REDACTED

Division 7-49 (Second Supplemental)

Request:

Referring to the pending rate case of the Company's gas distribution affiliates in Massachusetts, Boston Gas Company and Colonial Gas Company (Gas Companies), in Department of Public Utilities docket 17-170, please provide copies of

a. all pre-filed testimony filed by the Gas Companies and any other parties in that case relating to the subject matter of the Gas Business Enablement Program,

b. all information request responses of the Gas Companies and any other parties in that case, relating to the subject matter of the Gas Business Enablement Program, and

c. any transcripts of live testimony relating to the subject matter of the Gas Business Enablement Program.

Response:

a. Please see the following attachments for the requested information:

Attachment DIV 7-49-1: Pre-filed Direct Testimony of the Gas Business Enablement Panel;

Attachment DIV 7-49-2: Pre-filed Direct Testimony of Company Witness Daniel S. Dane (Revenue Requirement witness) relating to the subject matter of the Gas Business Enablement Program;

Attachment DIV 7-49-3: Exhibit NG-DSD-2-BOS, Schedule 33; and

Attachment DIV 7-49-4: Exhibit NG-DSD-2-COL, Schedule 33.

b. Boston Gas Company, Colonial Gas Company, nor any other party has filed any responses to information requests relating to the subject matter of the Gas Business Enablement Program in the Massachusetts Department of Public Utilities Docket No. D.P.U. 17-170. The D.P.U. 17-170 is in its early stages of discovery.

c. No transcripts of live testimony relating to the subject matter of the Gas Business Enablement Program are yet available with respect to D.P.U. 17-170, pending before the Massachusetts Department of Public Utilities. The evidentiary hearings are anticipated to occur in May 2018.

Prepared by or under the supervision of: Anthony Johnston and Christopher Connolly

Supplemental Response:

a. Please see the following attachments with corrected headers for the requested information:

Attachment DIV 7-49-1: Pre-filed Direct Testimony of the Gas Business Enablement Panel;

Attachment DIV 7-49-2: Pre-filed Direct Testimony of Company Witness Daniel S. Dane (Revenue Requirement witness) relating to the subject matter of the Gas Business Enablement Program;

Attachment DIV 7-49-3: Exhibit NG-DSD-2-BOS, Schedule 33; and

Attachment DIV 7-49-4: Exhibit NG-DSD-2-COL, Schedule 33.

b. Please see Attachment DIV 7-49-5 through Attachment DIV 7-49-31 for information request responses and their respective attachments relating to the subject matter of the Gas Business Enablement Program, as listed on the table below.

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
DPU-NG 1-2	Attachment DIV 7-49-5		
DPU-NG 1-3	Attachment DIV 7-49-7		
DPU-NG 1-4	Attachment DIV 7-49-9		
DPU-NG 1-5	Attachment DIV 7-49-11		
DPU-NG 1-6	Attachment DIV 7-49-8	Attachment DIV 7-49-6	
DPU-NG 1-7	Attachment DIV 7-49-14	Attachment DIV 7-49-10 CONFIDENTIAL Attachment DIV 7-49-12 CONFIDENTIAL Attachment DIV 7-49-13 CONFIDENTIAL	
DPU-NG 1-8	Attachment DIV 7-49-15		
DPU-NG 1-9	Attachment DIV 7-49-16		
DPU-NG 1-10	Attachment DIV 7-49-18	Attachment DIV 7-49-17	
DPU-NG 1-11	Attachment DIV 7-49-19		

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DPU-NG 1-12	Attachment DIV 7-49-21	Attachment DIV 7-49-20 CONFIDENTIAL	Attachment DIV 7-49-29 CONFIDENTIAL Attachment DIV 7-49-31 CONFIDENTIAL
DPU-NG 1-13	Attachment DIV 7-49-22		Attachment DIV 7-49-30
DPU-NG 1-14	Attachment DIV 7-49-24	Attachment DIV 7-49-23 CONFIDENTIAL	
DPU-NG 1-15	Attachment DIV 7-49-25		
DPU-NG 1-20	Attachment DIV 7-49-26		
DPU-NG 1-21	Attachment DIV 7-49-27		
DPU-NG 1-23	Attachment DIV 7-49-28		

Second Supplemental Response:

a. Please see Attachment DIV 7-49-32 through Attachment DIV 7-49-151; Attachment DIV 7-49-153 through Attachment DIV 7-49-209; Attachment DIV 7-49-211 through Attachment DIV 7-49-253; Attachment DIV 7-49-255 though Attachment DIV 7-49-260, and Attachment DIV 7-49-263 through Attachment DIV 7-49-267 for information request responses and their respective attachments relating to the subject matter of the Gas Business Enablement Program, as listed on the table below.

MA Rate Case Information Request	**Response**	**PDF Attachment**	**XLS Attachment**
AG 21-2	Attachment DIV 7-49-32	Attachment DIV 7-49-33 Attachment DIV 7-49-34 Attachment DIV 7-49-35 Attachment DIV 7-49-36 Attachment DIV 7-49-37 Attachment DIV 7-49-38 Attachment DIV 7-49-39 Attachment DIV 7-49-40	
AG 21-3	Attachment DIV 7-49-41	Attachment DIV 7-49-211	
AG 21-4	Attachment DIV 7-49-42		
AG 21-5	Attachment DIV 7-49-43	Attachment DIV 7-49-44	
AG 21-6	Attachment DIV 7-49-45		

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
AG 21-7	Attachment DIV 7-49-46	Attachment DIV 7-49-47	
AG 21-8	Attachment DIV 7-49-48		
AG 21-9	Attachment DIV 7-49-49	Attachment DIV 7-49-50	
AG 21-10	Attachment DIV 7-49-51		
AG 21-11	Attachment DIV 7-49-52		
AG 21-12	Attachment DIV 7-49-53		
AG 21-13	Attachment DIV 7-49-54	Attachment DIV 7-49-154 CONFIDENTIAL Attachment DIV 7-49-155	
AG 21-14	Attachment DIV 7-49-55		
AG 21-15	Attachment DIV 7-49-56	Attachment DIV 7-49-57 CONFIDENTIAL	
AG 21-16	Attachment DIV 7-49-58		
AG 21-17	Attachment DIV 7-49-59		
AG 21-18	Attachment DIV 7-49-60		
AG 21-19	Attachment DIV 7-49-61		
AG 21-20	Attachment DIV 7-49-62		
AG 21-21	Attachment DIV 7-49-63		
AG 21-22	Attachment DIV 7-49-64	Attachment DIV 7-49-65	
AG 21-23	Attachment DIV 7-49-66		

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MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
AG 21-24	Attachment DIV 7-49-67	Attachment DIV 7-49-68 Attachment DIV 7-49-69 Attachment DIV 7-49-70 Attachment DIV 7-49-71 Attachment DIV 7-49-72 Attachment DIV 7-49-73	
AG 21-25	Attachment DIV 7-49-74		
AG 21-26	Attachment DIV 7-49-75		
AG 21-27	Attachment DIV 7-49-76		
AG 21-28	Attachment DIV 7-49-77		
AG 21-29	Attachment DIV 7-49-78	Attachment DIV 7-49-79	
AG 21-30	Attachment DIV 7-49-80		
AG 21-31	Attachment DIV 7-49-81	Attachment DIV 7-49-156 Attachment DIV 7-49-157 CONFIDENTIAL	
AG 21-32	Attachment DIV 7-49-82		
AG 21-33	Attachment DIV 7-49-83		
AG 21-34	Attachment DIV 7-49-84		
AG 21-35	Attachment DIV 7-49-85		
AG 21-36	Attachment DIV 7-49-86	Attachment DIV 7-49-263 Attachment DIV 7-49-264 CONFIDENTIAL Attachment DIV 7-49-265 CONFIDENTIAL Attachment DIV 7-49-266 Attachment DIV 7-49-267	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
AG 21-37	Attachment DIV 7-49-87		
AG 21-38	Attachment DIV 7-49-88	Attachment DIV 7-49-89 Attachment DIV 7-49-162	
AG 21-39	Attachment DIV 7-49-90	Attachment DIV 7-49-163 CONFIDENTIAL Attachment DIV 7-49-164 CONFIDENTIAL Attachment DIV 7-49-165 CONFIDENTIAL Attachment DIV 7-49-166 CONFIDENTIAL Attachment DIV 7-49-167 CONFIDENTIAL Attachment DIV 7-49-168 CONFIDENTIAL Attachment DIV 7-49-169 CONFIDENTIAL Attachment DIV 7-49-170 CONFIDENTIAL Attachment DIV 7-49-171 CONFIDENTIAL Attachment DIV 7-49-172 CONFIDENTIAL Attachment DIV 7-49-173 CONFIDENTIAL Attachment DIV 7-49-174 CONFIDENTIAL Attachment DIV 7-49-175 CONFIDENTIAL Attachment DIV 7-49-176 CONFIDENTIAL Attachment DIV 7-49-177 CONFIDENTIAL Attachment DIV 7-49-178 CONFIDENTIAL Attachment DIV 7-49-179 CONFIDENTIAL	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
		Attachment DIV 7-49-180 CONFIDENTIAL Attachment DIV 7-49-181 CONFIDENTIAL Attachment DIV 7-49-182 CONFIDENTIAL Attachment DIV 7-49-183 Attachment DIV 7-49-184 CONFIDENTIAL Attachment DIV 7-49-185 CONFIDENTIAL Attachment DIV 7-49-186 CONFIDENTIAL Attachment DIV 7-49-187 CONFIDENTIAL Attachment DIV 7-49-188 CONFIDENTIAL Attachment DIV 7-49-189 CONFIDENTIAL Attachment DIV 7-49-190 CONFIDENTIAL Attachment DIV 7-49-191 CONFIDENTIAL Attachment DIV 7-49-192 CONFIDENTIAL Attachment DIV 7-49-193 CONFIDENTIAL Attachment DIV 7-49-194 CONFIDENTIAL Attachment DIV 7-49-195 CONFIDENTIAL Attachment DIV 7-49-196 CONFIDENTIAL Attachment DIV 7-49-197 CONFIDENTIAL Attachment DIV 7-49-198 CONFIDENTIAL Attachment DIV 7-49-199 CONFIDENTIAL	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
		Attachment DIV 7-49-200 Attachment DIV 7-49-201 CONFIDENTIAL Attachment DIV 7-49-202 Attachment DIV 7-49-203 CONFIDENTIAL Attachment DIV 7-49-204 CONFIDENTIAL Attachment DIV 7-49-212 Attachment DIV 7-49-213 Attachment DIV 7-49-214 Attachment DIV 7-49-215 Attachment DIV 7-49-216 Attachment DIV 7-49-217 Attachment DIV 7-49-218 Attachment DIV 7-49-219 Attachment DIV 7-49-220 Attachment DIV 7-49-221 Attachment DIV 7-49-222 Attachment DIV 7-49-223 Attachment DIV 7-49-224 Attachment DIV 7-49-225 Attachment DIV 7-49-226 Attachment DIV 7-49-227 Attachment DIV 7-49-228 Attachment DIV 7-49-229 Attachment DIV 7-49-230 Attachment DIV 7-49-231 Attachment DIV 7-49-232 Attachment DIV 7-49-233 Attachment DIV 7-49-234 Attachment DIV 7-49-235 Attachment DIV 7-49-236 Attachment DIV 7-49-237 Attachment DIV 7-49-238 Attachment DIV 7-49-239 Attachment DIV 7-49-240 Attachment DIV 7-49-241 Attachment DIV 7-49-242	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
		Attachment DIV 7-49-243 Attachment DIV 7-49-244 Attachment DIV 7-49-245 Attachment DIV 7-49-246 Attachment DIV 7-49-247 Attachment DIV 7-49-248 Attachment DIV 7-49-249 Attachment DIV 7-49-250 Attachment DIV 7-49-251 Attachment DIV 7-49-252 Attachment DIV 7-49-253	
AG 21-40	Attachment DIV 7-49-91	Attachment DIV 7-49-205 CONFIDENTIAL Attachment DIV 7-49-206 CONFIDENTIAL Attachment DIV 7-49-207 CONFIDENTIAL Attachment DIV 7-49-208 CONFIDENTIAL Attachment DIV 7-49-209 CONFIDENTIAL Attachment DIV 7-49-255 Attachment DIV 7-49-256 Attachment DIV 7-49-257 Attachment DIV 7-49-258 Attachment DIV 7-49-259	
AG 21-41	Attachment DIV 7-49-92 CONFIDENTIAL		
AG 21-41	Attachment DIV 7-49-158		
AG 21-42	Attachment DIV 7-49-93	Attachment DIV 7-49-159 CONFIDENTIAL Attachment DIV 7-49-160	
AG 21-43	Attachment DIV 7-49-94		
AG 21-44	Attachment DIV 7-49-95	Attachment DIV 7-49-96	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
AG 21-45	Attachment DIV 7-49-97		
AG 21-46	Attachment DIV 7-49-98		
AG 21-47	Attachment DIV 7-49-99		
AG 21-48	Attachment DIV 7-49-100		
AG 21-49	Attachment DIV 7-49-101		
AG 21-50	Attachment DIV 7-49-102		
AG 20-17	Attachment DIV 7-49-103	Attachment DIV 7-49-104	
AG 20-18	Attachment DIV 7-49-105	Attachment DIV 7-49-106 Attachment DIV 7-49-107	
AG 20-19	Attachment DIV 7-49-108		
AG 20-20	Attachment DIV 7-49-109		
AG 24-2	Attachment DIV 7-49-110	Attachment DIV 7-49-111 Attachment DIV 7-49-112 Attachment DIV 7-49-113 Attachment DIV 7-49-114 Attachment DIV 7-49-115	
AG 24-3	Attachment DIV 7-49-116	Attachment DIV 7-49-117 CONFIDENTIAL Attachment DIV 7-49-118 CONFIDENTIAL Attachment DIV 7-49-119 CONFIDENTIAL Attachment DIV 7-49-120 Attachment DIV 7-49-121 Attachment DIV 7-49-122	
AG 15-11	Attachment DIV 7-49-123	Attachment DIV 7-49-124	

MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
AG 15-12	Attachment DIV 7-49-125		
AG 19-2	Attachment DIV 7-49-126		
AG 19-3	Attachment DIV 7-49-127		
AG 19-9	Attachment DIV 7-49-128		
AG 26-5	Attachment DIV 7-49-129		
AG 26-6	Attachment DIV 7-49-130	Attachment DIV 7-49-131	
AG 26-7	Attachment DIV 7-49-132	Attachment DIV 7-49-133	
AG 26-8	Attachment DIV 7-49-134		
AG 26-9	Attachment DIV 7-49-135	Attachment DIV 7-49-136	
DPU-NG 22-1	Attachment DIV 7-49-137		
DPU-NG 22-2	Attachment DIV 7-49-138		
DPU-NG 22-3	Attachment DIV 7-49-139		
DPU-NG 22-4	Attachment DIV 7-49-140		
DPU-NG 22-5	Attachment DIV 7-49-141		
DPU-NG 22-7	Attachment DIV 7-49-142		
DPU-NG 12-1	Attachment DIV 7-49-143		
DPU-NG 12-2	Attachment DIV 7-49-144	Attachment DIV 7-49-145	
DPU-NG 12-6	Attachment DIV 7-49-146	Attachment DIV 7-49-147	
DPU-NG 12-8	Attachment DIV 7-49-148		

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MA Rate Case Information Request	Response	PDF Attachment	XLS Attachment
DPU-NG 12-9	Attachment DIV 7-49-149		
DPU-NG 1-10 CORRECTED	Attachment DIV 7-49-150	Attachment DIV 7-49-161	
DPU-NG 4-13	Attachment DIV 7-49-151		
AG 21-51	Attachment DIV 7-49-153		

b. Please see Attachment DIV 7-49-254, and Attachment DIV 7-49-260 through Attachment DIV 7-49-262 for transcripts of live testimony relating to the subject matter of the Gas Business Enablement Program:

- Attachment DIV 7-49-254 – DPU 17-170 May 10, 2018 Vol. 6 Transcript
- Attachment DIV 7-49-260 – DPU 17-170 May 1, 2018 Vol. 1 Transcript
- Attachment DIV 7-49-261 – DPU 17-170 May 2, 2018 Vol. 2 Transcript
- Attachment DIV 7-49-262 – DPU 17-170 May 7, 2018 Vol. 4 Transcript

Prepared by or under the supervision of: Anthony Johnston and Christopher Connolly

Confidential Attachment DIV 7-49-57 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-57 contains an Accenture PowerPoint on National Grid Business Enablement Program, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 51-page document in its entirety.

Confidential Attachment DIV 7-49-92 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-92 contains a confidential response to Information Request AG-21-41, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 2-page document in its entirety.

Confidential Attachment DIV 7-49-117 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-117 contains a Company PowerPoint presentation on Gas Business Enablement, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 307-page document in its entirety.

Confidential Attachment DIV 7-49-118 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-118 contains a Company PowerPoint presentation on Gas Business Enablement, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 425-page document in its entirety.

Confidential Attachment DIV 7-49-119 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-119 contains a Company PowerPoint presentation on Gas Business Enablement, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 168-page document in its entirety.

Confidential Attachment DIV 7-49-154 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-154 contains projected total expenditures for the Gas Business Enablement Program, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 10-page document in its entirety.

Confidential Attachment DIV 7-49-157 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-157 contains a Pipeline Safety Compliance Assessment prepared by Process Performance Improvement Consultants, LLC, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 53-page document in its entirety.

Confidential Attachment DIV 7-49-159 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-159 contains a Gas Business Enablement Statement of Work by PA Consulting, Inc., for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 21-page document in its entirety.

Confidential Attachment DIV 7-49-163 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-163 contains a Company PowerPoint presentation on Gas Business Enablement System Integration, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 13-page document in its entirety.

Confidential Attachment DIV 7-49-164 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-164 contains a Company Request for Information for Gas Business Enablement – Systems Integration Vendor Sourcing, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 34-page document in its entirety.

Confidential Attachment DIV 7-49-165 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-165 contains a Company RFI Response Template for Gas Business Enablement – System Integration Vendor Sourcing, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 13-page document in its entirety.

Confidential Attachment DIV 7-49-166 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-166 contains a Company PowerPoint presentation on the Gas Business Enablement Program System Integrator RFI, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 112-page document in its entirety.

Confidential Attachment DIV 7-49-167 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-167 contains a Company Request for Proposal for US Gas Business Enablement (GBE) Value Assurance, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 25-page document in its entirety.

Confidential Attachment DIV 7-49-168 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-168 contains a Gas Business Enablement Systems Integration Vendor Sourcing Written Response Submission, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 224-page document in its entirety.

Confidential Attachment DIV 7-49-169 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-169 contains a Gas Business Enablement Systems Integration Vendor Sourcing Written Response Submission, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 137-page document in its entirety.

Confidential Attachment DIV 7-49-170 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-170 contains a Gas Business Enablement Systems Integration Vendor Sourcing Written Response Submission, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 127-page document in its entirety.

Confidential Attachment DIV 7-49-171 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-171 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 99-page document in its entirety.

Confidential Attachment DIV 7-49-172 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-172 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 54-page document in its entirety.

Confidential Attachment DIV 7-49-173 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-173 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 51-page document in its entirety.

Confidential Attachment DIV 7-49-174 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-174 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 50-page document in its entirety.

Confidential Attachment DIV 7-49-175 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-175 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 113-page document in its entirety.

Confidential Attachment DIV 7-49-176 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-176 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 82-page document in its entirety.

Confidential Attachment DIV 7-49-177 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-177 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 72-page document in its entirety.

Confidential Attachment DIV 7-49-178 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-178 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 74-page document in its entirety.

Confidential Attachment DIV 7-49-179 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-179 contains a draft System Integration Services Agreement by and between the Company and PWC, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 80-page document in its entirety.

Confidential Attachment DIV 7-49-180 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-180 contains a Gas Business Enablement Statement of Work between the Company and Kotter International, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 37-page document in its entirety.

Confidential Attachment DIV 7-49-181 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-181 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 33-page document in its entirety.

Confidential Attachment DIV 7-49-182 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-182 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 15-page document in its entirety.

Confidential Attachment DIV 7-49-184 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-184 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 63-page document in its entirety.

Confidential Attachment DIV 7-49-185 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-185 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 51-page document in its entirety.

Confidential Attachment DIV 7-49-186 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-186 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-187 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-187 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 3-page document in its entirety.

Confidential Attachment DIV 7-49-188 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-188 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 6-page document in its entirety.

Confidential Attachment DIV 7-49-189 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-189 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 17-page document in its entirety.

Confidential Attachment DIV 7-49-190 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-190 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 3-page document in its entirety.

Confidential Attachment DIV 7-49-191 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-191 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-192 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-192 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-193 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-193 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-194 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-194 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 3-page document in its entirety.

Confidential Attachment DIV 7-49-195 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-195 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 37-page document in its entirety.

Confidential Attachment DIV 7-49-196 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-196 contains Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-197 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-197 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 3-page document in its entirety.

Confidential Attachment DIV 7-49-198 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-198 contains a GBE Work Breakdown Structure, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 32-page document in its entirety.

Confidential Attachment DIV 7-49-199 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-199 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-201 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-201 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 4-page document in its entirety.

Confidential Attachment DIV 7-49-203 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-203 contains a Gas Business Enablement RFP Written Response, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 92-page document in its entirety.

Confidential Attachment DIV 7-49-204 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-204 contains Company requests for information regarding a Gas Business Enablement RFP, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 11-page document in its entirety.

Confidential Attachment DIV 7-49-205 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-205 contains a System Integration Services Agreement by and between the Company and Accenture, LLP, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 720-page document in its entirety.

Confidential Attachment DIV 7-49-206 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-206 contains a Services Agreement by and between the Company and PWC Advisory Services LLC, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 436-page document in its entirety.

Confidential Attachment DIV 7-49-207 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-207 contains an Amended and Restated System Integration Services Agreement by and between the Company and PWC Advisory Services LLC, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 880-page document in its entirety.

Confidential Attachment DIV 7-49-208 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-208 contains a GBE Services Agreement between the Company and Kotter International, Inc., for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 242-page document in its entirety.

Confidential Attachment DIV 7-49-209 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-209 contains a Master Framework Agreement for General Management Consulting Services between the Company and PA Consulting Group, Inc., for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 100-page document in its entirety.

Confidential Attachment DIV 7-49-264 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-264 contains a Company PowerPoint presentation providing an update on Gas Transformation, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 17-page document in its entirety.

Confidential Attachment DIV 7-49-265 – REDACTED INFORMATION

Confidential Attachment DIV 7-49-265 contains a Company draft PowerPoint presentation on Gas Business Enablement, for which the Company's affiliates, Boston Gas Company and Colonial Gas Company, sought and obtained confidential treatment before the Massachusetts Department of Public Utilities. The Company has requested protective treatment of this 22-page document in its entirety.

Information Request AG-21-2

Request:

Please provide copies of any and all testimony, affidavits, exhibits, attachments, and any other evidence provided, submitted, or sponsored by Anthony H. Johnston in New York Public Service Commission Dockets Nos. 16-G-0058/0059, 17-E-0238, and 17-G-0239.

Response:

Attached are the testimonies and exhibits provided by Anthony H. Johnston in New York:

- Attachment AG 21-2-1: 16-G-0058 Direct Testimony Book 4 -LI GIOP
- Attachment AG 21-2-2: 16-G-0059 Direct Testimony Book 4 - NY GIOP
- Attachment AG 21-2-3: 16-G-0058 and 16-G-0059 Johnston Affidavit
- Attachment AG 21-2-4: 16-G_0058 and 16-G-0069 Rebuttal (GIOP Panel) June 10 2016
- Attachment AG 21-2-5: 16-G-0058 KEDLI - Corrections and Updates (GIOP) April 4 2016
- Attachment AG 21-2-6: 16-G-0059 KEDNY - Corrections and updates (GIOP) April 4 2016
- Attachment AG 21-2-7: 17-E-0238/17-G-0239 – Direct Testimony April 28, 2017
- Attachment AG 21-2-8: 17-E-0238/17-G-0239 – Rebuttal Testimony September 15, 2017

Prepared by or under the supervision of: Anthony H. Johnston and Reihaneh Irani-Famili

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF THE BROOKLYN UNION GAS COMPANY FOR GAS SERVICE

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF KEYSPAN GAS EAST CORPORATION FOR GAS SERVICE

Testimony and Exhibits of:

Gas Infrastructure and Operations Panel

Book 4 - KEDLI

January 29, 2016

Submitted to:
New York State Public Service Commission
Case 16-G-____
Case 16-G-____

Submitted by:
The Brooklyn Union Gas Company and
KeySpan Gas East Corporation

nationalgrid

Testimony of
Gas IOP

Before the Public Service Commission

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Gas Infrastructure and Operations Panel

Ross W. Turrini
Johnny Johnston
Laurie T. Brown

January 29, 2016

Testimony of the Gas Infrastructure and Operations Panel

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Testimony of the Gas Infrastructure and Operations Panel

Testimony of the Gas Infrastructure and Operations Panel

I. Introduction and Qualifications

Q. Please introduce the members of the Gas Infrastructure and Operations Panel.

A. The Panel consists of Ross W. Turrini, Johnny Johnston and Laurie T. Brown.

Q. Mr. Turrini, please state your name and business address.

A. My name is Ross W. Turrini. My business address is 25 Hub Drive, Melville, New York 11747.

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

A. I am employed by National Grid USA Service Company, Inc., a subsidiary of National Grid USA ("National Grid"), as the Senior Vice President for Gas Process and Engineering. I oversee approximately 2,735 employees and $6 billion of gas infrastructure assets serving 3.6 million customers in New York, Massachusetts and Rhode Island.

National Grid owns and operates three gas distribution companies in New York that provide retail gas service to more than 2.4 million customers in three service territories: Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC") serves areas of eastern and central New York, The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") serves Brooklyn, Staten Island and parts of Queens in New York City, and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI" or "Company") serves customers on Long Island and the Rockaway Peninsula in Queens. I am responsible for all aspects of the performance of National Grid's New York gas networks, including emergency/storm response, gas engineering, construction activities, and the operation and maintenance of gas transmission and distribution facilities.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science in Civil Engineering from the United States Military Academy at West Point in 1985. I have worked for National Grid and its predecessor companies (the Long Island Lighting Company and KeySpan Corporation ("KeySpan")) for 22 years in various roles in engineering, operations and procurement. Prior to joining National Grid, I spent five years as an Officer in the United States Army Corps of Engineers and three years in engineering and construction roles at Brown & Root Services Corporation, an international engineering, procurement and construction company.

Testimony of the Gas Infrastructure and Operations Panel

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. No, I have not.

Q. Mr. Johnston, please state your full name and business address.

A. My name is Johnny Johnston. My business address is One MetroTech Center, Brooklyn, New York 11201.

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

A. I am employed by National Grid USA Service Company, Inc. Effective January 1, 2016, I was appointed the Senior Vice President for National Grid's Gas Enablement Project, a long-term initiative to establish new work management systems and enhance gas safety, compliance, customer service and the performance of National Grid's US gas business. Immediately prior to serving in my current role, I served as the Vice President of Customer Meter Services where I oversaw more than 2,400 personnel supporting National Grid's electric and gas distribution businesses in the US. With respect to the New York gas business, I was responsible for all field service personnel who provide gas emergency response, meter related activities (including meter installation and removal) and field operations related to billing (including meter reading, bill investigations and collections). My responsibilities also included overseeing the gas dispatch centers.

Q. Please describe your educational background and professional experience.

A. I received a Master of Engineering Science from Oxford University in 2002 and a Master of Business Administration from Cranfield University in 2006. I have worked for National Grid for 18 years. I started in Network Design in National Grid's United Kingdom business before moving to Cleveland, Ohio to join GridAmerica LLC, a wholly owned subsidiary of National Grid, where I worked on transmission planning. I then moved to Salt Lake City, Utah to support a transmission project to deliver wind energy from Wyoming to California, before returning to the United Kingdom. Back in the United Kingdom, I worked in National Grid's Engineering Department and was responsible for Network Design, including renewable gas projects. I was then promoted to the Gas Distribution Executive Team to lead Customer Operations with responsibility for the gas call centers, resource planning and dispatch teams. I then became Chief of Staff for the global Chief Executive Officer before relocating to Brooklyn to lead Customer Meter Services.

Testimony of the Gas Infrastructure and Operations Panel

Q. Have you previously testified before the Commission?

A. No, I have not.

Q. Ms. Brown, please state your full name and business address.

A. My name is Laurie T. Brown. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

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

A. I am employed by National Grid USA Service Company, Inc. as the Director, Network Strategy - Gas. I am responsible for all gas Network Strategy issues in New York, including those related to the Company's capital investment strategy. I support the New York Jurisdictional President (Company Witness Kenneth Daly) and his staff on all matters related to the operation of National Grid's New York gas systems. My responsibilities also include working as the regulatory liaison on operational issues and developing the New York gas work plan.

Q. Please describe your educational background and experience.

A. I received an Associates of Science in Engineering Science from Canton College in 1980 and a Bachelor of Science in Civil and Environmental Engineering from Clarkson University in 1982. I have worked for NMPC and now National Grid for over 30 years in various technical positions. I began my career as a Quality Assurance Engineer at Nine Mile Point Unit 2 Nuclear Plant in 1982. I later became an Engineer in NMPC's Gas Engineering Department. I was then promoted to Gas Engineering Supervisor, Gas Operations Support Manager, and then Lab and Testing Services Director. At the time of National Grid's merger with KeySpan, I returned to the gas business as Director, Operations Regulatory Compliance for New York, as well as Massachusetts, New Hampshire and Rhode Island, before taking my current position of Director, Network Strategy - Gas. I am a member of the American Gas Association, a member of the Northeast Gas Association, a senior member of the Society of Women Engineers, and I serve on the Board of Directors for Dig Safely New York, the One-Call Center for upstate New York.

Q. Have you previously testified before the Commission?

A. Yes. I have submitted pre-filed testimony in NMPC's 2012 rate proceeding (Case 12-G-0202) and testified before the Commission in NMPC's Article VII proceedings on Natural Gas Pipeline 58, Hall Road to Oswego in Oswego, New York (Case 89-T-058) and Natural Gas Pipeline 63, Schroeppel to Scriba and Oswego proceeding (Case 92-T-0252).

II. Purpose of Testimony

Q. What is the purpose of the Gas Infrastructure and Operations Panel's testimony?

A. The purpose of the Panel's testimony is to provide a forecast of the capital investments of the Company during the 12 months ending December 31, 2017 ("Rate Year"), the 12 months ending December 31, 2018 ("Data Year 1") and the 12 months ending December 31, 2019 ("Data Year 2") (Data Year 1 and Data Year 2 are collectively referred to as the "Data Years"). The Panel discusses capital expenditures that will (i) increase the safety and reliability of the Company's gas network, (ii) modernize the Company's gas transmission and distribution infrastructure, (iii) promote gas growth in a manner consistent with the Commission's policy objectives and (iv) enhance storm resiliency and the Company's ability to respond to future weather events. The Panel will also discuss the Company's practices and policies for maximizing the efficiency of its capital construction program from planning and budgeting through the completion of construction.

