Thomas R. Teehan
Senior Counsel

August 18, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
<u>Response to Data Requests</u>

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to data requests issued by the Division, the Commission and the Navy in the above-referenced proceeding. Attached is a listing of the data requests issued to date and designating the responses included in this filing in bold.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4065 Service List

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

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically submitted, hand delivered and mailed to the individuals listed below.

___/S/________________________________ August 18, 2009
Linda Samuelian Date

National Grid (NGrid) – Request for Change in Electric Distribution Rates
Docket No. 4065 - Service List as of 7/22/09

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The Narragansett Electric Company d/b/a National Grid					
Docket 4065					
Discovery Log					
As of: August 18, 2009					
[C-denotes confidentiality is being sought]					
Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-1	Filed	6/26/2009	O'Brien		Attachments COMM 1-1-3, 1-1-4, 1-1-5, 1-1-7, 1-1-8, 1-1-9 **BULK**
COMM 1-2	Filed	6/26/2009	O'Brien		Attachments COMM 1-2 A-D
COMM 1-3	Filed	6/26/2009	Dinkel		Attachments COMM 1-3 A-B **BULK**
COMM 1-4	Filed	6/26/2009	O'Brien		
COMM 1-5	Filed	7/22/2009	O'Brien/Dinkel		Attachments COMM 1-5 (1-3)
COMM 1-6	Filed	6/26/2009	Dinkel	C-attachment	Attachments COMM 1-6-1 & 1-6-2 **BULK**
COMM 1-7	Filed	6/26/2009	O'Brien		Attachment COMM 1-7
COMM 1-8	Filed	6/26/2009	Dinkel		Attachments COMM 1-8 (A-D) **BULK**
COMM 1-9	Filed	6/26/2009	Dinkel	C-attachment	Attahments COMM 1-9 (1-11) **BULK**
COMM 1-10	Filed	6/26/2009	Dinkel		Attachment COMM 1-10 (hard copy only) **BULK**
COMM 1-11	Filed	6/26/2009	O'Brien		
COMM 1-12	Filed	7/1/2009	Dinkel/Morrissey		Attachments COMM 1-12 (1-2)
COMM 1-13	Filed	6/26/2009	Dinkel		Attachment COMM 1-13
COMM 1-14	Filed	6/26/2009	Dinkel		Attachment COMM 1-14
COMM 1-15	Filed	6/26/2009	Dinkel		Attachment COMM 1-15
COMM 1-16	Filed	6/26/2009	O'Brien		Attachments COMM 1-16 (1-12)
COMM 1-17	Filed	7/6/2009	Pettigrew		
COMM 1-18	Filed	7/14/2009	Pettigrew		Attachments COMM 1-18-1, 1-18-2, 1-18-3, 1-18-4(a) - (d) **Bulk**
COMM 1-19	Filed	8/11/2009	O'Brien		Attachment COMM 1-19
COMM 1-20	Filed	6/26/2009	O'Brien		
COMM 1-21	Filed	6/26/2009	O'Brien		Attachments COMM 1-21 (1-4)
COMM 1-22	Filed	6/26/2009	O'Brien		Attachments COMM 1-22 (1-2)
COMM 1-23	Filed	6/26/2009	O'Brien		Attachments COMM 1-23 (1-2)
COMM 1-24	Filed	6/26/2009	O'Brien		Attachment COMM 1-24
COMM 1-25	Filed	6/26/2009	O'Brien		Attachments COMM 1-25 (1-14) **BULK**
COMM 1-25 (supp.)	Filed	8/11/2009	O'Brien		Attachments COMM 1-25 (1-3)
COMM 1-26	Filed	6/26/2009	O'Brien		Attachment COMM 1-26
COMM 1-27	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachments COMM 1-27 (1-3) **BULK**
COMM 1-28	Filed	7/6/2009	O'Brien		Attachment COMM 1-28
COMM 1-29	Filed	6/26/2009	O'Brien		
COMM 1-30	Filed	6/26/2009	O'Brien		
COMM 1-31	Filed	6/26/2009	King		
COMM 1-32	Filed	6/26/2009	O'Brien		Attachment COMM 1-32
COMM 1-33	Filed	6/26/2009	O'Brien		Attachment COMM 1-33 (1-3) **BULK**
COMM 1-34	Filed	6/26/2009	Dowd		Attachments COMM 1-34 (1-2) **BULK**
COMM 1-35	Filed	6/26/2009	Dowd		Attachment COMM 1-35 **BULK**
COMM 1-36	Filed	6/26/2009	Dowd		Attachment DIV 2-1 (electronic only)
COMM 1-37	Filed	6/26/2009	O'Brien		Attachment COMM 1-37
COMM 1-38	Filed	6/26/2009	O'Brien		Attachment COMM 1-38
COMM 1-39	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment COMM 1-39
COMM 1-40	Filed	6/26/2009	Dowd		Attachment COMM 1-40
COMM 1-41	Filed	6/26/2009	Dowd		Attachment COMM 1-41
COMM 1-42	Filed	6/26/2009	Dowd		Attachment COMM 1-42
COMM 1-43	Filed	6/26/2009	Dowd		Attachment COMM 1-43
COMM 1-44	Filed	6/26/2009	Dowd		Attachment COMM 1-44

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Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-45	Filed	6/26/2009	O'Brien		Attachment COMM 1-45
COMM 1-46	Filed	6/26/2009	Dowd		
COMM 1-47	Filed	6/26/2009	Dowd		Attachments COMM 1-47 (1-3) **BULK**
COMM 1-48 (Part 1)	Filed	7/1/2009	Dowd		Attachment COMM 1-48
COMM 1-48 (Parts 2-5)	Filed	6/26/2009	O'Brien		
COMM 1-49	Filed	6/26/2009	O'Brien		Attachments COMM 1-49 (1-5)
COMM 1-50	Filed	6/26/2009	Dowd		Attachments COMM 1-50 (1-38) **BULK**
COMM 1-51	Filed	6/26/2009	Dowd		
COMM 1-52	Filed	6/26/2009	Dowd		Attachment COMM 1-52
COMM 1-53	Filed	6/26/2009	Dowd		Attachment COMM 1-53
COMM 1-54	Filed	6/26/2009	O'Brien		Attachments COMM 1-54 (1-2)
COMM 1-55	Filed	7/14/2009	O'Brien		Attachment COMM 1-55
COMM 1-56	Filed	6/26/2009	O'Brien		
COMM 1-57	Filed	6/26/2009	O'Brien		Attachment COMM 1-57
COMM 1-58	Filed	6/26/2009	O'Brien		Attachment DIV 3-11 (PDF and working excel)
COMM 1-59	Filed	6/26/2009	O'Brien		Attachment COMM 1-59
COMM 1-60	Filed	7/1/2009	O'Brien		Attachment COMM 1-60 (A-B)
COMM 1-61	Filed	6/26/2009	Dowd		
COMM 1-62	Filed	6/26/2009	O'Brien		Attachments COMM 1-62 (1-2)
COMM 1-63	Filed	8/11/2009	O'Brien		Attachments COMM 1-63 (A-F) A-C EXCEL FILES D & E **BULK** (hard copy only)
COMM 1-64	Filed	6/26/2009	O'Brien		Attachment COMM 1-64
COMM 1-65	Filed	6/26/2009	O'Brien		Attachments COMM 1-65
COMM 1-66	Filed	6/26/2009	O'Brien		Attachments COMM 1-66 (1-2)
COMM 1-67	Filed	6/26/2009	O'Brien		Attachments COMM 1-67 (1-3)
COMM 1-68	Filed	6/26/2009	Wynter		Attachment COMM 1-68
COMM 1-69	Filed	6/26/2009	Wynter		Attachment COMM 1-69
COMM 1-70	Filed	6/26/2009	Wynter		
COMM 1-71	Filed	6/26/2009	O'Brien		Attachments DIV 4-1 (1-2) **BULK**
COMM 1-72	Pending				
COMM 1-73	Filed	6/26/2009	O'Brien		Attachments COMM 1-73 (1-2)
COMM 1-74	Filed	7/6/2009	O'Brien		
COMM 1-75	Filed	6/26/2009	O'Brien		
COMM 1-76	Filed	7/1/2009	O'Brien		Attachment COMM 1-76
COMM 1-77	Pending				
COMM 1-78	Filed	7/14/2009	O'Brien	C-attachment	
COMM 1-79	Filed	6/26/2009	O'Brien		Attachment COMM 1-79
COMM 1-80	Filed	8/3/2009	O'Brien		
COMM 1-81	Filed	8/3/2009	O'Brien		
COMM 1-82	Filed	7/1/2009	O'Brien		
COMM 1-83	Filed	6/26/2009	O'Brien		Attachments COMM 1-83
COMM 1-84	Filed	6/26/2009	O'Brien		Attachment COMM 1-84
COMM 1-85	Filed	6/26/2009	O'Brien		Attachment COMM 1-85
COMM 1-86	Filed	6/26/2009	O'Brien		
COMM 1-87	Filed	6/26/2009	O'Brien		
COMM 1-88	Filed	6/26/2009	O'Brien		Attachment COMM 1-88
COMM 1-89	Filed	6/26/2009	O'Brien		Attachment COMM 1-89
COMM 1-90	Filed	7/6/2009	O'Brien		Attachments COMM 1-90 (1-2) **BULK**
COMM 1-91	Filed	6/26/2009	O'Brien		Attachment DIV 4-21 (1-2) **BULK**
COMM 1-92	Filed	6/26/2009	O'Brien		Attachment COMM 1-92
COMM 1-93	Filed	6/26/2009	O'Brien		
COMM 1-94	Filed	6/26/2009	O'Brien		Attachment COMM 1-94
COMM 1-95	Filed	6/26/2009	O'Brien		Attachment COMM 1-95
COMM 1-96	Filed	6/26/2009	King		Attachment COMM 1-96
COMM 1-97	Filed	6/26/2009	O'Brien		

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Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-98	Filed	7/1/2009	Dowd		
COMM 1-99	Filed	6/26/2009	Gorman		Attachment COMM 1-99
COMM 1-100	Filed	7/1/2009	Gorman		
COMM 1-101	Filed	7/1/2009	Gorman		
COMM 1-102	Filed	6/26/2009	Gorman		Attachment COMM 1-102
COMM 1-103	Filed	6/26/2009	Wynter		
COMM 1-104	Filed	6/26/2009	Wynter		
COMM 1-105	Filed	6/26/2009	O'Brien		
COMM 1-106	Pending				
COMM 1-107	Filed	6/26/2009	O'Brien		Attachment COMM 1-107
COMM 1-108	Filed	6/26/2009	Wynter		Attachment COMM 1-108
COMM 1-109	Filed	6/26/2009	Dowd/Pettigrew		Attachment COMM 1-109
COMM 2-1	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
COMM 2-2	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
COMM 2-3	Pending				
COMM 2-4	Filed	8/14/2009	Stout		
COMM 2-5	**Filed Herewith**	**8/18/2009**	**O'Brien**		
COMM 2-6	**Filed Herewith**	**8/18/2009**	**Tierney**		
COMM 2-7	**Filed Herewith**	**8/18/2009**	**Tierney**		
COMM 2-8	**Filed Herewith**	**8/18/2009**	**Tierney**		
COMM 2-9	**Filed Herewith**	**8/18/2009**	**Tierney**		
COMM 2-10	Filed	8/14/2009	Stout		
COMM 2-11	Pending				
COMM 2-12	Filed	8/18/2009	Tierney		
COMM 2-13	**Filed Herewith**	**8/18/2009**	**Tierney**		
COMM 2-14	Filed	8/14/2009	Morrissey		Attachment COMM 2-14
COMM 2-15	Filed	8/14/2009	Morrissey		Attachments COMM 2-15 (1-2)
COMM 2-16	**Filed Herewith**	**8/18/2009**	**Morrissey/Stout**		
COMM 2-17	**Filed Herewith**	**8/18/2009**	**O'Brien**	**C-attachment**	Attachment COMM 2-17
COMM 2-18	Pending				
COMM 2-19	Pending				
COMM 2-20	Pending				
COMM 2-21	Pending				
COMM 2-22	Pending				
COMM 2-23	Pending				
COMM 2-24	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment COMM 2-24
COMM 2-25	Pending				
COMM 2-26	**Filed Herewith**	**8/18/2009**	**O'Brien**		
COMM 2-27	Pending				
COMM 2-28	Filed	8/14/2009	Wynter		
COMM 2-29	Filed	8/14/2009	Wynter		
COMM 2-30	Filed	8/14/2009	O'Brien		
COMM 2-31	Filed	8/14/2009	O'Brien		
COMM 2-32	**Filed Herewith**	**8/18/2009**	**O'Brien**		
COMM 2-33	**Filed Herewith**	**8/18/2009**	**O'Brien**		
COMM 2-34	Filed	8/14/2009	Gorman		
COMM 2-35	Filed	8/14/2009	Gorman		
COMM 2-36	Pending				
COMM 2-37	Filed	8/14/2009	Wynter		
COMM 2-38	Filed	8/14/2009	Wynter		
COMM 2-39	Pending				
COMM 2-40	Pending				
COMM 2-41	Pending				
COMM 2-42	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment COMM 2-42
COMM 2-43	Pending				
COMM 2-44	Filed	8/14/2009	Gorman		
COMM 2-45	Filed	8/14/2009	Wynter		
COMM 2-46	Filed	8/14/2009	Wynter		
COMM 2-47	Filed	8/14/2009	Wynter		
COMM 2-48	Filed	8/14/2009	Wynter		
COMM 2-49	Filed	8/14/2009	Wynter		Attachment COMM 2-49
COMM 2-50	Filed	8/14/2009	Wynter		

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COMM 2-51	Filed	8/14/2009	Wynter		Attachment COMM 2-51
COMM 2-52	Filed	8/14/2009	Wynter		
COMM 2-53	Filed	8/14/2009	Wynter		
COMM 2-54	Filed	8/14/2009	Wynter		Attachment COMM 2-54 (1-2)
COMM 2-55	Pending				
COMM 2-56	Filed	8/14/2009	Wynter		Attachment COMM 2-56 (1-2)
COMM 2-57	Filed	8/14/2009	Gorman		
COMM 2-58	Filed	8/14/2009	Gorman		
COMM 3-1	Pending				
COMM 3-2	Pending				
COMM 3-3	Pending				
COMM 3-4	Pending				
COMM 3-5	Pending				
COMM 3-6	Pending				

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DIV-1-1	Filed	6/26/2009	O'Brien		Attachment DIV 1-1
DIV-1-2	Filed	7/1/2009	O'Brien		Attachment DIV 1-2
DIV-1-3	Filed	7/1/2009	O'Brien		Attachment DIV 1-3
DIV-1-4	Filed	6/26/2009	O'Brien		
DIV-1-5	Filed	6/26/2009	O'Brien		
DIV-1-6	Filed	7/1/2009	O'Brien		
DIV-1-7	Filed	7/1/2009	O'Brien		
DIV-1-8	Filed	7/1/2009	O'Brien		
DIV-1-9	Filed	6/26/2009	O'Brien		Attachment DIV 1-9
DIV-1-10	Filed	6/26/2009	O'Brien		
DIV-1-11	Filed	6/26/2009	Dowd		Attachment DIV 1-11
DIV-1-12	Filed	6/26/2009	O'Brien		Attachment DIV 1-12
DIV-1-13	Filed	6/26/2009	Dowd		Attachment DIV 1-13
DIV-1-14	Filed	6/26/2009	Dowd		
DIV-1-15	Filed	6/26/2009	O'Brien		
DIV-1-16	Filed	6/26/2009	O'Brien		
DIV-1-17	Filed	6/26/2009	O'Brien		Attachment DIV 1-17
DIV-1-18	Filed	6/26/2009	O'Brien		
DIV-1-19	Filed	6/26/2009	O'Brien		
DIV-1-20	Filed	6/26/2009	Dowd		Attachment DIV 1-20
DIV-1-21	Filed	7/1/2009	O'Brien		
DIV-1-22	Filed	7/1/2009	O'Brien		
DIV-1-23	Filed	7/1/2009	O'Brien		
DIV-1-24	Filed	7/1/2009	O'Brien		
DIV-1-25	Filed	7/14/2009	O'Brien		
DIV-1-26	Filed	6/26/2009	O'Brien		Attachment DIV 1-26
DIV-1-27	Filed	6/26/2009	O'Brien		
DIV-1-28	Filed	6/26/2009	O'Brien		
DIV-1-29	Filed	7/14/2009	O'Brien		Attachment DIV 1-29
DIV-1-30	Filed	7/1/2009	O'Brien		
DIV-1-31	Filed	6/26/2009	O'Brien		Attachment DIV 1-31
DIV-1-32	Filed	6/26/2009	O'Brien		Attachment DIV 1-32
DIV-1-33	Filed	6/26/2009	O'Brien		Attachment DIV 1-33
DIV-1-34	Filed	6/26/2009	O'Brien		
DIV-2-1	Filed	7/1/2009	Gorman	C-attachment	Attachment DIV 2-1 (electronic only)
DIV-2-2	Filed	6/26/2009	Gorman		
DIV-2-3	Filed	6/26/2009	Gorman		
DIV-2-4	Filed	6/26/2009	Gorman		Attachment DIV 2-4
DIV-2-5	Filed	6/26/2009	Gorman		
DIV-2-6	Filed	6/26/2009	Gorman		
DIV-2-7	Filed	6/26/2009	Gorman		
DIV-2-8	Filed	6/26/2009	Gorman		
DIV-2-9	Filed	6/26/2009	Gorman		
DIV-2-10	Filed	6/26/2009	Gorman		Attachment DIV 2-10
DIV-2-11	Filed	6/26/2009	Gorman		
DIV-2-12	Filed	6/26/2009	Gorman		
DIV-3-1	Filed	7/6/2009	O'Brien		
DIV-3-2	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachments DIV 3-2 (1-4)
DIV-3-3	Filed	7/6/2009	O'Brien		Attachment DIV 3-3
DIV-3-4	Pending				
DIV-3-5	Filed	7/6/2009	O'Brien		
DIV-3-6	Pending				
DIV-3-7	Filed	8/3/2009	O'Brien		Attachment DIV 3-7
DIV-3-8 (Supp.)	Filed	8/3/2009	Morrissey		Attachment DIV 3-8 (Supp.)
DIV-3-9 (Supp.)	Filed	8/3/2009	Morrissey		Attachment DIV 3-9 (Supp.)
DIV-3-10	Filed	7/6/2009	Morrissey		Attachment DIV 3-10
DIV-3-11	Filed	7/6/2009	Morrissey		Attachment DIV 3-11 (PDF and working excel)
DIV-3-12	Filed	7/6/2009	O'Brien/Morrissey		Attachment DIV 3-12
DIV-3-13	Filed	7/6/2009	O'Brien/Morrissey		
DIV-3-14	Filed	7/6/2009	O'Brien/Morrissey		Attachment DIV 3-14
DIV-3-15	Filed	7/6/2009	Morrissey		Attachment DIV 3-15
DIV-3-16	Filed	7/6/2009	Pettigrew		

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Information Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
DIV-3-17	Filed	7/6/2009	Pettigrew		
DIV-3-18	Filed	7/6/2009	Pettigrew		
DIV-3-19	Pending				
DIV-3-20	Pending				
DIV-3-21	Filed	7/6/2009	Pettigrew		
DIV-3-22	**Filed Herewith**	**8/18/2009**	**O'Brien/Dowd**		
DIV-4-1	Filed	7/6/2009	Moul		Attachments DIV 4-1 (1-2) **BULK**
DIV-4-2	Filed	7/6/2009	Dinkel		
DIV-4-3	Filed	7/6/2009	Dinkel		
DIV-4-4	Filed	7/6/2009	Dinkel		
DIV-4-5	Filed	7/6/2009	O'Brien		
DIV-4-6	Filed	7/6/2009	Moul		
DIV-4-7	Filed	7/6/2009	Dinkel		Attachment DIV 4-7
DIV-4-8	Filed	7/6/2009	Dinkel		Attachments DIV 4-8 (1-3)
DIV-4-9	Filed	7/6/2009	Dinkel		Attachment DIV 4-9
DIV-4-10	Filed	7/6/2009	Dinkel		
DIV-4-11	Filed	7/14/2009	O'Brien		Attachment DIV 4-11
DIV-4-12	Filed	7/6/2009	Dinkel		
DIV-4-13	Filed	7/6/2009	Moul		
DIV-4-14	Filed	7/6/2009	Moul		
DIV-4-15	Filed	7/6/2009	Moul		Attachment DIV 4-15
DIV-4-16	Filed	7/6/2009	Moul		Attachment DIV 4-16 (1-2)
DIV-4-17	Filed	7/6/2009	Moul		
DIV-4-18	Filed	7/6/2009	Moul		
DIV-4-19	Filed	7/6/2009	Moul		Attachment DIV 4-19
DIV-4-20	Filed	7/6/2009	Moul		Attachment DIV 4-20
DIV-4-21	Filed	7/6/2009	O'Brien		Attachment DIV 4-21 (1-2) **BULK**
DIV-4-22	Filed	7/6/2009	Moul		Attachment DIV 4-22 (1-2)
DIV-4-23	Filed	7/6/2009	Dinkel		Attachment DIV 4-23
DIV-4-24	Filed	7/6/2009	Moul		
DIV-4-25	Filed	7/6/2009	Moul		
DIV-4-26	Filed	7/6/2009	Moul		
DIV-4-27	Filed	7/6/2009	Moul		Attachment DIV 4-27
DIV-5-A	Filed	7/22/2009	Wynter	**C-attachments**	Attachments DIV 5-A (1-3)
DIV-5-B	Filed	7/22/2009	Wynter		Attachment DIV 5-B
DIV-5-C	Filed	7/22/2009	Wynter		Attachment DIV 5-C
DIV-6-1	Filed	7/14/2009	Tierney		
DIV-6-2	Filed	7/14/2009	Tierney		
DIV-6-3	Filed	7/14/2009	Tierney		
DIV-6-4	Filed	7/14/2009	Tierney		
DIV-6-5	Filed	7/14/2009	Tierney		
DIV-6-6	Filed	7/14/2009	Tierney		Attachment DIV 6-6 **BULK**
DIV-6-7	Pending				
DIV-6-8	Pending				
DIV-6-9	Filed	7/14/2009	Tierney		
DIV-6-10	Filed	7/14/2009	Tierney		
DIV-6-11	Filed	7/14/2009	Tierney		
DIV-6-12	Filed	7/14/2009	Tierney		Attachments DIV 6-12 (a) and (d)
DIV-6-13 (a) - (d)	Filed	7/22/2009	Tierney		Attachment DIV 6-13
DIV0-6-13 (e)	Pending				
DIV-6-14	Filed	7/14/2009	Tierney		Attachment DIV 6-14 (hard copy only)
DIV-6-15 (a)	Pending				
DIV-6-15 (b) and (c)	Filed	7/22/2009	Tierney		
DIV-6-16	Pending				
DIV-6-17	Filed	7/14/2009	Tierney		Attachment DIV 6-17
DIV-6-18	Filed	7/14/2009	Tierney		Attachment DIV 6-18
DIV-6-19 (a) - (d) and (f)	Filed	7/22/2009	Tierney		Attachments DIV 6-19 and DIV 6-19-F (1-2)
DIV-6-19 (e)	Pending				
DIV-6-20	Filed	7/14/2009	Tierney		
DIV-6-21	Filed	7/14/2009	Tierney		
DIV-6-22	Filed	7/14/2009	Tierney		
DIV-6-23	Filed	7/14/2009	Tierney		
DIV-6-24	Filed	7/22/2009	Tierney		Attachment DIV 6-24

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Information Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
DIV-6-25	Filed	7/22/2009	Stout		Attachment DIV 6-25 (1-2)
DIV-6-26	Filed	7/14/2009	Tierney		
DIV-6-27	Filed	7/14/2009	Tierney		Attachment DIV 6-27 (working excel included)
DIV-6-28	Filed	7/14/2009	Tierney		
DIV-6-29	Filed	7/14/2009	Tierney		
DIV-6-30	Filed	7/22/2009	Tierney		
DIV-6-31 (a) - (d) and (f)	Filed	7/22/2009	Tierney		
DIV-6-31 (e)	**Filed Herewith**	**8/18/2009**	**Tierney**		
DIV-6-32	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 6-32
DIV-6-33	Filed	7/14/2009	Tierney		
DIV-6-34	Filed	7/22/2009	Tierney		Attachment DIV 6-34 (1-2)
DIV-6-35	Filed	7/14/2009	Tierney		Attachment DIV 6-35 (c) and (d)
DIV-6-36	Filed	7/14/2009	Gorman		
DIV-6-37	Filed	7/14/2009	Gorman		Attachment DIV 6-37(a)
DIV-6-38	Filed	7/14/2009	Tierney		
DIV-6-39	**Filed**	**8/18/2009**	**Tierney**		
DIV-7-1	Filed	8/3/2009	King		
DIV-7-2	Filed	7/22/2009	King/Pettigrew		
DIV-7-3	Filed	7/22/2009	King		
DIV-7-4	Filed	7/22/2009	Wynter		
DIV-7-5	Filed	7/22/2009	King		
DIV-7-6	Filed	7/22/2009	Wynter/Stout		Attachment DIV 7-6
DIV-7-7	Filed	7/22/2009	Fields		Attachment DIV 7-7 (a) (hard copy only) and (b)
DIV-7-8	**Filed Herewith**	**8/18/2009**	**Dowd**		
DIV-7-9	Filed	7/22/2009	Pettigrew		
DIV-7-10	Filed	7/22/2009	King		
DIV-7-11	Filed	7/22/2009	King		
DIV-7-12	Filed	7/22/2009	King		
DIV-7-13	Filed	7/22/2009	King		
DIV-7-14	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-7-15	Filed	7/22/2009	King		
DIV-7-16	Filed	7/22/2009	Gorman		
DIV-7-17	Filed	7/22/2009	Gorman		Attachment DIV 7-17
DIV-7-18	Filed	7/22/2009	Smithling		Attachment DIV 7-18
DIV-7-19	Pending				
DIV-7-20	Filed	7/22/2009	King		
DIV-7-21	Filed	7/22/2009	King		
DIV-8-1	Pending				
DIV-8-2	Filed	8/3/2009	Wynter		Attachment DIV 8-2
DIV-8-3	Filed	7/22/2009	Wynter		Attachment DIV 8-3 (hard copy only)
DIV-8-4	Filed	7/22/2009	Gorman		Attachment DIV 8-4 (excel)
DIV-8-5	Filed	7/22/2009	Wynter		Attachment DIV 8-5
DIV-8-6	Filed	8/3/2009	Wynter		
DIV-8-7 a-g (no d)	Filed	8/3/2009	Wynter		Attachments DIV 8-7 (a-g, no d)
DIV-8-7(d)	Filed	8/11/2009	Wynter		Att. DIV 8-7(d)
DIV-8-8	Filed	7/22/2009	Wynter		
DIV-8-9	Filed	8/3/2009	Wynter		Attachment DIV 8-9
DIV-8-10	**Filed Herewith**	**8/18/2009**	**Wynter**		Attachment DIV 8-10
DIV-8-11	Filed	7/22/2009	Wynter		
DIV-8-12	Filed	8/3/2009	Wynter		
DIV-8-13	Filed	8/3/2009	Wynter		
DIV-8-14	Filed	8/3/2009	Wynter		
DIV-8-15	Filed	8/3/2009	Wynter		
DIV-8-16	Filed	8/3/2009	Wynter		
DIV-8-17	Pending				
DIV-8-18	Filed	8/3/2009	Wynter		Attachment DIV 8-18
DIV-8-19	Filed	8/3/2009	Wynter		Attachment DIV 8-19
DIV-8-20	Pending				
DIV-8-21	Filed	8/3/2009	Wynter		
DIV-8-22	Pending				
DIV-8-23	Filed	8/3/2009	Wynter		Attachment DIV 8-23
DIV-8-24	Filed	8/3/2009	Wynter		

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DIV-8-25	Filed	8/3/2009	Wynter		Attachments DIV 8-25 (a-i)
DIV-9-1	Filed	7/22/2009	Pettigrew		
DIV-9-2	Filed	7/22/2009	O'Brien		
DIV-9-3	Filed	7/22/2009	Gorman		
DIV-9-4	Filed	7/22/2009	Gorman		
DIV-9-5	Filed	7/22/2009	Gorman		
DIV-9-6	Filed	7/22/2009	Gorman		
DIV-9-7	Filed	7/22/2009	Gorman		
DIV-9-8	Filed	7/22/2009	Gorman		
DIV-9-9	Filed	7/22/2009	Gorman		
DIV-9-10	Filed	7/22/2009	Gorman		
DIV-9-11	Filed	7/22/2009	Gorman		
DIV-9-12	Filed	7/22/2009	Gorman		
DIV-9-13	Filed	7/22/2009	Gorman		
DIV-9-14	Filed	7/22/2009	Gorman		
DIV-9-15	Filed	7/22/2009	Gorman		
DIV-9-16	Filed	7/22/2009	Gorman		
DIV-9-17	Filed	7/22/2009	Gorman		
DIV-9-18	Filed	7/22/2009	Gorman		
DIV-9-19	Filed	7/22/2009	Gorman		
DIV-10-1	Pending				
DIV-10-2	Pending				
DIV-10-3	Filed	7/22/2009	Gorman		Attachment DIV 10-3
DIV-10-4	Filed	7/22/2009	Gorman		Attachment DIV 10-4
DIV-10-5	Filed	8/11/2009	Gorman		Attachment DIV 10-5 (1-4) EXCEL files **BULK**
DIV-10-6	Filed	7/22/2009	Gorman		Attachment DIV 10-6 (excel)
DIV-10-7	Filed	7/22/2009	Dowd		
DIV-10-8	Pending				
DIV-10-9	Filed	7/22/2009	Dowd		
DIV-10-10	Filed	8/11/2009	O'Brien		Attachment DIV 10-10
DIV-10-11	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-10-12	Filed	7/22/2009	Wynter		
DIV-10-13	Filed	8/11/2009	Wynter		Attachment DIV 10-13 (1-2)
DIV-10-14	Filed	7/22/2009	Kateregga		
DIV-10-15	Filed	7/22/2009	O'Brien		
DIV-10-16	Filed	7/22/2009	O'Brien		
DIV-10-17	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 10-17
DIV-10-18	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-10-19	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 10-19
DIV-10-20	Filed	7/22/2009	Dowd		
DIV-10-21	Filed	7/22/2009	Dowd		
DIV-10-22	Filed	7/22/2009	Dowd		
DIV-10-23	Pending				
DIV-10-24	Filed	7/22/2009	O'Brien		Attachment DIV 10-24
DIV-10-25	Filed	7/22/2009	O'Brien		
DIV-10-26	Filed	7/22/2009	O'Brien		
DIV-10-27	Pending				
DIV-10-28	Filed	7/22/2009	Gorman		
DIV-10-29	Filed	7/22/2009	Wynter		
DIV-11-1	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachments DIV 11-1 (1-2)
DIV-11-2	Filed	8/11/2009	Pettigrew		
DIV-11-3	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-4	Pending				
DIV-11-5	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-6	Pending				
DIV-11-7	Pending				
DIV-11-8	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-9	Pending				
DIV-11-10	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-11	Pending				
DIV-11-12	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachments DIV 11-12 (1-3) **BULK**
DIV-11-13	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 11-13
DIV-11-14	**Filed Herewith**	**8/18/2009**	**Pettigrew**		

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DIV-11-15	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-16	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-17	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-18	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 11-18
DIV-11-19	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-20	Filed	8/11/2009	O'Brien		Attachment DIV-11-20 (1-2)
DIV-11-21	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-22	Pending				
DIV-11-23	Pending				
DIV-11-24	Pending				
DIV-11-25	Filed	8/11/2009	Pettigrew		Attachment DIV-11-25
DIV-11-26	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-27	Pending				
DIV-11-28	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-29	Pending				
DIV-11-30	Pending				
DIV-11-31	Pending				
DIV-11-32	Pending				
DIV-11-33	Pending				
DIV-11-34	Pending				
DIV-11-35	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-11-36	Pending				
DIV-11-37	Pending				
DIV-11-38	Filed	8/11/2009	Dinkel		Att. DIV 11-38 (1-17) **BULK** hard copy only
DIV-11-39	Filed	8/11/2009	Pettigrew		Attachment DIV-11-39 EXCEL file
DIV-11-40	Filed	8/11/2009	Gorman		
DIV-11-41	**Filed Herewith**	**8/18/2009**	**Gorman**		
DIV-11-42	Pending				
DIV-12-1	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachments DIV 12-1 (CD-ROM) **BULK**
DIV-12-2	Filed	8/11/2009	O'Brien		Attachment DIV 12-2 (1-2) **BULK**
DIV-12-3	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachments DIV 12-3 (CD-ROM) **BULK**
DIV-12-4	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 12-4 (excel)
DIV-12-5	Pending				
DIV-12-6	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment 12-6 (excel) **BULK**
DIV-12-7	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment 12-7
DIV-12-8	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-12-9	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-12-10	Pending				
DIV-12-11	**Filed Herewith**	**8/18/2009**	**O'Brien**		
DIV-12-12	Pending				
DIV-12-13	Pending				
DIV-12-14	Pending				
DIV-12-15	Pending				
DIV-12-16	Filed	8/14/2009	O'Brien		
DIV-12-17	Pending				
DIV-12-18	Filed	8/11/2009	O'Brien		
DIV-12-19	Filed	8/11/2009	O'Brien		
DIV-13-1	Filed	8/11/2009	Gorman		
DIV-13-2	Filed	8/11/2009	Gorman		
DIV-13-3	Filed	8/11/2009	O'Brien		
DIV-13-4	Filed	8/11/2009	O'Brien		
DIV-13-5	Filed	8/11/2009	Walter		
DIV-13-6	Filed	8/11/2009	Gorman		Attachment DIV-13-6 EXCEL
DIV-13-7	Filed	8/14/2009	Gorman		Attachment DIV-13-7
DIV-13-8	Filed	8/11/2009	Gorman		
DIV-13-9	Filed	8/11/2009	Gorman		
DIV-13-10	Filed	8/11/2009	Gorman		
DIV-14-1	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachments DIV 14-1 (1-8) **BULK**
DIV-14-2	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-2
DIV-14-3	**Filed Herewith**	**8/18/2009**	**Pettigrew**		

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DIV-14-4	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-5	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-5
DIV-14-6	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-6
DIV-14-7	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-8	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-9	Pending				
DIV-14-10	Pending				
DIV-14-11	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachments DIV 14-11 (1-8) **BULK**
DIV-14-12	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachments DIV 14-12 (1-2) **BULK**
DIV-14-13	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-14	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-15	Pending				
DIV-14-16	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-17	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-18	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-18
DIV-14-19	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-19
DIV-14-20	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-21	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 14-21
DIV-14-22	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-23	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-24	**Filed Herewith**	**8/18/2009**	**Pettigrew**		
DIV-14-25	Pending				
DIV-15-1	Filed	8/11/2009	Gorman		
DIV-15-2	Filed	8/11/2009	Gorman		Attachment DIV 15-2 (1-2)
DIV-15-3	Filed	8/14/2009	Fields		
DIV-15-4	Filed	8/11/2009	O'Brien		
DIV-16-1	Filed	8/11/2009	Fields		Attachment DIV 16-1
DIV-16-2	Filed	8/11/2009	Fields		
DIV-16-3	Filed	8/11/2009	Fields		Attachment DIV 16-3
DIV-16-4	Filed	8/11/2009	Fields		Attachment DIV 16-4
DIV-16-5	Filed	8/11/2009	Fields		
DIV-16-6	Filed	8/11/2009	Fields		
DIV-16-7	Filed	8/11/2009	Fields		
DIV-16-8	Filed	8/11/2009	Fields		
DIV-16-9	Filed	8/11/2009	Fields		Att. DIV 16-9 (1-5) **BULK**
DIV-16-10	Filed	8/11/2009	Fields		
DIV-16-11	Filed	8/11/2009	Fields		
DIV-16-12	Filed	8/11/2009	Fields		
DIV-16-13	Filed	8/11/2009	Fields		
DIV-16-14	Filed	8/11/2009	Fields		
DIV-16-15	Filed	8/11/2009	Fields		
DIV-16-16	**Filed Herewith**	**8/18/2009**	**Fields**		
DIV-16-17	Filed	8/11/2009	Fields		Attachment DIV 16-17
DIV-16-18	Filed	8/11/2009	Fields		
DIV-16-19	Filed	8/11/2009	Fields		
DIV-16-20	Filed	8/11/2009	Fields		
DIV-16-21	Filed	8/11/2009	Fields		
DIV-16-22	Filed	8/11/2009	Fields		
DIV-16-23	Filed	8/11/2009	Fields		Attachment DIV 16-23
DIV-16-24	Filed	8/11/2009	Fields		
DIV-16-25	Filed	8/11/2009	Fields		
DIV-16-26	Filed	8/11/2009	Fields		
DIV-17-1	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 17-1
DIV-17-2	**Filed Herewith**	**8/18/2009**	**O'Brien**		Attachment DIV 17-2
DIV-17-3	**Filed Herewith**	**8/18/2009**	**Pettigrew**		Attachment DIV 17-3(e)
DIV-17-4	Pending				
DIV-17-5	Pending				
DIV-17-6	**Filed Herewith**	**8/18/2009**	**Wynter**		
DIV-17-7	Pending				
DIV-17-8	Pending				
DIV-17-9	Pending				
DIV-17-10	Pending				
DIV-17-11	Pending				
DIV-17-12	Filed	8/14/2009	Gorman		
DIV-17-13	Filed	8/14/2009	Gorman		

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DIV-18-1	Filed	8/11/2009	Gorman		Attachment DIV 18-1
DIV-18-2	Filed	8/14/2009	Gorman		
DIV-18-3	Filed	8/11/2009	Gorman		
DIV-18-4	Filed	8/11/2009	Gorman		
DIV-18-5	Filed	8/14/2009	Pettigrew		
DIV-19-1	Pending				
DIV-19-2	Pending				
DIV-20-1	Pending				
DIV-20-2	Pending				
DIV-20-3	Pending				
DIV-20-4	Pending				
DIV-20-5	Pending				
DIV-20-6	Pending				
DIV-21-1	Pending				
DIV-21-2	Pending				
DIV-21-3	Pending				
DIV-21-4	Pending				
DIV-21-5	Pending				
DIV-22-1	Pending				
DIV-22-2	Pending				
DIV-22-3	Pending				
DIV-22-4	Pending				
DIV-22-5	Pending				

The Narragansett Electric Company d/b/a National Grid
Docket 4065
Discovery Log
As of: August 18, 2009

[C-denotes confidentiality is being sought]

Information Request	Status	Date Filed	Witness	CONFIDENTIAL	Attachments
NAVY-1-1	Filed	6/29/2009			
NAVY-1-2	Filed	6/29/2009			
NAVY-1-3	Filed	6/29/2009			
NAVY-1-4	Filed	6/29/2009			
NAVY-2-1	Filed	7/22/2009	Gorman, Wynter, O'Brien		Excel attachments
NAVY-2-2	Filed	7/22/2009	Gorman, O'Brien		Excel attachments
NAVY-3-1	**Filed Herewith**	**8/18/2009**	**Gorman**		Attachment NAVY 3-1 (a)
NAVY-3-2	Filed	8/14/2009	Fields/Gorman		
NAVY-3-3	Filed	8/14/2009	Gorman		
NAVY-3-4	Filed	8/14/2009	Gorman		
NAVY-3-5	Pending				
NAVY-3-6	Filed	8/14/2009	Gorman		
NAVY-3-7	**Filed Herewith**	**8/18/2009**	**Gorman**		Attachments NAVY 3-7 (1-2) Excel
NAVY-3-8	**Filed Herewith**	**8/18/2009**	**Gorman**		

The Narragansett Electric Company d/b/a National Grid					
Docket 4065					
Discovery Log					
As of: August 18, 2009					
[C-denotes confidentiality is being sought]					
Information Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
GWC-1-1	Pending				
GWC-1-2	Pending				
GWC-1-3	Pending				
GWC-1-4	Pending				
GWC-1-5	Pending				
GWC-1-6	Pending				
Discovery Log Ends Here: August 18, 2009					

nationalgrid

Thomas R. Teehan
Senior Counsel

August 18, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
<u>Motion for Protective Treatment</u>

Dear Ms. Massaro:

Enclosed please find an original and nine (9) copies of National Grid's[1] Motion for Protective Treatment concerning the Company's response to the Commission's second set of data requests being filed under separate cover in the above-captioned proceeding. Specifically, the Company is requesting confidential treatment of Attachment COMM 2-17, as permitted by Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(i)(B).

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4065 Service List

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

280 Melrose Street, Providence, RI 02907
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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

National Grid	)	
Application to Change Rate Schedules	)	Docket 3943

MOTION OF NATIONAL GRID
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

Now comes The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company") and hereby requests that the Rhode Island Public Utilities Commission (the "Commission) grant protection from public disclosure of certain confidential, competitively sensitive and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and by R.I.G.L. § 38-2-2(4)(i)(B).

I. BACKGROUND

On August 18, 2009, the Company filed responses to data requests issued by the Commission in the above-referenced proceeding concerning the Company's application for a change in base rates. In those data requests, the Commission requested a copy of a confidential performance audit as part of a response to Data Request COMM-2-17. For the reasons stated below, the Company requests that the performance audit be protected from public disclosure.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L.

§38-2-1, *et seq*. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(i)(B) provides that the following records shall not be deemed public:

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

The Rhode Island Supreme Court has held that the determination as to whether this exemption applies requires the application of a two-pronged test set forth in Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001). The first prong of the test assesses whether the information was provided voluntarily to the governmental agency. Providence Journal, 774 A.2d at 47. If the answer to the first question is affirmative, then the question becomes whether the information is "of a kind that would customarily not be released to the public by the person from whom it was obtained." Id.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established by the Court in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under this balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

III. BASIS FOR CONFIDENTIALITY

National Grid seeks protection from public disclosure for the confidential and proprietary performance audit set forth in the Company's response to Data Request COMM-2-17. Information contained in the performance audit is not provided to the public and is collected and maintained by the Company only for internal use in order to improve the Company's performance. The Company is requesting that its internal audit be protected from public disclosure because of the critical importance of encouraging employees to participate in audits and provide all of the information necessary for the audit to be successful.

