3.6 *Alternatives*

Alternative 1: Do Nothing – Not recommended

Doing nothing (the "No-Build Alternative") does not address the projected growth for this area and, based on 2022/23 projections, puts up to 3,750 customers at risk of losing service during the winter. In addition, this alternative does not allow the Company to meet its regulatory obligation to provide safe and reliable service. While there would be no capital expense associated with this alternative, this alternative would prevent the Company from responding to gas capacity requests in Southern RI because new customer requests could not be supported and the Company likely would need to impose a moratorium on all new gas service requests and requests for expansion of existing gas service. The No-Build Alternative would also continue to require the Company to depend heavily on pressure support from the Exeter LNG facility for winter operations pressure support, which is expected to exceed maximum capacity by 2019.

As part of its No-Build Alternative analysis, the Company considered the impacts of energy efficiency on the project's need. The Company offers a broad array of energy efficiency programs to its Rhode Island customers. Consistent with R.I. Gen. Laws § 39-1-27.7 and PUC Docket No. 4684, the Company's programs are designed to create energy and economic costs savings for Rhode Island consumers. The Company proposed a 2018 Energy Efficiency Plan with a gas savings goal of 1.01% of 2015 natural gas load, which is equivalent to 414,795 MMBtu.

While the Company's many energy efficiency programs will help its customers manage their energy costs, they are not, on their own, an acceptable alternative to the project. The gas energy efficiency programs are designed to reduce annual natural gas consumption, but are not specifically designed to reduce peak demand. Moreover, they are not intended to alleviate location-specific capacity constraints like those affecting the Southern RI Distribution Mains. Thus, it is difficult to determine their impact on peak demand and, consequently, the location-specific need for the project. Even if the programs achieved an equivalent annual peak demand reduction (approximately 1%), this minor savings would not obviate the risk to existing customers and/or the need for a moratorium in the absence of the project.

US Sanction Paper

As described in the its Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27, filed in PUC Docket No. 4816 on March 30, 2018, the Company already considers the impacts of energy efficiency on its retail demand forecasts. Specifically, the Company determined an expected annual energy efficiency savings based on a three-year average of actual 2014 through 2016 savings, which are already included in the econometric forecasting models. The Company further reduced its forward-looking demand forecast by expected incremental savings that are not reflected in the models. Thus, even including energy efficiency, the project is still needed.

Moreover, the No-Build Alternative with respect to environmental impact primarily means a continuation of the status quo. Therefore, while there would be no direct environmental impacts, there would be no benefits either. For example, the project provides environmental benefits in the way of lower carbon dioxide ("CO2") emission by enabling the continued conversion from other sources, such as oil to natural gas, and the option of using natural gas over oil as a heat source in new construction. Assuming the current average of 350 oil-to-gas conversions per year, the project will enable the reduction of between approximately 635 tons of CO2 per year (with no concurrent furnace efficiencies) to 1,470 tons of CO2 per year (with concurrent furnace efficiencies) from such conversions. Further assuming 647 new residential units expected to be enabled by the project, the Company has estimated that the project also will prevent an additional 1,176 tons of CO2 emissions. If the total of 14,000 oil-to-gas conversions or new gas services enabled by the project are achieved, the project will reduce CO2 emissions by a total of approximately 25,438 tons of CO2 (with no concurrent furnace efficiencies) to 58,777 tons of CO2. In total, if furnace efficiency measures are implemented, the No Build Alternative may also have detrimental environmental impacts if the Company has to impose a moratorium, resulting in no further annual CO2 reductions that currently are being realized from the oil-to-gas conversions. For all these reasons, the Company rejected the No-Build Alternative.

Alternative 2: Exeter Take Station – Not recommended

The Exeter Take Station Alternative proposes the installation of a new Kinder Morgan/Tennessee Gas Pipeline take station within the vicinity of the existing Exeter LNG facility. This installation would be part of an incremental supply agreement with Kinder Morgan/Tennessee Gas Pipeline and would require the installation of approximately 17 miles of transmission pipeline extension from the end of Cranston lateral near the existing Cranston Take Station to the Exeter LNG facility. The new transmission pipeline would require approval from the Federal Energy Regulatory Commission, which would require more lengthy permitting. This alternative could also require work upstream of Cranston. The high level conceptual estimate of the cost of the pipeline extension and new take station build is approximately $450M.

In addition to its excessive cost, this alternative does not address projected growth for this area and, based on 2022/23 projections from June 2017 annual forecast, puts up to

3,750 customers at risk of losing service during the winter. In addition, this alternative does not allow the Company to meet its regulatory obligation to provide safe and reliable service. While there would be no direct capital expense associated with this alternative, since costs for these types of projects are covered in the cost of gas, this alternative would prevent the Company from responding to gas capacity requests in Southern RI because new customer requests could not be supported. The Exeter Take Station Alternative would also require the Company to continue heavy dependency on pressure support from the Exeter LNG facility for winter operations pressure support, which is expected to exceed maximum capacity by 2019. For these reasons, the Exeter Take Station Alternative was rejected because it does not address the identified need.

Alternative 3: New Distribution Main from Providence to Warwick – Not recommended

This alternative involves the construction of approximately 17 miles of 16-inch and 12-inch distribution mains. This alternative includes five miles of 12-inch 200 psig distribution main from the Allens Avenue Regulator Station in Providence to the inlet of district regulator RIS-107 in Warwick, then extending approximately 12 miles of 16-inch and 12-inch 99 psig distribution main near the inlet of district regulator RIS-066 in North Kingstown. This alternative would allow the incremental supply volume to be supplied from the Enbridge pipeline. However, this alternative requires construction in more densely populated areas with higher traffic volumes and more existing utilities. Thus, this alternative would take longer to construct than the project due to its length and location. Further, this alternative does not allow the Company to tie into the 99 psig system in a phased approach, which would allow for incremental growth capacity as segments are completed. Rather, the additional capacity needed for customer growth would not be realized until the entire 17 miles of the main are completed. Considering that this alternative would be three times as long as the proposed project, the Company concluded that this alternative could not be constructed by the winter of 2022/2023 and would be more costly than the proposed project. Therefore, the Company dismissed this alternative from further consideration, because the Company would not be able to meet the identified need in the time required and at a greater cost.

Alternative 4: New Distribution Main from Westerly to Kenyon – Not recommended

This alternative involves the construction of approximately 14 miles of 12-inch 200 psig distribution main from the Westerly Take Station to the approximate location of Kenyon Industries, a potential new customer in the Village of Kenyon, RI. This alternative can only go forward if a five-mile extension of the existing 99 psig distribution main in South Kingstown is completed by Kenyon prior to completion of the 14-mile distribution main extension. This alternative would also require upstream transmission upgrades to Enbridge's Algonquin Pipeline, because the pipe that feeds the Company's Westerly

Take Station is only 4.5 inches in diameter. Such upgrades would likely fall under FERC jurisdiction, which would greatly increase permitting times and costs.

Moreover, the new distribution main contemplated by this alternative would likely impact the Great Swamp Management Area, which would further increase environmental impacts, permitting costs and construction time. Therefore, the Company dismissed this alternative from further consideration because it would not be able to meet the identified need in the time required and it is very likely to be more costly.

3.7 *Safety, Environmental and Project Planning Issues*

The installation of approximately five miles of distribution main parallel to an existing distribution main located wholly within RI Department of Transportation ("RIDOT") right of way along Route 2 does not create significant new impacts on the environment, public health, safety or welfare. Environmental issues are mainly related to soil and water contamination along the proposed route. Soil and groundwater contamination will be handled in accordance with RI Department of Environmental Management ("RIDEM") approvals and remedial operation requirements. Additionally, the Project will create temporary impacts to traffic and access to commercial properties. The Company is working closely with RIDOT to mitigate traffic impacts and access issues. The Company also hired a consultant to perform a noise study of the potential impacts associated with operations at the two Horizontal Directional Drilling (HDD) locations. The noise study identified several potential mitigation measures, and the Company will work with its contractor to implement these measures as appropriate.

A health and safety plan will be developed and all National Grid safety and environmental rules will be followed.

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US Sanction Paper

3.8 *Execution Risk Appraisal*

Number	Detailed Description of Risk / Opportunity	Probability	Impact		Score		Strategy	Pre-Trigger Mitigation Plan	Residual Risk	Post Trigger Mitigation Plan
			Cost	Schedule	Cost	Schedule				
1	Opposition to the project: If project is opposed in a meaningful way. Then the permitting process could be delayed.	4	1	5	4	20	Mitigate	Engaging the public through the outreach group to educate them about the project and the impacts, as well as the positive impacts for customers.	Project can be opposed during construction.	Additional security can be necessary, also schedule can be impacted, both will add costs.
2	Permit Restrictions: If permits restrict working hours / days. Then the project construction schedule will be extended beyond the proposed timeline.	4	2	3	8	12	Exploit	PM, Eng, and SM should seek negotiations with the towns / state to loosen restrictions and allow for more work time to complete the project by the proposed gas in date.	Project can have different restriction per location or phase.	Continue negotiations with the town and state after construction start.
3	EFSB or other Agency Requirements: If more requirements are requested by regulators or EFSB decides application should proceed through the fall or longer. Then permitting could be delayed/extended. Design changes could be required for the project for approval.	2	2	5	4	10	Accept	Plan is to mitigate this risk through proper planning prior to the submission of the plan to the EFSB.	If EFSB process is extended	Work with contactor on new schedule, add resources to the project
4	Qualified Bidders and availability: If contractors are not available and/or not qualified. Then outside contractors could be pulled in or submit bids that are significantly higher.	4	2	2	8	8	Mitigate	Engage contract management and plan to bid the project as early as possible in the season to reach more contractors.	Bids are significantly higher	Negotiate with contractor. Review the bids focusing not only on the price but ability to complete installation on time
5	Political pressure to expedite schedule: If political pressure is applied to expedite the project. Then pitfalls in the design may lead to higher construction costs.	4	2	1	8	4	Mitigate	Reduce risk by being transparent about the process with upper management on where the Company is in the progress of the project.	Higher bidder is chosen in order to deliver on schedule	Through constant contact with the upper management and transparency with the regulators the Company can express the need to properly vet the project and all concerns the Company can better understand the impact to the Customers.