The Panel's testimony provides an overview of the significant projects in the Company's capital plan, including acceleration of replacement of leak prone pipe ("LPP") and new safety programs to identify and address system risks. The Panel's testimony also presents an overview of the Company's pipeline integrity and reliability programs that will improve the overall safety and reliability of the Company's gas system, and will also address recently enacted, as well as pending, pipeline safety regulations administered by the U.S. Department of Transportation ("DOT"), Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Lastly, the Panel discusses the Company's plans to expand gas service to customers through targeted capital investments.

Q. Does the Panel's testimony also address the Company's operations and maintenance ("O&M") programs?

A. Yes. In addition to capital investments in gas infrastructure, the Panel describes a number of O&M programs the Company proposes to expand or implement in the Rate Year, the costs of which are not fully reflected in the 12-month period beginning October 1, 2014 and ending September 30, 2015 ("Historic Test Year"). These programs represent known and measureable changes from Historic Test Year expense, including programs to (i) improve system reliability, (ii) address new and emerging safety regulations, (iii) enhance customer service and (iv) support the Company's capital investments. The Panel also discusses various factors contributing to an increase in overall O&M costs, such as an increase in the number of gas odor calls and leak repairs, additional costs to facilitate customer account transitions and lock inactive meters, higher materials and labor costs, expanded municipal paving requirements and increases in permitting fees and penalties.

Q. Does the Panel address any other topics?

A. Yes. The Panel's testimony describes investments in information technology, including digital risk and security systems that will benefit the Company's gas business.

Q. Does the Panel sponsor any exhibits as part of its testimony?

A. Yes. The Panel sponsors the following exhibits that were prepared under its direction and supervision:

Exhibit __ (GIOP-1): Actual and Projected Capital Expenditures: Historic Test Year, Rate Year, Data Year 1 and Data Year 2.

Exhibit __ (GIOP-2): Graph Comparing Actual and Projected Annual Investment Levels for calendar years ("CY") 2015 – 2020.

Exhibit __ (GIOP-3): Chart Summarizing Projected Leak Rates for LPP for Various Main Replacement Strategies.

Exhibit __ (GIOP-4): Data Sheets for Significant Capital Programs. This exhibit includes summaries of the Company's significant capital projects/programs.

Exhibit __ (GIOP-5): Incremental O&M Expenditures: Rate Year, Data Year 1 and Data Year 2.

Exhibit __ (GIOP-6): Incremental Full Time Equivalent Positions by Function in the Rate Year, Data Year 1 and Data Year 2.

Q. For what periods does the Panel provide information?

A. The Panel provides detailed information on (i) capital and O&M spending for the Historic Test Year, (ii) proposed capital investments and O&M spending in the Rate Year and (iii) projected capital and O&M spending for the Data Years.

Q. How is the Panel's testimony organized?

A. The testimony is organized into the following sections:

<u>Sections I and II</u> are introductory sections outlining the Panel's testimony.

<u>Section III</u> provides an overview of the Company's capital investment and O&M program priorities and objectives, including the retirement of leak prone mains, investments in pipeline safety, including

programs to address emerging regulations that are expected to impact future capital and O&M costs, as well as the Company's plans to expand gas service. This discussion includes justification for the Company's gas capital and O&M expenditures for these programs, and the public interest considerations that will be served by their implementation. Section III also addresses the Company's cast iron lining program, as well as investments in storm hardening.

Section IV provides details on the Company's proposed capital investment program for the Rate Year and Data Years, including the Company's spending rationales, categories of capital investment and specific work activities within each category.

Section V describes the Company's O&M programs, including those targeted at current and emerging safety regulations. Section V also describes O&M costs for leak repairs and inspections/damage prevention programs.

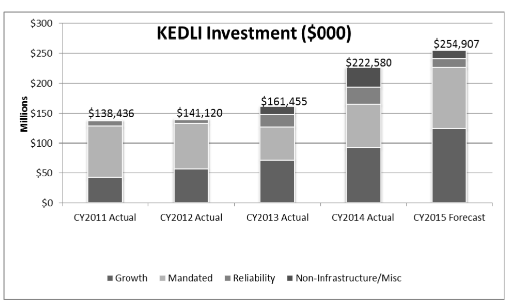
Section VI describes various information technology and digital risk and security programs that will support gas operations.

III. Capital and O&M Plan Priorities and Objectives

Q. Please describe the Company's overall objective of its infrastructure and operations plans.

A. The Company's gas infrastructure and operations plans are designed to provide safe and reliable gas delivery service to customers at reasonable costs. Over the last several years, the Company has significantly increased investment to modernize and enhance the resiliency of its gas assets.

Table 1: Historic Capital Investment



Significant capital investment over the next several years is required to ensure that the gas system continues to meet the demands of customers. The proposed plan includes capital and O&M spending to meet these needs and to satisfy state and federal regulatory requirements and goals, including a program to significantly accelerate the replacement of LPP. In developing its capital and O&M plans, the Company balanced the need for spending to achieve safety and service objectives with the need to manage costs and minimize impacts on customer rates.

Q. Why have the Company's capital expenditures increased over the last several years?

A. Several developments have required KEDLI and other natural gas distribution utilities to increase their annual capital expenditures. First, the development of new domestic gas sources has created an abundant natural gas supply that is conducive to the growth of the gas distribution business from both an economic and security/reliability perspective. Natural gas supplies are likely to be available to KEDLI and its customers now and for the foreseeable future at a significantly lower cost than the cost to develop alternative energy sources. To take advantage of the favorable gas supply dynamics, natural gas utilities are increasing their growth spending to offer the economic benefits of relatively inexpensive natural gas supplies to the greatest possible number of consumers.

Second, recent pipeline safety incidents, such as the tragic events in San Bruno, California, Allentown, Pennsylvania and more recent incidents have appropriately increased focus on pipeline safety and the need to carefully monitor and replace aging pipeline infrastructure.

Finally, recent weather events such as Superstorm Sandy, Hurricane Irene and the Polar Vortex, and the expectation that such events will continue to occur, require the Company to find ways to protect its facilities from severe weather.

The foregoing developments indicate that the Company must increase capital spending to modernize its transmission and distribution assets, increase the size and scope of its safety replacement and reliability programs, and promote gas growth.

Q. How will the Company support this increased level of capital investment?

A. As the Company developed plans to modernize its gas assets, it also began to build and enhance its operations, engineering, resource planning, work management and quality control organizations and capabilities to deliver an unprecedented level of capital investment. Over the last several years, the Company has hired and trained engineers, designers, planners, estimators, project managers, analysts, inspectors and other construction support personnel as the investment plan has grown. The Company will further develop these capabilities during CY 2016 and the Rate Year by adding incremental resources to execute the capital plan and support the increased operations workload (discussed below). The Company's efforts to develop its internal workforce are also discussed by the Human Resources Panel.

With regard to contractor resources, the Company has developed a procurement strategy that supports sustainable growth in qualified contractors to meet the work plan increases. To address the overall shortage of qualified, skilled labor and the challenges around developing qualified contractors, the Company's resource plan includes the following elements:

- Establishing longer term contracts to enable contractors to plan and invest in hiring, training, facilities and equipment to meet the Company's construction needs;
- Providing greater work plan visibility to contractors on forecast crew requirements to enable them to develop the required capacity; and
- Managing the work plan to limit seasonal variability to support a stable contractor workforce and promote worker retention.

To encourage portability of the regional contractor workforce, the Company recently completed a pilot program, developed in conjunction with the Northeast Gas Association ("NGA") and the Gas Technology Institute, to enhance contractor training and standardize gas pipeline construction skills. The Company is also working with contractors to develop new pipelines of skilled labor to feed into the workforce, including by recruiting prospective utility workers from community colleges, trade schools and veteran groups (as discussed in the Human Resources Panel's testimony).

Q. Does the Company require additional personnel in the Rate Year and Data Years to execute its capital and O&M programs?

A. Yes. The Company forecasts the need for an additional 110 full time equivalent ("FTE") positions in the Rate Year to support the additional capital investment, increased O&M workload and new programs discussed below. These FTEs include positions in field operations, meter services, engineering, project management, resource planning, instrumentation and regulation, damage prevention, gas production and gas control. The cost of these FTEs will be charged to both capital and O&M programs based on the job function and nature of the work. Exhibit __ (GIOP-6) identifies the incremental FTE positions by function and these positions are discussed in more detail below. The Company has already begun to fill these positions and will continue to hire and train in CY 2016 and into the Rate Year to deliver KEDLI's capital plan and incremental O&M workload.

A. Pipeline Integrity and Reliability Programs

i. Accelerated LPP Replacement

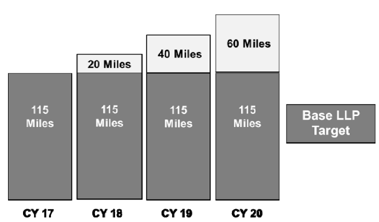
Q. What is the Company's proposal regarding the acceleration of its LPP replacement program?

A. The Company currently has approximately 3,860 miles of LPP in its inventory comprised of: (i) unprotected (*i.e.*, non-cathodically protected) steel pipe whether bare or coated, (ii) cast and wrought iron pipe and (iii) pre-1985 Aldyl-A plastic pipe.

To reduce the risk of leaks and breaks, improve system performance and reliability, meet the Company's commitment to enhance customer satisfaction and reduce methane emissions, the Company has prioritized the replacement of older and higher-risk gas infrastructure – specifically, LPP that disproportionally contributes to leaks on KEDLI's system. To accelerate replacement of LPP, KEDLI proposes to increase its annual replacement mileage target from 95 miles in CY 2016 to 115 miles in the

Rate Year. In addition, the Company is proposing a mechanism that would fund an increase in LPP retirements of 20 miles or more in each year following the Rate Year.

Table 2: Proposed LPP Retirements CYs 2017 to 2020



Q. Why is the Company proposing to accelerate its LPP replacement program?

A. The Company's gas distribution network dates to the first half of the twentieth century. Its piping inventory consists of cast iron, wrought iron, unprotected bare/coated steel, protected steel and plastic. Based on operating experience, the Company anticipates a larger number of failures on leak prone mains as these facilities continue to deteriorate over time.

Indeed, as discussed below, the Company has observed leak rates for its leak prone mains that are double the average leak rate for all Company-owned distribution mains.

Accelerating the rate of main replacements is the best long term approach to reducing leaks on the gas system and enhancing system safety. By accelerating the replacement rate to the target schedule, the Company expects to see lower leak rates over time – with the inventory of LPP replaced completely in 20 years (as compared to more than 40 years at the current rate). The Company's accelerated replacement targets are consistent with the Commission's stated goal of replacing all LPP in New York within the next 20 years (Case 15-G-0151).

Q. Please provide a brief overview of the Company's distribution system, including a breakdown of the composition of mains and services.

A. The Company has approximately 7,900 miles of main and 536,000 active services. This distribution infrastructure consists of varying material compositions, vintages and performance histories. As of December 31, 2014, the delivery infrastructure was comprised as follows:

Table 3: Composition of Mains & Active Services on KEDLI Distribution System

Category	Miles of Main	Percent of Total	Number of Services	Percent of Total
Non-Cathodically Protected Steel				
Bare Steel	2,394	30%	86,672	16%
Coated Steel	747	10%	17,331	3%
Cast Iron & Wrought Iron	317	4%	0	0%
Pre-1985 Aldyl-A Plastic	402	5%	27,147*	5%
LPP Subtotal	**3,860**	**49%**	**131,150**	**24%**
Cathodically Protected Steel				
Bare Steel	239	3%	12,948	3%
Coated Steel	914	11%	22,606	4%
Other				
Plastic	2,918	37%	363,568	68%
Copper/Undetermined	0	0%	5,308	1%
Non – LPP Subtotal	**4,071**	**51%**	**404,430**	**76%**
Distribution System Total	**7,931**		**535,580**	

Source: Annual DOT filing for Calendar Year 2014 Gas Distribution System for KEDLI
* Pre-1985 Aldyl-A Plastic services determined based on mileage of Pre-1985 Aldyl-A main and average services per mile within the KEDLI distribution system.

A significant amount of infrastructure that remains in service was installed during expansion periods before 1940 (approximately 1,278 miles) and then during the eastward migration to the suburban areas of Long Island from 1950-1969 (approximately 2,477 miles). Most unprotected steel mains in service today were installed prior to 1959 and as early as pre-

1910, which means that the inventory ranges from 50 to 100 years of age or greater.

Q. Why does the Company's LPP replacement program incorporate some vintages of plastic pipe?

A. Some early vintage Aldyl-A plastic pipe has performance issues. In its performance monitoring of early vintage plastic pipe on its system, KEDLI has observed brittle cracking of these pipes in recent years.

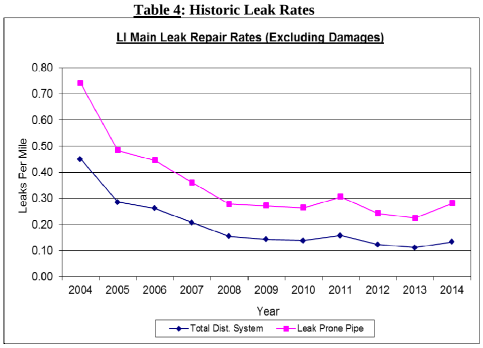
Q. How does the Company prioritize the replacement of main segments for the replacement program?

A. Each year, the Company prioritizes LPP replacements by using a risk-ranking algorithm that is part of the Company's Distribution Integrity Management Plan ("DIMP") and the Company's Gas Operating Procedure for the Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement (ENG04030). The Company's risk model calculates a relative risk score for each LPP segment based on specific performance data and localized incident probabilities and consequences, combined with calculated risk factors for the asset classes being evaluated. This risk-based algorithm along with the Company's good engineering judgment (taking all factors and risks into consideration in each case) form the foundation of the LPP replacement strategy.

Q. Please provide an overview of the performance of LPP on the Company's distribution system.

A. As would be expected, the Company has observed a significantly higher leak rate on its LPP inventory as compared to all other distribution facilities. The current leak rate for all distribution piping is 0.13 leaks per mile, slightly increased from 0.11 leaks per mile in 2013, which was due in part to extremely cold weather in 2014. The current leak rate for LPP is 0.28 leaks per mile. After several years of decline, the leak rate on LPP has been trending up since 2013 (when it was 0.23 leaks per mile) as these facilities continue to deteriorate.

Table 4: Historic Leak Rates



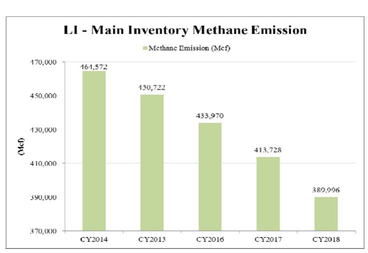
Q. How will the Company's proposed accelerated replacement program impact leak rates?

A. As demonstrated in Exhibit __ (GIOP-3), there is a direct correlation between the rate of LPP replacement and the annual reduction of leaks. In terms of the anticipated timing of leak rate reductions, the Company expects to see reductions in leak rates after several years of accelerated replacements, when sufficient incremental LPP has been replaced to offset the leaks experienced on the remaining leak prone facilities (which will experience increasing leak rates as these facilities deteriorate). At a retirement rate of 115 miles in the Rate Year, increasing by 20 miles each subsequent year, the Company expects leak rates to decline measurably over the next five years.

Q. Is there an environmental benefit associated with an accelerated LPP replacement program?

A. Yes. Retirement of LPP reduces gas losses and fugitive emissions of methane, considered by the United States Environmental Protection Agency ("EPA") to be a greenhouse gas. Table 5 provides a high-level estimate of potential methane emissions reductions over the next several years assuming the retirement of LPP pursuant to KEDLI's proposed program.

Table 5: Estimated Methane Emissions Reduction



Emission reductions estimates are based on the calculation methodology set forth in the EPA's regulations (40 CFR § 98, Subpart W).

Q. What is the level of total spending required to achieve the Company's accelerated replacement program in the Rate Year and the Data Years?

A. Exhibit __ (GIOP-1) sets forth the projected spending for CYs 2017 through 2019 to achieve the base LPP replacement target (115 miles/year) discussed above. As shown in Exhibit __ (GIOP-1), annual program spending would increase from approximately $88.6 million in CY 2016 to $130.54 million in the Rate Year, $143.33 million in Data Year 1 and $146.2 million in Data Year 2.

Q. Please describe the factors contributing to increased main replacement costs in KEDLI's service territory.

A. Several factors are increasing the cost of LPP replacement. The remaining LPP population contains a significant amount of large diameter pipe, which is more costly to replace. The installation of large diameter plastic pipe (larger than four inches) calls for fusion joints every 40 feet, requiring a larger layout area, larger trenches and more permits as compared to the installation of smaller diameter pipe. Larger pipe is also heavier and requires more resources for transportation, handling and installation.

Next, main replacements are costing more as a result of working conditions and more onerous municipal permitting/restoration requirements. For example, many municipalities on Long Island now require that the Company repave larger areas of the road following gas excavations or, in some cases, that the Company repave the entire street (curb to curb). This has led to a substantial increase in paving costs on the average main installation job. Municipalities are also increasing the fees for road opening permits and/or charging for post-construction road inspections. Although KEDLI works closely with municipalities to minimize costs associated with construction (*i.e.*, by coordinating main replacements with municipal paving projects), many of these costs are driven by field conditions and, therefore, are not within the Company's control.

Finally, the cost of capital work has increased over the last several years due to rising material costs and increased labor and contractor costs because of market competition to secure qualified construction resources.

To mitigate the cost, main replacements are coordinated with other programs, such as the Public Works, Reinforcement and Reliability programs, to capture synergy savings and cost avoidance. As the Company continues to accelerate its rate of LPP replacement, it will look for more of these opportunities to deploy construction resources more efficiently. The Company will also identify areas of the gas network where entire LPP systems can be retired efficiently and cost effectively. Finally, KEDLI is implementing a long term contractor sourcing strategy (discussed above) to secure qualified construction resources capable of performing LPP replacements at reasonable costs.

Q. **What is the Company's proposal for the recovery of LPP replacement costs following the Rate Year?**

A. The Company is targeting the replacement of up to 775 miles of LPP over a five-year period (2017 through 2021). In recognition of the unprecedented incremental work associated with the Company's accelerated main replacement targets, and to allow the Company to begin recovering the actual costs of the accelerated replacement of LPP as the work is completed, the Company proposes a Gas Safety and Reliability Surcharge under which the Company would be allowed to recover a return on investment, depreciation expense and related O&M expense (*i.e.*, disconnects and reconnects) associated with prudent investment in LPP replacement incremental to the level funded in base rates. Provided the Company exhausts its rate allowance for LPP replacements, incremental investment in LPP above the base level of 115 miles in any calendar year, in an amount not to exceed the Company's average cost of main replacement for comparable pipe materials, sizes, strata (*e.g.*, pavement, grass) and working conditions, would be included in the Gas Safety and Reliability Surcharge. The Gas Safety and Reliability Surcharge is discussed more by the Revenue Requirements Panel.

Q. Why is the Company proposing a base level of LPP replacement miles in the Rate Year and Data Years?

A. The base level (115 miles) represents a significant increase in replacement miles compared to the replacement targets just two years ago when the Company was targeting 50 miles per year (an increase of 130 percent). The Company must continue to ramp up its engineering, procurement, construction and project management resources to support these new levels of main replacement. The Company's ability to accelerate replacement above the base level could be impacted in any year by resource constraints as local distribution companies ("LDCs") in the area compete for scarce construction resources that are capable of safely performing main replacements. Only a limited number of qualified contractors are available, and it will take significant time and effort to "up-skill" nonqualified construction staff to get all of the work done. Similarly, the Company's ability to secure construction permits and coordinate construction activities with municipalities and other utilities will be challenged as the Company pursues unprecedented levels of main replacement. At the same time, significant municipal infrastructure projects in a given year may present opportunities to replace main more cost effectively.

The Company's proposal ensures it will replace at least 115 miles of LPP each year (with an associated negative revenue adjustment for failing to achieve the penalty target, as discussed by the Gas Safety Panel), while providing incentives to significantly accelerate its LPP replacement each year. The proposal also provides flexibility to target additional replacements when resources are available and other opportunities present to complete the work more cost effectively. The surcharge mechanism ensures that KEDLI will recover LPP replacement costs only to the extent it is successful in delivering its program.

Q. Is the Company proposing an incentive regarding its replacement of LPP?

A. Yes. The Gas Safety Panel discusses the Company's proposed incentive for LPP replacements above the base target.

Q. Does the Company propose to enhance reporting on LPP replacement?

A. Yes. The Company will provide Department of Public Service Staff ("Staff") with visibility to the status of its LPP replacement program. The Company proposes to report to Staff on a quarterly basis, including main retired (pipe material, feet, location), cost data, opportunistic replacements and the status of the Company's LPP replacement work plan.

In addition, thirty days prior the beginning of each calendar year the Company will submit its LPP prioritization summary identifying the proposed projects for the year, the estimated cost for these projects and a forecast of average LPP replacement costs per mile. Within ninety days after the end of the calendar year, the Company will submit a report detailing the actual projects completed and any incremental replacement miles performed under the Gas Safety and Reliability Surcharge.

ii. ***<u>Cast Iron Lining</u>***

Q. In addition to the LPP replacement program, is the Company proposing a program to recondition existing main?

A. Yes, the Company's capital plan includes a cured-in-place ("CIP") pipe lining program that will cost effectively recondition large diameter cast iron and steel mains.

Q. Please describe the CIP program.

A. The CIP pipe lining process installs a treated fabric liner into cast iron and steel mains. An adhesive resin in the liner bonds with the inside wall of the pipe, forming a new layer that is impervious to gas. CIP lining reconditions larger diameter cast iron and steel mains, eliminates existing leaks, prevents future leaks, reduces emissions, improves performance and extends the life of the main for more than 50 years. CIP lining technology has been used extensively on water and sewer facilities in the United States for years and, more recently, has been deployed by natural gas utilities to recondition aging cast iron and steel mains. KEDLI is proposing to line one mile of main per year commencing in the Rate Year.

Q. How does CIP complement the Company's LPP replacement program?

A. Reconditioning large diameter main with CIP extends the life of the main and defers its replacement. This allows the Company to focus more attention, capital investment and construction resources on retiring smaller diameter LPP with higher risk profiles, which will enhance the effectiveness of KEDLI's LPP replacement program and promote public safety.

Q. What are the cost advantages of CIP lining?

A. Large diameter main replacements and repairs are typically expensive because of the location and depth of the excavations required to access the pipe joints. CIP lining is cost effective and efficient, especially in congested metropolitan areas where it is not always possible to locate a sufficient subsurface space to install new large diameter main. Because CIP involves less excavation than traditional pipe replacement, it reduces construction costs, avoids damage to roads and vegetation, minimizes disruptions to the public and provides environmental benefits in the form of reduced gas emissions and construction debris while maintaining the safety of the main until it can be replaced.

At $3.5 million per mile, CIP lining costs less than half of the pipeline replacement it defers.

Q. What are the Company's expected capital expenditures for CIP?

A. The Company's forecast includes $3.37 million in the Rate Year, $3.57 million in the Data Year 1 and $3.6 million in Data Year 2.

Q. Is the Company proposing a productivity mechanism for its CIP program?

A. Yes. While CIP is a cost effective program in its own right, the Company is proposing to enhance the potential cost benefits to customers by including this program in a productivity pilot that will share any CIP cost underruns directly with customers. To the extent KEDLI's actual cost to deliver the CIP program is less than the rate allowance, the Company will share the resulting saving with customers. The Company proposes to retain 20 percent of any budget underrun as a positive revenue adjustment and return 80 percent directly to customers. This mechanism will incent the Company to achieve savings in the CIP program, while at the same time providing customers with a direct financial benefit. The Revenue Requirements Panel also discussed the productivity sharing mechanism.

iii. <u>Storm Hardening</u>

Q. What is storm hardening?

A. The Company maintains approximately 58,000 gas services within the Federal Emergency Management Agency's designated flood zones. These services are especially susceptible to storm surge and flooding that could cause over-pressurization of the gas facilities connecting customers' premises. The impacts of recent severe storms (*i.e.*, Superstorm Sandy and Hurricane Irene) demonstrate the need for the Company to harden its infrastructure to provide greater protection from future storms.

The Company's storm hardening proposal involves the installation of automated service shut-off valves with flood sensors on gas services in flood zones. These valves will operate on a fixed communication network that will allow for remote operation and monitoring. Automated valves stop the flow of gas as soon as flooding is detected. This will prevent regulator over-pressurization and stop gas from flowing to premises with damaged equipment and/or extinguished pilot lights, mitigating the risk of a potential incident. Automated valves also provide a real-time count of services impacted by flooding to inform the Company's storm response about the resources needed to restore the affected customers expeditiously. Lastly, in areas where flooding prevents physical access to valves and regulators, remote shut off valves will allow the Company to interrupt only those services impacted by flooding, which could spare entire neighborhoods or larger areas from losing gas service because of access issues.

The Company's proposed storm hardening program will deploy approximately 58,000 remote shut off valves in the flood prone areas of KEDLI's system over five years beginning in the Rate Year.

Q. What are the Company's expected capital expenditures for these remote valves?

A. The Company's forecast for this program includes $8.29 million in the Rate Year, $11.22 million in Data Year 1 and $11.44 million in Data Year 2.

iv. __Integrity Management and Pending PHMSA Safety Regulations__

Q. What is the Company's Integrity Management Program?

A. The Company's transmission pipeline Integrity Management Program ("IMP") is a safety program mandated by the Pipeline Safety Improvement Act of 2002. The IMP identifies and addresses potential issues affecting the physical soundness of Company facilities before they become safety or performance issues. The Company conducts baseline and periodic reassessments of transmission facilities to identify and evaluate potential threats to "Covered Segments" of pipelines, *i.e.*, transmission pipelines that could affect High Consequence Areas (areas where a pipeline failure could have significant adverse consequences), as well as remediation of significant defects discovered during such assessments. Although tests and inspections are generally an operating expense, the first inspection run of a pipeline segment is capitalized. Additional capital work is required to support in-line inspections (*e.g.*, installation of pig launchers and receivers, and pipe reconfiguration/replacement) and to resolve issues discovered during pipeline inspections.

KEDLI's capital investment plan includes IMP investments necessary to comply with PHMSA's current regulations governing transmission pipeline integrity management:

Table 6: Integrity Management Program Expenditures

($000)	CY 2017	CY 2018	CY 2019
Capital Expenditures	1,168	5,844	4,265
Operating Expense	2,100	2,610	1,520

The construction activities associated with these expenditures involve the installation of "hot tap" fittings, the reconfiguration of such fittings to allow in-line inspection passage, the construction of access points to allow tethered in-line inspection and the replacement of pipeline segments.

Q. What is the status of the federal regulations in this area?

A. The federal regulations in this area are evolving, and PHMSA is expected to release proposed pipeline safety regulations in 2016. One major component of the anticipated IMP regulations is a requirement for increased inspection of IMP-covered pipelines utilizing in-line inspection technology. To meet this requirement, transmission pipelines must be "piggable," or capable of accepting in-line inspection tools.

Because the Company believes it is a prudent expenditure, and in anticipation of new regulations expanding IMP, KEDLI is proposing to increase its piggable inventory through reconfiguring existing facilities and, in some cases, replacing transmission pipeline sections. The Company expects to spend $1.16 million in the Rate Year. At the end of this program, the Company estimates approximately 25 percent of its transmission main will be piggable. The Company believes that its proposed program is a reasonable and conservative approach pending the promulgation of PHMSA's new regulations, and would be a prudent investment in any case, given that it will enhance the Company's ability to assess the integrity of its transmission pipelines.

Q. What if the heightened requirements associated with the Pipeline Safety Act of 2011 do not become effective during the Rate Year?

A. The Company is constantly evaluating the performance of the gas system and analyzing the need for capital investment and maintenance. Having spent considerable time examining the San Bruno, Allentown and other incidents, and having closely followed the legislative process that culminated in the Pipeline Safety Act of 2011, the Company is being proactive rather than reactive to address important safety issues and to incorporate lessons learned in its capital plan. These capital proposals are prudent investments that will improve system safety and performance. Moreover, these investments should go a long way toward satisfying the heightened safety requirements that are expected to result from the Pipeline Safety Act of 2011.

Q. What is covered in the Company's Integrity Verification Program ("IVP")?

A. The Pipeline Safety Act of 2011 also mandates that PHMSA establish rules requiring operators to demonstrate their pipelines are "fit for service" by reviewing construction records for each pipeline segment to confirm it is operating within design parameters. Among the specific changes under consideration by PHMSA are new rules regarding the maximum allowable operating pressure ("MAOP") and pressure testing requirements for existing pipelines, including (i) eliminating the exemption for establishing the MAOP of pre-1970 "grandfathered" pipe segments; (ii) mandating additional pressure testing for pipelines previously operating above MAOP; and (iii) requiring operators who lack certain records to establish material properties using approved methods (*e.g.*, cutting and testing pipe samples). The final rules are expected to be released in 2016. However, in advance of a final rulemaking, PHMSA issued an advisory bulletin (ADB-11-01; January 2011) directing operators to perform a detailed threat and risk analysis that includes a records review of their systems.

Accordingly, the Company is proceeding with an IVP program that includes thorough record reviews, pressure tests, pipeline replacement and retirement of non-essential pipeline segments. As with the IMP program, the proposed IVP program is based on the Company's assessment of system risks, while also incorporating PHMSA's proposed rulemaking.

Q. What are the Company's forecast expenditures on IVP?

A. The Company forecasts capital expenditures of $0.25 million and O&M expense of $1.15 million in the Rate Year. Capital expenditures include pipeline replacement and pressure testing, while O&M expenses include material sampling and critical engineering analysis:

Table 7: Integrity Verification Program Expenditures

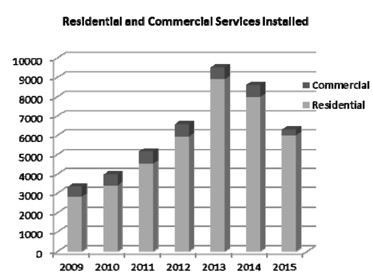
($000)	CY 2017	CY 2018	CY 2019
Capital Expenditures	250	250	250
Operating Expense	1,150	1,150	1,150

B. Expansion of Gas Service

Q. Please describe recent growth trends in the Company's service territory?

A. As a consequence of relatively low natural gas commodity prices, KEDLI has experienced significant growth and a concomitant need for growth-related capital expenditures over the last five years. In 2015, this trend slowed as oil prices dropped more than 30 percent, eroding the price advantage of natural gas to oil (a primary driver of natural gas conversions on Long Island), and the number of conversion opportunities along existing main shrunk. However, compared to prior periods, growth in KEDLI's service territories remains strong.