To ensure the integrity of the audit process, employees are given assurances that their answers will not be made available to the public. These assurances serve an important role in the Company's ability to obtain and detect information that would otherwise be difficult or impossible to gather. The chilling effect that would be created as a result of public disclosure of the information obtained during an audit would substantially reduce the value of the audit process. That is, confidentiality is critical to the process of all internal Company audits in order to obtain the highest quality information. Accordingly, the Company's internal audits should be granted confidential status by the Commission.

Consistent with the standard for confidentiality established under Rhode Island law, the confidential price terms are information "of a kind that would customarily not be released to the public by the person from whom it was obtained." The Company is under no obligation in any other forum to disclose the information and, as is customary in relation to confidential performance audits, the Company would not ordinarily release the information in a public forum because of the detrimental impact that such a release would have on the interests of the Company (and its customers) in protecting the integrity of internal audits on a going forward basis. Accordingly, in this case, the need to ensure that the confidential and proprietary customer data are protected outweighs the general public interest inherent in disclosure of information pending before regulatory agencies.

V. CONCLUSION

The confidential performance audit contained in the Company's response to Data Request COMM 2-17 should be protected from the public record, because release of this information would be detrimental to the public interest. Accordingly, the Company requests that the Commission protect the confidential information submitted in response to Data Request COMM 2-17.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorneys,

____

Thomas R. Teehan, Esq.
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7667

____

Cheryl M. Kimball, Esq. (RI #6458)
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400

Dated: August 18, 2009

Commission Data Request 1-27

Request:

Please itemize all expenses allocated or assigned to the Company from each of its affiliates. In your response, please include the expense account description, account number, allocation formula, all workpapers, calculations, assumptions and basis for assumptions for each expense allocated.

Response:

Please see the following attachments to this response for the requested information:

Attachment 1: Expenses charged directly or allocated to the Company
Attachment 2: Bill pool allocation detail
Attachment 3: Bill pool calculations

Prepared by or under the supervision of: Robert L. O'Brien

Commission Data Request 1-39

Request:

Please provide both the dollar amount and percent capitalized of the wages and salaried and of each of the employee benefits for each of the last five years.

Response:

Please see Attachment COMM 1-39 for the requested information.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company d/b/a National Grid
Payroll Costs

Sum of Posted Jrnl $		Calendar Year				
Cost Type	Expense Type Descr	2004	2005	2006	2007	2008
Capital	Base OT Pay Monthly	305,761	381,678	457,528	394,923	452,596
	Base OT Pay Weekly	1,113,263	1,437,285	1,628,016	1,716,095	2,041,940
	Bonus & Misc Pay	594,700	1,420,567	1,045,338	1,007,359	1,262,474
	Incremental OT Pay Monthly	66,127	134,067	185,161	174,056	205,129
	Incremental OT Pay Weekly	372,162	848,723	991,170	995,744	1,248,286
	Regular Pay Monthly	4,176,595	5,210,327	5,736,913	5,862,326	6,361,697
	Regular Pay Weekly	9,104,890	9,322,162	9,075,332	10,064,496	10,809,245
	Time Not Worked	2,667,443	2,690,202	3,076,186	3,756,134	3,957,531
Capital Total		18,400,940	21,445,011	22,195,645	23,971,134	26,338,898
Expense	Base OT Pay Monthly	360,704	623,357	698,572	768,121	862,328
	Base OT Pay Weekly	1,630,115	2,098,417	2,498,862	2,385,251	2,768,136
	Bonus & Misc Pay	1,779,568	4,741,026	3,776,655	2,687,814	3,999,793
	Incremental OT Pay Monthly	68,035	205,122	276,954	321,673	381,022
	Incremental OT Pay Weekly	634,500	1,254,167	1,495,002	1,400,660	1,643,123
	Regular Pay Monthly	14,788,759	13,663,582	16,105,556	16,224,491	16,733,301
	Regular Pay Weekly	13,213,670	12,083,897	12,170,632	13,048,744	13,715,627
	Time Not Worked	5,319,797	4,650,335	5,630,037	6,310,787	6,674,220
Expense Total		37,795,149	39,319,902	42,652,270	43,147,542	46,777,549
Grand Total		56,196,088	60,764,913	64,847,915	67,118,675	73,116,446

Percentage Capital\Expense		Calendar Year				
Cost Type	Expense Type Descr	2004	2005	2006	2007	2008
Capital	Base OT Pay Monthly	0.54%	0.63%	0.71%	0.59%	0.62%
	Base OT Pay Weekly	1.98%	2.37%	2.51%	2.56%	2.79%
	Bonus & Misc Pay	1.06%	2.34%	1.61%	1.50%	1.73%
	Incremental OT Pay Monthly	0.12%	0.22%	0.29%	0.26%	0.28%
	Incremental OT Pay Weekly	0.66%	1.40%	1.53%	1.48%	1.71%
	Regular Pay Monthly	7.43%	8.57%	8.85%	8.73%	8.70%
	Regular Pay Weekly	16.20%	15.34%	13.99%	15.00%	14.78%
	Time Not Worked	4.75%	4.43%	4.74%	5.60%	5.41%
Capital Total		32.74%	35.29%	34.23%	35.71%	36.02%
Expense	Base OT Pay Monthly	0.64%	1.03%	1.08%	1.14%	1.18%
	Base OT Pay Weekly	2.90%	3.45%	3.85%	3.55%	3.79%
	Bonus & Misc Pay	3.17%	7.80%	5.82%	4.00%	5.47%
	Incremental OT Pay Monthly	0.12%	0.34%	0.43%	0.48%	0.52%
	Incremental OT Pay Weekly	1.13%	2.06%	2.31%	2.09%	2.25%
	Regular Pay Monthly	26.32%	22.49%	24.84%	24.17%	22.89%
	Regular Pay Weekly	23.51%	19.89%	18.77%	19.44%	18.76%
	Time Not Worked	9.47%	7.65%	8.68%	9.40%	9.13%
Expense Total		67.26%	64.71%	65.77%	64.29%	63.98%
Grand Total		100.00%	100.00%	100.00%	100.00%	100.00%

The Narragansett Electric Company d/b/a National Grid
Benefits Costs

Sum of Posted Jrnl $		Calendar Year				
Cost Type	Expense Type Descr	2004	2005	2006	2007	2008
Capital	FAS 106	3,108,555	554,644	1,905,107	1,137,232	1,337,731
	FAS 112	215,897	(236,308)	(830,493)	577,081	150,509
	Group Life Insurance	145,756	209,035	218,777	261,439	328,994
	Health Care	1,636,209	1,949,251	2,076,307	2,003,424	2,270,824
	Other Benefits	286,974	211,304	1,091,810	(446,733)	(199,474)
	Payroll Taxes	1,295,378	1,663,844	1,227,764	1,472,190	1,739,612
	Pension	748,681	2,469,931	2,362,423	2,558,363	1,877,339
	Thrift Plan	501,708	1,145,006	619,670	665,507	712,392
	Workers Comp	213,672	317,408	200,285	420,674	290,569
Capital Total		8,152,830	8,284,115	8,871,650	8,649,176	8,508,497
Expense	FAS 106	9,177,744	8,687,003	6,923,461	8,356,221	7,949,753
	FAS 112	1,277,474	(1,201,039)	547,227	(219,489)	(718,513)
	Group Life Insurance	425,102	405,127	526,248	537,804	639,155
	Health Care	3,852,240	3,811,350	4,067,695	4,543,361	4,251,070
	Other Benefits	1,294,698	2,257	(12,978)	577,468	373,821
	Payroll Taxes	3,473,918	2,785,729	3,381,193	3,654,483	3,567,486
	Pension	4,079,234	5,041,208	4,495,598	5,526,518	5,596,730
	Thrift Plan	1,173,345	639,405	1,420,269	1,411,560	1,410,865
	Workers Comp	2,323,095	171,623	510,758	457,536	1,050,974
Expense Total		27,076,849	20,342,662	21,859,471	24,845,463	24,121,341
Grand Total		35,229,678	28,626,777	30,731,122	33,494,639	32,629,838

Percentage Capital\Expense		Calendar Year				
Cost Type	Expense Type Descr	2004	2005	2006	2007	2008
Capital	FAS 106	8.82%	1.94%	6.20%	3.40%	4.10%
	FAS 112	0.61%	-0.83%	-2.70%	1.72%	0.46%
	Group Life Insurance	0.41%	0.73%	0.71%	0.78%	1.01%
	Health Care	4.64%	6.81%	6.76%	5.98%	6.96%
	Other Benefits	0.81%	0.74%	3.55%	-1.33%	-0.61%
	Payroll Taxes	3.68%	5.81%	4.00%	4.40%	5.33%
	Pension	2.13%	8.63%	7.69%	7.64%	5.75%
	Thrift Plan	1.42%	4.00%	2.02%	1.99%	2.18%
	Workers Comp	0.61%	1.11%	0.65%	1.26%	0.89%
Capital Total		23.14%	28.94%	28.87%	25.82%	26.08%
Expense	FAS 106	26.05%	30.35%	22.53%	24.95%	24.36%
	FAS 112	3.63%	-4.20%	1.78%	-0.66%	-2.20%
	Group Life Insurance	1.21%	1.42%	1.71%	1.61%	1.96%
	Health Care	10.93%	13.31%	13.24%	13.56%	13.03%
	Other Benefits	3.68%	0.01%	-0.04%	1.72%	1.15%
	Payroll Taxes	9.86%	9.73%	11.00%	10.91%	10.93%
	Pension	11.58%	17.61%	14.63%	16.50%	17.15%
	Thrift Plan	3.33%	2.23%	4.62%	4.21%	4.32%
	Workers Comp	6.59%	0.60%	1.66%	1.37%	3.22%
Expense Total		76.86%	71.06%	71.13%	74.18%	73.92%
Grand Total		100.00%	100.00%	100.00%	100.00%	100.00%

1/ Includes charges from affiliates; excludes costs charged by Narragansett to affiliates.
2/ Includes VERO costs and VERO amortization per Docket. No. 3617.

Commission Data Request 2-1

Request:

Will implementation of the Asset Management Approach being proactive as opposed to reactive as described by John Pettigrew result in savings to ratepayers and if so why?

Response:

National Grid is in the early stages of implementation of the Asset Management Approach so the savings to customers cannot be estimated at this point. The objectives of the Asset Management Approach are:

Safety: Achieve zero injuries every day. Continue to work on processes, systems and designs that improve safety, and to reinvigorate our safety culture to bring fresh effort to improving performance.

Reliability: Meet service quality requirements for all states by calendar year 2008 and attain first quartile performance (excluding IEEE 1366 major event days) compared to a selected group of peers in SAIDI, SAIFI and CAIDI by calendar year 2012. Achieving this objective, and making it sustainable, will require a significant investment in the replacement of our aging infrastructure. Additionally, building relationships with regulatory commissions is required to achieve mutual understanding for the need to support long-term investment in order to achieve a sustainable distribution network.

Customer Service: Meet regulatory targets for customer satisfaction scores in all states in calendar year 2008. T he longer-term goal is to achieve first quartile performance (as measured by JD Power & Associates Electric Utility Satisfaction Surveys) compared to a selected group of peers in residential and business customer satisfaction across all service territories by end of calendar year 2012.

Efficiency: The long-term goal is to achieve first quartile performance compared to a selected group of peers in operation and maintenance (O&M) spending per customer by end of calendar year 2012. National Grid will constantly strive to be more efficient in the service provided to customers by improving annual O&M cost efficiency and improving capital efficiency.

Prepared by or under the supervision of: John Pettigrew

Commission Data Request 2-2

Request:

Will centralizing administrative support services cause an increase in costs to Rhode Island ratepayers? If so, how much?

Response:

No. The Company does not anticipate an increase in costs associated with administrative support services in Rhode Island. The Company expects to achieve greater efficiencies and improved customer interactions.

Prepared by or under the supervision of: John Pettigrew

Commission Data Request 2-5

Request:

Can National Grid factor in the amount of efficiency savings into its revenue requirement?

Response:

Yes. Please see Schedule RLO-3 (Page 1) for details regarding the calculation of the net synergy value. Also, please see Schedule RLO-2 (Page 1, sum of lines 31 and 32), which highlight the inclusion of this component as a Pro Forma Adjustment in the revenue requirement calculation.

Prepared by or under the supervision of: Robert L. O'Brien

Commission Data Request 2-6

Request:

If the Commission allows for decoupling, what incentive does National Grid have to promote efficiency?

Response:

If the Commission were to adopt revenue decoupling as part of its ratemaking plan for the Company, revenue decoupling would operate in parallel with other regulatory mechanisms in place now or in the future to help assure that the Company satisfies Rhode Island's goals for energy efficiency. In this way, decoupling would be like many other areas of regulatory supervision over utilities in which the ratemaking process, its component parts and its outcomes, work in concert with other forms of regulation to enable the state's regulatory agency to guide how utilities meet their obligations to serve. For example, general rate cases provide support for a utility recovering its operating expenses and investment in utility plant; and these provide revenue support that works in parallel with other service quality requirements, customer service requirements, and other mechanisms through which regulators establish expectations, penalties and rewards for utility performance. In this way, revenue decoupling would be part of the ratemaking process to align better the utility's financial interests with the customers' goals of reducing their electricity bills through energy efficiency; and the utility's energy efficiency programs, supervised through the Rhode Island Commission, would outline with greater specificity the Company's, and the Commission's, expectations about delivery of energy efficiency programs and outcomes for customers.

For example, as described in the pre-filed direct testimony of Mr. Timothy Stout, the Company carries out a number of energy efficiency and conservation programs under the direction of the Commission. As described by Mr. Stout in his pre-filed direct testimony, expectations for energy efficiency programs have been articulated by the "Energy Efficiency Resource Management Council ("EERMC") and a group of other stakeholders that acts as a subcommittee to the EERMC to produce the Standards for Energy Efficiency and Conservation Procurement and System Reliability, which the Commission adopted on July 17, 2008 in Docket No. 3931. Those Standards, as well as the Opportunities Report commissioned by the EERMC, served as guides for the Company to create its three-year Least Cost Procurement Plan. On March 31, 2009, the Commission approved the Company's three-year plan for energy efficiency and system reliability procurement for 2009-2011. Earlier, in late 2008, the Commission had approved the Company's DSM programs for 2009, which provide the design and initial year's funding for the Company as it sets out upon this aggressive and promising three-year energy efficiency course for Rhode Island." Thus, these

Commission Data Request 2-6 (cont.)

other regulatory mechanisms help to support the Company's efforts in the area of energy efficiency.

That said, as Dr. Tierney described in her pre-filed direct testimony, there are other important regulatory and ratemaking tools that can help to provide a more direct *incentive* for the Company to *promote* energy efficiency. As she says on pages 8-10,

> "Although my testimony addresses the role of revenue decoupling in removing financial *dis*incentives for companies to pursue all cost-effective energy efficiency, this is not the only regulatory policy that is important to realizing such opportunities. I understand that the matter of proposed shareholder incentives for companies to deliver energy efficiency programs has long been addressed in utility company energy efficiency proceedings and other regulatory venues (e.g., RIPUC Dockets 3892 and 3790, and other future dockets. [footnote: See, e.g., RI PUC, In Re: The Narragansett Electric Company d/b/a National Grid Gas and Electric Energy Efficiency Program Plans for 2009, Docket No. 4000, Report and Order, Order dated April 6, 2009]). Of course, the character of these incentives should take into consideration details of the design of demand-side programs, their targets, and performance factors. However, given the important policy issues raised in this proceeding about the various ratemaking approaches (including revenue decoupling) needed to support utilities' aggressive deployment of cost-effective energy efficiency programs, I comment briefly on this issue here. Appropriate shareholder financial incentives are a critical element of distribution utility ratemaking policy that will enhance Rhode Island's ability to capture the full benefits of cost-effective demand-side measures for customers, and for Rhode Island's economy and environment. This perspective is reflected in the various provisions of "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006" ("2006 Act"), including the findings that there is untapped potential to help Rhode Island consumers control their energy costs through increased energy efficiency [footnote: § 42-140.1-2 The 2006 Act: "Legislative findings….(b) Energy conservation and energy efficiency have enormous, untapped potential for controlling energy costs and mitigating the effects of energy crisis for Rhode Island residents and the Rhode Island economy."] and that the state's electric and gas utilities should pursue least-cost "procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply."[footnote: The 2006 Act, Section 39-1-27.7(a)(2).] Support for shareholder incentives is also consistent with the 2006 Act's call for the establishment of performance-based incentives to provide additional compensation based on "the level of its success in mitigating the cost and variability of electric and gas services through procurement portfolios."6 Given the many and persistent disincentives that currently and will

Commission Data Request 2-6 (cont.)

continue to exist in many markets and that impede adoption of energy efficiency and other demand-side measures even when they may be economical, encouraged and even required by law, a full array of regulatory tools should be used by the Commission to accomplish effectively the state's statutory and regulatory goals. This toolkit includes: (1) revenue decoupling (which is proposed in the instant proceeding), (2) full recovery of all appropriate costs for energy efficiency programs needed to meet these statutory goals for deployment of all cost-effective energy efficiency (which has been and will be addressed in separate energy efficiency-related proceedings), and (3) the provision of shareholder financial incentives to utilities that perform well in meeting these goals (which also has been and will be addressed in separate energy efficiency-related proceedings). Although decoupling revenues from sales effectively neutralizes one disincentive to energy efficiency investments, it does not address the remaining problems very effectively. Thus even with revenue decoupling, additional measures that align utility and customer interests are needed. A recent DOE report emphasizes that regulators should ensure that efficiency investments are *at least as* attractive to utilities as supply-side alternatives, and that customers will be better off as a consequence."

Commission Data Request 2-7

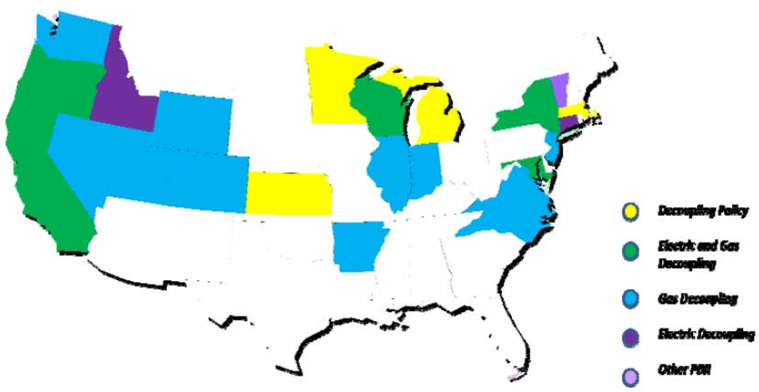
Request:

Dr. Tierney asserts in her testimony that more utilities will adopt revenue decoupling over time. On what evidence is this statement based and what is the time period referred to?

Response:

According to a recent industry survey conducted by the Edison Electric Institute,[1] there are three states (Hawaii, New Hampshire, Delaware) with decoupling policy where there are utilities awaiting regulatory decisions on their proposals. There are also several states that have recently adopted policy in support of decoupling mechanisms. Given these recent trends, and the increasing interest and priority of policy makers and consumers in energy efficiency and climate policies at large, it can be reasonably expected that more states will consider revenue decoupling for their electric utilities.

Also, according to another recent comprehensive survey of revenue decoupling plans conducted by Ms. Pamela Lesh for the Regulatory Assistance Project and published on June 30, 2009, "A total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, have operative decoupling mechanisms.1 Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place. The map below shows the states covered by this report:" Ms. Lesh's report has been provided in response to Information Request COMM-2-8. This map highlights Kansas, Massachusetts, Minnesota, and Michigan as states with a decoupling policy that has not yet been implemented in a utility rate plan; her report also mentions Nevada as having adopted a decoupling policy for natural gas companies. Her report appears not to mention Hawaii by name.



[1] Lost Revenue Adjustment & Revenue Decoupling mechanisms for Electric utilities by State, Edison Electric Institute, May 2009.

Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-8

Request:

Please identify the total number of utilities that have full or partial revenue decoupling and the number of utilities that do not have revenue decoupling.

Response:

According to a recent survey of investor-owned utilities' experience in revenue decoupling which was published on June 30, 2009 (after the date on which Dr. Tierney submitted her pre-filed direct testimony in this proceeding), there are "[a] total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, [that] have operative decoupling mechanisms. Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place."

Source: Pam Lesh, Graceful Systems, LLC, "Rate Impacts and Key Design Elements of Gas and Electric Decoupling: A Comprehensive Review," June 30, 2009.

This report is presented here as Attachment COMM 2-8.

This report is also available through the Regulatory Assistance Project, http://www.raponline.org/showpdf.asp?PDF_URL=Pubs/Lesh%2DCompReviewDecouplingInfoElecandGas%2D30June09%2Epdf.

According to the Energy Information Administration, there are 212 investor-owned electric utilities and there are 236 investor-owned natural gas distribution companies. See, EIA, 176 Database Query System for natural gas companies, and the 861 Database Query System for electric utility companies (http://www.eia.doe.gov/cneaf/electricity/page/eia861.html; http://www.eia.doe.gov/oil_gas/natural_gas/applications/nat_applications.html).

Additionally, there are 1,843 municipally-owned electric utilities and 883 cooperatively owned electric utilities. These companies generally operate under a form of revenue decoupling because their ratemaking typically includes a regular reconciliation of their revenues with their costs in order to meet the implicit and/or explicit requirements of their regulatory, statutory and/or bond covenants that their rates recover their cost of providing service. Thus, fluctuations in sales due to weather, economic conditions, and other factors lead to adjustments in customer rates to allow over time a reconciliation of the municipally owned and cooperatively owned utility's costs with its revenues.

Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-9

Request:

As more penetration of energy efficiency resulting in saturation of certain areas is achieved will the need for decoupling diminish?

Response:

From the point of view of establishing sound ratemaking policy that accomplishes a number of objectives (e.g., sending price signals to customers about the cost of providing them with service; providing recovery of the cost of providing utility service, including recovery of and on investment at reasonable rates of return; better aligning the utility's financial interests with those of its customers in adopting and maintaining cost-effective energy efficiency measures), there is no more reason to remove decoupling once it is in place than there is to remove other important ratemaking incentives (e.g., metrics and/or other performance targets designed to provide incentives to assure service quality). Ratemaking policy, combined with other regulatory tools, is designed to provide appropriate incentives to assure that utilities provide reliable, economically efficient and high quality service to customers. Traditionally, regulators do not remove one or another element of such ratemaking approaches once these policies, combined with the company's performance, achieve a level of satisfactory outcome.

Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-12

Request:

Please produce a chart/table that compares the monthly billings for distribution service assuming an RDM had been in place for 2003-2008 against actual monthly billings for distribution, similar to that submitted in Dr. Tierney's testimony (Figure NG-SFT-6, page 42 of 97).

Response:

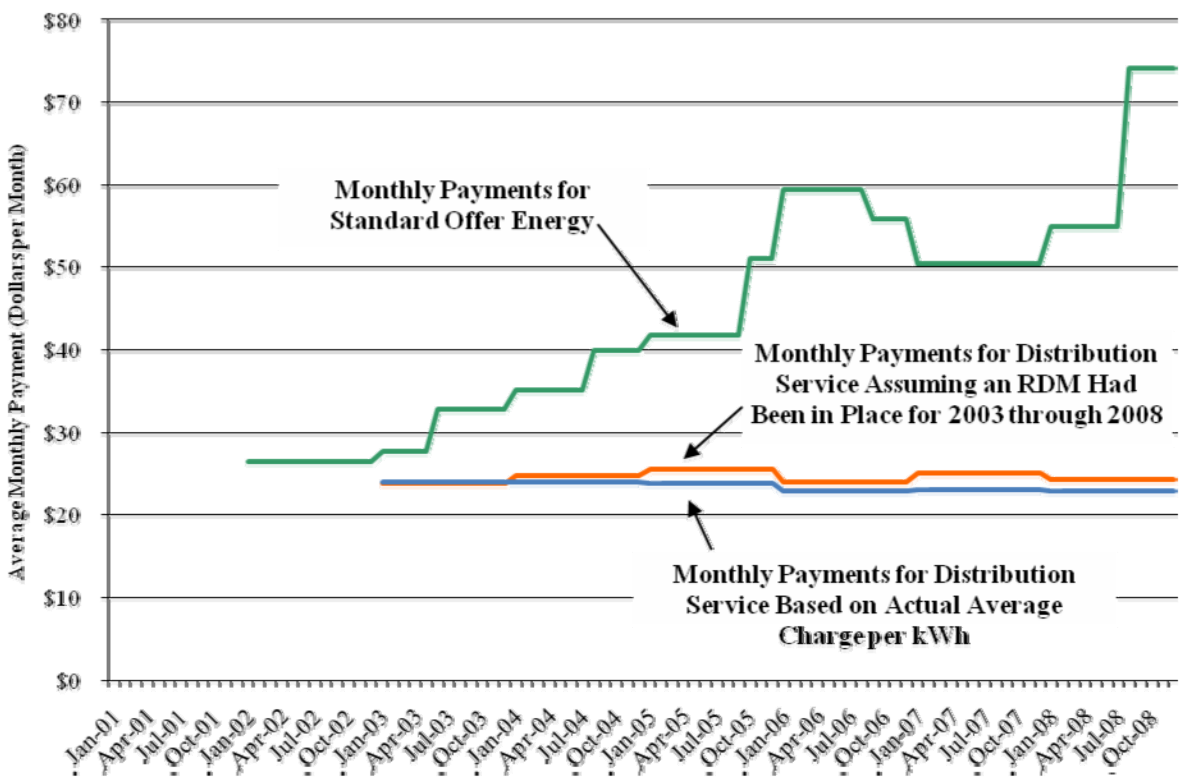
Figure NG-SFT-6 of Dr. Tierney's pre-filed direct testimony showed monthly customer billings for standard offer commodity service and distribution service under a simplified revenue decoupling mechanism ("RDM"), based upon the Company's actual revenues, sales and charges for the period from 2001 through 2008. In Figure COMM-2-12, below, several modifications have been made to Figure NG-SFT-6. First, monthly billings are based upon actual average monthly use per customer in each year over the period from 2001 through 2008, rather than fixed at a constant level. Thus, changes in monthly billings reflect both changes in rates (i.e., cent/kWh) and changes in the amount of energy services used (i.e., kWh). Second, the actual average monthly billings for distribution service over the period from 2001 through 2008 have been added.

Figure COMM-2-12 shows that monthly billings for distribution service would have been slightly higher under the simplified RDM over the period from 2001 through 2008 in comparison to actual residential customer monthly billings over this period. The largest difference in monthly billings is $2.24 per month for 2007. When considering the results in Figure COMM-2-12, please keep in mind that the decoupling mechanism modeled in these figures relies upon a highly simplified model for determining the Company's revenues (and thus the resulting annual adjustments) under the hypothetical revenue decoupling mechanism. Both Figure NG-SFT-6 and Figure COMM-2-12 illustrate that the level of and variation in distribution service billings under an RDM is small in comparison to those for monthly billings for energy commodity service. This underscores the importance of potential bill savings that customers stand to realize from implementing energy efficiency, which is a primary purpose of encouraging the Commission to adopt a revenue decoupling mechanism that better aligns the Company's financial interests with those of its customers.

Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-12 (cont.)

Figure NG-SFT-6
National Grid Retail Unbundled Electric Service for Residential Customers in Rhode Island:
Comparison of Monthly Distribution and Standard Offer Service Billings



Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-13

Request:

Dr. Tierney's testimony includes references in Schedule NG-SFT-2 to several approved RDM's. Please list the approved ROEs for those utilities with approved and currently active RDMs as listed in that schedule.

Response:

Figure COMM-2-13, below, provides information on the approved return on equity ("ROE") and rate of return ("ROR") for utilities included in Schedule NG-SFT-2 of Dr. Tierney's pre-filed direct testimony. The information in Figure COMM-2-13 is based on data published in publicly available reports from the Edison Electric Institute ("EEI"), and is based on the most recent information available from EEI as of the period from the 1st quarter of 2007 through the 2nd quarter of 2009. The approved ROE for utilities with an RDM ranges from 8.75 percent for United Illuminating to 11.35 percent for Pacific Gas & Electric. The approved ROR for these utilities ranges from 7.34 for Consolidated Edison of Company of New York to 8.79 percent for Pacific Gas & Electric.

Commission Data Request 2-13 (cont.)

Figure COMM-2-3
Approved Return on Equity and Approved Rate of Return on Capital for Electric (or Electric/Gas) Utilities with Revenue Decoupling

Company	Subsidiary Company	State	Commission Approved ROE and ROR	Approval Date (Q1 2007 - Q2 2009)
Consolidated Edison	Consolidated Edison Company of New York Inc	NY	9.1% ROE 7.34% ROR	3/25/2008
	Orange & Rockland Utilities Inc	NY	9.4% ROE 7.69% ROR	7/16/2008
IDACORP Inc.	Idaho Power Co	ID	10.5% ROE 8.18% ROR	1/30/2009
PEPCO Holdings	Delmarva power & Light Co	MD	10% ROE 7.68% ROR	7/19/2007
	Potomac Electric Power Co	MD	10% ROE 7.99% ROR	7/19/2007
PG&E Corp.	Pacific Gas & Electric Co	CA	11.35% ROE 8.79% ROR	3/21/2007
Portland General		OR	10.1% ROE 8.33% ROR	12/29/2008
Sempra Energy	San Diego Gas & Electric	CA	10.7% ROE 8.23% ROR	7/31/2008
United Illuminating		CT	8.75% ROE 7.59% ROR	(2/4/09)

Source: Edison Electric Institute, Quarterly Financial Reports, Rate Case Summary, Q4 2007, Q4 2008, and Q2 2009.

Prepared by or under the supervision of: Susan F. Tierney

Commission Data Request 2-16

Request:

Please explain why there is a forecasted decline of 5.8% in total GWh DSM savings between 2009 and 2010 even though total GWh sales are forecasted to increase by 1.1% increase during the same period, as shown in Schedule NG-APM-6.

Response:

Most of the decline in 2010 compared to 2009 is due to lighting measures that have reached their end of life around that timeframe; 2003 through 2005 had very rapid growth in the residential lighting market. With a 5 to 7 year measure life, the bulk of the residential portfolio from the 2003-2005 years will stop contributing savings in the 2010 timeframe. The efficiency savings forecast only projects new measures installed through 2008, and therefore there are no new savings occurring in 2009 and 2010 that will counteract the 2010 decline. In reality, the programs will continue and there will be new savings that apply to the future years.

There was also a smaller decline in the Small Business Services program in 2003 and 2004, which also has some lighting measures with a six-year lifetime that will reach their end-of-life.

Therefore, the DSM forecast includes savings from programs approved and installed to date. Although the Company has goals to increase energy efficiency programs beyond this, meeting those goals is contingent upon a variety of factors, including the Commission's decisions on proposed energy efficiency programs.

Prepared by or under the supervision of: Alfred P. Morrissey, Jr. and Timothy Stout

Commission Data Request 2-17

Request:

Please provide a copy of the Employee Expense performance audit reference no. 278 identified in the response to Commission 1-7 on page 5 of 9.

Response:

Please see CONFIDENTIAL Attachment COMM 2-17, which is a copy of Audit Report No. 0278 - Employee Expense Performance.

Prepared by or under the supervision of: Robert L. O'Brien

Commission Data Request 2-24

Request:

Describe the policy and process for making donations to charitable organizations as set forth in Commission 1-74 including what or who determines to whom and how much is donated. Please explain why such expense should not be disallowed by the Commission.

Response:

In COMM 1-74, the Commission requested that the Company list lobbying expenses. As indicated in the response to COMM 1-74, lobbying costs are booked below the line and are not reflected in the cost of service. Neither the question nor the response in COMM 1-74 relate to charitable contributions. To be responsive to the question posed here, the Company offers the following in relation to charitable contributions:

The Social Policy Committee sets the strategy and policy for the Company. Approvals are based on the National Grid Delegations of Authority matrix. Recipients must be an IRS approved 501(c)(3) non-profit charitable organization and must be in or serve the National Grid service territory. The Company aims to designate funds to organizations that will have a positive impact on the lives of our customers, especially in the areas of energy, education and the environment.

Attachment COMM 2-24 provides the adopted guidelines by the Public Utilities Commission on charitable contributions by regulated utilities in accordance with Report and Order No. 12467, pursuant to an open meeting decision on September 7, 1989.

Per the calculation below, the amount of charitable contributions included by the Company in its cost of service in this proceeding of $548,593 falls within these guidelines which support $942,222.

Test Year Operating Revenue	$1,155,277,407
Cost of Service Percentage Limitation	0.08%
Cost of Service $ Limitation	$924,222
Test Year Donations Included in Cost of Service	$548,593

Prepared by or under the supervision of: Robert L. O’Brien

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION
100 Orange Street
Providence, R.I. 02903

MEMORANDUM

TO: Gas, Electric and Telephone Utilities

FROM: Luly E. Miller, Commission Clerk

SUBJECT: Charitable Contributions - Docket No. 1862

DATE: September 8, 1989

Attached are the adopted guidelines by the Public Utilities Commission on charitable contributions by regulated utilities in accordance with Report and Order No. 12467, pursuant to an open meeting decision on September 7, 1989.

cc Joseph R. Vanni, Fund for Community Progress
Albert Sisti, Injured Workers of Rhode Island
William J. Allen, United Way of Southeastern of NE
Bernadette Farina, March of Dimes
Henry Shelton, George A. Wiley Center

GUIDELINES ON CHARITABLE CONTRIBUTIONS BY REGULATED UTILITIES

I. PREAMBLE

The Public Utilities Commission's treatment of charitable contributions by regulated utilities is circumscribed by the pronouncements of the Rhode Island Supreme Court in United Transit Authority v. Nunes, 99 R.I. 501, 513-514, 209 A.2d 215, 59 PUR 3d 11 (1965) and Providence Gas Company v. Burman, 119 R.I. 78, 99-100, 376 A.2d 687, 22 PUR 4th 103 (1977): when charitable contributions are modest in amount, and productive of good community relations which will benefit the utility or its patrons, they must be allowed as legitimate operating expenses.

The Commission has reviewed the charitable contribution policies of its regulated utilities pursuant to its Report and Order in Docket 1862. (Order 12467, entered November 5, 1987). To delineate its own understanding of the Supreme Court standards and assist the regulated utilities' development of charitable giving plans, the Commission hereby announces its guidelines for contributions qualifying for operating expense treatment. The Commission's posture on cost of service treatment should not be interpreted as limiting the utilities' charitable giving. The utilities' ratepayers contribute a modest amount; decisions regarding a utility's "fair share" rest with the utility's shareholders. The utilities are encouraged to give back to the community some of the benefit they derive from doing business here.

II. OPERATING EXPENSE TREATMENT GUIDELINES

A. To qualify for operating expense treatment, a charitable contribution must be modest in amount and productive of good community relations:

(1) Modest in amount means equal to or less than .08% of operating revenues.

(2) Productive of good community relations means that the gifts shall be made to organizations operating within the service district, or which provide benefits to the utility, its employees, or its patrons.

B. Other Considerations

(1) The recipient charity must qualify as an IRC §501(c)(3) non-profit charitable organization.

(2) The utility shall establish a committee to draft internal guidelines, review solicitations and distributions, and keep records. At a minimum, the committee shall:

a. require solicitations to be in writing;

b. issue its decisions approving or rejecting solicitations in writing.

c. determine whether and under what conditions employees are solicited in the work place.

(3) A list of charitable contributions which are included in cost of service shall be filed in the utility's Annual Report to the Commission, and shall be provided by the company to its ratepayers, upon request.

(4) The time spent by executives on loan to charities shall not be included in the percentage limitation set forth in II A (1). However, if additional employees (part or full-time) must be hired to replace loaned executives, all expenses incurred therefrom shall be considered charitable contributions and included as part of the utility's annual contributions, subject to the percentage limitation established above.

Adopted in Open Meeting 9/7/89

Commission Data Request 2-26

Request:

Describe the policy and process for making political contributions as set forth in Commission 1-92 including what or who determines to whom and how much is contributed. Please explain why such expense should not be disallowed by the Commission.

Response:

As an initial matter, please note that Attachment COMM 1-92 shows that there were *no contributions* made in 2008, which is the test year for this case. Moreover, even if there were contributions made in 2008, the contributions would have been *excluded* from the test-year cost of service consistent with the Commission's ratemaking rules. As a result, there is no type of political contribution included in rates, or in any way recovered through rates.

Second, please note that the Commission's request in Commission Data Request 1-92 was for the Company to list any political contributions it made in the years 2006, 2007 and 2008. In answering the question, the Company listed items that were coded in its accounting system as "political or civic contributions." Two of the four items listed were associated with political contributions made outside of Rhode Island and the remaining two items were not "political contributions," but rather contributions to civic organizations.

Specifically, in Attachment COMM 1-92, there were four items categorized as "political contributions" in the years 2006 and 2007. The nature of these contributions is as follows:

- June 2006 – Niagara Mohawk Holdings Inc. ($5,000)
- June 2007 – National Grid Voluntary New York State PAC ($5,000)

The New York State Board of Elections allows corporate contributions to NY State Political Action Committees (PAC). The National Grid New York State PAC (formerly the Niagara Mohawk Holdings Inc PAC) is funded primarily by corporate contributions from a variety of National Grid companies, including Narragansett Electric Company. The contribution limit per company is $5,000 per calendar year.

- May 2006 – New England Governor's Conference Inc. ($25,000)

Commission Data Request 2-26 (cont.)

The New England Governor's/Eastern Canadian Premiers (NEG/ECP) held their 30th Annual Conference in Newport, RI on May 11 to 13, 2006. National Grid made a contribution in support of the event.

- August 2007 – Republican Governors Association ($10,000)

This payment was made for membership in the Republican Governors Association and sponsorship of the Education and Financial Services Forum held by the Republican Governors Association in Newport, RI.

Commission Data Request 2-32

Request:

Please identify in which company schedule an adjustment is made to reduce distribution costs by the amount of Standard Offer administrative costs that the company is proposing to recover through Standard Offer rates.

Response:

Please refer to Schedule NG-RLO-2, Page 2 of 39 at Line 23 for the requested adjustment to exclude Commodity Procurement Administrative Costs from the distribution revenue requirement in this proceeding

Prepared by or under the supervision of: Robert L. O'Brien

Commission Data Request 2-33

Request:

Assuming a customer moves back and forth between competitive supply and Standard Offer, please provide a detailed explanation of how, under the company's proposal, associated administrative expense is calculated and allocated.

Response:

The following is a detailed description of the Company proposed methodology to calculate and allocate uncollectible expenses to Standard Offer Customers. This calculation and allocation is presented on page 7 of Schedule NG-RLO-6. The Company's net charge-offs, as derived from its general ledger, and the Company's system that tracks charge-offs, only do so at the highest level (e.g., billing components are aggregated and there is no differentiation between service classification (rate class) and energy supply (Standard Offer and Last Resort versus Competitive Supply)). Therefore, the Company established a method to determine a proportionate share of net charge-offs that would fairly reflect only Standard Offer and Last Resort net charge-offs. Since all gross charge-offs must be initiated through the Company's billing system and the majority of recoveries also flow through the billing system, the Company believes that this information is a reasonable source for performing such an allocation.

The Company uses this information as a means to allocate net charge-offs to rate classes and then to amounts associated with Standard Offer and Last Resort billings. First, the Company allocates the total net charge-offs to rate classes. The reason for this allocation is that charge-off levels differ among rate classes, and the percentage of a customer's total bill that is attributable to what he/she is billed for Standard Offer and Last Resort Service is also dependent upon which rate class the customer receives delivery service. Therefore, to reach as accurate an end result of the analysis as possible, which is a fair representation of the level of Standard Offer and Last Resort charge-offs, it is necessary to perform the analysis by rate class. Based upon gross charge-off and recovery reports generated from the Company's billing system, the Company derives allocators by rate class. These allocators are then applied to the total net charge-offs to arrive at allocated total net charge-offs by rate class. This allocation is presented in Section 1: Allocation of 2008 Net Charge-Offs to Rate Classes.

Next, the Company needs to arrive at a way to estimate the proportionate share of total net charge-offs for Standard Offer and Last Resort Service customers that related only to Standard Offer and Last Resort Service amounts. Using the gross charge-off and recovery reports discussed above, the Company was able to accumulate the gross charge-off and recovery data associated with customers classified on Standard Offer and Last Resort

Commission Data Request 2-33 (cont.)

Service. The Company was then able to calculate, based on the data contained in its billing system, the percentage of net charge-offs attributable to Standard Offer and Last Resort Service accounts. This percentage is calculated in Section 2. Standard Offer % Last Resort Service Accounts as a Percentage of All Accounts. By determining this percentage, the Company could then estimate an allocable share of total net charge-offs attributable to amounts billed for Standard Offer and Last Resort Service for those Standard Offer and Last Resort Service accounts. This estimate is calculated in Section 3. Allocation of 2008 Net Charge-Offs to Standard Offer & Last Resort Service Accounts.

From the net charge-offs for Standard Offer and Last Resort Service customers accumulated from the Company's billing system, the Company then derives an estimate of the level of Standard Offer and Last Resort Service billings reflected in these net charge-offs. To accomplish this, the Company determines each rate class's total average rate for Standard Offer and Last Resort Service customers on a monthly basis. By determining how much the Standard Offer and Last Resort Service rate represents of the total average rate for each rate class, the Company derives an allocator used to determine a reasonable level of Standard Offer and Last Resort Service billings, measured as a percentage, that were likely included in the net Standard Offer and Last Resort Service charge-off amount. The result of this analysis represents an estimate of what was charged off related to Standard Offer and Last Resort Service billings as reflected in the Company's billing system. This estimate is converted to a percentage of total Standard Offer and Last Resort Service charge-offs attributable to Standard Offer and Last Resort Service billings. This percentage is calculated in Section 4. Commodity Billing Charge-Offs as a Percentage of Standard Offer and Last Resort Service Accounts Charged Off. Finally, this percentage is applied to the estimate of the allocated share of Standard Offer and Last Resort Service charge-offs to arrive at an estimate of the allocable share of Standard Offer and Last Resort Service charge-offs attributable to Standard Offer and Last Resort Service billings. This estimate is calculated in Section 5. Allocation of Estimated Commodity Charge-Offs to Commodity Billings.

The methodology described above is the same methodology currently used by Narragansett Electric Company's affiliates in Massachusetts and New Hampshire.