US Sanction Paper

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3.9 ***Permitting***

Permit Name	Probability Required (Certain/ Likely/ Unlikely)	Duration To Acquire Permit	Status (Complete/ In Progress Not Applied For)	Estimated Completion Date
Energy Facility Siting Board (EFSB)	Certain	90 days	In progress	03-15-19
RIDEM Office of Waste Management	Certain	3 months	In progress	03-15-19
Rhode Island Pollutant Discharge Elimination System (RIPDES) and Rhode Island Historical Preservation & Heritage Commission (RIHPHC)	Certain	2 months	In progress	03-15-19
RIDOT Traffic Management Plan (TMP) for FY20 work	Certain	3 months	In progress	03-08-19
RIDOT Traffic Management Plan (TMP) for FY21 and FY22 work	Certain	3 months	Not applied	TBD
RT 4 HDD requires Federal easement (FY22 installation)	Certain	TBD	Not applied	TBD

US Sanction Paper

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3.10 ***Investment Recovery***

3.10.1 Investment Recovery and Regulatory Implications

Investment recovery will be through standard rate recovery mechanisms approved by appropriate regulatory agencies. Specifically, this project is included in the most recent Rhode Island ISR filing.

3.10.2 Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $15.907M.

3.10.3 CIAC / Reimbursement

N/A

3.11 ***Financial Impact to National Grid***

3.11.1 Cost Summary Table

					Current Planning Horizon						
					Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
C079252	Southern RI Growth Reinf-Quaker Ln	Est Lvl (e.g. +/- 10%)	CapEx	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786

Total Project Sanction	CapEx	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786
	OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Total	0.545	1.881	35.794	30.569	8.772	0.225	0.000	77.786

US Sanction Paper

3.11.2 Project Budget Summary Table

Project Costs per Business Plan

		Current Planning Horizon						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
CapEx	0.545	1.500	0.000	0.000	0.000	0.000	0.000	2.045
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.545	1.500	0.000	0.000	0.000	0.000	0.000	2.045

Variance (Business Plan-Project Estimate)

		Current Planning Horizon						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
CapEx	0.000	(0.381)	(35.794)	(30.569)	(8.772)	(0.225)	0.000	(75.741)
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	(0.381)	(35.794)	(30.569)	(8.772)	(0.225)	0.000	(75.741)

3.11.3 Cost Assumptions

3.11.4 Net Present Value / Cost Benefit Analysis

3.11.4.1 *NPV Summary Table*

This is not a NPV project.

3.11.4.2 *NPV Assumptions and Calculations*

N/A

3.11.5 Additional Impacts

3.12 *Statements of Support*

3.12.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities
Investment Planner	Pat Pensabene	Endorses relative to 5-year business plan or emergent work
Resource Planning	Laeyeng Hunt	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	David Weimer	Endorses Resources, cost estimate, schedule
Gas Project Estimation	John Duffy	Endorses Cost Estimate

3.12.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Function	Individual
Finance	Felicia Midkiff
Regulatory	Ed Turieo
Jurisdictional Delegate	John Currie
Procurement	Diego Chevere
Control Center	Paul Loiacono

4 Appendices

4.1 *Sanction Request Breakdown by Project*

N/A

4.2 *Other Appendices*

N/A

4.3 *NPV Summary*

N/A

4.4 *Customer Outreach Plan*

The Company believes in an open, transparent and regular two-way dialogue with project stakeholders throughout the life of its projects. The Company has launched a comprehensive campaign to educate and inform neighborhood residents, municipal officials, and businesses about the full scope of work to be undertaken to support this Project. This multi-faceted campaign includes:

- Meetings with municipalities and relevant governmental organizations with interest in the project scope.
- Open House events.
- A user-friendly, interactive website.
- A Project hotline.
- Social media for additional community access (Twitter)
- Fact sheets, door hangers, FAQs, timelines, etc.
- Advertising.
- A Project Ombudsman who serves as a single point-of-contact for the public.

The team will continue to maintain a high level of outreach to discuss the Project, receive comments, and answer questions throughout the permitting and construction phases.

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Resanction: US Sanction Paper

Title:	Southern RI Growth Reinforcement-Quaker Ln	Sanction Paper #:	USSC-19-001V2
Project #:	C079252	Sanction Type:	Resanction
Operating Company:	The Narragansett Electric Company	Date of Request:	1/27/2020
Author:	Hogan, Andrew	Sponsor(s):	Bennett, Thomas E. VP Gas Asset Management
Utility Service:	Gas	Project Manager:	Hogan, Andrew

Executive Summary

This paper requests Resanction of C079252 in the amount of $96.792M with a tolerance of +/-10% for the purposes of Engineering, Materials Procurement, Full implementation, and any other activities related to the design and construction of the project..

This sanction amount is $96.792M broken down into:
- $96.792M Capex
- $0.000M Opex
- $0.000M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

Note the originally requested sanction amount of $77.786M.

This project has been evaluated for capital efficiencies, which are reflected in the sanction amount. The project will continue to be evaluated for any procurement or construction efficiency opportunities upon its release for construction.

Project Summary

This project seeks to fund the installation of approximately 5.1 miles of transmission main on The Narragansett Electric Company's natural gas system in Warwick, West Warwick and East Greenwich, located south of the Cranston Take Station. The scope of work includes installation of new 20 inch steel transmission main designed for a maximum allowable operating pressure (MAOP) of 200 psig and constructed to be in-line inspected (ILI). The new main installation begins in Quaker Lane, West Warwick near Regulator Station #133 at the intersection of Cowesset Road and continues south through South Country Trail, East Greenwich. The project is segmented into three phases, each temporarily connected to the existing distribution system at a maximum operating pressure (MOP) of 99 psig. Once all phases are installed and the associated projects are completed, the pressure will be increased to a MOP of 200 psig.

Drivers:

This project is needed to maintain continuous service to all customers on the Southern Rhode Island service territory distribution network during periods of peak demand (i.e., design weather conditions) while increasing capacity in an area that is currently constrained. The results of the growth analysis on the gas distribution network predicts that for the 2022/23 winter, using the current Gas Supply send-out forecast, approximately 3,750 customers could experience below minimum design pressures and be at risk of losing service if design conditions were experienced. The estimated restoration cost (i.e., relight, plus claims) for such an event is approximately $6.5M, based on an estimated $1,750 per customer. The estimated restoration cost does not include other significant costs, such as business interruption costs and other customer and societal costs that result from loss of natural gas service when gas is needed most. To avoid this situation, without this project the Company may need 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.

The Company's service territory around the Southern RI Distribution Mains is unique because there are fewer interstate pipelines than other areas. Thus, the Company relies on LNG for pressure support at warmer temperatures as compared with other parts of its service territory, which traditionally rely on LNG for peak shaving on design days. The additional capacity from the project should reduce reliance on the Exeter LNG facility for pressure support.

Related Projects, Scoring and Budget

Summary of Projects

Project Number	*Project Type* (Elec only)	*Project Title*	*Estimate Amount($M)*
C079252		Southern RI Growth Reinforcement-Quaker Ln	96.792
		Total:	96.792

Prior Sanctioning History

Date	*Governance Body*	*Sanctioned Amount*	*Potential Project Investment*	*Sanction Type*	*Sanction Paper*	*Potential Investment Tolerance*
1/9/2019	SESC	$77.786M	$77.786M	Sanction	USSC-19-001	+/- 10%
11/1/2018	USSC	$5.300M	N/A - Note 1	Re-sanction	USSC 18-243V2	+/- 10%
6/1/2018	USSC	$1.300M	N/A - Note 1	Partial	USSC 18-243	+/- 10%

Note 1 - Project scope was developed under the annual program sanction, FY19 Annual Project Development – RI Gas, USSC-18-243.

Over / Under Expenditure Analysis

Summary Analysis	Capex	Opex	Removal	Total
Resanction Amount	96.792	0.000	0.000	96.792
Latest Approval	77.786	0.000	0.000	77.786
Change	19.006	0.000	0.000	19.006

Key Milestones

Milestone	*Date (Month / Year)*
Sanction - (Under Project Development)	June, 2018
Gate C - Approval to Begin Engineering & Design	November, 2018
Re-sanction (Under Project Development)	November, 2018
Sanction	January, 2019
Gate C1 - Approval to Progress to Field Execution	February, 2019
Construction Start	April, 2019
Re-sanction	January, 2020

Construction Complete - CC	November, 2021
Gate D - Approval to Progress to Closeout	January, 2022
Gate E - Approval to Close Project	June, 2022
Project Closure Sanction	June, 2022

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
June, 2022	Closure

Business Plan

Business Plan Name & Period (BP 18)	*Project Included in approved Business Plan?*	*(Over) / Under Business Plan*	*Project Cost relative to approved Business Plan ($M)*
FY 20-24 Gas Capital Plan	◉ Yes ○ No	◉ Over ○ Under ○ N/A	(15.494)

If Cost > Approved

if costs > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio has been managed by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements. In particular, the project is included in the FY20-24 Gas Capital Plan at the sanctioned amount.