<u>Table 8</u>: KEDLI Services Installed



Expanding the availability of natural gas in KEDLI's service territory can bring significant economic benefits in the form of energy cost savings for customers, job creation and increased local tax revenues, as well as environmental benefits associated with lower carbon emissions. To enable growth, KEDLI must make significant capital investments in mains, services and system reinforcements.

Q. Please describe the Company's proposals to increase the availability of gas service within its service territory.

A. The Company is expanding and reinforcing its gas infrastructure to serve additional customers who wish to take advantage of currently low gas commodity costs. To that end, the Company proposes to extend its Neighborhood Expansion Program to provide access to gas to additional prospective customers.

Q. Please describe the Neighborhood Expansion Program.

A. In 2015, KEDLI launched its two-year Neighborhood Expansion Program, which was approved by the Commission in Case 14-G-0214. The program utilizes geospatial, engineering, main, supply, customer interest, customer load and other data to identify potential growth projects – including streets or neighborhoods where prospective customer density would support main extensions based on facilities entitlements under the Company's tariff (*i.e.*, locations with not less than eight potential customers per 500 feet of main). Once these areas are identified, the Company looks to secure commitments from a threshold level of customers to justify the capital investment in the infrastructure necessary to serve the area. If the Company is able to secure sales commitments from enough new customers to cover at least 60 percent of the project through tariff main entitlements (*e.g.*, 100 feet per new customer), the Company will proceed with the project without charging customers a Contribution In Aid of Construction ("CIAC") and target additional customers in the area to achieve the entitlement coverage for the entire main extension and maximize conversion rates.

Under the Neighborhood Expansion Program, the Company has sold projects to install 106,000 feet of main to serve more than 500 new customers. The Program also identified the opportunity to bring gas service to more than 1,000 homes in the previously unserved Village of East Hills in Nassau County. Over the next two years, the Company will install 60,000 feet of main to support the East Hills project without requiring CIACs.

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Q. What is the Company's proposal for extending the Neighborhood Expansion Program?

A. The current Neighborhood Expansion Program is due to expire on December 31, 2016. The Company proposes to extend the Neighborhood Expansion Program in the Rate Year with the goal of achieving 930 conversions and installing 125,000 feet of main in CY 2017, at an estimated cost of $16.35 million. This program will result in economic and environmental benefits including significant customer energy savings, reductions in emissions and job creation.

Company Witness Sean Mongan discusses KEDLI's proposed rebate program for new residential customers that agree to connect to the Company's distribution system and take service along the routes of planned main replacements and incremental marketing initiatives designed to achieve the Company's load growth target.

Q. Is the Company evaluating the feasibility of extending its gas distribution network to areas that are not currently served?

A. Yes, the Company is currently undertaking a review of its customer base and distribution network to identify expansion opportunities beyond its current footprint. In furtherance of this effort, the Company's Analytics, Modeling and Forecasting group is developing an analysis of the Company's service territory to identify localities with sufficient demand for gas service to support investment in gas distribution infrastructure. Additionally, the Analytics, Modeling and Forecasting group is working to integrate engineering data and analysis into a growth analysis in an effort to identify growth opportunities and explore new and creative cost recovery mechanisms (*e.g.*, surcharges) that would economically facilitate customer growth in expansion areas.

IV. Gas Infrastructure Capital Investment

Q. How much is the Company planning to invest in its gas system assets in the Rate Year?

A. The Company plans to invest approximately $337.6 million in its gas infrastructure and other capital investments in the Rate Year. Exhibit __ (GIOP-2), which provides the actual or budgeted capital investment for CYs 2015 to 2020, is segmented into four primary spending rationales (programs): “Mandated,” “Growth,” “Reliability” and “Non-Infrastructure.” Table 9 summarizes the planned capital investment for the Historic Test Year and CYs 2017 to 2019 in each of these programs

Table 9: Capital Budget by Spending Rationale
($000)

Spending Rationale	HTY	CY 2017	CY 2018	CY 2019
Growth	134,723	97,839	82,484	81,992
Mandated	94,498	166,905	187,222	189,885
Reliability	12,603	70,132	108,599	96,412
Non-Infrastructure	20,061	2,733	2,917	3,111
Total	264,348	337,609	381,222	371,400

Each spending rationale is broken down further into sub-categories that identify specific programs. In addition to the forecast Rate Year capital investment levels, Exhibit __ (GIOP-1) shows actual capital spending for the Historic Test Year and projected capital spending for the Data Years in each of these categories.

Q. How were the projected capital estimates derived?

A. In accordance with the Company's budgeting policies and procedures, capital budgets are prepared annually with a five-year forward look. Budget projections are based on historical work levels and unit cost performance for ongoing mandated and routine work and programs, plus any identified new requirements, programs and projects, such as those related to the anticipated regulations under the Pipeline Safety Act of 2011. Projects that fall outside of routine work, such as safety-driven programs (*e.g.*, the Company's LPP replacement program in the Mandated Category), are developed by Engineering based on the most recent material, labor and overhead costs.

Q. What are the primary drivers of the difference in the Company's planned capital spending in the Rate Year compared to historic capital spending?

A. As Exhibit __ (GIOP-1) shows, the primary driver of the increase in planned capital investment in the Rate Year compared to the Historic Test Year is increased investment in Mandated and Reliability programs. Investments in these programs are approximately $72 million and $57.5 million higher, respectively, in the Rate Year than in the Historic Test Year, and account for the difference between the total annual capital spend level between the two periods. The specific drivers for these increases are discussed below.

Q. Does the Company's revenue requirement in this case also include cost of removal associated with the capital investment plan?

A. Yes. In addition to the capital costs discussed below, there is a level of cost of removal required to implement the Company's infrastructure investment plan. As reflected in Exhibit __ (GIOP-1), the Company is forecasting costs of removal as follows: approximately $13.54 million in the Rate Year, $14.81 million in Data Year 1 and $15.27 million in Data Year 2. The capital forecasts for each program presented below are inclusive of cost of removal.

Q. What types of activities are associated with cost of removal?

The Company defines removal as any work on an asset that results in it being removed from the asset inventory, whether or not a different asset is added in its place. This type of work would include, but is not limited to, the activities associated with disconnection, removal and disposal (or retirement in place) of gas mains, gas services and related facilities.

Q. What information is presented in Exhibit __ (GIOP-4)?

A. Exhibit __ (GIOP-4) provides additional information for each of the significant gas capital projects and programs expected to be performed during the Rate Year. This additional information includes:

- Project or Program name
- Spending rationale
- Project or Program description
- Project or Program justification
- Estimated costs
- Customer benefits discussion
- Alternatives discussion
- Reference to other supporting information

Q. Please describe some of the technologies and practices the Company uses to reduce the total cost of its capital expenditures.

A. The Company continues to employ a number of technologies and best practices designed to increase the efficiency and reduce the cost of its capital expenditures. These practices include:

- Increasing the amount of planned capital work (versus reactive work).
- Increasing coordination among capital programs to increase efficiencies (*e.g.*, leveraging LPP opportunities).
- Installing more small diameter, high-pressure facilities that can be installed at lower cost.
- Using smaller excavating equipment, increasing operating efficiency and reducing instances of damage (because of decreased size and weight of equipment).
- Employing "low dig" technology as opposed to traditional open cut methods for main installation, including use of small directional drilling machines for services and small diameter mains.
- Using "coring and keyhole" technology to repair existing mains
- Enhancing contractor management.
- On-site reporting for work crews in many large construction projects.
- Deploying CIP lining (as described in Section III (A) (iii) above).

In addition, the Company is addressing escalating municipal permitting fees and restoration costs through proactive outreach to municipalities in the service territory.

Finally, as discussed by the Revenue Requirements Panel, the Company's performance excellence initiatives have contributed to lower Historic Test Year and Rate Year capital costs. The capital savings associated with these initiatives are embedded in the capital plan and, therefore, not reflected as separate adjustments.

Q. Is the Company doing anything to reduce methane releases during construction activities?

A. Yes. The Company is developing a new operating procedure to capture gas during "blow-downs," during which gas is purged from a gas pipeline and released. Under the Company's new protocol, a draw down compressor will capture the gas (where possible) and inject it into another pipeline that is in service. The Company is currently developing standards and procedures for this new blow down process, and anticipates deployment in the Rate Year.

Q. Did the recent Gas Management Audit address any aspects of the Company's gas operations?

A. Yes. While the New York Gas Management Audit found the Company's gas operations perform well overall in providing gas service in a reliable manner, the audit identified a number of findings and recommendations addressing aspects of the Company's system planning, engineering, project management and work management functions. These recommendations, which are in varying stages of implementation, suggest that the Company: (i) develop an integrated natural gas system-wide plan that includes all reliability work, mandated replacements, growth projects and system planning work identifiable over a five year period (in progress); (ii) update and consolidate the Company's IMP (completed); (iii) develop an estimating program for the Company's gas projects (in progress); (iv) implement a program to track and manage crew and individual worker productivity (in progress); and (v) develop a manpower planning program (in progress). Once fully implemented, these recommendations will enhance the Company's system planning, estimating and work management capabilities. The testimony of Company Witness Keri Sweet Zavaglia discusses the status of the Gas Management Audit implementation.

A. <u>Capital Plan Budgeting</u>

Q. Please describe the annual development of the Company's capital plan.

A. Each year, the Company develops a ten-year capital plan to achieve its performance objectives of delivering safe, reliable service. In the summer of each year, Investment Planning compiles proposed spending for programs and individual capital projects. Programs and projects are categorized by the four spending rationales (Mandated, Growth, Reliability and Non-Infrastructure). The proposed spending for each program or project includes the latest cost estimates for in-progress projects as well as initial estimates for new projects. Expected deviations from historical trends in mix, volume and cost of work are considered.

All known mandatory programs and projects are included in the ten-year capital plan. Once the budget level has been established for Mandated work, the programs and projects in the other spending rationales are reviewed for inclusion in the plan. Whether any other project is included in the plan is based on several factors, including, but not limited to, whether the project is new or in-progress, the project risk score and/or resource availability. In addition, program work is examined to capture any possible cost efficiencies, specifically with respect to LPP replacement.

In late fall, the capital plan is reviewed by the New York Jurisdictional President (Company Witness Kenneth Daly) and the Vice President, Finance, New York (Company Witness David Doxsee). The New York Jurisdictional President reviews the overall customer, service quality and financial impacts of the investment plan as part of the business planning process and may request changes to the level or mix of investments. In early winter, a capital plan is presented to the National Grid plc Executive Committee and, in early spring, the capital portfolio is presented to the National Grid plc Board of Directors for review and approval.

Q. Are there additional approvals needed before a project in the annual capital plan may proceed?

A. Yes. Aside from the capital planning and budgeting process, specific "delegation of authority" approval must be obtained for any project in the ten-year capital plan to proceed. Presently, all projects greater than $8 million, and all complex projects greater than $1 million, up to a limit of $25 million, are reviewed and approved by the U.S. Sanctioning

Committee, a committee established by the National Grid USA Board of Directors specifically for this purpose. Projects from $1 million to $8 million are approved by the Senior Vice President for Gas Process and Engineering. Projects less than $1 million are approved through a supervisory hierarchy based on certain established thresholds. Effective January 1, 2016, projects between $25 million to $176 million will be reviewed by a newly-established Senior Executive Sanctioning Committee.

Q. Please describe how the Company's DIMP impacts its capital investment planning.

A. The DIMP involves a risk-based assessment of the Company's distribution system to identify threats in seven categories: corrosion, natural forces, excavation damage, other outside force damage, material and weld failure, equipment failure/malfunction and inappropriate operation. The DIMP requires evaluation and prioritization of the risks that these threats pose, and the implementation of measures to address the highest risks with an emphasis on leak management, enhanced damage prevention, operator qualification to reduce human error and system replacement. Consistent with the DIMP, the Company prioritizes asset replacements in its investment plan based on a risk ranking that considers, among other things, leak repair history, types of leak, pipe material, surrounding geography, segment length, nearby construction activity, field conditions, customer issues, open leaks and engineering judgment. The risk ranking factors are carefully designed to consider known differences in the performance of asset subclasses, extensive experience with asset failures, current performance data for the asset subclasses for various threat categories, and subject matter experts' analysis and opinions on the future performance of the assets.

B. <u>Mandated Category of Capital Spending</u>

Q. What portion of the Company's capital investment plan is Mandated?

A. The Mandated category of work accounts for approximately 49 percent ($166.9 million) of the total planned capital investment in the Rate Year.

Q. Please describe what is included in the Mandated spending category.

A. Projects covered by the Mandated spending rationale are those needed to comply with regulatory obligations and rate plan commitments, including: City/State construction projects that require the Company to relocate facilities, code-required corrosion testing and mitigation or other pipeline integrity related activity, proactive and reactive capital main and service replacement, required meter replacement and cross bore investigations.

Exhibit __ (GIOP-4) includes a summary description of each of the significant projects included in the Company's Mandated spending rationale/category, along with the estimated annual funding during the Rate Year and Data Years for each.

Q. Please describe what is included in the City/State construction sub-category.

A. City/State construction work is performed to accommodate third-party, municipal construction activity that could impact the integrity of the Company's natural gas facilities. Typical third-party construction activities that impact gas facilities include work on water, sewer and drainage infrastructure, street reconstruction, road realignment and bridge replacement. The forecast cost for this program is approximately $10.17 million in the Rate Year.

State regulations and Company procedures require the replacement of eight inch and smaller cast iron gas mains if roadway or underground construction is being performed in such a way that would impact the integrity of the Company's mains. Non-cast iron gas mains (*i.e.*, steel and plastic) are not subject to the same replacement regulations and are typically supported and protected if not in direct conflict with third-party construction. Direct conflicts are addressed through relocation regardless of material type.

KEDLI forecasts its City/State expenditures by reviewing the known and planned work identified by municipalities, historical work volumes and unit information. In CY 2015, approximately 21,100 linear feet (approximately four miles) of main replacement was required to address municipal infrastructure improvements. Thirty-seven percent ($3.1 million) of this replacement work was subject to some level of reimbursement from third parties, while the remaining 63 percent ($5.2 million) of capital investment was non-reimbursable main and service replacements.

Q. Are there opportunities to retire LPP during City/State construction projects?

A. Yes. As part of the City/State construction program, the Company looks to identify cost-effective opportunities to retire LPP when main replacements are required to accommodate municipal construction. City/State construction projects present opportunities to perform safety and reliability upgrades on the Company's infrastructure, the costs of which can be offset by coordinating construction activities (shared trenching and paving) and securing third party reimbursements. Of the approximately 21,120 linear feet of City/State construction main replacements in CY 2015, approximately 15,840 linear feet (three miles) of LPP was retired.

Q. Does the Company's forecast reflect potential reimbursement from municipalities and other third parties?

A. Yes. KEDLI's forecast reflects likely reimbursements of expenditures obtained by KEDLI pursuant to the Gas Facility Cost Allocation Act and other cost sharing arrangements with municipalities. Expected reimbursements total $0.78 million in the Rate Year, $0.79 million in Data Year 1 and $0.81 million in Data Year 2.

Q. Why is the cost of the City/State construction program increasing to more than $10 million in the Rate Year?

A. Aging municipal infrastructure (buildings, schools, bridges, roadways, transportation systems, water mains and sewer facilities) will require significant upgrades in the coming years. Over the last two years, there has been an increase in the level of municipal construction activity, as Superstorm Sandy and recent gas incidents focused attention on the state of municipal infrastructure. Going forward, the City of New York (on the

Rockaway Peninsula) and municipalities on Long Island will continue to invest billions of dollars to upgrade their infrastructure, and many of these projects will impact KEDLI's gas system.

Based on the current five-year construction plans of New York State and the municipalities within its service territory, the Company estimates that main replacement associated with infrastructure projects will increase from 21,120 linear feet in CY 2015 to approximately 31,680 linear feet (six miles) in the Rate Year. Thereafter, the Company projects that the amount of footage installed in accord with City/State construction will remain the same for the next four years. The Company forecasts that approximately 21,120 linear feet (four miles) of LPP will be retired as part of the public works program in the Rate Year. While the Company believes its forecasts are reasonable based on available information, capital expenditures in this area are subject to a high degree of variability as the scope and scheduling of municipal construction projects are constantly revised.

Q. Please describe New York City's joint bidding process and its potential impact on City/State construction costs.

A. In 2014, New York State adopted a "joint bidding" requirement for public works projects in cities with populations of one million or more (N.Y.S. Assembly Bill A10021B) that will impact KEDLI's City/State construction projects in New York City. Currently, utilities impacted by New York City public works projects are individually responsible for performing their own relocation work, as well as negotiating all support and protect work directly with the City's contractor. Under the "joint bidding" model, the City will bid and manage the entire project. If the City's contractor is qualified by National Grid to work on its gas facilities, the contractor may perform the gas relocation work. If the City's contractor is not gas qualified, KEDLI will perform its own relocation work ahead of the planned project. Each impacted utility will also be responsible for a portion of the "shared costs" of work performed by the City's contractors, including, for example, maintaining the construction site, establishing field offices, setting up transportation and managing contracts and expenses. The joint bidding process is expected to be fully implemented by July 2016, but the scope of its application is currently unknown. While the Company's forecast includes an estimate of the expected costs, the true cost implications on utilities of working through the City's selected contractors, as well as the impact of the shared costs contribution, remains to be seen.

Q. Please describe the Company's proposal to track and defer for future recovery the capital and O&M costs relating to City/State construction.

A. While the Company has projected costs for City/State construction, there is significant risk that the actual work required to support municipal construction activities will be more than what is assumed in the capital plan. Indeed, over the past several years, the Company's forecasts have underestimated City/State costs to support construction activities in New York City. This is partially attributable to changes in the City's annual construction plans and the scope/location of the City's emergency and "where and when" construction projects, which the Company does not know in advance. Also, a single large municipal project can necessitate tens of millions of dollars in unplanned City/State costs. The new Joint Bidding requirements will add uncertainty to the level of City/State construction costs over the next few years.

Because it is difficult to predict the level of City/State construction during the Rate Year, and the investment requirements are beyond the Company's reasonable control, the Company is proposing that the Commission authorize a discrete deferral mechanism for recovery of costs in excess of the Rate Year allowance for City/State construction. In the event the scope and/or timing of City/State construction causes the Company to incur capital and/or O&M costs in excess of amounts reflected in base rates, such amounts would be deferred for collection in subsequent years. Conversely, to the extent the Company's City/State construction costs are lower than the allowance in base rates, the Company will credit the City/State deferral for the revenue requirement impact of any over recovery.

Prior to incurring any significant costs in excess of the rate allowance, the Company will submit an annual report to Staff that will detail the incremental projects or programs required to accommodate City/State construction. The Company will establish specific capital and/or expense work orders in its plant accounting system and record all associated costs. The Company will defer the revenue requirement associated with the cumulative incremental costs not included in rates (or credit any over recovery), which would include the return on the capital investment, depreciation and any associated O&M costs.

Q. Please describe what is included in the Transmission Pipeline Integrity program.

A. The transmission pipeline integrity management program is discussed above in Section III (A) (iv).

Q. Please describe what is included in the Corrosion Control program.

A. This program funds work on above-ground gas mains at bridge locations and includes complete recoating of existing aged, dis-bonded, deteriorated or uncoated gas mains, as well as retirement of LPP where it extends underground near these crossings. In addition, this program includes upgrades to existing cathodic protection systems.

Q. Please describe what is included in the Meter Changes program.

A. The Meter Changes program involves the labor to replace gas meters that are retired from service or abandoned based on the result of periodic testing requirements established by the Commission.

Q. Please describe what is included in the Purchase Meters program.

A. This program includes the purchase, testing, processing and delivery of gas meters and associated instrumentation needed to support the Meter Change program, gas growth and Customer Meter Service (“CMS”) operations.

Q. Please describe the Main Replacements - Proactive Program.

A. The Main Replacements-Proactive Program funds the planned replacement of LPP, discussed above in Section III (A) (i).

Q. Please describe what is included in the Reactive Main and Service Replacement program.

A. The Reactive Main and Service Replacement program provides for the replacement of gas mains and services during urgent or emergency situations that fall outside the normal scope of integrity, reinforcement, reliability and public works programs. These replacements are performed in lieu of repair in instances when repairing damaged facilities is not possible, or where the pipeline segment is too short be covered by the Proactive Program.

Q. Please describe the Cross Bore Investigation program.

A. A cross bore is an unintended consequence of horizontal directional drilling ("HDD"). It occurs when a plastic gas main goes through a sewer lateral that was not identified during the gas installation process. A cross bore can block the sewer line and any attempt to clear the blockage can damage the gas line and cause gas to migrate into a building. Over the last few years, several such incidents have occurred in the industry and, as a result, many utilities have initiated programs to remedy this situation.

The Company updated its HDD procedures in 2014 to address and eliminate possible cross bores. The proposed investigation and remediation program will address all HDD installations prior to 2014 to ascertain if any cross bores exist and, if so, to remediate them.

Q. What work is addressed in the Latent Damage category?

A. In response to recent industry events and directives coming out of the Commission's generic safety proceedings (including the Horseheads Proceeding (11-G-0565) and Plastic Fusions Proceeding (Case 14-G-0212), which are discussed in the testimony of the Gas Safety Panel), the Company will perform additional inspections of its underground infrastructure when opportunities present during the course of normal operations. For example, the Horseheads Proceeding focused attention on the need to inspect facilities near third party excavations for potential latent damage. While the Company's risk assessment did not identify systemic issues with third party latent damage, increased inspections will certainly identify facilities in need of repair. Similarly, in the Plastic Fusion Proceeding, the Commission directed all LDCs to conduct inspections of plastic fusion joints exposed during regular operations. As some of the plastic facilities on KEDLI's system are more than 40 years old, the Company anticipates these incremental inspections will identify the need to replace or repair plastic mains and joints. The Latent Damage category includes an estimate of cost to perform these capital repairs, which includes $1.75 million in the Rate Year, $2.03 million in Data Year 1 and $2.07 million in Data Year 2.

C. <u>Growth Spending Rationale of Capital Spending</u>

Q. What portion of the Company's capital investment plan is in the Growth spending category?

A. The Growth category of work accounts for approximately 29 percent ($97.8 million) of the total planned capital investment in the Rate Year.

Q. Please describe what is included in the Growth category.

A. Growth programs are designed to support forecast customer growth and add new load by increasing system utilization in a cost-effective way. Growth programs involve the installation of new mains, services and meters and include Base Growth and system reinforcement. Contained in the Growth category are the estimated capital costs of new mains, services and meters required to serve additional load. Exhibit __ (GIOP-4) includes a summary of significant projects included in the Company's Growth spending rationale/category, along with the estimated annual funding during the proposed Rate Year and Data Years for each project.

Q. Please describe what is included in the Base Growth category.

A. As discussed in Section III (B) above, Base Growth occurs as a result of new construction, customer-initiated conversions and/or gas marketing. Generally, facilities, including main, services and meters, must be installed to serve the additional load. To serve new load economically, the Company must balance the costs of adding that load against incremental revenues.

Q. Please describe the System Reinforcement category.

A. The System Reinforcement category contains projects intended to ensure that minimum system pressures are maintained throughout the gas network during periods of peak demand. The Company models peak demand based on the sendout forecasts developed by Analytics, Modeling and Forecasting (Company Witness Theodore Poe). As a result of growth in gas usage in its service territory, KEDLI has determined that it is necessary to complete a number of projects to ensure its ability to meet peak requirements. These reinforcement projects are essential to serve growing demand on the system.

During the winter of 2014/2015, KEDLI recorded six of its top ten sendout records, including a firm load record of 950,697 dekatherms on February 15, 2015 when the average temperature was nine degrees Fahrenheit. The recent growth in peak sendout underscores the need to ensure that minimum system design pressures are maintained throughout the distribution network during periods of peak demand.

Q. Please provide examples of System Reinforcement projects.

A. Examples of System Reinforcement projects include:

- Replacing undersized mains with larger diameter mains. LPP is targeted whenever practical during this work.
- Looping or connecting system endpoints by installing new main.
- System pressure uprates (*e.g.*, 10 pounds per square inch ("psi") to 60 psi).
- Installing new district regulators and replacing existing undersized district regulators.
- Transferring existing low pressure customers to an adjacent high-pressure main (*i.e.*, load shedding).

D. Reliability Category of Capital Spending

Q. What portion of the Company's capital investment plan is Reliability?

A. The Reliability category accounts for approximately 21 percent ($70 million) of the total planned capital investment in the Rate Year.

Q. Please describe the goals of the Gas System Reliability Program.

A. Investment in this category is intended to maintain reliable service to customers by ensuring that all facilities on the gas system are operating efficiently and reliably.

Q. Please describe what is included in the Reliability category.

A. The Reliability category includes programs related to gas control, heaters, reactive Instrument & Regulation ("I&R"), pressure regulating facilities, valve installation/replacement, remote-controlled valves, gas planning, system reliability, water intrusion, system automation and control line integrity and liquefied natural gas ("LNG") facilities. Exhibit __ (GIOP-4) includes a summary description of significant projects included in the Reliability spending rationale/category, along with the estimated cost during the proposed Rate and Data Years for each project. A significant reliability project, the Northwest Nassau Transmission Main and Control Valve Project, is described in more detail below.

Q. Please describe what is included in the Heater Program category.

A. There are 31 natural gas heaters currently operating on the Company's system. Because high-pressure gas cools when reduced to a lower pressure, heaters are required at pressure regulating stations to prevent freeze-ups that can impact flow control devices. In addition, cold gas temperatures can lead to reduced pipe toughness and increased potential for frost heave and cold temperature-induced stresses. The heater program adds new heaters (where required) and replaces or rebuilds existing heaters that have reached the end of their useful lives or require component replacement.

Q. Please describe what is included in the I&R Reactive category.

A. The reactive I&R budget provides funding for capital investment in pressure regulating and control stations. Typical projects in this category include unplanned capital work resulting from emergency conditions, including the replacement of station valves, regulators and relief valves, as well as related capital work on station equipment.

Q. Please describe what is included in the Pressure Regulating Facilities category.

A. The Pressure Regulating Facilities category provides funding for replacement and/or rebuilding and reconditioning of existing regulating and control stations. Pressure regulating facilities (or stations) are designed to control system pressures and maintain continuity of supply during normal operating conditions and during periods of peak gas demand. This category includes full or partial replacement of existing stations.

KEDLI has assessed regulating stations on its system, evaluating factors such as pressure, location and the number of dependent customers for each station. In addition, the assessment considered station condition, including pipe corrosion, location and type of overpressure protection, automation, condition of vaults, vault covers, wall sleeves, piping vents and ladders. The results of the assessment were used to create an overall risk rating for each station that serves as the basis for prioritizing projects in this area.

Q. Please describe what is included in the Remote Controlled Valve (“RCV”) category.

A. This program involves the installation of additional RCVs on transmission pipelines to improve emergency response capability and reduce the risk of gas releases. In the event of a pipeline failure, RCVs allow control room operators to stop the flow of gas and isolate and shut down a portion of the system remotely. Currently, transmission pipelines can only be shut down using manually-controlled isolation valves, which can take longer to close and result in a larger number of customers being isolated. Improving response time through the expanded deployment of RCVs reduces the quantity of gas released and reduces the likelihood of harm to people and property.

Q. Why does the Company propose to make this investment in the Rate Year?

A. The PHMSA regulations promulgated in response to the Pipeline Safety Act of 2011 will mandate the installation of additional RCVs. But even in the absence of the PHMSA regulations, investment in RCVs is required given the safety and reliability benefits. As highlighted by recent industry events, there are significant operational benefits associated with the increased deployment of RCVs, such as enhanced pipeline shutdown capabilities.

Q. Please describe what is included in the Valve Installation and Replacement category.

A. Federal and state regulations require installation, inspection, operation and maintenance of critical pipeline valves on all gas distribution systems. The purpose of these valves is to facilitate the rapid shutdown of distribution piping during gas emergencies such as third-party damage or water intrusion. A secondary purpose of these valves is to facilitate maintenance and pipe replacement on associated distribution piping. This program will strengthen the Company's emergency response capabilities by improving the level at which Field Operations personnel can safely and efficiently isolate sections of the distribution system while mitigating customer impacts (*e.g.*, reducing the duration of future outages). Ensuring all critical valves are properly maintained and operable is a key public safety function and is essential to the effective operation of the Company's gas distribution system.

Q. Please describe what is included in the Water Intrusion category.

A. The Water Intrusion program is designed to address water entering the gas distribution system, resulting in main obstructions, poor pressure and/or freezing customer services. This program targets the retirement of LPP that is susceptible to water intrusion but is not prioritized for replacement under the Main Replacement programs because of the absence of leaks and/or historical leak repair activity.

Q. What are the goals of the Water Intrusion program?

A. The goals of the Water Intrusion program include improved customer satisfaction by focusing on addressing reliability and integrity issues. Also, the program will support the continued elimination of low pressure distribution systems by elevating pressure whenever practical. Finally, successful execution of the program will promote public and municipal relations as fewer outages will reduce unplanned road excavations.

Q. Please describe what is included in the Control Line Integrity category.

A. Control line piping is small diameter (two inches or less) piping used to monitor and control the pressures and flows at pressure regulating facilities. Control lines provide pressure feedback to the regulators and system automation equipment within the station. They are critical to maintaining control of system pressures and to maintaining continuity of supply during periods of normal and peak gas demand. The key driver for the Control Line Integrity program is the remediation or replacement of control line piping at pressure regulator stations that do not meet current standards of reliability, safety and performance. The program is designed to assess, remediate and/or replace control lines with these issues. Field data on control line conditions is collected during annual regulator station testing and on-site inspections. Based on the results of those inspections, projects in this area are coordinated with the proactive regulator program.

Q. Please describe what is included in the Gas Planning category.

A. The Gas Planning program ensures that customers continue to have reliable service and that no customers experience interruptions as a result of an unplanned outage of a facility under normal winter conditions.

Q. Please provide examples of Gas Planning projects.

A. Examples of Gas Planning projects include: eliminating distribution systems fed by a single district regulator or main, integrating distribution systems with the same operating pressures through pipeline connections, adding new supply diversity, and projects targeting areas of the system where large numbers of customers would lose service if a gas facility becomes inoperable when the average daily temperature is 15 degrees Fahrenheit.

Q. Please describe what is included in the System Automation category.

A. This program will install Remote Terminal Units ("RTUs") at multiple gate and regulator stations. RTUs provide temperature, pressure and flow data back to the Gas Control Room. RTUs can also monitor gas detectors and intrusion alarms and allow Gas Control Operators to adjust flow and pressure set points at regulator stations. The benefits include enhanced calibration of network models from automation and telemetry data, improved accuracy of network analysis, and enhanced ability to forecast the need for capital reinforcements, which will lead to more efficient capital planning. Automation allows Gas Control Operators to selectively close valves, raise or lower pressures, and shut down take stations. System alarms also alert Gas Control Operators to system issues and allow quick pinpointing of the source.