Commission Data Request 2-42

Request:

Please provide an itemized breakdown of "other revenue" of $7,699,395. (See NG-RLO-1)

Response:

Please see the Attachment to COMM 2-42 for the breakdown of "other revenue". Please note that as stated in the response to Division 3-2, the Company discovered an error in the Energy Profiler Online calculation, which had overstated revenue by approximately $20,000. The corrected amount has been reflected in this response.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company d/b/a National Grid
Detailed Summary of Other Revenue
Calendar Year 2008

Line	Summary by Ferc:		Rate Year Amount	
1	450	Forfeited Discount (Customer Late Payment Charges)	$2,230,203	
2	451	Miscellaneous Service Revenue	752,619	
3	454	Rent From Electric Property	2,947,916	
4	456	Other Electric Revenues	1,748,417	
5	Total		$7,679,155	
6				
7				
8	Additional Details:			
9				
10	451	Other Miscellaneous Service Revenues-Customer Service	$149,213	
11		Reconnect Charges	522,685	
12		Interval Data Services	(5,739)	1/
13		Service Turn on Charge	83,535	
14		Bad Debt Charge	2,925	
15		Total	$752,619	
16				
17	454	Pole Attachment Rental	$1,348,945	
18		Rent from Electric Property	581,347	
19		Rent from Support Payments	614,142	
20		Rent from Electric Property to Affiliates		
21		Lincoln Facility	159,540	
22		National Grid USA Service Company	51,742	
23		Wayfinder Group Inc.	192,200	
24		Total	$2,947,916	
25				
26	456	Supervisory and Administrative Allocations	$866,488	
27		CIAC Reclassifications	623,370	
28		Other Electric Revenues - Billing	257,813	
29		Cash receipts and miscellaneous entries	746	
30		Total	$1,748,417	

1/ Based on updated Energy Profiler Online calculation per response to Division 3-2.

Division Data Request 3-2

Request:

Referring to O'Brien testimony, Page 7, lines 19-20, please provide workpapers for the pro forma adjustment to other revenues.

Response:

Please see the following attachments for detail to the pro forma adjustment to other revenues:

- DIV 3-2 Attachment 1: Summary of the pro forma adjustment to revenues related to the Company's miscellaneous service offerings
- DIV 3-2 Attachment 2: Energy Profiler Online Calculation
- DIV 3-2 Attachment 3: Reconnection Fee Calculation
- DIV 3-2 Attachment 4: Enhanced Metering Calculation

Please note that in reviewing the calculations, the Company discovered an error in Attachment 2, which overstated revenue by approximately $20,000. This correction is reflected in both the Attachment 1 (Summary) and Attachment 2 (Energy Profiler Online) calculation. The Company will submit revised schedules reflecting this correction.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company
d/b/a National Grid
Revenue Adjustment Related to Service Offerings

Description	Number of Customers (2008)	2009 Charge		2009 Amount	2008 Charge	2008 Amount	Required Revenue
EPO - Single Requests	551	$83	1/	$45,733	$69	$38,019	$7,714
EPO - Annual Subscription Price for Single Account	369	$154	2/	56,826	$321	118,449	(61,623)
Reconnect Fee	16,419	$38	3/	624,743	$15	246,285	378,458
Enhanced Metering (option one)	0	$342	4/	-	$268	-	-
Enhanced Metering (option two)	35	$176	5/	6,170	$136	4,752	1,418
Total Additional Revenue				$733,472		$407,505	$325,967

1/ Attachment 2, Page 1, Line 21
2/ Attachment 2, Page 2, Line 7
3/ Attachment 3, Line 5
4/ Attachment 4, Page 1, Line 14
5/ Attachment 2, Page 1, Line 29

Narragansett Electric Company
Energy Profiler Online
Internet Access to Interval Data
Single Load Data Request Cost Analysis

Line	Fee for Managing Single Request		
1	Monthly Licensing Fee (Energy Profiler Online)	$6.41	1/
2			
3			
4	Cost of Preparing Bill and Cash Collections for Customer Data Analysis:		
5	Cost of labor per hour for Revenue Accounting senior clerk	$17.81	2/
6	Estimated time required to process data request	0.50	3/
7	Cost of labor to process data request	$8.91	
8	Labor-related overheads for Revenue Accounting senior clerk	6.54	4/
9	Total Revenue Accounting labor cost of processing data request	$15.45	
10			
11			
12			
13	Cost of Performing Customer Data Analysis:		
14	Cost of labor per hour for Load Data analyst	$35.34	5/
15	Estimated time required to process data request	1.00	3/
16	Cost of Labor to Process Data Request	$35.34	
17	Labor-Related Overheads for Load Data Analyst	25.95	6/
18	Total Load Data Labor Cost of Processing Data Request	$61.29	
19			
20			
21	**Total Fee for Performing Single Request**	**$83.00**	7/
22			
23	**Fee for Additional Account Requested at the Same Time**	**$6.41**	8/

1/ Monthly Licensing Fee based on two year average costs and participation. See page 3, Line 15
2/ Estimated average hourly rate
3/ Estimated time required to complete work required with each request
4/ Based upon actual average calendar year 2008 overhead rates for Service Company
5/ Estimated average hourly wage per analyst provided by department manager
6/ Based upon actual average calendar year 2008 overhead rates for Service Company
7/ Line 1 + Line 9 + Line 18, rounded
8/ Reflects one month subscription fee per Line 1

Narragansett Electric Company
Internet Access to Interval Data
Annual Subscription Pricing for "Energy Profiler Online"

Line			
1	Set-up costs of Load Data Services	$61.29	1/
2			
3	Cost of preparing bill and cash collections for customer data analysis	15.45	2/
4			
5	Annual customer cost of "Energy Profiler Online"	76.89	3/
6			
7	Annual subscription price for single account	**$154.00**	4/

1/ See Page 1, Line 18
2/ See Page 1, Line 9
3/ See page 3, Line 13

Narragansett Electric Company
Internet Access to Interval Data
Annual Pricing for "Energy Profiler Online"

Line			
1	Costs		
2			
3	Software Costs		
4	Annual Maintenance	$126,000	1/
5			
6	Total Costs	$126,000	
7			
8	Recovery		
9			
10	Customer Participation		
11	Total Accounts	1,639	
12			
13	Annual recovery per account (2 year average)	$76.89	2/
14			
15	Monthly Fee	**$6.41**	3/

1/ Contracted prices with web site provider
2/ Line 6 divided by Line 11
3/ Line 13 divided by Line 12

Narragansett Electric Company
Processing Costs for Reconnection Fee

Line	Transaction Costs		
1	Company costs for meter turn off due to non payment	$18.88	1/
2	Transportation costs for meter turn off due to non payment	1.38	2/
3	Company costs for meter turn on due to customer payment	16.18	3/
4	Transportation costs for meter turn on due to customer payment	1.61	4/
5	Total cost of reconnection	**$38.05**	5/

1/ Labor cost is based on the hourly wage of a meter worker to perform meter turn offs times an overhead accrual rate
2/ Reflects estimated transportation charges
3/ Labor costs is based on the hourly wage of a meter worker to perform meter turn ons times an overhead accrual rate
4/ Reflects estimated transportation charges
5/ Sum of Lines 1 through 4

Narragansett Electric Company
Commercial Enhanced Metering Options
One-Time Fee

Line			
1	**Service Option One**		
3	Hourly Reporting Equipment - Pulse Interface - Narragansett Electric Owned Equipment		
5	Incremental Cost of Commercial Meter with Internal Modem Installed		
8	Cost of capitalized meter	$174.07	
9	Cost of labor	60.92	1/
10	Labor - related overheads	69.17	2/
11	Transportation	2.99	3/
12	Estimated Materials	35.00	4/
14	**One Time Fee for Commercial Option One**	**$342.15**	
16	**Service Option Two**		
18	Hourly Reporting Equipment - Pulse Interface - Customer Owned Equipment		
20	Incremental Cost of Pulse Interface Box Installed		
23	Cost of pulse interface box	$38.20	
24	Cost of labor	60.92	5/
25	Labor - related overheads	69.17	2/
26	Transportation	2.99	3/
27	Estimated Materials - Pulse Initiator	5.00	
29	**One Time Fee for Commercial Option Two**	**$176.28**	

1/ Labor cost reflects estimate of 2.0 hours of meter worker time required to install meter with internal modem and complete meter exchange. This time estimate is based upon historical business practices. Labor cost is based upon the hourly wage of a meter worker.
2/ Based upon actual average calendar year 2008 overhead rates for Narragansett Electric.
3/ Reflects estimated transportation charges
4/ Includes telephone line surge suppresser, gel connectors, miscellaneous wire, tape, etc.
5/ Labor cost reflects estimate of 2.0 hours of meter worker time required to install program and connect pulses in meter, complete meter exchange and test. This time estimate is based upon historical business practices. Labor cost is based upon the hourly wage of meter worker per union labor agreement.

Narragansett Electric Company
Calculation of Monthly Charge for Enhanced Metering

Line	Service Option One		
1	Total Installation Cost of Enhanced Metering		
2	Equipment for this Option per Page 1 of 3	$342.15	1/
3			
4	Proposed Annual Carrying Charge	24.83%	2/
5			
6	Annual Enhanced Metering Charge	$84.97	3/
7			
8	**Monthly Enhanced Metering Charge**	**$7.08**	4/
9			
10			
11	**Service Option Two**		
12			
13	Total Installation Cost of Enhanced Metering		
14	Equipment for this Option per Page 1 of 3	$176.28	5/
15			
16	Proposed Annual Carrying Charge	24.83%	2/
17			
18	Annual Enhanced Metering Charge	$43.78	6/
19			
20	**Monthly Enhanced Metering Charge**	**$3.65**	7/

1/ Service Option One one-time cost as per attached Page 1, Line 14
2/ Annual Carrying Charge as per attached Page 3, Line 24
3/ Line 4 times Line 6.
4/ Line 8 divided by twelve.
5/ Service Option Two one-time cost as per attached Page 1, Line 29
6/ Line 16 times Line 18
7/ Line 20 divided by twelve

Narragansett Electric Company
Annual Carrying Charge
Enhanced Metering

Line								
1	Total Cost of Capital						8.98%	1/
2								
3								
4	Income Taxes:	Rate						
5								
6	Federal (FIT)	35%					3.12%	
7								
8	Composite Depreciation Rate						3.53%	2/
9					Average			
10					Depreciable			
11			Expense		Plant in Service			
12	Property Taxes ('000s)		17,959,422	3/	1,114,190,156	4/	1.61%	
13								
14	Pensions & Benefits ('000s)		18,593,491	5/	1,114,190,156	4/	1.67%	
15								
16	Employment Taxes ('000s)		145,000	6/	1,114,190,156	4/	0.01%	
17								
18								
19					Average			
20					Depreciable			
21			Expense		Dist. Plant in Svc.			
22	Distribution O & M Expense ('000s)		50,896,793	2/	860,582,621	2/	5.91%	
23								
24	Total Carrying Charge						24.83%	

1/ Reflects after-tax weighted average cost of capital as proposed in RIPUC Docket No. 4065
2/ Reflects composite depreciation rate on distribution plant for calendar year 2008
3/ Reflects distribution-related property tax expense per Company financials
4/ Reflects average distribution plant in service as of December 31, 2008
5/ Reflects calendar year 2008 amounts charged to FERC 926000, net of amounts applicable to the IFA per Earnings Report filed in RIPUC Docket No. 3617
6/ Reflects calendar year 2008 amounts for state and federal unemployment taxes applicable to distribution per December 31, 2008 Earnings Report filed in RIPUC Docket No. 3617
7/ Reflects calendar year 2008 distribution O&M amounts per Company financials

Division Data Request 3-22

Request:

Referring to NG-RLO-2, Page 5, line 26, please provide the amount of variable pay related operational goals and the amount related to financial goals.

Response:

As is stated in the testimony of Mr. Dowd (at page 8), approximately 40-50 percent of variable pay compensation is linked to individual objectives directly tied to established service quality measures such as safety, reliability, and customer satisfaction. The remaining portion is tied to Company financial performance. The Company is not able to identify the amounts on Page 5, line 26 of Schedule NG-RLO-2 associated with individual objectives versus financial performance because the variable pay is recorded to the Company's general ledger based on the total amount paid to employees.

Prepared by or under the supervision of: Robert L. O'Brien and William F. Dowd

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Division Data Request 6-31

Request:

Re: Schedules NG-SFT-4 and NG-SFT-5, please:

a. Provide the analyses and rationales upon which National Grid would rely to demonstrate to this Commission that the productivity offsets estimated in the referenced schedules for past periods are reasonably indicative of the levels of productivity offsets that this Commission should expect in future periods for National Grid's Rhode Island operations;

b. Provide the analyses upon which the Company relies to determine that it is reasonable to set a productivity offset factor at a fixed level that does not vary over time or with changing economic conditions, changing utility operations, or changes in factors within managements control;

c. Provide the witness' understanding of impact that utility acquisitions and mergers and utility industry restructuring have had on distribution utility productivity over the past 10-15 years;

d. Provide the data, studies and analyses the witness relies upon to support her understanding of the manner in which the influences of utility acquisitions and mergers and utility industry restructuring were addressed in the development of the estimates of energy distribution productivity that are presented in the referenced schedules;

e. Provide the Company's best estimate of the expected dollar value of the proposed 0.5% productivity offset at the time that the first annual Net Inflation Adjustment would be computed under the provisions of the Company's RDM;

f. Indicate when and in what forum the Company would propose that the on-going appropriateness of the initial 0.5% productivity offset factor would be reviewed by the Commission.

Response:

Please note that the Company previously responded to other sections in this Data Request.

e. The Company's estimate of the expected dollar value of the proposed 0.5% productivity offset at the time of the first annual Net Inflation Adjustment, using the illustrative data as presented in Schedule NG-RLO-7, is $734,000.

Prepared by or under the supervision of: Susan F. Tierney

Division Data Request 6-32

Request:

Re: witness O'Brien's Schedule NG-RLO-7. Please provide estimates that are comparable to those presented in Schedule NG-RLO-7 for CY 2013, CY 2014 and CY 2015.

Response:

Please see Attachment DIV-6-32-1 for the requested information.

Prepared by or under the supervision of: Robert L. O'Brien

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of RDM Revenue Adjustments

Line		(A) CY 2010	(B) CY 2011	(C) CY 2012	(D) CY 2013	(E) CY 2014	(F) CY 2015
	Calculation of Annual Target Revenue (ATR)						
1	Revenue Requirement Docket _______	281,076,526	281,076,526	281,076,526	281,076,526	281,076,526	281,076,526
2	Net Inflation Adjustment		1,697,274	4,136,372	6,631,368	9,168,778	11,749,325
3	Prior Year RDR Plan Revenue Reconciliation		0	2,752,724	6,127,883	5,515,501	5,188,950
4	Cumulative Net Historic Capital Adjustment	0	3,926,349	11,819,741	19,643,465	27,318,055	34,902,911
5	Annual Target Revenue	281,076,526	286,700,149	299,785,363	313,479,242	323,078,860	332,917,712
		Rates for CY 2010	**Rates for CY 2011**	**Rates for CY 2012**	**Rates for CY 2013**	**Rates for CY 2014**	**Rates for CY 2015**
	Components of Billed Revenue						
6	Revenue Requirement Docket _______	281,076,526	281,076,526	281,076,526	281,076,526	281,076,526	281,076,526
7	Prior Year RDR Plan Revenue Reconciliation		0	2,752,724	6,127,883	5,515,501	5,188,950
8	Net Inflation Adjustment		1,697,274	4,136,372	6,631,368	9,168,778	11,749,325
9	Cumulative Net Historic Capital Adjustment - Prior Year		0	3,926,349	11,819,741	19,643,465	27,318,055
10	Current Year Capital Adjustment		1,173,625	1,765,509	2,308,223	2,485,640	2,485,640
11	Cumulative RDR Plan Adjustment Factor Revenue	0	2,870,899	12,580,954	26,887,215	36,813,384	46,741,970
12	Total RDM Plan Revenue	281,076,526	283,947,425	293,657,480	307,963,741	317,889,910	327,818,496
13	Incremental RDR Plan Adjustment Factor Revenue	0	2,870,899	9,710,055	14,306,261	9,926,169	9,928,586
	Calculation of Annual RDM Reconciliation						
14	Actual Billed Revenue	281,076,526	283,947,425	293,657,480	307,963,741	317,889,910	327,818,496
15	Annual Target Revenue	281,076,526	286,700,149	299,785,363	313,479,242	323,078,860	332,917,712
16	Excess/(Under) billed Revenue	0	(2,752,724)	(6,127,883)	(5,515,501)	(5,188,950)	(5,099,216)

Line Notes

1 Distribution Revenue Requirement per Docket No. 4065
2 From Page 2 of 4, Line 22
3 Prior year Line 16 x (-1)
4 From Page 3 of 4 Line 52 for Current Year
5 Sum of Lines 1 through 4
6 From Line 1
7 Prior year Line 15 x (-1) - Amount to be allocated over total forecasted kWh's
8 From Line 2 - Amount to be allocated to each class based on class O&M allocator
9 Prior Year Line 4 - Amount to be allocated to each class based on class rate base allocator
10 From Page 4 Line 37 for Current Year - Amount to be allocated to each class based on class rate base allocator
11 Sum of Lines 7 through 10
12 Line 6 + Line 11
13 Current Year Line 11 - Prior Year Line 11
14 From Line 12
15 From Line 5
16 Line 14 - Line 15

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation Of Net Inflation Adjustment

		(A) As Approved Dkt 09____	(B) CY 2011	(C) CY 2012	(D) CY 2013	(E) CY 2014	(F) CY 2015
1	Four Quarter Average Annual Change - GPD PI		1.69%	2.19%	2.20%	2.20%	2.20%
2	Productivity Offset		-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
3	Net Inflation Allowance		1.19%	1.69%	1.70%	1.70%	1.70%
4							
5	Total Operating Expenses	218,758,717					
6	Less:						
7	Pension / OPEB expense	(13,581,795)					
8	Commodity Costs Tracker	(9,751,787)					
9	Loss on Reacquired Debt	(686,219)					
10	Depreciation	(41,465,676)					
11	Economic Development Program	(1,000,000)					
12	Net Synergy Expense Adjustments	(850,000)					
13	Environmental and Storm fund collections	(4,119,000)					
14	Inspection & Maintenance Program	(4,676,172)					
15							
16	Net Operating Expenses Subject to Inflation	142,628,068	142,628,068	144,325,342	146,764,440	149,259,436	151,796,846
17							
18	Net Inflation Adjustment		1,697,274	2,439,098	2,494,995	2,537,410	2,580,546
19							
20	Net Operating Expenses Subject to Inflation		144,325,342	146,764,440	149,259,436	151,796,846	154,377,393
21							
22	Cumulative Net Inflation Adjustment		1,697,274	4,136,372	6,631,368	9,168,778	11,749,325

Line Notes

1	Illustrative to be replaced with actual mid-year to mid year inflation rate in report file in November of current year.
2	Productivity offset rate as established in this proceeding, Docket No. 4065
3	Line 1 + Line 2
5	Total non-income tax operating expenses as approved in this proceeding Docket No. 4065
7 - 14	As approved in Docket No. 4065
16	Sum of Lines 5 through 14 for Column (A). All other Years, Prior Year Line 20
18	Line 3 x Line 16
20	Line 16 + Line 18
22	Prior Year Line 22 + Current Year Line 18

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Illustrative Computation of Historic Capital Adjustment

Line No.			(A) CY 2009	(B) CY 2010	(C) CY 2011	(D) CY 2012	(E) CY 2013	(F) CY 2014	(G) CY 2015
	Depreciable Net Plan Additions								
1	Actual Capital Spend - Illustrative to be replaced with Actual when known		$59,948,598	$75,931,916	$81,253,000	$87,479,000	$87,479,000	$87,479,000	$87,479,000
2	Beginning of Year CWIP - Actual Dec 31, 2008 amount		$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057
3	End of Year CWIP - Actual Year end amounts when known		$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057	$23,263,057
4	Plant Additions (Line 1 + Line 2 - Line 3)		$59,948,598	$75,931,916	$81,253,000	$87,479,000	$87,479,000	$87,479,000	$87,479,000
5	Plant Additions included in base Rates (Sch NG-RLO-2, Page 28, Line 11)		$59,948,598	$75,931,916					
6	Plant Additions not in base rates (Line 4 - Line 5)		$0	$0	$81,253,000	$87,479,000	$87,479,000	$87,479,000	$87,479,000
7									
8	Actual Retirements	1/	8,016,527	10,153,870	12,187,950	13,121,850	13,121,850	13,121,850	13,121,850
9	Retirements reflected in base rates (Sch NG-RLO-2, Page 28, Line 22)		8,016,527	10,153,870					
10	Retirements not in base rates (Line 8 - Line 9)		$0	$0	$12,187,950	$13,121,850	$13,121,850	$13,121,850	$13,121,850
11									
12	Net Depreciable Additions (Line 6 - Line 10)		$0	$0	$69,065,050	$74,357,150	$74,357,150	$74,357,150	$74,357,150
13	Cumulative Net Depreciable Additions (Prior Year Line 13 + Cur Year Line 12)		$0	$0	$69,065,050	$143,422,200	$217,779,350	$292,136,500	$366,493,650
14									
15	Change in Net Plant								
16	Plant Additions (From Line 6)		$0	$0	$81,253,000	$87,479,000	$87,479,000	$87,479,000	$87,479,000
17	Depreciation Expense - from Dkt No.____				41,321,762	41,321,762	41,321,762	41,321,762	41,321,762
18	Incremental Depreciable Amount (Line 10 - Line 11)		0	0	39,931,238	46,157,238	46,157,238	46,157,238	46,157,238
19	Cumulative Depreciable Amount (Prior Year Line 13 + Cur Year Line 12)		$0	$0	$39,931,238	$86,088,476	$132,245,714	$178,402,952	$224,560,190
20									
21	Deferred Tax Calculation:								
22	Composite Book Depreciation Rate - as approved in this proceeding, Dkt - 4065		3.56%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%
23	20 YR MACRS Tax Depreciation Rates		3.75%	7.22%	6.68%	6.18%	6.18%	6.18%	6.18%
24	20 YR MACRS Tax Depreciation Rates - 50% Bonus Depreciation		51.88%	3.61%	3.34%	3.09%	3.09%	3.09%	3.09%
25	Vintage Year Tax Depreciation:								
26	2009 Spend	2/	0	0	0	0	0	0	0
27	2010 Spend			0	0	0	0	0	0
28	2011 Spend				3,046,988	5,866,467	5,427,700	5,021,435	5,021,435
29	2012 Spend					3,280,463	6,315,984	5,843,597	5,406,202
30	Annual Tax Depreciation (Sum of Lines 26 through 29)		0	0	3,046,988	9,146,929	11,743,684	10,865,033	10,427,638
31	Cumulative Tax Depreciation (Prior Year Line 31 + Cur Year Line 30)		0	0	3,046,988	12,193,917	23,937,601	34,802,633	45,230,271
32									
33	Book Depreciation (Prior Line 13 x Line 22 +Cur. Line 12 x Line 22 x 50%)		0	0	1,170,653	3,601,659	6,122,366	8,643,074	11,163,781
34	Cumulative Book Depreciation (Prior Year Line 34 + Cur Year Line 33)		0	0	1,170,653	4,772,311	10,894,678	19,537,751	30,701,532
35									
36	Cumulative Book / Tax Timer (Line 31 - Line 34)		0	0	1,876,335	7,421,605	13,042,923	15,264,882	14,528,739
37	Effective Tax Rate		35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
38	Deferred Tax Reserve (Line 36 * Line 37)		$0	$0	$656,717	$2,597,562	$4,565,023	$5,342,709	$5,085,058
39									
40	Rate Base Calculation:								
41	Cumulative Incremental Spend (Line 19)		$0	$0	$39,931,238	$86,088,476	$132,245,714	$178,402,952	$224,560,190
42	Accum Depreciation (Line 34 x (-1))		0	0	(1,170,653)	(4,772,311)	(10,894,678)	(19,537,751)	(30,701,532)
43	Deferred Tax Reserve (Line 38 x (-1))		0	0	(656,717)	(2,597,562)	(4,565,023)	(5,342,709)	(5,085,058)
44	Deferred Tax Reversal on 2008 assets		0	0	7,444,836	11,568,759	16,415,863	21,953,012	28,133,213
45	Year End Rate Base (Sum of Lines 41 through 44)		$0	$0	$45,548,704	$90,287,362	$133,201,876	$175,475,504	$216,906,813
46									
47	Revenue Requirement Calculation:								
48	Average Rate Base ((Prior Line 45 + Cur Year Line 45) /2)		$0	$0	$22,774,352	$67,918,033	$111,744,619	$154,338,690	$196,191,158
49	Pre-Tax ROR	3/	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
50	Return and Taxes (Line 48 x Line 49)		0	0	2,755,697	8,218,082	13,521,099	18,674,981	23,739,130
51	Book Depreciation (Line 33)		0	0	1,170,653	3,601,659	6,122,366	8,643,074	11,163,781
52	Annual Revenue Requirement (Line 50 + Line 51)		$0	$0	$3,926,349	$11,819,741	$19,643,465	$27,318,055	$34,902,911

1/ Assumes 15% of Capital Spend to be replaced with actual retirements
2/ Assumes 75% of CY 2009 capital spending qualifies for 50% bonus depreciation deduction
3/ Weighted Average Cost of Capital as approved in this Proceeding Docket No. 4065

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax Return
Long Term Debt	44.80%	6.79%	3.04%		3.04%
Short Term Debt	5.00%	2.50%	0.13%		0.13%
Preferred Stock	0.20%	4.50%	0.01%		0.01%
Common Equity	50.00%	11.60%	5.80%	3.12%	8.92%
	100.00%		8.98%	3.12%	12.10%

National Grid - Narragansett Electric Company
Illustrative Revenue Decoupling Mechanism
Computation of Current Capital Adjustment

Line No.	Description	Reference		(A) 2009 Actual Capital Spend	(B) 2010 Actual Capital Spend	(C) 2 Year Average Actual Spend	(D) Company /Cust Sharing Adj.	(E) CY 2011	(F) 2010 Actual Capital Spend	(G) 2011 Capital Spend	(H) 2 Year Average Actual Spend	(I) Company /Cust Sharing Adj.
	Depreciable Net Plan Additions											
1	Actual Capital Spend - Illustrative to be replaced with Actual when known											
2	Actual Capital Spend - Illustrative to be replaced with Actual when known			$59,948,598	$75,931,916	$67,940,257	75.00%	$50,955,193	$75,931,916	$81,253,000	$78,592,458	75.00%
3	Beginning of Year CWIP - Actual Dec 31, 2008 amount, then prior year Line 4							$23,263,057				
4	End of Year CWIP - Actual Year end amounts when known							$23,263,057				
5	Plant Additions	(Line 1 + Line 2 - Line 3)						$50,955,193				
6	Retirements		1/					$12,187,950				
7	Net Depreciable Additions	(Line 5 - Line 6)						$38,767,243				
8												
9	Net Rate Base Change											
10	Plant Additions (From Line 4)							$50,955,193				
11	Depreciation Expense - actual 2009 then from Dkt 09-39							41,321,762				
12	Incremental Depreciable Amount	(Line 10 - Line 11)						9,633,431				
13												
14	Composite Book Depreciation Rate - as approved in this proceeding, Dkt - 09-__							3.39%				
15	20 YR MACRS Tax Depreciation Rates							3.75%				
16												
17	Tax Depreciation:	(Line 5 x Line 15)						1,910,820				
18												
19	Book Depreciation	(Line 7 x Line 14 x 50%)						657,105				
20												
21	Book / Tax Timer	(Line 17 - Line 19)						1,253,715				
22	Effective Tax Rate							35.000%				
23	Deferred Tax Reserve	(Line 21 x Line 22)						$438,800				
24												
25	Rate Base Calculation:											
26	Cumulative Incremental Spend	(Line 12)						$9,633,431				
27	Accum Depreciation	(Line 19 x (-1))						(657,105)				
28	Deferred Tax Reserve	(Line 23 x (-1))						(438,800)				
29	Deferred Tax Reversal on 2008 assets											
30	Year End Rate Base	(Sum of Lines 26 through 29)						$8,537,526				
31												
32	Revenue Requirement Calculation:											
33	Average Rate Base	(Line 30/2)						$4,268,763				
34	Pre-Tax ROR		2/					12.10%				
35	Return and Taxes	(Line 33 x Line 34)						516,520				
36	Book Depreciation	(Line 19)						657,105				
37	Annual Revenue Requirement	(Line 36 + Line 37)						$1,173,625				

Line No.	(J) CY 2012	(K) 2011 Actual Capital Spend	(L) 2012 Capital Spend	(M) 2 Year Average Actual Spend	(N) Company /Cust Sharing Adj.	(O) CY 2013	(P) 2012 Actual Capital Spend	(Q) 2013 Capital Spend	(R) 2 Year Average Actual Spend	(S) Company /Cust Sharing Adj.	(T) CY 2014	(U) 2013 Actual Capital Spend	(V) 2014 Capital Spend	(W) 2 Year Average Actual Spend	(X) Company /Cust Sharing Adj.	(Y) CY 2015
1																
2	$58,944,344	$81,253,000	$87,479,000	$84,366,000	75.00%	$63,274,500	$87,479,000	$87,479,000	$87,479,000	75.00%	$65,609,250	$87,479,000	$87,479,000	$87,479,000	75.00%	$65,609,250
3	$23,263,057					$23,263,057					$23,263,057					$23,263,057
4	$23,263,057					$23,263,057					$23,263,057					$23,263,057
5	$58,944,344					$63,274,500					$65,609,250					$65,609,250
6	$13,121,850					$0					$0					$0
7	$45,822,494					$63,274,500					$65,609,250					$65,609,250
8																
9																
10	$58,944,344					$63,274,500					$65,609,250					$65,609,250
11	41,321,762					41,321,762					41,321,762					41,321,762
12	17,622,582					21,952,738					24,287,488					24,287,488
13																
14	3.39%					3.39%					3.39%					3.39%
15	3.75%					3.75%					3.75%					3.75%
16																
17	2,210,413					2,372,794					2,460,347					2,460,347
18																
19	776,691					1,072,503					1,112,077					1,112,077
20																
21	1,433,722					1,300,291					1,348,270					1,348,270
22	35.000%					35.000%					35.000%					35.000%
23	$501,803					$455,102					$471,895					$471,895
24																
25																
26	$17,622,582					$21,952,738					$24,287,488					$24,287,488
27	(776,691)					(1,072,503)					(1,112,077)					(1,112,077)
28	(501,803)					(455,102)					(471,895)					(471,895)
29																
30	$16,344,088					$20,425,133					$22,703,517					$22,703,517
31																
32																
33	$8,172,044					$10,212,567					$11,351,758					$11,351,758
34	12.10%					12.10%					12.10%					12.10%
35	988,817					1,235,721					1,373,563					1,373,563
36	776,691					1,072,503					1,112,077					1,112,077
37	$1,765,509					$2,308,223					$2,485,640					$2,485,640

1/ Assumes 15% of Capital Spend to be replaced with actual retirements
2/ Weighted Average Cost of Capital as approved in this Proceeding Docket 4065

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax Return
Long Term Debt	44.80%	6.79%	3.04%		3.04%
Short Term Debt	5.00%	2.50%	0.13%		0.13%
Preferred Stock	0.20%	4.50%	0.01%		0.01%
Common Equity	50.00%	11.60%	5.80%	3.12%	8.92%
	100.00%		8.98%	3.12%	12.10%

Division Data Request 7-8

Request:

Re: page 9 of 27, lines 1-9, of the testimony of witness King. Please provide:

a. The number of persons employed by the Company that were Rhode Island residents as of December 31, 2008 and the percentage of total employees serving in Rhode Island operations that were Rhode Island residents as of that date;

b. The number of persons employed by the Company that were Rhode Island residents as of the date that National Grid closed on its merger with Narragansett Electric Company and the percentage of total employees serving the Company's Rhode Island operations that were Rhode Island residents as of that date.

Response:

a. As of December 31, 2008, there were 457 employees of The Narragansett Electric Company (electric operations), of which 399 employees (or 87%) live in Rhode Island.

b. As of May 1, 2000, there were 701 employees of The Narragansett Electric Company (electric operations), of which 576 employees (or 82%) lived in Rhode Island.

Please note that a factor in the change in the total number of employees associated with the Rhode Island electric operations is that employees of The Narragansett Electric Company as of May 1, 2008 may now be providing services to The Narragansett Electric Company as an employees of National Grid's service companies. For the service companies, the requested information is as follows:

As of December 31, 2008, there were 2,431 service company employees (consisting of employees from the legacy National Grid USA Service Company and two legacy KeySpan service companies), of which 222 live in Rhode Island.

As of May 1, 2000, there were 1,723 National Grid USA Service Company employees, of which 175 lived in Rhode Island.

Prepared by or under the supervision of: William F. Dowd

Division Data Request 7-14

Request:

Re: page 16 of 27, line 12, through page 17 of 27, line 5, of the testimony of witness King. Please:

a. Provide the Company's rate base and revenue requirement that were approved by the Commission at the conclusion of the referenced 1995 rate proceeding and identify the portions of each that would be attributable to its Rhode Island distribution system operations; and

b. Explain why the Company does not consider any of the subsequent reviews of the Company's rates (e.g., Dockets 2930 and 3617, which occurred subsequent to the 1995 proceeding) to reflect a "full base rate proceeding." As part of the response to this request, please indicate the elements of the Company's cost of service and rates that were not reviewed in each of the subsequent Commission proceedings that the witness references that would be necessarily reviewed as part of a "full base rate proceeding".

Response:

a. Please see Attachment 7-14, which is a copy of the Commission's Order in Docket No. 2290 (October 11, 1995), which was the Company most recent base-rate proceeding. Attachment 1 to the Order presents the Company's approved cost of service. The revenue requirement and rate base attributable to distribution system operations are shown on pages 1 and 16, respectively.

b. The proceedings conducted in Dockets 2930 and 3617 each involved agreement on, and approval of, a long-term "Incentive Based Rate Plan". Neither docket involved the adjudication of the Company's cost of service, including a review of annual O&M expenses, annual revenues or capital investments. In particular, Docket 3617 involved the review and approval of a "savings proof" as a follow-up to the Settlement Agreement approved in Docket 2930. As part of that review proceeding, the Company agreed to a revenue reduction and prospective sharing calculation included as part of a "black-box" settlement, which did not include specific findings regarding each element of rate base, revenue or expense. A "full base-rate proceeding" would involve review of each element of the Company's revenue requirement to align rate recovery with the Company's actual costs incurred to serve customers, including a fair return. This did not occur in either Docket 2930 or 3617.

Prepared by or under the supervision of: Robert L. O' Brien

Division Data Request 8-10

Request:

Please provide detailed information on your theft of service process/program.

Response:

Please refer to Attachment DIV 8-10.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Revenue Protection

Service Description:

Management and oversight of the strategy, policy and procedure for suspected theft of service investigations (Referral, Investigation, Case Tracking, Billing, Prosecution, and Collection); Development and implementation of a robust analytical framework to assist in the detection, deterrence and prevention of revenue losses utilizing the meter tamper information and customer information systems.

Revenue Protection investigates:

- Suspected Energy Theft Cases (Tampering and Bypass)
- Company Meter Errors (Meters not in the billing systems, wrong billing constants (multipliers), incorrect wiring
- Meter and Equipment Failures: High value situations or bulk failures resulting in significant revenue loss.

Revenue Protection maintains the Meter and Metering Equipment Security Key program.

NG NE Theft of Service Process Flow

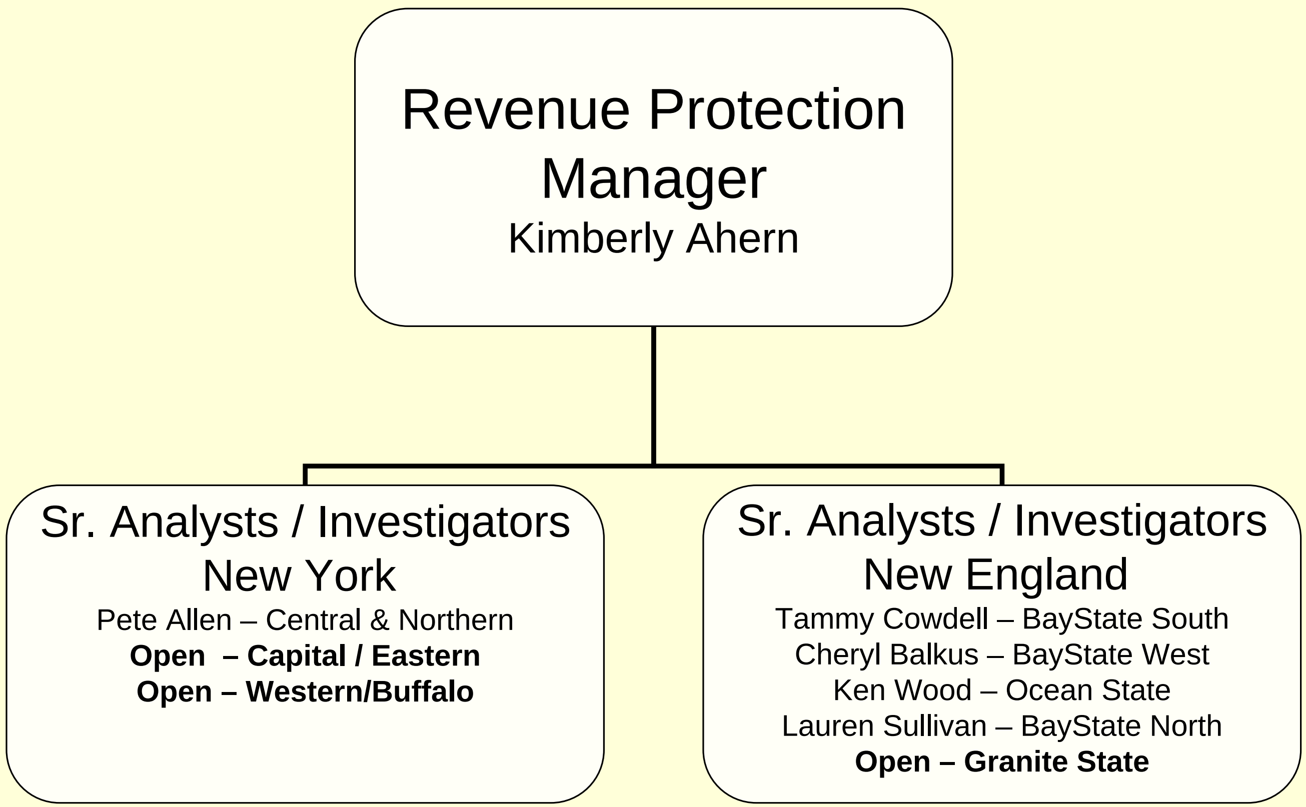
- Receives report of suspected theft
- Review Customer Service System (CSS) for account, customer and meter history.
- If theft exists, Initiate case in Case Tracking System (CTS)
- Revenue Protection group (within Credit & Collections) creates a Revenue Assurance (RA) investigation order for a follow-up investigation, as required. (If field visit not required by Customer Meter Services (CMS), Loss Reconstruction analysis is performed.)
- Customer Meter Services performs investigation to determine problem.
- CMS completes Revenue Protection Field Investigation Report
- Revenue Protection group reviews completed Field Investigation reports
- Loss Reconstruction analysis performed
- Coordinates installation of check meter (electric only when required)
- Determine litigation and /or prosecution, civil or criminal (Based on case value, customer cooperation, if search warrant needed for evidence)
- Review case with company attorney
- Customer is contacted, interview conducted when required
- Loss reconstruction completed, Billing Request Form emailed to Accounts Processing
- Accounts Processing bills account in system
- Credit & Collections performs collection activities to collect monies due from customer via settlement, payment in full, or payment agreement.
- Close case in CTS

Theft of Service

Reactive

Detection		Referral	Case Tracking	Investigation		Billing	Collection	Prosecution	Award Processing
Field Personnel Employees Customers Law Enforcement	NGNY	Tip Line Email Website - Intra & Extra Field Report Phone Call Electronic Rev Pro Report (Collections)	Revenue Protection CASE TRACKING SYSTEM (CTS) (Collections)	Collections	Security	Accounts Processing	Collections	Collections	Customer Meter Services
	NGNE	Tip Line Email Website - Intra & Extra Field Report Phone Call Electronic Rev Pro Report (Collections)	Revenue Protection CASE TRACKING SYSTEM (CTS) (Collections)	Collections		Accounts Processing	Collections	Collections	Collections
	KEDNY	Suspect Tickets Phone Call Theft of Service Report (Customer Meter Services)	None (Customer Meter Services)	Customer Meter Services		Accounts Processing	Collections	Collections	Customer Meter Services
	KEDNE	Phone Call Revenue Protection Form (Customer Meter Services)	None (Customer Meter Services)	Customer Meter Services		Accounts Processing	Customer Meter Services	Customer Meter Services	Customer Meter Services
	LI	Tip Line UMS Report Phone Call (Collections)	Revenue Protection Quickbase Tracking System (Collections)	Customer Meter Services		Collections	Collections	Collections	Collections

National Grid New England &Upstate NY



Division Data Request 10-11

Request:

Referring to Exhibit NG-RLO-2, Page 5, please provide an analysis of the reasons for the approximate 9.2% increase in actual test year union wages on Line 1 to the annualized wages as of January 1, 2009 on Line 11. The response should break down the increase by increases in wage rates, employee complement, and any other identifiable causes and should include supporting calculations.

Response:

The table below lists the identifiable causes of the increase in test-year wages, based on the Company's best estimation:

Ice Storm Wages Excluded from Line 1 ($259,000)	1.1%
Net Increase in Employee Complement (1/1/2008 through 1/1/2009)	4.6%
Effect of General Union Wage Increase (effective 5/12/2008)	1.1%
Time-in-Grade Promotions/Salary Progressions	1.0%
All other	1.4%
Total	9.2%

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-17

Request:

Referring to the response to Division Data Request 1-3, please explain the increase in the IFA plant from December 31, 2008 to March 31, 2009.

Response:

The increase in IFA plant from December 31, 2008 to March 31, 2009, as shown in the Attachment DIV 10-17 is related to the following three components:

- Transmission Plant (+$3.7 million): an increase in transmission plant in service due to additional projects being placed into service during the period.