Detailed Analysis Table

Detail Analysis	*Over/Under Expenditure?*	*Amount (M's)*
Contractor Pricing Greater than Sanctioned Estimate	◉ Over ○ Under	8.200
Removal of Ledge Impact	◉ Over ○ Under	6.403
Paving Curb to Curb	◉ Over ○ Under	4.403

Explanation of Key Variations

The estimate used for sanctioning was created prior to receiving contractor pricing. After sanction, the major cost headwinds were due to:

1. Higher contractor bids than estimated
2. Significant increase in ledge
3. Changes in Rhode Island General Law requiring curb to curb paving

Variance #1 – Contractor Bid ($8.2M variance)
When the bids were submitted, the low bid, including capital overheads, was $8.2M over the estimate. A review was conducted; it was determined that the cost of installing the pipe was in-line with our estimate, but the Horizontal Directional Drill costs were higher than anticipated. This was the first HDD with the new estimating process. As a lessons learned this information has been provided to estimating.

Variance #2 – Impacts of Ledge ($6.403M variance)
When the project was designed, the team, used test holes and Rhode Island Department of Transportation

(RIDOT) highway as-built data, based on this data estimated quantity of ledge was 125 cubic yards over 5.1-mile. Prior to contract award, our vendor reviewed this data, as well as their internal data, and confirmed the estimate. In the first mile, over 1,100 cubic yards of ledge was removed. This resulted in have to pay the contractor the pre-negotiated unit price rate and the cost premium associated with working additional hours to recover schedule. The team extrapolated the actual ledge encountered and projects, at the end of the project, 5,700 cubic yards of ledge will be removed.

Variance #3 – The Rhode Island Utility Fair Share Roadway Repair Act ($4.403M variance)
The Rhode Island Utility Fair Share Roadway Repair Act was enacted into state law on July 15, 2019. The Act requires 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. The new curb to curb paving restoration requirement will significantly impact the costs of this Rhode Island project. The current estimate for the curb to curb paving is $4.43M and is based on expected conditions that RIDOT will impose when the permits are issued for Phases 2 and 3.

These costs have been included in the FY21 ISR submission.

Cost Summary Table

Project Number	C079252	Project Title	Southern RI Growth Reinforcement-Quaker Ln	Project Estimate Level	+/- 10%

Spend	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	39.922	41.362	14.908	0.600	0.000	0.000	0.000	96.792
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	39.922	41.362	14.908	0.600	0.000	0.000	0.000	96.792

Total Project Sanction								
Capex	39.922	41.362	14.908	0.600	0.000	0.000	0.000	96.792
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	39.922	41.362	14.908	0.600	0.000	0.000	0.000	96.792

Project Costs per Business Plan

$M	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	39.922	32.036	9.340	0.000	0.000	0.000	0.000	81.298
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	39.922	32.036	9.340	0.000	0.000	0.000	0.000	81.298

Variance

$M	Prior Yrs	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	Total
Capex	0.000	(9.326)	(5.568)	(0.600)	0.000	0.000	0.000	(15.494)
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	(9.326)	(5.568)	(0.600)	0.000	0.000	0.000	(15.494)

Improvements / Lessons Learned

When this project was developed, lessons learned were reviewed and best practices were implemented as part of the design development process. To date, the execution team has developed additional lessons learned and best practices:

1. Ledge will be profiled for future phases. A meeting will be facilitated with project team, development and estimating to address for future projects.
2. The horizontal directional drilling estimate was not in line with market pricing. The estimating process will use this information in future estimates.

Statement of Support

Department	***Individual***	***Responsibilities***
Investment Planner	Eddleston, Stephanie	Endorses relative to 5-year business plan or emergent work
Resource Planning	LaFond, Phil	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule
Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers

Function	***Individual***
Finance	Attard, Jason V.
Regulatory	Azarcon, Carolyn
Jurisdictional Delegate	Schmid, Randy
Procurement	Chevere, Diego
Control Center	Loiacono, Paul A.

Decisions

The Senior Executive Sanctioning Committee (SESC) approved this paper at a meeting held on 01/27/2020:
(a) APPROVE the investment of $96.792M and a tolerance of +/-10% for Engineering, Materials Procurement, Full implementation, and any other activities related to the design and construction of the project..

(b) NOTED that Hogan, Andrew has the approved financial delegation

Signature Margaret M Smyth

Date January 27, 2020

Margaret Smyth
US Chief Financial Officer
Chair, Senior Executive Sanctioning Committee

Appendix

N/A

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Short: US Sanction Paper

Title:	LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	Sanction Paper #:	USSC-21-285
Project #: C55 Invst Code:	C085181 5360101095	Sanction Type:	Sanction
Operating Company:	The Narragansett Electric Company	Date of Request:	7/27/2021
Author:	Przybysz, Agnieszka	Sponsor(s):	Fromm, Walter F. VP Gas Cap D
Utility Service:	Gas	Project Manager:	Hogan, Andrew

Executive Summary

This paper requests Sanction of C085181 in the amount of $4.240M with a tolerance of +/-10% for the purposes of final design and execution; indicating that the baseline cost, scope and schedule as described herein has been approved through the Complex Capital Construction.

This sanction amount is $4.240M broken down into:
$4.227M Capex
$0.000M Opex
$0.013M Removal

With a CIAC/Reimbursement of $0.000M
With a Salvage Value of $0.000M

This project has been evaluated for capital efficiencies, which are reflected in the sanction amount. The project will continue to be evaluated for any procurement or construction efficiency opportunities upon its release for construction.

Project Summary

Installation proposed as the scope of this project will address an additional reliability and redundancy risk posed to the existing, single run regulator station, as a result of increased flows that prompts increased gas velocities.

As a part of the Southern Rhode Island Growth Reinforcement project, it is expected that the existing station will see a significant increase in peak flows over the next 5 years.

Background

June 2017 forecasted flows through Cowesett Rd Regulator Station (RIS-133) triggered a thorough review of the existing assets. The review was required to ensure that increases in gas flows and velocities are mitigated to maintain safe levels and that the regulator equipment has sufficient capacity to meet the increased flows projected on the system.

Upgrades and replacements were anticipated for the pressure regulating equipment and associated inlet and outlet piping, including adding additional runs for reliability and redundancy and adding a third layer of protection to meet current Company standards .

Project Description

Project scope is to install additional regulator runs in parallel with the existing regulator station at the intersection of Cowesett Rd & Quaker Lane in West Warwick, RI.

Install inlet piping including a new inlet ball valve. Inlet piping is tied into existing 200# main.

Install outlet piping including a new outlet valve. Tie outlet piping in to existing stub piece. Further downstream, the existing stub piece is to be tied into the existing 99# main by installing an additional pipe.

Summary of Benefits

The key driver for this project is asset condition and reliability. Additional customer benefits include reinforcement, load relief, and safety.

The station upgrades help to meet the system capacity requirements for Southern Rhode Island in the June 2017 forecast and continue to maintain minimum system pressures.

Increased flows exacerbate the risk due to in increased gas velocities and continued reliance on a single run regulator station poses an additional reliability and redundancy risk.

Business and Customer Issues

There are no significant business or customer issues beyond what has been described elsewhere.

Drivers:

Existing RIS-133, Cowesett Rd @ Quaker Ln, is a regulator station located in the town of West Warwick in the Rhode Island Central Region. The station is currently fed by the 149PSIG line from Cranston Gate Station and reduces pressure to 99PSIG. National Grid is currently working to raise the pressure on the inlet system back up to its MAOP of 200PSIG, and any new station work will be designed for this inlet.

The station is critical based on its current flow and the number of feed customers.

As a part of the Southern Rhode Island Growth Reinforcement project, it is expected that this station will see a significant increase in peak flows over the next 5 years. This station experiences high gas velocities, lacks dual regulator runs for redundancy, and requires the addition of a third layer of over pressure protection.

Alternatives

Number	*Title*
1	This option would seek to rebuild the existing regulator run in place in the current vaults. As there is limited space, it would be unlikely that this option could address the risks at this facility. It would not include installation of strainer equipment on the run, three independent layers of pressure control, and full independent isolation capabilities for the regulator run. Most importantly, it would not address the reliability risk at this station due to only having a single run without a regulated backup run for redundancy. (Not Recommended)
2	

	This option would seek to replace the existing regulator run with a new regulator station. The new station would feature three fully independent layers of pressure control, independent isolation valves, and strainer equipment to protect from particulate debris in the gas stream. A standard three-layer prefabricated regulator station (like those installed elsewhere on National Grid's RI gas distribution system) cannot meet the flow requirements at this site, and therefore it is likely that a custom station, or multiple prefabricated stations would be needed. (Not Recommended)
3	Do Nothing. This option would result in the existing regulator run being left in place with no additions or modifications. This option does not address the risks identified. (Not Recommended)

Related Projects, Scoring and Budget

Summary of Projects

Project Number	***Project Type*** (Elec only)	***Project Title***	***Estimate Amount($M)***
C085181		LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	4.240
		Total:	4.240

Associated Projects

Project Number	***Project Title***	***Estimate Amount ($M)***
TBD	Gas Planning - LTRI13064 - Growthpoint - New Regulator Station Near Cowesett	2.350
C079252	Gas Planning - LTRI13056 - Growthpoint - Main Installation	98.643
C081907	Gas Planning - LTRI13060 - Growthpoint - MOP Increase	4.057
C082302	Gas Planning - LTRIxxxxx - Growthpoint - Regulator Station Upgrades - Cranston	10.041
C081906	Gas Planning - LTRIxxxxx - Reg Station/Launcher -Receiver/Install ROV	12.251
		127.342

Prior Sanctioning History

Date	***Governance Body***	***Sanctioned Amount***	***Potential Project Investment***	***Sanction Type***	***Sanction Paper***	***Potential Investment Tolerance***
3/2/2021	USSC	$0.500M	$1.687M	Project Development	USSC-21-102	+/-10%
3/19/2020	USSC	$0.347M	$1.687M	Project Development	USSC-20-146	+/-10%

Note: $1.687M potential project investment total was based on a very preliminary scope description. Final estimate of $4.24M was based on developed design. It includes additional scope determined during project development process required night work, assumptions on permitting and traffic management plan.