PHMSA regulations regarding Control Room Management require Operators to ensure that “practices and procedures within their control rooms are adequate to maintain pipeline safety and integrity.” These rules indicate that Operators should have telemetry to monitor pipelines, as it would increase system awareness and enable a proactive response to abnormal operating conditions. The System Automation program complies with these regulations by providing for increased deployment of telemetry on the Company’s system.

Q. How is system performance monitored currently?

A. Currently, all of KEDLI's pressure regulation stations are equipped with some form of telemetry. However, some of this telemetry equipment is at the end of its useful life. RTUs installed under the System Automation program will replace obsolete and aging equipment and provide the Company with enhanced ability to monitor system performance and remotely adjust pressures on the gas system.

Q. Please describe the Company's LNG program.

A. The Company maintains on-system gas supply through its LNG facility at the Holtsville LNG Plant. The LNG tank (0.6 billion cubic feet ("bcf")) was placed into service in 1971. The Holtsville LNG Plant is capable of supplying 100 million cubic feet of gas per day, which represents approximately 10 percent of KEDLI's peak day demand. Refilling the tanks is accomplished through liquefaction during the summer period when gas supplies are available and less expensive. The liquefaction system can refill at a rate of about 6 to 6.3 million cubic feet of gas per day and it takes from 75 to 100 days to refill the tank.

Q. Please describe the Company's proposed capital investments for the LNG program during the Rate Year and Data Years.

A. The Holtsville LNG Plant has been in service for more than 40 years and requires significant investment to support continued safe and reliable operation. Therefore, the Company proposes a number of capital projects for the Holtsville LNG Plant, including programs to upgrade critical facilities and equipment at the plant, and an LNG tank modernization project.

Table 10: LNG Investments ($000)

Program	CY 2017	CY 2018	CY 2019
LNG Blanket Programs	1,935	1,633	540
LNG Special Projects	8,907	8,000	3,458
Tank Modernization	5,250	13,563	11,813

Q. What is covered in the LNG Blanket Program?

A. The LNG Blanket Program provides funding for near-term and emergent capital projects needed to maintain safety and reliability at the Holtsville LNG facility. Examples of projects in this category include: upgrades to mechanical equipment and systems; upgrades and replacement of electrical and control systems; structural improvements of plant and facilities; procurement of capital tools and equipment; preliminary engineering and design of capital projects; and retirement and decommissioning of equipment, plant and facilities. These projects will extend the service life of the facility and improve operational performance of plant equipment.

Q. Please describe the LNG Special Projects category.

A. In addition to the LNG Blanket Program work, KEDLI has identified a number of significant, discrete capital projects to be completed in the Rate Year and Data Years. These projects each have a cost of approximately $1 million or greater and include: a program to add a high expansion foam safety system; field instrumentation upgrades; a new emergency generator; control system upgrades; and tank painting. These projects are discussed in more detail in Exhibit __ (GIOP-4).

Q. What is the Tank Modernization Project?

A. This project will temporarily take the tank out of service to allow entry into the tank to perform major tank upgrades. Specifically, the project scope includes: (i) eliminating the bottom penetration nozzles on the tank, (ii) installing new LNG pumps internal to the tank, (iii) modifying the level gauging systems on the tank to bring them up to current code, and (iv) performing detailed non-destructive examination of tank plate welds to validate long term integrity.

Q. Please describe the Northwest Nassau Transmission Project.

A. This project addresses three aging natural gas transmission lines in northwestern Nassau County. In response to the events of San Bruno and

PHMSA's IVP recommendations, the Company undertook a review of historical records to substantiate the MAOP of its gas transmission mains, as well as a review of each pipe's operating history. This review indicated that replacement and down rating of these three transmission pipelines will mitigate system risks, increase reliability, resolve low pressure issues and position the gas transmission system to accommodate a future supply point in that area. This project would replace 8.8 miles of transmission main, install 5.6 miles of new pipe, down rate 9.1 miles of pipe and construct two new regulator stations. The Company forecasts investment of $34 million in the Rate Year, $60 million in Data Year 1 and $53.7 million in Data Year 2 for this project.

E. <u>Non-Infrastructure and Other Capital Spending</u>

Q. What portion of the Company's capital investment plan is the Non-Infrastructure and Other?

A. The Non-Infrastructure and Other category of work accounts for less than one percent ($2.7 million) of the total planned capital investment in the Rate Year. Other Capital includes special projects not included in the Company's other investment programs, most notably KEDLI's investment in automated meter reading ("AMR"). The Non-Infrastructure budget also includes funds for the purchase of tools that meet the criteria for capitalization.

Table 11: Other and Non-Infrastructure Capital

($000)	CY 2017	CY 2018	CY 2019
Automated Meter Reading	835	855	873
Tools and Equipment	1,789	1,953	2,126
Indirect Capital	2,894	1,280	670

i. Automated Meter Reading

Q. Please describe the Company's AMR program.

A. In 2013, KEDLI began a program to install AMRs because it would no longer have access to the meter reading workforce that previously read both electric and gas meters on Long Island. Otherwise, KEDLI would have needed to hire additional employees or contractors to manually read the Company's gas meters. KEDLI is approximately 94 percent complete with the installation of AMRs throughout its service territory, and expects to complete AMR deployment in CY 2016.

Q. Is additional investment required after full AMR deployment has been achieved?

A. Yes. The Company requires an ongoing capital budget for replacement of existing AMR units and batteries.

Q. What are the customer benefits of AMR?

A. The installation of AMRs will significantly decrease the number of estimated bills. Additionally, AMRs enhance storm resiliency and improve customer service. In the aftermath of major storms, meters usually go unread because meter-reading personnel are needed to assist with storm recovery. AMRs will allow the Company to continuing gathering gas usage data following major weather events that can be used to identify customer outages and restore service more quickly.

ii. <u>Capital Tools and Equipment</u>

Q. What is included in the Purchase of Miscellaneous Capital Tools and Equipment program?

A. The Purchase of Miscellaneous Capital Tools and Equipment program captures the items that are not used for specific projects but support the safe, efficient and on-going day-to-day operations of the gas business. Examples include tools (hand, power, pneumatic, hydraulic), specialty equipment, personal protection equipment, office machines, electronic data processing equipment and software applications, shop and garage equipment and communications devices.

iii. <u>Indirect Capital Costs</u>

Q. Is the Company allocated indirect capital costs?

A. Yes, KEDLI is allocated a portion of indirect costs, such as facilities and fleet services and inventory management/warehouse management. For example, major projects/expenditures during the Rate Year and Data Years include:

- <u>Facilities</u> - upgrades at the Company's Melville Hub Drive facility ($0.2 million in the Rate Year).
- <u>Fleet</u> - fuel tank replacements, vehicle lifts, bulk storage tanks, diagnostic scanners and technician tool boxes ($1.56 million in the Rate Year).

The proposed fleet and facilities expenditures will provide required upgrades to these critical operating facilities. KEDLI's capital plan also includes $0.25 million for construction of a customer office in Brentwood during the Rate Year. This project is described in the testimony of the Shared Services Panel.

Non-Infrastructure capital also includes the cost of demonstration programs to deploy new technologies to facilitate the Commission's Reforming the Energy Vision goals, as discussed in the testimony of Company Witness Sean Mongan.

iv. ***Capitalization Policy Change – Corrosion***

Q. Is the Company proposing any changes to its capitalization policy for corrosion control activities?

A. Yes. Accounting for some corrosion control activities is currently expensed by the Company. However, applicable accounting principles and regulations permit the installation/replacement of new test stations and rectifiers, among other items, to be capitalized. The Company is proposing to capitalize these corrosion control activities in accordance with Accounting Standards Codification 360, the Federal Energy Regulatory Commission's accounting regulations and International Accounting Standard 16. This change will standardize the accounting treatment of these work items between National Grid's downstate New York gas distribution companies. Testing and inspection activities related to corrosion control will remain as expensed items.

Table 12: Corrosion Capitalization

Activity Description	KEDLI	KEDNY	Proposal
Install test station (TS) on Main	Capital	Expense	Capital
Replace existing TS	Capital	Expense	Capital
Install TS on main across Insulated Joints (IJ)	Capital	Expense	Capital
Install TS on Distribution Service	Capital	Expense	Capital
Install TS on Main with anode(s)	Capital	Expense	Capital
Install TS on main across IJ with anode(s)	Capital	Expense	Capital
Install TS on Distribution Service with anode(s)	Capital	Expense	Capital
Install/Replace IJ at Meter	Expense	Expense	Capital
Install/Replace IJ at Distribution Service Tie-in	Expense	Expense	Capital

Install/Replace IJ on Main	Capital	Expense	Capital
Special Request - Renew Service with Plastic	Capital	Capital	Capital
Install new Rectifier	Capital	Expense	Capital
Relocate Existing Rectifier	Expense	Expense	Capital
Recoat Main	Capital	Capital	Capital

V. <u>Gas Operations and Maintenance Expenses</u>

Q. Please summarize the Panel's testimony regarding the costs of operating the gas system.

A. The Panel addresses major expenses associated with operating the Company's gas delivery system, and incremental O&M expenses the Company expects to incur in the Rate Year.

Q. Please generally describe the nature of the Company's gas system O&M expenses.

A. O&M expenses relate to work performed to provide customer support, respond to emergencies, perform safety inspections and other compliance activities, restore service and maintain the life of capital assets. The Company has a significant maintenance program to ensure that system assets are utilized to their fullest potential life expectancy. As gas facilities age, maintenance costs increase. These costs include costs for more frequent inspection and testing, increased volume of repairs, more significant repair work and increased emergency work. These expenditures are required to prevent failure and maintain the life of the assets until replacement occurs.

The Company's O&M programs are also designed to maintain the service commitments in its gas safety performance metrics, which cover various aspects of its performance in the areas of reliability and safety, including metrics measuring pipeline replacement, emergency response, leak management and damage prevention. Since these performance measures were established, the Company has consistently met or exceeded performance targets.

Q. How does the projected Rate Year expense level compare to the Historic Test Year expenses for operating the gas system?

A. The Company projects its Rate Year O&M expense to be approximately $13.09 million greater than its adjusted O&M expense for the Historic Test Year.

Q. Please summarize the adjustments to the Historic Test Year O&M expense necessary to arrive at the proposed Rate Year expense.

A. Increases in O&M expense are primarily driven by (i) an increase in the Company's O&M workload, (ii) increased costs associated with the

Company's increasing capital investments and (iii) initiatives the Company is undertaking in the Rate Year to address new or expanding safety requirements. The Company's incremental O&M costs include: costs associated with responding to an increased volume of gas odors calls from the public as a result of heightened public awareness; costs associated with locking gas meters on a shorter timeline at premises with inactive accounts; increased costs associated with capital investments needed to comply with new safety requirements; implementation of enhanced damage prevention measures; and incremental costs for operational support personnel to deliver KEDLI's significant capital plan.

Q. What is the Company doing to manage its O&M costs?

A. The Company has implemented various initiatives to reduce its O&M expenses, including:

- Increasing the use of scheduled O&M work appointments to reduce multiple unproductive field visits to complete work.
- Coordinating O&M activities required at each premise so that multiple maintenance requirements can be completed during a single visit.
- Modifying shift schedules to more efficiently respond to higher leak volumes.

- Exploring new work management systems to optimize dispatch of resources.

In addition, the Company's expanded installation of AMRs has significantly decreased manual meter reading costs in the Historic Test Year.

A. <u>Increased O&M Workload</u>

Q. Has the Company identified areas where the O&M workload is forecast to be higher in the Rate Year?

A. Yes. The table below sets forth the more significant O&M items where the Company expects to see an increase in workload in the Rate Year.

<u>Table 13</u>: Incremental O&M Workload

Category ($000)	CY 2017
Emergency Response	56
Leak Repairs and Surveillance	616
Meter Oriented Services	306
Pressure Testing	28
I&R Support	395

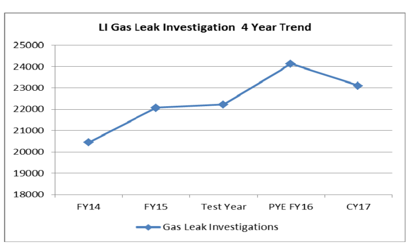
i. <u>Emergency Response</u>

Q. Why has the Company's emergency response workload increased in recent years?

A. The primary driver is the public's increased awareness of gas safety following well-publicized gas incidents in New York City in 2014 and

2015. This increase in public awareness is attributable to extensive media coverage following these incidents, New York City and Consolidated Edison gas safety campaigns, and the Company's own increased outreach and education (described in the Company's Gas Safety Panel testimony). As a result, the Company forecasts an approximate four percent increase in emergency response work in the Rate Year as compared to the Historic Test Year. The Company expects this elevated level of emergency response work will continue through the Data Years.

<u>Table 14</u>: KEDLI Leak Investigation Trends



ii. <u>Leak Repairs and Surveillance</u>

Q. Please describe how the Company manages leak repairs and surveillance.

A. CMS is responsible for leak response and inside repairs. Field Operations is responsible for repairs on mains and services and leak surveillance. Leak surveillance includes completion of all transmission and distribution mandated leak survey and system patrols to ensure the integrity of the gas system.

Over the last several years, KEDLI has seen an increase in its leak surveillance and repair workload due to an increase in identified system leaks, which require repair and/or inspection at designated intervals depending on the leak classification (*i.e*., Type 1, 2, 2A, 3). This increase in the number of detected leaks is attributable to a combination of increased public awareness on gas safety driving more leak calls, higher leak rates on the Company's LPP and colder weather. As a result, KEDLI has experienced an increase in its leak surveillance activities to monitor and investigate additional system leaks. Similarly, the Company is performing additional leak repairs to address the increased volume of new leaks and to reduce its backlog of non-hazardous leaks.

Q. What are the anticipated incremental O&M costs associated with leak repairs and surveillance?

A. Incremental costs in the Rate Year, approximately $0.616 million, include the costs to conduct additional leak surveillance and the costs to repair additional leaks.

iii. <u>Meter Oriented Services</u>

Q. Please describe the increase in Meter Oriented Services.

A. CMS has observed an increase in its workload of Meter Oriented Services, which include regulator inspections, corrosion inspections, warning tag rechecks, cut on/off service orders and meter repair/maintenance. An increase in the Company's forecast number of customer cut on/offs resulting from increased collections activity and an increase in regulator and other safety inspections are the main drivers of further workload increases in the Rate Year.

iv. <u>Pressure Testing</u>

Q. Please describe the increased O&M expense to perform pressure testing on new pipeline segments.

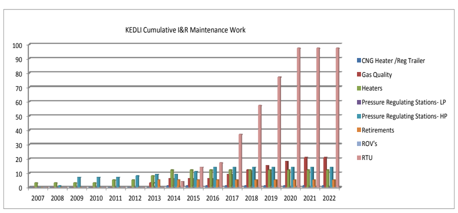
A. In 2015, the Commission amended its regulations (16 NYCRR § 255.507) to eliminate the option of soap testing short sections (100 feet or less) of gas piping before it is placed into service. As result, the Company must now perform a pressure test on each segment of new pipe, which requires that the field crew weld caps on each end of the new pipe segment, pressurize the pipe and confirm that the pipe maintains pressure for an hour or more. The new pressure testing requirement adds several man-hours to the typical leak repair. As a result of this change in process, the Company estimates incremental O&M costs of $0.028 million in the Rate Year.

v. I&R Support

Q. How have new Instrumentation & Regulation ("I&R") assets on the gas system impacted the Company's O&M costs?

A. The increased deployment of pressure regulating, heater, gas quality and system automation assets have increased the O&M workload and associated expenses, as these assets require regular maintenance, inspection, calibration and repair. These I&R assets were installed over the last ten years as the gas industry and safety regulators have stressed the need to enhance remote monitoring and control capabilities.

Table 15: Increased I&R Maintenance Workload



O&M activities include mandated inspections and testing of the I&R assets, as well as regular demand maintenance/repairs. For example, the Company estimates that each take station requires approximately 240 man-hours of annual O&M activities. Other examples of O&M related to I&R investments include:

- Remote Controlled Valves (RCV) – leased communication lines and increased inspection and maintenance for newly installed RCVs
- System Automation – leased communication lines, wireless communications and equipment inspection and maintenance
- Valve Installation/Replacement – incremental inspection costs and maintenance associated with newly installed distribution valves

Q. What are the Company's incremental I&R operating costs in the Rate Year as compared to the Historic Test Year?

A. As discussed above, the Company is deploying additional system automation, regulation and control facilities and, therefore, the Company expects to see its O&M workload in this area continue to increase. The Company estimates approximately $0.395 million of incremental costs in this area in the Rate Year.

B. <u>Incremental O&M Costs Associated With Capital Investment</u>

Q. Please describe the Company's need for incremental O&M costs associated with its planned capital investments.

A. As discussed above, the Company needs to significantly increase its capital investment program during the Rate Year. This increase in capital investment will result in incremental operating expense as well. As shown in Exhibit __ (GOIP-5), the Company estimates incremental O&M costs of approximately $7.36 million in the Rate Year directly related to the Company's capital investments.

Table 16: Incremental O&M Costs Related to Capital Investments

Category ($000)	CY 2017
Capital Support – General	2,273
Disconnects/Reconnects	5,111

i. Capital Support - General

Q. What O&M services will the various construction support functions provide to support the Company's increased capital investments?

A. Construction support functions include internal groups providing contract administration, project management, budgeting and resource planning. While the majority of costs from these functions are directly charged to capital projects, the Company incurs O&M expenses for items such as training, travel, conferences, licensing, new employee on-boarding, and costs for administering O&M contracts. The Company estimates that approximately 10 percent of construction support employees' time is O&M expense.

As KEDLI increases its capital expenditures, the Company will require additional capital support resources, including gas system engineering (estimators, designers, engineers), investment planning (clerks, inspectors, program managers), operations support (permit clerks) and resource planning (analysts, coordinators).

Q. Why are incremental Gas Control resources required in the Rate Year?

A. Additional Gas Control resources are required to support increased construction activities affecting system operations, including coordinating standard operating procedures ("SOPs") for all major growth, system reinforcements, reliability and gate station projects. SOPs ensure that all critical systems potentially impacted by construction are identified, temperature and other work restrictions are followed, and that all internal process owners (engineering, construction, I&R, Planning and Gas Control) review and approve the project before construction begins.

Q. What are the incremental support costs in the Rate Year?

A. The Company forecasts approximately $ 2.27 million in incremental O&M expenses from these support functions in the Rate Year.

ii. <u>Disconnects and Reconnects</u>

Q. Please describe the O&M costs associated with service line disconnects and reconnects.

A. Main replacements require the Company to disconnect gas service lines from the main being removed, and then reconnect the service to the new main. A 2,000 foot main replacement can require dozens of disconnects and reconnects, especially in densely populated, urban areas. The Company's capital plan involves significant investment in main and service replacements, including the accelerated retirement of LPP. This work will increase O&M costs for disconnection and reconnection of gas services by $5.11 million in the Rate Year.

C. <u>O&M Costs Related to Safety and Reliability Programs</u>

Q. Has the Company identified other areas of increased O&M expense related to gas safety and reliability that it anticipates incurring in the Rate Year?

A. Yes. The table below sets forth the incremental O&M expenses related to safety and reliability.

<u>Table 17</u>: Safety and Reliability Programs

Category ($000)	CY 2017
Enhance Damage Prevention	246
Latent Damage	2,000
Inactive Accounts	351
Compliance Analysts	298
QA/QC Inspectors	84
Process Safety	122
Independent Compliance Assessment	243

The Company's Compliance Analyst, Quality Assurance/Quality Control and Independent Compliance Assessment programs are discussed in the testimony of the Gas Safety Panel.

i. <u>Enhanced Damage Prevention</u>

Q. Please describe the nature and impact of the Company's efforts to promote damage prevention as a cost-containment strategy.

A. The Company is focusing new attention on its damage prevention program in an effort to reduce instances of third-party damage. Third-party damage not only raises public safety concerns, but it also increases the costs of maintaining the distribution system because the Company has to remediate, repair or replace its facilities that have been damaged and Company resources have to be devoted to these activities on an unplanned basis.

To reduce the potential for third-party damage and the resulting public safety and cost impacts, over the last several years the Company has invested in improvements to training and education of third-party excavators. Also, the Company has stepped up its communications with third-party excavators and has instituted new communication protocols with municipalities regarding permitting and construction activities.

Q. Please describe the Company's proposal to reduce instances of third-party damage.

A. The Company's plan is to drive improvement in the area of damage prevention by focusing on the most frequent cause of third-party damage, which is excavator error. Accordingly, the Company is proposing a Damage Prevention Advisor program based on a similar program adopted by NMPC. This program would consist of seven incremental Damage Prevention Advisors, who would be equipped with vehicles and equipment that allow employees/contractors to survey the ticket management systems for active location requests and proactively work with excavators to reduce instances of damage.

Q. Please explain in more detail how adding seven Damage Prevention Advisors would help lower instances of third-party damage.

A. Of the 333 instances of third-party damage recorded in CY 2014, 119 were the result of excavator errors. While it is difficult to quantify the expected impact of the Damage Prevention Advisors on instances of third-party damage, the program is specifically targeted at lowering these excavator errors. These dedicated damage prevention employees would visit excavation sites with active One Call tickets to:

- Remind excavation crews of the requirements included in the New York State Damage Prevention regulations to improve compliance.

- Remind excavators to verify and expose facilities via hand digging, as required.
- Discuss appropriate steps to take if facilities are not located.
- Provide safe digging literature.
- Coordinate requests for safe digging training.

The Damage Prevention Advisors would also stay on site with excavators with repeated errors during excavation and investigate sites where there is no location request.

Q. Is the Company's proposed Damage Prevention program supported by the findings in the Commission's recent Horseheads proceeding?

A. Yes. In the Horseheads proceeding (Case 11-G-0565), the Commission directed New York's LDCs to perform risk assessments of their gas systems to identify instances of latent damage to underground gas facilities caused by third party excavations. The Company's response to the Horseheads proceeding is described in the Gas Safety Panel's testimony. While KEDLI's risk assessment did not identify significant instances of latent damage on the gas system, the Company believes it is prudent to enhance inspections of municipal infrastructure work near gas facilities. Accordingly, the Company's damage prevention program will include (i) proactive inspections of municipal infrastructure projects and (ii) increased municipal and public outreach in its service territory.

Q. What are the estimated costs of these damage prevention measures?

A. The estimated costs for the Damage Prevention Advisor program is $0.246 million in the Rate Year.

ii. Latent Damage

Q. What is included in the Latent Damage category?

A. The Latent Damage program is discussed above in Section IV(B). The O&M component includes the costs to conduct additional latent damage inspections and perform non-capital repairs on damaged facilities identified during these inspections. The Company forecasts Latent Damage O&M costs of $2.0 million in the Rate Year.

iii. Inactive Accounts

Q. Please explain why the Company is incurring additional costs to address inactive accounts.

A. The Company's operating procedures provide that a gas service should be locked when an account becomes inactive (*i.e.*, an account with no customer of record). If the Company is unable to gain access to lock its meter after reasonable attempts (*e.g.*, mailings, site visits), the Company will physically cut service at the street or, for accounts in multi-unit buildings, attempt to secure a court order allowing access to the premises to lock the meter. The Company recently modified its practices and procedures regarding inactive accounts. Under the new process, the Company will employ a more structured process to access and lock gas facilities on an accelerated schedule.

Q. Has the Company's modified process for inactive accounts increased O&M costs?

A. Yes. The modified procedures have significantly increased the number of field visits and customer mailings, the level of back office support to identify property owners, Field Operations costs to physically cut services and legal costs. As a result, the Company estimates approximately $0.351 million in additional costs to address inactive accounts in the Rate Year. The Shared Services Panel addresses the related back office support costs.

Q. What is the Company doing to improve its process and better address inactive accounts?

A. To better manage this issue going forward, the Company is coordinating a number of programs and initiatives to reduce the number of inactive accounts. For example, the Company is pursuing non-traditional options to assist with identifying responsible owners/occupants and accessing premises with inactive accounts, including: (i) supporting potential legislation to assist utilities in gaining access to premises for purposes of accessing facilities by creating a database of contact information for superintendents or other individuals authorized to provide access to customers' buildings, (ii) working with other utilities to identify owners/occupants of premises with inactive accounts and (iii) developing an enhanced public awareness program to educate customers and other stakeholders about the Company's need to access premises to lock meters when accounts are terminated.

iv. Process Safety

Q. Please describe the proposed Process Safety program.

A. As discussed in the testimony of the Gas Safety Panel, the Company is adopting the American Petroleum Institute's ("API") recommended pipeline safety management system standards (Recommended Practice 1173 ("API RP 1173")), which provides a framework for identifying hazards and controlling potential risks, and addressing safety and maintenance requirements throughout a pipeline's life cycle to significantly reduce the likelihood of safety incidents. API RP 1173 is a holistic approach to pipeline safety that applies key principles, including risk management, incident investigation, safety assurance, emergency preparedness, recordkeeping, training, management review and continuous improvement to enhance the operator's existing risk control standards and programs (*e.g.*, DIMP/IMP, Compliance Assessment Control Room Management). API RP 1173 does not replace existing risk management systems, but strengthens accountability and effectiveness. Through the Process Safety program, the Company will conduct process workshops to isolate risks, identify process hazards, and then develop, implement and oversee process safety documents and procedures. KEDLI's estimated cost for this program is $0.122 million in the Rate Year.

D. <u>O&M Other – Gas Control</u>

Q. What is the Temperature Control Communications Upgrade project?

A. KEDLI has more than 80 Temperature Controlled (temperature-dependent interruptible) customers whose meters are remotely managed using a vendor-hosted application that uses a gateway modem to monitor gas usage and remotely switch these customers to their alternate fuel at the designated interruption temperature (or when emergency system conditions warrant load shedding). These gateway modems will become obsolete in January 2017 when the cellular network technology they utilize (2G) sunsets. Under the Temperature Control Communications Upgrade Project, the Company will upgrade each gateway modem with new cellular technology (4G), which involves removing the current device, sending the device to the vendor to upgrade, and re-installing the upgraded device on each active meter. The upgrade from 2G to 4G, which is expected to be completed in CY 2016, will provide a reliable communications network to monitor and control Temperature Controlled tariff compliance. In addition, the communications upgrade is critical to preserving KEDLI's ability to remotely manage its non-firm load during periods of peak demand. Therefore, even as the Company considers options for serving its non-firm customers, and is proposing a collaborative to develop and implement a new demand response service classification (see the testimony of the Rate Design Panel), this system is needed to maintain system reliability for the foreseeable future.

Ongoing O&M expenses related to this program include the cost of the new vendor application and maintenance/repair of the remote switching devices. The Company forecasts approximately $0.088 million in incremental expense in the Rate Year.

VI. Information Technology/Cyber and Security

Q. Is National Grid making any information technology investments to support KEDLI's gas business in the Rate Year and Data Years?

A. Yes. National Grid is pursuing the Gas Geographic Information System ("GIS") Consolidation and Gas GIS Upgrade initiatives that will improve KEDLI's ability to capture, store, access and analyze geographical asset information concerning its gas distribution network.

In addition, National Grid is in the early planning stages of an effort to update, simplify and standardize its gas work management and asset management processes and systems, known as the Gas Enablement System initiative.

Finally, National Grid is planning a number of cyber security projects to detect and respond to known and emerging cyber security threats.

Q. Please describe the Gas GIS Consolidation project.

A. The Gas GIS Consolidation project will merge the multiple gas GIS systems onto a single platform. The project will:

- Provide field technicians and engineers a single, streamlined source of gas asset information to improve leak response and enhance the ability to coordinate other emergency work.
- Simplify the viewing and querying of GIS data for customer service representatives, thereby reducing phone wait time for customers.
- Provide a simplified and faster GIS user interface that will decrease response times for customers contacting the call center (or querying publicly available National Grid map data on the web) regarding new gas service or reporting service interruptions.
- Streamline and simplify regulatory reporting with the use of a single system to obtain data and generate reports.

The anticipated in service date of this project is April 2019.

Q. What is the cost of the Gas GIS Consolidation project?

A. The Gas GIS Consolidation project is estimated to cost $11.6 million. As shown in Exhibit __ (RRP-11), the Workpaper to Exhibit __ (RRP-3), Schedule 9, Workpaper 6, KEDLI's allocated share of the forecast costs for the Gas GIS Consolidation project is $0.39 million in Data Year 2.

Q. Please describe the Gas GIS Upgrade project.

A. The Gas GIS Upgrade project is required to support the Gas GIS Consolidation project discussed above. The performance of the current mapping application has been degrading, and there are issues not only with system response time but with the ability to utilize certain tools and features of the software such as map data storage and consolidated data models. National Grid plans to upgrade the software for additional functionality such as the availability of standard reports and tools (*e.g.*, leak reports) in anticipation of the Gas GIS Consolidation project. The anticipated in service date of this project is October 2016.

Q. What is the cost of the Gas GIS Upgrade project?

A. The Gas GIS Upgrade project is estimated to cost approximately $1.2 million. As shown in Exhibit __ (RRP-11), the Workpaper to Exhibit __ (RRP-3), Schedule 9, Workpapers 2, 4 and 6, KEDLI's allocated share of the forecast costs for the Gas GIS Consolidation project is approximately $0.06 million in the Rate Year and $0.06 million and $0.05 million in Data Years 1 and 2, respectively.

Q. Please describe the Gas Enablement System initiative.

A. The Gas Enablement System initiative will replace, update, consolidate and simplify aging and disparate gas work and asset management systems, including gas leak management systems, to:

- standardize work and asset management processes that directly support gas processes
- improve forecasting, scheduling and planning
- enhance field device mobility
- improve analytics and data insight and
- improve customer interactions

Q. Please summarize the overall objectives of this project.

A. There are dozens of applications and associated systems that directly support gas processes. Most of National Grid's current work and asset management systems are more than ten years old, lack vendor support because of their age and present an increased risk of failure. These systems also lack the ability to meet new business requirements and to plan, track and manage work efficiently and consistently.

The overall objective of the project is to standardize and simplify the work, asset and performance management processes and replace aging work management systems and field-based computers with new technology that will improve virtually all interactions with the customer, from the contact center through field operations. The Gas Enablement System initiative will deploy field devices that are in continuous communication with the work and asset management systems, providing mobile access to the Company's maps, policies and procedures to enhance work quality, reduce the potential for errors and improve the Company's recordkeeping.

Q. When will the Gas Enablement System initiative be implemented?

A. Although some preliminary scoping work has been completed, a detailed project plan and timetable for implementation have not. National Grid is in the process of organizing a program planning team, and will provide an update on the program effort and, to the extent they are available at the time, a timetable, project scope and costs in its Corrections & Updates filing.

Q. How is KEDLI addressing cyber security threats?

A. In 2010, National Grid formally established the Digital Risk and Security organization within its Information Services organization to protect National Grid's energy networks, IS systems, and confidential company and customer information from cyber security threats. The cyber security environment is fluid as threats become more common and diverse. The Digital Risk and Security organization not only addresses known threats, but also proactively identifies and protects National Grid from emerging threats. The current organization is staffed internally to determine the cyber security projects necessary to protect National Grid's energy networks, systems, and information but utilizes an external vendor to monitor and provide immediate response to threats. As discussed below, National Grid plans to perform the monitoring and response functions internally.