- General Plant (+$6.8 million): an increase in general plant allocated to transmission resulting from an increase in the salary allocator upon which general plant is allocated to transmission. The increase in the salary allocator reflects higher base Company salaries charged to transmission for the quarter ended March 31, 2009, as a percentage of total Company base salaries, excluding Administrative and General costs.

- Tower Hill Reclass (+$2.9 million): the manner in which the reclass of the Tower Hill project from transmission to distribution was reflected in December 2008 versus in March 2009 in the response to Division Data Request 1-3. As this project was placed in service in June 2008 but reclassed from transmission to distribution in May 2009, the reclass should have been reflected in each quarter from June 2008 through March 2009, rather than just in December 2008.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company d/b/a National Grid
Change in IFA Plant - December 2008 versus March 2009

Line			Dec 2008	Mar 2009	Difference	
			(a)	(b)	(c)	
1	Total Per IFA:					
2	Plant in Service					
3	Transmission Plant in Service	Ferc 101	225,908,256	231,099,949	5,191,693	
4	Transmission Plant in Service	Ferc 106	11,442,596	9,969,160	(1,473,436)	
5	Total Transmission Plant in Service		237,350,851	241,069,109	3,718,258	
6	General Plant in Service Allocated to Transmission	Ferc 101	1,391,216	8,085,914	6,694,698	1/
7	General Plant in Service Allocated to Transmission	Ferc 106	18,747	108,949	90,202	1/
8	Total General Plant in Service Allocated to Transmission		1,409,963	8,194,863	6,784,900	1/
9	Subtotal Plant in Service		238,760,815	249,263,972	10,503,158	
10						
11	Less Tower Hill Reclass		(2,927,735)		2,927,735	
12						
13	Total IFA Plant in Service per Schedule NG-RLO-2, Page 31, Line 1 and Division Data Request 1-3		235,833,080	249,263,972	13,430,893	
14						
15						
16	1/ Allocation of General Plant to Transmission:					
17						
18	Company Plant in Service (Transmission & General Plant)					
19	Transmission Plant in Service	Ferc 101	225,908,256	231,099,949	5,191,693	
20	Transmission Plant in Service	Ferc 106	11,442,596	9,969,160	(1,473,436)	
21	Total Transmission Plant in Service		237,350,851	241,069,108	3,718,257	
22	Total General Plant in Service	Ferc 101	57,558,087	57,564,057	5,970	
23	Total General Plant in Service	Ferc 106	775,615	775,615	0	
24	Total General Plant in Service		58,333,702	58,339,672	5,970	
25	Subtotal Plant in Service		295,684,553	299,408,780	3,724,227	
26						
27	Salary Allocator for Transmission applicable to General Plant		2.42%	14.05%		2/
28						
29	General Plant in Service Applicable to Transmission	Ferc 101	1,391,216	8,085,914	6,694,698	3/
30	General Plant in Service Applicable to Transmission	Ferc 106	18,747	108,949	90,202	4/
31	Total General Plant in Service Applicable to Transmission		1,409,963	8,194,863	6,784,900	

2/ Derivation of the Salary Allocator

	Dec 2008	Mar 2009
Company Salaries Charged to Transmission O&M	48,483	254,124
Company Salaries Charged to Distribution and Customer O&M	1,957,365	1,554,999
Total	2,005,847	1,809,123
	2.42%	14.05%

3/ December and March columns = Line 22 x Line 27
4/ December and March columns = Line 23 x Line 27

Division Data Request 10-18

Request:

Referring to the response to Division Data Request 1-3, please explain the decrease in the IFA accumulated deferred FIT from December 31, 2008 to March 31, 2009.

Response:

The main driver in the decrease in the total accumulated deferred tax liability between December 31, 2008 and March 31, 2009 was due to an increase in both the pension and OPEB liabilities, booked under FAS 158 accounting rules in March 2009. Since FAS 158 is a fair market value approach, the decline in the stock market in the past year led to a decrease in the asset value of the pension and OPEB investments, requiring an increase in the liability accounts. Since that increase in pension and OPEB liability is not a good current deduction for income tax purposes (tax deductions occur when plans are funded), an increased deferred tax asset is also recorded.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 10-19

Request:

Referring to Exhibit NG-RLO-2, Page 32, please explain the decrease in IFA plant from September 2008 to December 2008.

Response:

The decrease in IFA plant from September 2008 to December 2008, as shown in the Attachment to DIV 10-19 is related to the following three components:

- Transmission Plant (-$5.0 million): a decrease in transmission plant related principally to an inadvertent error in an accounting transfer between FERC account 106000, Completed Construction not Classified, which is part of rate base, and FERC account 107000, Construction Work in Progress, which is not part of rate base, which left the balance in rate base overstated as of September 2008. This was corrected in October 2008.

- General Plant (-$2.1 million): a decrease in general plant allocated to transmission resulting from a decrease in the salary allocator upon which general plant is allocated to transmission. The decrease in the salary allocator reflects lower base Company salaries charged to transmission for the quarter ended December 31, 2008, as a percentage of total Company base salaries, excluding Administrative and General costs.

- Tower Hill Reclass (-$2.9 million): the manner in which the reclass of the Tower Hill project from transmission to distribution which was reflected in the cost of service in December 2008 versus September 2008. As this project was placed in service in June 2008 but reclassed from transmission to distribution in May 2009, the reclass should have been reflected in each quarter from June 2008 through March 2009, rather than just in December 2008.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company d/b/a National Grid
Change in IFA Plant - September 2008 versus December 2008

Line			Sept 2008 (a)	Dec 2008 (b)	Difference (c)	
1	Total Per IFA:					
2	Plant in Service					
3	Transmission Plant in Service	Ferc 101	201,315,010	225,908,256	24,593,245	
4	Transmission Plant in Service	Ferc 106	41,045,385	11,442,596	(29,602,789)	
5	Total Transmission Plant in Service		242,360,395	237,350,851	(5,009,543)	
6	General Plant in Service Allocated to Transmission	Ferc 101	3,465,003	1,391,216	(2,073,786)	1/
7	General Plant in Service Allocated to Transmission	Ferc 106	48,604	18,747	(29,857)	1/
8	Total General Plant in Service Allocated to Transmission		3,513,606	1,409,963	(2,103,643)	1/
9	Subtotal Plant in Service		245,874,001	238,760,815	(7,113,186)	
10						
11	Less Tower Hill Reclass			(2,927,735)	(2,927,735)	
12						
13	Total IFA Plant in Service per Schedule NG-RLO-2, Page 32, Line 1		245,874,001	235,833,080	(10,040,921)	
14						
15						
16	1/ Allocation of General Plant to Transmission:					
17						
18	Company Plant in Service (Transmission & General Plant)					
19	Transmission Plant in Service	Ferc 101	201,315,010	225,908,256	24,593,245	
20	Transmission Plant in Service	Ferc 106	41,045,385	11,442,596	(29,602,789)	
21	Total Transmission Plant in Service		242,360,395	237,350,851	(5,009,543)	
22	Total General Plant in Service	Ferc 101	57,761,594	57,558,087	(203,507)	
23	Total General Plant in Service	Ferc 106	810,228	775,615	(34,613)	
24	Total General Plant in Service		58,571,822	58,333,702	(238,120)	
25	Subtotal Plant in Service		300,932,217	295,684,553	(5,247,664)	
26						
27	Salary Allocator for Transmission applicable to General Plant		6.00%	2.42%		2/
28						
29	General Plant in Service Applicable to Transmission	Ferc 101	3,465,013	1,391,216	(2,073,797)	3/
30	General Plant in Service Applicable to Transmission	Ferc 106	48,604	18,747	(29,857)	4/
31	Total General Plant in Service Applicable to Transmission		3,513,617	1,409,963	(2,103,654)	

2/ Derivation of the Salary Allocator

	Sept 2008	Dec 2008
Company Salaries Charged to Transmission O&M	106,665	48,483
Company Salaries Charged to Distribution and Customer O&M	1,671,435	1,957,365
Total	1,778,100	2,005,847
	6.00%	2.42%

3/ December and March columns = Line 22 x Line 27
4/ December and March columns = Line 23 x Line 27

Division Data Request 11-1

Request:

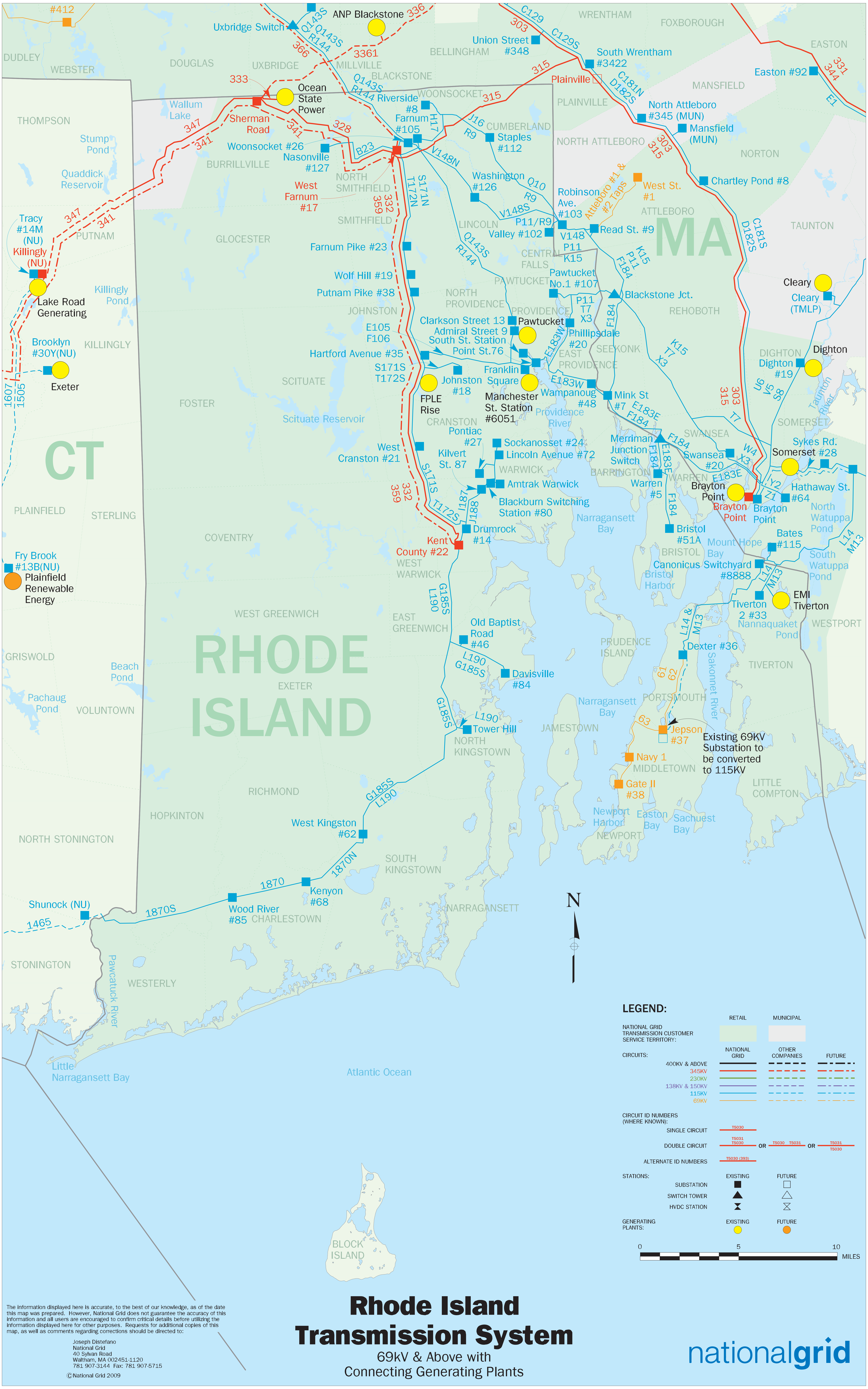
Page 4, line 1: Please provide a geographic, transmission level map of the National Grid system in RI, showing lines by voltage and the location of the 100 substations. Also provide a summary of the circuit miles of distribution lines broken down by voltage level and overhead / underground.

Response:

Please refer to Attachment DIV-11-1-1, which is a Rhode Island Transmission System Map showing the location of lines with voltages of 69kV and above, together with a transmission voltage legend and substation locations.

Please refer to Attachment DIV-11-1-2 for the summary of Rhode Island distribution circuit miles for overhead/underground by line voltage and circuit length.

Prepared by or under the supervision of: John Pettigrew



The information displayed here is accurate, to the best of our knowledge, as of the date this map was prepared. However, National Grid does not guarantee the accuracy of this information and all users are encouraged to contact all direct sources before utilizing the information displayed here for other purposes. Requests for additional copies of this map, as well as comments regarding corrections should be directed to:

Joseph Distefano
National Grid
40 Sylvan Road
Waltham, MA 002451-1120
781 907-3144 Fax: 781 907-5715

Rhode Island Transmission System

69kV & Above with Connecting Generating Plants

nationalgrid

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DATE: 14-Aug-09 09:23

Rhode Island Circuit Miles

By Operating District and Voltage Group

Operating District	Line Voltage Group	Number of Rows/Segments	Length (miles)	Length (feet)
53 - Capital	2.4	2,159	114.4	603,972
53 - Capital	4.16	3,999	130.0	686,647
53 - Capital	4.8	15	0.4	1,877
53 - Capital	13.2	29,322	1,785.0	9,424,636
53 - Capital	23	520	51.2	270,571
53 - Capital	35	113	10.9	57,513
56 - Coastal	2.4	2,026	155.8	822,754
56 - Coastal	4.16	2,358	103.0	543,902
56 - Coastal	4.8	3	0.2	1,291
56 - Coastal	13.2	21,881	1,522.1	8,036,856
56 - Coastal	23	283	32.2	169,753
56 - Coastal	35	362	39.3	207,518
	Total	**63,041**	**3,944.5**	**20,827,290**

Division Data Request 11-3

Request:

Page 6: Does National Grid monitor other reliability measures such as CAIDI, CAIFI, or MAIFI? If so, please provide those statistics from 2001 to 2009.

Response:

National Grid regularly monitors CAIDI in Rhode Island. The statistics for the years 2001-2009 are provided below.

Year	CAIDI
2001	63.3
2002	73.2
2003	69.4
2004	72.6
2005	71.3
2006	75.6
2007	64.1
2008	64.4
2009 YTD	55.2

National Grid does not regularly monitor CAIFI or MAIFI in Rhode Island.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-5

Request:

Page 7, lines 9-13: Please describe the changes to its organizational structure that will increase efficiency and effectiveness. Provide an organizational chart before and after these changers are made.

Response:

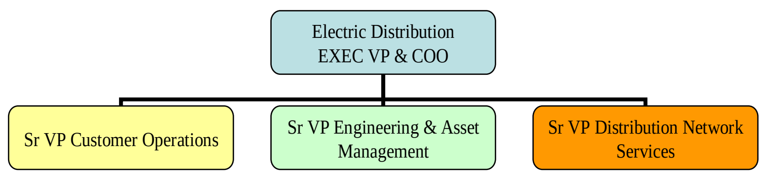
The primary changes are focused on an analysis of where work is performed and how work flows across the organization. The Company's objective is to clarify functional accountabilities and linkages across processes. The changes were primarily an attempt to resolve role overlaps or gaps within the organization and to drive improved performance in safety, reliability, customer service and efficiency. The Company utilized benchmarking and best practice information to assess the work currently performed against the four strategic priorities of customer service, reliability, safety and efficiency. Based on this analysis, the Company produced a recommended model that altered the original organizational structure and realigned specific processes into new areas of accountability. The EDO organization combines the benefits of functional alignment of capabilities with the benefits of strong process orientation. In some cases, pursuing a center of excellence for specific processes ensures the Company could deliver a more consistent and better aligned output that enhances the customer experience, maintains our highest levels of safety, and ensures our continued focus on reliability while providing for efficient execution of work.

Please see the organization tables below.

Prepared by or under the supervision of: John Pettigrew

<u>Division Data Request 11-5 (cont.)</u>

EDO Organization Chart
Prior to transformation



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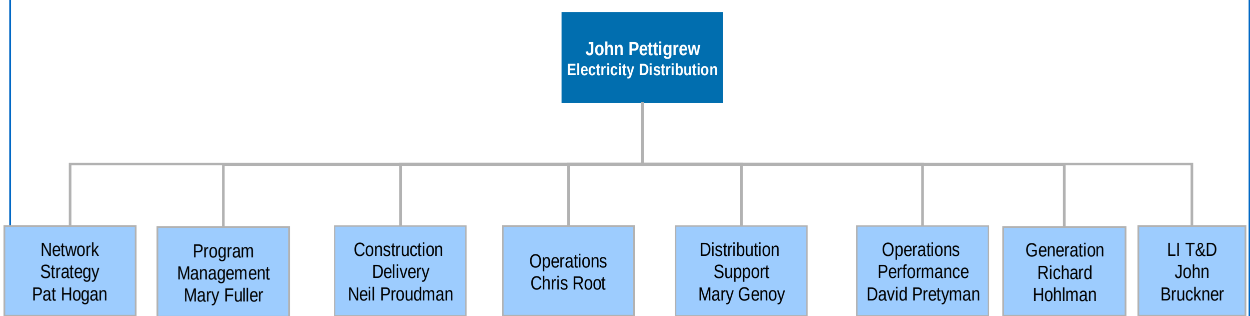
nationalgrid
The power of action.

Division Data Request 11-5 (cont.)

EDO Organization Chart Post transformation



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nationalgrid
The power of action.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-8

Request:

Page 8, line 21 to page 9, line 2: Please describe in as much detail as possible the organizational changes and series of initiatives referenced.

Response:

As a matter of good business practice, National Grid consistently undertakes efforts to improve the quality, efficiency and level of service it provides to its customers. These efforts vary in terms of approach and motivating factors. Motivating factors include market/industry driven change or specific business-improvement programs, as well as ongoing internal review, discussion and sharing of best practices, which occurs across National Grid's international footprint as a normal course of business.

As part of the Company's ongoing efforts to improve the ways in which it provides service to its customers and the efficiency with which it provides this service, Electricity Distribution Operations ("EDO") has formalized its current review of its work processes in a program to which it refers as "transformation." The Company's goal as part of the transformation effort is to realize its vision of becoming a first quartile performer in North America in safety, efficiency, reliability and customer satisfaction.

The specific goals of the transformation efforts are to:

- Identify best practices common approaches to support an integrated operating model.
- Strive for operational excellence in customer service, reliability, safety, and efficiency.
- Develop asset strategies and regulatory support to ensure long-term sustainability of the Company's networks.
- Develop new approaches to planning the Company's networks and customer services.
- Create a high-performance culture.

An example of the types of changes that National Grid is working to establish are the "Centers of Excellence," as described at page 16 of Mr. Pettigrew's testimony. Centers of Excellence are not a new concept within the industry, but are more commonly associated with Service Companies and thus more focused within the Shared Services areas of Human Resources, Supply Chain, Finance and Legal. Within the EDO organization, National Grid has historically utilized the centralized concepts with specialized activities such as scheduling or

Division Data Request 11-8 (cont.)

design that were geographically dispersed, and the Company is now looking to provide larger working hubs to take advantage of economies of scale and skill.

National Grid's operating model (organizational definition) was an outcome of work performed within transformation, based on an analysis of National Grid's "capability framework." These capabilities underlie the operating model. In addition, the transformation program took shape as a result of work with a third party consultant (Accenture), which analyzed the organization using a "High Performance Utility Model (HPUM)." The HPUM represents a collection of best practices compiled by Accenture from over 20 years of work with leading utility companies around the world.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-10

Request:

Page 8, lines 1-10. What agreement was there to reduce SF6 and what is used in its place? From 2004 to present, what has been the progress and what is the ultimate goal of the partnership?

Response:

In 2004, National Grid partnered with the U.S. Environmental Protection Agency to monitor, report and reduce its SF6 emissions. National Grid set a goal to reduce its emissions by 57 percent of its baseline year 2000 by 2008. In 2008, Rhode Island emissions were reduced by 54 percent of year 2000 levels (from 1,876 lbs. to 859 lbs.).

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-12

Request:

Page 12-14: Please describe in detail what is meant by PAS 55 certification, and what was involved in achieving that milestone. Also provide any benchmarking studies in the possession of National Grid regarding how it compares to the companies that have received PAS 55 certification. Provide any conference presentations made by National Grid on the subject of PAS 55.

Response:

PAS 55 is an abbreviation for the Publicly Available Specification for "Optimal Management of Physical Infrastructure Assets." The development of PAS 55 was led by the Institute of Asset Management (IAM) in collaboration with the British Standards Institute (BSI) and is a management standard similar in format to ISO 9000, 14001. This is an industry established minimum level of competency and processes to insure a company's asset management objectives can be fulfilled efficiently and effectively.

PAS 55 is comprised of several sections where a company has to pass and show that they are compliant for certification. The sections are: General Requirements; Asset Management Policy; Asset Management Strategy, Objectives & Plans; Asset Management Enablers & Controls; Implementation of Asset Management Plans; Performance Assessment & Improvement; and Management Review.

The elements to achieving PAS 55 certification are to complete and pass a Gap Analysis, Preliminary Assessment, Stage 1 (System Design) and Stage 2 (System Implementation). Each element is conducted by a PAS 55 accredited consultant/auditor. Passing is based on approval by such consultant/auditor. Both the Gap Analysis and Preliminary Assessment are optional and the Stage 1 and Stage 2 are mandatory for achieving certification. Biannual surveillances are also mandatory for the retention of the certification. The PAS 55 certification has a triennial re-assessment timeframe where the entire certification process reoccurs.

The Gap Analysis and Preliminary Assessment are periods where PAS 55 consultants/auditors work with the company on reviewing where the company has gaps and deficiencies in their asset management system in being PAS 55 compliant. The Stage 1 is a desk-based review of the company's management system. It requires the involvement of the company's key process owners. Once the company has met all the necessary requirements in showing compliance with PAS 55, Stage 2 takes place. Stage 2 consists of an assessment across the organization looking for evidence that the system assessed in Stage 1 work is consistently applied across the scope of the asset management system. Samples across technical disciplines, geographical spread and functional areas are taken.

Division Data Request 11-12 (cont.)

National Grid has not benchmarked other companies that have received PAS-55 certification for comparison.

Provided as Attachments DIV-11-12-1, DIV-11-12-2, and DIV-11-12-3 are three presentations National Grid has made at conferences on the subject of PAS-55.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-13

Request:

Page 15-16: Has the Company already developed or prepared the I&M Strategy referenced in these pages. If so, please provide copies of all relevant documents. Include a description of the I&M Strategy for each class of assets.

Response:

The Company has prepared the I&M Strategy referenced on pages 15-16 of Mr. Pettigrew's testimony, although it is not yet formally approved. A copy of the draft I&M Strategy is provided in Attachment DIV-11-13.

Prepared by or under the supervision of: John Pettigrew

Distribution Inspection and Maintenance Strategy

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Strategy Statement

The intent of this strategy is to provide an approach for a comprehensive inspection and maintenance program for our overhead, underground, and subtransmission line assets. This program will include visual, aerial, infrared inspection and elevated voltage testing.

This strategy is designed to both meet regulatory requirements and provide for a sustainable distribution and sub-transmission system.

Based on the results of this inspection program, budgets can be adjusted to allow for the timely replacement of the required plant.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	03/13/2009	Initial Issue	Mohamed H Shamog Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG

Strategy Justification

1.0 Purpose and Scope

The intent of this strategy is to provide an approach for a comprehensive inspection program for our overhead, underground, and subtransmission line assets. This program will include visual, aerial, infrared inspection and elevated voltage testing.

2.0 Strategy Description

2.1 Background

National Grid's electric distribution and subtransmission assets are extensive. National Grid has over 70,000 circuit miles of distribution overhead, underground, and subtransmission lines, which serve approximately 3.3 million customers in four states: Massachusetts, New Hampshire, New York and Rhode Island. Breakdowns of the major assets by state are listed in Table 1

	NY	MA	RI	NH	Total
Primary Miles:					
Distribution					
Overhead	35,874	13,708	4,974	681	55,237
Underground	7,454	4,907	1,058	211	13,630
Subtransmission					0
Overhead	3,169	570	310	45	4,094
Underground	unknown	530	140	5	675
Poles	1,232,152	716,541	294,867	36,641	2,280,201
Manholes	16,804	22,317	5,097	331	44,549
Vaults	1,802	1,685	1,032	116	4,635
Transformers:					
Overhead	380,057	157,263	67,459	7,584	612,363
Underground					
- Padmount	46,174	31,224	7,592	1,640	86,630
- Other underground	19,577	4,380	1,263	126	25,346
Step-down	14,570	2,565	274	62	17,471
Cutouts	252,564	275,895	105,114	13,273	646,846
Switchgear	3,084	848	222	17	4,171
Reclosers	888	997	308	52	2,245
Regulators	3,404	155	52	9	3,620
Capacitors	4,711	2,535	953	87	8,286
Sectionalizers	51	24	2	1	78
Switches:					
Overhead	66,041	18,530	9,588	684	94,843
Underground	773	1,714	458	6	2,951
Undefined structures	74	33	5	6	118

Table 1: National Grid Asset Statistics[1]

[1] All the information obtained from SDE data base (as of April, 2009)

Trees, animals, lightning and deteriorated equipments are the major drivers in National Grid's reliability performance[2]. The Reliability Enhancement Program (REP) was developed to reverse this trend. The REP program consists of four major initiatives:

1. Feeder Hardening/Engineering Reliability Reviews
2. Incremental Asset Replacement
3. Incremental Vegetation Management
4. Inspection and Maintenance

The goal of the REP is to meet state regulatory targets and attain first quartile reliability performance. The inspection and maintenance strategy will build on the lessons learned from REP and develop an ongoing program, which will once fully implemented replace Feeder Hardening and some of the distribution line asset replacement programs. This cyclic inspection and maintenance program plays a significant role in having a sustainable and reliable system as well as meeting regulatory requirements for inspection in Massachusetts and New York.

2.2 Strategy

Distribution and subtransmission shall have a cyclic inspection and maintenance program. The inspection priority system will identify and provide for the timely condition-based replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle. The following is a brief description of the inspection program:

Identify and address all problems found based on following priority levels:

Level 1[3]- Must be repaired/replaced within one week
Level 2[4]- Must be repaired/replaced within one year
Level 3[5]- Must be repaired/replaced within three years
Level 4[6]- Information only, replace based on engineering judgment and budget

The inspection system is linked to the work management system for streamlined work order creation, execution, field completion, closeout and tracking.

On an annual basis, the inspection criteria shall be reviewed for effectiveness and adequacy with representative from the following departments; asset strategy, network asset planning, inspections, safety, operations, standards and any other stakeholders deemed appropriate.

[2] Refer to Feeder Hardening Strategy
[3] An immediate issue that requires the inspector to stand-by until a qualified crew/supervisor arrives to resolve the issues as soon as practical, but no longer than 5 business days.
[4] An issue that, if left unresolved, has a high probability of failure within 1 year of the feeder inspection. Either the identified work will be completed within 1 year or a project will be initiated to complete the work in a timely fashion (e.g., pole replacement or addition may require permits or DOT involvement that may require longer than 6 mo. to complete.).
[5] An issue that has a high probability of failure within 3-5 years of the feeder inspection. Either the identified work will be completed within 3 years, or a project will be initiated to complete the work. These issues may require permitting and or significant design/engineering/construction and may need to be budgeted to complete.
[6] This information will be used for asset decision making and to aid inspectors during the subsequent inspections

A Quality Assurance/Quality Control program is required for New York and shall be implemented in all states to insure the efficiency and effectiveness of the inspection and maintenance program.

Line assets across the system shall be inspected as follows:

2.2.1 Overhead Inspection

- Five-year cycle visual inspection of overhead assets, which at minimum includes poles, crossarms, insulators, primaries, transformers, capacitors, regulators, switches, reclosers, ground, guys, anchors, secondaries, services, spacer cable, cutouts, risers, switch gears, padmounted transformers, enclosures, and right of way (R.O.W).
- Five-year cycle infrared inspection on overhead mainline circuits

2.2.2 Underground Inspection

- Five-year cycle visual inspection of underground assets, which at minimum includes metallic handholes, padmounted transformers, switchgears, manholes, vaults, splice boxes, junction boxes, and submersible equipments.
- Five-year cycle internal inspections of padmounted transformers and switch gears
- Five-year cycle infrared inspection of all separable components

2.2.3 Subtransmission Inspection

- Five-year cycle visual inspection of overhead assets, which at minimum includes towers, poles, crossarms, insulators, switches, reclosers, sectionalizers, conductors, guys, anchors, risers, R.O.W, and foundations.
- Annual aerial helicopter patrol for visual examinations
- Three-year cycle aerial Helicopter Infrared Patrol

2.2.4 Elevated Voltage Testing

Elevated voltage testing shall be conducted on all utility facilities that are capable of conducting electricity and are publicly accessible which include:

- Substation Fences
- Overhead distribution facilities
- Subtransmission facilities
- Underground facilities
- Street Lights
- Daily work area

Due to regulatory requirements, elevated voltage testing shall be performed based on the state requirements but no longer than a 5 year cyclic testing on all equipment. Refer to the Appendixes for state specific requirements.

2.2.5 Street Light Standards

Street light standards inspection shall be performed on all street lights as part of the inspection program. The inspection shall include at a minimum:

- Luminaires
- Arms
- Standards
- Foundations
- Conductors

The inspection is based on a five-year cycle such that one-fifth of the inspection should be scheduled on an established annual basis.

2.2.6 Regulators/Capacitors

Regulators and Capacitors shall be inspected annually to determine the operability and general condition.

2.2.7 Reclosers/ Sectionalizers

Reclosers and sectionalizers shall be inspected on a semi-annual base. Reclosers outages typically involve large number of customers so an appropriate level of maintenance is needed to offset the higher risk of misoperations and failures.

2.2.8 Feeder Patrols

Feeder patrol is an assessment to identify and fix immediate problems on overhead distribution feeder's main line constructions from substation breakers to fuses. The patrol will exclude all underground constructions as well as all fused laterals. Feeder patrols are currently used by all divisions in an informal means to respond to reliability concerns throughout the year. Feeder patrol shall be performed semi annually by each division.

3.0 Benefits

3.1 Safety & Environmental

Asset replacement prior to failure provides an incremental employee and public safety benefit and avoids the potential environmental problems related to some assets i.e. transformers and poles. In addition, implementation of this strategy addresses safety concerns relating to elevated voltage on all publicly accessible facilities.

3.2 Reliability

Condition based repair/ replacement will result in improved reliability and support the creation of a sustainable system. Collectively deteriorated equipment related interruptions are one of the main drivers of poor reliability. The high impact deteriorated equipment problems are being addressed by the Feeder Hardening Program. However, the inspection program will extend the Feeder Hardening benefits to a larger group of assets.

3.3 Customer/Regulatory/Reputation

The main customer benefits to this strategy are eliminating hazard of elevated voltage, improved reliability, and the creation of a sustainable system. Additionally, condition based replacement will support the attainment of our regulatory targets. The combination of cyclic inspection and replacing only what is required lead to having a sustainable system and should be supported by state regulators.

4.0 Estimated Costs

The annual estimated incremental cost of inspection and QA/QC implementation proposed by this strategy is approximately $7,000,000.

	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17
CAPEX	$25,750,000	$60,350,000	$91,650,000	$87,250,000	$71,150,000	$51,850,000	$20,750,000	$20,750,000
OPEX related to CAPEX & EXPENSE	$12,370,000	$31,620,000	$35,020,000	$32,120,000	$26,020,000	$23,270,000	$9,570,000	$9,570,000
REMOVAL	$3,418,000	$8,118,000	$11,218,000	$10,318,000	$8,418,000	$6,813,000	$2,413,000	$2,413,000
System Total	$41,538,000	$100,088,000	$137,888,000	$129,688,000	$105,588,000	$81,933,000	$32,733,000	$32,733,000

Table 2: System Total inspection work estimate

Please refer to Appendixes F & G for more details.

5.0 Implementation

The high impact deteriorated equipment problems are being addressed by the Feeder Hardening Program. Starting in FY09, equipment identified as part of the revised inspection program has extended the Feeder Hardening benefits on a smaller scale to a larger group of assets across National Grid. The inspection program will replace the Feeder Hardening program after the initial five year (FY07-FY11) plan has been completed and service quality targets are being achieved.

- Level 1 items require immediate replacement in the current fiscal year.
- Level 2 items require replacement within one year cycle.
- Level 3 items will provide a baseline for budgeting over the next two fiscal years.

Additionally, Problem Identification Worksheets, Feeder Hardening, Engineering Reliability Reviews and Pockets of Poor Performance may identify additional miscellaneous overhead replacement work.

5.1 Performance Targets

The performance of this strategy will be measured by:

- Maintaining the inspection cycle
- Replacing assets in accordance with the priority codes and associated replacement time frames as adjusted in the long term compliance plan
- Meeting all states specific regulatory requirement

6.0 Risk Assessment

Individual assets have a minimal risk in any of the categories listed below. Collectively deteriorated equipment related interruptions are one of the main drivers of an unreliable system.

6.1 Safety & Environmental

The inspection identifies potential environmental and safety problems (e.g. oil leaks, damaged equipment and elevated voltage). Failure to implement this strategy and identify these and correct these potential problems can lead to increased risk of injury to our own employees or the public and undesirable environmental damage.

6.2 Reliability

Not proactively replacing marginal equipment as part of a cyclic inspection program will negatively impact reliability. The overall impact will increase over time as the quantity of marginal equipment increases. This risk is difficult to measure, due to the trend of deteriorated equipment.

6.3 Customer/Regulatory/Reputation

Failing to implement this strategy will negatively impact our customers due to the potential of increasing poor reliability performance and increase of hazards due to elevated voltage on publicly accessible facilities. In several states we have regulatory requirements prescribing cyclic inspection program and associated repair timeframes based on the severity of the problem. The Inspection Program meets or exceeds these regulatory requirements in some cases. Failing to inspect and repair/ replace assets would result in noncompliance with our regulatory requirement. Refer to the state specific section in the Appendix of the strategy.

7.0 Data Requirements

7.1 Existing/Interim:

Smallworld/ArcSDE – feeder assets
Computapole – inspection data

7.2 Proposed:

Same

7.3 Comments:

Conversion from computapole to a more easily integrated (with GIS) tool will be reviewed as part of the Transformation Program.

8.0 References

EOP D004 – Distribution Line Patrol and Maintenance
EOP UG006 – Underground Inspection and Maintenance
EOP T007 – Transmission Line Patrol 23kV – 345kV
EOP G016 – Elevated Equipment Voltage Testing
EOP G017 – Street Light Standard Inspection Program
NY PSC Order 04-M-0159
Massachusetts DTE Directive 12/9/05
Feeder Hardening Strategy (Approved July, 2, 2008)

9.0 Appendix A

Definitions:

Elevated Equipment Voltage Test: An A.C. rms voltage difference between utility equipment and the earth, or to nearby grounded facilities that exceeds the highest perceptible voltage levels for humans.

Infrared Inspection: An inspection conducted to detect abnormal heating conditions associated with separable connectors. An infrared inspection is required before work begins in an enclosed space, enclosure, pad mounted transformer or pad mounted switchgear.

Patrol: An assessment of National Grid facilities for the purpose of determining the condition of the facility and any associated components.

Aerial Infrared: Helicopter based thermographic imaging of connections and equipment.

Aerial Patrols: Helicopter based visual examination of subtransmission and transmission facilities and equipment.

10.0 Appendix B

New York Specific

The New York Public Safety Commission (PSC) requires the following:

1. Annual stray voltage testing shall be conducted on all utility facilities that are capable of conducting electricity and are publicly accessible including municipal-owned streetlights. Elevated voltage testing shall be performed based on 1 volt standard set by the PSC

2. Inspection program on a five-years cycle, which shall include, at a minimum, visual examination of towers, poles, guy wires, risers, overhead cables and conductors, transformers, breakers, switches, other aboveground equipment and facilities, the interior of manholes, service boxes, vaults, and other underground structures.

3. A quality assurance program to ensure timely and proper compliance with safety standards.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection	✓	✓
Infrared inspection on overhead mainline		✓
Underground		
Five-year cycle Underground inspection	✓	✓
Infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection	✓	✓
Sub-transmission		
Five-year cycle ground base patrol inspection	✓	✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter patrol		✓
Other Inspections		
Elevated voltage testing[1]	✓	✓
Five-year cycle inspection on Street Lights	✓	✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓

Table 3: NY Regulatory vs. Strategy Inspection Requirements

1- Per New York PSC, elevated voltage testing shall be performed annually.

11.0 Appendix C

Massachusetts Specific

The Massachusetts department of public utilities (DPU) requires the following:

- 20% of facilities shall be tested for elevated voltage annually on five years rolling basis. This include at minimum to inspect and test the following equipment where accessible by the general public:
    - Metallic street lights and fixtures
    - Metallic risers, sweeps and conduits
    - Manhole and handhole covers
    - Secondary pedestals
    - Pad mount transformers and transclosures
    - Pad mount switchgear, termination cabinets and junction boxes
    - Control cabinets such as pole mounted capacitor controls

- Inspect all manholes over a 5-year cycle, and create a database of manhole conditions and required repairs.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Infrared inspection on overhead mainline		✓
Underground		
Five-year cycle Underground inspection[1]	✓	✓
Infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Sub-transmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter visual patrol		✓
Other Inspections		
Elevated voltage testing[2]	✓	✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓

Table 4: MA Regulatory vs. Strategy Inspection Requirements

1- Massachusetts DPU require inspections on manholes only

2- For Massachusetts, elevated voltage testing shall be performed on a five-year cycle (20% annually)

12.0 Appendix D

Rhode Island Specific

There are no specific regulatory inspection requirements for Rhode Island

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Infrared inspection on overhead mainline		✓
Underground		
Five-year cycle Underground inspection		✓
Infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Subtransmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter patrol		✓
Other Inspections		
Annual elevated voltage testing		✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓

Table 5: RI Regulatory vs. Strategy Inspection Requirements

The strategy recommends the inspection and maintenance program to meet the requirements of the electric operating procedures and the creation of sustainable system.

13.0 Appendix E

New Hampshire Specific

There are no specific regulatory inspection requirements for New Hampshire

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Infrared inspection on overhead mainline		✓
Underground		
Five-year cycle Underground inspection		✓
Infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Subtransmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter patrol		✓
Other Inspections		
Annual elevated voltage testing		✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓

Table 6: NH Regulatory vs. Strategy Inspection Requirements

The strategy recommends the inspection and maintenance program to meet the requirements of the electric operating procedures and the creation of sustainable system.

14.0 Appendix F

		Operations				Inspection Group			
	Responsibilities	Incremental Cost		Incremental FTEs		Incremental Cost		Incremental FTEs	
		NE	NY	FTEs-NE	FTE -NY	NE	NY	FTEs -NE	FTEs-NY
Overhead Distribution									
Five-year cycle distribution overhead inspection	Inspection					$0	$0		
Infrared inspection on overhead mainline	Inspection					$75,000	$125,000		
Sub-transmission									
Five-year cycle ground base patrol inspection	Inspection					$224,000	$0	2	
Three-year cycle Aerial Helicopter infrared Patrol	Inspection					$32,000	$96,000		
Annual Aerial helicopter patrol	Inspection					$70,000	$210,000		
Underground									
Five-year cycle Manhole inspection including infrared	Operations	$0	$0	0	0	$0	$0		
Five-year cycle Vaults inspection including infrared	Operations	$0	$0	0	0	$0	$0		
Five-year cycle Metallic Handhold inspection	Inspection					$112,000	$0	1	
Metallic Handholds Infrared Inspection	Inspection					$112,000	$112,000	1	1
Five-year cycle Padmounted transformers-Live Front &Switch Gears	Operations	$224,000	$1,344,000	3	12	$0	$0		
Live Front Transformers & Switchgears Infrared Inspection	Operations					$0	$0		
Five-year cycle Padmounted transformers - Dead Front	Inspection					$672,000	$0	6	
Dead front Padmounted Transformers Infrared Inspection	Inspection					$224,000	$224,000	2	2
Other Inspections									
Elevated Voltage (EV) testing[1]	Inspection					$50,660	$0		
Five-year cycle inspection on Street Lights	Inspection					$34,000	$0		
Annual inspection of Capacitors and Regulators	Operations	$0	$672,000	0	6	$0	$0		
Semi Annual inspection on Reclosers	Operations	$0	$0			$0	$0		
Additional Resources									
Coordinators/ Program Mangers FTE						$149,000	$149,000	1	1
QA/QC Recommendations	Performance Mgt					$651,000	$1,326,000	8	15
Total (includes direct labor costs only - Loaded)		$224,000	$2,016,000	3	18	$2,405,660	$2,242,000	21	19
Total Vehicle, Equip, Tools, Other		$81,000	$486,000			$229,500	$85,000		
Total Implementation Costs by State		$305,000	$2,502,000			$2,635,160	$2,327,000		
Total Implementation Costs - NY & NE		**$2,807,000**		**21**		**$4,962,160**		**40**	

Table 7: Incremental Inspections Resources/Costs

15.0 Appendix G

Below are approximate estimates for a 7 years plan for the resulting work based on the inspection program

			FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17
Overhead Distribution	NH	CAPEX	$132,000	$1,120,000	$3,342,000	$2,228,000	$1,672,000	$837,000	$420,000	$420,000
		OPEX/ EXP	$144,000	$695,000	$1,116,000	$744,000	$556,000	$303,000	$235,000	$235,000
		REMOVAL	$6,000	$105,000	$336,000	$224,000	$164,000	$84,000	$40,000	$40,000
	RI	CAPEX	$682,000	$6,272,000	$14,482,000	$15,039,000	$11,286,000	$5,859,000	$2,268,000	$2,268,000
		OPEX/ EXP	$744,000	$3,892,000	$4,836,000	$5,022,000	$3,753,000	$2,121,000	$1,269,000	$1,269,000
		REMOVAL	$31,000	$588,000	$1,456,000	$1,512,000	$1,107,000	$588,000	$216,000	$216,000
	MA	CAPEX	$1,386,000	$15,008,000	$37,876,000	$38,433,000	$28,842,000	$21,204,000	$5,712,000	$5,712,000
		OPEX/ EXP	$1,512,000	$9,313,000	$12,648,000	$12,834,000	$9,591,000	$7,676,000	$3,196,000	$3,196,000
		REMOVAL	$63,000	$1,407,000	$3,808,000	$3,864,000	$2,829,000	$2,128,000	$544,000	$544,000
	NY	CAPEX	$12,100,000	$24,500,000	$22,500,000	$18,100,000	$15,900,000	$17,700,000	$6,100,000	$6,100,000
		OPEX/ EXP	$8,200,000	$16,100,000	$14,800,000	$11,900,000	$10,500,000	$12,300,000	$4,000,000	$4,000,000
		REMOVAL	$2,400,000	$4,900,000	$4,500,000	$3,600,000	$3,200,000	$3,600,000	$1,200,000	$1,200,000
Subtransmission	NE	Budget is included as part of the above overhead distribution estimates in NE States								
	NY	CAPEX	$7,600,000	$9,600,000	$9,600,000	$9,600,000	$9,600,000	$2,400,000	$2,400,000	$2,400,000
		OPEX/EXP	$350,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$250,000	$250,000	$250,000
		REMOVAL	$740,000	$940,000	$940,000	$940,000	$940,000	$235,000	$235,000	$235,000
Underground	NH	CAPEX	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
		OPEX	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
		REMOVAL	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
	RI	CAPEX	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
		OPEX	$28,000	$28,000	$28,000	$28,000	$28,000	$28,000	$28,000	$28,000
		REMOVAL	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000
	MA	CAPEX	$950,000	$950,000	$950,000	$950,000	$950,000	$950,000	$950,000	$950,000
		OPEX	$283,000	$283,000	$283,000	$283,000	$283,000	$283,000	$283,000	$283,000
		REMOVAL	$54,000	$54,000	$54,000	$54,000	$54,000	$54,000	$54,000	$54,000
	NY	CAPEX	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
		OPEX	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
		REMOVAL	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
		EXPENSE	$800,000	$900,000	$900,000	$900,000	$900,000	$400,000	$400,000	$400,000
System Total			**$41,538,000**	**$100,988,000**	**$138,788,000**	**$130,588,000**	**$106,488,000**	**$82,333,000**	**$33,133,000**	**$33,133,000**

Table 8: Long Term Budget for Inspection Work

The long term Inspection and maintenance budgets are based on the following assumptions:

- **Overhead Distribution:**
  - After full cycle of inspection repairs are complete, beginning FY15 assume 25% of cost to maintain the program
  - 50% of Level 3 work from will be completed in 2 years (FY09-FY10).
  - no inflation for FY10 costs

- **Underground:**
  - For NY, used FY09 spending data and Computapole Level 3 information (for FY10). Also added a contingency to the Level 3 work of 100%.
  - For NE, Used estimates based on FY10 sanction paper estimates, which was based on FY08 and FY09 spending.