Key Milestones

Milestone	***Date (Month / Year)***
Project Development Sanction	March 2020
Project Development Sanction	March 2021
Gate C - Approval to Begin Engineering & Design	July 2021
Sanction	July 2021

Gate C1 - Approval to Progress to Field Execution	September 2021
Construction Start	April 2022
Construction Complete - CC	October 2022
Gate D - Approval to Progress to Closeout	January 2023
Project Closure Sanction	November 2023

Next Planned Sanction

Date (Month/Year)	Purpose of Sanction Review
November 2023	Closure

Category

Category	Reference to Mandate, Policy, or NPV
◉ Mandatory ○ Policy-Driven ○ Justified NPV	Federal Code 49 CFR 192.623 and RI Division of Public Utilities and Carriers' Standards for Gas Utilities, 815-RICR-20-00-1, Section 1.5.B.,require minimum pressures to be maintained in the gas system.

Asset Management Risk Score: 35

PRIMARY RISK SCORE DRIVER

○ Reliability ○ Environment ○ Health & Safety ◉ Not Policy Driven

Complexity Level: 23

○ High Complexity ◉ Medium Complexity ○ Low Complexity ○ N/A

Net Zero

Contribution to National Grid's 2050 80% emissions reduction target:	◉ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	◉ Neutral	○ Positive	○ Negative
Qualifies for Green Financing:	○ Yes	○ No	◉ N/A

Investment Recovery and Customer Impact

Investment Recovery

Investment recovery will be through standard rate recovery mechanisms.

Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $0.864M.

Business Plan

Business Plan Name & Period (BP 20)	*Project Included in approved Business Plan?*	*(Over) / Under Business Plan*	*Project Cost relative to approved Business Plan ($M)*
FY22 - FY26 Gas Capital Plan	(●) Yes ( ) No	(●) Over ( ) Under ( ) N/A	(1.593)

If Cost > Approved

if costs > approved Business Plan how will this be funded?

Reallocation of funds within the portfolio has been managed and approved by Resource Planning to meet jurisdictional budgetary, statutory and regulatory requirements.

Cost Summary Table

Project Number	C085181	Project Title	LTRI - Growthpoint - Regulator Station Upgrades - Cowesett	Project Estimate Level	+/-10%

Spend	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.347	0.700	3.080	0.100	0.000	0.000	0.000	4.227
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.013	0.000	0.000	0.000	0.000	0.013
Total	0.347	0.700	3.093	0.100	0.000	0.000	0.000	4.240

Total Project Sanction								
Capex	0.347	0.700	3.080	0.100	0.000	0.000	0.000	4.227
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.013	0.000	0.000	0.000	0.000	0.013
Total	0.347	0.700	3.093	0.100	0.000	0.000	0.000	4.240

Project Costs per Business Plan

$M	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.347	0.700	1.487	0.100	0.000	0.000	0.000	2.634
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.013	0.000	0.000	0.000	0.000	0.013
Total Cost in Bus. Plan	0.347	0.700	1.500	0.100	0.000	0.000	0.000	2.647

Variance

$M	Prior Yrs	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	Total
Capex	0.000	0.000	(1.593)	0.000	0.000	0.000	0.000	(1.593)
Opex	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Variance	0.000	0.000	(1.593)	0.000	0.000	0.000	0.000	(1.593)

Statement of Support

Department	*Individual*	*Responsibilities*
Investment Planner	Eddleston, Stephanie	Endorses relative to 5-year business plan or emergent work
Resource Planning	LaFond, Phil	Endorses resources, cost estimate, schedule, and portfolio alignment
Project Management	Wheeler, Bradley	Endorses resources, cost estimate, and schedule
Project Estimation	Duffy, John E.	Endorses cost estimate

Reviewers

Function	*Individual*
Finance	Grzesiuk, Brian
Regulatory	Azarcon, Carolyn
Jurisdictional Delegate	Schmid, Randy
Procurement	Chevere, Diego
Control Center	Loiacono, Paul J.

Decisions

I:

(a) APPROVE the investment of $4.240M and a tolerance of +/-10% for final design and execution; indicating that the baseline cost, scope and schedule as described herein has been approved through the Complex Capital Construction.

(b) NOTED that Hogan, Andrew has the approved financial delegation

DocuSigned by:

Signature Mike Gillespie
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Date 8/10/2021

Michael Gillespie, Vice President, Head of Finance Business Partnering, USSC Chair

Appendix

N/A

PUC 10-6
Latent Knight and Cowesett Regulator Work

Request:

Regarding the "Latent Knight and Cowesett Regulator" project,

a. Please provide an explanation, description, and detailed budget of/for the project referenced as the "Latent Knight and Cowesett Regulator,"

b. Referring to the response to Division 1-42 and the reference to "additional gas," please explain what was meant by the statement: "This work was required to supply Southern Rhode Island with additional gas."

c. Please also explain whether the project is needed to maintain reliability of the system or being developed in response to a forecast of growth in gas distribution system. If based on a forecast, please provide an explanation of the forecast and how it relates to the need for the project work.

Please indicate whether the "Latent Knight and Cowesett Regulator" work was identified in the original budget estimates for the Southern Rhode Island Expansion Project when that project was first proposed for inclusion in the ISR.

Response:

a. **Cowesett Regulator Station**

The Cowesett Regulator consists of the installation of a new three (3) compartment 6-inch regulator station at the intersection of Cowesett Road and Quaker Lane in West Warwick.

The new station will provide additional reliability and redundancy to mitigate risk posed by the existing, single-run regulator station and to mitigate future increases in gas velocity as a result of increased flows.

The budget estimate is $4.46M.

PUC 10-6, page 2

Latent Knight and Cowesett Regulator Work

Laten Knight Project

The Laten Knight Project is intended to replace and upgrade the Laten Knight Take Station.

The June 2017 forecasted flows and an increase of Maximum Operating Pressure ("MOP") from 150 to 200 psig through the Laten Knight take station triggered a thorough review of the existing assets. The review was required to ensure the increase in gas flows, outlet pressure and velocities are mitigated to maintain safe levels and minimize noise and vibration through equipment. The Laten Knight Project will provide material traceability, reliability, a third layer of overpressure protection, and, by using a larger pipe, will reduce gas velocity thereby minimizing noise and vibration

The budget for this project is estimated at $6.59M.

b. As explained in subpart a., in June 2017 the Company forecasted increased flows and an increase of Maximum Operating Pressure ("MOP") from 150 to 200 psig through the Laten Knight take station triggering a need to ensure the increase in gas flows, outlet pressure and velocities are mitigated to maintain safe levels and minimize noise and vibration through equipment.

c. The Laten Knight Project and Cowesett Regulator Project are needed to ensure reliability. The Cowesett Regulator Project will provide additional reliability, a third layer of over pressure protection and provide redundancy which will lower the risk posed to the existing, single-run regulator station, as a result of increased flows that prompts increased gas velocities. The Laten Knight Project will provide material traceability, reliability, a third layer of overpressure protection, and, by using a larger pipe we will reduce gas velocity thereby minimizing noise and vibration.

The Laten Knight and Cowesett Regulator work was identified in the original budget estimates for the Southern Rhode Island Expansion Project when that project was first proposed for inclusion in the ISR in the Company's FY2020 Gas ISR Plan approved by the Commission in Docket No. 4916.

PUC 10-7

Proactive Low Pressure System Elimination

Request:

Regarding the "Proactive Low Pressure System Elimination" initiative, why has the Company categorized this initiative as "Non-discretionary" if it is a "proactive" program? Does the Company have discretion in choosing timing and locations for implementing this initiative?

Response:

Please see the Company's response to Data Request Division 1-4 in this docket, which is attached to this response as Attachment PUC 10-7, that explains why the Company categorized the budget for the "Proactive Low Pressure System Elimination" initiative as "Non-discretionary." The program name was labeled as "proactive" since its inception in ISR fiscal year ("FY") 2022 because the purpose of the program is to systematically replace low pressure gas systems ("LP") with high pressure ("HP") gas systems to enhance gas system safety and transfer customers on the selected LP systems to a nearby HP system by installing new distribution mains, services, and service regulators.[1]

The Company can plan locations and timing of projects included in this budget category. Of note, with the newly proposed budget structure, there is no longer a distinction between "Discretionary" and "Non-Discretionary" work, but rather the budget categories are laid out in a prioritized order. Should the new budget structure be approved, any reference to Discretionary status designation would only be from legacy plans.

[1] *See The Narragansett Electric Company d/b/a National Grid Gas Infrastructure, Safety and Reliability Plan FY 2022 Proposal*, Docket No. 5099 at Bates Page 53 (filed December 18, 2020).

Prepared by or under the supervision of: Brandon Flynn and Phil LaFond

Division 1-4

Request:

Please explain why the Low Pressure System Elimination (Proactive) Budget is denominated as a Mandated Program. Include in your discussion any risks associated with low-pressure systems?

Response:

The Low Pressure System Elimination (Proactive) budget is denominated as a mandated program due to its original purpose to replace low pressure areas prone to water intrusion. The associated budget was used for a proactive program targeting leak prone low pressure systems within flood planes that have been notorious for water intrusion in the past. In 2019, the name of the program was changed to Low Pressure System Elimination as a result of the Merrimac Valley incident, and the program was adapted to replace low pressure systems with high pressure systems, when feasible, to address safety concerns with no over pressure protection on low pressure systems.