Q. What cyber security projects is National Grid planning for the Rate Year and Data Years?

A. National Grid plans to complete 17 cyber security projects in the Rate Year and Data Years. An additional 11 cyber security projects are expected to be in service after the Historic Test Year but prior to the Rate Year. The complete list of projects is provided in Exhibit __ (RRP-11), the Workpaper to Exhibit __ (RRP-3), Schedule 9, Workpapers 2, 4 and 6. The projects will address a wide range of cyber security issues, including:

- Ensuring adequate security protection to cyber assets supporting critical reliability functions across National Grid's networks and systems;

- Providing security information and event management capabilities to analyze security alerts in real time, and to collect, store and report on data for compliance and forensic analysis across critical assets and business functions;
- Strengthening identity, access and authorization management capabilities to ensure that only authorized personnel are able to access critical assets and perform only those functions for which they are authorized;
- Protecting energy networks from malicious and inadvertent damage that can occur as a result of the increased use of smart devices (*e.g.*, smart meters, remote terminal units, temperature and pressure sensors); and
- Implementing a Security Operations Center to consolidate security operations and monitoring systems in a centralized facility, which will significantly improve National Grid's ability to detect security threats, determine their nature and deal with them as, or before, they occur.

Q. What are the projected costs of the cyber security projects planned for the Rate and Data Years?

A. The cyber security projects summarized above are forecast to cost $45 million in capital costs, as shown in Exhibit __ (RRP-11), the Workpaper to Exhibit __ (RRP-3), Schedule 9, Workpapers 2, 4 and 6. KEDLI's allocated share of these forecast project costs are $0.39 for the Rate Year, $0.48 for Data Year 1, and $0.66 for Data Year 2, as shown Exhibit __ (RRP-11), the Workpaper to Exhibit __ (RRP-3), Schedule 9, Workpapers 2, 4 and 6. An incremental $0.27 million in operating expenses, as shown in Exhibit ___ RRP-3, Schedule 27, Workpaper 13, is required in the Rate Year for licenses, software, hardware, infrastructure maintenance fees, and vendor support costs such as configuration and network security changes.

Q. What is National Grid's staffing plan for the Digital Risk and Security organization?

A. Currently, National Grid utilizes an outside firm to monitor and provide immediate response to cyber threats. Because of the critical nature of this work, National Grid plans to perform the function internally. This will further strengthen National Grid's capability to ensure the safe and effective operation of the company's energy networks and protect confidential customer and company information. National Grid projects that the costs of the incremental employees needed to perform the function internally will be cost neutral compared to the costs of the outside monitoring firm. Accordingly, no adjustment has been made to the revenue requirements.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibits of
Gas IOP

Testimony of the Gas Infrastructure and Operations Panel

Index of Exhibits

Exhibit__ (GIOP-1)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-1)

Actual and Projected Capital Expenditures: Historic Test Year,
Rate Year and Data Years

KEDLI
Capital Investment Plan
$000

Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
Growth	Base Growth - Install Main	$ 52,559	$ 16,140	$ 11,596	$ 8,821
	Base Growth - Install Services	$ 51,406	$ 31,147	$ 28,748	$ 27,070
	Base Growth - NEP Main	$ -	$ 11,974	$ 12,125	$ 12,125
	Base Growth - NEP Services	$ -	$ 4,380	$ 5,574	$ 7,014
	Base Growth - Customer Contributions	$ (2,342)	$ (2,313)	$ (2,417)	$ (2,417)
	Base Growth - Install Meter / Regulator	$ 1,912	$ 1,144	$ 1,169	$ 1,194
	Base Growth- Meter Purchases	$ 787	$ 2,284	$ 2,398	$ 2,518
	Gas System Reinforcement	$ 30,401	$ 33,083	$ 23,291	$ 25,667
	Total Growth	**$ 134,723**	**$ 97,839**	**$ 82,484**	**$ 81,992**
Mandated	CSC/Public Works - Non Reimbursable	$ 3,971	$ 5,064	$ 5,226	$ 5,331
	CSC/Public Works - Reimbursable	$ 2,047	$ 5,107	$ 5,272	$ 5,377
	CSC/Public Works - Reimbursements	$ (1,376)	$ (783)	$ (799)	$ (815)
	Corrosion	$ 1,199	$ 940	$ 958	$ 978
	Service Replacement (Reactive) - Leaks	$ 2,941	$ 4,848	$ 5,965	$ 6,302
	Service Replacements (Reactive) - Non Leaks - Other	$ 6,578	$ 2,955	$ 3,014	$ 3,074
	Atmospheric Corrosion Inside Inspections	$ 99	$ 497	$ 507	$ 517
	Service Replacements - Proactive	$ 1,679	$ -	$ -	$ -
	Main Replacements (Proactive) - Leak Prone Pipe	$ 60,044	$ 130,546	$ 143,335	$ 146,202
	Cross Bore Remediation	$ -	$ 2,643	$ 2,805	$ 2,805
	Latent Damage	$ -	$ 1,750	$ 2,030	$ 2,071
	Large Diameter CI Lining Program	$ -	$ 3,375	$ 3,575	$ 3,600
	Main Replacements (Reactive) - Maintenance	$ 4,699	$ 2,902	$ 2,975	$ 3,034
	Plastic Fusions - New	$ -	$ 1,491	$ 1,943	$ 2,393
	Meter Changes	$ 3,719	$ 1,228	$ 1,252	$ 1,277
	Pipeline Integrity - IMP	$ 3,312	$ 1,168	$ 5,844	$ 4,265
	Pipeline Integrity - IVP	$ -	$ 250	$ 250	$ 250
	ISO Joints	$ 4,184	$ -	$ -	$ -
	Purchase Meters (Replacements)	$ 1,131	$ 2,924	$ 3,070	$ 3,224
	Misc Mandated Work	$ 271	$ -	$ -	$ -
	Total Mandated	**$ 94,498**	**$ 166,905**	**$ 187,222**	**$ 189,885**
Reliability	Gas System Control	$ 2	$ 152	$ 155	$ 209
	Gas System Control - M2M Upgrade	$ -	$ 23	$ -	$ 41
	Gas System Reliability - Gas Planning/RCV Program	$ 17	$ 2,000	$ 2,893	$ 3,109
	East End Reliability Program	$ 1,138	$ -	$ -	$ -
	Valve Installations/Replacements	$ (44)	$ 130	$ 130	$ 130
	Heater Installation Program	$ 1,088	$ 1,500	$ 1,500	$ 1,500
	Pressure Regulating Facilities	$ 2,318	$ 3,129	$ 4,218	$ 5,046
	Bay Shore Take Station Overhaul	$ -	$ 860	$ 340	$ -
	Rockville Centre Take Station Overhaul	$ -	$ -	$ 860	$ 340
	Long Beach Gate Station Overhaul	$ -	$ -	$ -	$ 860
	System Automation	$ 525	$ 1,358	$ 1,370	$ 1,392
	Water Intrusion	$ 1,588	$ 939	$ 1,033	$ 1,075
	Storm Hardening - Remote Service Shutoff Valves	$ -	$ 8,295	$ 11,225	$ 11,445
	I&R - Reactive/CNG	$ (20)	$ 1,654	$ 1,679	$ 1,704
	LNG - Blanket	$ 1,580	$ 1,935	$ 1,633	$ 540
	LNG - Special Projects	$ 3,577	$ 8,907	$ 8,000	$ 3,458
	LNG - Tank Upgrade	$ -	$ 5,250	$ 13,563	$ 11,813
	Northwest Nassau Transmission Main & Control Valve	$ -	$ 34,000	$ 60,000	$ 53,750
	Misc Reliability Work	$ 834	$ -	$ -	$ -
	Total Reliability	**$ 12,603**	**$ 70,132**	**$ 108,599**	**$ 96,412**
Non-Infrastructure	AMR Installation/Replacements	$ 18,274	$ 835	$ 855	$ 873
	Tools & Equipment - All	$ 1,589	$ 1,789	$ 1,953	$ 2,129
	Telecomm	$ -	$ 109	$ 109	$ 109
	Combustible Gas Indicators	$ 198	$ -	$ -	$ -
	Total Non-Infrastructure	**$ 20,061**	**$ 2,733**	**$ 2,917**	**$ 3,111**
Misc	SuperStorm Sandy	$ 4,068	$ -	$ -	$ -
	Misc	$ (1,605)	$ -	$ -	$ -
	Total Misc	**$ 2,463**	**$ -**	**$ -**	**$ -**

KEDLI
Capital Investment Plan
$000

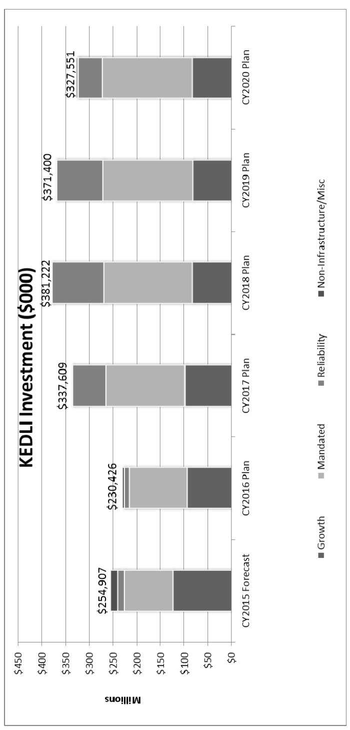
Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
	Total Direct Gas (Capital & COR)	**$ 264,348**	**$ 337,609**	**$ 381,222**	**$ 371,400**
	Cost of Removal	$ 6,885	$ 13,545	$ 14,810	$ 15,279
	Total Direct Gas (Net of COR)	**$ 257,463**	**$ 324,064**	**$ 366,412**	**$ 356,121**
Indirect Capital					
Facilities/Customer/Other	Facilities	$ 7,413	$ 200	$ 200	$ 200
	Customer - Office Equipment	$ -	$ 248	$ -	$ -
	Customer - Gas REV Pilots	$ -	$ 751	$ -	$ -
	Other	$ 694	$ -	$ -	$ -
	COR	$ -	$ 50	$ 50	$ 50
	Total Facilities/Customer	**$ 8,107**	**$ 1,249**	**$ 250**	**$ 250**
Fleet/IM/IR (Capex only)	Fleet	$ 496	$ 1,560	$ 960	$ 350
	IM/IR	$ -	$ 85	$ 70	$ 70
	Total Fleet/IM/IR (Capex only)	**$ 496**	**$ 1,645**	**$ 1,030**	**$ 420**
	Total Capital/COR	**$ 272,951**	**$ 340,503**	**$ 382,502**	**$ 372,070**

Exhibit__(GIOP-2)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-2)

Actual and Projected Annual Investment Levels CYs 2015 – CY 2020


KEDLI Investment ($000)
Millions
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
$254,907
$230,426
$337,609
$381,222
$371,400
$327,551
CY2015 Forecast
CY2016 Plan
CY2017 Plan
CY2018 Plan
CY2019 Plan
CY2020 Plan
Growth
Mandated
Reliability
Non-Infrastructure/Misc

Exhibit__(GIOP-3)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-3)

Projected Leak Rates for Leak Prone Pipe for Different
Main Replacement Strategies

Projected Leaks Impact with Various Replacement Rates – KEDLI 2014

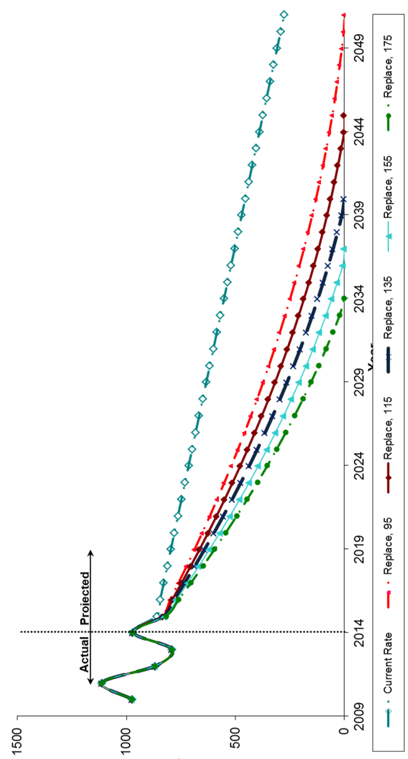


Exhibit__ (GIOP-4)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-4)

Data Sheets for Significant Capital Programs

Program Title: Base Growth Capital Plan - KEDLI

Spending Rationale: Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI's Base Growth program involves the installation of new main, services and meters to serve projected customer growth on Long Island. This program also includes the extension of the Neighborhood Expansion Program, a two-year growth program set to expire on December 31, 2016 (Case 14-G-0214).

Program Justification:

Conversions. The Company's growth forecast shows reduced demand in the residential conversion market due to lower oil prices. The commercial conversion market is forecasted to decrease slightly due to market saturation, system constraints, and fewer large project opportunities. Changes in the sales mix to mostly residential conversion projects will require more capital spending per new customer.

New Construction. The forecast shows an increased demand in the residential new construction market. The Long Island market has experienced flat new construction activity since 2008; however, Moody's is forecasting an increase in New Construction activity beginning in late 2015 and continuing for the next several years.

Neighborhood Expansion. In 2015, KEDLI launched its Neighborhood Expansion Program (as approved in Case 14-G-0214). Under the Program, the Company utilize geospatial, engineering, main, supply, customer interest, customer load and other data in its modeling to identify good locations for growth projects – streets or neighborhoods where prospective customer density would support entitlements-based main extensions (*i.e*., locations with not less than eight potential customers per 500 feet of main). Once these areas are identified, the Company will look to secure commitments from a threshold level of customers to justify the capital investment in the infrastructure necessary to serve the area. If the Company is able to secure commitments to proceed from enough customers to cover at least 60% of the cost of the main extension, the Company will proceed with the project without charging Contributions In Aid of Construction ("CIACs") and look to market gas service to additional customers in the area to achieve the entitlement coverage for the main investment and maximize conversion rates.

The growth forecast considers the implications of (a) changes in the various market segments; (b) large project inventories; (c) rate/regulatory changes; and (d) system constraint. The forecast also considers factors that drive growth projections and the associated capital investments:

- Fuel Pricing – oil versus natural gas
- Inventory levels and turnover ratios
- Saturation levels
- Marketing Lead performance
- Designs and resourcing that supports the delivery of capital at efficient pricing.
- Economic Conditions / Building Starts
- Gas system constraints
- LI municipal requirements that increase permitting/restoration costs.

Total Project Cost Breakdown:

The capital growth program will provide support to meet the anticipated customer demand for a five year period.

$000	CY17	CY18	CY19
Services	7250	7240	7220
Main Footage	307,000	294,000	285,000
Base Growth - Install Main	$ 16,140	$ 11,596	$ 8,821
Base Growth - Install Services	$ 31,147	$ 28,748	$ 27,070
Base Growth - NEP Main	$ 11,974	$ 12,125	$ 12,125
Base Growth - NEP Services	$ 4,380	$ 5,574	$ 7,014
Base Growth - Customer Contributions	$ (2,313)	$ (2,417)	$ (2,417)
Base Growth - Install Meter / Regulator	$ 1,144	$ 1,169	$ 1,194

Customer Benefit:

7,250 gas heating conversions on Long Island have positive economic benefits and environmental impacts:

- $18.68 million annual customer energy savings
- 45 tons of local emissions reduced (NOx, SO2, VOC, NH3 and PM2.5)
- 24,022 tons of CO2 reduced
- 7.81 million gallons of oil displaced (231,373 barrels)
- Same as taking 108,675 cars off the road
- $10.95 million annual GDP created
- $6.84 million annual income created
- 131 annual jobs created
- $1.05 million state and local tax revenues

Per Customer

- $2,578 annual energy savings

- 1,077 gallons of oil eliminated
- $1,511 individual GDP created
- Equivalent emissions reduction to removing 15 cars off the road

<u>Alternatives</u>

Alternative 1: Tariff Change to Increase Contributions in Aid of Construction

Amend tariff section to require smaller customers to pay for necessary reinforcements to provide service. This alternative is rejected because it increases customer costs and will likely lead to reduced growth.

Alternative 2: Discontinuance of Neighborhood Expansion Program

Discontinue the Neighborhood Expansion Program. This alternative is rejected because the Neighborhood Expansion Program was approved by the Commission in Case 14-G-2014 to enhance customers' opportunity to connect to the distribution system and furthers the Commission's policy goals to provide safe and reliable service as well as create economic growth and lower emissions.

Program Title: Gas System Reinforcement Program – KEDLI

Spending Rationale: ☐ Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The System Reinforcement Program consists of capital reinforcement projects required to maintain pressure above system minimums on the gas network during periods of peak demand, thereby maintaining continuous service to all gas customers within the territory. This program is a five year program covering the winter periods for 2017/18 through 2021/22.

Program Justification:

Federal (49 CFR 192.623) and New York (16 NYCRR 255.623) regulations require the Company to maintain minimum pressures on the gas system necessary to maintain reliable service to all firm customers. The System Reinforcement Program identifies projects required to maintain service under peak day, peak hour conditions. KEDLI's gas system is designed for a peak day with an average temperature equal to 0°F (65HDD – Heating Degree Days) with 5% of the daily send-out as a peak hour. The peak demand is based on the same forecast utilized to develop the gas supply portfolio, and the System Reinforcement program is a critical component for enabling that gas supply to be delivered to firm customers.

Examples of distribution system reinforcement projects include, but are not limited to, the following:

- Replacing existing undersized mains with larger diameter mains. Leak-prone pipe is targeted whenever practical.
- Looping or connecting system endpoints by installing new main.
- System operating pressure up-ratings
- Installing new district regulators as well as replacing and/or rebuilding existing undersized district regulators.
- Transferring existing customers supplied from low-pressure mains to adjacent high-pressure mains (*i.e.*, load shedding).

Total Project Cost Breakdown:

$000	CY 2017	CY 2018	CY 2019
CAPEX	33,083	23,291	25,667

Customer Benefit:

By installing these reinforcements, the Company is ensuring that service is maintained to all firm gas customers on the system. Without the reinforcement program, as many as 39,000 customers are at risk of experiencing pressures below minimum design pressures and, therefore, at risk of losing service. The estimated cost to relight these customers is $39M (approximately $1,000 per customer based on previous experiences). A secondary benefit of the program is the elimination of leak-prone pipe wherever practicable. For example, of the new pipe installed under the program approximately 33.7% replaces leak-prone pipe, approximately19,770 feet (3.7 miles), in the first year of the plan.

Alternatives

Alternative 1: Do Nothing

This alternative is rejected because 39,000 customers are predicted to experience pressures below minimum design levels and be at risk of losing service if design conditions were to be experienced during the five year heating season term under the current Gas Supply send-out forecast.

Studies/References That Support the Program:

Studies were run on the Company's network models using Synergi software, which is industry standard software used by nearly all of the LDC gas companies. The models, which are validated on an annual basis, were loaded with the forecast provided by National Grid's Analytics, Modeling, and Forecasting (AMF) department. Additionally, AMF provided a forecast at a zip code level. There is a high degree of confidence with the accuracy of the modeling and forecast and that the appropriate reinforcement projects were identified.

Program Title: Public Works Program (City/State Construction) – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The City/State Construction (CSC) program consists of work to accommodate municipal infrastructure projects by various Long Island municipalities, as well as the NYC Department of Design and Construction (NYCDDC) and NYC Department of Transportation (NYCDOT) on the Rockaway Peninsula. The CSC program is directed at replacing gas infrastructure that will be compromised by third party construction activities.

The scope of the FY2017 program includes approximately 31,680 linear feet (6.0 miles) of main installation to accommodate municipal capital infrastructure improvements. The program will contribute ~ 21,120 linear feet (4.0) miles of leak prone pipe (LPP) retirement program on Long Island. The LPP retirement mileage and spending estimates are based on historical information and the current schedule of municipal work.

Program Justification

National Grid facilities are in often direct conflict with proposed municipal infrastructure installations or are required to be relocated based on regulatory and code requirements.

The CSC program is subdivided into three components: Reimbursable, Non-Reimbursable and Reimbursements. Projects are categorized into these buckets based on the project funding source. Capital projects initiated by the NYCDDC on behalf of the NYC Department of Environmental Protection (NYCDEP) are reimbursable and subject to the requirements of the NYC Gas Facility Cost Allocation Act (Gas Cost Sharing agreement). As per the NYC Gas Facility Cost Allocation Act (Gas Cost Sharing agreement), relocation costs incurred by National Grid on this project are eligible for reimbursement by the City of New York based on the age of the main (depreciated book value). Conversely, projects funded by the NYSDOT, NYCDOT and private entities are not eligible for reimbursement.

National Grid's Government Liaisons work closely with engineers and consultants from the NYCDDC and Long Island municipalities to minimize any direct conflicts to the existing gas infrastructure. Collaborating with municipalities reduces the Company's support and protect (O&M) costs, maximizes remuneration and reduces risk exposure to the Company.

Total Capital Project Cost Breakdown:

$000	CY 2017	CY 2018	CY 2019
CSC/Public Works - Non Reimbursable	5,064	5,226	5,331
CSC/Public Works - Reimbursable	5,107	5,272	5,377
CSC/Public Works - Reimbursements	(783)	(799)	(815)

Customer Benefit:

Minimal customer impact is expected during the construction of these projects; they are intended to ensure continuous service to customers.

Customers can benefit from the program in the following ways:

- CSC will contribute approximately 21,120 linear feet (4.0) miles of LPP retirement on Long Island.
- Synergistic opportunities are realized through integration with other Operational Program work including, but not limited to: Main & Service Replacement, Customer Driven Construction, Reliability, and Long Term Planning

Alternatives:

None.

Studies/References That Support the Program:

The program is supported by KEDLI's legal obligations under New York State codes (including 16 NYCRR Part 255.755, Part 255.756, and Part 255.757), New York law (including NYS General Obligations Law Section 11-102 and Part 131 of NYSDOT Rules & Regulations, NYCRR Title 17 - Accommodation of Utilities within State Highway Right-of-Way) and the New York City Gas Facility Cost Allocation Act (Gas Cost Sharing agreement), which require replacement and/or support and protection of gas facilities during third-party construction.

Program Title: Gas Corrosion Control Inspection and Remediation – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Corrosion can lead to failures in plant infrastructure and equipment, which are costly to repair and adversely impact system reliability. Decisions regarding the future integrity of an asset or its components depend entirely upon an accurate assessment of the conditions affecting its corrosion and rate of deterioration. The Corrosion group performs field testing, monitoring, upgrades and repairs to existing corrosion control systems in accordance with federal and state code requirements (Federal CFR Title 49 – Transportation (Subpart D - Pipeline Safety Part 192) and 16 NYCRR Part 255 (Transmission and Distribution of Gas)), as well as industry standards. This includes periodic testing, inspection, monitoring and diagnostic troubleshooting of existing corrosion control systems. The Corrosion group also provides engineering standards as well as the design and development of new cathodic protection system and upgrades to existing cathodic protection systems.

There are two components to corrosion mitigation for buried piping:

1. Protective Coating/Barrier – installed and tested at the mill or in the field and provides a protective barrier from the elements and the naturally occurring corrosion process.

2. Cathodic Protection - installation of cathodic protection system and acceptance testing of buried piping, which is typically performed during the installation of the piping or shortly thereafter. There are two types of cathodic protection systems:
   1. *Galvanic* - provide direct current (DC) onto the pipe through the use of sacrificial anodes (typically 17 lbs. of magnesium) that corrode away. Thus they sacrifice themselves to corrosion to protect the pipe from corrosion.
   2. *Rectifier* - takes alternating current (AC) and changes it to DC while utilizing specialized anodes (due to the higher current demands of the piping system).

   All cathodic protection systems require the following:

   - Proper protective coatings
   - Isolation from other metallic structures
   - Test boxes with anodes & lead wires
   - Periodic inspection and testing

- Periodic upgrades (remediation measures) to provide for extended life of the asset

Program Justification:

The work in the corrosion control programs is mandated by federal and state regulations.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	940	958	978

The work in this area is either expense (OpEx) or capital depending on the activity being performed. Typically, testing and monitoring are operating expenses to maintain the asset. Capital work is normally remediation, which substantially extends the life of the asset.

> OpEx Work: periodic testing, inspection, monitoring and diagnostic troubleshooting of existing corrosion control system in accordance with state and federal codes.
>
> CapEx Work: asset improvements to the pipeline to enhance and remediate the existing cathodic protection system in accordance with state and federal codes and extend the life of the asset.

KEDLI is projecting a modest increase in spending for KEDLI's program in CY 2017-2019. The capital work on Long Island to date has been to upgrade the corrosion control systems and for exposed gas mains that require remediation work. That work includes hanger bracket or roller modifications, re-coating or replacement of the piping. The work is typically performed in September and October to minimize interference with local summer traffic congestion. The increase in spending is to support additional improvements to the cathodic protection system as described above.

Customer Benefit:

Minimal customer impact is expected during the performance of these corrosion control programs and construction of these projects. Customers can benefit from the program in the following ways:

- Improved public safety due to reduced risk of gas incidents;
- Fewer unplanned service interruptions; and

- Fewer unplanned disruptions to traffic on roads.

Alternatives

None.

Studies/References that Support the Program:

This program is in accordance with the Company's standards and complies with Federal CFR Title 49 - Transportation, Subpart D Pipeline Safety Part 192 and 16 NYCRR Part 255 Transmission and Distribution of Gas.

Program Title: Gas Distribution Main Replacement (proactive) Leak Prone Pipe - KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI considers leak prone pipe ("LPP") as including all 12 inch and smaller pipe that is (i) unprotected (*i.e.*, non-cathodically protected) steel pipe (whether bare or coated), (ii) cast and wrought iron pipe, (iii) pre-1985 vintage Aldyl-A plastic pipe, and (iv) unprotected steel/wrought iron, copper and Aldyl-A plastic services ("associated services").

KEDLI's recent capital recovery order (Case 14-G-0214 - *Petition of KeySpan Gas East Corporation d/b/a National Grid for Authority to Defer Costs Associated with Incremental Capital Expenditures and Other Related Relief*, Order Directing Investments and Allowing, In Part, Deferral Authority for Costs Associated with Incremental Capital Expenditures and Establishing a Surcharge (Issued December 11, 2014)("December 2014 Order") requires the Company to replace at least 172.5 miles of LPP over two calendar years (CY2015-CY2016), 77.5 miles in CY2015 and 95 miles in CY2016. Failure to meet program targets will result in penalties. The December 2014 Order also directs KEDLI's current filing to address leak prone pipe removal at a proposed mileage target of 115 miles for CY 2017.

For the reasons described below, the Company is recommending a proactive base LPP replacement target of 115 miles in CY2017. In addition, the Company is recommending an incentive target of 20 additional miles in CY2018 (135 total miles), increasing by 20 miles per years thereafter. Accelerating replacement to the incentive target levels will eliminate all LPP on KEDLI's system in 20 years.

Calendar Year	2017	2018	2019	2020
Base Target	115	115	115	115
Incentive Target	0	20	40	60
Total Miles	115	135	155	175

The current inventory of LPP of 12 inch and smaller pipe is 3,853 miles (3,141 miles of unprotected steel and 310 miles of cast iron/wrought iron, and 402 miles of Aldyl-A), which represents approximately 48 percent of the distribution system in KEDLI's territory. The current leak repair rate for all distribution piping on KEDLI system is 0.13 leaks per mile (excluding excavation leaks), decreased from 0.29 leaks per mile in 2005. However, while the current leak rate for LPP is trending down since 2005, when it was 0.52 leaks per mile (excluding excavation leaks), the leak rate on LPP is more than double the system leak rate (0.28 leaks per mile).

The proposed accelerated LPP replacement program is also supported by the Company's recently developed Distribution Integrity Management Plan (DIMP), which specifies that the Company: (i) know its distribution piping system, (ii) understand the threats to the system, and (iii) evaluate the risks and prepare replacement programs for its leak prone mains and services inventory to help mitigate those risks.

Leak predictive models show that main replacement levels below a certain threshold will cause leak rates to increase exponentially. Replacement levels below this amount will cause leaks to increase to a point where it will not be feasible to timely react to the quantity of new leaks. The model shows that there is a practical limit to how many leaks a system can have and continue to operate safely.

Program Justification:

LPP is only 48% of the KEDLI distribution main inventory, yet accounts for 85% of leak repairs (excluding damages). Accelerated replacement of this pipe will improve safety, reliability, and customer satisfaction. The key benefits of an accelerated replacement program for LPP include:

- Improved public safety by reducing the risk for gas related incidents
- Improved system reliability and customer satisfaction
- Compliance with federal and state code requirements, including new US Department of Transportation's DIMP requirements
- Increased efficiency resulting from reduced commodity loss
- Reduction of methane emissions help reduce greenhouse gases

Total Project Cost Breakdown:

Base Target – 115 miles/year

$000	CY17	CY18	CY19
Main Replacements (Proactive) - LPP	130,546	143,335	146,202

Note: The Company is proposing a surcharge to recover the costs incurred replace LPP miles above the base target.

Customer Benefit:

Minimal customer impact is expected during the construction of these projects. Customers can benefit from the program in the following ways:

- Improved public safety due to reduced risk of gas incidents
- Fewer unplanned service interruptions
- Fewer unplanned disruptions to traffic and roadways

Alternatives

Alternative 1: Minimal Replacement

This option would replace only the quantity of main required to hold leak rates to present levels. This option increases safety risks and does not align with the Company's or the Commission's goals. This option also will have negative financial consequences for failure to meet LPP replacement targets in the existing rate agreement.

Alternative 2: Do Nothing

No main replacement will result in increasing leak activity and increased risk to public safety. This will also result in a negative financial incentive (current rate agreement) and loss of credibility with regulators and also put the Company in violation of its federally-regulated DIMP.

Studies/References that Support the Program:

This program is supported by the Company's recently developed DIMP, and complies with the requirement in Federal Code 49 CFR, 192.1005, 1007, 1009, 1011 and 1013. Accelerating the rate of LPP replacement is also consistent with the NYPSC's stated goal of of reducing the statewide LPP average replacement timeline to 20 years (Case 15-G-0151).

Recent gas related incidents in the industry have emphasized the urgency of eliminating the aging infrastructure at faster pace. Annual System Integrity Analysis, which reviews last 10 years of system trends, clearly demonstrates the benefits of leak reduction due to accelerated LPP main replacements.

Program Title: Cross Bore Remediation – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI is proposing a cross bore investigation and remediation program. A "cross bore" is an unintended consequence of horizontal directional drilling (HDD) technology where a plastic gas main goes through a sewer lateral that is not positively identified (marked) during the installation process. This program will address all previous HDD installations to ascertain if a cross bore incident has occurred, and if so, take proactive steps to remediate the situation. The Company updated its HDD procedures in 2014 to address and eliminate possible cross bores.