- **NY Subtransmission:**
  - Based on one calendar year of inspection results plus FY09 actual for Level 2 work – needs to be updated next year.
  - West has double the number of poles identified than east and west combined – recommend an audit on a sample of the inspections.
  - 228 Level 3 poles were identified as defective due to woodpecker or insect activity. Since this represents approximately $3.4m in CAPEX spend, alternative repair solutions may be viable.
  - There is additional work in the orders due to the aerial survey – discounted FY09 spending by 25%.

Division Data Request 11-14

Request:

Page 16: Please describe the changes involved in transitioning from a geographically based organization to an approach founded on key capabilities. Will such a transition change the number of employees that the Company has in Rhode Island? If so, please describe how Rhode Island employment will change. Please include any expected changes to Rhode Island engineering staff.

Response:

The Company is actively migrating from a geographically based organization to an organization founded on capabilities and centers of excellence. This migration will require implementing process changes and transitioning work to new locations. It also requires the creation of new roles and responsibilities for both the field work force as well as the centralized work force.

Although the Company expects changes to Rhode Island employment, the Company cannot fully predict those changes at this time because of active negotiations with the Unions. For example, the Company is planning to centralize clerical and administrative work activities currently performed by 40 clerks and 24 administrative assistants across our New England operating area. The Company's New England operating area includes Narragansett Electric. Within this category of employees, the actual number of employees affected by this plan is contingent upon a number of factors, including their ability to transition to other roles, the current bargaining agreements, normal attrition, acceptance of relocation packages, etc.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-15

Request:

Page 18: Please describe in detail what is meant by feeder reinforcement or hardening.

Response:

The Feeder Hardening Strategy was developed to specifically address overhead deteriorated equipment and lightning-related interruptions on distribution feeders. Feeder Hardening utilizes remediation measures, such as: replacement of fuse cutouts, crossarms, poles and transformers; lightning protection with bonding, grounding and lightning arrester installations; and installation of animal guards. All poles on which work is performed are brought up to current standards as part of the program. Equipment is inspected and replaced as needed on the selected Feeder Hardening circuits.

The intent of this Feeder Hardening Strategy is to provide a method to identify feeders with characteristics indicating the potential for significant reliability performance improvements related to deteriorated overhead equipment and/or lightning interruptions. These circuits are reviewed and adjusted based on the expertise of the division engineers. A review is also performed to ensure that work is done in both urban and rural areas. Feeders are reviewed not only across all of National Grid, but also on a state-by-state basis. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-16

Request:

Page 19, lines 21-23: please provide a detailed description of the strategies developed for individual distribution asset classes.

Response:

Please refer to the Company's Response to DIV-11-26 for details of the individual asset strategies.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-17

Request:

Page 20, line 4: Please provide the referenced risk-scoring system.

Response:

Prioritization of Distribution Improvement Projects

This section describes the prioritization ranking process used for the Company's distribution projects that are expected to be ongoing within a 5-year planning horizon. The prioritization is not a proposed or new concept; it is one that has been employed with the utilization of asset strategies and the evaluation of work in the past. A bulleted summary of the Company's prioritization process is shown in **Figure 1** while further detail is presented below:

The prioritization scoring method employs a risk/opportunity matrix, as shown in **Figure 2** (which is commonly applied across all projects within National Grid's lines of business), and is discussed below in the section entitled Prioritization Ranking Process. All projects new to the plan are reviewed and scored using the risk/opportunity matrix. The prioritization ranking process documented below is applied to the entire Capex portfolio consisting of Blanket Projects, Programs, Mandatory Specific Projects, and Carryover Project Spending. It has been chosen by the Company to be used by all lines of business.

Prioritization Ranking Process

The Company includes in the prioritization exercise all Capex projects and programs identified by the Network Asset Planning group that stem from Company strategies, plans, and operating requirements. The 5-Year spending plan is developed based upon the priority and category of the work. The spending plan is then cast into a fiscal year work plan, which is managed on a monthly basis by key personnel from the Program Management, Network Strategy, Finance, and Construction departments. Resources are allocated based upon the project priority score, need date, and type and schedule of resources. The project priority number is calculated using a project risk/prioritization decision support matrix that assigns a project risk score based upon the estimated consequence and probability of a particular distribution or sub-transmission system event occurring. The tool is Excel-based and uses a risk/opportunity scoring approach similar to other programs in the industry.

The project priority score takes into account key performance areas including safety, environmental, and reliability (See example in **Figure 3**), including system equipment performance such as thermal loading, voltage, and condition. The overall objective of the approach is to establish a capital project ranking that optimizes investments in the distribution

Division Data Request 11-17 (cont.)

system based upon the measure of risk or improvement opportunity associated with a project. Projects undertaken to meet franchise, regulatory, or statutory requirements are designated as "Mandatory" and are given a score of 50, outside of the scoring matrix exercise. These types of projects provide little or no opportunity to exercise discretion with respect to the scope and timing of the work.

FIGURE 1

RISK SCORING - SUMMARY

Methodology

- Every project is scored using a risk-scoring system that factors in the potential risk from safety, reliability, efficiency, and environmental responsibility.
- The ranking and selection of projects is reviewed in challenge sessions and prioritized to achieve an optimized portfolio of projects and an optimal capital budget.

Ranking capital projects by risk assesses the impact to customers and timing of the potential risk.

- Capital projects are designed to mitigate environmental, safety and reliability risks.
- For each project, the impact of the risk in terms of environmental, safety and reliability is determined on a 7 point scale from very low to very high. The likelihood of the event is also scored on a 7 point scale from very low to very high.
- A risk matrix score is assigned to each project based upon the impact and likelihood scores.
- All capital projects, whether identified by National Grid or requested by customers, are ranked according to their highest score for the three risks: safety, environmental and reliability.

Prioritization of capital projects in the budget process considers relative risk rankings of projects and available resources to accomplish projects.

- Balance must be found between mitigating prioritized risks and managing budgets for efficient investment over time.
- Challenge sessions discussion risk and priority of projects to optimize the capital plan and maximize the value to customers from the investments.

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(Continued on next page)

Division Data Request 11-17 (cont.)

FIGURE 2

Figure – Project Prioritization Matrix

Project Prioritization

Impact								
Time to Failure								
< 1Year	25	32	38	43	47	48	49	
1-3 Years	20	29	33	40	44	45	46	
3-5 Years	15	22	26	35	39	41	42	
5-10 Years	9	17	19	28	34	36	37	
10 - 20 Years	5	10	14	21	27	30	31	
20-100Yyears	3	6	8	16	18	20	24	
>100 yrs	1	2	4	7	11	12	13	
	Very Low	Low	Moderately Low	Moderate	Moderately High	High	Very High	**Consequence**

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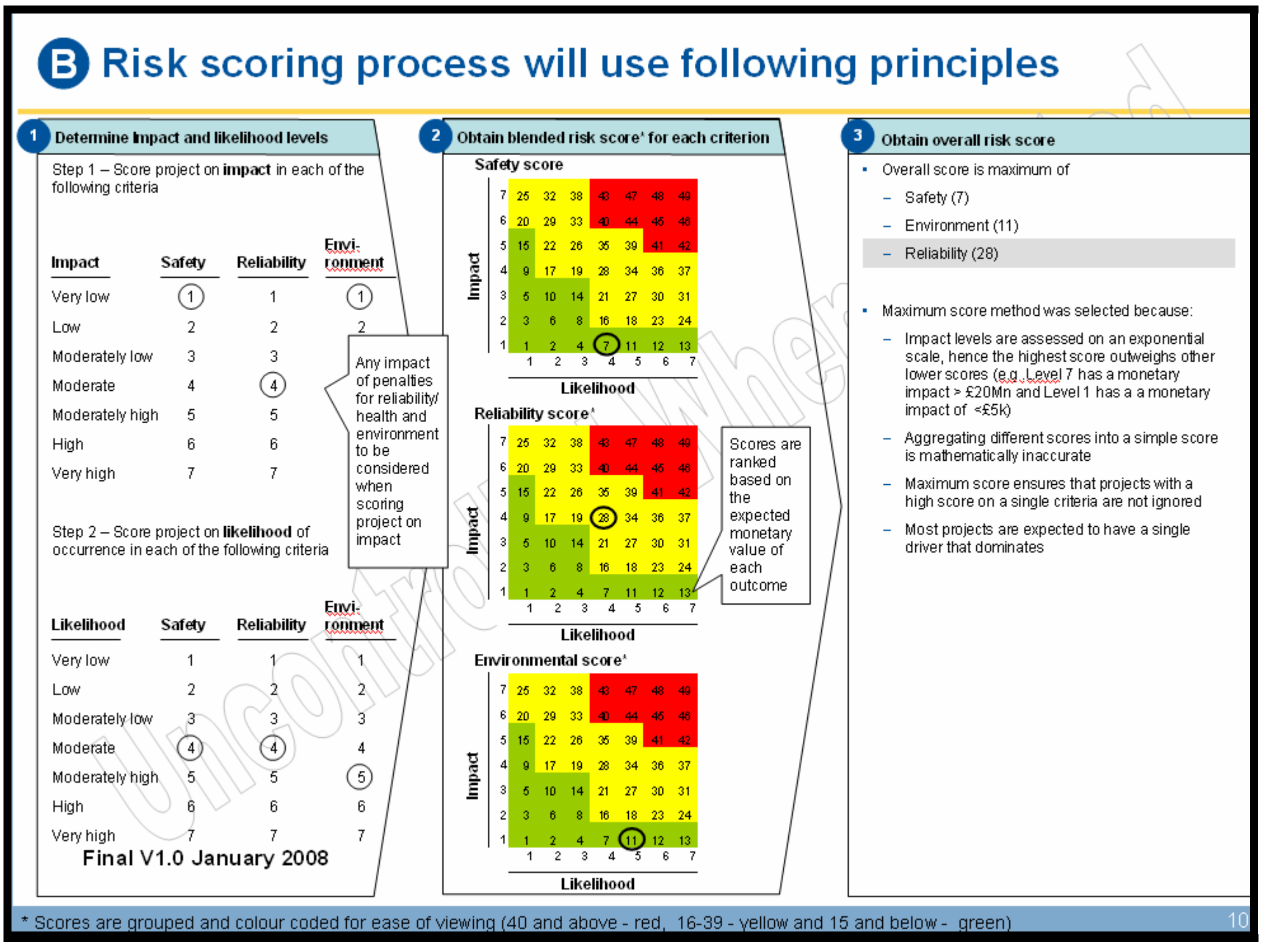
(Continued on next page)

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-17 (cont.)

FIGURE 3



Division Data Request 11-18

Request:

Page 20 - 27: Please provide a list of any equipment that was replaced in the last three years as a result of each of these strategies. Also provide examples of the information that the company had available to it in making those decisions for each strategy.

Response:

Strategy	**2006***	**2007***	**2008***
Capacity Planning	See Note 1		
DLine Transformer	285	88	156
Vegetation Management (Dist & Sub T)	-	1301 miles	1327 miles
Feeder Hardening (miles hardened)	-	379 miles	485 miles
DLine Recloser	25	44	23
Potted Porcelain Cutout	7263	7526	6346
Wood Pole	131	465	417
Manhole & Vault	See Note 2		
Oil Fused Cutout	125	145	78
Station Transformers	0	0	0
Station Breakers	15	18	7

* Individual asset strategies have only formally existed since the beginning of 2008, therefore replacement volumes/numbers are not available. However, the information provided in the table relates to other initiatives that were ongoing in those related areas prior to the strategies and many of the concepts of these initiatives were incorporated into the strategies when written.

Note 1 - Capacity Planning Strategy
The Company has completed numerous distribution capacity enhancement projects over the last three years. These projects ensure the distribution system can accommodate Rhode Island's growing electrical demand. The scope of these projects varies significantly and range from small upgrades in wire size to entire new substations. The load relief projects progressed during this period are shown in Attachment 11-18 with the associated capital spending in these years. Many of these projects require several years to implement and some expenditures may have occurred in prior years or may still be on-going.

Note 2 – Manhole and Vaults
Manholes and vaults are typically refurbished rather than replaced in their entirety.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-18 (cont.)

Asset Strategy Supporting Information Examples

Distribution Line Transformers
The Company utilizes a "proactive load-based replacement program" which is a formalization of past practice in National Grid. Load-based replacement and transformer loading reviews have been occurring in excess of 20 years. These reviews were typically conducted at the district level on an annual basis. As part of the focus on developing and documenting asset strategies, the past practice of transformer loading review has been documented and formalized in the "Distribution Line Transformer Strategy". The program calls for annual loading reviews based on loading limits outlined in the distribution standards using information in the GIS (Geographic Information System), as well as the continued review of transformer loading as part of normal business (new service investigations, system improvement projects, etc.). The summer season is the main focus of the program due to typically higher transformer loading in June, July and August. The identification of individual units selected for replacement is performed by Distribution Design on a division basis.

Distribution Line Reclosers
The intent of the Distribution Line Recloser Strategy is to set forth the general conditions for the installation of line reclosers on overhead distribution feeders. Ultimately, the goal is to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure (>10 miles) with a three year average distribution line SAIDI performance (Regional IEEE 1366 basis) greater than the internal National Grid SAIDI goal (~ 96 minutes). Additionally any feeder identified as a desirable candidate from the Recloser Model or locations with competitive $/Delta CMI values (~ $1.50) are considered. The Recloser Model provides a ranked list of candidate feeders, which is a starting point for candidate feeder identification in addition to the knowledge of the area engineering staff. In practice most candidate feeders come from either the Recloser Model or poor performing feeders as identified by the worst performing feeder lists.

Line reclosers are needed to isolate permanent faults on the distribution system and minimize the scope of the interruption by protecting the feeder breaker. Ideally, reclosers are installed at locations that limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. Reclosers should be installed at natural breakpoints in the distribution primary; bifurcations, long three phase taps, etc. The ideal line recloser location would be on a long three phase tap serving few customers.

Historically National Grid has selectively used line reclosers to improve SAIFI and SAIDI on feeders with poor reliability performance. Beginning in 2006 (FY07), the Recloser Program was rolled out as part of the Reliability Enhancement Program, to significantly increase the rate of

Division Data Request 11-18 (cont.)

recloser installations in response to poor reliability performance. Over the course of the program (FY07 – FY09) approximately 92 reclosers have been installed.

Prepared by or under the supervision of: John Pettigrew

Narragansett Electric Distribution Capacity Project Spending FY06-FY08

				Data		
CO	Budget Class	Project	Proj Description	Sum of 2006 Cap	Sum of 2007 Cap	Sum of 2008 Cap
		C00817	NEW KILVERT FEEDERS 87F2 & F4	32,729	0	0
		C00927	South County East Area Study	-62,078	0	
		C00940	LOAD RELIEF-16J1 CONVERSION	33,988	921	0
		C00999	KILVERT STREET DUCT LINE	7,553	0	0
		C01057	76F5 FEEDER-POINT ST SUB-OH&UG	96,200	15,728	0
		C01091	Westerly Area Planning Study	-85,854	-549	0
		C01103	NEW 68F5 FEEDER	25,048	652	
		C01158	LOAD RELIEF-30F2-TEN ROD RD NK	45,751	16,705	0
		C01250	CLARKSON ST 13F9 FDR - PROV	875	0	
		C01256	63F6 FEEDER - HOPKINS HILL	2,489	2,700	0
		C01258	CAPITAL DIST. 200% XFMR OVRLDS	4	0	0
		C01259	OVERLOADED TRANSFORMERS 2002	5,371	32	-32
		C01276	KILVERT ST. FEEDER RECONFIGURE	45,331	1,494	
		C01281	PECK ST DUCTLINE	14,483	2,785	
		C01309	18F9 FEEDER-JOHNSTON SUB-OH&UG	4,226	-1,498	
		C01312	Putnam Pike OH Dist for 5th Fdr	712,048	9,941	-1,112
		C01474	RIVERSIDE SUB REBLD	-19,312	0	
		C01482	POINT ST #76-INSTALL F3 AND F6	22	37	0
		C01486	WAKEFIELD #17: 17F3 FDR & CAPS	1,060	3,302	-3,708
		C01487	SOUTH COUNTY EMS INTEGRATION	80,747	88,173	111,607
		C01489	HOPKINS HILL-INST 12KV CAP	16,348	0	
		C01492	CLARKSON-INST 9TH FDR & CAP	103,777	157,373	0
		C01495	DRUMROCK REACTORS & SWITCHES	-703	0	0
		C01498	INST NEW LPS SUB - KILVERT ST	16,010	15,249	0
		C01500	Smithfield Area Planning Study	-94,392	0	0
		C01509	STUDY - JOHNSTON FEEDERS STUDY	0	0	-12,708
		C01511	WAKEFIELD #17: 17F1 & F2 FDRS	72,225	42,699	0
		C01512	KENYON SUB - INSTALL 68F5	9,142	9,794	878
		C01513	STUDY-OLNEYVILLE 4KV BREAKERS	-916	0	
		C01514	STUDY-HARRIS AVE 4KV BREAKERS	-1,386	0	
		C01516	POINT ST #76: ADD 76F5 & TIES	59,278	0	
		C01518	Newport Area Planning Study	73,034	59,909	-252,811
		C01519	LINCOLN AVE-INST 3.6MVAR CAP	-3,339	0	
		C01520	PONTIAC -INST 3.6MVAR CAP	-832	0	
		C01533	JOHNSTON #18 - F8 & F9 FEEDERS	31,720	9,520	23,196
		C01534	CHOPMIST SUB: THIRD FEEDER	85,285	18,376	-2,017
		C01535	PUTNAM PIKE #38: ADD FDR's & Cap	1,013,802	67,074	4,665
		C02324	27F1,27F2,27F3 REBUILD-CRANSTN	-1,773	0	0
		C02326	LINCOLN FEEDERS	30,554	0	0
		C02540	12KV OHLE FOR LASALLEACAD-PRV	22,523	0	0
		C03032	NEW 17F1 FEEDER RECONFIG	0	221	
		C03033	Putnam Pike OH&UG Dist 38F6 Fdr	1,270,952	1,087,354	20,931
		C05047	Farnum Pike OH&UG Dist 5th&6th fdrs	58,594	775,456	769,326
		C05414	Farnum Pike Sub_115 kV Dist Assets		1,334,684	211,560
		C05417	Old Baptist Feeder Getaways	23,593	724,524	1,159
		C05853	Reconductor 2500' of 85T1	125,735	628	0
		C05854	New Wood River 85T2 & 85T3 duct lin	5,048		
		C05857	Replace 85T2 PTR Pole 70	5,580	5,390	0
		C05861	Reconductor 8000' of 16F1 to Watch	439,359	64,766	0
		C05866	Wood Rvr Replace CR1-2, 85T1 & 85T2	14,196		
		C05868	Westerly Sub Replace Transformers	26,033	41,252	-67,284
		C06641	Extend 16F4 to John St	41,548	663,757	80,272
		C07397	Blackstone Valley South Area Study	70,916	8,717	-109,830
		C08627	York Ave. Sub #174 Convert 4kV load	0	0	4,106
		C09546	alley Sub - upgrade W42 & W43 Brks	11,010		
			Valley Sub - upgrade W42 & W43 Brks		45,651	44,760
		C10764	Tower Hill New 12kV Substation			326,867
			Tower Hill Rd New 12kV Substation		87,819	
			Tower Hill Rd Sub New 12kV Fdrs	41,820		
		C10765	Tower Hill Distribution Project			1,087,671
			Tower Hill Rd OH&UG Dist New Fdrs	36,909	38,890	
		C13022	Pawt No1 W62 and W63 Load Relief	120,659	156,103	0
		C13967	OS - Planning Studies	0	6,314	
			PS&I Activity - Rhode Island			167,552
		C15158	Newport Mall Substation		0	54,435
			15F2 Hope Furnace Road			39,593
			Newport Mall New Sub Distribution			187,020
		C16126	OS HUF FY'08		7,002	82,118
		C18151	Bramans Conversion 37W43			14,709
		C20111	HUF-Reconductor 52F3 Feeder		3,408	58,786
		C20813	Newport 38K23 Line Reconductoring		4,404	117,616
		C23854	Inst Reactors South St 1152B & 1151			4,577
		C24159	Newport Sub Transmission Line Tap			30,042
		C24170	2291 Line Upgrades			19,014
		C24173	Kilvert New 87F3 Feeder (Dist Sub)			2,026
		C24174	Kilvert New 87F3 Feeder (Dist Line)			2,919
		C24176	Hopkinton Substation (Dist Sub)			372
		C24178	61F4 Feeder Extension			0
		C24179	Coventry MITS (Dist Sub)			4,345
		COS002	Ocean St-Dist-Subs Blanket	480,659	382,425	
		COS016	Ocean St-Dist-Load Relief Blanket	338,820	296,342	351,614
	Load Relief Total			5,482,467	6,255,526	3,374,234
49 Total				5,482,467	6,255,526	3,374,234
Grand Total				5,482,467	6,255,526	3,374,234

Narragansett Electric Distribution Capacity Projects Capital Spending FY09

Proj #	Project Description		FY09 Total Capital
C01258	CAPITAL DIST. 200% XFMR OVRLDS		1,998
C01487	SOUTH COUNTY EMS INTEGRATION		3,893
C01498	INST NEW LPS SUB - KILVERT ST		34,169
C05047	Farnum Pike OH&UG Dist 5th&6th fdrs		96,170
C05414	Farnum Pike Sub_115 kV Dist Assets		(157,844)
C05505	IE - OS Dist Transformer Upgrades		411,014
C06641	Extend 16F4 to John St		(2,801)
C08627	York Ave. Sub #174 Convert 4kV load		238,128
C09546	Valley Sub - upgrade W42 & W43 Brks		1,510
C10764	Tower Hill New 12kV Substation		1,711,069
C10765	Tower Hill Distribution Project		2,137,527
C13967	PS&I Activity - Rhode Island		(55,785)
C15158	Newport Mall Substation		22,874
C15220	15F2 Hope Furnace Road		69,449
C15409	Newport Load Relief - Phase 1		533,912
C18151	Bramans Conversion 37W43		192,738
C23011	63F6 reconductor #1 Al primw/477		25,054
C23012	63F6 Ext 2 PH down Ten Rod Rd		10,056
C23854	Inst Cable South St sub 1152B-1151		64,184
C24170	2291 Line Upgrades		217,465
C24173	Kilvert New 87F3 Feeder (Dist Sub)		100,524
C24174	Kilvert New 87F3 Feeder (Dist Line)		166,337
C24175	Hopkinton Substation (Dist Line)		25,841
C24176	Hopkinton Substation (Dist Sub)		71,242
C24179	Coventry MITS (Dist Sub)		59,263
C24180	Coventry MITS (Dist Line)		30,815
C24221	Load Relief to 9J3 - Brown Street		30,241
C26497	Wood River 85T2&T3 Disconnects		41,273
C27244	107W65 & 53 for T7 reconductor		12,909
C28534	South St Sub Inst Reactor Lds&Cable		50,731
C28615	BRISTOL 51F1 Load Relief		11,911
C28627	WAMPANOAG 48F3 Load Relief		9,752
C28628	NEWPORT Load Relief - Phase 2		20,185
C29407	Dyer St Subst 1105 Inst CTs & Cable		8,395
C29408	Inst Cable Fr Sq Feeder 1107 Prov		93,918
C29409	Franklin Sq Sub 1107 Reactor Leads		5,115
C29411	Dyer St Sub 1109 CTs and Cable		16,303
C29412	South St Sub 1111 CTs & Cable		11,141
C29413	South St Sub 1113 Install Cable		6,764
C29414	Inst Cable South St Fdr 1127 Prov		74,963
C29416	Inst Cable So St Fdr 1135 Prov		69,147
C29417	Fr Sq Sub 1139 Reactor Leads		4,631
C29418	South St Subm Cable Xing 1152B-1153		7,861
COS016	Ocean St-Dist-Load Relief Blanket		307,234
		Total	6,791,276

Division Data Request 11-19

Request:

Page 28: Did the Company perform any benefit / cost analyses to determine if these strategies will be cost-effective. If so, please provide copies of such studies.

Response:

The Company did not perform any benefit/cost analysis for the strategies because the strategies are designed to address the management of physical distribution and sub transmission assets throughout their lifecycle. The management of physical assets is inextricably linked to the management of all other aspects of the electric distribution business. Individual asset strategies are developed in order to meet overall business objectives and address risk in the following areas:

- Safety and Environmental
- Reliability
- Customer/Regulatory/Reputation
- Efficiency

Asset strategies are included in the establishment of the annual work plan developed to optimize investments in the system. The Company uses a prioritization model based on the relative risk of each project proposal to facilitate the selection of appropriate projects to be included in the annual work plan. The prioritization model considers the risks relative to safety, reliability, and environmental impact. Strategies are funded annually to ensure the necessary investments are being made to maintain and improve the system and ensure cost effective use of resources.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-21

Request:

Does the Company's proposed I&M strategy apply only to its distribution assets, or does it also apply to any transmission assets?

Response:

The I&M Strategy applies only to distribution and sub-transmission assets.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26

Request:

Page 32: Please describe the 50 Asset Strategies that the Company employs as they apply to facilities in Rhode Island, and what the Company has spent on these strategies in each of the last five years.

Response:

A brief description of the Company's approved asset strategies is provided below. Those strategies marked with a * are approved as a conceptual strategy, but key elements require more development (typically additional or better data). Please note that National Grid tracks spending by project, not by asset strategy, and therefore, there is no reasonable method for calculating the amount spent by strategy.

Distribution Fusing Strategy
This strategy sets forth the conditions for the installation of sectionalizing fuses on overhead distribution feeders. In all cases the purpose of sectionalizing fusing is to protect the feeder mainline and/or limit the size of the interruption. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

Distribution Line Capacitor Strategy
This strategy sets forth the asset management philosophy for distribution line capacitors with the intent of maximizing system performance while minimizing safety, environmental, reliability and regulatory impacts to the Company.

Currently, the asset condition of distribution line capacitors does not, in general, significantly affect the Company's performance from safety, environmental, reliability or regulatory standpoint. Identification of capacitor plant requiring maintenance or replacement should be made through the annual capacitor inspection and the five-year overhead inspection and maintenance program. Recommendations for installation of new capacitors and/or removal of existing capacitor plant should be made as a result of capacity planning studies performed by the appropriate engineering department.

Distribution Line Regulator Strategy
This strategy sets forth the asset management philosophy for distribution line voltage regulators with the intent of maximizing system performance while minimizing safety, environmental, reliability and regulatory impacts to the Company.

Currently, the asset condition of distribution line voltage regulators does not, in general, significantly affect the Company's performance from safety, environmental, reliability or

Division Data Request 11-26 (cont.)

regulatory standpoint. Identification of voltage regulator plant requiring maintenance or replacement should be made through regular inspections. Recommendations for installation of new voltage regulators and/or removal of existing voltage regulator plant should be made as a result of feeder voltage and capacity studies performed by the appropriate engineering department.

Distribution Line Transformer Strategy
This strategy sets forth the asset management philosophy for distribution line transformers with the intent of maximizing asset performance while maintaining existing performance in the way of safety, environmental, reliability and regulatory impacts to the Company. This strategy does not cover step up/down (ratio) transformers installed on the distribution system.

Currently, the performance of distribution line transformers does not represent a major impact to the Company's performance from, safety, environmental, reliability, or customer standpoints. To ensure this continued level of performance and a sustainable network, a proactive load-based replacement program for these assets beyond what is already being performed during customer service upgrades and system improvement projects is recommended. In addition, the condition of these assets will be evaluated and addressed as needed as part of the formal Overhead and Underground Inspection and Maintenance Programs.

Distribution Vegetation Program
The intent of this strategy is to outline all the procedures used to manage the distribution circuit-pruning program and the distribution hazard tree program currently in place. These are reliability-focused strategies designed to meet both state regulatory targets and support first quartile reliability performance. In addition, cycle pruning provides a measure of public safety by minimizing the potential for public contact with energized conductors though tree climbing as well as the potential for electrically caused fire in trees.

Feeder Hardening Strategy
The intent of this strategy is to provide a method to identify feeders with characteristics indicating the potential for significant reliability performance improvements related to deteriorated overhead equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

After identification and local review by Distribution Field Engineering, the feeders become part of the Feeder Hardening Program. Feeders in this program are surveyed for deteriorated equipment and non-standard grounding/bonding. All poles on which work is performed are brought up to current standards as part of the program.

Division Data Request 11-26 (cont.)

Miscellaneous Overhead Equipment Strategy
The intent of this strategy is to recommend a general approach for miscellaneous equipment in the overhead distribution asset grouping. This grouping includes: guys and anchors, crossarms, brackets, insulators, insulator pins, braces, lightning arresters, grounds, spacers, connectors, etc. This strategy is designed to both provide for a sustainable distribution system and improve system reliability.

These assets are to be inspected once every five years as part of the revised overhead inspection program. The inspection priority system (1-4) will identify and provide for the timely condition-based replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle.

Open Wire Primary Strategy*
The intent of this strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

Approximately 7,020 circuit miles (13%) of the National Grid overhead circuit mileage falls into the category of small wire. The three-phase portion of the small wire circuit mileage is 840 miles (< 2% of total, 12% of small wire). The majority of this small wire population is #6 and #4 copper/copperweld conductor.

Overhead Secondary Strategy
The intent of this strategy is to provide guidance on the replacement of open wire secondary with multiplex secondary cable. This strategy is designed to provide for a sustainable distribution system as well as improve reliability at the customer level. Secondary cable will be a target of opportunity, no specific replacement schedule is recommended.

The reliability impact of secondary interruptions is negligible on an indices basis; however at the customer level it becomes significant due to the typically long interruption durations. This is especially true during storm conditions where secondary and service related interruptions are not normally the first priority. The storm resistance qualities of secondary cable will limit the impact of severe weather on secondary related interruptions.

Overhead Switch Strategy*
The intent of this strategy is to provide an approach to manage our distribution and sub transmission line switches. This strategy is designed to provide for a sustainable distribution system as well as improve employee safety in normal and emergency conditions.

Division Data Request 11-26 (cont.)

National Grid has approximately 104,700 distribution and sub transmission switches. Loadbreak switches were first widely used beginning in the early 1980's. Prior to the use of loadbreak switches, airbreak switches were the standard. Disconnect switches have been used consistently over the entire age profile.

The inspection program will identify and assign a priority code (1-3) to switches in need of replacement on a five-year cycle across National Grid. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle.

Potted Porcelain Cutout Strategy
It is the Company's intention to remove all potted porcelain cutouts from service by FY 2012/13. Fuse cutouts provide a critical overcurrent protection function in the utility distribution system. However, one style of fuse cutout, potted porcelain cutouts, have proved to be a failure problem across the industry. Although the overall failure rate of cutouts at National Grid (all types) is approximately 0.4% per year, which is typical of distribution equipment in general, potted porcelain cutouts have a greater failure rate.

National Grid began purchasing potted porcelain cutouts in the early to mid-1980s and continued to purchase them through early 2001. During that time, and continuing today, potted porcelain cutouts were the style most extensively used in the utility industry.

Due to the mechanical failure mode and potential hazard associated with potted porcelain cutouts, National Grid is no longer purchasing this style of cutout and currently purchases only non-porcelain cutouts. Beginning in 2006, National Grid adopted a policy of replacing all potted porcelain cutouts on the Company's system over a 7-year period.

Recloser Application Strategy
This intent of this strategy is to set forth the general conditions for the installation of line reclosers on overhead distribution feeders. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance. The strategy should serve as a guide to when, where and why a recloser should be installed on a feeder. It is not intended to cover every possible situation, but provide enough guidance to allow Distribution Field Engineering to make an informed decision.

The line recloser strategy is to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure (more than 10 miles) with a 3-year average distribution line SAIDI performance (Regional IEEE 1366 basis) greater than the internal National Grid SAIDI goal (estimated at 96 minutes, based on 120 minute goal less 20%).

Division Data Request 11-26 (cont.)

Additionally any circuit identified as a desirable candidate from the Recloser Model would be eligible or any location having a $/Delta CMI equal to or less than $1.50. Candidates will compete for inclusion in the budget based on their $/Delta CMI value, the more economic reclosers will be included.

Recloser Replacement Strategy
The intent of this strategy is to provide an approach to manage distribution and sub transmission line reclosers. This strategy is designed to provide for a sustainable distribution and sub transmission system. National Grid has approximately 1,700 reclosers and 120 sectionalizers in service across the company.

The proposed approach for managing line reclosers and controls is condition-based using routine inspection data to determine when a unit should be replaced. A common data format and location will be determined to support the management of these assets.

Services Strategy
Currently, the asset condition of customer service cable does not have a significant impact on the Company's performance from, safety and environmental, reliability, or customer standpoints. As a result, a proactive replacement program for service cable beyond what is already being performed during customer service upgrades and system improvement projects is not recommended at this time. In addition, the condition of overhead service cables will be evaluated and maintenance performed if needed as part of the formal overhead and underground Inspection and Maintenance Programs.

Spacer Cable Strategy
The intent of this strategy is to replace all pre-1975 vintage grey spacer cable with signs of insulation ringing. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

When grey spacer cable with evidence of insulation ringing is present in an area and multiple interruptions can be linked to the grey spacer cable, a project should be initiated to replace the conductor. A 3-year reliability review of the feeder and the grey spacer cable's contribution to the reliability performance will be documented.

Consideration will also be given for proactive replacement of grey spacer cable provided there is evidence of insulation ringing. A reliability review will be completed documenting the expected impact of the conductor replacement.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26 (cont.)

Step-down/Ratio Transformer Strategy*

Currently, the performance of distribution line step-down transformers does not represent a major impact to the company's performance from, safety, environmental, reliability, or regulatory standpoints, although potential significant risk does exist if this asset class is not maintained. To ensure the continued level of performance and sustainable network, a proactive load-based replacement program for these assets beyond what is already being performed during new customer service investigations and system improvement projects is recommended at this time. In addition, the condition of these assets will be evaluated and addressed as needed as part of the formal Overhead and Underground Inspection and Maintenance Programs.

Wood Pole Strategy

The intent of this strategy is to provide an approach for managing our distribution and sub-transmission wood poles. This strategy is designed to provide for a sustainable distribution and sub-transmission system. This is a very large asset class (2.4 million poles) and is the foundation of the overhead distribution system. Reasonable age data is available for sub-transmission and distribution poles.

The Inspection Program has been updated to improve the consistency of the equipment condition reporting. Enhanced pole inspection has been added to the program, which includes both a visual and structural review of all poles on a five-year cycle. The Inspection Program is identifying and assigning a priority code to poles in need of replacement. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle
.

Interruptions caused by pole related issues are not significant; most pole problems are safety and environment related. Although we have not experienced a large number of pole failures, the few we have experienced are getting more media attention. Maintaining or slightly improving our pole age profile is recommended to hold steady at our current level of failures.

Duct Strategy

Failed (damaged, blocked or otherwise unusable) ducts are generally first discovered during emergency work or during the construction stage of planned work. There are currently no methods available to identify failed ducts short of rodding or other internal inspection. It is not practical to create a program to inspect ducts for damage on a routine basis.

When failed ducts are encountered during work or in other circumstances, they are to be repaired or replaced as necessary to complete the work. Otherwise, a PIW (Problem Identification Worksheet) will be issued. The PIW will be evaluated, alongside other proposed work through the Company's project evaluation process.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26 (cont.)

When significant infrastructure work (road work, sewer work, etc.) is planned for an area, the adequacy of the duct system in that area will be assessed at that time. This assessment will consider current and likely future needs of the distribution system and restrictions on future underground construction (such as municipal moratoriums on pavement cutting after re-paving). This evaluation will consider the size, type, quantity and condition of the existing conduit. An inspection of existing conduit for blocked or broken ducts may be appropriate at that time.

Manhole Strategy
This strategy identifies the asset strategy for distribution manholes. For the purposes of the strategy, manholes, include all underground structures in the public or private way large enough for a person to enter. This would include structures generally referred to as manholes or vaults. These manholes may contain sub transmission cables and equipment as well as distribution. This strategy is not intended to apply to building vaults or other structures entered through a doorway or to hand holes (underground structures too small for a person to enter).

Manholes are inspected on a five-year cycle. Inspections are also made whenever work is done inside a manhole. When defects are discovered during an inspection, they should be cataloged in existing systems according to current procedures and identified for repair. Repair work should be prioritized within the company's current scoring system.

Miscellaneous Underground Equipment Strategy
The intent of this strategy is to recommend a general strategy for miscellaneous equipment in the underground distribution asset group that is not addressed elsewhere by specific strategies. This group includes such item as: elbows, joints, grounds, racks, minor transformer and equipment issues, underground residential distribution (URD) foundations and structures, and anodes.

These assets are inspected once every five years. A new inspection priority system identifies specific assets that require attention. It is the intent to replace or repair all assets identified as deficient during the inspection process.

Oil Fuse Cutout Strategy
This strategy sets forth the replacement strategy of Oil Fuse Cutouts (OFCs) and other older style submersible oil switches, such as the PKL style switches. OFCs are fusing and switching devices used primarily in 4kV underground distribution areas. These devices were first designed and installed on the distribution system in the pre-war era (pre-World War I). OFCs are opened and closed manually by an operator. These devices have no spring loaded or other operator-independent opening mechanism and therefore are dependant on the speed of the human operator for adequate load breaking. OFCs have no load-make or load-break rating in the modern sense. It is the company's intention to remove all OFCs from service by FY 2015/16.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26 (cont.)

Primary Underground Cable Strategy*

This paper describes an asset management strategy for primary underground distribution cable intended to provide for a sustainable system going forward. This strategy applies to typical urban cable systems, substation get-aways (for age based replacements, as opposed to failure replacement), industrial park and similar applications. It is the intent of this strategy to eliminate all primary underground cable more than 60 years old from the system and complete the works in fifteen years. This strategy is not intended to apply to primary cable used in underground residential distribution (URD) systems or as supply to single or small groups of pad-mounted transformers (siphons). There is a separate strategy covering sub-transmission cables.

Underground Getaway Strategy

Getaway cables are defined as the underground cables from a substation to the first overhead structure of a predominately overhead or a mixed overhead/underground circuit. Get-away cables are to be replaced based on their individual failure record. Proactive replacement of get-away cables is not provided for by this strategy.

The strategy provides recommendations for both direct buried cables and duct lay cables:-

Direct Buried Cables

Upon the first failure of a direct buried get-away cable, the cable is to be repaired as an emergency, that is, repaired immediately as opposed to being scheduled for future repair. An estimate should be prepared for replacing the get-away and that project should be evaluated with all other proposed projects with the Company’s existing scoring model. A list of cables not replaced should be maintained. Upon the second failure of a direct buried get-away cable, the cable should be repaired as an emergency and the cable should be replaced. Any replacement of direct buried cables should be with a duct lay cable system in accordance with current Company construction standards.

Duct Lay Cables

Upon the first failure of a duct lay get-away cable, the cable is to be repaired as an emergency. Strong consideration should be given to replacing an entire section of cable (manhole-to-manhole or pole-to-pole, etc.) even if the cable could be pieced-out. Upon the second failure of duct lay get-away cable, the entire get-away cable should be replaced except for those sections that had been previously replaced due to earlier failures.

Division Data Request 11-26 (cont.)

Underground Siphon Strategy
This strategy provides an approach for addressing primary underground cable feeds from the overhead system to single pad-mounted transformers (sometimes referred to as siphons). Siphons from the overhead system to pad-mounted transformers may be direct buried or duct-lay. Generally these transformers are not part of a complete underground development and typically supply one transformer although, on occasion, multiple transformers are supplied. Generally, these cables supply single buildings or small complexes generally thought of as a single customer even though multiple meters may be involved (common and tenant areas for example).