In Docket No. PHMSA-2020-0025, PHMSA issued an alert to all low-pressure natural gas distribution system operators of the possibility of a failure of over pressure protection. *See* Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems, 85 Fed. Reg. 61097 provided as Attachment DIV 1-4. The alert recommends that operators use a failure modes and effects analysis or **equivalent structured and systematic method to identify potential failures and take action to mitigate those identified failures**.

The Company scoped projects to be low pressure to high pressure replacements to eliminate low points or single feed low pressure systems as part of gas planning and reliability projects as well. This budget allows the Company to focus on the various concerns the legacy low pressure systems present, especially in an older system such as Rhode Island. Examples of these concerns are as follows:

- Majority of leak prone pipe is on the Low Pressure (LP) gas systems.
- More than half of the Company's regulator stations throughout the distribution system are for LP systems and require larger relief valves and three layer prefabricated stations for over pressure protection at the highest risk point of the system.
- There are no excessive flow valves on new plastic services on LP systems, nor are there service regulators as a second layer of over pressure protection to customers' houses.
- There is significantly lower line pack in LP systems (compared to high pressure systems) because it operates at 0.25 psig. Consequently, larger diameter mains are required to span

Division 1-4, page 2

longer distances and to serve lower use customers. This is a reason of concern and prompted recent analysis of electric outages during design winter conditions. When electric systems are restored after an outage, and gas appliances start simultaneously, for heat, water heat, cooking, drying, etc, there is a potential for LP system pressures to drop significantly. Extremities, low points, and unknown blockages in the older system could potentially lead to gas outages under these conditions.

- LP systems are susceptible to water intrusion which was the original driver for this program.

- There is minimal gas delivery pressure to customers that sometimes require a higher inlet pressure for more energy efficient appliances. These customers often need to install boosters to maintain a higher delivery pressure to these appliances including generators, tankless water heaters, combo units and similar equipment.

- The inefficiency of leak prone LP systems would be problematic for the distribution of alternative sources of energy, such as hydrogen blended gas, renewable gas, or others, because of the lower BTU content of these fuels. In order to deliver these fuels through the Company's distribution system as a potential pathway to address the mandates of the Act on Climate, the Company would need to advance LP system elimination.

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on respondents, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended; 49 CFR 1.49; and DOT Order 1351.29.

Chou-Lin Chou,

Associate Administrator, National Center for Statistics and Analysis.

[FR Doc. 2020–21417 Filed 9–28–20; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2020–0025]

Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; Issuance of advisory bulletin.

SUMMARY: The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this advisory bulletin to remind owners and operators of natural gas distribution pipelines of the possibility of failure due to an overpressurization on low-pressure distribution systems. PHMSA is also reminding such owners and operators of existing federal integrity management regulations for gas distribution systems.

ADDRESSES: PHMSA guidance, including the advisory bulletin, can be found on PHMSA's website at *https://www.phmsa.dot.gov/guidance.*

FOR FURTHER INFORMATION CONTACT:

Technical Questions: Michael Thompson, Transportation Specialist, by phone at 503–883–3495 or by email at *michael.thompson@dot.gov.*

General Questions: Ashlin Bollacker, Technical Writer, by phone at 202–366–4203 or by email at *ashlin.bollacker@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Natural Gas Distribution Systems

Natural gas distribution systems deliver natural gas to customers for heating, cooking, and other domestic and industrial uses. A basic natural gas distribution system has four elements: (1) Mains that transport gas underground; (2) service lines that deliver natural gas from the main to the customer; (3) regulators that control the pressure of gas to a designated value; and (4) meters that measure the quantity of natural gas used by each customer. Customer piping takes natural gas from the meter to the customer's heating equipment and other appliances.

There are two types of natural gas distribution systems used to supply natural gas to the customer: High-pressure distribution systems and low-pressure distribution systems. In a high-pressure distribution system, the gas pressure in the main is higher than the pressure provided to the customer. A pressure regulator installed at each meter reduces the pressure from the main to a pressure that can be used by the customer's equipment and appliances. These regulators incorporate an overpressure protection device to prevent overpressurization of the customer's piping and appliances should the regulator fail. Additionally, as of April 14, 2017, all new or replaced service lines connected to a high-pressure distribution system must have excess flow valves. (§ 192.383).[1] Excess flow valves can reduce the risk of overpressurization in natural gas distribution pipelines by shutting off unplanned, excessive gas flows. Because each customer's service line in a high-pressure distribution system is protected by an excess flow valve and a pressure regulator, it is highly unlikely that an overpressurization condition in the main would impact customers.

In a low-pressure natural gas distribution system, however, the natural gas in a distribution pipeline flows predominantly at the same pressure as the pressure contained within the customer's service line piping. Natural gas is typically supplied to distribution pipeline mains from a high-pressure source that connects to, and flows through, a regulator station. The regulator station functions to reduce the pressure to a level that allows the gas to flow continuously at a low pressure all the way to premises of the customers where the gas is ultimately consumed. Since there are no regulators at the customer meter set in a low-pressure system, an overpressure condition occurring on the distribution system can affect all customers served by the system in the event that the regulator(s) that controls the pressure for the system fails. This scenario is what happened in the September 13, 2018, accident in Merrimack Valley that prompted the subsequent National Transportation Safety Board (NTSB) report and recommendations.

II. CMA's Accident in Merrimack Valley

A. Accident Synopsis

On September 13, 2018, a series of structure fires and explosions occurred after high-pressure natural gas entered a low-pressure natural gas distribution system operated by Columbia Gas of Massachusetts (CMA), a subsidiary of NiSource, Inc.[2] CMA delivers natural gas to about 325,000 customers in Massachusetts. According to an investigation of the accident conducted by the National Transportation Safety Board,[3] the fires and explosions damaged 131 structures, including at least 5 homes that were destroyed in the city of Lawrence and the towns of Andover and North Andover. CMA shut down the low-pressure natural gas distribution system serving 10,894 customers, including some outside the affected area who had their service shut off as a precaution. An 18-year-old male was killed when a home exploded, and the house's chimney fell onto the vehicle where he was sitting. Another person in the vehicle at the time of the explosion was seriously injured, as was someone on the second floor of the house. In total, 22 people, including 3 firefighters, were transported to hospitals for treatment of their injuries.

B. Background on CMA's Natural Gas Main Replacement Project

The low-pressure natural gas distribution system in the Merrimack Valley was installed in the early 1900s and was constructed with cast iron mains. The system was designed with 14 regulator stations to control the pressure of natural gas entering the downstream distribution pipeline mains. Each regulator station contained two regulators in series—a ''worker regulator'' and a ''monitor regulator''—each with a sensing line connected to a downstream section of main for the purpose of providing a pressure measurement back to the regulator station so that the system could be maintained at a specified pressure level of 0.5 pounds per square inch. The

[1] PHMSA published the final rule, ''Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences,'' on October 14, 2016, but delayed the effective date by six months to give operators time to comply with the new provisions. (81 FR 70987). A copy of this final rule is available in the docket PHMSA–2011–0009 at *https://www.regulations.gov.*

[2] CMA is expected to be officially transferred by NiSource, Inc., to Eversource Energy in November 2020.

[3] ''Pipeline Accident Report: Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts; September 13, 2018.'' The National Transportation Safety Board. Accident Report: NTSB/PAR–19/02. Adopted September 24, 2019.

''worker'' regulator is the primary regulator that maintains the natural gas pressure, and the ''monitor'' regulator provides a redundant backup to the ''worker'' regulator. Each of the regulator stations reduced the natural gas pressure from about 75 pounds per square inch gauge (psig) to 12 inches of water column (w.c.), or about 0.5 psig, for distribution through the mains and delivery to customers.[4]

Beginning in 2016, CMA initiated an effort to replace 7,595 feet of low-pressure cast iron and bare steel mains with 4,845 feet of low-pressure and high-pressure polyethylene (plastic) mains. CMA contracted with Feeney Brothers, a pipeline services firm, to complete the replacement project. A work package, which included materials such as isometric drawings and procedural details for disconnecting and connecting pipes, was prepared for each of the planned construction activities. However, no package was prepared for the relocation of the Winthrop Avenue sensing lines serving the Winthrop Avenue regulator station.

The first stage of the project involved the installation of the plastic main, which was completed in late 2016. The regulator sensing lines at the Winthrop Avenue regulator station remained attached to the cast iron main that would ultimately be decommissioned.

CMA connected the plastic pipe to the distribution system, which allowed it to be monitored for pressure changes. The second stage of the project began in 2018 and involved the installation of tie-ins to the new plastic main, after which the legacy cast iron mains would be decommissioned and abandoned in their existing location. On the day of the accident, the sensing lines were still connected to the abandoned cast iron main.

At the Winthrop Avenue regulator station, about 0.5 mile south of the work area, the sensing lines connected to the abandoned cast iron mains continued providing data input to the two pressure regulators used to control the system pressure.[5] Once the contractor crew isolated the cast iron main, the natural gas pressure began to drop in the cast iron main and the sensing lines continued to provide those readings to the regulator station. As the pressure dropped, the pressure regulators responded by opening further to inject more gas to into the downstream system to the newly installed plastic system.

Because there were no sensing lines connecting the regulator station to the newly installed plastic mains, the legacy sensing lines continued to provide ''zero'' pressure readings to Winthrop Avenue regulators, thereby causing them to fully open and provide a continuous flow of gas into the new low-pressure plastic system, resulting in an extreme overpressurization of the distribution system. This immediately resulted in multiple fires, explosions, and injuries.