Program Justification:

The remediation program will address a potential hazardous situation that exists as a result of cross bore situations. In these cases, the sewer line may become blocked. If a mechanical clearing tool is used to remove the blockage, it may lead to damaging the gas line, causing the gas to migrate into the building. Over the last years, several incidents have occurred in the industry. Many utilities have initiated programs to address this substantial risk. PHMSA has taken a step further and declared the necessity for operators to review and assess the risk that cross bore poses on their system as a part of their Distribution Integrity Management Plan (DIMP), and depending on the risk evaluation, to identify and implement measures to reduce the risk.

The Company will investigate and identify all previous HDD installations using CCTV technology to inspect sewer laterals that could have been compromised during the service installation process, and remediate any possible damage to sewer lateral. KEDLI has an estimated population of 19,000 sewer laterals requiring inspection.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	2,643	2,805	2,805

Customer Benefit:

Minimal customer impact is expected during the operation of this project. This program will enhance public safety due to the reduced risk of gas incidents.

Alternatives

Alternative 1: Inspect only when requested by customer.

This option could miss potential situation where customer is not fully aware of the possibility of a cross bore.

Alternative 2: Do Nothing

This option is not consistent with the Company's DIMP requirements.

Studies/References that Support the Program:

This program is in accordance with the Company's recently developed DIMP; complies with Federal Code 49 CFR, 192.1005, 1007, 1009, 1011 and 1013.

Program Title: Damage Inspection - Latent Damage & Plastic Fusions – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The Damage Inspection Program provides for latent damage and inspection of plastic fusions pursuant to:

- New York State PSC order Case 11-G-0565 dated February 20th 2014, which required all New York State natural gas local distribution companies (LDC's) to conduct risk assessments of their distribution network.
- New York State PSC order Case 14-G-0212 dated May 15th 2015, which required all New York State natural gas local distribution companies (LDC's) to keep records of each fuse uncovered in the regular course of business and shall remediate any fuse that fails visual inspection.

The proposed program is to proactively inspect all third party excavations in the operating region that occur in close proximity to gas facilities and to inspect uncovered plastic fuses during regular course of business. This will ensure appropriate procedures are followed and faster emergency response, if required. Improved public awareness through mass media, social media as well as awareness among municipalities will significantly reduce latent damages. If any latent damage or failed plastic fuse on the gas infrastructure is observed, its proactive replacement will significantly enhance public safety.

Program Justification:

KEDLI has approximately 536,000 services and more than 7,900 miles of main including 3,320 miles of plastic mains. Much of this gas infrastructure intersects with other municipal infrastructure in the region. Similar to gas infrastructure, ageing municipal infrastructure is also being replaced at an accelerated pace. Replacement of these infrastructures will increase the risk of latent damage to gas facilities. On an average, the Company receives 154,037 gas related tickets and 334 damages per year. The need of all third party excavations and uncovered plastic fuse inspections as well as improved public awareness programs will improve the integrity of gas facilities and hence enhance the public safety.

KEDLI has conducted a thorough risk assessment of its gas facilities to evaluate a potential risk of latent damage where municipal infrastructure is installed subsequent to gas facilities within its operating region. Furthermore, The Company has randomly selected potential locations for field verification of latent damages. Although, this risk assessment did not reveal any widespread latent damage to the system, The Company intends to proactively inspect all third party excavations including but not limited to water, sewer, drainage, electric and cable infrastructure projects, street reconstruction and road realignment projects, and bridge replacement projects near the vicinity of its gas facilities. In addition, the Company will ramp up public awareness programs regarding third party excavations and will incorporate changes to the Leak Management Systems (LMS) to capture leaks caused by latent damages.

KEDLI has also initiated a program to record exposed plastic fuses and remediate any damage to plastic fuses which might pose an integrity issue. These gas facilities will be replaced.

Following are the key benefits of inspecting third party excavation near gas facilities and uncovered plastic fuses:

- Improved public safety by reducing the risk for gas related incidents
- Improved system reliability and customer satisfaction
- Compliance with federal and state code requirements including new US Department of Transportation (USDOT) Distribution Integrity Management Program requirements (DIMP)
- Increased efficiency resulting from reduced commodity loss
- Reduce natural gas emissions

Total Project Cost Breakdown:

$000	**CY17**	**CY18**	**CY19**
CAPEX	1,750	2,030	2,071

Customer Benefit:

Minimal customer impact is expected during the inspection of third party excavations. Customers can benefit from the program in the following ways:

- Improved public safety due to reduced risk of gas incidents
- Fewer unplanned service interruptions

Alternatives

None

Studies/References that Support the Program:

Risk assessment conducted by Keyspan East Corp., d/b/a National Grid regarding latent damage, which included statistically significant sample excavations at randomly selected and geographically spread locations across the operating territory as recommended by Gas Technology Institute.

Program Title: Lining of Large Diameter Mains – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI utilizes several different types of main: cast iron, steel and, more recently, plastic. Cast iron mains were constructed with bell and spigot joints and over time, leaks have begun to develop at these connections, whereas steel mains typically develop leaks due to corrosion.

While there are cost effective methods of repairing and reducing the leaks on small diameter mains, leak repairs on large diameter pipes greater than 12" typically cost more due to the location and the depth of the excavations required to access the pipe joints. KEDLI is proposing to recondition large diameter cast iron and unprotected steel with cured in place lining, which can extend the life of the main for more than 50 years. This proven technology has been successfully used by the Company for several years. In congested metropolitan areas, where it is almost impossible to find another lane in the roadway to install new large diameter mains, lining is the most cost effective way to recondition the existing mains, reduce costs and minimize disruptions to the public. KEDLI is proposing to line approximately one mile per year.

Program Justification:

The current leak repair rate of large diameter LPP distribution piping on the KEDLI system is 0.16 leaks per mile (excluding damages), decreasing from 1.0 leak per mile in 2010. KEDLI has approximately 7 miles of large diameter cast iron and unprotected steel mains. The current LPP replacement program only addresses mains up to 12" whereas this program seeks to treat the remaining large diameter pipe. Installation of the lining is the most cost effective way to recondition the existing mains, reduce costs and minimize disruptions to the public.

KEDNY's lining program is also supported by the Company's recently-developed Distribution Integrity Management Plan (DIMP), which specifies that the Company should: (i) know its distribution piping system, (ii) understand the threats to the system, and (iii) evaluate the risks and prepare replacement programs for its leak prone mains and services inventory to help mitigate those risks.

Following are the key benefits of the large diameter lining program:

- More cost-effective than replacing the large diameter pipe
- Improved public safety by reducing the risk for gas related incidents
- Improved system reliability and customer satisfaction

- Compliance with federal and state code requirements including new US Department of Transportation (USDOT) Distribution Integrity Management Program requirements (DIMP)
- Increased efficiency resulting from reduced commodity loss
- Ability to focus more attention on retiring small diameter main segments with higher risk profiles
- Reduction in Methane emission

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
Miles	1	1	1
CAPEX	3,375	3,575	3,600

Customer Benefit:

Minimal customer impact is expected during the construction of these projects. Customers can benefit from the program in the following ways:

- Improved public safety due to reduced risk of gas incidents
- Fewer unplanned service interruptions
- Fewer unplanned disruptions to traffic and roadways

Alternatives

Alternative 1: Minimal reconditioning of pipe

This option would treat only the quantity of main required enabling the company to hold leak rates to present levels. This option will have negative financial consequences as it would require the more traditional repair methods to be used on the large diameter mains which are typically very expensive.

Alternative 2: Do Nothing

No proactive replace/reconditioning method would result in increasing leak activity and increased risk to public safety. This may also result in violation of the Company's federally-regulated DIMP and lead to financial penalties.

Studies/References that Support the Program:

This program is in accordance with the Company's recently developed DIMP; complies with Federal Code 49 CFR, 192.1005, 1007, 1009, 1011 and 1013.

Program Title: Perform Plastic Fusions – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

In May 2015, KEDLI and all gas local distribution companies (LDCs) in New York State were ordered by the New York State Public Service Commission to "begin keeping records in an auditable database that can be tied into and correlates with the location of plastic fusions so that the exact locations of fuses can be determined using either a GPS system or a comparably specific system of identifying and recording the location of plastic fusions" by January 1, 2016.

KEDLI is developing a process for capturing, recording and reporting on geospatial and specific asset information (*i.e.*, size, type) for plastic fusions. Contractor unit pricing for installation of plastic facilities is anticipated to increase 2 percent due to:

1. Increased crew time spent on second qualified person to visually inspect fuse;
2. Increased time for fuser to enter data into the mobile device that is required;
3. Back office QA/QC of data.

Program Justification:

KEDLI gas operations personnel and contractors will capture information on plastic fusion joints in the field, using GPS-enabled mobile devices within the "Plastic Fusion Joint-Data Collector" application.

This program enables National Grid gas field employees and contractors to collect the locations of plastic fuses, record the employees performing and inspecting the fusion, and asset information (i.e., size, type). Geospatial information provides the ability to return to those locations at a later point in time and perform inspections, as necessary. In addition, this asset information will be utilized to enhance the Distribution Integrity Management Program (DIMP) managed within Network Strategy.

Total Project Cost Breakdown

$000	CY 2017	CY 2018	CY 2019
CAPEX Request	1,491	1,943	2,393

Customer Benefit:

The program seeks to further reduce the risk of operating the gas distribution system which will improve public safety and the reliability of the gas delivery system.

Alternatives

Alternative 1: Capture Fusion Information on Paper

All data is captured on paper, which will then be entered into an electronic database by back office personnel.

During peak construction season, KEDLI and its contractors perform nearly 500 fuses per day. Capturing all required information on paper to be entered at a later date by back office staff is not practical and increases the likelihood of missed or inaccurately entered data. Risks include:

- Increased risk of human errors when capturing the data or entry into the database;
- Risk of fuses not being in the database due to loss of paperwork;
- Increased crew time to capture measurements off of acceptable landmarks for fuse location.

Cost: $1,850,000 – 2,410,000

Program Title: Gas Meter Change Program - KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI'S Gas Meter Change Program involves the replacement of gas meters that are retired from service or abandoned based on the result of periodic testing requirements established by the New York Public Service Commission.

Program Justification:

New York requires random sampling of gas meter performance on an annual basis. Meters are segregated into classifications based on manufacturer/model, and the number of meters to be tested within each of these classifications is determined by the population size. New York code requires remediation of meters that do not meet the required level of accuracy. The Company is typically allowed eight years to remove and replace a "failed" meter population. The Commission has the discretion, however, to require utilities to remove the population at a faster rate. In addition, New York code allows for the retirement of meter groupings. KEDLI currently has meters in each of the meter change program types (random, remediation, and retirement). The quantity of meters changed annually is based on the prior year's performance and remediation program status.

In addition to the mandated programs, the Company also initiates requests to change meters based on performance. These meters are known as "change for cause" meters.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	1,228	1,252	1,277

Customer Benefit:

Testing and replacing meters supports accurate meter reading and customer billing.

Alternatives

None.

Program Title: Integrity Management Program – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the management of KEDLI's gas transmission system, specifically the O&M and capital projects that are components of the US Department of Transportation's (DOT) mandated Integrity Management Program (IMP). The Pipeline Safety Improvement Act of 2002 requires operators of DOT-reportable gas transmission systems to develop and implement an IMP program for all pipelines operating above 20 percent specified minimum SYMS in a high consequence area (HCA). The renewed Pipeline Safety Act of 2011 mandates that Pipeline and Hazardous Material Safety Administration (PHMSA) consider whether the existing transmission IMP should be expanded beyond the current requirements, including increased inspections of IMP-covered pipelines using in-line inspection technology.

KEDLI proposes an improved IMP that incorporates the elements of the current IMP program along with proactive programs such as retrofitting for ILI including free swimming, robotic and tethered tools. The proposed IMP enhancements provide the greatest amount of risk reduction, thereby improving system safety and reliability. Additionally, it is anticipated that the company will be in compliance with future regulatory requirements.

Program Justification:

The Pipeline Safety Improvement Act of 2002 was signed into law in December 2002. Among several important requirements, the 2002 Act directed the DOT to issue rules on managing the integrity of transmission pipelines used by the gas and hazardous liquids industries. The rules affecting the gas industry are included in CFR Title 49, Part 192.901-192.951, and became effective on January 14, 2004. These regulations require pipeline operators to develop and implement an IMP for "covered" transmission pipelines, which are defined as certain pipelines in High Consequence Areas (HCA). The program required that the first cycle of pipeline assessments be completed no later than 2012. Reassessments are required to be completed at intervals not exceeding seven years thereafter from the last assessment. The assessments are comprised of External Direct Assessment (ECDA) and Inline Inspection (ILI). The results of each operator's program are summarized and reported to the DOT on an annual basis.

Pipeline safety laws and regulations constantly evolve driving progressive changes in utility operations and asset management. San Bruno and several other high profile pipeline incidents have set in motion recommendations, proposed rulemaking, and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 signed into law on

January 3, 2012. The Pipeline Safety Act, and the regulations to follow, will create very significant compliance challenges for the gas LDCs.

The Act requires the PHMSA to write code requirements that:

- Make all pipeline segments operating at or over 20 percent SYMS ILI enabled
- Consider requiring installation of RCVs/ASVs where economically, technically and operationally feasible
- Consider expansion of IMP beyond HCAs
- Develop requirements for medium consequence areas (MCA)
- Consider reduction of the IMP reassessment time cycle
- Reduce or eliminate the use of external direct assessment (ECDA)

Proposed rulemaking by PHMSA in response to the Pipeline Safety Act is expected in 2016.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	1,168	5,844	4,265

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system which will improve public safety and the reliability of the gas delivery system.

Alternatives:

Alternative 1: Maintain Current IMP

Proceed with the current IMP utilizing current inspection methods until such time as US DOT/PHMSA issues final rule making from the Pipeline Safety Act of 2011. Proceeding with the current IMP plan does not position the Company to improve on risk reduction or public safety.

This approach also fails to account for the likely impact of expected future rule making. Compliance with new code requirements will likely be required within a prescribed schedule. The established regulation time frame will likely require accelerated project and assessment schedules. Accordingly, there is a risk of not meeting new established deadlines, or spending on an accelerated basis which is not necessarily effective. The new proposed rulemaking also has provisions for large fines for non-compliance and not meeting deadline requirements.

Current vs Proposed Assessment Method Summary

Description	MAOP >125psig	DOT >20% SMYS	HCA
Transmission Pipe (Miles, Total)	244	135	135
Existing IMP			
ECDA	115 (47%)	115 (85%)	115 (85%)
ILI	20 (8%)	20 (15%)	20 (15%)
Sub Total	135	135	135
Proposed IMP			
ECDA	107 (44%)	107 (80%)	107 (80%)
ILI	28 (11%)	28 (20%)	28 (20%)
Sub Total	135	135	135

Studies/References That Support the Program:

Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("Pipeline Safety Act of 2011"), signed into law by the President on January 3, 2012 (Public Law. No. 112-90).

Pipeline Safety: Safety of Gas Transmission Pipelines; Advance Notice of Proposed Rulemaking, Federal Register, Vol. 76, No. 165 (August 25, 2011).

NTSB Safety Study: NTSB/SS-15/01 PB2015-102735 (Integrity Management of Gas Transmission Pipelines in High Consequence Areas – January 27,2015

Program Title: Integrity Verification Program – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the US Department of Transportation's pending rules on Integrity Verification Process (IVP) programs. The renewed Pipeline Safety Act of 2011 mandates that Pipeline and Hazardous Materials Safety Administration (PHMSA) establish rules requiring operators to demonstrate their pipelines are "Fit For Service." This includes reviewing existing records to determine if prior strength tests (hydro static pressure tests) were completed at the time of construction, as well as other records that prove the pipeline is operating within design parameters. On January 10, 2011, PHMSA issued advisory bulletin ADB-11-01 directing operators to conduct a comprehensive records review and verification prior to issue of the final rule making.

KEDNY proposes an IVP Program that incorporates the elements of the proposed IVP rule making and PHMSA guidance document ADB-11-01 along with proactive programs, records review, pipeline replacement and the retirement of non-essential pipeline segments. The proposed IVP provides the greatest amount of risk reduction, thereby improving system safety and reliability. Additionally, it is anticipated that the company will be in compliance with future regulatory requirements.

Program Justification:

PHMSA is expected to issue a Notice of Proposed Rulemaking (NOPR) that will address the 2011 Pipeline Safety Act mandates, and implement a number of additional changes to the regulations for gas pipelines. Among the changes under consideration are the establishment of maximum allowable operating pressure (MAOP) and testing mandates for existing pipelines. PHMSA is considering eliminating the exemption clause for establishing the MAOP of pre-1970 "grandfathered" pipe, which allows certain pipelines to operate at the highest actual operating pressure to which they were subjected during the five years prior to July 1, 1970, without having to perform a pressure test. PHMSA is also considering whether all pipelines not previously pressure tested at or above 1.1 times MAOP should be required to be pressure tested in accordance with current regulations. Another initiative under consideration is PHMSA's IVP, which may require operators lacking certain records to conduct pressure tests to confirm MAOP, and require operators with missing records, inadequately validated or traceable material documentation (TVC) to design and implement a program to establish material properties by one or more of the following methods: (1) cutting out and testing pipe samples; (2) institue non-destructive testing; (3) field verification of code stamp for components such as valves, flanges, and fabrications; or (4) other verifications.

Some pipelines without adequate material and pressure test documentation may be required to be retired or replaced. The IVP may also require an operator to develop a "Fit for Service Program" to establish that all pipelines are operating within their design parameters. On January 10, 2011 PHMSA issued advisory bulletin ADB-11-01 directing operators to conduct a comprehensive records review and verification prior to issue of the final rule making.

The Act requires PHMSA to:

- Issue rules to eliminate grandfathering of non-hydrostatically tested pipe satisfying the following three criteria: (i) installed prior to 1970, (ii) having a maximum allowable operating pressure ("MAOP") >30% SMYS, and (iii) are located in HCAs. Such pipelines will now be subject to hydrostatic testing. The threshold of 30% Specified Minimum Yield Strength (SMYS) supports recent studies which have shown that pipe operating below the 30% level will fail as a leak as opposed to rupture.
- Require operators to confirm the records they use to justify MAOP (TVC)
- Re-Hydro test pipe segments
- Run Inline Inspection Tools (ILI)
- Abandon / retire pipelines
- Replace pipelines
- Material sampling to establish properties
- Advance fit for service analysis

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	250	250	250

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system, which will improve public safety and the reliability of the gas delivery system.

Alternatives:

Alternative 1: Maintain Current IVP

Do not proceed with the IVP Program until such time as US DOT/PHMSA issues the final rule based on the Pipeline Safety Act of 2012. Proceeding with the current IVP plan does not position the Company to improve on risk reduction or public safety. This approach also fails to account for the likely impact of expected future rule making.

Compliance with new code requirements will likely be required within a prescribed schedule. The established regulation time frame will likely require accelerated project and assessment schedules. Accordingly, there is a risk of not meeting new established deadlines, or spending on an accelerated basis which is not necessarily effective. The new proposed rulemaking also has provisions for large fines for non-compliance and not meeting deadline requirements.

Studies/References That Support the Program:

Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("Pipeline Safety Act of 2011"), signed into law by the President on January 3, 2012 (Public Law. No. 112-90).

Pipeline Safety: Safety of Gas Transmission Pipelines; Advance Notice of Proposed Rulemaking, Federal Register, Vol. 76, No. 165 (August 25, 2011).

PHMSA Advisory Bulletin (ADB-11-01) 1/10/11

Program Title: Meter Purchases – KEDLI

Spending Rationale: ☒ Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program includes the purchase, testing, processing, and delivery of gas meters and associated instrumentation, including Mandated Meter Test/Replacement Program, growth targets, and continued Customer Meter Services (CMS) operations. This program does not include the installation of meters (see Meter Change program).

Each year, National Grid is required to randomly select and remove from service a quantity of meters to be tested for accuracy. The number of meters removed and tested is sufficient to assure a statistical confidence level of 95 percent. Test results are entered into a program that performs the statistical calculations based on an approved American National Standards Institute (ANSI) Standard. The NY Public Service Commission has set accuracy limits for both residential and commercial meter types. Meter groups that fall beyond the specified limits are placed in a retirement program and are subsequently removed from service and retired.

Program Justification:

The primary driver for meter and metering instrumentation purchases is compliance with state regulations governing meter accuracy and measurement of gas usage for customer bills. PSC requirements stipulate a random sample and associated remediation/retirement program for installed gas meters.

In addition to the mandated meter change program, meters are required to support growth targets, as well as to support CMS operational requirements (load change, meter and/or service relocations, damage, & stopped meters)

Total Project Cost Breakdown:

$000	CY17	CY 18	CY 19
Purchase Meters – Growth	2,284	2,398	2,518
Purchase Meters – Replacements	2,924	3,070	3,224

Customer Benefit:

- Metering and billing accuracy
- Fewer unplanned service interruptions
- Ensure meters meet safety standards

Alternatives:

Alternative 1: Partial Deferral of meter replacements

This option is not viable as it would result in a partial violation of regulatory requirements, or result in our inability to support fiscal year growth targets

Program Title: Temperature Control Communications Upgrade (M2M) – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

National Grid has over three thousand Temperature Controlled (temperature-dependent interruptible) accounts in New York City (KEDNY) and Long Island (KEDLI) whose meter reads are managed by a vendor-hosted application and are collected via by the vendor's gateway modems. These gateway modems will become obsolete when the cellular network technology they utilize sunsets on January 1, 2017. Under the Temperature Control Communications Upgrade project, the Company's Metering personnel will un-install each of the gateway devices and ship the communications board containing the obsolete modem back to the vendor. The vendor will upgrade each board, which includes: installing a new cellular modem, testing the board's functionality, and shipping the board back to the Company. The Company's Metering personnel will re-install an upgraded board back into each active meter gateway device.

The project also seeks to identify an alternative technology to reduce KEDLI's reliance upon its sole sourced hardware/software vendor. The vendor has also indicated that it may discontinue service in the longer term, and will not provide service assurance and support beyond 2021. Therefore, KEDLI needs to identify an alternative technology and develop a migration plan to move its Temperature Controlled customers to a new meter reading and control platform before 2021.

Program Justification:

In an effort to maximize the availability of natural gas to its customers and utilize the excess capacity of the system during non-peak load periods, KEDLI created a Temperature Controlled (TC) service classification. These customers utilize the excess capacity of the system during non-load periods and have agreed to switch to their alternate fuel source during peak load periods. To ensure the safety and reliability of the gas system each, TC customer has a remote control device on their boiler that allows KEDLI to monitor and remotely switch these customers to their alternate fuel source at the designated interruption temperature or when emergency system conditions warrant local or regional load sheading. KEDLI is required to facilitate the immediate ability for customers to switch fuels as well as remotely verify/measure a customer's compliance with gas usage restrictions during an interruptible period.

The existing "M2M" Communications platform was installed in the mid-2000's and enabled KEDLI to remotely monitor network communication performance and TC customer compliance during an interruption. The 2G communications network platform facilitated remote fuel switching and remote data collection of hourly meter readings for each TC account. In January 2011, M2M Communications was acquired by EnerNOC. The EnerNOC solution consists of a hosted application platform in the cloud and a custom made Gateway device attached to each KEDLI TC meter. The Gateway device collect consumption information and remotely switch fuel source on-command or automatically in response to meeting pre-determined thresholds. The fuel switch will occur within 1 minute of the trigger condition being met.

In February 2014, AT&T has announced that it is sun-setting its 2G network on January 1, 2017 to free up space for its newer networks. If left as is, all of KEDLI's current TC gateways will be unable to communicate after January 1, 2017. Accordingly, KEDLI began discussions with EnerNOC to identify an alternative communications network and subsequently agreed to upgrade its service from 2G to 4G. During these discussions, the vendor indicated it may not be willing to support this application beyond 2021 due to changing technological advancements, prompting KEDLI to seek an alternative longer term solution. This project serves to identify the costs to upgrade its system from 2G to 4G and in the longer term identify and implement a new communications and control network for KEDLI's TC customers.

Total Project Cost Breakdown

$000	CY 2017	CY 2018	CY 2019
CapEx	23	0	41

Customer Benefit:

Allows non-firm customers to utilize excess system capacity during peak load periods and maintains gas system safety and reliability

Without the Temperature Control Communications Upgrade project KEDLI will need to interrupt non-firm customers with increased frequency and will not be able to monitor and control the gas system in a safe and reliable manor and could cause the elimination of the TC service classifications.

Alternatives

Alternative 1: Do nothing.

Doing nothing will adversely impact cost, customer satisfaction and reliability. This alternative does not meet the company objective to provide service under the current tariff service classification and will adversely impact the safety and reliability of the KEDLI gas system.

Program Title: Gas System Reliability/Remote Control Valve (RCV) Program – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The System Reliability Program includes the capital projects required to maintain system minimum pressures on the gas network in the event of an abnormal operating condition (failure involving a regulator station, gate station, critical main or other major pressure facility on the system). This program includes new RCVs on transmission pipelines to improve emergency response capabilities and reduce risk. In the event of a pipeline failure that results in a release of natural gas, RCVs will allow control room operators to stop the flow of gas, isolate and shutdown a portion of the system, and mitigate further consequences utilizing a remote command.

Program Justification:

Federal Code (49 CFR 192.623) and New York State (16 NYCRR 255.623) require minimum pressures to be maintained in the gas system. The Gas System Reliability Program identifies projects required to maintain service during normal winter temperatures under peak hour conditions should there be a loss or failure of a major facility.

Gas system reliability concerns include transmission and distribution systems with limited number of feeds (*i.e.*, from take stations or regulator stations), systems that are either weakly integrated or consist of long single-feed laterals, networks that contain a wide variety of operating pressures, and varying design philosophies associated with system and supply redundancy (*e.g.*, production plants, take stations, regulator stations).

Gas safety concerns focus on the Company's ability to quickly and efficiently shut down gas supply remotely following a pipeline failure resulting in the release of natural gas, to ensure the safety of the first responders, impacted gas customers and the public. The use of RCVs also eliminates the need to locate and excavate manual valves.

In addition, the Company anticipates federal regulations (see Pipeline and Hazardous Materials Safety Administration (PHMSA), Advanced Notice of Proposed Rule Making (ANPRM), dated August 25, 2011, FR 53086, Docket PHMSA-2011-0023) will require installation of RCVs following several off-system, high-profile pipeline failures. RCV programs will be developed utilizing PHMSA criteria.

Total Project Cost Breakdown:

$000	CY 2017	CY 2018	CY 2019
CAPEX	2,000	2,893	3,109

Customer Benefit:

The Gas System Reliability program ensures that service is maintained in the event of a failure on a major pressure facility. Reliability is improved by adding supply flexibility, integrating single feed systems, making progress to eliminate single feed systems, and by installing RCVs. Without this program, greater numbers of customers are at risk of losing service in the event of a facility failure.

KEDLI's goal is to proactively upgrade the existing valves or install new valves in certain high-volume and high-risk locations to enhance reliability and safety by reducing the amount of time needed to stop the flow of gas in the event of a pipeline failure thereby mitigating the consequences of any such event. Installation of RCVs will be undertaken in a manner that will ultimately comply with federal regulatory guidance (PHMSA's August 25, 2011 ANPRM).

Alternatives:

Alternative 1: Do Nothing

If RCVs are not installed, a pipeline failure would require a manual shutdown of the transmission pipe. This may result in longer times to contain the incident and could result in more damage. Also, by not adding any RCVs the isolation area could be larger in some instances, resulting in a larger loss of service to customers. Given pending PHMSA regulations, this option would leave the Company in violation of industry code requirements.

Studies/References that Support the Program:

Studies were run on the Company's network models using Synergi software, which is industry standard software used by nearly all of the LDC companies. The models, which are validated on an annual basis, were loaded with the forecast provided by National Grid's Analytics, Modeling, and Forecasting (AMF) Department. Individual facilities were taken out of service, and reliability projects were then identified to bring pressures back above minimum.

Several studies have been conducted regarding the benefits of RCVs. The results were summarized in a report by the Department of Transportation (DOT), Research and Special Programs Administration (RSPA) in September 1999, entitled "*Remotely*

Controlled Valves on Interstate Natural Gas Pipelines," and updated in another report by Robert J. Eiber Consultants, Inc. and Keifner and Associates in July 2010, entitled "*Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing.*" Based on these reports and underlying studies, the vast majority of fatalities, injuries and property damage associated with a catastrophic pipeline accident occur within the first few minutes of the event, well before any activation of RCVs would be possible. Even if RCVs are installed on a transmission line, there would be a considerable delay before the equipment "recognizes" that a pipeline incident has occurred, and closes the valve in response to the incident. In the case of an RCV, there would be a delay associated with the control center recognizing the event as an incident, and making a determination as to the appropriateness of closing RCVs in response to the event. However, the true benefit of a RCV would be to minimize the loss of natural gas after the incident had occurred and minimizing the impact of the incident on the operation of the gas system (such as pressure collapse due to a rupture). In addition it will shorten the duration of the event (*i.e*., gas fueled fire) and that could help to reduce the amount of damage resulting from the event.

Program Title: Valve Installation and Replacement Program – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The Valve Installation and Replacement Program addresses valve replacements in addition to new valve installations necessitated by ongoing annual inspections. The program will strengthen the emergency response capabilities of the gas organization by improving the level at which Field Operations can safely and efficiently isolate sections of the distribution system while ensuring minimum customer impact and will benefit KEDNY's customers by reducing the duration of future outages. This program highlights the need to provide investment in our infrastructure to maintain acceptable standards for system reliability and emergency response.

Program Justification:

KEDLI is required by federal (49 CFR 192.181) and state (16 NYCRR 255.181) regulations to install, inspect, maintain and operate critical pipeline valves on all gas distribution systems. The purpose of these valves is to facilitate the rapid shutdown of distribution piping or regulator stations during gas emergencies such as third party damage, water intrusion, or other operational reasons. A secondary purpose of these valves is to facilitate maintenance and pipe replacement activities on associated distribution piping. Ensuring all critical valves are properly maintained and operable is a key public safety function and is critical to the effective operation of National Grid's gas distribution system.

In New York, the local gas distribution yards are responsible for performing annual valve inspections and any resulting repair and/or replacement work identified through the inspections. Program status and compliance is reported monthly. Gas Systems Engineering has enterprise-wide responsibility for the Critical Valve Program. This includes valve selection criteria and determination, development of system isolation districts. The Gas Operations Engineering and Project Engineering & Design teams also provide ongoing support to Field Operations through diagnosis of inoperable valves, identification of alternate valves and selection of new valves.

Total Project Cost Breakdown:

$000	CY 2017	CY 2018	CY 2019
CAPEX	$130	$130	$130

Customer Benefit:

Successful execution of the program will ensure the safety and reliability of the gas assets while focusing on improvements in customer satisfaction. The primary driver for this program is to improve distribution system and customer reliability while maintaining the highest standards for safety of the gas distribution assets. The program will minimize the unplanned release of gas during restoration of damage to Company facilities.