Duct Lay Cable
Although there are exceptions, duct lay siphons are typically relatively short and involve a single section of cable. When a duct lay cable fails the entire section of cable should be replaced under the damage/failure blanket. There is no provision made in this strategy for blanket replacement of duct lay siphons.

Direct Buried Cable
Upon the first failure, Company-owned direct buried cable should be repaired. A record should be kept in the underground cable failure database. Upon the second failure of a direct buried cable, an estimate should be prepared to replace the cable and that project should be evaluated with all other proposed projects with the company's existing scoring model. Repairs should be done under the damage/failure blanket. Any replacement of direct buried cables should be with a duct lay cable system in accordance with current company construction standards

Underground Residential Distribution (URD) Primary Strategy
This strategy is for replacing or rehabilitating Underground Residential Distribution (URD) Cables. URD cables are typically served by 15kV class, #2 or 1/0, solid dielectric cables. Through the years a number of different insulations have been employed across the Company including PE, XLPE, EPR and Kerite. Cable installations have been either direct buried or duct lay. Since the early 1990s and continuing today, the practice in New England is to install duct lay cable.

Upon the failure of a cable in a URD, the failure should be repaired and the failure recorded. If two cable failures occur in the same section of URD cable, that individual section should be replaced. If three failures occur in the same half-loop in a 3-year period the cable should be evaluated for replacement or rehabilitating.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26 (cont.)

Vault Strategy
See Manhole Strategy.

Sub transmission and Distribution Tower Strategy*
This strategy provides an approach to managing sub-transmission and distribution steel towers. (Wood poles are addressed in a separate strategy). This strategy is focused on sustainability. It is designed to prevent steel members from deteriorating to the point of structural failure under expected mechanical loading or becoming weak to the point of compromised safety.

The initial strategy is to use an existing walking inspection, which was conducted for Sub transmission Engineering Design several years ago, together with Sub transmission Engineering Design engineering judgments to identify required tower maintenance. As soon as a planned helicopter sub-transmission survey and inspection is completed this information will be used to prioritize tower maintenance. After this initial stage the maintenance and replacement program can be managed via the inspection data from the new planned walking inspection program, which will be on a 5-year cycle.

Sub transmission Automation Strategy*
Although this strategy addresses automation of the sub transmission system, the tools are similar to distribution automation. In addition sub transmission is managed by distribution not transmission. For both of these reasons it is common practice to refer to sub-transmission automation as distribution automation or DA.

The objectives, in decreasing order of priority, for using distribution automation (DA) are to improve reliability performance, increase ease of operation (thereby reducing labor costs that can then be used for other reliability enhancing purposes), and to provide more and better data for expansion or operational studies. This DA strategy will encompass sub transmission automation and also supervisory control and data acquisition (SCADA) of reclosers, fault locators, switches; the interface of DA enabled line devices with the substation circuit breaker along with communication of these devices back to central Operations centers and database warehouses; and other related issues.

The distribution system of the future (DSF) is a Technology Transfer initiative that encompasses DA along with other issues such as load control, switched capacitor control and automated voltage profiling, and advanced metering infrastructure (AMI). Pilots related to these other initiatives are occurring in parallel with DA pilots and are coordinated by Technology Transfer. Thus were practical equipment (particularly communication for back haul of data and control signals) will be shared for economy.

Division Data Request 11-26 (cont.)

Sub-transmission Hardening Strategy*
This strategy is focused on reliability performance improvement. It provides a method to identify sub transmission circuits with characteristics indicating the potential for significant reliability performance improvements related to overhead deteriorated equipment and/or lightning interruptions. After identification and local review by Distribution Field Engineering and Sub transmission Engineering Design, the circuits will become part of the Sub transmission Hardening Program. Sub transmission circuits identified in this program are surveyed for deteriorated equipment and lightning arrester problems and brought up to standard.

Sub transmission Underground Cable Strategy*
This strategy describes an asset management approach for sub transmission cable intended to provide for a sustainable system going forward. The definition of sub-transmission used varies by location. In New England, the definition takes into account the number of customers served by a circuit and voltage. In New York the definition used is the FERC definition in the Plant Account System. Generally speaking, in New England the sub-transmission system is managed as part of the distribution system.

It is the intent of this strategy to eliminate all sub transmission underground cable more than 60 years old from the system within 15 years.

Battery and Related Strategy
Battery systems (or sets) are at the heart of a substation's operational capability – providing, for example, the power to charge breaker coils, which allow the breaker to operate successfully. Eye wash stations are provided near each battery set to ensure that safety is maintained; seismic racks are installed for new systems.

The present approach of proactive battery inspection and reactive Problem Identification Worksheets is successful in that very few system interruptions relate to batteries. This strategy should be continued. National Grid aims to be more proactive in implementation of our Substation Maintenance Standard's which require that batteries should be replaced at 20 years, allowing for an extra 5 years if the battery system tests in good condition. The 20-year limit is based on industry best practice and our experience in managing battery systems.

The strategy recommends bringing all battery systems to less than 25 years old in 5 years, and less than 20 years old in ten years (as per Substation Maintenance Standards); identify date of manufacture of all battery systems and chargers within 2 years. Replace battery systems & chargers as a whole, leading to cost efficiencies in replacement.

Division Data Request 11-26 (cont.)

Circuit Switcher Strategy
Circuit Switchers are multipurpose devices that are used for switching and protection of transformers, single and back-to-back shunt capacitor banks, reactors, lines, and cables. They can close, carry, and interrupt fault currents as well as load currents.

Circuit Switchers are inspected during regular Visual and Operational (V&O) inspections and as part of annual InfraRed (IR) surveys. They also undergo a detailed inspection and operational check during routine transformer maintenance.

The strategy recommends the need to replace less reliable circuit switchers targeting S&C Type G, S&C Mark II, S&C Mark III, and Siemens Linebacker.

Distribution Automation*
The objectives for installing distribution automation (DA) are to improve reliability performance, increase ease of operation (thereby reducing labor costs that can then be used for other reliability enhancing purposes), and to provide more and better data for expansion or operational studies.

This DA strategy will encompass distribution automation (referred to as DA) and also supervisory control and data acquisition (SCADA) of reclosers, fault locators, switches; the interface of DA enabled line devices with the substation feeder breaker along with communication of these devices back to central Operations centers and database warehouses; and other related issues.

The distribution system of the future (DSF) is a Technology Transfer initiative that encompasses DA along with other issues such as load control, switched capacitor control and automated voltage profiling, and advanced metering infrastructure (AMI). Pilots related to these other initiatives are occurring in parallel with DA pilots and are coordinated by Technology Transfer. Thus were practical equipment (particularly communication for back haul of data and control signals) will be shared for economy.

Generator Strategy
Substation emergency generators are covered by the Northeast Power Coordinating Council (NPCC) requirements. This equipment is administered a monthly run check for inspection and diagnostic purposes and are otherwise under a ‘fix on fail’ approach. Replacement of older units would bring the population below a maximum of 40 years.

Note: this strategy is shortly to be withdrawn as there are no distribution-only locations that must comply with NPCC requirements. The original strategy paper identified 82 locations, however it has now been confirmed that these are all Transmission stations.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-26 (cont.)

Instrument Transformers/Sensing Device Strategy
The strategy recommends replacement of identified less reliable units, particularly GE Type Butyl PT's and CT's.

A current transformer (CT) is a measurement device designed to provide a current in its secondary coil proportional to the current flowing in its primary. Current transformers are commonly used in metering and protective relaying where they facilitate the safe measurement of large currents, often in the presence of high voltages. The current transformer safely isolates measurement and control circuitry from the high voltages typically present on the circuit being measured.

Voltage transformers (VTs) or potential transformers (PTs) are used for metering and protection in high-voltage circuits. They are designed to present negligible load to the supply being measured and to have a precise voltage ratio to accurately step down high voltages so that metering and protective relay equipment can be operated at a lower potential.

Instrument transformers (sensing devices) are inspected during Visual and Operational (V&O) checks and through annual InfraRed (IR) inspections.

Substation Cable & Conductor*
The strategy for substation cables and conductors is to include them in general visual inspection during visual and V&O inspections. Replacement of cables and conductors is considered during condition assessment and asset replacement activities on each substation.

Substation Capacitor & Switch Strategy
The intent of this strategy is to recommend the continued testing, monitoring and condition based replacement of substation capacitor banks. The current method of using inspections and pre-peak checks to monitor condition and to maintain performance is both proactive and prevents failure.

Capacitor bank switches of particular Joslyn vacuum design are known to have occasional failures and are replaced on a case by case basis (they do not impact reliability and are a stores item) and are known not to fail catastrophically.

Substation Circuit Breaker/Recloser Strategy
The present approach of maintenance and ‘fix on fail’ is supplemented by a replacement program to target aged/unreliable units, and formation of a formal spares policy as the Company moves to first condition based maintenance then risk/criticality based maintenance. Aged units can be difficult to fix or repair as the availability of parts for obsolescent breakers and reclosers is poor.

Division Data Request 11-26 (cont.)

Substation Disconnect & MOD Strategy
This strategy recommends replacement of old and unreliable equipment and covers disconnects (fuses, air breaks, line breaks etc) and motorized versions of the same items. The disconnect part of the device is treated separately to the motor in terms of maintenance.

Replacement programs are recommended for flying ground switches (all in NY), liquid filled fuses, sacrificial air breaks (in line with transmission strategy SG001), hook stick disconnects, known unreliable motor operators.

Substation Infrastructure Strategy*
Substation infrastructure is assessed during regular inspections, including infra red surveys, and has further input through Problem Identification Worksheets (PIW's). These inspections have lead to a program for replacement or refurbishment of foundations and related supports across the system.

Substation Insulator Strategy
Insulators are required to ensure that live system components do not connect to ground unintentionally through provision of a very high impedance path to grounded structures. They are of a size and a composition to ensure that system event, weather and environmental effects do not cause unintentional grounding. Insulators are not normally entered as unique assets as they are so numerous and are considered low cost, consumable items. Many are 40-50 years old, based on date of station installation and are at the end of their design life.

Insulators may fail to perform their function if they are spanned by contamination, suffer degradation, which leads to reduced impedance or structural failure, or are spanned by an animal; deterioration of the cement may lead to water ingress and subsequent cement failure. Any insulator failure may be catastrophic and usually leads to an interruption of supply – insulator components may be propelled long distances leading to possible damage of other substation components and may insulator pieces may leave the confines of the station.

Insulators are replaced if they are damaged or broken. Cap-pin insulators are known industry 'bad actors' – they have lead to several PIW's and interruptions through failure. A program to replace cap-pin insulators is being put in place in 2008/2009 to replace cap-pin insulators on an opportunity basis (through related construction projects, maintenance or outages) and to collect appropriate data as to the actual location and volume of cap-pin insulators through inspections and subsequent follow up visits.

Division Data Request 11-26 (cont.)

Substation Metal Clad Switchgear Strategy
The intent of this strategy is to remove older and less reliable units and to apply new technologies to detect onset of unreliability.

Metal clad switchgear is surveyed using Visual and Operational (V&O) surveys and Infra Red (IR) inspections. Replacement is performed based on age and type. Animal based outages are being addressed through an animal incursion prevention program. Newer methods of detecting onset of unreliability, using acoustic emission partial discharge (AE PD) detection, should be pursued. These have yielded benefits in breakers already and are applicable to metal clad.

Substation Non-transformer Reactor Strategy
The present strategy for substation-based reactors (non transformer type) is to monitor during inspections. Those with concrete as part of their structure will be targeted for replacement; they are more prone to failure.

Substation Power Transformer Strategy
Substation transformers are a critical asset class in the successful operation of the electricity distribution system. The strategy aims to minimize random transformer failures, ensure that transformer population is capable of performing its function and provide early replacement for those units that are likely to fail and supports the objective to improve reliability to meet service quality standards in all states in which National Grid operates.

The strategy also sets forth a Distribution Substation Transformers program to allow National Grid:

- to confidently rank our substation transformers in terms of health
- identify those transformers which are most critical to the system
- identify those transformers which are in locations most susceptible to through faults and interruptions
- rank transformers in terms of risk, and thus prioritize transformers for asset replacement

Substation Surge Arrester Strategy
The surge (lightning) arrester strategy is to replace ‘at risk’ units. Attention to SiC arresters, which have a known failure mode and tend to be older units, will lead to a replacement program being introduced in 2008/09.

Surge arresters are monitored during Visual and Operational (V&O) inspections and annual InfraRed (IR) surveys. Units identified as at risk are replaced. Arresters greater than 15 MVA are tested with the associated transformer when the transformer is taken out for maintenance.

Division Data Request 11-26 (cont.)

Substation Voltage Regulator Strategy

The present strategy for voltage regulators recommends replacement of known less reliable units. Particular voltage regulators are known bad actors including Siemens JFR, General Electric IRS Induction and Westinghouse IRT. Regulators are a stores item which are monitored via Visual and Operational (V&O) inspection and InfraRed (IR) surveys.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-28

Request:

Please provide the prioritization model referenced on page 33.

Response:

Please refer to the Company's response to Division Data Request 11-17.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-35

Request:

Does the Company's request for a rate increase consider the potential sharing of pole replacement costs with any Joint Owners? If so, please describe in detail the impact of this sharing. If not, please explain why not.

Response:

The impact of joint pole ownership is built into the Company's proposed capital budget. The capital budget is net of any contributions in aid of construction or funds received for joint pole ownership. These items are built into project estimates either on a project-by-project basis or using historical trends in the case of a blanket project.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-41

Request:

For each year from 1994 through 2008, please provide the annual kilowatthours delivered or consumed on the Narragansett Electric system. This should include all kilowatt hours delivered by the Company regardless of who the generation supplier was.

Response:

Please see the table below for the annual kilowatt-hours delivered on the Narragansett Electric system to all customers, regardless of generation supplier, for each year from 1994 through 2008.

Year	kWh Delivered
1994	6,530,493,085
1995	6,509,795,840
1996	6,584,071,041
1997	6,652,198,549
1998	6,830,047,643
1999	7,073,323,966
2000	7,166,025,590
2001	7,341,097,343
2002	7,515,613,982
2003	7,694,091,648
2004	7,822,279,925
2005	7,985,335,205
2006	7,732,329,004
2007	7,879,655,164
2008	7,733,619,602

Prepared by or under the supervision of: Howard S. Gorman

Division Data Request 12-1

Request:

Please provide copies of National Grid's current Service Company allocation agreements (including agreements with KeySpan) and any direct assignment agreement(s) as well as copies of those agreements for the years 2008, 2007 and 2006.

Response:

Please refer to the CD-ROM provided for National Grid USA Service Company agreements (including legacy KeySpan) and direct assignments for the years 2006 through 2009.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-3

Request:

For each services agreement in effect during 2006, 2007 and 2008, please provide the calculation of the monthly actual allocation factors used to allocate costs. Include all supporting documentation (including copies of all original source documents for each allocation formula component), calculations, workpapers and working Excel spreadsheets, including all calculations, source files and links enabled.

Response:

Please refer to the CD-ROM provided for the supporting documentation of allocation factors calculated in 2006, 2007, and 2008.

Calculations or supporting documentation has not been provided for the legacy KeySpan Service Companies for 2006 since the Company did not receive services until after the KeySpan / National Grid merger in 2007.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-4

Request:

Please produce a spreadsheet separately listing all the costs that were allocated or assigned to Narragansett Electric from any National Grid affiliate under the agreements produced in response to question #1 and organize the costs in the spreadsheet by FERC account and sub-account. For this response, please produce a fully functioning spreadsheet in Excel format.

Response:

Please see Attachment DIV 12-4, which is also provided in Excel format.

Prepared by or under the supervision of: Robert L. O'Brien

Calendar Year 2006
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit	
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co.	Grand Total
1	107000	Construction in Progress	13,928,527	13,928,527
2	108001	RWIP Reclass	462,207	462,207
3	118000	Common Plant in Service	5,713	5,713
4	124000	Oth Inv-Cash Surr Val-Life Ins	21,807	21,807
5	124001	Oth Inv-Cash Surr-Policy Loan	(4,702)	(4,702)
6	124002	Oth Inv-Miscellaneous	5,000	5,000
7	163000	Stores Clearing-Debit	2,383	2,383
8	163010	Stores Clearing Db Bill Pool	1,395,727	1,395,727
9	163100	Stores Clearing-Credit	408,022	408,022
10	165000	Prepaids	665,610	665,610
11	165002	Prepaid Employee Insurance	18,979	18,979
12	174000	Misc Curr and Accrued Assets	62,917	62,917
13	183000	Prelim Survey & Investigation	917,640	917,640
14	184020	Transp Exp-DR-Clearing Only	1,586,338	1,586,338
15	184030	Communication Expenses-Debit	13,509	13,509
16	184118	TNW-Clearing Operating	(91,392)	(91,392)
17	184200	Transportation Exp-Debit	188,049	188,049
18	216000	Surp-Unappr Earnd Surplus	0	0
19	253031	Def Incentive Comp-Pensions	403,453	403,453
20	253033	EUA Deferred Revenue McNeil	315	315
21	253106	FAS 106 Recovery	62,435	62,435
22	408100	Tx Oth Inc Tx-Fed Unempl Comp	1,077	1,077
23	408110	Tx Oth Inc Tx-FICA Co Portion	1,569,651	1,569,651
24	409157	Fed Inc Tax-Curr-Util Oper Inc	(553,373)	(553,373)
25	417110	NGT Share Awards	623,000	623,000
26	421002	Misc Non-Operating Income	(10,464)	(10,464)
27	421200	Loss on Disp of Property	36,250	36,250
28	426100	Donations	98,245	98,245
29	426200	Def Comp Inv-Life Ins	(149,700)	(149,700)
30	426400	Civic & Political Activity	162,846	162,846
31	426500	Other Deductions	42,079	42,079
32	431000	Other Interest Expense	339,681	339,681
33	431130	Oth Int Exp-Commitment Fee	8,700	8,700
34	454000	Rent From Electric Property	(38,421)	(38,421)

Calendar Year 2006
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit	
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co.	Grand Total
35	456040	Other Elec Rev-Misc	895	895
36	557000	Other Power Supply Expenses	5,720	5,720
37	560000	Trans Oper-Supervision & Eng	86,236	86,236
38	561000	Trans Oper-Load Dispatching	950,481	950,481
39	562000	Trans Oper-Substations	88,849	88,849
40	563000	Trans Oper-Overhead Lines	16,177	16,177
41	564000	Trans Oper-Underground Lines	1,178	1,178
42	566000	Trans Oper-Misc Expenses	169,315	169,315
43	568000	Trans Maint-Supervision & Eng	276,608	276,608
44	569000	Trans Maint-Buildings	80	80
45	570000	Trans Maint-Substations	240,958	240,958
46	570010	Trans Maint-Substation-Trouble	121,905	121,905
47	571000	Trans Maint-Overhead Lines	79,865	79,865
48	571010	Trans Maint-Switch-Unplanned	46	46
49	571020	Trans Maint-Right of Way	165,644	165,644
50	572000	Trans Maint-Underground Lines	9,755	9,755
51	573000	Trans Maint-Misc Expenses	17,706	17,706
52	580000	Dist Oper-Supervision & Eng	1,415,485	1,415,485
53	581000	Dist Oper-Load Dispatching	1,825,444	1,825,444
54	582000	Dist Oper-Substations	280,630	280,630
55	583000	Dist Oper-Overhead Lines	1,009,089	1,009,089
56	584000	Dist Oper-Underground Lines	227,827	227,827
57	585000	Dist Oper-Outdoor Lighting	2,641	2,641
58	586000	Dist Oper-Electric Meters	220,596	220,596
59	587000	Dist Oper-CustomerInstallation	122,568	122,568
60	588000	Dist Oper-Misc Expenses	1,437,905	1,437,905
61	589000	Dist Oper-Rents	203	203
62	589001	Rents-Building-Dist-Elim	50,612	50,612
63	590000	Dist Maint-Supervision & Eng	339	339
64	591000	Dist Maint-Structures	3,681	3,681
65	592000	Dist Maint-Substations	892,076	892,076
66	592010	Dist Maint-Substations-Trouble	188,397	188,397
67	593000	Dist Maint-Overhead Lines	4,310,111	4,310,111
68	593020	Dist Maint-OH Lines-Veg Mgmt	212,232	212,232

Calendar Year 2006
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit	
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co.	Grand Total
69	594000	Dist Maint-Underground Lines	2,109,246	2,109,246
70	595000	Dist Maint-Line Transformers	17,778	17,778
71	596000	Dist Maint-Outdoor Lighting	324,217	324,217
72	597000	Dist Maint-Electric Meters	227,936	227,936
73	598000	Dist Maint-Misc Distr Plant	889	889
74	892000	Gas Maint-Services	0	0
75	901000	Cust Acct-Supervision	685,931	685,931
76	902000	Cust Acct-Meter Reading Exp	152,133	152,133
77	903000	Cust Records & Collection	6,272,045	6,272,045
78	904000	Uncollectible Accounts	(4)	(4)
79	905000	Cust Acct-Misc Expenses	94,815	94,815
80	907000	Cust Service-Supervision	29,358	29,358
81	908000	Cust Assistance Expenses	1,931,569	1,931,569
82	909000	Info&Instruct Advertising Exp	33,995	33,995
83	910000	Cust Service-Misc Expenses	792,987	792,987
84	912000	Demo & Selling Expenses	116	116
85	920000	A&G-Salaries	8,746,913	8,746,913
86	921000	A&G-Office Supplies	7,257,582	7,257,582
87	922000	Admin Expense Transferred-CR	15	15
88	923000	A&G-Outside Services Employed	1,319,949	1,319,949
89	924000	Property Insurance	394,811	394,811
90	925000	Injuries & Damages Insurance	959,346	959,346
91	926000	Employee Pensions & Benefits	8,633,800	8,633,800
92	928000	Regulatory Comm Expenses	495,848	495,848
93	930200	A&G-Misc Expenses	704,887	704,887
94	930210	A&G-Research & Development	70,488	70,488
95	931000	A&G-Rents	3,188,149	3,188,149
96	935000	A&G Maint-General Plant-Elec	412,527	412,527
	Grand Total		81,470,686	81,470,686

Calendar Year 2007
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit		
Line	Regulatory	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	Grand Total
1	107000	Construction in Progress	28,763,475		28,763,475
2	108001	RWIP Reclass	398,002		398,002
3	124000	Oth Inv-Cash Surr Val-Life Ins	21,807		21,807
4	134000	Special Deposits	5,000		5,000
5	163000	Stores Clearing-Debit	36,831		36,831
6	163010	Stores Clearing Db Bill Pool	1,384,452		1,384,452
7	163100	Stores Clearing-Credit	706,981		706,981
8	165001	Prepaid Insurance	220,382		220,382
9	165002	Prepaid Employee Insurance	22,020		22,020
10	174000	Misc Curr and Accrued Assets	(4,555)		(4,555)
11	183000	Prelim Survey & Investigation	848,448		848,448
12	184000	Other Clearing		2,331	2,331
13	184020	Transp Exp-DR-Clearing Only	1,856,666		1,856,666
14	184030	Communication Expenses-Debit	21,903		21,903
15	184101	Pymts TNW-Vacation	(67,300)		(67,300)
16	184110	Pymts TNW-Weather	(184)		(184)
17	184118	TNW-Clearing Operating	(517,700)		(517,700)
18	184200	Transportation Exp-Debit	(5,075)		(5,075)
19	253106	FAS 106 Recovery	(474,531)		(474,531)
20	408100	Tx Oth Inc Tx-Fed Unempl Comp	933		933
21	408110	Tx Oth Inc Tx-FICA Co Portion	1,744,237		1,744,237
22	408150	Tx Oth Inc Tx-Misc	1,198		1,198
23	409157	Fed Inc Tax-Curr-Util Oper Inc	(1,626,593)		(1,626,593)
24	410157	Def Inc Tax-Utility Oper Inc	114,068		114,068
25	417110	NGT Share Awards	506,500		506,500
26	421002	Misc Non-Operating Income	(3,645)		(3,645)
27	426100	Donations	87,194		87,194
28	426200	Def Comp Inv-Life Ins	251,713		251,713
29	426400	Civic & Political Activity	118,574		118,574
30	431000	Other Interest Expense	204,878		204,878
31	431130	Oth Int Exp-Commitment Fee	34,896		34,896
32	454000	Rent From Electric Property	(19,328)		(19,328)
33	557000	Other Power Supply Expenses	2,204		2,204
34	560000	Trans Oper-Supervision & Eng	124,226		124,226

Calendar Year 2007
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit		
Line	Regulatory	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	Grand Total
35	561000	Trans Oper-Load Dispatching	975,643		975,643
36	561200	Ld Disptch-Mon & Oper Tran Sys	99		99
37	561500	Reliab, Plan & Standards Dev	11,992		11,992
38	562000	Trans Oper-Substations	79,754		79,754
39	563000	Trans Oper-Overhead Lines	30,921		30,921
40	564000	Trans Oper-Underground Lines	2,430		2,430
41	566000	Trans Oper-Misc Expenses	254,652		254,652
42	568000	Trans Maint-Supervision & Eng	256,836		256,836
43	570000	Trans Maint-Substations	209,188		209,188
44	570010	Trans Maint-Substation-Trouble	218,154		218,154
45	571000	Trans Maint-Overhead Lines	230,882		230,882
46	571020	Trans Maint-Right of Way	19,925		19,925
47	572000	Trans Maint-Underground Lines	120,004		120,004
48	573000	Trans Maint-Misc Expenses	48,357		48,357
49	580000	Dist Oper-Supervision & Eng	1,294,663		1,294,663
50	581000	Dist Oper-Load Dispatching	1,930,452		1,930,452
51	582000	Dist Oper-Substations	395,143		395,143
52	583000	Dist Oper-Overhead Lines	1,133,789		1,133,789
53	584000	Dist Oper-Underground Lines	302,551		302,551
54	585000	Dist Oper-Outdoor Lighting	667		667
55	586000	Dist Oper-Electric Meters	220,779		220,779
56	587000	Dist Oper-CustomerInstallation	156,143		156,143
57	588000	Dist Oper-Misc Expenses	2,249,084		2,249,084
58	589000	Dist Oper-Rents	3		3
59	589001	Rents-Building-Dist-Elim	50,502		50,502
60	589002	Rents-Equip-Dist-Elim	3,538		3,538
61	590000	Dist Maint-Supervision & Eng	(286)		(286)
62	591000	Dist Maint-Structures	287		287
63	592000	Dist Maint-Substations	628,670		628,670
64	592010	Dist Maint-Substations-Trouble	269,096		269,096
65	593000	Dist Maint-Overhead Lines	4,078,832		4,078,832
66	593010	Dist Maint-OH Lines-Trouble	3,552		3,552
67	593020	Dist Maint-OH Lines-Veg Mgmt	1,037,439		1,037,439
68	594000	Dist Maint-Underground Lines	1,383,240		1,383,240

Calendar Year 2007
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit		
Line	Regulatory	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	Grand Total
69	595000	Dist Maint-Line Transformers	138,166		138,166
70	596000	Dist Maint-Outdoor Lighting	339,072		339,072
71	597000	Dist Maint-Electric Meters	176,627		176,627
72	598000	Dist Maint-Misc Distr Plant	193		193
73	901000	Cust Acct-Supervision	932,935		932,935
74	902000	Cust Acct-Meter Reading Exp	191,414		191,414
75	903000	Cust Records & Collection	6,485,061		6,485,061
76	905000	Cust Acct-Misc Expenses	492,285		492,285
77	907000	Cust Service-Supervision	50,504		50,504
78	908000	Cust Assistance Expenses	2,014,183		2,014,183
79	909000	Info&Instruct Advertising Exp	92,076		92,076
80	910000	Cust Service-Misc Expenses	1,052,661		1,052,661
81	912000	Demo & Selling Expenses	3		3
82	920000	A&G-Salaries	7,909,626	34,366	7,943,993
83	921000	A&G-Office Supplies	8,327,921	28,030	8,355,951
84	922000	Admin Expense Transferred-CR	4		4
85	923000	A&G-Outside Services Employed	1,603,791		1,603,791
86	924000	Property Insurance	18,482		18,482
87	925000	Injuries & Damages Insurance	1,820,616		1,820,616
88	926000	Employee Pensions & Benefits	8,725,358		8,725,358
89	928000	Regulatory Comm Expenses	513,247		513,247
90	930200	A&G-Misc Expenses	707,806		707,806
91	930210	A&G-Research & Development	95,856		95,856
92	931000	A&G-Rents	3,398,146		3,398,146
93	931005	Airplane Rent Expense-Elim	26,984		26,984
94	935000	A&G Maint-General Plant-Elec	221,365		221,365
95	Grand Total		97,689,037	64,728	97,753,765

Calendar Year 2008
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit			
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	KeySpan Utility Svcs	Grand Total
1	107000	Construction in Progress	31,474,140			31,474,140
2	108001	RWIP Reclass	447,805			447,805
3	124000	Oth Inv-Cash Surr Val-Life Ins	82,602			82,602
4	124001	Oth Inv-Cash Surr-Policy Loan	(45,980)			(45,980)
5	163000	Stores Clearing-Debit	1,425			1,425
6	163010	Stores Clearing Db Bill Pool	1,528,640			1,528,640
7	163100	Stores Clearing-Credit	676,611			676,611
8	165002	Prepaid Employee Insurance	26,716			26,716
9	174000	Misc Curr and Accrued Assets	11,075			11,075
10	183000	Prelim Survey & Investigation	5,605,861			5,605,861
11	184000	Other Clearing	929	11,076		12,006
12	184020	Transp Exp-DR-Clearing Only	2,509,025			2,509,025
13	184030	Communication Expenses-Debit	25,727			25,727
14	184118	TNW-Clearing Operating	4,164			4,164
15	184200	Transportation Exp-Debit	19,685			19,685
16	253106	FAS 106 Recovery	39,478			39,478
17	408100	Tx Oth Inc Tx-Fed Unempl Comp	(478)			(478)
18	408110	Tx Oth Inc Tx-FICA Co Portion	1,702,551			1,702,551
19	408150	Tx Oth Inc Tx-Misc	18,993			18,993
20	409157	Fed Inc Tax-Curr-Util Oper Inc	(3,279,577)			(3,279,577)
21	410157	Def Inc Tax-Utility Oper Inc	2,661,753			2,661,753
22	417110	NGT Share Awards	732,500			732,500
23	421002	Misc Non-Operating Income	(6,018)			(6,018)
24	426100	Donations	87,625	149,000		236,625
25	426200	Def Comp Inv-Life Ins	(507,869)			(507,869)
26	426400	Civic & Political Activity	152,626			152,626
27	431000	Other Interest Expense	129,116			129,116
28	431130	Oth Int Exp-Commitment Fee	38,500			38,500
29	454000	Rent From Electric Property	(12,585)			(12,585)
30	456040	Other Elec Rev-Misc	(12,035)			(12,035)
31	560000	Trans Oper-Supervision & Eng	93,455			93,455
32	561000	Trans Oper-Load Dispatching	1,019,749			1,019,749
33	561500	Reliab, Plan & Standards Dev	31,407			31,407
34	562000	Trans Oper-Substations	128,880			128,880

Calendar Year 2008
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit			
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	KeySpan Utility Svcs	Grand Total
35	563000	Trans Oper-Overhead Lines	93,386			93,386
36	564000	Trans Oper-Underground Lines	705			705
37	566000	Trans Oper-Misc Expenses	501,718			501,718
38	568000	Trans Maint-Supervision & Eng	232,445			232,445
39	569100	T Maint of Computer Hardware	5			5
40	570000	Trans Maint-Substations	436,234			436,234
41	570010	Trans Maint-Substation-Trouble	241,597			241,597
42	571000	Trans Maint-Overhead Lines	299,277			299,277
43	571010	Trans Maint-Switch-Unplanned	18,499			18,499
44	571020	Trans Maint-Right of Way	62,972			62,972
45	572000	Trans Maint-Underground Lines	25,297			25,297
46	573000	Trans Maint-Misc Expenses	(455,843)			(455,843)
47	580000	Dist Oper-Supervision & Eng	1,132,600			1,132,600
48	581000	Dist Oper-Load Dispatching	2,019,381			2,019,381
49	582000	Dist Oper-Substations	648,325			648,325
50	583000	Dist Oper-Overhead Lines	2,895,338			2,895,338
51	584000	Dist Oper-Underground Lines	322,765			322,765
52	585000	Dist Oper-Outdoor Lighting	2,717			2,717
53	586000	Dist Oper-Electric Meters	233,845			233,845
54	587000	Dist Oper-CustomerInstallation	167,890			167,890
55	588000	Dist Oper-Misc Expenses	4,173,084	132,998		4,306,082
56	589000	Dist Oper-Rents	18			18
57	589001	Rents-Building-Dist-Elim	49,658			49,658
58	589002	Rents-Equip-Dist-Elim	722			722
59	590000	Dist Maint-Supervision & Eng	449			449
60	592000	Dist Maint-Substations	899,958			899,958
61	592010	Dist Maint-Substations-Trouble	406,623			406,623
62	593000	Dist Maint-Overhead Lines	3,956,011			3,956,011
63	593010	Dist Maint-OH Lines-Trouble	1,565			1,565
64	593020	Dist Maint-OH Lines-Veg Mgmt	1,526,632			1,526,632
65	594000	Dist Maint-Underground Lines	2,168,192			2,168,192
66	595000	Dist Maint-Line Transformers	58,377			58,377
67	596000	Dist Maint-Outdoor Lighting	380,764			380,764
68	597000	Dist Maint-Electric Meters	231,243			231,243

Calendar Year 2008
Charges to Narragansett Electric Company
Originating from National Grid Service Companies

			Orig Business Unit			
Line	Regulatory Acct	Regulatory Acct Descr	NGUSA Svc Co	KeySpan Corp Svcs	KeySpan Utility Svcs	Grand Total
69	598000	Dist Maint-Misc Distr Plant	121			121
70	901000	Cust Acct-Supervision	1,133,673			1,133,673
71	902000	Cust Acct-Meter Reading Exp	114,735	411		115,146
72	903000	Cust Records & Collection	8,648,517			8,648,517
73	904000	Uncollectible Accounts	5			5
74	905000	Cust Acct-Misc Expenses	1,021,581			1,021,581
75	907000	Cust Service-Supervision	82,193			82,193
76	908000	Cust Assistance Expenses	2,713,445			2,713,445
77	909000	Info&Instruct Advertising Exp	111,977			111,977
78	910000	Cust Service-Misc Expenses	2,095,240			2,095,240
79	912000	Demo & Selling Expenses	3	420		423
80	916000	Sales-Misc Expenses	172			172
81	920000	A&G-Salaries	6,689,295	1,005,724	53,622	7,748,641
82	921000	A&G-Office Supplies	7,103,058	545,346	1,618	7,650,023
83	923000	A&G-Outside Services Employed	833,555	275,193		1,108,747
84	924000	Property Insurance	12,319			12,319
85	925000	Injuries & Damages Insurance	1,970,408	5,798		1,976,206
86	926000	Employee Pensions & Benefits	9,944,720			9,944,720
87	928000	Regulatory Comm Expenses	536,203			536,203
88	930110	A&G-Institutional/Goodwill Adv		508,532		508,532
89	930200	A&G-Misc Expenses	789,842	30,984		820,826
90	930210	A&G-Research & Development	128,069			128,069
91	931000	A&G-Rents	3,402,618			3,402,618
92	931005	Airplane Rent Expense-Elim	38,196			38,196
93	931006	NE Share CSS Costs-Elim	635,181			635,181
94	935000	A&G Maint-General Plant-Elec	211,349			211,349
95	Grand Total		116,335,423	2,665,482	55,241	119,056,146

Division Data Request 12-6

Request:

Please list by separate FERC account for 2006, 2007, 2008 and projected 2010, NGrid Service Company expenses in all accounts which are allocated to Narragansett Electric and any National Grid affiliates in the form of the chart as illustrated below. Show the total expense for each separate account, the amount allocated to Narragansett Electric, and the amount allocated to each National Grid affiliate. For this response, please produce a fully functioning spreadsheet in Excel format.

FERC Account Number	Total Expense	Allocation to Affiliate A	Allocation to Affiliate B	(Continue columns for all affiliates)	Allocation to Company

Response:

Please see Attachment DIV 12-6 for expenses charged to Narragansett Electric and affiliates for the years 2006 through 2008 from legacy National Grid USA Service Company and legacy KeySpan Service, which is also provided in EXCEL format. The requested information for projected 2010 service company costs to be allocated to each individual operating company is not available.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-7

Request:

Please list by separate FERC account for 2008 and projected 2010 KeySpan Service Company expenses in all accounts which are allocated to Narragansett Electric and any National Grid affiliates. Show the total expense for each separate account, the amount allocated to Narragansett Electric, and the amount allocated to each National Grid affiliate. For this response, please produce a fully functioning spreadsheet in Excel format.

Response:

Please see Attachment DIV 12-7 for expenses charged to Narragansett Electric and affiliates in 2008 from legacy KeySpan Service Companies, which is also provided in Excel format. Please note that these charges are also included as part of the amounts shown in the response to DIV 12-6, reflecting charges from both legacy National Grid USA Service Company and legacy KeySpan Service Companies. The requested information for projected 2010 service company costs to be allocated to individual operating companies is not available.