C. National Transportation Safety Board (NTSB) Accident Investigation and Recommendations

Since the accident, the National Transportation Safety Board (NTSB) issued several safety recommendations. On November 14, 2018, NTSB recommended that the operator, NiSource Inc.:

- Revise the engineering plan and constructability review process across all of its subsidiaries to ensure that all applicable departments review construction documents for accuracy, completeness, and correctness, and that the documents or plans be sealed by a professional engineer prior to commencing work (P–18–6);
- Review and ensure that all records and documentation of its natural gas systems are traceable, reliable, and complete (P–18–7);
- Apply management of change process to all changes to adequately identify system threats that could result in a common mode failure (P–18–8); and
- Develop and implement control procedures during modifications to gas mains to mitigate the risks identified during management of change operations. Gas main pressures should be continually monitored during these modifications and assets should be placed at critical locations to immediately shut down the system if abnormal operations are detected (P–18–9).

In response, NiSource Inc. has taken actions that satisfied the NTSB's recommendations, which are now classified as ''Closed.''

On September 24, 2019, the National Transportation Safety Board (NTSB) issued its accident report and identified the probable cause of, and contributing factors to, CMA's accident in Merrimack Valley. NTSB found that the probable cause of the accident was CMA's weak engineering management that failed to adequately plan, review, sequence, and oversee the construction project that abandoned the cast iron main without first relocating the regulator sensing lines to the new plastic main. NTSB also found that a contributing cause of the accident was a low-pressure natural gas distribution system that was designed and operated without adequate overpressure protection. As a result of its investigation, NTSB made several recommendations to NiSource, Inc., the Commonwealth of Massachusetts and several other States, and PHMSA. NTSB made two recommendations to PHMSA. The first (P–19–14) called for PHMSA to ''revise Title 49 *Code of Federal Regulations* Part 192 to require overpressure protection for low-pressure natural gas distribution systems that cannot be defeated by a single operator error or equipment failure.'' Having investigated multiple overpressurization accidents over the past 50 years, NTSB concluded that low-pressure natural gas distribution systems that use only sensing lines and regulators to detect and prevent overpressurization are not optimal to prevent overpressurization accidents.

NTSB's second recommendation (P–19–15) called for PHMSA to ''issue an alert to all low-pressure natural gas distribution system operators of the possibility of a failure of overpressure protection, and the alert should recommend that operators use a failure modes and effects analysis (FMEA) or equivalent structured and systematic method to identify potential failures and take action to mitigate those identified failures.'' NTSB found that CMA's constructability review[6] process was not sufficiently robust to detect the omission of a work order to relocate the sensing lines; and that CMA's engineering risk management processes were deficient. NTSB explained that for regulator sensing lines, CMA only considered excavation damage as a risk to be mitigated. NTSB concluded that a comprehensive and formal risk assessment, such as FMEA, would have identified the human error that caused the redundant regulators to open and over pressurize the low-pressure system.

In response to NTSB's recommendation P–19–15, PHMSA is issuing this advisory bulletin to remind owners and operators of low-pressure natural gas distribution systems of the possibility of a failure of overpressure protection devices. Currently, there are Federal regulations in place that specify several minimum safety standards requiring operators to account for the possibility of overpressure events in the

[4] In the pipeline industry, it is customary to measure anything less than 1 psig in inches of water column. A measurement of 1 inch w.c. equals 0.0361 psig.

[5] *Sensing lines* are also called *control lines* or *static lines.*

[6] ''Constructability reviews'' are a recognized and generally accepted good engineering practice commonly used for the execution of professional design services and are intended to provide an independent and structured review of construction plans and specifications to ensure there are no conflicts, errors, or omissions.

design and operation of their systems. Specifically, the Distribution Integrity Management Program (DIMP) regulations at 49 CFR 192.1005 require operators of natural gas distribution systems to develop and implement an integrity management program for pipelines they own, operate, or maintain. Under DIMP, operators must identify existing and potential threats to the integrity of their systems, and to rank the risks so that known issues can be evaluated by the risks they pose. PHMSA agrees with the NTSB that low-pressure distribution system operators need to be reminded of their obligation to identify all threats to their systems and take mitigative measures in accordance with the risks to their systems. The diversity of designs and operating conditions of those systems mean that the risks associated with overpressure conditions may be best managed by a combination of design elements and engineering practices tailored to the unique attributes and conditions of their specific systems that pipeline operators are best positioned to identify and implement. Therefore, PHMSA is reminding operators of low-pressure distribution systems of their existing obligations under the DIMP regulations to consider and implement such tailored approaches to mitigate or eliminate the risk of an overpressurization event.

D. Distribution Integrity Management Program Regulatory Provisions

PHMSA first adopted integrity management regulations for hazardous liquid pipelines in 2000, then for gas transmission pipelines in 2003. Subsequently, the Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 (PIPES Act of 2006; Pub. L. 109–468) mandated that PHMSA prescribe minimum safety standards to extend integrity management to gas distribution pipeline systems. The 2006 legislation directed PHMSA to require operators of distribution pipelines to identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. In response to that mandate, PHMSA implemented new requirements in 49 CFR part 192, subpart P, that rely on operator-specific programs to improve the overall integrity of pipeline systems and reduce risk (74 FR 63905; December 4, 2009). PHMSA concluded that this performance-based approach was a more effective method for improving pipeline system safety—given the diversity of distribution systems and the particular threats to which different systems may each be exposed—than imposing a ‘‘one-size-fits-all’’ prescriptive requirement.

The DIMP regulations require operators of natural gas distribution systems to develop, write, and implement an integrity management program for pipelines they own, operate, or maintain. An integrity management plan is a written set of policies and procedures that each operator must develop and implement to ensure compliance. Pursuant to § 192.1007,[7] an integrity management plan must include procedures for implementing the following elements:

- Periodically assess and improve the integrity management program; and
- Report performance results to PHMSA and, where applicable, also to state public utility commissions.

a. *Knowledge (192.1007(a)).* This section requires an operator to develop an understanding of its distribution pipeline. An operator must identify the characteristics of its pipeline's design and operations, and of the environment in which it operates, which are necessary to assess applicable threats and risks. This must include considering information gained from past design, operations, and maintenance. This section further requires that operators develop their understanding from reasonably available information. Operators have considerable knowledge of their pipeline to support routine operations and maintenance, but this information may be distributed throughout the company, in possession of groups responsible for individual functions. Operators must assemble this information to the extent necessary to support the development and implementation of their IM program.

PHMSA recognizes that there may be gaps in the knowledge an operator possesses when it develops its initial IM plan. Operators must identify these gaps and the additional information needed to improve their understanding. Operators are required to provide a plan for gaining that information over time through the normal activities of operating and maintaining pipeline systems (*e.g.,* collecting information about underlying components when portions of the pipeline must be excavated for other reasons). Operators must also develop a process by which the program will be periodically reviewed and refined, as needed.

[7] ‘‘Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines.’’ Final Rule. (74 FR 63905; Dec. 4, 2009). *https://www.federalregister.gov/documents/2009/12/04/E9-28467/pipeline-safety-integrity-management-program-for-gas-distribution-pipelines#h-22*

b. *Identify threats ((§ 192.1007(b)).* Identification of the threats that affect, or could potentially affect, a distribution pipeline remains critical to ensuring integrity. Knowledge of applicable threats allows operators to evaluate the safety risks they pose and to rank those risks, allowing safety resources to be applied where they will be most effective. This section requires that operators consider the general categories of threats that must be reported on annual reports. Operators are required to consider reasonably available information to identify threats that affect their pipeline or that could potentially affect it (*e.g.,* landslides in a hilly area with loose soils even if no landslide has been experienced). The section specifies that operators should minimally consider data sources resulting from normal operation and maintenance in evaluating threats.

c. *Evaluate and rank risk (192.1007(c)).* This section requires that an operator evaluate the identified threats to determine their relative importance and rank the risks associated with its pipeline. Operators must consider the likelihood of threats and the consequences of a failure that might result from each threat. Consideration of consequences is important to help ensure that risks are properly ranked. A potential accident of relatively low probability but that would produce significant consequences should be considered to be of higher risk than an accident with somewhat greater likelihood, but one that is not expected to produce major consequences.

d. *Identify and implement measures to address risks (§ 192.1007(d)).* This section requires operators to determine and implement measures designed to reduce the risk of failure of gas distribution pipeline systems.

e. *Measure performance, monitor results, and evaluate effectiveness (§ 192.1007(e)).* This section requires operators to develop performance measures, including some that are specified for use by all operators. Measuring performance periodically enables operators to determine whether actions being taken to address threats are effective, or whether different or additional actions are needed. An operator must also periodically re-evaluate the threats and risks to its gas distribution pipeline.

f. *Periodic evaluation and improvement (§ 192.1007(f)).* This section requires operators to re-evaluate risks across the entire pipeline system periodically and to consider the relevance of threats in one specific location as compared to other locations.

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Operators must consider the results of their performance monitoring in these evaluations, which must be performed at least once every five years. An operator must determine an appropriate period for conducting a complete program evaluation based on the complexity of its system. An operator should conduct a program evaluation any time there are changes in factors that would increase the risk associated with a failure.

While DIMP regulations have been in place since 2009, some operators may not be sufficiently aware of their pipeline attributes, nor adequately or consistently assessing threats as part of their DIMP programs. Early in the investigation, NTSB determined that several of NiSource's engineering processes were deficient. For example, the NTSB found that CMA's inadequate planning, documentation, and recordkeeping processes led to the omission of the relocation of sensing lines during a construction project. Further, NTSB found that CMA's constructability review process was not sufficiently robust to detect the omission of a work order to relocate sensing lines. It was the abandonment of the cast iron main without first relocating the sensing lines that led directly to the accident. Thus, it is necessary to identify and evaluate the physical and operational characteristics of each pipeline system to evaluate risks adequately. It is also important that an operator focus its DIMP on identifying the conditions that can cause failures and address them before a failure occurs. Therefore, PHMSA is reminding owners and operators of their continuing obligation to comply with DIMP regulations and is alerting operators that PHMSA considers the possibility of an overpressure protection failure to be a high-risk threat. PHMSA reminds operators of low-pressure systems that they must consider reasonably available information about possible threats to their gas distribution system, including such sources as the NTSB report, industry publications, and this advisory bulletin.