Alternatives:

Alternative 1: Do Nothing

The valves found to be deficient will need to be managed on a case by case basis, creating process and investment inefficiencies. Lack of the ability to properly plan and employ uniform criteria to these issues increases risk to the Company and can portray a negative image of the organization to customers, investors and regulators.

Studies/References That Support the Program:

1. Outage Restoration Costs Study

Estimates for relighting customers and recovering from a system outage have been prepared to quantify the impact of outages related to insufficient system capacity during periods of peak demand and severe winter cold.

Actual relight costs have been captured from recent incidents to quantify company expenses related to restoring service. These were all related to outages that occurred for reasons other than insufficient system capacity and operations were conducted under benign weather conditions. It is likely that during severe winter weather, costs would increase.

The claims data related to burst pipes and equipment damage due to a lack of heat during severe cold weather was captured from National Grid incidents in other jurisdictions. The combined cost of relighting customers and resolving claims in those incidents averaged $1,764 per customer. Recognizing the amount of variability in different incidents such as weather conditions, different types of neighborhoods, variable labor costs, economies of scale, etc., for purposes of evaluating the benefits of reinforcement projects, an average value of service restoration costs and claims of $1,000 per customer is used.

<u>Program Title</u>: Heater and Regulator Station Management Program – KEDLI

<u>Spending Rationale</u>: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

<u>Brief Description:</u>

This program covers capital projects involving the pressure regulating facilities and heaters utilized on the Company's gas system. Regulating stations identified for full replacement are those that do not meet current company standards for design, including the following criteria:

- Severe corrosion; usually occurs where no cathodic protection was installed (*i.e.* Pre-DOT pipe; pre-1971),
- It is not cost effective to repair or modify,
- Under capacity – the station is too small and would require new vaults, new piping with larger valves and regulators as identified by Gas System Planning,
- Structural problems with vaults, coupled with flooding and traffic problems that need to be addressed.

The program will also install new heaters to mitigate cold gas temperatures and to replace heaters nearing the end of their useful lives, manage control line integrity, and provide for special projects related to heaters and regulator stations.

<u>Program Justification:</u>

There are three elements to consider when ensuring adequate safety and reliability of pressure regulators stations: heater management, pressure regulator station management and control line integrity. Using data from the annual Performance Testing (PT), Cathodic Protection (CP) testing, risk assessments and on-site inspections, technical assessments were made for each pressure regulating station taking into account pipe and equipment condition, regulator performance, corrosion data, heater and scrubber performance. In addition, Guided Bulk Wave Testing (GBWT) has been used in regulator vaults to determine if there are any anomalies in the pipe within the vault penetrations. The results of these tests/assessments, combined with an analysis of the potential customer impact resulting from a station outage, were used to prioritize and schedule capital projects in the Heater and Regulator Station Management Program

Pressure Regulating Facilities: Planned replacements will eliminate older regulating stations that no longer meet current company standards for design (*i.e.*, over pressure protection). These replacements will comply with regulatory requirements for the operation of the gas system and will improve system integrity.

Collaboration with other programs such as the Main Replacement Program, System Reinforcements and System Reliability can change the scope of work for an existing pressure regulation station by increasing flow, reducing flow or allowing the station to be retired.

An event at any vault could jeopardize the customers downstream through loss of supply or by over pressurizing the system. The program addresses corrosion issues, structural vault problems, obsolete pressure control valves, inadequate by-pass designs, accessibility and maintainability (automation is handled within a separate System Automation Program).

Since Superstorm Sandy, KEDLIKEDLI has begun a program to storm harden pressure regulating stations that are within the identified 100 year flood plan. This program consists of making the vaults watertight by: installing Roxtec seals at all vault penetrations, water tight manhole covers, vent poles, water proof vault, and relocate telemetry to above grade cabinets.

Heaters: The Company's policy ("Management of Cold Gas Temperatures") recommends that heaters be considered for installations where pressure drops of 200 psi or more occur. Because natural gas temperature will decrease approximately 14 degrees given a 200 psi pressure drop, the temperature of the gas leaving a pressure regulating station can fall below freezing if heat is not added. On a cold day, flowing gas temperatures may average 40 degrees or less. After a 200 psi pressure reduction, the gas will be flowing at 26 degrees or less. Frost heave can occur as ice forms below 32 degrees and piping can begin to lose strength (become more brittle) as temperature falls below 20 degrees.

The heaters in the program are earmarked for full replacement because they are reaching the end of their service lives. Natural gas heaters are made from carbon steel. They contain a glycol-water mixture, similar to the antifreeze in an automobile radiator. These heaters have a life expectancy of approximately 25 years, which can be extended or diminished according to maintenance practices. However, at some point, the integrity of the steel tubes within the heater can become compromised and may result in a leak. Since all of these heaters are connected to transmission piping, they are subject to higher pressures and the impact of a leak or tube failure can be catastrophic.

There have been past pipeline failures on KEDLI affiliates' systems due to increased stresses associated with cold gas being introduced into the distribution network. The higher stresses have created axial contraction, coupled with frost heave and lower pipe toughness, which has resulted in weld failures. The installation of additional heaters will help to address these issues.

Control Line Integrity: Control lines are an integral part of each regulating station. This program is managed in conjunction with the pressure regulating facility replacements and rebuilds. When Guided Bulk Wave Testing (GBWT) is performed at a regulating station, all control line vault penetrations are inspected. This program corrects any control line integrity deficiencies identified.

Control line integrity will provide cathodic protection to previously unprotected buried steel lines, which will improve the reliability of the gas system. Cathodic protection is a proven and cost effective method to enhance the life cycle of pressure regulating stations.

Special Projects: These are complex projects that are multiyear and are typically located at take/gate stations, which are at transmission pressure. A typical take station overhaul will include an overhaul of all equipment and buildings on the site, retirement of obsolete equipment, and the abatement of environmental concerns such as lead paint, asbestos and soil contamination.

Total Project Cost Breakdown

$000	CY 2017	CY 2018	CY 2019
Pressure Regulating Facilities	$ 3,129	$ 4,218	$ 5,046
Heater Installation Program	$ 1,500	$ 1,500	$ 1,500
Bay Shore Take Station Overhaul	$ 860	$ 340	$ -
Rockville Centre Take Station Overhaul	$ -	$ 860	$ 340
Long Beach Gate Station Overhaul	$ -	$ -	$ 860

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas without unplanned outages due to pressure regulating facility shutdowns. Pressure regulating stations supply from 500 customers for low pressure distribution stations to 500,000 customers for high pressure stations.

Alternatives – Pressure Regulating Facilities

Alternative 1: Station rebuild in lieu of replacement.

The station can be rebuilt and brought to current standards. This may require the following:

- Control line rework or replacement
- Minor work to ensure adequate sustained CP readings
- New regulators or replacement of "soft goods"
- New sleeves, ladders, vault covers, and pipe stubs
- Recoating of all exposed piping with epoxy

Station rebuilds can extend the life of an existing station by twenty years or more and are cost effective.

Cost: $500,000 - $850,000 depending on size and condition

Alternatives – Heaters

Alternative 1: Rebuild existing heaters in lieu of replacement

The main components of gas heaters can be replaced; however, the manufacturers of older heaters are generally no longer in business after 25 years. For example, BS&B, Tulpro, and QB Johnson are all heater manufacturers that have gone out of business in the last 20 years. This presents a unique problem as replacement parts are not available and large components would have to be custom fabricated. The cost to remove and replace large components in the field coupled with the availability generally makes the cost to rebuild a heater as high (or higher) than the replacement cost.

Studies/References that Support the Program:

The Company's Distribution Integrity Management Program was put in place in 2011. The program includes a risk ranked approach for ranking pressure regulating facilities according to Health & Safety Risks and the Technical risks associated with their age and condition.

TI 020040 - Management of Cold Gas Temperatures. This TI provides the Company's general strategy which is that all stations with a pressure drop of 200 psi or greater should have heaters where practical. It supports the operation of natural gas heaters and the need to add or replace heaters.

Program Title: System Automation & Control – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This program will replace obsolete Remote Terminal Units (RTUs) at multiple gate stations and regulator stations located throughout KEDLI's service territory. RTUs are installed locally at gate stations to provide temperature, pressure and flow data back to the Gas Control Room. Where required, the RTUs can also monitor gas detectors, intrusion alarms and allow Gas Control to adjust flow and pressure set point at the regulator stations. Data is transmitted via phone lines or cellular networks. The automation projects include raise/lower controllers to remotely adjust pressure on the gas system. Gas analyzers projects are also included to provide gas composition and BTU content of the gas.

The objective is to standardize operations, maintain custody check metering and increase control and monitoring at city gate stations and regulator stations. Project delivery also serves to increase operational understanding of the system to identify abnormal operating conditions and taking a proactive approach to alarm management in support of new PHMSA requirements (*i.e.*, Control Room Management). The program also adopts a best practice with respect to check metering and leak management.

Program Justification:

This program is necessary to enhance system reliability. Improving the level of automation at pressure regulating stations will enhance the ability of the Gas Control to pinpoint problems and take corrective action. The system automation program supports the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirement that "each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined." This program supports compliance with these regulations.

Currently, the KEDLI gas system has 100 percent of the pressures regulating stations equipped with some form of telemetry and 89 percent of the system has full remote control of the regulators. Some of this equipment was installed many years ago and has become obsolete. Updating this obsolete equipment supports the standardization of telemetry across National Grid's gas transmission and distribution system. Enhanced calibration of network models from automation and telemetry data improves the accuracy of network analysis and enhances the ability to forecast future capital reinforcements, which leads to more efficient capital investment.

The recent change from traditional Gulf gas supplies to Marcellus shale gas has brought about a significant need for new equipment to measure and monitor the gas quality at change of custody points. Where gas is introduced into the National Grid system, gas monitoring instruments are needed to monitor odorant levels, BTU, composition, hydrates, and hydrocarbon dew point (HCDP). This equipment will be installed at take stations (transfer of custody points). This program to meet gas quality monitoring standards will take five years to implement.

Also, due to the increased scrutiny placed on system automation in the aftermath of the San Bruno pipeline incident, it is anticipated that federal regulations will require additional levels of system automation on both transmission and distribution systems.

Total Project Cost Breakdown

$000	CY 2017	CY 2018	CY 2019
CAPEX	1,358	1,370	1, 392

Customer Benefit:

More reliable system performance with fewer customer outages.

The advantages of system automation and telemetry are that the source and location of any system problem can be more readily and accurately identified from the Gas Control Center. Crews can be dispatched immediately to the location of the problem. This process saves valuable time and will reduce the need to wait for customers to call in and report a problem. In addition, the removal of paper charts recorders provides a more accurate and timely record of station pressures and this information is also available for Gas Planning.

Alternatives

Alternative 1: Do nothing

Doing nothing does not meet the long term company objective to actively manage system pressures and leak activity.

Studies/References That Support The Program:

National Grid Policy PL 030002 – SCADA Instrument & Control

This policy requires that new telemetry points are approved by Gas Control in accordance with the U.S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA) Control Room Management standards (49CFR 192.631)

Program Title: Water Intrusion and Main Exposure Program – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI's Water Intrusion and Main Exposure program will have two components. The first will address unanticipated (*i.e.*, emergent) water intrusion causing disruption of service to customers as well as poor pressures requiring investigation by I&R, CMS and Field Operations. The second part of the program will address unanticipated infrastructure washouts/main exposures that can occur during storms, heavy rains and/or seasonal snow melting, which can cause damage to facilities, emergency response and potential loss of service to customers. The program will address both water intrusion projects that have already been identified and management of emergent reliability problems as they are identified. Newly identified locations meeting the program criteria will be risk ranked and prioritized for replacement or other action within the existing budgetary limits.

Program Justification:

The Water Intrusion/Main Exposure Program will support two critical areas not currently linked to specific capital or operating expense budgets. This program will enable improved management of these budgets with specific focus on emergent activities. Previous efforts have linked these emergent projects with LPP replacement activities whenever practical. The program will also facilitate swift decision making based upon predetermined criteria for project execution, allowing improved customer satisfaction while further ensuring the safety and reliability of the system.

Total Project Cost Breakdown.

$000	CY 2017	CY 2018	CY 2019
CAPEX	939	1,033	1,075

Customer Benefit:

Successful execution of the program will further ensure the safety and reliability of the gas assets while focusing on the improvements in service delivery. Unplanned customer outages, driving poor system reliability in low pressure distribution systems are targeted through this program. Customer satisfaction is negatively impacted due to disruptions of gas service, inconvenience associated with relight process and in instances customer costs associated with remedy and/or repair of customer owned equipment. Customer disruptions portray a negative image of the Company impacting reputation. The recommended program will resolve future, recurring disruptions to customers on low pressure systems. The program will take the opportunity to support continued elimination of low pressure distribution systems by upgrading to elevated pressure whenever practical. Successful execution of the program will also realize improvements in public and municipal relations due to a decrease in unplanned outages which will result in lower occurrence in unplanned road excavation.

Alternatives

Alternative 1: Previously-Identified Projects Only

This option highlights the minimum capital investment and operating expense requirements to execute the replacement and/or permanent remedy of the identified aforementioned water intrusion and main exposure projects meeting the criteria for replacement under the said program, and would exclude newly-identified issues going forward. This scenario will not include the additional allocated funding to support walk-in projects as they are identified during the fiscal year. The risk with this option presents itself with the program approval in advance of the rainy season which can highlight new areas of concern and/or scope adjustments to existing problematic areas. As such, this limits flexibility to initiate timelier repair to pressing/urgent needs on the system which has potential to manifest itself in customer outages. Additional in-year emergent issues would need to be managed on a case by case basis and will require additional funding support

Alternative 2: Do Nothing

This option does not allow water intrusion/washout issues to be identified for consideration through the budget planning process. Further, the emergent issues presented in this proposal are likely to continue and will need to be managed on a case by case basis and will require additional funding support from other programs. These occurrences present the risk of pipe failure due to unsupported segments; failure of the pipelines can negatively impact safety and system reliability leading to increased Opex and customer dissatisfaction. Lack of the ability to properly plan and employ uniform criteria to these issues increases risk to the Company and can portray a negative image of the organization to customers, investors and regulators.

Studies/References that Support the Program:

Outage Restoration Costs Study

Estimates for relighting customers and recovering from a system outage have been prepared to quantify the impact of outages related to insufficient system capacity during periods of peak demand and severe winter cold.

Program Title: Storm Hardening – Remotely Operated Service Shutoff Valves – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI has more than 58,000 services within the Federal Emergency Management Agency's (FEMA) 500 year flood zones. Approximately 10 percent of the Company's total services are susceptible to storm surge. To mitigate the risk of flood damage to the Company's facilities, the Storm Hardening program will install remotely operated service shut-off valves with flood sensors within the FEMA defined flood zones across the operating region. The program proposes to install the valves on both existing services in the identified flood zone and on new services installed within that zone. This will address two important objectives in the event of flooding. The first objective will be shutting off the services automatically as soon as flood water reaches the service so there will be no regulator over-pressurization, thereby preventing a potential incident and ensuring the safety of our customers. The second objective is to provide an accurate count of services impacted by flooding in real time, which will inform the Company's storm response with respect to the resources needed to restore the impacted customers expeditiously. Remote shut off valves will also allow the Company to interrupt the services impacted by flooding without shutting down the entire neighborhood.

Program Justification:

The Storm Hardening Program – installing Remote Service Shutoff Valves with flood sensors that automatically shut off gas to structures that experience flooding and provide an accurate count of services impacted by the flooding - will enable improved emergency response in the event of flooding. This targeted approach shuts down only the services affected by flooding (as opposed to the larger gas service districts) and sends alerts to the customers impacted, isolating the system and alerting the Company of the loss of service to our customers in real time. This will enable improved management of storm restoration with specific focus on the affected customers. During Superstorm Sandy, the Company had to shut down much larger service districts because of there were no remotely operated service shut-off valves. This resulted in the loss of service to a larger number of our customers for a significantly longer time than would be the case if remote shut off valves were in place. This program will also facilitate swift decision making focused upon affected regions, thus generating efficient execution of service restoration work and allowing improved customer satisfaction while further ensuring the safety and reliability of the system.

Total Project Cost Breakdown:

$000	CY 2017	CY 2018	CY 2019
CAPEX	8,295	11,225	11,445

Customer Benefit:

Implementing these storm hardening measures will further ensure the safety and reliability of the gas assets within the flood zone while focusing on improvements in service delivery. This program will address the gas service reliability of the customers within the flood zone in the event of storm surge. Customer satisfaction is negatively impacted due to disruptions of gas service, inconvenience and company cost associated with the relight process. Conducting targeted interruption of service will reduce the customer impact and water intrusion in mains that has a long lasting impact on the system. The recommended program will resolve future, recurring disruptions to customers in a flood zone due to service freeze ups during winter. This program will also generate improvements in emergency planning, incident management and public safety.

Alternatives:

Alternative 1: Identified Flood Zone Services Only

This option highlights the minimum capital investment and operating expense requirements to install remotely operated service shutoff valves for the existing services within the flood zones, excluding new services. The risk with this option presents itself with the unsystematic management in the event of flooding. The new services will be susceptible to similar problems that currently exist within the system. Moreover, with two different sets of services, one with remotely operated service shutoff valves and other without these valves will call for emergency response in two different scenarios in the event of flooding. This not only impacts the response time but also increases the customer outages and puts customers and public at risk.

Alternative 2: Do Nothing

This option leaves services within the Flood Zone vulnerable in the event of flooding. Further, the emergent issues presented in this proposal are likely to continue and customers will be susceptible to longer durations of service loss. The flooding occurrences present a risk to customers and public safety; flooding of the services can negatively impact safety and system reliability leading to increased Opex and customer dissatisfaction. Lack of the ability to properly plan and employ uniform criteria to future flooding events increases public risk and significant cost to shut off and restore the customers in the event of flooding.

Studies/References that Support the Program:

1. Outage Restoration Costs Study

Estimates for relighting customers and recovering from a system outage have been prepared to quantify the impact of outages related to insufficient system capacity during periods of peak demand and severe winter cold.

Actual relight costs have been captured from recent incidents to quantify company expenses related to restoring service. These were all related to outages that occurred for reasons other than insufficient system capacity and operations were conducted under benign weather conditions. It is likely that during severe winter weather, costs would increase.

The claims data related to burst pipes and equipment damage due to a lack of heat during severe cold weather was captured from National Grid incidents in other jurisdictions. The combined cost of relighting customers and resolving claims in those incidents averaged $1,764 per customer. Recognizing the amount of variability in different incidents such as weather conditions, different types of neighborhoods, variable labor costs, economies of scale, etc., for purposes of evaluating the benefits of reinforcement projects, an average value of service restoration costs and claims of $1,000 per customer is used.

Program Title: I&R Reactive – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI's Instrumentation and Regulation (I&R) Reactive program includes demands maintenance, repairs and upgrades of all pressure regulating devices, valves, gas telemetering equipment, gas quality equipment, compressed natural gas (CNG) equipment, compressor stations and gas plant facilities (buildings, grounds, etc.). This reliability program will ensure that systems upgrades/replacements are accomplished reactively while performing regular maintenance activities.

Pressure Regulating Stations

KEDLI operates and maintains 239 pressure regulating stations within Nassau, Suffolk and Queens Counties (Rockaway Peninsula) that regulate high pressure gas to distribution pressures, ensuring system reliability, efficiency and safety. 184 are dual stage stations and 55 are single stage stations. Each station is composed of several valves, vent poles and filter-strainers. Two additional regulator stations were commissioned in FY 2015-16 for Nassau and Suffolk County.

Valves

KEDLI maintains and inspects over 4,000 valves (consisting of line, facilities, station and customer curb valves) throughout Nassau and Suffolk Counties. These valves are inspected annually pursuant to state regulations. Maintenance of these valves involves regular repair and replacements.

Gas Telemetering Equipment

KEDLI operates and maintains 112 test points and 239 pieces of telemetering equipment at its regulator stations. These devices provide a live pressure read and system control to SCADA using both cellular and network communications. Control to the regulator stations is provided by electrically driving gas control pilots, which can remotely raise and lower station outlet pressures.

Due to the increased scrutiny placed on system automation in the aftermath of the San Bruno pipeline incident, it is anticipated that federal regulations will require additional levels of system automation on both transmission and distribution systems. Improving the level of automation at pressure regulating stations will enhance the ability of the Gas Control to pinpoint problems and take corrective action. The system automation program supports the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirement that "each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined." This program supports compliance with these regulations.

Gas Quality Equipment

Heaters - this equipment maintains gas temperatures at 40 degrees Fahrenheit to prevent freeze-up of regulator stations and customer services. KEDLI has heaters located at six sites in Nassau and Suffolk.

Odorant Equipment – this includes one portable odorant injection trailer, one portable odorant injection skid, an Odorant Chromatograph to measure odorant levels in the gas main, six portable odorant detection devices, and a permanent odorant injection site in Northport, New York.

Compressed Natural Gas (CNG) Equipment

CNG Fill Stations - KEDLI supports the operation and maintenance of four CNG fill stations in Nassau and Suffolk.

CNG Tube Trailer/Heater-Regulator Trailers - KEDLI maintains and operates two CNG trailers. One trailer holds large volume CNG tanks. The second trailer is used to heat and pressure control the gas supplied by the CNG trailer. Trailers are mobilized on demand based on system requirements during cold weather operations.

Compressor Station:

KEDLI operates and maintains a compressor station in Suffolk County. The station is comprised of two compressors. One is driven by and electric motor, the other a natural gas powered engine. Site has gas leak detection equipment, telemetering equipment, gas valves and regulating equipment.

Gas Plant Facilities:

KEDLI maintains thirteen pant facilities supporting gas operations. Site support is necessary to ensure personal and public safety, site security, and equipment maintainability. Along with maintaining valves, regulators, strainers, filters, pig launchers, vents vaults, telemetering equipment, these sites also require maintenance of driveways, gates, fences, security (cameras and alarms), grounds keeping, building maintenance, plumbing, heating and general housekeeping.

Program Justification:

Reliability:
Maintaining proper pressure control on the gas system is imperative to ensuring the safety and reliability from the gate station to the customer meter. Proper pressure control also increases efficiency by reducing commodity loss.

Mandated:
The reliability program is administered in accordance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	1,654	1,679	1,704

Customer Benefit:

Minimal customer impact is expected during the maintenance and replacements of these assets.
Various stakeholders can benefit from this improvement plan in the following ways:

- Improved public safety due to reduced risk of gas incidents
- Fewer unplanned service interruptions
- Reduction in gas leaks

Alternatives

None

Program Title: LNG Blanket Program – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

KEDLI's Liquefied Natural Gas ("LNG") Blanket Program provides for the safe, reliable and compliant operation of the Holtsville LNG Facility through procurement, installation, modification and/or enhancements to equipment, systems and facilities (excluding special projects and tank upgrades that are individually budgeted). An effective LNG operations capital program allows for replacement of obsolete and/or deteriorating equipment, systems and facilities that are reaching the end of their useful lives along with modifications to enhance the safe, reliable, compliant and efficient operation. This program will extend the service life of critical production facilities and institute process safety improvements for plant equipment. Capital investments in the program include projects identified and planned in advance of the fiscal year as well as projects to address emerging issues during the course of the year.

The capital work to be sanctioned under this program includes, but is not limited to, the following:

- Upgrades and improvements to mechanical equipment and systems
- Upgrades to and replacement of electrical and control systems including safety shutdown systems
- Structural improvements of plant and facilities
- Procurement of capital tools and equipment
- Preliminary engineering and design of capital projects
- Retirement and/or decommissioning of equipment, plant and facilities

Program Justification:

KEDLI operates the Holtsville LNG plant which is an on-system peak shaving facility. LNG is primarily methane gas cooled to minus 260 F at which point it changes from a gaseous state to a liquid state and occupies about 600 times less volume. Natural gas converted into LNG is an ideal method for storing supply to be used during peak days (periods of high demand). Holtsville has one storage tank with a total capacity of 600 million cubic feet of natural gas which supplies up to 100 million cubic feet on any given peak day. The LNG is warmed up to supply the distribution system through the vaporization process and feeds both high pressure and low pressure distribution systems.

The refilling operation today is done exclusively through liquefaction.. The liquefaction system can refill at a rate about 6 to 6.3 million cubic feet of gas per day. The refilling/liquefaction operation can take up to 100 days to refill the Holtsville LNG tank between the months of April through December and varies based on how empty the tank is from the previous heating season use.

The LNG Blanket Program provides funding for near-term and emergent capital projects needed to maintain safety and reliability at the Holtsville LNG facility by: 1) replacing obsolete and/or deteriorating equipment, systems, and facilities that are near the end of their useful lives; and 2) modifying/enhancing equipment needed to operate facilities safely and reliably.

Additionally, these projects are designed to maintain compliance with federal and state rules and regulations regarding the safe and reliable operation of LNG facilities. Operator noncompliance could result in penalties and forced removal from service as directed by federal and state regulators.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	1,935	1,633	540

Customer Benefit:

This plant is a critical component of the Company's gas supply portfolio and gas operating network. Holtsville LNG can provide as much as 9% of KEDLI's peak day demand. The key driver for this project is to ensure the continued, safe operation and availability of the Holtsville LNG as a natural gas supply point into the NY distribution system. This plant is critical to the NY gas supply portfolio over the next 10 years. KEDLI's firm gas customers benefit from the availability of this less-expensive peaking supply because gas is liquefied during the summer and stored for use in the winter.

The Holtsville LNG plant has played a significant role in KEDLI's ability to supply unprecedented volumes of gas during record breaking cold spells over the past two winters. The plants inability to vaporize during peak winter weather conditions may result in the unplanned interruption of a significant number of gas customers.

Alternatives

Alternative 1: Portable CNG

The only comparable alternative to LNG is portable CNG. The Company currently utilizes portable CNG skids to manage low pressure conditions on the gas system. This is effective for boosting pressures at specific low points on the system. This alternative is rejected because replacing Holtsville LNG with portable CNG is not feasible due to the number of units and CNG tanks required to match Holtsville's output.

Alternative 2: Do Nothing

If the LNG Blanket Program investments are not made, there is a risk that the Holtzville LNG resources will become unavailable during the heating season. This would require the purchase of higher cost city gate supplies (if available) and may result in financial penalties from pipelines if the Company cannot adhere to operational flow orders and other contractual requirements. The lack of LNG Plant availability could lead to customer outages during heating season resulting in a negative customer impact.

Any potential short-term savings of doing nothing are quickly outweighed by increased maintenance, operating and replacement costs. A "Do Nothing" alternative does not address potential reliability and safety risks associated with not replacing obsolete and/or deteriorating equipment, systems and facilities that are reaching the end of their useful life, or modifying/enhancing equipment needed to operate facilities safely and reliably. These risks include:

- Deterioration of gas facilities/assets:
  - severe reduction in useful service life
  - leaks – safety hazards and increased greenhouse gas emissions
  - unplanned maintenance and repairs
  - operator work around to continue system operations

- Potential loss or danger to customers and public

Program Title: LNG Special Projects – KEDLI

Spending Rationale: ☒ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

In addition to the LNG Blanket Program, KEDLI has identified a number of special projects to be completed over the next five years that are required to ensure the continued safe and reliable operation of the Holtsville LNG plant. "Special" projects are those having a cost of approximately $1 million or greater. Special projects planned during the next five years include the following:

- 480 V Westinghouse Power Breaker Replacement
- High Expansion Foam for LNG Pump Area
- Field Instrumentation upgrades
- HMI upgrades
- Boil-off System
- Control System Upgrade
- Emergency Generator
- Safety PLC for associated trips for Gas and Fire Detection
- Storage Building
- Upgrade APACS System for Liquefier
- Tank Painting - Complete step replacement

Program Justification:

480 V Westinghouse Power Breaker Replacement

The 480V Westinghouse Power Breakers were installed in the late 1960's are original to the Holtsville LNG plant. The breakers are reaching the end of their useful life and it is becoming difficult to find replacement parts for this equipment. LNG Operations is pursuing the replacement of these breakers and integrate their system condition status into the Holtsville Control Room Human Interface (HMI) System.

High Expansion Foam for LNG Pump Area

Holtsville will add a high expansion foam system to the impoundment area around the LNG pumps. This system will contain foam generators, foam makeup storage tanks, switches and panels. The purpose of the high expansion foam system is for vapor control during a substantial LNG spill or release. When activated, the impoundment area will have a blanket of high expansion foam discharged to cover the LNG. This blanket of foam serves two purposes: (1) It slows the rate of vapor generation, and (2) It ensures that sufficient heat will be transferred to the LNG vapors before they are released so that they rise into the atmosphere and dissipate instead of creating a cold vapor cloud at or near the ground surface.

Field Instrumentation upgrades

Some of the existing LNG plant field instrumentation that is used to monitor temperatures, pressures, level gauges or valve positioners connected to the control panel in the control room is original to the plant and needs to be upgraded. The project will transition the existing instrumentation to Programmable Logic Controllers (PLC) that will be integrated into the Holtsville Control Room HMI System. A vendor will be used to help integrate this project into the HMI and Control System upgrade projects.

HMI upgrades

The Holtsville Control Room is comprised of a control panel and a series of Human Machine Interface (HMI) monitors that plant operators use to run different processes at the plant. Over the years there has been an effort to move controls from the control panel to HMI and now Holtsville is in a position that some of the hardware and software needs to be upgraded. This project will involve upgrading the LNG Plant's HMI System and build a redundant server system that will have a "hot" standby should the primary server fail. A vendor will be used to help integrate this project into the field instrumentation and Control System upgrade projects.

Boil-off System

The Holtsville boil-off compressors are original to plant and are reaching the point where parts for the compressors are not available. The replacement of these two compressors is necessary to ensure continued and reliable vaporization, truck loading/unloading operations and to eliminate venting of the LNG tank to atmosphere. The purpose of the vapor recovery system is to maintain safe pressure levels inside the LNG tank. The process captures the vapors generated from the LNG increasing in temperature inside the tank , truck unloading operations, and liquefaction flash and compress them for use in the regeneration system (if necessary) and recovery into the pipeline. The project will add a series of controllers and diagnostic instrumentation visuals from the Holtsville Control Room HMI.

Control System Upgrade

The liquefaction, vaporization and other ancillary systems in the Holtsville LNG Plant have control systems attached to their equipment. These control systems either feed signals into the control panel or the plant's Control Room HMI. This project will direct these systems (e.g. water, fuel gas, etc.) to feed into the HMI and upgrade their connections. In addition, the original systems did not have common shut-off valves and water supply valves. Vaporizer upgrades will allow for those signaling capabilities providing greater system visibility to the Controller. A vendor will be used to help integrate this project into the HMI and Field Instrumentation upgrade projects.

Emergency Generator

Holtsville LNG is looking to install an Emergency Generator on the plant property to serve as auxiliary power in the event of a power failure rather than using the two 13kV primary circuits on Union Avenue, Substation 8D Holbrook. The Holtsville plant receives primary electric power source from LIPA which is supplied from the 69kV system through Substation "LNG Plant - 8KR," at the northwest corner of the plant property. The alternate power source which is supplied from two 13kV primary circuits on Union Avenue, Substation 8D Holbrook. The emergency generator will be controlled and monitored from the Control Room HMI and will be sized based on the power required for starting and running of all the loads.