Prepared by or under the supervision of: Robert L. O’Brien

Calendar Year 2008
Charges to Narragansett Electric Company and Affiliates
Originating from National Grid Service Companies-KeySpan Companies only

Line	Regulatory Acct	Allocation to Affiliate NGUSA	Allocation to Affiliate Nantucket Elec	Allocation to Affiliate Mass Electric	Allocation to Affiliate NEH Trans Elec	Allocation to Affiliate NEH Trans Corp	Allocation to Affiliate NE Power Co.	Allocation to Affiliate NE Elec Trans Co.	Allocation to Affiliate Niagara Mohawk	Allocation to Affiliate Granite State Elec	Allocation to Affiliate Narragansett Gas	Allocation to Affiliate Boston Gas	Allocation to Affiliate Essex Gas
1	107000										1,486,161	24,486,998	66,314
2	108001											596	
3	154000												
4	163000											3,292,068	
5	174002											64,871	
6	175002											910,696	121,213
7	181000												
8	182352												
9	182357											228	
10	182365												
11	184000		449	26,163					279,369	980	152,937	21,750,556	
12	184010												
13	184118												
14	185000											10,717	
15	408150											19,090	
16	417000												
17	426100			155,900					463,483	20,000	261,500	4,831	
18	426400											12,248	
19	426500												
20	430101											3,932	
21	431000												
22	454000												
23	456040												
24	495000												
25	500000												
26	502000												
27	505000												
28	506000												
29	510000												
30	511000												
31	512000												
32	513000												
33	514000												
34	548000												
35	549000												
36	551000												
37	554000												
38	560000												
39	561000												
40	562000												
41	566000												
42	570000												
43	572000												
44	573000												
45	580000												
46	582000												
47	583000												
48	586000												
49	587000												
50	588000		5,385	316,070					162,599	11,825			

Calendar Year 2008
Charges to Narragansett Electric Company and Affiliates
Originating from National Grid Service Companies-KeySpan Companies only

Line	Regulatory Acct	Allocation to Affiliate NGUSA	Allocation to Affiliate Nantucket Elec	Allocation to Affiliate Mass Electric	Allocation to Affiliate NEH Trans Elec	Allocation to Affiliate NEH Trans Corp	Allocation to Affiliate NE Power Co.	Allocation to Affiliate NE Elec Trans Co.	Allocation to Affiliate Niagara Mohawk	Allocation to Affiliate Granite State Elec	Allocation to Affiliate Narragansett Gas	Allocation to Affiliate Boston Gas	Allocation to Affiliate Essex Gas
51	590000												
52	592000												
53	593000												
54	594000												
55	717000												
56	718000										37,341	197,363	728
57	735000												
58	742000											42,009	119
59	812000												
60	813000											39,042	
61	841000											140,974	520
62	853000												
63	856000												
64	857000											81,584	223
65	863000												
66	865000												
67	874000											3,552,571	62
68	875000												
69	878000											1,056,766	1,472
70	879000											245,142	
71	880000											77,299	119
72	885000								28,602		432,164		
73	886000											9,787	11
74	887000											377,879	435
75	889000											226,043	880
76	892000											217,084	853
77	893000											1,297,510	
78	901000											162,822	
79	902000		16	1,037					2,206	38	235	20,246	
80	903000											17,020,791	
81	905000											5,055	
82	910000								660		343	105,135	7,863
83	912000		17	1,059					813,029	39	2,996,789	12,401,059	160,125
84	913000								330,329		383,051	1,427,525	
85	916000										(785,527)	(2,802,905)	(116,958)
86	917000											334,051	
87	920000	24,851	52,386	3,218,251	15,997	13,750	345,527	1,634	6,950,354	119,566	840,833	24,300,770	6,508
88	921000	18,137	57,666	1,397,749	11,194	9,632	165,022	1,173	3,095,849	44,389	341,914	15,168,914	
89	923000	11,099	10,846	669,570	5,751	4,974	338,392	674	1,516,633	24,318	164,674	4,624,115	
90	924000											407,388	
91	925000	340	223	13,849	246	211	2,559	23	32,791	516	3,122	1,234,222	
92	930110	29,870	19,559	1,214,671	21,618	18,530	224,402	2,059	2,876,059	45,291	273,835	714,404	
93	930200		1	147,253					380,126	37,807	125,629	645,620	315,674
94	931001												
95	932000											312,437	
96	Grand Total	84,297	146,548	7,161,572	54,806	47,098	1,075,902	5,564	16,932,089	304,769	6,714,999	134,199,533	566,161

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate Colonial Gas-Lowell	Allocation to Affiliate Colonial Gas-Cape Cod	Allocation to Affiliate EnergyNorth Natural Gas	Allocation to Affiliate KeySpan New England, LLC	Allocation to Affiliate KeySpan Money Pools	Allocation to Affiliate KeySpan Engineering Services LLC	Allocation to Affiliate KeySpan Electric Services LLC	Allocation to Affiliate KeySpan Generation LLC
1	107000	6,125,035	75,596	3,230,519				8,816,894	2,017,492
2	108001	20						506,344	7,493
3	154000							18,108	
4	163000		256,001					4,499,367	
5	174002	14,756		8,845				106,755	30,921
6	175002	121,891	126,657	100,968					
7	181000								(5,000)
8	182352								
9	182357								
10	182365			164,848					
11	184000	4,672,167	26,996	2,659,764				2,195,538	
12	184010								
13	184118						307		
14	185000								
15	408150	451		266				3,251	935
16	417000								
17	426100	1,141		653					34,524
18	426400	2,948		1,647					3,898
19	426500							17,112	5,823
20	430101							4,437,359	969,626
21	431000							12,397	1,810
22	454000								(29,742)
23	456040							(88,549)	
24	495000								
25	500000								90,988
26	502000								4,579
27	505000								(1,924)
28	506000							301	422,086
29	510000								(2,450)
30	511000								1,401
31	512000								15,035
32	513000								19,941
33	514000								5,301
34	548000								
35	549000								491
36	551000								
37	554000								
38	560000							329	
39	561000							626	
40	562000							(34,981)	
41	566000							188,025	
42	570000							271	
43	572000							2,434	
44	573000							7	
45	580000							7,561	
46	582000							502,422	
47	583000							126,808	
48	586000							958,133	
49	587000							1,271,337	
50	588000								

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate Colonial Gas-Lowell	Allocation to Affiliate Colonial Gas-Cape Cod	Allocation to Affiliate EnergyNorth Natural Gas	Allocation to Affiliate KeySpan New England, LLC	Allocation to Affiliate KeySpan Money Pools	Allocation to Affiliate KeySpan Engineering Services LLC	Allocation to Affiliate KeySpan Electric Services LLC	Allocation to Affiliate KeySpan Generation LLC
51	590000							892	
52	592000							42,072	
53	593000							21,198	
54	594000							838	
55	717000	67,162	948	35,643					
56	718000								
57	735000			1,150					
58	742000	2,607	35	15,523					
59	812000								
60	813000	9,018		5,274					
61	841000								
62	853000								
63	856000								
64	857000	26,074	305	6,792					
65	863000								
66	865000								
67	874000	842,485	13	486,380				500	
68	875000								
69	878000	262,100	1,255	176,925					
70	879000	11,025		6,076					
71	880000	31,826	446	7,115					
72	885000								
73	886000		11	1,036					
74	887000	49,881	(340)	18,104					
75	889000	58,328		25,580					
76	892000	49,701	855	23,533					
77	893000	301,779		175,276					
78	901000	5,281	2	2,351					
79	902000	713		414				9,568,996	
80	903000	4,178,894		2,135,455				39,424,039	266
81	905000	1,161		657					
82	910000	32,791		20,000				3,330,118	
83	912000	1,581,655	658,213	1,296,116				326,067	
84	913000	331,412		195,699					
85	916000	(151,450)	(174,863)	(239,129)				190,688	
86	917000	81,555		45,155					
87	920000	5,331,494	12,616	3,157,021	10,921			31,397,276	12,355,653
88	921000	2,665,225		1,800,681	113,528			23,148,799	10,763,688
89	923000	946,452		503,315				4,763,828	1,377,899
90	924000	118,381		68,604				989,936	596,759
91	925000	303,786		135,889				2,371,307	445,941
92	930110	168,676		17,240				1,179,180	321,566
93	930200	399,832	315,674	268,830				220,781	546,952
94	931001							1,475,720	
95	932000	60,155		29,614				332,753	215,761
96	Grand Total	28,706,409	1,300,420	16,589,829	124,449	-	307	142,332,833	30,217,711

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KEDC Holdings Corp	Allocation to Affiliate KeySpan Gas East Corp	Allocation to Affiliate Brooklyn Union Gas Co.	Allocation to Affiliate KeySpan Ravenswood, Inc.	Allocation to Affiliate KeySpan Ravenswood Srvcs,LLC	Allocation to Affiliate KS Energy Trading Services LLC	Allocation to Affiliate LIPA KS Gen Services, LLC Cons
1	107000	485,389	12,930,342	38,024,877		624,551	321,405	
2	108001		1,680	21,577				
3	154000							
4	163000		2,705,812	121,658				
5	174002	4,410	68,362	104,720		36,499	984	
6	175002							
7	181000							
8	182352		62,358					
9	182357		45,371	171,042				
10	182365		1,300,986	1,978,059				
11	184000		11,904,535	15,753,172				
12	184010			(3,052,914)				
13	184118							
14	185000							
15	408150	133	2,162	3,359		1,147	32	
16	417000		231	863				
17	426100	4,551	80,758	125,911		45,161	1,188	
18	426400	557	9,426	15,631		6,284	199	
19	426500		10,873				196	
20	430101		2,893,301	3,721,602		1,096,104	53,465	
21	431000						838	
22	454000							
23	456040							
24	495000		(56,087)					
25	500000					(7,593)		
26	502000							
27	505000							
28	506000					83,153		
29	510000							
30	511000					221,152		
31	512000					0		
32	513000							
33	514000					8,540		
34	548000					15,249		
35	549000					42,168		
36	551000					134		
37	554000					15,980		
38	560000							
39	561000							
40	562000							
41	566000							
42	570000							
43	572000							
44	573000							
45	580000							
46	582000							
47	583000							
48	586000							
49	587000							
50	588000							

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KEDC Holdings Corp	Allocation to Affiliate KeySpan Gas East Corp	Allocation to Affiliate Brooklyn Union Gas Co.	Allocation to Affiliate KeySpan Ravenswood, Inc.	Allocation to Affiliate KeySpan Ravenswood Srvcs,LLC	Allocation to Affiliate KS Energy Trading Services LLC	Allocation to Affiliate LIPA KS Gen Services, LLC Cons
51	590000							
52	592000							
53	593000							
54	594000							
55	717000							
56	718000	70,863						
57	735000							
58	742000							
59	812000		(171,464)	(525,860)				
60	813000							
61	841000		248,544	40,094				
62	853000		3,167					
63	856000		386,584	760				
64	857000							
65	863000			33,725				
66	865000		11,837					
67	874000		67,410	219,014				
68	875000		3,117	50,605				
69	878000		206,942	476,380				
70	879000		663,065	182,563				
71	880000		614,162	22,033				
72	885000							
73	886000							
74	887000		111,258	636,759				
75	889000		6,696	33,774				
76	892000		35,519	120,839				
77	893000			1,118				
78	901000			69,338				
79	902000		4,593,331	216,100				
80	903000		19,989,791	36,746,304			8	
81	905000		5,070	8,180				
82	910000		780,231	362,256				
83	912000		10,173,810	8,345,105				
84	913000		1,479,873	1,293,457				
85	916000		(43,286)	2,387,334				
86	917000		556,666	1,516,195				
87	920000	3,096,880	24,672,464	39,566,857		8,927,974	4,658,285	
88	921000	1,224,012	19,470,479	31,320,068		8,407,027	1,338,842	
89	923000	125,957	4,018,877	6,734,456	35,674	1,432,221	41,211	
90	924000	20,103	632,672	722,045		1,315,947	1,472	
91	925000	46,466	1,049,989	1,701,419		757,507	14,420	
92	930110	43,183	136,271	215,650		383,102	11,694	
93	930200	12,270	1,048,791	3,365,974		126,867	3,822	
94	931001		121,527	41,591				1,861
95	932000	177	372,241	661,763		95,378	3,446	
96	Grand Total	5,134,949	123,205,742	193,555,455	35,674	23,634,553	6,451,506	1,861

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KS Glenwood Energy Center, LLC	Allocation to Affiliate KS Port Jefferson Energy Cntr	Allocation to Affiliate KeySpan Energy Services Inc.	Allocation to Affiliate KeySpan Services Inc.	Allocation to Affiliate KeySpan Corporation	Allocation to Affiliate Seneca-Upshur Petroleum, Inc.	Allocation to Affiliate KeySpan LNG LP Regulated Entity
1	107000	23,367	17,710	201	1,073,941	76,765	50,175	
2	108001							
3	154000							
4	163000							
5	174002	1,473	1,473	984	37,724	13,378	8,326	
6	175002							
7	181000							
8	182352							
9	182357							
10	182365							
11	184000			371				
12	184010							
13	184118							
14	185000							
15	408150				1,032	10	231	
16	417000							
17	426100	1,798	1,798		35,952	12,483		
18	426400	239	239		2,307	1,734		
19	426500							
20	430101	53,465	53,465					
21	431000	28	29					
22	454000					(713,124)		
23	456040							
24	495000							
25	500000							
26	502000							
27	505000							
28	506000					1,423		
29	510000							
30	511000					6,020		
31	512000							
32	513000							
33	514000							
34	548000					139		
35	549000					928		
36	551000					3		
37	554000					828		
38	560000							
39	561000							
40	562000							
41	566000							
42	570000							
43	572000							
44	573000							
45	580000							
46	582000							
47	583000							
48	586000							
49	587000							
50	588000							

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KS Glenwood Energy Center, LLC	Allocation to Affiliate KS Port Jefferson Energy Cntr	Allocation to Affiliate KeySpan Energy Services Inc.	Allocation to Affiliate KeySpan Services Inc.	Allocation to Affiliate KeySpan Corporation	Allocation to Affiliate Seneca-Upshur Petroleum, Inc.	Allocation to Affiliate KeySpan LNG LP Regulated Entity
51	590000							
52	592000							
53	593000							
54	594000							
55	717000							
56	718000							
57	735000							
58	742000							
59	812000							
60	813000							
61	841000						(1,986)	(3,177)
62	853000							
63	856000							
64	857000							
65	863000							
66	865000							
67	874000							
68	875000							
69	878000							
70	879000							
71	880000							
72	885000							
73	886000							
74	887000							
75	889000							
76	892000							
77	893000							
78	901000							
79	902000			8				
80	903000				3,540,754			
81	905000							
82	910000							
83	912000			8				
84	913000							
85	916000							
86	917000							
87	920000	243,033	260,079	293,602	5,847,489	1,576,866	601,918	
88	921000	198,624	202,607	24,839	2,059,106	519,559	220,097	
89	923000	46,616	49,504	26,226	1,380,147	350,823	237,758	
90	924000	81,542	90,892	548	40,904	12,510	30,642	
91	925000	17,886	19,867	28,699	395,704	38,247	76,283	
92	930110	15,218	15,485	10,291	348,083	469,601	74,456	
93	930200	4,607	5,304	229	73,929	60,189	8,255	
94	931001							
95	932000				64,056	573	1,255	
96	Grand Total	687,895	718,452	386,006	14,901,128	2,428,954	1,307,409	(3,177)

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KeySpan Exploration & Production	Allocation to Company Narragansett Electric	Grand Total
1	107000	124		99,933,856
2	108001			537,710
3	154000			18,108
4	163000			10,874,907
5	174002	3		504,484
6	175002			1,381,425
7	181000			(5,000)
8	182352			62,358
9	182357			216,641
10	182365			3,443,893
11	184000		11,076	59,434,074
12	184010			(3,052,914)
13	184118			307
14	185000			10,717
15	408150			32,097
16	417000			1,093
17	426100		149,000	1,400,632
18	426400			57,356
19	426500			34,003
20	430101			13,282,316
21	431000			15,102
22	454000			(742,866)
23	456040			(88,549)
24	495000			(56,087)
25	500000			83,395
26	502000			4,579
27	505000			(1,924)
28	506000			506,963
29	510000			(2,450)
30	511000			228,574
31	512000			15,035
32	513000			19,941
33	514000			13,841
34	548000			15,388
35	549000			43,587
36	551000			137
37	554000			16,808
38	560000			329
39	561000			626
40	562000			(34,981)
41	566000			188,025
42	570000			271
43	572000			2,434
44	573000			7
45	580000			7,561
46	582000			502,422
47	583000			126,808
48	586000			958,133
49	587000			1,271,337
50	588000		132,998	628,878

Calendar Year 2008
Charges to Narraganse
Originating from Natio

Line	Regulatory Acct	Allocation to Affiliate KeySpan Exploration & Production	Allocation to Company Narragansett Electric	Grand Total
51	590000			892
52	592000			42,072
53	593000			21,198
54	594000			838
55	717000			103,753
56	718000			306,295
57	735000			1,150
58	742000			60,293
59	812000			(697,323)
60	813000			53,333
61	841000			424,970
62	853000			3,167
63	856000			387,344
64	857000			114,978
65	863000			33,725
66	865000			11,837
67	874000			5,168,434
68	875000			53,721
69	878000			2,181,841
70	879000			1,107,871
71	880000			753,000
72	885000			460,766
73	886000			10,845
74	887000			1,193,976
75	889000			351,301
76	892000			448,384
77	893000			1,775,683
78	901000			239,793
79	902000		411	14,403,751
80	903000			123,036,303
81	905000			20,123
82	910000			4,639,397
83	912000		420	38,753,511
84	913000			5,441,346
85	916000			(1,736,096)
86	917000			2,533,621
87	920000	6,260	1,059,346	178,966,463
88	921000	2,508	546,964	124,338,291
89	923000	3,035	275,193	29,720,236
90	924000	240		5,130,585
91	925000	815	5,798	8,698,125
92	930110	1,297	508,532	9,359,823
93	930200	696	30,984	8,146,094
94	931001			1,640,698
95	932000			2,149,607
96	Grand Total	14,978	2,720,722	761,747,402

Division Data Request 12-8

Request:

Please explain any changes to the terms of the agreements from year to year for each agreement produced in response to question #1. Include in this response a discussion of changes in pricing terms, services offered, services procured and allocation factors.

Response:

There have been no changes to the terms of the agreements from year to year for the agreements produced in response to Division Data Request 12-1.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-9

Request:

Please describe specifically the services now provided to Narragansett by KeySpan.

Response:

Please see the response to Division Data Request 12-1, which provides the service agreements detailing the services provided to Narragansett Electric from KeySpan companies.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-11

Request:

Please explain the relationship between the ($850) thousand reported by Mr. Gorman on p. 6 of Sched. NG-HSG-1 as "Merger/Synergy Benefits" and the calculation of Net Synergy values shown in Sched. NG-RLO-3. Provide an electronic workpaper that derives the ($850) thousand.

Response:

The $850,000 reported by Mr. Gorman on Page 6 of Schedule NG-HSG-1 as "Merger/Synergy Benefits" is the sum of three items included in Schedule NG-RLO-2 and summarized on Page 1, Lines 21, 31, and 32 as follows:

Line 21: Merger Related Costs to Achieve	$2,100,000
Line 31: Estimated NGRID/KeySpan Transaction Synergies	($6,200,000)
Line 32: Company Share of Net Synergies	$3,250,000
Total	($ 850,000)

There is no electronic workpaper that derives the $850,000 in question. Please refer to Schedule NG-RLO-3 for details of the amounts listed above.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 14-1

Request:

Provide a copy of the company's vegetation management plan, guidelines, specifications, and detailed procedures including, but not limited to, the clearing methods and clearing cycle for all of the areas of the National Grid System. Additionally, provide copies of all studies that support the clearing cycle and methods outlined in the company's plans, specifications and guidelines and procedures.

Response:

Please see the attachments listed below, which set out the Company's vegetation management plan, guidelines, specifications and procedures.

Attachment 14-1-1: Vegetation Management Strategy – June 2008

Attachment 14-1-2: National Grid US Tree Pruning General Specifications

Attachment 14-1-3: NGrid NE Veg Dist Spec 091008

Attachment 14-1-4: NGrid NY Veg Dist Spec 091008

Attachment 14-1-5: NGRID-NE Sub T Spec 08_22_08

Attachment 14-1-6: Hazard_Tree_Specification

Attachment 14-1-7: VM Program Reliability Response 7-15-09

Attachment 14-1-8: Final Report NGrid

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-2

Request:

Provide a copy of the company's system voltage and thermal analysis for its electric distribution system lines, including maps which outline all violations and load levels upon which the violations occur as well as all voltage violations and thermal violations which currently exist together with a listing of all areas in which voltages or thermal loadings are within ten percent (10%) of the violation level.

Response:

In Rhode Island, the distribution system is summer peaking and summer limited. A thermal analysis of the summer loading of all distribution lines (feeders) is updated on an annual basis with loads typically projected for a period of at least five years. This is used to identify feeders that may require relief in that period and allow adequate time to implement relief actions.

Attachment DIV 14-2 presents a composite thermal analysis spreadsheet showing projected normal summer loading for radial distribution feeders for the period 2009-2015. Also shown is the projected loading as a percent of normal summer ratings.

The Company does not prepare maps that detail the thermal violations predicted for the individual feeders. The distribution system is divided into study areas and maps of each study area showing the geographic location of distribution substations is included in the analysis worksheet.

Also, the Company does not perform a voltage analysis on its feeders on an annual basis. Annual changes to circuit loading do not generally result in voltage problems developing on the feeders. When system voltage performance concerns are reported (by Company Operations personnel or customers), an analysis of the specific issue/event is completed. Most voltage problems experienced are localized problems resulting from distribution transformer loading or interference from other loads on the system.

Prepared by or under the supervision of: John Pettigrew

Attachment Div 14-2

2009 Annual Plan Feeder Problem Identification Spreadsheet

Projected Load

Study Area	Substation	Feeder Voltage (kV)	Feeder Number	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	Emergency Limiting Element	Emergency Element Specifics	SE Rating (Amps)	2008 Amps	2008 % SN	2009 Growth Rate	2009 Spot Loads	2009 Amps	2009 % SN	2010 Growth Rate	2010 Spot Loads	2010 Amps	2010 % SN	2011 Growth Rate	2011 Spot Loads	2011 Amps	2011 %SN	2012 Growth Rate	2012 Spot Loads	2012 Amps	2012 %SN	2013 Growth Rate	2013 Spot Loads	2013 Amps	2013 %SN	2014 Growth Rate	2014 Spot Loads	2014 Amps	2014 %SN	2015 Growth Rate	2015 Spot Loads	2015 Amps	2015 %SN
BLACKSTONE VALLEY NORTH																																							
	FARNUM	23	105K1	OH Line	336.4 Al	515	OH Line	336.4 Al	515	84	16%	2.3%		86	17%	0.2%		86	17%	0.6%	0	87	17%	0.8%		87	17%	0.5%		88	17%	0.2%		88	17%	0.2%		88	17%
	NASONVILLE	13.8	127W40	UG Cable	1000 Al	461	UG Cable	1000 Al	515	314	68%	2.3%		321	70%	0.2%		322	70%	0.6%	-150	174	38%	0.8%		175	38%	0.5%		176	38%	0.2%		176	38%	0.2%		177	38%
	NASONVILLE	13.8	127W41	UG Cable	1000 Al	432	UG Cable	1000 Al	515	268	62%	2.3%		274	63%	0.2%		275	64%	0.6%	-30	246	57%	0.8%		248	57%	0.5%		250	58%	0.2%		250	58%	0.2%		251	58%
	NASONVILLE	13.8	127W42	UG Cable	1000 Al	458	UG Cable	1000 Al	515	285	62%	2.3%		292	64%	0.2%		292	64%	0.6%	-195	99	22%	0.8%		100	22%	0.5%		100	22%	0.2%		100	22%	0.2%		101	22%
	NASONVILLE	13.8	127W43	UG Cable	1000 Cu	545	UG Cable	1000 Cu	586	532	98%	2.3%		544	99.9%	0.2%		545	100%	0.6%	0	549	101%	0.8%		553	101%	0.5%		556	102%	0.2%		557	102%	0.2%		558	102%
	RIVERSIDE 8	13.8	108W51	UG Cable	1000 Al	499	UG Cable	1000 Al	631	322	65%	2.3%		329	66%	0.2%		330	66%	0.6%		332	67%	0.8%		335	67%	0.5%		336	67%	0.2%		337	68%	0.2%		338	68%
	RIVERSIDE 8	13.8	108W53	UG Cable	1000 Al	499	UG Cable	1000 Al	631	417	84%	2.3%		427	85%	0.2%		427	86%	0.6%		430	86%	0.8%		433	87%	0.5%		436	87%	0.2%		436	87%	0.2%		437	88%
	RIVERSIDE 8	13.8	108W55	UG Cable	1000 Al	510	UG Cable	1000 Al	600	457	90%	2.3%		468	92%	0.2%		468	92%	0.6%		471	92%	0.8%		475	93%	0.5%		477	94%	0.2%		478	94%	0.2%		479	94%
	RIVERSIDE 8	13.8	108W60	OH Line	336.4 Al	515	OH Line	2/0 Cu	515	286	56%	2.3%	90	383	74%	0.2%		383	74%	0.6%		386	75%	0.8%		389	75%	0.5%		391	76%	0.2%		391	76%	0.2%		392	76%
	RIVERSIDE 8	13.8	108W61	OH Line	4/0 Cu	500	OH Line	4/0 Cu	500	248	50%	2.3%	0	254	51%	0.2%		254	51%	0.6%	-170	86	17%	0.8%		86	17%	0.5%		87	17%	0.2%		87	17%	0.2%		87	17%
	RIVERSIDE 8	13.8	108W62	OH Line	336.4 Al	515	OH Line	336.4 Al	515	396	77%	2.3%		405	79%	0.2%		406	79%	0.6%	-150	258	50%	0.8%		260	51%	0.5%		262	51%	0.2%		262	51%	0.2%		263	51%
	RIVERSIDE 8	13.8	108W63	OH Line	336.4 Al	515	OH Line	336.4 Al	515	450	87%	2.3%	20	480	93%	0.2%		481	93%	0.6%		484	94%	0.8%		488	95%	0.5%		491	95%	0.2%		491	95%	0.2%		492	96%
	RIVERSIDE 8	13.8	108W65	OH Line	336.4 Al	520	OH Line	336.4 Al	520	270	52%	2.3%	0	276	53%	0.2%		277	53%	0.6%		278	54%	0.8%		281	54%	0.5%		282	54%	0.2%		283	54%	0.2%		283	54%
	STAPLES 112	13.8	112W41	OH Line	336.4 Al	515	OH Line	336.4 Al	515	395	77%	2.3%		404	78%	0.2%	63	468	91%	0.6%	-110	361	70%	0.8%		364	71%	0.5%		365	71%	0.2%		366	71%	0.2%		367	71%
	STAPLES 112	13.8	112W42	UG Cable	500 Cu	440	UG Cable	500 Cu	484	398	90%	2.3%		407	93%	0.2%		408	93%	0.6%	-50	360	82%	0.8%		363	83%	0.5%		365	83%	0.2%		366	83%	0.2%		367	83%
	STAPLES 112	13.8	112W43	OH Line	336.4 Al	515	OH Line	336.4 Al	515	399	77%	0.0%	89	488	95%	0.2%		489	95%	0.6%		492	96%	0.8%		496	96%	0.5%		498	97%	0.2%		499	97%	0.2%		500	97%
	STAPLES 112	13.8	112W44	UG Cable	500 Cu	406	UG Cable	500 Cu	484	361	89%	2.3%		369	91%	0.2%		370	91%	0.6%		372	92%	0.8%		375	92%	0.5%		377	93%	0.2%		378	93%	0.2%		379	93%
	WEST FARNUM #17	13.8	17W42	UG Cable	1000 Al	495	UG Cable	1000 Al	495	72	15%	2.3%		74	15%	0.2%		74	15%	0.6%	-74	0	0%	0.8%		0	0%	0.5%		0	0%	0.2%		0	0%	0.2%		0	0%
	WEST FARNUM #17	13.8	17W43	UG Cable	1000 Al	495	UG Cable	1000 Al	495	250	51%	2.3%	0	256	52%	0.2%	0	256	52%	0.6%	-258	0	0%	0.8%		0	0%	0.5%		0	0%	0.2%		0	0%	0.2%		0	0%
	WOONSOCKET	13.8	26W41	OH Line	336.4 Al	515	OH Line	336.4 Al	515	0	0%	2.3%		0	0%	0.2%		0	0%	0.6%	107	107	21%	0.8%		108	21%	0.5%		108	21%	0.2%		109	21%	0.2%		109	21%
	WOONSOCKET	13.8	26W42	OH Line	336.4 Al	515	OH Line	336.4 Al	515	0	0%	2.3%		0	0%	0.2%		0	0%	0.6%	340	340	66%	0.8%		343	67%	0.5%		344	67%	0.2%		345	67%	0.2%		346	67%
	WOONSOCKET	13.8	26W43	OH Line	336.4 Al	515	OH Line	336.4 Al	515	0	0%	2.3%		0	0%	0.2%		0	0%	0.6%	375	375	73%	0.8%		378	73%	0.5%		380	74%	0.2%		381	74%	0.2%		381	74%
	WOONSOCKET	13.8	26W44	OH Line	336.4 Al	515	OH Line	336.4 Al	515	0	0%	2.3%		0	0%	0.2%		0	0%	0.6%	365	365	71%	0.8%		368	71%	0.5%		370	72%	0.2%		370	72%	0.2%		371	72%
BLACKSTONE VALLEY SOUTH																																							
	PAWTUCKET #1 STATION	13.8	107W43	OH Line	2/0 Cu	365	OH Line	2/0 Cu	365	250	68%	1.4%		254	69%	-1.0%		251	69%	-0.6%		249	68%	-0.6%		248	68%	-0.4%		247	68%	-0.2%		246	68%	0.0%		246	68%
	PAWTUCKET #1 STATION	13.8	107W49	UG Cable	350 PL	202	UG Cable	350 PL	250	153	76%	1.4%		155	77%	-1.0%		154	76%	-0.6%		153	76%	-0.6%		152	75%	-0.4%		151	75%	-0.2%		151	75%	0.0%		151	75%
	PAWTUCKET #1 STATION	13.8	107W50	UG Cable	1000 Al	356	OH Line	2/0 Cu	365	235	66%	1.4%		238	67%	-1.0%		236	66%	-0.6%		234	66%	-0.6%		233	65%	-0.4%		232	65%	-0.2%		232	65%	0.0%		232	65%
	PAWTUCKET #1 STATION	13.8	107W51	OH Line	2/0 Cu	365	OH Line	2/0 Cu	365	140	38%	1.4%		142	39%	-1.0%		141	39%	-0.6%		140	38%	-0.6%		139	38%	-0.4%		138	38%	-0.2%		138	38%	0.0%		138	38%
	PAWTUCKET #1 STATION	13.8	107W53	UG Cable	1000 Al	407	CT	600 A	540	258	63%	1.4%		262	64%	-1.0%		259	64%	-0.6%		257	63%	-0.6%		256	63%	-0.4%		255	63%	-0.2%		254	62%	0.0%		254	62%
	PAWTUCKET #1 STATION	13.8	107W60	UG Cable	500 Cu	334	Relay set.	528 A pick up	449	275	82%	1.4%		258	77%	-1.0%		255	76%	-0.6%		254	76%	-0.6%		252	76%	-0.4%		251	75%	-0.2%		251	75%	0.0%		251	75%
	PAWTUCKET #1 STATION	13.8	107W61	UG Cable	1000 Al	343	OH Line	2/0 Cu	411	290	85%	1.4%		311	91%	-1.0%		308	90%	-0.6%		306	89%	-0.6%		304	89%	-0.4%		303	88%	-0.2%		302	88%	0.0%		302	88%
	PAWTUCKET #1 STATION	13.8	107W62	OH Line	2/0 Cu	480	OH Line	2/0 Cu	480	425	89%	1.4%		431	90%	-1.0%		427	89%	-0.6%		424	88%	-0.6%		422	88%	-0.4%		420	87%	-0.2%		419	87%	0.0%		419	87%
	PAWTUCKET #1 STATION	13.8	107W63	OH Line	336.4 Al	515	OH Line	336.4 Al	515	383	74%	1.4%		388	75%	-1.0%		384	75%	-0.6%		382	74%	-0.6%		380	74%	-0.4%		378	73%	-0.2%		378	73%	0.0%		378	73%
	PAWTUCKET #1 STATION	13.8	107W65	UG Cable	500 Cu	345	CT	400 A	360	280	81%	1.4%		353	102%	-1.0%		349	101%	-0.6%		347	101%	-0.6%		345	100%	-0.4%		344	100%	-0.2%		343	99%	0.0%		343	99%
	PAWTUCKET #1 STATION	13.8	107W66	CT	400 A	360	CT	400 A	360	185	51%	1.4%		188	52%	-1.0%		186	52%	-0.6%		185	51%	-0.6%		183	51%	-0.4%		183	51%	-0.2%		182	51%	0.0%		182	51%
	PAWTUCKET #1 STATION	13.8	107W80	UG Cable	350 Cu	285	OH Line	2/0 Cu	365	172	60%	1.4%		174	61%	-1.0%		173	61%	-0.6%		172	60%	-0.6%		171	60%	-0.4%		170	60%	-0.2%		170	60%	0.0%		170	60%
	PAWTUCKET #1 STATION	13.8	107W81	UG Cable	1000 Al	368	CT	600 A	540	308	84%	1.4%		324	88%	-1.0%		321	87%	-0.6%		319	87%	-0.6%		317	86%	-0.4%		316	86%	-0.2%		315	86%	0.0%		315	86%
	PAWTUCKET #1 STATION	13.8	107W83	UG Cable	1000 Al	346	CT	600 A	540	260	75%	1.4%		264	76%	-1.0%		261	75%	-0.6%		259	75%	-0.6%		258	75%	-0.4%		257	74%	-0.2%		256	74%	0.0%		256	74%
	PAWTUCKET #1 STATION	13.8	107W84	UG Cable	1000 Al	332	OH Line	2/0 Cu	365	268	81%	1.4%		234	70%	-1.0%		232	70%	-0.6%		230	69%	-0.6%		229	69%	-0.4%		228	69%	-0.2%		228	69%	0.0%		228	69%
	PAWTUCKET #1 STATION	13.8	107W85	UG Cable	350 Cu	305	OH Line	2/0 Cu	365	215	70%	1.4%		218	71%	-1.0%		216	71%	-0.6%		215	70%	-0.6%		213	70%	-0.4%		212	70%	-0.2%		212	69%	0.0%		212	69%
	VALLEY SUB	13.8	102W41	UG Cable	1000 Al	493	OH Line	336.4 Al	515	260	53%	3.8%		270	55%	1.2%		273	55%	0.8%		275	56%	0.8%		278	56%	0.6%		279	57%	0.4%		280	57%	0.3%		281	57%
	VALLEY SUB	13.8	102W42	UG Cable	500 Cu	463	OH Line	336.4 Al	515	330	71%	1.4%		335	72%	-1.0%		331	72%	-0.6%		329	71%	-0.6%		327	71%	-0.4%		326	70%	-0.2%		325	70%	0.0%		325	70%
	VALLEY SUB	13.8	102W44	UG Cable	350 Cu	328	UG Cable	350 Cu	460	257	78%	3.8%		267	81%	1.2%		270	82%	0.8%		272	83%	0.8%		274	84%	0.6%		276	84%	0.4%		277	84%	0.3%		278	85%
	VALLEY SUB	13.8	102W50	UG Cable	500 Cu	364	Current Trans	300/5A	375	125	34%	3.8%		130	36%	1.2%		131	36%	0.8%		132	36%	0.8%		133	37%	0.6%		134	37%	0.4%		135	37%	0.3%		135	37%
	VALLEY SUB	13.8	102W51	UG Cable	500 Cu	341	UG Cable	500 Cu	497	400	117%	3.8%		415	122%	1.2%		420	123%	0.8%		424	124%	0.8%		427	125%	0.6%		429	126%	0.4%		431	126%	0.3%		433	127%
	VALLEY SUB	13.8	102W52	UG Cable	350 PL	300	OH Line	2/0 Cu	365	100	33%	0.8%		101	34%	-1.5%		99	33%	-1.0%		98	33%	-1.0%		97	32%	-0.6%		97	32%	-0.3%		96	32%	0.0%		96	32%
	VALLEY SUB	13.8	102W54	UG Cable	350 Cu	292	UG Cable	350 Cu	413	220	75%	3.8%		228	78%	1.2%		231	79%	0.8%		233	80%	0.8%		235	80%	0.6%		236	81%	0.4%		237	81%	0.3%		238	81%
	WASHINGTON SUB	13.8	126W40	UG Cable	1000 Al	515	OH Line	477 Al Spca	645	250	49%	3.8%		260	50%	1.2%		263	51%	0.8%		265	51%	0.8%		267	52%	0.6%		268	52%	0.4%		270	52%	0.3%		270	52%
	WASHINGTON SUB	13.8	126W41	UG Cable	1000 Al	520	OH Line	336.4 Al	535	400	77%	3.8%		415	80%	1.2%		420	81%	0.8%		424	81%	0.8%		427	82%	0.6%		429	83%	0.4%		431	83%	0.3%		433	83%
	WASHINGTON SUB	13.8	126W42	UG Cable	1000 Al	525	Switch	600 A Vac.	600	335	64%	3.8%		348	66%	1.2%		352	67%	0.8%		355	68%	0.8%		358	68%	0.6%		360	69%	0.4%		361	69%	0.3%		362	69%
	WASHINGTON SUB	13.8	126W50	UG Cable	1000 Al	528	OH Line	477 Al Spca	645	390	74%	3.8%		405	77%	1.2%		410	78%	0.8%		413	78%	0.8%		416	79%	0.6%		419	79%	0.4%		420	80%	0.3%		422	80%
	WASHINGTON SUB	13.8	126W51	OH Line	336.4 Al	515	OH Line	336.4 Al	515	370	72%	3.8%		384	75%	1.2%		389	75%	0.8%		392	76%	0.8%		395	77%	0.6%		397	77%	0.4%		399	77%	0.3%		400	78%
	WASHINGTON SUB	13.8	126W53	UG Cable	1000 Cu	583	UG Cable	1000 Cu	750	18	3%	3.8%		19	3%	1.2%		19	3%	0.8%		19	3%	0.8%		19	3%	0.6%		19	3%	0.4%		19	3%	0.3%		19	3%
	WASHINGTON SUB	13.8	126W54	OH Line	477 Al Spca	530	OH Line	477 Al Spca	645	380	72%	3.8%		394	74%	1.2%		399	75%	0.8%		402	76%	0.8%		406	77%	0.6%		408	77%	0.4%		410	77%	0.3%		411	78%
	COTTAGE STREET SUB	4.16	109J1	Relay/Fuse	Safe Carry - 408A	408			408		0%	0.3%		0	0%	-1.0%		0	0%	-0.6%		0	0%	-0.6%		0	0%	-0.4%		0	0%	-0.2%		0	0%	0.0%		0	0%
	COTTAGE STREET SUB	4.16	109J3	Relay/Fuse	Safe Carry - 408A	408			408		0%	0.3%		0	0%	-1.0%		0	0%	-0.6%		0	0%	-0.6%		0	0%	-0.4%		0	0%	-0.2%		0	0%	0.0%		0	0%
	COTTAGE STREET SUB	4.16	109J5	Relay/Fuse	Safe Carry - 408A	408			408		0%	0.3%		0	0%	-1.0%		0	0%	-0.6%		0	0%	-0.6%		0	0%	-0.4%		0	0%	-0.2%		0	0%	0.0%		0	0%
CENTRAL RI EAST																																							
	APPONAUG 3	12.47	3F1	Relay/Fuse	Safe Carry Phase	510	Relay/Fuse	Safe Carry Phase	510	396	78%	5.5%		418	82%	2.8%		429	84%	3.7%		445	87%	4.0%		463	91%	3.3%		478	94%	2.6%		491	96%	2.4%		503	99%
	APPONAUG 3	12.47	3F2	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	457	89%	5.5%		482	94%	2.8%		495	96%	3.7%		514	100%	4.0%		534	104%	3.3%		552	107%	2.6%		566	110%	2.4%		580	113%
	DRUMROCK 14	12.47	14F1	OH Line	477 Al Spacer Cable 15kV	530	Relay/Fuse	612 Amp Safe Carry	612	436	82%	5.5%		460	87%	2.8%		473	89%	3.7%		490	93%	4.0%		510	96%	3.3%		527	99%	2.6%		540	102%	2.4%		553	104%
	DRUMROCK 14	12.47	14F2	OH Line	477 Al Spacer Cable 15kV	530	Relay/Fuse	595 Amp Safe Carry	595	445	84%	5.5%		469	89%	2.8%		482	91%	3.7%		500	94%	4.0%		520	98%	3.3%		537	101%	2.6%		551	104%	2.4%		564	107%
	DRUMROCK 14	12.47	14F3	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	408	79%	5.5%		430	84%	2.8%		442	86%	3.7%		459	89%	4.0%		477	93%	3.3%		493	96%	2.6%		506	98%	2.4%		518	101%
	DRUMROCK 14	12.47	14F4	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	466	91%	5.5%		492	96%	2.8%		506	98%	3.7%		524	102%	4.0%		545	106%	3.3%		563	109%	2.6%		578	112%	2.4%		592	115%
	KILVERT STREET 87	12.47	87F1	UG Cable	1C 750 Al XLPE	502	UG Cable	1C 750 Al XLPE	602	396	79%	5.5%		417	83%	2.8%		429	85%	3.7%		445	89%	4.0%		463	92%	3.3%		478	95%	2.6%		490	98%	2.4%		502	100%
	KILVERT STREET 87	12.47	87F2	OH Line	477 Al Spacer Cable (W+35/S+40)	570	Regulator	333 kVA 7.2 kV - 65C	662	402	71%	5.5%		424	74%	2.8%		436	76%	3.7%		452	79%	4.0%		470	82%	3.3%		486	85%	2.6%		498	87%	2.4%		510	90%
	KILVERT STREET 87	12.47	87F3	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al (COSMOS) Bare	645	0	0%	5.5%		445	84%	2.8%		457	86%	3.7%		474	90%	4.0%		493	93%	3.3%		510	96%	2.6%		523	99%	2.4%		535	101%
	KILVERT STREET 87	12.47	87F4	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	306	58%	5.5%		323	61%	2.8%		332	63%	3.7%		344	65%	4.0%		358	68%	3.3%		370	70%	2.6%		379	72%	2.4%		388	73%
	LINCOLN AVENUE 72	12.47	72F1	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	366	69%	5.5%		386	73%	2.8%		397	75%	3.7%		412	78%	4.0%		428	81%	3.3%		442	83%	2.6%		454	86%	2.4%		465	88%
	LINCOLN AVENUE 72	12.47	72F2	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	345	65%	5.5%		364	69%	2.8%		374	71%	3.7%		388	73%	4.0%		403	76%	3.3%		416	79%	2.6%		427	81%	2.4%		438	83%
	LINCOLN AVENUE 72	12.47	72F3	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	327	62%	5.5%		345	65%	2.8%		354	67%	3.7%		367	69%	4.0%		382	72%	3.3%		395	74%	2.6%		405	76%	2.4%		415	78%
	LINCOLN AVENUE 72	12.47	72F4	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	350	66%	5.5%		370	70%	2.8%		380	72%	3.7%		394	74%	4.0%		410	77%	3.3%		423	80%	2.6%		434	82%	2.4%		445	84%
	LINCOLN AVENUE 72	12.47	72F5	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	422	82%	5.5%		445	86%	2.8%		457	89%	3.7%		474	92%	4.0%		493	96%	3.3%		509	99%	2.6%		523	102%	2.4%		535	104%
	LINCOLN AVENUE 72	12.47	72F6	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	353	69%	5.5%		373	72%	2.8%		383	74%	3.7%		397	77%	4.0%		413	80%	3.3%		427	83%	2.6%		438	85%	2.4%		449	87%
	PONTIAC 27	12.47	27F1	UG Cable	1C 750 Al XLPE DB	460	OH Line	336 Al (W+35/S+50)	555	387	84%	5.5%		408	89%	2.8%		419	91%	3.7%		435	95%	4.0%		452	98%	3.3%		467	102%	2.6%		479	104%	2.4%		491	107%
	PONTIAC 27	12.47	27F2	UG Cable	1C 750 Al XLPE DB	460	OH Line	336.4 Al (TULIP) Bare	515	264	57%	5.5%		279	61%	2.8%		286	62%	3.7%		297	65%	4.0%		309	67%	3.3%		319	69%	2.6%		327	71%	2.4%		335	73%
	PONTIAC 27	12.47	27F3	UG Cable	1C 750 Al XLPE DB	460	OH Line	336 Al	515	172	37%	5.5%		181	39%	2.8%		187	41%	3.7%		193	42%	4.0%		201	44%	3.3%		208	45%	2.6%		213	46%	2.4%		218	47%
	PONTIAC 27	12.47	27F4	UG Cable	1C 750 Al XLPE DB	460	OH Line	336.4 Al (TULIP) Bare	515	268	58%	5.5%		283	61%	2.8%		291	63%	3.7%		301	66%	4.0%		313	68%	3.3%		324	70%	2.6%		332	72%	2.4%		340	74%
	PONTIAC 27	12.47	27F5	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	407	77%	5.5%		429	81%	2.8%		441	83%	3.7%		457	86%	4.0%		476	90%	3.3%		491	93%	2.6%		504	95%	2.4%		516	97%
	PONTIAC 27	12.47	27F6	OH Line	477 Al Spacer Cable 15kV	530	OH Line	477 Al Spacer Cable 15kV	650	481	91%	5.5%		507	96%	2.8%		521	98%	3.7%		541	102%	4.0%		562	106%	3.3%		581	110%	2.6%		596	112%	2.4%		610	115%
	WARWICK 52	12.47	52F1	Regulator	250 kVA 7.2 kV - 55C	409	Relay/Fuse	476 Amp Safe Carry	476	150	37%	5.5%		158	39%	2.8%		163	40%	3.7%		169	41%	4.0%		175	43%	3.3%		181	44%	2.6%		186	45%	2.4%		190	47%
	WARWICK 52	12.47	52F2	Regulator	250 kVA 7.2 kV - 55C	409	Relay/Fuse	476 Amp Safe Carry	476	309	76%	5.5%		326	80%	2.8%		335	82%	3.7%		348	85%	4.0%		362	88%	3.3%		374	91%	2.6%		383	94%	2.4%		393	96%
	WARWICK 52	12.47	52F3	OH Line	2/0 Cu (W+8A, S+12A)	377	OH Line	2/0 Cu (W+8A, S+12A)	377	347	92%	5.5%		366	97%	2.8%		376	100%	3.7%		390	103%	4.0%		405	108%	3.3%		419	111%	2.6%		430	114%	2.4%		440	117%
	AUBURN 73	4.16	73J1	Regulator	300 Amp 2.4 kV Step	369	Relay/Fuse	408 Amp Safe Carry	408	172	47%	5.5%		181	49%	2.8%		187	51%	3.7%		193	52%	4.0%		201	55%	3.3%		208	56%	2.6%		213	58%	2.4%		218	59%
	AUBURN 73	4.16	73J2	OH Line	4/0 Al (OXLIP) Bare	385	OH Line	4/0 Al (OXLIP) Bare	385	98	25%	5.5%		103	27%	2.8%		106	28%	3.7%		110	29%	4.0%		115	30%	3.3%		118	31%	2.6%		121	32%	2.4%		124	32%
	AUBURN 73	4.16	73J3	OH Line	4/0 Al (OXLIP) Bare	385	OH Line	4/0 Al (OXLIP) Bare	385	304	79%	5.5%		321	83%	2.8%		330	86%	3.7%		342	89%	4.0%		356	92%	3.3%		367	95%	2.6%		377	98%	2.4%		386	100%
	AUBURN 73	4.16	73J4	OH Line	4/0 Al (OXLIP) Bare	385	OH Line	4/0 Al (OXLIP) Bare	385	247	64%	5.5%		260	68%	2.8%		268	69%	3.7%		277	72%	4.0%		289	75%	3.3%		298	77%	2.6%		306	79%	2.4%		313	81%
	AUBURN 73	4.16	73J5	Relay/Fuse	408 Amp Safe Carry	408	Relay/Fuse	408 Amp Safe Carry	408	272	67%	5.5%		287	70%	2.8%		295	72%	3.7%		306	75%	4.0%		318	78%	3.3%		329	81%	2.6%		337	83%	2.4%		345	85%
	AUBURN 73	4.16	73J6	UG Cable	1C 500 Al XLPE	381	Relay/Fuse	408 Amp Safe Carry	408	184	48%	5.5%		194	51%	2.8%		200	52%	3.7%		207	54%	4.0%		215	56%	3.3%		222	58%	2.6%		228	60%	2.4%		234	61%
	LAKEWOOD 57	4.16	57J1	Regulator	300 Amp 2.4 kV Step	369	Regulator	300 Amp 2.4 kV Step	441	288	78%	5.5%		304	82%	2.8%		312	85%	3.7%		324	88%	4.0%		337	91%	3.3%		348	94%	2.6%		357	97%	2.4%		366	99%
	LAKEWOOD 57	4.16	57J2	Switch	400 Amp	452	Switch	400 Amp	556	244	54%	5.5%		257	57%	2.8%		265	59%	3.7%		274	61%	4.0%		285	63%	3.3%		295	65%	2.6%		302	67%	2.4%		310	69%
	LAKEWOOD 57	4.16	57J3	Relay/Fuse	408 Amp Safe Carry	408	Relay/Fuse	408 Amp Safe Carry	408	252	62%	5.5%		266	65%	2.8%		273	67%	3.7%		283	69%	4.0%		295	72%	3.3%		304	75%	2.6%		312	77%	2.4%		320	78%