As part of the DIMP plans, PHMSA recommends that operators enhance their processes and procedures by including a failure modes and effects analysis, or equivalent structured and systematic method of risk analysis. Including a failure mode and effect analysis or equivalent methodology can help identify and mitigate the possibility of an overpressure failure event. PHMSA also urges operators to develop and implement procedures for construction-related work that are specific to low-pressure distribution systems, such as repairs, uprates in pressure, or replacement of pipeline or pressure regulation facilities.

II. Advisory Bulletin (ADB–2020–02)

To: Owners and Operators of Natural Gas Distribution Systems

Subject: Overpressure Protection on Low-pressure Natural Gas Distribution Systems.

Advisory: PHMSA is reminding all owners and operators of low-pressure natural gas distribution systems of the risk of failure of overpressure protection systems. This advisory bulletin is intended to clarify for the public existing pipeline safety standards and highlight the importance of evaluating and implementing overpressure protection design elements and operational practices within their compliance programs. The contents of this advisory bulletin do not have the force and effect of law. They are not meant to bind the public in any way, even as pipeline owners and operators must comply with the underlying safety standards.

PHMSA encourages operators to review the NTSB's Pipeline Accident Report concerning Columbia Gas of Massachusetts' (CMA) overpressurization event in the Merrimack Valley on September 13, 2018. It may be instructive regarding a host of potential safety problems that operators of low-pressure natural gas distribution systems may need to address. A copy of NTSB's accident report is contained within Docket No. PHMSA–2020–0025 for this advisory bulletin.

PHMSA also reminds pipeline operators of their obligations to comply with the gas DIMP regulations at 49 CFR part 192, subpart P. Under DIMP, gas distribution operators must have knowledge of their pipeline systems; identify threats to their systems; evaluate and rank risks; and identify, evaluate, and implement measures to address those risks. CMA's accident in Massachusetts highlights the need for operators of low-pressure systems to review thoroughly their current DIMP for the threat of overpressurization and to make any necessary changes or modifications to become fully compliant with the Federal Pipeline Safety Regulations (§ 192.1007(f)).

Written Procedures (§ 192.1005)

Developing and implementing comprehensive written procedures with sufficient specificity is one of the most effective ways to prevent overpressurization of a low-pressure gas system. Therefore, PHMSA reminds operators of low-pressure systems to review their written integrity management plans to help ensure that they comply with § 192.1005 and to ensure that they specifically address the risk of an overpressurization event. PHMSA further recommends, in addition to having procedures for operations, maintenance, and emergencies (§ 192.605), that operators develop written procedures for all activities involving new construction or pipe replacement projects for low-pressure distribution systems. PHMSA recommends that these procedures account for the additional precautions needed to protect those systems from an overpressurization event. These procedures should include:

- Clear roles and responsibilities across all departments involved in the planning and execution of construction or pipe replacement projects;
- Description and delineated scope of work to be conducted, with a materials list, necessary schematics, and maps of the location of the work;
- Requirements to review and ensure that all records and documentation of the affected gas system(s) are traceable, reliable, and complete;
- The sequential process of how the work is to be carried out and who or what group is responsible for each step;
- Application of a ''management of change'' process to identify all changes that could threaten system integrity, particularly where there is a risk emanating from a common mode of failure, including a list of individuals and groups necessary for review along with their comment and approval before work commences; and
- Implement a review process sufficiently robust to detect the omission of critical process and procedural steps that could prevent possible overpressurization events.

Knowledge of Distribution System (§ 192.1007(a))

PHMSA reminds operators that they are required to develop procedures in their DIMP that demonstrate an understanding of their gas distribution systems (§ 192.1007(a)). An operator must identify the characteristics of its pipeline design and operations, and of the environment in which it operates, in the process of assessing applicable threats and risks. Section 192.1007(a) requires that operators develop their understanding from reasonably available information. This must include information gained from past design, operations, and maintenance. If an operator acquires a pipeline and the historical records were not obtained or are not reasonably available, the records do not need to be re-created. However, operators must assemble this information to the extent necessary to support the development and implementation of their integrity management programs. Underlying procedures must also identify additional information necessary to improve their understanding and provide a plan for gaining that information over time through the normal activities of operating and maintaining pipeline systems (*e.g.,* collecting information about buried components when portions of the pipeline must be excavated for other reasons). Operators must also develop a process by which the program will be periodically reviewed and refined, as needed. The outcome of the process should be that all affected departments of an operator's organization are aware of any planned construction work, have had the opportunity to review and provide comments on potential failure modes and to adopt a process for providing final approval of construction procedures.

Identifying Threats and Ranking Risk (§ 192.1007(b)–(c))

PHMSA reminds operators of their obligation under DIMP regulations (part 192, subpart P) to consider available information when identifying all potential and existing threats to the integrity of their systems (§ 192.1007(b)). In accordance with § 192.1007(b), operators are required to consider seven specific threats, including equipment failure and incorrect operation. Further, PHMSA reminds operators to evaluate the risks associated with their distribution pipelines, determine the relative importance of each threat, and rank the risks posed to their pipeline systems (§ 192.1007(c)). PHMSA reminds operators that consideration of consequences is important to help ensure that risks are properly ranked. A potential accident of relatively low likelihood but one that would produce significant consequences may be a higher risk than an accident with somewhat greater likelihood, but one that is not expected to produce major consequences.

Given the catastrophic consequences of the Merrimack Valley accident, PHMSA considers the possibility of an overpressure protection system failure to be a high-risk threat for low-pressure distribution systems where there are not adequate provisions to protect such systems. Therefore, PHMSA recommends that operators consider the single point of failure that could lead to an overpressurization of a low-pressure system as a high-risk threat and to review and adjust their DIMP plans accordingly. NTSB's Pipeline Accident Report sufficiently documents the occurrence of overpressurization of low-pressure distribution systems such that the threat of overpressurization should be considered a real and present threat. If the threat of overpressurization of low-pressure distribution systems is not considered an existing threat by an operator, justification for the elimination of this threat from consideration should be documented.

In performing a risk analysis required by DIMP (§ 192.1007), PHMSA recommends operators use a failure modes and effectiveness analysis (FMEA) model or an equivalent structured and systematic method to identify and mitigate risks. Failure modes and effects analysis (FMEA) is a generally accepted and recognized engineering practice used to identify and assess potential failures, including common mode failures. As NTSB concluded, a comprehensive and formal risk assessment, such as FMEA, would have identified the human error that caused the redundant regulators to open and over-pressurize the low-pressure system. Operators may already be leveraging FMEA or other similarly robust methodologies to perform the risk analysis and should continue to do so. PHMSA recommends that operators consider adopting FMEA or another qualitative tool that may help to identify possible failures or consequences of those failures that would not be identified otherwise.

Identify and Implement Measures To Address Risk (§ 192.1007(d))

PHMSA reminds operators that they must determine and implement measures designed to reduce the risk of failure on their pipeline systems (§ 192.1007(d)). If additional actions have not been taken to reduce risks, justification should be documented (*e.g.,* current overpressure protection design was determined to be sufficient; risks were deemed to be low).

There are several ways that operators can protect low-pressure distribution systems from overpressure events. Some notable examples include:

- Installing a full-capacity relief valve downstream of the low-pressure regulator station, including in applications where there is only worker-monitor pressure control;
- Installing a ''slam shut'' device;
- Using telemetered pressure recordings at district regulator stations to signal failures immediately to operators at control centers; and
- Completely and accurately documenting the location for all control (*i.e.,* sensing) lines on the system.

Measure Performance, Monitor Results, and Evaluate Effectiveness (§ 192.1007(e))

PHMSA reminds operators that they must monitor performance measures from an established baseline to evaluate the effectiveness of DIMP (§ 192.1007(e)). Section 192.1007(e)(vi) requires that these performance measures include any additional measures determined necessary to control identified threats. PHMSA reminds operators to modify their DIMP as appropriate, considering the potential failure of overpressure protection systems as a high-risk threat.

Issued in Washington, DC, on September 24, 2020, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2020–21508 Filed 9–28–20; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2020–0115]

Pipeline Safety: Inside Meters and Regulators

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; issuance of advisory bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to alert owners and operators of natural gas distribution pipelines to the consequences of failures of inside meters and regulators. PHMSA is also reminding operators of existing Federal regulations covering the installation and maintenance of inside meter and regulators, including the integrity management regulations for distribution systems to reduce the risks associated with failures of inside meter and regulator installations.

ADDRESSES: PHMSA guidance, including this advisory bulletin, can be found on PHMSA's website at *https://www.phmsa.dot.gov/guidance.* You may also view this advisory bulletin and related documents at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT:

Technical Questions: Michael Thompson, Transportation Specialist, by phone at 503–883–3495.

PUC 10-8

Proactive Low Pressure System Elimination

Request:

Why is the Company forecasting actual FY 2024 spending on the "Proactive Low Pressure System Elimination" initiative of only $800,000 on a budget of $1.3 million, as represented in the FY 2024 Third Quarter update? What is the cause of the underspend?

Response:

The FY2024 Low Pressure System Elimination program targeted the single feed Middletown Low Pressure system to eliminate the single feed and upgrade the area to high pressure. There are three project phases associated with this single feed elimination, Phase 1 is complete and was sponsored by the City State Construction/Public Works program. The second phase on "Tuckerman Ave" began in FY2024.