Safety PLC for associated trips for Gas and Fire Detection

The Holtsville LNG plant needs to update the programmable logic controller and digital computer used for the Gas and Fire Detection Systems to improve safety of plant operations. A newer PLC will allow for greater flexibility of digital and analog inputs and outputs from these devices.

Storage Building

The Holtsville LNG Operations Team has outgrown the existing storage area and needs additional space to store equipment, tools, spare parts and other miscellaneous materials needed to operate and maintain the plant.

Upgrade APACS System for Liquefier

The Holtsville Liquefaction System was put into service in 2001 and part of this system is called the APACS System, which is the central processing unit of the liquefier. Due to the age and limited ability to get replacement parts it is time to upgrade the system to a newer central processing unit. The replacement of the APACS System ensures the continued reliability of the of the Holtsville liquefier system.

Tank Painting - Complete step replacement

The Holtsville LNG Tank needs to be repainted by a qualified vendor that will perform surface preparation, prime and apply a final coat to the tank surface in accordance with painting specifications of carbon steel tanks. The qualified vendor will be reviewing all weathered areas to ensure the proper re-application of a primer and final coat are performed per coating specifications. This work will also include the erection of scaffolding equipment and proper air monitoring to ensure the safety of those working on and around this project. In advance of the Holtsville tank repainting project, it is necessary to replace the steps that are attached to the roof of the tank. The current configuration of the tank steps do not allow the free flow of rain through them that has led to some corrosion. The steps require redesign to allow the free flow of moisture through the steps to prevent this recurring maintenance issue that needs to be addressed each year.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	8,907	8,000	3,458

Customer Benefit:

This plant is a critical component of the Company's gas supply portfolio and gas operating network. Holtsville LNG can provide as much as 9 percent of KEDLI's peak day demand. The key driver for this project is to ensure the continued, safe operation and availability of the Holtsville LNG as a natural gas supply point into the NY distribution system. This plant is critical to the NY gas supply portfolio over the next 10 years. KEDLI's firm gas customers benefit from the availability of this less-expensive peaking supply because gas is liquefied during the summer and stored for use in the winter.

The Holtsville LNG plant has played a significant role in KEDLI's ability to supply unprecedented volumes of gas during record breaking cold spells over the past two winters. The plants inability to vaporize during peak winter weather conditions may result in the unplanned interruption of a significant number of gas customers.

Alternatives

Alternative 1: Portable CNG

The only comparable alternative to LNG is portable CNG. The Company currently utilizes portable CNG skids to manage low pressure conditions on the gas system. This is effective for boosting pressures at specific low points on the system. This alternative is rejected because replacing Holtsville LNG with portable CNG is not feasible due to the number of units and CNG tanks required to match Holtsville's output.

Alternative 2: Do nothing.

If the LNG Special Projects Program investments are not made, there is a risk that the Holtsville LNG resources will become unavailable during the heating season. This could require the purchase of higher cost city gate supplies (if available) and may result in financial penalties from pipelines if the Company cannot adhere to operational flow orders and other contractual requirements. The lack of LNG Plant availability could lead to customer outages during heating season resulting in a negative customer impact.

Program Title: Holtsville LNG Tank Modernization Project – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The Project scope includes the following:

- Replace all of the inner tank penetrations below the liquid level with new piping and two internal tank pumps.
- Reduce the design spill through the elimination of inner tank penetrations below the liquid level.
- Make minor piping changes to provide new locations for the existing tank fill and pump recycle lines.
- Modify the level gauging systems on the tank to bring them up to current code by:
    - Adding a stilling well to the existing servo motor operated level gauge
    - Adding a second level gage that is maintainable without taking the tank out of service
    - Adding an independent high level switch and controls to automatically close the fill valve
    - Add new temperature elements to measure the temperature of LNG and the inner tank during cool down (code required)

Program Justification:

This project is necessary to ensure the long term safety and reliability of the LNG tank. Prior studies of LNG tanks of this age and style have recommended that the tank be taken out of service temporarily to perform tank entry to install new in-tank LNG withdrawal pumps and to eliminate the existing internal valves and bottom penetration withdrawal nozzles.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	5,250	13,563	11,813

Customer Benefit:

This plant is a critical component of the Company's gas supply portfolio and gas operating network. Holtsville LNG can provide as much as 9 percent of KEDLI's peak day demand. The key driver for this project is to ensure the continued, safe operation and availability of the Holtsville LNG as a natural gas supply point into the New York distribution system. This plant is critical to the New York gas supply portfolio over the next 10 years. KEDLI's firm gas customers benefit from the availability of this less-expensive peaking supply because gas is liquefied during the summer and stored for use in the winter.

The Holtsville LNG plant has played a significant role in KEDLI's ability to supply unprecedented volumes of gas during record breaking cold spells over the past two winters. The plant's inability to vaporize during peak winter weather conditions may result in the unplanned interruption of a significant number of gas customers.

Alternatives

Alternative 1: Portable CNG

The only comparable alternative to LNG is portable CNG. The Company currently utilizes portable CNG skids to manage low pressure conditions on the gas system. This is effective for boosting pressures at specific low points on the system. This alternative is rejected because replacing Holtsville LNG with portable CNG is not feasible due to the number of units and CNG tanks required to match Holtsville's output.

Alternative 2: Do nothing.

If upgrades to the LNG tank are not made, there is a risk that the Holtsville LNG resources will become unavailable during the heating season. This would require the purchase of higher cost city gate supplies (if available) and may result in financial penalties from pipelines if the Company cannot adhere to operational flow orders and other contractual requirements. The lack of LNG Plant availability could lead to customer outages during heating season resulting in a negative customer impact.

Program Title: Northwest Nassau Project – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This project addresses three aging natural gas transmission lines in northwestern Nassau County. This project would replace 8.8 miles of transmission main, install 5.6 miles of new pipe, down rate 9.1 miles of pipe and construct two new regulator stations in response to gaps in records and concerns regarding the materials originally used to construct existing mains 1, 8 and 16. The project is planned over five years in three phases:

Phase One (FY 2017-19):

- Install approximately 1.7 miles of 24” 350 psig main on the LIE North Service Road from Red Ground Road to Jefferson Avenue. (FY18)
- Install two 350 psig to 233 psig regulator stations – one at Red Ground Road and LIE North service Road and the other at Jefferson Avenue and LIE North Service Road. (FY19)
- Down rate segments of Gas Main 1 and segments of Gas Mains 8/16 to 233 psig from LIE to Glenwood and possible modification SL-39 in Roslyn for lower minimum inlet pressures. (FY19)

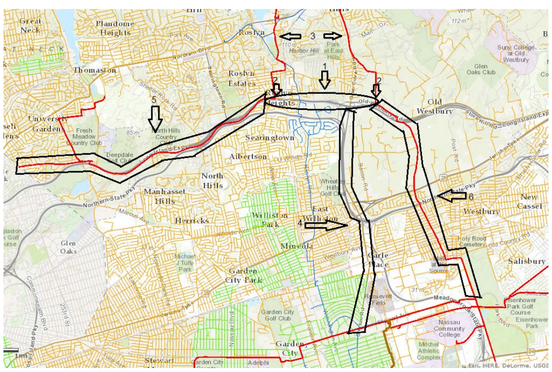
Phase Two (FY 2019-20):

- Install approximately 3.9 miles of 24” 350 psig main. Proposed route on Clinton Avenue/Glen Cove Road from Stewart Ave to the LIE
- Downrate the existing 16” main from 350 psig and operate at 60 psig, tie into the local distribution system and certify as a 124/60 main

Phase Three (FY 2022-23):

- Relay approximately 4.8 miles of Gas Main 1 along the LIE From Lake Success to Roslyn Heights with 20” or 24” 350 psig main. Operate the existing 16” main at 60 psig - certify as a 124/60 main.
- There are also some additional 60 psig distribution system reinforcements that will not be required as a result of the down ratings to 124/60.
- Any future supply connection into Glenwood Landing would require 4 to 4.5 miles of new 24” 350 psig main from there to the LIE and is not identified above. That has been identified as its own line item in the Cap by Category Report in FY22.

The project scope is shown below:



Project Justification

In response to the events of San Bruno and PHMSA's integrity verification program (IVP) recommendations, the Company has undertaken a review of historical records to substantiate the MAOP of its gas transmission mains, as well as a review of each pipe's operating history. The results of this review indicate the replacement and down rating of Gas Mains 1, 8, and 16 will mitigate system risks, increase reliability and position the gas transmission system to accommodate a future supply point in that area. For example, the system reinforcement and reliability review revealed that that system pressure along Gas Main 1 under design day conditions will drop below minimum pressures feeding into the bi-directional meter station at Lake Success under forecasted FY18 loads. The project will ensure continuous service to all customers on the KEDLI gas distribution network in Northwestern Nassau County during periods of forecasted peak demand.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	34,000	60,000	53,750

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system and provide for system growth, which will improve public safety and the reliability of the gas delivery system. By downrating existing pipelines where possible to reinforce the distribution system rather than replacing these pipelines, this project also results in avoidance of future replacement work.

Alternatives

Alternative 1: Re-test each pipeline segment.

As an alternative, KEDNY could establish properties and re-hydro test each pipeline segment. This alternative would leave in place pipe that is over 50-years old operating at a stress level of 20 percent and greater. This option is rejected because it does not achieve the Company's risk reduction goals.

Alternative 2: Do Nothing.

This alternative is rejected because the Company's review indicates that existing facilities in this area may not be sufficient to meet forecasted peak demand in future years. Pending regulations will require establishment of complete records and Engineering Critical Assessments or ECAs.

Supporting References:

Title 49 CFR Part 192.901- 192.951

Program Title: Automatic Meter Reading Installation /Maintenance – KEDLI

Spending Rationale: ☐ Mandated ☐ Growth

☐ Reliability ☒ Non-Infrastructure

Brief Description:

This program provides for the purchase and installation of Automatic Meter Reading (AMR) equipment in KEDLI's service area. This project will be completed in FY 2017. KEDLI is implementing AMRs at this time because it no longer has access to the meter reading workforce that previously read both electric and gas meters on Long Island. Absent initiating the AMR program, KEDLI would have been required to hire additional employees or contractors to manually read the Company's gas meters.

In 2013, KEDLI began a program to install a Mobile Based AMR system, and has currently installed 555,000 of 593,000 total units (93.5% of the service area). This program supports the continued purchase of AMR equipment for: (i) the remaining non-AMR meters that were not converted as part of the 2013 project due to meter access problems or other issues (10% of the service area), (ii) repairs/replacements to existing AMR meters, and (iii) new meter installations.

Program Justification:

Continuation of the AMR Installation/Maintenance program will increase meter reading accuracy, reduce the number of estimated bills, and reduce the cost of meter reading.

Total Project Cost Breakdown:

$000	CY17	CY18	CY19
CAPEX	835	855	873

Customer Benefit:

The installation of AMRs will decrease the incidence of both estimated bills and erroneous bills that require cancellation and rebilling. Additionally, KEDLI's AMR installation will enhance storm resiliency and improve customer service. In the aftermath of major storms, such as Superstorm Sandy, meters are not read because of the need to use the meter reading workforce to assist in storm recovery. With AMRs, the Company can confirm remotely if the customer is burning gas. Also, the AMR devices can store forty days of hourly data, which will assist in billing following an extended outage.

Alternatives

Alternative 1: Do Nothing

This option is rejected as it will result in inefficiencies by increasing the number of estimated customer bills, and increasing meter reading costs by requiring manual meter reading.

Program Title: Purchase of Miscellaneous Capital Tools & Equipment – KEDLI

Company Name: KeySpan Gas East Corporation d/b/a National Grid

Spending Rationale: ☐ Mandated ☐ Growth

☐ Reliability ☒ Non-Infrastructure

Brief Description:

KEDLI's Purchase of Miscellaneous Capital Tools and Equipment program covers tools that are not used for specific projects. These items relate to safety (*e.g.*, mechanized maintenance of traffic devices, worker safety enhancements), emissions reduction (*e.g.*, apparatus to minimize emissions through natural gas drawdown operations), support of new, emerging and on-going technologies (*e.g.*, capital spares and parts for trenchless and keyhole technologies) and the innovative applications that will lead to improved operations. These items support the safety of our employees, our customers and the general public. The items provide cost efficiencies across multiple mandated programs, support commitments to customer needs and expectations, and will allow the potential increase of productivity for on-going day-to-day operations of the gas business unit.

Program Justification:

Company policy capitalizes general tool and/or equipment purchases subject to predetermined minimal dollar thresholds ($500 for KEDLI). Such general equipment includes tooling (hand, power, pneumatic, hydraulic), specialty equipment, PPE, office machines, electronic data processing equipment and software applications, shop and garage equipment and communications. The Purchase Miscellaneous Capital Tools and Equipment program captures the items that are not used for specific projects but rather support the safe, efficient and on-going day-to-day operations of the gas business unit. Purchase of Miscellaneous Capital Tools and Equipment utilize project numbers that are budgeted based on historical funding due to the inability to associate this equipment with any one specific project.

Program Budget Methodology:

The Purchase of Miscellaneous Capital Tools and Equipment budget reflects historical budgets, increases in conjunction with additional pipe replacement of mandated programs (*e.g.*, Leak Prone Pipe replacement), as well as cost of inflation budget increases. The volume of Public safety equipment, road traffic plates and sheeting systems are just a few examples of additional tools and equipment needed to support mandated program increases.

Total Program Cost:

$000	CY 17	CY 18	CY 19
CapEx	1,789	1,953	2,129

Customer Benefit:

- Improved public safety due to mechanized maintenance of traffic devices and public safety enhancements.
- Noise reduction enhancements with new technology tooling.
- Productivity increases and potential unit cost reductions.
- Compliance with federal and state code requirements including new US Department of Transportation (USDOT).
- Reduction of methane emissions and reduction of greenhouse gases.

Alternatives:

Alternative 1: Reduce Request

Reducing the budget line item is not recommended because funds allocated here drive process changes that support new initiatives and productivity improvements throughout the Gas distribution organization. It will potentially drive a downturn in safety for the company, employees, customers and general public.

Alternative 2: Do Nothing

It will force the spending of these items to be allocated to specific projects and mandated programs resulting in inconsistent unit costs, excessive tool ordering (lack of controls) and jeopardize safety for the company, employees, customers and general public.

Exhibit__ (GIOP-5)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-5)

O&M Expenditures: Rate Year and Data Years

GIOP-5 KEDLI Incremental O&M CY17-CY19

			CY17			CY18			CY19		
Company	Testimony Category	Program/Position	Labor	Non-labor	Total	Labor	Non-labor	Total	Labor	Non-labor	Total
KEDLI	Increased OPEX Workload	CMS- Director	$ 69,368	$ -	$ 69,368	$ 71,449	$ -	$ 71,449	$ 73,593	$ -	$ 73,593
		CMS- Field Collections	$ 94,270	$ -	$ 94,270	$ 97,120	$ -	$ 97,120	$ 100,055	$ -	$ 100,055
		CMS- Gas Leak Investigations	$ 55,622	$ -	$ 55,622	$ 57,303	$ -	$ 57,303	$ 59,035	$ -	$ 59,035
		CMS- Meter Oriented Services	$ 305,920	$ -	$ 305,920	$ 315,166	$ -	$ 315,166	$ 324,692	$ -	$ 324,692
		CMS- Meter/Regulator	$ 27,811	$ -	$ 27,811	$ 28,651	$ -	$ 28,651	$ 29,517	$ -	$ 29,517
		CMS- Supervisor	$ 78,436	$ -	$ 78,436	$ 80,789	$ -	$ 80,789	$ 83,213	$ -	$ 83,213
		Field Operations- Pressure Testing	$ -	$ 27,766	$ 27,766	$ -	$ 27,766	$ 27,766	$ -	$ 27,766	$ 27,766
		Field Operations- Type 3 Leaks	$ 277,741	$ -	$ 277,741	$ 286,136	$ -	$ 286,136	$ 294,785	$ -	$ 294,785
		Field Operations- Type 3 Leaks	$ -	$ 338,492	$ 338,492	$ -	$ 338,492	$ 338,492	$ -	$ 338,492	$ 338,492
		I&R- Techs	$ 246,079	$ -	$ 246,079	$ 253,517	$ -	$ 253,517	$ 261,180	$ -	$ 261,180
		I&R- Utility/Other Increases	$ -	$ 148,600	$ 148,600	$ -	$ 148,600	$ 148,600	$ -	$ 148,600	$ 148,600
	Increased OPEX Workload Total		**$ 1,155,247**	**$ 514,858**	**$ 1,670,105**	**$ 1,190,131**	**$ 514,858**	**$ 1,704,989**	**$ 1,226,069**	**$ 514,858**	**$ 1,740,927**
	OPEX related to CAPEX	Complex Construction- Contractor Oversight	$ 38,757	$ -	$ 38,757	$ 39,919	$ -	$ 39,919	$ 41,117	$ -	$ 41,117
		Complex Construction- Expenses	$ -	$ 2,431	$ 2,431	$ -	$ 2,431	$ 2,431	$ -	$ 2,431	$ 2,431
		Construction- D&R	$ -	$ 5,111,747	$ 5,111,747	$ -	$ 6,205,071	$ 6,205,071	$ -	$ 6,513,048	$ 6,513,048
		Construction- Main Replacement- Construction Inspectors	$ 50,108	$ -	$ 50,108	$ 51,622	$ -	$ 51,622	$ 53,182	$ -	$ 53,182
		Construction- Main Replacement- Engineer	$ 24,808	$ -	$ 24,808	$ 25,553	$ -	$ 25,553	$ 26,319	$ -	$ 26,319
		Construction- Main Replacement- Supervisor	$ 9,228	$ -	$ 9,228	$ 9,505	$ -	$ 9,505	$ 9,790	$ -	$ 9,790
		Construction- Permit/Summons/Paving Coordinator	$ 17,850	$ -	$ 17,850	$ 18,386	$ -	$ 18,386	$ 18,937	$ -	$ 18,937
		Contract Strategy & Administration- Program Manager	$ 12,589	$ -	$ 12,589	$ 12,966	$ -	$ 12,966	$ 13,355	$ -	$ 13,355
		Corrosion- Techs	$ 17,786	$ -	$ 17,786	$ 18,323	$ -	$ 18,323	$ 18,877	$ -	$ 18,877
		Damage Prevention- Markout Tickets	$ -	$ 193,687	$ 193,687	$ -	$ 193,687	$ 193,687	$ -	$ 193,687	$ 193,687
		Damage Prevention- Supervisor	$ 92,278	$ -	$ 92,278	$ 95,046	$ -	$ 95,046	$ 97,897	$ -	$ 97,897
		Gas Control- Control Room Operator	$ 293,442	$ -	$ 293,442	$ 302,246	$ -	$ 302,246	$ 311,313	$ -	$ 311,313
		Gas Control- SOP Coordinator	$ 151,545	$ -	$ 151,545	$ 156,092	$ -	$ 156,092	$ 160,774	$ -	$ 160,774
		Gas Distribution Engineering- Engineer	$ 78,560	$ -	$ 78,560	$ 80,916	$ -	$ 80,916	$ 83,344	$ -	$ 83,344
		Investment Planning- In Year Budget- Program Manager	$ 8,992	$ -	$ 8,992	$ 9,262	$ -	$ 9,262	$ 9,540	$ -	$ 9,540
		Investment Planning- Rate Case- Program Manager	$ 17,984	$ -	$ 17,984	$ 18,523	$ -	$ 18,523	$ 19,079	$ -	$ 19,079
		Investment Planning- Work Order Closeout- Clerks	$ 11,365	$ -	$ 11,365	$ 11,709	$ -	$ 11,709	$ 12,063	$ -	$ 12,063
		Investment Planning- Work Order Closeout- Inspectors	$ 16,703	$ -	$ 16,703	$ 17,207	$ -	$ 17,207	$ 17,727	$ -	$ 17,727
		Investment Planning- Work Order Closeout- Lead Program Manager	$ 9,932	$ -	$ 9,932	$ 10,230	$ -	$ 10,230	$ 10,537	$ -	$ 10,537
		Investment Planning- Work Order Closeout- Manager	$ 12,909	$ -	$ 12,909	$ 13,297	$ -	$ 13,297	$ 13,696	$ -	$ 13,696
		Investment Planning- Work Order Closeout- Program Manager	$ 17,984	$ -	$ 17,984	$ 18,523	$ -	$ 18,523	$ 19,079	$ -	$ 19,079
		LNG- Field Engineer	$ 82,694	$ -	$ 82,694	$ 85,175	$ -	$ 85,175	$ 87,730	$ -	$ 87,730
		LNG- Mechanics	$ 227,685	$ -	$ 227,685	$ 234,566	$ -	$ 234,566	$ 241,656	$ -	$ 241,656
		LNG- Techs	$ 205,066	$ -	$ 205,066	$ 211,264	$ -	$ 211,264	$ 217,650	$ -	$ 217,650
		Operations Support- ESRI Analyst	$ 34,083	$ -	$ 34,083	$ 35,105	$ -	$ 35,105	$ 36,158	$ -	$ 36,158
		Operations Support- Manager	$ 12,909	$ -	$ 12,909	$ 13,297	$ -	$ 13,297	$ 13,696	$ -	$ 13,696
		Operations Support- Mappers	$ 125,068	$ -	$ 125,068	$ 128,848	$ -	$ 128,848	$ 132,742	$ -	$ 132,742
		Operations Support- Permit Clerks	$ 22,730	$ -	$ 22,730	$ 23,417	$ -	$ 23,417	$ 24,125	$ -	$ 24,125
		Project Controls- Analyst	$ 12,781	$ -	$ 12,781	$ 13,165	$ -	$ 13,165	$ 13,559	$ -	$ 13,559
		Project Controls- Expenses	$ -	$ 765	$ 765	$ -	$ 765	$ 765	$ -	$ 765	$ 765
		Project Management- Expenses	$ -	$ 1,566	$ 1,566	$ -	$ 3,132	$ 3,132	$ -	$ 1,566	$ 1,566
		Project Management- Project Manager	$ 33,720	$ -	$ 33,720	$ 34,731	$ -	$ 34,731	$ 35,773	$ -	$ 35,773
		Resource Planning- Analyst	$ 25,562	$ -	$ 25,562	$ 26,329	$ -	$ 26,329	$ 27,119	$ -	$ 27,119
		Resource Planning- Coordinator	$ 8,925	$ -	$ 8,925	$ 9,193	$ -	$ 9,193	$ 9,469	$ -	$ 9,469
		Resource Planning- Expenses	$ -	$ 15,113	$ 15,113	$ -	$ 15,113	$ 15,113	$ -	$ 15,113	$ 15,113
		Resource Planning- Program Manager	$ 31,472	$ -	$ 31,472	$ 32,416	$ -	$ 32,416	$ 33,388	$ -	$ 33,388
		Resource Planning- Report Analyst	$ 25,562	$ -	$ 25,562	$ 26,329	$ -	$ 26,329	$ 27,119	$ -	$ 27,119
		Resource Planning- Work Package Reviewer- Program Manager	$ 8,992	$ -	$ 8,992	$ 9,262	$ -	$ 9,262	$ 9,540	$ -	$ 9,540
		Gas Long Term Planning- Engineer	$ 66,155	$ -	$ 66,155	$ 68,140	$ -	$ 68,140	$ 70,184	$ -	$ 70,184
		Gas Long Term Planning- Engineer	$ -	$ 18,700	$ 18,700	$ -	$ 18,700	$ 18,700	$ -	$ 18,700	$ 18,700
		Pressure Regulation Engineering- Engineer	$ 33,078	$ -	$ 33,078	$ 34,070	$ -	$ 34,070	$ 35,092	$ -	$ 35,092
		Gas Estimating Office of Excellence- Estimator	$ 12,404	$ -	$ 12,404	$ 12,776	$ -	$ 12,776	$ 13,160	$ -	$ 13,160
		Gas Estimating Office of Excellence- Manager	$ 3,227	$ -	$ 3,227	$ 3,324	$ -	$ 3,324	$ 3,424	$ -	$ 3,424
		Gas Operations Engineering	$ 66,155	$ -	$ 66,155	$ 68,140	$ -	$ 68,140	$ 70,184	$ -	$ 70,184
		Gas Project Eng & Design- Designer	$ 24,808	$ -	$ 24,808	$ 25,553	$ -	$ 25,553	$ 26,319	$ -	$ 26,319
		Gas Project Eng & Design- Engineer	$ 82,694	$ -	$ 82,694	$ 85,175	$ -	$ 85,175	$ 87,730	$ -	$ 87,730

GIOP-5 KEDLI Incremental O&M CY17-CY19

			CY17			CY18			CY19		
Company	**Testimony Category**	**Program/Position**	**Labor**	**Non-labor**	**Total**	**Labor**	**Non-labor**	**Total**	**Labor**	**Non-labor**	**Total**
		Main & Service Replacement- Engineer	$ 12,404	$ -	$ 12,404	$ 12,776	$ -	$ 12,776	$ 13,160	$ -	$ 13,160
	OPEX related to CAPEX Total		**$ 2,040,994**	**$ 5,344,010**	**$ 7,385,004**	**$ 2,102,376**	**$ 6,438,899**	**$ 8,541,275**	**$ 2,165,604**	**$ 6,745,310**	**$ 8,910,915**
					$ 2,273,256						
	Other OPEX	CMS- Investigations	$ (20,858)	$ -	$ (20,858)	$ (21,489)	$ -	$ (21,489)	$ (22,138)	$ -	$ (22,138)
		CMS- Other Emergency	$ (6,953)	$ -	$ (6,953)	$ (7,163)	$ -	$ (7,163)	$ (7,379)	$ -	$ (7,379)
		CMS- Related to Meter Reading	$ (458,879)	$ -	$ (458,879)	$ (472,749)	$ -	$ (472,749)	$ (487,038)	$ -	$ (487,038)
		CMS- Shift Work	$ (69,527)	$ -	$ (69,527)	$ (71,629)	$ -	$ (71,629)	$ (73,794)	$ -	$ (73,794)
		Gas Control- Service Contract	$ -	$ 88,000	$ 88,000	$ -	$ 91,000	$ 91,000	$ -	$ 110,000	$ 110,000
	Other OPEX Total		**$ (556,217)**	**$ 88,000**	**$ (468,217)**	**$ (573,029)**	**$ 91,000**	**$ (482,029)**	**$ (590,349)**	**$ 110,000**	**$ (480,349)**
	Safety Programs	CMS- Invactive Accounts	$ 146,007	$ -	$ 146,007	$ 150,420	$ -	$ 150,420	$ 154,967	$ -	$ 154,967
		Construction- Plastic Fusion New	$ -	$ 130,000	$ 130,000	$ -	$ 130,000	$ 130,000	$ -	$ 130,000	$ 130,000
		Damage Prevention- Latent Damage- Advisors	$ -	$ 246,288	$ 246,288	$ -	$ 246,288	$ 246,288	$ -	$ 246,288	$ 246,288
		Field Operations- Inactive Accounts	$ 140,930	$ -	$ 140,930	$ 145,190	$ -	$ 145,190	$ 149,578	$ -	$ 149,578
		Field Operations- Inactive Accounts	$ -	$ 63,709	$ 63,709	$ -	$ 63,709	$ 63,709	$ -	$ 63,709	$ 63,709
		Gas Distribution Engineering- Latent Damage	$ -	$ 2,000,000	$ 2,000,000	$ -	$ 2,000,000	$ 2,000,000	$ -	$ 2,000,000	$ 2,000,000
		Gas Pipeline and Safety Compliance- 3rd Paty Independent Compliance Assessments	$ -	$ 243,000	$ 243,000	$ -	$ 243,000	$ 243,000	$ -	$ 243,000	$ 243,000
		Gas Pipeline and Safety Compliance- Compliance Analyst	$ 298,225	$ -	$ 298,225	$ 307,172	$ -	$ 307,172	$ 316,387	$ -	$ 316,387
		Gas Pipeline and Safety Compliance- Public Awareness	$ -	$ 820,000	$ 820,000	$ -	$ 820,000	$ 820,000	$ -	$ 820,000	$ 820,000
		Gas Pipeline and Safety Compliance- QA/QC Inspectors	$ 83,604	$ -	$ 83,604	$ 86,112	$ -	$ 86,112	$ 88,696	$ -	$ 88,696
		Pressure Regulation Engineering- Transmission Station Integrity Testing	$ -	$ 208,300	$ 208,300	$ -	$ 208,300	$ 208,300	$ -	$ 208,300	$ 208,300
		Process Safety- Analyst	$ 17,041	$ -	$ 17,041	$ 17,553	$ -	$ 17,553	$ 18,079	$ -	$ 18,079
		Process Safety- Director	$ 32,644	$ -	$ 32,644	$ 33,623	$ -	$ 33,623	$ 34,632	$ -	$ 34,632
		Process Safety- Engineering	$ 33,078	$ -	$ 33,078	$ 34,070	$ -	$ 34,070	$ 35,092	$ -	$ 35,092
		Process Safety- Lead Program Manager	$ 39,727	$ -	$ 39,727	$ 40,919	$ -	$ 40,919	$ 42,146	$ -	$ 42,146
	Safety Programs Total		**$ 791,257**	**$ 3,711,297**	**$ 4,502,554**	**$ 815,059**	**$ 3,711,297**	**$ 4,526,356**	**$ 839,577**	**$ 3,711,297**	**$ 4,550,874**
KEDLI Total			**$ 3,431,281**	**$ 9,658,165**	**$ 13,089,445**	**$ 3,534,537**	**$ 10,756,054**	**$ 14,290,591**	**$ 3,640,901**	**$ 11,081,465**	**$ 14,722,367**

Exhibit__ (GIOP-6)

Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-6)

Incremental Full Time Equivalent Positions by Function in the Rate Year
and Data Years

GIOP-6 KEDLI Incremental FTEs CY17-CY19

Company	L05 Receiving Cost Center	CY17	CY18	CY19
KEDLI	110-Complex Project Mgmt	3.5		
	110-Contract Management	5.6		
	110-Gas Control	4.5		
	110-LNG/Propane-NY Downstate	6.0		
	110-Ops Support Services	11.5	2.0	1.0
	110-Program Management	7.5		
	120-Customer Meter Svcs	2.6		
	120-Gas Pipeline Safety & Compliance	7.5		
	120-Maint & Const-NY Gas	22.0	8.0	9.0
	130- Gas Estimating Office of Excellence	3.5		
	130-Corrosion Control	2.0		
	130-Gas Distribution Engineering	1.0		
	130-Gas Investment Planning	11.0		
	130-Gas Long Term Planning	1.0		
	130-Gas Operations Engineering	1.0		
	130-Gas Project Eng & Design	13.0		
	130-Main & Service Replacement	3.0		
	130-Pressure Regulation Engineering	4.0	-	-
KEDLI Total		**110.2**	**10.0**	**10.0**