This project had to be put on hold until after Labor Day per the request of the town, then later required some redesign of the temporary regulator station. The project requires this temporary regulator station to maintain safe operational performance with the load reduction on the system caused by the low pressure to high pressure service relays. The low pressure to high pressure service relays could not be completed without the temporary regulator station maintaining pressure as load is removed from the low pressure system. These delays caused the project to forecast less spending, and will cause the project to carryover into FY2025. Phase 3, "Wolcott Ave" will start live gas work following the completion of Phase 2 (Tuckerman Ave), and will culminate with the overall goal of abandoning the single feed low pressure system in Middletown in FY2026.

Prepared by or under the supervision of: Brandon Flynn and Nathan Kocon

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PUC 10-9

Proactive Low Pressure System Elimination

Request:

Please provide a schedule showing the breakdown by component and location for the forecast of spending $6.5 million on the "Proactive Low Pressure System Elimination" initiative in FY 2025.

Response:

Please refer to Attachment DIV 1-5-1 to the Company's response to Data Request Division 1-5 in this docket, which is attached hereto as Attachment PUC 10-9 for ease of reference.

RI Energy LP Elimination– DIV 1-5-1

FY Project	WO #	Related WO#s	Town	Street	Installation Miles	Abandonment Miles	# of Services	FY24 Forecast	FY25 Proposed Budget	FY26 (Carryover from FY25)	Total Cost Estimate
Carryover FY24	90000221104	90000239809	MDT	Tuckerman	1.6	1.6	112	$0.80	$0.76	N/A	$1.56
FY25	90000229980	90000221104	MDT	Wolcott	2.0	2.1	125	N/A	$1.29	$0.80	$2.08
FY25	90000239809	MSR 90000214976	PVD	Charles	0.9	0.6	207	N/A	$0.80	$0.20	$1.00
FY25	90000235353	Reliability 90000180671 (FY24),MSR 90000226113 (FY25),MSR 90000236076 (FY25),	WSO	Privilege St	2.0	2.0	175	N/A	$1.60	$0.40	$2.00
FY25	90000237699	MSR 90000236254, FY25	NPV	Tiffany	1.5	1.5	148	N/A	$1.52	$0.40	$1.90
FY25	90000234969	MSR 90000235508	WSO	East St	0.3	0.3	15	N/A	$0.35	$0.10	$0.44
FY25	90000235554	MSR 90000235508	WSO	Mitris	0.3	0.3	14	N/A	$0.23	$0.10	$0.29
FY25 Backup, FY26	90000238318	MSR 90000237914	JOH	Morton St	0.7	0.7	43	N/A	FY25 Backup Project Planned for FY26	$0.62	$1.01
FY25 Backup, FY26	90000239843	MSR 90000226113	WSO	Social St	1.7	1.7	241	N/A	FY25 Backup Project Planned for FY26	$1.86	$3.00
								FY25 Budget	**$6.56**		

PUC 10-10
Proactive Low Pressure System Elimination

Request:

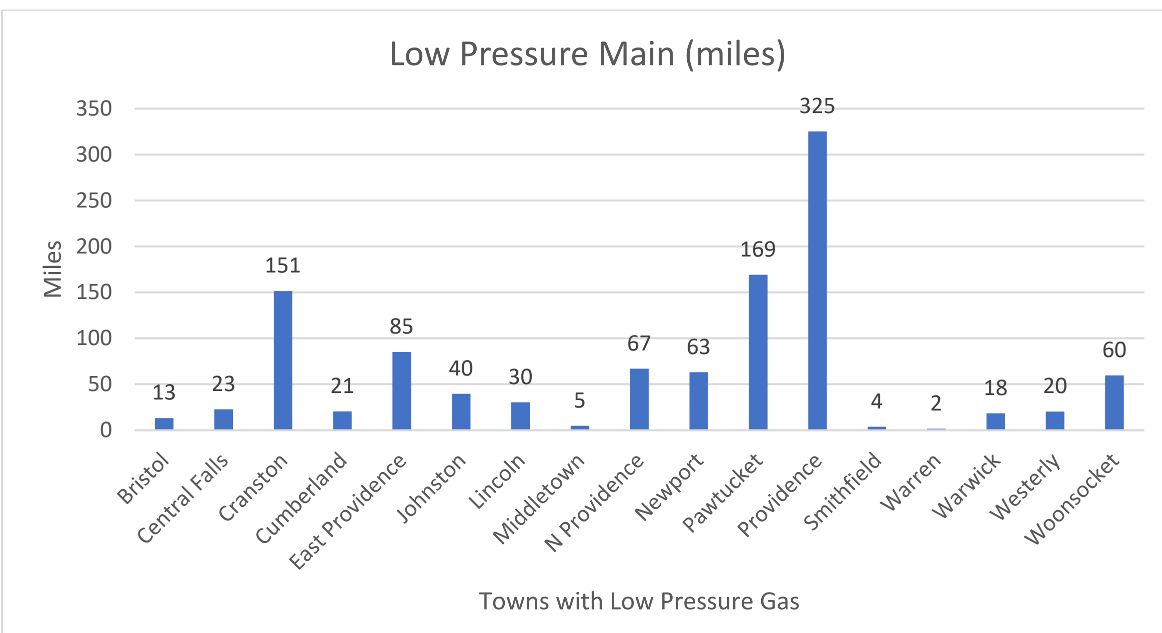
Please provide schedule(s) supporting the forecast of spending on the "Proactive Low Pressure System Elimination" initiative in fiscal years 2026, 2027, 2028, and 2029, as shown on Table 2 on Bates page 80 of the Company's filing.

Response:

The Company does not have a schedule providing specific projects upon which its forecast of Low Pressure System Elimination Projects is based.

The spending forecasts for the Low Pressure System Elimination program in fiscal years 2026-2029 are placeholder amounts for future projects that would still need to be fully scoped and designed.

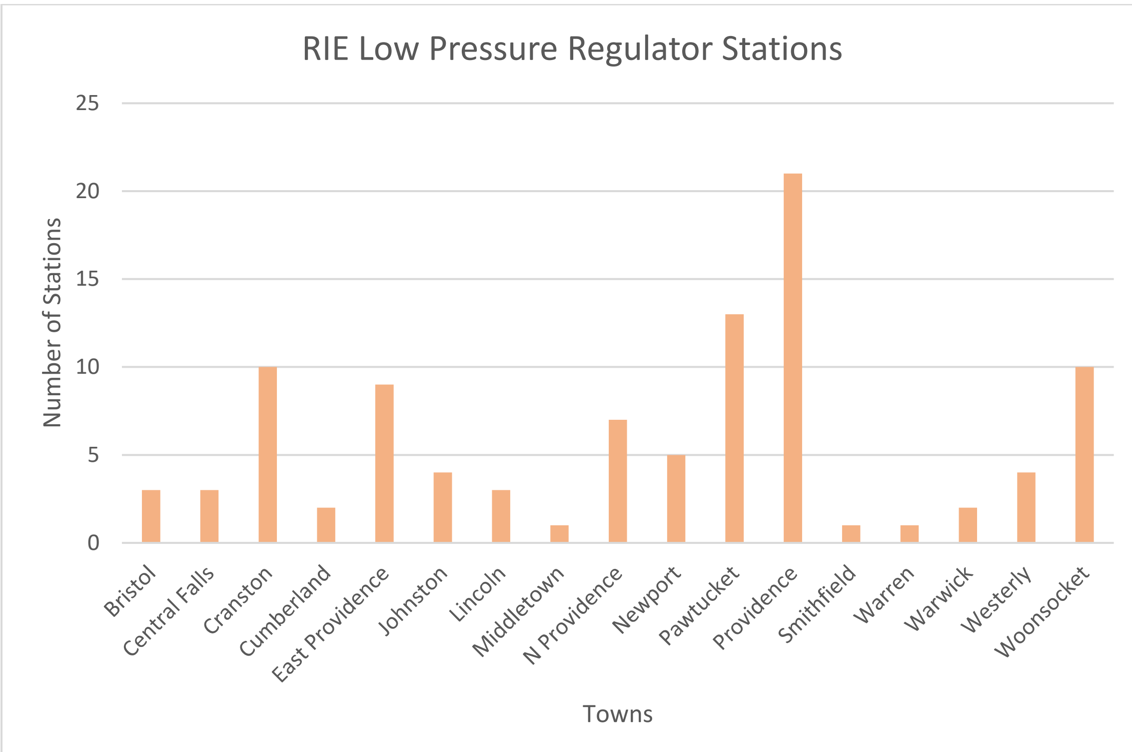
The Company's forecasted spending on the Low Pressure System Elimination program is based upon certain known facts. Approximately half of Rhode Island's gas customers are served by low pressure systems, one third of the main inventory is low pressure, and over half of Rhode Island's Regulator Station assets are used to support low pressure systems.



Prepared by or under the supervision of: Brandon Flynn and Phil LaFond

PUC 10-10, page 2

Proactive Low Pressure System Elimination



Future Low Pressure System Elimination projects will target areas where the existing low pressure main can be replaced by high pressure main and leak prone pipe can also be abandoned in the process. This program would target areas at extremities of the low pressure system, but adjacent to high pressure, to eliminate, or bring high pressure main to areas where there are only low pressure systems serving the customers. This would permit other programs in the Gas ISR portfolio such as the proactive leak prone pipe replacement program, public works (encroachments), and projects "ahead of paving" to utilize a high pressure system instead of remaining on a low pressure system. This approach can also target flood prone areas, system extremities, low pressure regulator station retirements, and eliminate low pressure single feed systems such as the project in Middletown.

The Company is working to develop a schedule for a long term strategy to support the Low Pressure System Elimination program at this time.

Prepared by or under the supervision of: Brandon Flynn and Phil LaFond

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

February 29, 2024
Date

Docket No. 23-49-NG- RI Energy's Gas Infrastructure, Safety and Reliability (ISR) Plan 2025 - Service List 2/28/2024

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