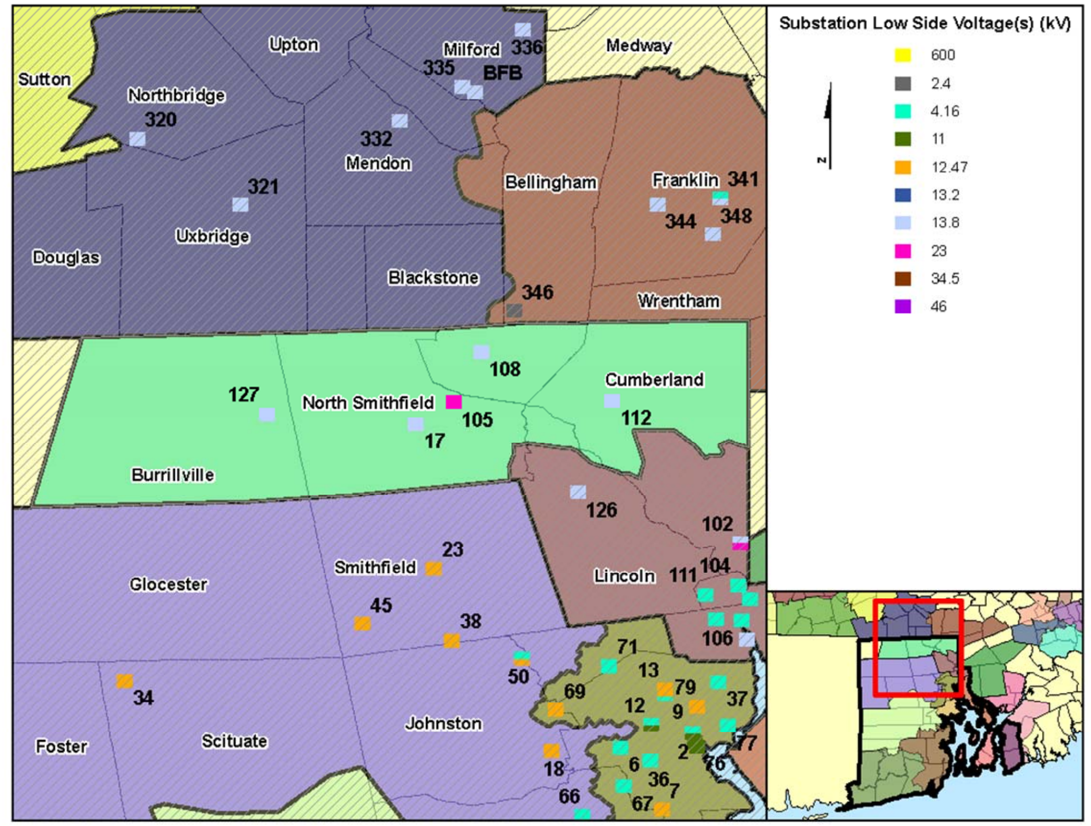
Study Area	Substation	Feeder Voltage (kV)	Feeder Number	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	Emergency Limiting Element	Emergency Element Specifics	SE Rating (Amps)	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN
	LAKEWOOD 57	4.16	57J4	Regulator	187.5 kVA GE ML32 300A	354	Relay/Fuse	408 Amp Safe Carry	408	302	85%	5.5%		319	90%	2.8%		328	93%	3.7%		340	96%	4.0%		353	100%	3.3%		365	103%	2.6%		374	106%	2.4%		383	108%
	LAKEWOOD 57	4.16	57J5	Relay/Fuse	Safe Carry Phase	408	Relay/Fuse	Safe Carry Phase	408	348	85%	5.5%		367	90%	2.8%		377	93%	3.7%		391	96%	4.0%		407	100%	3.3%		420	103%	2.6%		431	106%	2.4%		442	108%
	PAWTUXET 31	4.16	31J1	Switch	Disconnect - 300A	348	Switch	Disconnect - 300A	405	148	43%	5.5%		156	45%	2.8%		161	46%	3.7%		167	48%	4.0%		173	50%	3.3%		179	52%	2.6%		184	53%	2.4%		188	54%
	PAWTUXET 31	4.16	31J2	Regulator	250 kVA 7.2 kV - 55C	409	Regulator	250 kVA 7.2 kV - 55C	459	384	94%	5.5%		405	99%	2.8%		416	102%	3.7%		432	106%	4.0%		449	110%	3.3%		464	113%	2.6%		476	116%	2.4%		487	119%
CENTRAL RI WEST																																							
	ANTHONY 64	12.47	64F1	Transformer	5.6/6.25 MVA	361	Transformer	5.6/6.25 MVA	374	336	93%	5.5%		354	98%	2.8%		364	101%	3.7%		378	105%	4.0%		393	109%	3.3%		406	112%	2.6%		417	115%	2.4%		427	118%
	ANTHONY 64	12.47	64F2	Transformer	5.6/6.25 MVA	361	Transformer	5.6/6.25 MVA	374	300	83%	5.5%		317	88%	2.8%		325	90%	3.7%		337	93%	4.0%		351	97%	3.3%		362	100%	2.6%		372	103%	2.4%		381	105%
	COVENTRY 54	12.47	54F1	Relay/Fuse	Safe Carry - 510A	526	OH Line	4/0 Al (OXLIP) Bare	385	461	88%	5.5%		487	93%	2.8%		500	95%	3.7%		519	99%	4.0%		540	103%	3.3%		557	106%	2.6%		572	109%	2.4%		586	111%
	DIVISION ST 61	12.47	61F1	UG Cable	1C 750 Al DB	450	Relay/Fuse	476 Amp Safe Carry	476	382	85%	5.5%		403	89%	2.8%		414	92%	3.7%		429	95%	4.0%		446	99%	3.3%		461	102%	2.6%		473	105%	2.4%		484	108%
	DIVISION ST 61	12.47	61F2	UG Cable	1C 750 Al DB	450	Relay/Fuse	476 Amp Safe Carry	476	340	76%	5.5%		359	80%	2.8%		369	82%	3.7%		382	85%	4.0%		398	88%	3.3%		411	91%	2.6%		421	94%	2.4%		432	96%
	DIVISION ST 61	12.47	61F3	UG Cable	1C 750 Al DB	450	Relay/Fuse	476 Amp Safe Carry	476	270	60%	5.5%		285	63%	2.8%		293	65%	3.7%		304	67%	4.0%		316	70%	3.3%		326	72%	2.6%		335	74%	2.4%		343	76%
	DIVISION ST 61	12.47	61F4	UG Cable	1C 750 Al DB	450	Bus Conducto	336 MCM Al	667	177	39%	5.5%		186	41%	2.8%		192	43%	3.7%		199	44%	4.0%		207	46%	3.3%		213	47%	2.6%		219	49%	2.4%		224	50%
	HOPE 15	12.47	15F1	Transformer	6.25 kVA	348	Transformer	5/6.25 MVA	394	329	95%	5.5%		347	100%	2.8%		357	103%	3.7%		370	106%	4.0%		385	111%	3.3%		398	114%	2.6%		408	117%	2.4%		418	120%
	HOPE 15	12.47	15F2	Relay/Fuse	476 Amp Safe Carry	476	Relay/Fuse	476 Amp Safe Carry	476	442	93%	5.5%		466	98%	2.8%		479	101%	3.7%		497	104%	4.0%		517	109%	3.3%		534	112%	2.6%		548	115%	2.4%		561	118%
	HOPKINS HILL 63	12.47	63F1	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	266	50%	5.5%		281	53%	2.8%		288	54%	3.7%		299	56%	4.0%		311	59%	3.3%		321	61%	2.6%		330	62%	2.4%		338	64%
	HOPKINS HILL 63	12.47	63F2	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	459	87%	5.5%		484	91%	2.8%		497	94%	3.7%		516	97%	4.0%		536	101%	3.3%		554	105%	2.6%		569	107%	2.4%		582	110%
	HOPKINS HILL 63	12.47	63F3	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	517	98%	5.5%		546	103%	2.8%		561	106%	3.7%		582	110%	4.0%		605	114%	3.3%		625	118%	2.6%		641	121%	2.4%		657	124%
	HOPKINS HILL 63	12.47	63F4	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	325	61%	5.5%		343	65%	2.8%		353	67%	3.7%		366	69%	4.0%		381	72%	3.3%		393	74%	2.6%		403	76%	2.4%		413	78%
	HOPKINS HILL 63	12.47	63F5	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	433	82%	5.5%		456	86%	2.8%		469	89%	3.7%		487	92%	4.0%		506	95%	3.3%		523	99%	2.6%		536	101%	2.4%		549	104%
	HOPKINS HILL 63	12.47	63F6	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	400	75%	5.5%		422	80%	2.8%		434	82%	3.7%		450	85%	4.0%		468	88%	3.3%		483	91%	2.6%		496	94%	2.4%		508	96%
	HUNT RIVER 40	12.47	40F1	Regulator	167 kVA 7.2 kV - 55C	274	Regulator	167 kVA 7.2 kV - 55C	327	200	73%	5.5%		211	77%	2.8%		217	79%	3.7%		225	82%	4.0%		234	85%	3.3%		242	88%	2.6%		248	90%	2.4%		254	93%
	KENT COUNTY 22	12.47	22F1	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	425	80%	5.5%		449	85%	2.8%		461	87%	3.7%		478	90%	4.0%		497	94%	3.3%		514	97%	2.6%		527	99%	2.4%		540	102%
	KENT COUNTY 22	12.47	22F2	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	364	69%	5.5%		384	72%	2.8%		394	74%	3.7%		409	77%	4.0%		425	80%	3.3%		439	83%	2.6%		451	85%	2.4%		462	87%
	KENT COUNTY 22	12.47	22F3	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	458	86%	5.5%		483	91%	2.8%		497	94%	3.7%		515	97%	4.0%		536	101%	3.3%		553	104%	2.6%		568	107%	2.4%		581	110%
	KENT COUNTY 22	12.47	22F4	OH Line	477 Al Spacer Cable - 15 kV	530	OH Line	477 Al Spacer Cable - 15 kV	650	498	94%	5.5%		525	99%	2.8%		540	102%	3.7%		560	106%	4.0%		582	110%	3.3%		602	114%	2.6%		617	116%	2.4%		632	119%
	NATICK 29	12.47	29F1	Bus Conductor	4/0 CU 7STR HD	526	Recloser	560A	560	481	92%	5.5%		508	97%	2.8%		522	99%	3.7%		541	103%	4.0%		563	107%	3.3%		582	111%	2.6%		597	113%	2.4%		611	116%
	NATICK 29	12.47	29F2	Relay/Fuse	Safe Carry - 408A	408	Relay/Fuse	408 Amp Safe Carry	408	347	85%	5.5%		366	90%	2.8%		376	92%	3.7%		390	96%	4.0%		405	99%	3.3%		419	103%	2.6%		430	105%	2.4%		440	108%
	WARWICK MALL 28	12.47	28F1	UG Cable	750 MCM Al	390	Transformer	5.6/6.25 W. Mall No. 1	412	101	26%	5.5%		107	27%	2.8%		110	28%	3.7%		114	29%	4.0%		119	30%	3.3%		122	31%	2.6%		126	32%	2.4%		129	33%
	WARWICK MALL 28	12.47	28F2	UG Cable	750 MCM Al	390	Transformer	5.6/6.25 W. Mall No. 1	422	173	44%	5.5%		183	47%	2.8%		188	48%	3.7%		195	50%	4.0%		203	52%	3.3%		209	54%	2.6%		215	55%	2.4%		220	56%
	WEST CRANSTON 21	12.47	21F1	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	432	84%	5.5%		456	88%	2.8%		469	91%	3.7%		486	94%	4.0%		505	98%	3.3%		522	101%	2.6%		536	104%	2.4%		548	106%
	ARCTIC 49	4.16	49J1	Regulator	250 Amp 2.4kV Ind.	285	Regulator	250 Amp 2.4kV Ind.	313	247	87%	5.5%		260	91%	2.8%		268	94%	3.7%		277	97%	4.0%		289	101%	3.3%		298	105%	2.6%		306	107%	2.4%		313	110%
	ARCTIC 49	4.16	49J2	Regulator	180 kVA GE IRT 250A	295	Regulator	180 kVA GE IRT 250A	352	130	44%	5.5%		137	46%	2.8%		141	48%	3.7%		146	50%	4.0%		152	52%	3.3%		157	53%	2.6%		161	55%	2.4%		165	56%
	ARCTIC 49	4.16	49J3	Regulator	180 kVA GE IRT 250A	295	OH Line	1/0 Cu - Hard/Soft Drawn	315	240	81%	5.5%		253	86%	2.8%		260	88%	3.7%		270	91%	4.0%		281	95%	3.3%		290	98%	2.6%		298	101%	2.4%		305	103%
	ARCTIC 49	4.16	49J4	Switch	400A	452	Relay/Fuse	Relay Safe Carry Phase	476	268	59%	5.5%		283	63%	2.8%		291	64%	2.4%		298	66%	4.0%		310	68%	3.3%		320	71%	2.6%		328	73%	2.4%		336	74%
EAST BAY																																							
	BARRINGTON 4	12.47	4F1	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	340	66%	3.2%		351	68%	0.4%		352	68%	1.0%		356	69%	1.3%		360	70%	0.9%		364	71%	0.4%		365	71%	0.3%		366	71%
	BARRINGTON 4	12.47	4F2	Relay/Fuse	510 Amp Safe Carry	510	Relay/Fuse	510 Amp Safe Carry	510	404	79%	3.2%		417	82%	0.4%		419	82%	1.0%		423	83%	1.3%		428	84%	0.9%		432	85%	0.4%		434	85%	0.3%		435	85%
	BRISTOL 51A	12.47	51F1	UG Cable	Getaway	502	Relay/Fuse	612 Amp Safe Carry	612	452	90%	3.2%		466	93%	0.4%		468	93%	1.0%		473	94%	1.3%		479	95%	0.9%		483	96%	0.4%		485	97%	0.3%		487	97%
	BRISTOL 51A	12.47	51F2	OH Line	477 Al Spacer Cable - 15 kV	530	Relay/Fuse	612 Amp Safe Carry	612	395	74%	3.2%		407	77%	0.4%		409	77%	1.0%		413	78%	1.3%		418	79%	0.9%		422	80%	0.4%		424	80%	0.3%		425	80%
	BRISTOL 51A	12.47	51F3	UG Cable	Getaway	502	Relay/Fuse	612 Amp Safe Carry	612	433	86%	3.2%		447	89%	0.4%		449	89%	1.0%		453	90%	1.3%		459	91%	0.9%		463	92%	0.4%		465	93%	0.3%		466	93%
	PHILLIPSDALE 20	12.47	20F1	OH Line	336.4 Al Spacer Cable	425	OH Line	336.4 Al Spacer Cable	450	231	54%	3.2%		239	56%	0.4%		240	56%	1.0%		242	57%	1.3%		245	58%	0.9%		247	58%	0.4%		248	58%	0.3%		249	59%
	PHILLIPSDALE 20	12.47	20F2	OH Line	336.4 Al Spacer Cable	425	OH Line	336.4 Al Spacer Cable	450	341	80%	3.2%		352	83%	0.4%		354	83%	1.0%		357	84%	1.3%		362	85%	0.9%		365	86%	0.4%		367	86%	0.3%		368	87%
	WAMPANOAG 48	12.47	48F1	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	416	81%	3.2%		430	83%	0.4%		431	84%	1.0%		436	85%	1.3%		441	86%	0.9%		445	86%	0.4%		447	87%	0.3%		448	87%
	WAMPANOAG 48	12.47	48F2	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	380	74%	3.2%		392	76%	0.4%		394	76%	1.0%		398	77%	1.3%		403	78%	0.9%		406	79%	0.4%		408	79%	0.3%		409	79%
	WAMPANOAG 48	12.47	48F3	UG Cable	1C 1000Al XLPE EB	510	OH Line	336.4 Al (TULIP) Bare	515	451	88%	3.2%		465	91%	0.4%		467	92%	1.0%		472	92%	1.3%		478	94%	0.9%		482	95%	0.4%		484	95%	0.3%		485	95%
	WAMPANOAG 48	12.47	48F4	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	457	89%	3.2%		471	92%	0.4%		473	92%	1.0%		478	93%	1.3%		484	94%	0.9%		488	95%	0.4%		490	95%	0.3%		492	96%
	WAMPANOAG 48	12.47	48F5	OH Line	4/0 Cu - Hard/Soft Drawn	485	OH Line	4/0 Cu - Hard/Soft Drawn	490	364	75%	3.2%		375	77%	0.4%		377	78%	1.0%		381	78%	1.3%		386	79%	0.9%		389	80%	0.4%		391	81%	0.3%		392	81%
	WAMPANOAG 48	12.47	48F6	OH Line	4/0 Cu - Hard/Soft Drawn	485	OH Line	4/0 Cu - Hard/Soft Drawn	490	389	80%	3.2%		402	83%	0.4%		403	83%	1.0%		407	84%	1.3%		413	85%	0.9%		416	86%	0.4%		418	86%	0.3%		419	86%
	WARREN 5	12.47	5F1	OH Line	336.4 Al Spacer Cable	425	OH Line	336.4 Al Spacer Cable	520	339	80%	3.2%		350	82%	0.4%		352	83%	1.0%		355	84%	1.3%		360	85%	0.9%		363	85%	0.4%		364	86%	0.3%		366	86%
	WARREN 5	12.47	5F2	OH Line	4/0Al (W+45A/S+50A)	434	OH Line	4/0Al (W+45A/S+50A)	434	352	81%	3.2%		363	84%	0.4%		365	84%	1.0%		368	85%	1.3%		373	86%	0.9%		377	87%	0.4%		378	87%	0.3%		379	87%
	WARREN 5	12.47	5F3	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	324	63%	3.2%		334	65%	0.4%		335	65%	1.0%		339	66%	1.3%		343	67%	0.9%		346	67%	0.4%		348	67%	0.3%		349	68%
	WARREN 5	12.47	5F4	OH Line	4/0Al (W+10A/S+15A)	510	OH Line	4/0Al (W+10A/S+15A)	510	388	76%	3.2%		400	78%	0.4%		402	79%	1.0%		406	80%	1.3%		411	81%	0.9%		415	81%	0.4%		416	82%	0.3%		418	82%
	WATERMAN AVENUE 78	12.47	78F3	Regulator	250 kVA 7.2 kV - 55C	409	Relay/Fuse	Relay Safe Carry	489	290	71%	3.2%		299	73%	0.4%		300	73%	1.0%		303	74%	1.3%		307	75%	0.9%		310	76%	0.4%		311	76%	0.3%		312	76%
	WATERMAN AVENUE 78	12.47	78F4	Regulator	250 kVA 7.2 kV - 55C	409	Relay/Fuse	Relay Safe Carry	489	210	51%	3.2%		217	53%	0.4%		218	53%	1.0%		220	54%	1.3%		223	54%	0.9%		225	55%	0.4%		226	55%	0.3%		226	55%
	KENTS CORNER 47	4.16	47J1	Regulator	250 Amp 2.4 kV Ind.	285	Regulator	250 Amp 2.4 kV Ind.	313	160	56%	3.2%		165	58%	0.4%		166	58%	1.0%		167	59%	1.3%		170	60%	0.9%		171	60%	0.4%		172	60%	0.3%		172	60%
	KENTS CORNER 47	4.16	47J2	Regulator	333 Amp 2.4 kV	379	Relay/Fuse	408 Amp Safe Carry	408	284	75%	3.2%		293	77%	0.4%		294	78%	1.0%		297	78%	1.3%		301	79%	0.9%		304	80%	0.4%		305	80%	0.3%		306	81%
	KENTS CORNER 47	4.16	47J3	Regulator	250 Amp 2.4 kV Ind.	285	Regulator	250 Amp 2.4 kV Ind.	313	309	109%	3.2%		319	112%	0.4%		321	112%	1.0%		324	114%	1.3%		328	115%	0.9%		331	116%	0.4%		332	117%	0.3%		333	117%
	KENTS CORNER 47	4.16	47J4	Regulator	333 Amp 2.4 kV	379	Relay/Fuse	408 Amp Safe Carry	408	350	92%	3.2%		361	95%	0.4%		363	96%	1.0%		366	97%	1.3%		371	98%	0.9%		374	99%	0.4%		376	99%	0.3%		377	99%
NEWPORT																																							
	DEXTER 36	13.8	36W41	UG Cable	500 Cu	464	UG Cable	500 Cu	566	277	60%	4.6%		290	62%	2.0%		296	64%	2.4%		303	65%	2.6%		310	67%	2.2%		317	68%	1.9%		323	70%	1.8%		329	71%
	DEXTER 36	13.8	36W42	UG Cable	500 Cu	464	OH Line	336.4 Al	515	174	38%	4.6%		182	39%	2.0%		186	40%	2.4%		190	41%	2.6%		195	42%	2.2%		199	43%	1.9%		203	44%	1.8%		207	45%
	DEXTER 36	13.8	36W43	UG Cable	500 Cu	464	UG Cable	500 Cu	566	114	25%	4.6%		119	26%	2.0%		122	26%	2.4%		125	27%	2.6%		128	28%	2.2%		131	28%	1.9%		133	29%	1.8%		135	29%
	DEXTER 36	13.8	36W44	UG Cable	500 Cu	464	UG Cable	500 Cu	566	245	53%	4.6%		256	55%	2.0%		261	56%	2.4%		268	58%	2.6%		275	59%	2.2%		281	60%	1.9%		286	62%	1.8%		291	63%
	JEPSON 37	13.8	37W41	Recloser	560A Recloser	560	Recloser	560A Recloser	560	204	36%	4.6%	0	213	38%	2.0%	234	452	81%	2.4%		462	83%	2.6%		475	85%	2.2%		485	87%	1.9%		494	88%	1.8%		503	90%
	JEPSON 37	13.8	37W42	Recloser	560A Recloser	560	Recloser	560A Recloser	560	300	54%	4.6%	125	439	78%	2.0%	12	460	82%	2.4%		471	84%	2.6%		483	86%	2.2%		493	88%	1.9%		503	90%	1.8%		512	91%
	JEPSON 37	13.8	37W43	Recloser	560A Recloser	560	Recloser	560A Recloser	560	320	57%	4.6%	-10	325	58%	2.0%	32	363	65%	2.4%		372	66%	2.6%		382	68%	2.2%		390	70%	1.9%		397	71%	1.8%		405	72%
	BAILEY BROOK SUB 19	4.16	19J2	Bus Conductor	3/0 Cu	447	Relay/Fuse	Safe Carry - 476A	476	411	92%	4.6%	-200	230	51%	2.0%		235	52%	2.4%		240	54%	2.6%		246	55%	2.2%		252	56%	1.9%		257	57%	1.8%		261	58%
	BAILEY BROOK SUB 19	4.16	19J14	Relay/Fuse	Safe Carry - 476A	476	Relay/Fuse	Safe Carry - 476A	476	283	59%	4.6%	0	296	62%	2.0%	-28	274	58%	2.4%		281	59%	2.6%		288	60%	2.2%		294	62%	1.9%		300	63%	1.8%		305	64%
	BAILEY BROOK SUB 19	4.16	19J16	Relay/Fuse	Safe Carry - 476A	476	Relay/Fuse	Safe Carry - 476A	476	20	4%	4.6%		21	4%	2.0%		21	4%	2.4%		22	5%	2.6%		22	5%	2.2%		23	5%	1.9%		23	5%	1.8%		24	5%
	CLARKE STREET 65	4.16	65J2	OH Line		487	Relay/Fuse	Safe Carry - 510A	510	323	66%	4.6%		338	69%	2.0%		345	71%	2.4%		353	72%	2.6%		362	74%	2.2%		370	76%	1.9%		377	77%	1.8%		384	79%
	CLARKE STREET 65	4.16	65J12	Transformer	1.725 MVA	277	Transformer	1.725 MVA	277	240	87%	4.6%		251	91%	2.0%		256	92%	2.4%		262	95%	2.6%		269	97%	2.2%		275	99%	1.9%		280	101%	1.8%		285	103%
	ELDRED SUB	4.16	45J2	Regulator	167 kVA	448	Relay/Fuse	Safe Carry - 476A	476	167	37%	4.6%		175	39%	2.0%		178	40%	2.4%		182	41%	2.6%		187	42%	2.2%		191	43%	1.9%		195	44%	1.8%		198	44%
	ELDRED SUB	4.16	45J4	Relay/Fuse	Safe Carry - 340A	340	Relay/Fuse	Safe Carry - 340A	340	212	62%	4.6%		222	65%	2.0%		226	67%	2.4%		232	68%	2.6%		238	70%	2.2%		243	71%	1.9%		247	73%	1.8%		252	74%
	ELDRED SUB	4.16	45J6	Regulator	167 kVA	448	Relay/Fuse	Safe Carry - 476A	476	130	29%	4.6%		136	30%	2.0%		139	31%	2.4%		142	32%	2.6%		146	33%	2.2%		149	33%	1.9%		152	34%	1.8%		154	34%
	GATE II 38	4.16	38J2	UG Cable	350 Cu	440	Relay/Fuse	Safe Carry - 476A	476	245	56%	4.6%	0	256	58%	2.0%	-28	233	53%	2.4%		239	54%	2.6%		245	56%	2.2%		251	57%	1.9%		255	58%	1.8%		260	59%
	GATE II 38	4.16	38J4	UG Cable	350 Cu	440	Relay/Fuse	Safe Carry - 476A	476	325	74%	4.6%		340	77%	2.0%		347	79%	2.4%		355	81%	2.6%		364	83%	2.2%		372	85%	1.9%		379	86%	1.8%		386	88%
	HARRISON 32	4.16	32J2	UG Cable	750 Cu	420	OH Line	3/0 Cu	420	408	97%	4.6%	-140	287	68%	2.0%		293	70%	2.4%		300	71%	2.6%		307	73%	2.2%		314	75%	1.9%		320	76%	1.8%		326	78%
	HARRISON 32	4.16	32J4	UG Cable	500 Cu	377	OH Line	3/0 Cu covered	380	228	60%	4.6%	-100	138	37%	2.0%		141	37%	2.4%		145	38%	2.6%		148	39%	2.2%		152	40%	1.9%		155	41%	1.8%		157	42%
	HARRISON 32	4.16	32J12	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	330	87%	4.6%	-85	260	68%	2.0%		265	70%	2.4%		272	72%	2.6%		279	73%	2.2%		285	75%	1.9%		290	76%	1.8%		296	78%
	HARRISON 32	4.16	32J14	OH Line	477 Al spca	530	OH Line	477 Al spca (temp)	530				325	325	61%	2.0%		332	63%	2.4%		339	64%	2.6%		348	66%	2.2%		356	67%	1.9%		363	68%	1.8%		369	70%
	HOSPITAL SUB 146	4.16	146J2	UG Cable	350 Cu	300	UG Cable	350 Cu	357	180	60%	4.6%	0	188	63%	2.0%	-192	0	0%	2.4%		0	0%	2.6%		0	0%	2.2%		0	0%	1.9%		0	0%	1.8%		0	0%
	HOSPITAL SUB 146	4.16	146J4	UG Cable	350 Cu	434	UG Cable	350 Cu	434	216	50%	4.6%		226	52%	2.0%		230	53%	2.4%		236	54%	2.6%		242	56%	2.2%		247	57%	1.9%		252	58%	1.8%		257	59%
	HOSPITAL SUB 146	4.16	146J12	UG Cable	350 Cu	434	UG Cable	350 Cu	434	113	26%	4.6%		118	27%	2.0%		121	28%	2.4%		123	28%	2.6%		127	29%	2.2%		129	30%	1.9%		132	30%	1.8%		134	31%
	HOSPITAL SUB 146	4.16	146J14	UG Cable	350 Cu	307	UG Cable	350 Cu	365	156	51%	4.6%	0	163	53%	2.0%	-97	69	23%	2.4%		71	23%	2.6%		73	24%	2.2%		75	24%	1.9%		76	25%	1.8%		77	25%
	JEPSON 37	4.16	37J2	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	111	29%	4.6%	0	116	31%	2.0%	-118	0	0%	2.4%		0	0%	2.6%		0	0%	2.2%		0	0%	1.9%		0	0%	1.8%		0	0%
	JEPSON 37	4.16	37J4	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	208	55%	4.6%	0	218	57%	2.0%	118	340	89%	2.4%		348	92%	2.6%		357	94%	2.2%		365	96%	1.9%		372	98%	1.8%		379	100%
	KINGSTON 131	4.16	131J2	UG Cable	500 Cu	397	Relay/Fuse	Safe Carry - 510A	510	293	74%	4.6%		306	77%	2.0%		313	79%	2.4%		320	81%	2.6%		328	83%	2.2%		336	85%	1.9%		342	86%	1.8%		348	88%
	KINGSTON 131	4.16	131J4	UG Cable	350 Cu	366	UG Cable	350 Cu	441	270	74%	4.6%		282	77%	2.0%		288	79%	2.4%		295	81%	2.6%		303	83%	2.2%		309	85%	1.9%		315	86%	1.8%		321	88%
	KINGSTON 131	4.16	131J6	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	105	28%	4.6%		110	29%	2.0%		112	29%	2.4%		115	30%	2.6%		118	31%	2.2%		120	32%	1.9%		123	32%	1.8%		125	33%
	KINGSTON 131	4.16	131J12	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	316	83%	4.6%		331	87%	2.0%		337	89%	2.4%		345	91%	2.6%		354	93%	2.2%		362	95%	1.9%		369	97%	1.8%		376	99%
	KINGSTON 131	4.16	131J14	UG Cable	350 Cu	307	UG Cable	350 Cu	365	225	73%	4.6%		235	77%	2.0%		240	78%	2.4%		246	80%	2.6%		252	82%	2.2%		258	84%	1.9%		263	86%	1.8%		267	87%
	MERTON 51	4.16	51J2	Transformer	1.93 MVA	310	Transformer	1.93 MVA	333	230	74%	4.6%	0	241	78%	2.0%	-9	236	76%	2.4%		242	78%	2.6%		248	80%	2.2%		254	82%	1.9%		259	83%	1.8%		263	85%
	MERTON 51	4.16	51J12	UG Cable	350 Cu	356	Relay/Fuse	Safe Carry - 408A	408	160	45%	4.6%		167	47%	2.0%		171	48%	2.4%		175	49%	2.6%		179	50%	2.2%		183	51%	1.9%		187	52%	1.8%		190	53%
	MERTON 51	4.16	51J14	UG Cable	350 Cu	310	UG Cable	350 Cu	368	144	46%	4.6%		151	49%	2.0%		154	50%	2.4%		157	51%	2.6%		161	52%	2.2%		165	53%	1.9%		168	54%	1.8%		171	55%
	MERTON 51	4.16	51J16	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	221	58%	4.6%		231	61%	2.0%		236	62%	2.4%		241	64%	2.6%		248	65%	2.2%		253	67%	1.9%		258	68%	1.8%		263	69%
	NORTH AQUIDNECK 21	4.16	21J2	UG Cable	500 Cu	480	UG Cable	500	480	248	52%	4.6%	-95	164	34%	2.0%		168	35%	2.4%		172	36%	2.6%		176	37%	2.2%		180	38%	1.9%		183	38%	1.8%		187	39%
	NORTH AQUIDNECK 21	4.16	21J4	UG Cable	500 Cu	480	UG Cable	500	480	308	64%	4.6%	0	322	67%	2.0%	-250	79	16%	2.4%		80	17%	2.6%		83	17%	2.2%		84	18%	1.9%		86	18%	1.8%		88	18%
	NORTH AQUIDNECK 21	4.16	21J6	UG Cable	500 Cu	480	UG Cable	500	480	180	38%	4.6%		188	39%	2.0%		192	40%	2.4%		197	41%	2.6%		202	42%	2.2%		206	43%	1.9%		210	44%	1.8%		214	45%
	SOUTH AQUIDNECK 122	4.16	122J2	UG Cable	350 Cu	360	UG Cable	350 Cu	360	304	84%	4.6%	0	318	88%	2.0%		324	90%	2.4%		332	92%	2.6%		341	95%	2.2%		348	97%	1.9%		355	99%	1.8%		361	100%
	SOUTH AQUIDNECK 122	4.16	122J4	UG Cable	500 Cu	480	UG Cable	500 Cu	480	396	83%	4.6%	0	414	86%	2.0%		423	88%	2.4%		433	90%	2.6%		444	92%	2.2%		454	95%	1.9%		462	96%	1.8%		471	98%
	SOUTH AQUIDNECK 122	4.16	122J6	UG Cable	500 Cu	480	UG Cable	500 Cu	480	225	47%	4.6%		235	49%	2.0%		240	50%	2.4%		246	51%	2.6%		252	53%	2.2%		258	54%	1.9%		263	55%	1.8%		267	56%
	VERNON 23	4.16	23J2	OH Line	4/0 Al	384	Relay/Fuse	Safe Carry - 408A	408	160	42%	4.6%		167	44%	2.0%		171	44%	2.4%		175	46%	2.6%		179	47%	2.2%		183	48%	1.9%		187	49%	1.8%		190	50%
	VERNON 23	4.16	23J4	OH Line	4/0 Al	384	Relay/Fuse	Safe Carry - 408A	408	240	63%	4.6%	0	251	65%	2.0%	-42	214	56%	2.4%		219	57%	2.6%		225	59%	2.2%		230	60%	1.9%		234	61%	1.8%		238	62%
	VERNON 23	4.16	23J6	OH Line	4/0 Al	384	Relay/Fuse	Safe Carry - 408A	408	120	31%	4.6%		126	33%	2.0%		128	33%	2.4%		131	34%	2.6%		135	35%	2.2%		137	36%	1.9%		140	36%	1.8%		143	37%
	VERNON 23	4.16	23J12	OH Line	4/0 Al	384	Relay/Fuse	Safe Carry - 408A	408	131	34%	4.6%	0	137	36%	2.0%	33	173	45%	2.4%		177	46%	2.6%		182	47%	2.2%		186	48%	1.9%		189	49%	1.8%		192	50%
	VERNON 23	4.16	23J14	OH Line	4/0 Al	384	Relay/Fuse	Safe Carry - 408A	408	158	41%	4.6%	0	165	43%	2.0%	-17	152	39%	2.4%		155	40%	2.6%		159	41%	2.2%		163	42%	1.9%		166	43%	1.8%		169	44%
	WEST HOWARD 154	4.16	154J2	UG Cable	500 Cu	480	UG Cable	500 Cu	688	275	57%	4.6%	0	288	60%	2.0%	-97	196	41%	2.4%		201	42%	2.6%		206	43%	2.2%		211	44%	1.9%		215	45%	1.8%		219	46%

Study Area	Substation	Feeder Voltage (kV)	Feeder Number	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	Emergency Limiting Element	Emergency Element Specifics	SE Rating (Amps)	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN
	WEST HOWARD 154	4.16	154J4	UG Cable	350 Cu	290	UG Cable	350 Cu	350	231	80%	4.6%		242	83%	2.0%		246	85%	2.4%		252	87%	2.6%		259	89%	2.2%		265	91%	1.9%		270	93%	1.8%		275	95%
	WEST HOWARD 154	4.16	154J6	UG Cable	350 Cu	268	UG Cable	350 Cu	346	65	24%	4.6%	0	68	25%	2.0%	-20	49	18%	2.4%		51	19%	2.6%		52	19%	2.2%		53	20%	1.9%		54	20%	1.8%		55	21%
	WEST HOWARD 154	4.16	154J8	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	298	78%	4.6%		312	82%	2.0%		318	84%	2.4%		326	86%	2.6%		334	88%	2.2%		341	90%	1.9%		348	92%	1.8%		354	93%
	WEST HOWARD 154	4.16	154J14	UG Cable	350 Cu	290	UG Cable	350 Cu	350	170	59%	4.6%	0	178	61%	2.0%	-56	125	43%	2.4%		128	44%	2.6%		132	45%	2.2%		135	46%	1.9%		137	47%	1.8%		140	48%
	WEST HOWARD 154	4.16	154J16	UG Cable	350 Cu	270	UG Cable	350 Cu	340	248	92%	4.6%		259	96%	2.0%		265	98%	2.4%		271	100%	2.6%		278	103%	2.2%		284	105%	1.9%		290	107%	1.8%		295	109%
	WEST HOWARD 154	4.16	154J18	OH Line	3/0 Cu covered	380	OH Line	3/0 Cu covered	380	330	87%	4.6%	0	345	91%	2.0%	-83	269	71%	2.4%		276	73%	2.6%		283	74%	2.2%		289	76%	1.9%		294	77%	1.8%		300	79%
NORTH CENTRAL RI																																							
	CENTREDALE 50	12.47	50F2	Transformer	5 MVA	367	Transformer	5 MVA	386	212	58%	5.5%		224	61%	2.8%		230	63%	3.7%		238	65%	4.0%		248	68%	3.3%		256	70%	2.6%		263	72%	2.4%		269	73%
	CHOPMIST 34	12.47	34F1	OH Line	477 Al Spca	530	Relay Safe C	640 A	544	365	69%	5.5%		385	73%	2.8%		396	75%	3.7%		411	77%	4.0%		427	81%	3.3%		441	83%	2.6%		452	85%	2.4%		463	87%
	CHOPMIST 34	12.47	34F2	OH Line	1/0 Cu	415	OH Line	1/0 Cu	415	330	80%	5.5%		348	84%	2.8%		358	86%	3.7%		371	89%	4.0%		386	93%	3.3%		399	96%	2.6%		409	99%	2.4%		419	101%
	CHOPMIST 34	12.47	34F3	OH Line	4/0 Al	385	OH Line	4/0 Al	385	185	48%	5.5%		195	51%	2.8%		201	52%	3.7%		208	54%	4.0%		216	56%	3.3%		224	58%	2.6%		229	60%	2.4%		235	61%
	FARNUM PIKE 23	12.47	23F1	OH Line	336.4 Al	515		New feeder - Temporay rating	515	381	74%	X		250	49%	2.8%		257	50%	3.7%		267	52%	4.0%		277	54%	3.3%		286	56%	2.6%		294	57%	2.4%		301	58%
	FARNUM PIKE 23	12.47	23F2	OH Line	336.4 Al	515		New feeder - Temporay rating	515	323	63%	X		215	42%	2.8%		221	43%	3.7%		229	45%	4.0%		238	46%	3.3%		246	48%	2.6%		253	49%	2.4%		259	50%
	FARNUM PIKE 23	12.47	23F3	OH Line	477 Al Spca	530		New feeder - Temporay rating	650		0%	X		350	66%	2.8%		360	68%	3.7%		373	70%	4.0%		388	73%	3.3%		401	76%	2.6%		411	78%	2.4%		421	79%
	FARNUM PIKE 23	12.47	23F4	OH Line	477 Al Spca	530		New feeder - Temporay rating	650	286	54%	X		335	63%	2.8%		344	65%	3.7%		357	67%	4.0%		371	70%	3.3%		384	72%	2.6%		394	74%	2.4%		403	76%
	FARNUM PIKE 23	12.47	23F5	OH Line	336.4 Al	515		New feeder - Temporay rating	515		0%	X		215	42%	2.8%		221	43%	3.7%		229	45%	4.0%		238	46%	3.3%		246	48%	2.6%		253	49%	2.4%		259	50%
	FARNUM PIKE 23	12.47	23F6	OH Line	336.4 Al	515		New feeder - Temporay rating	515	514	100%	X		290	56%	2.8%		298	58%	3.7%		309	60%	4.0%		322	62%	3.3%		332	64%	2.6%		341	66%	2.4%		349	68%
	JOHNSTON 18	12.47	18F1	OH Line	4/0 Cu	526	Switch	Disconnect - 400A	556	452	86%	5.5%	70	547	104%	2.8%		562	107%	3.7%		583	111%	4.0%		606	115%	3.3%		626	119%	2.6%		643	122%	2.4%		658	125%
	JOHNSTON 18	12.47	18F2	Switch	Disconnect - 400A	452	OH Line	336.4 Al	515	336	74%	5.5%		354	78%	2.8%	-150	214	47%	3.7%		222	49%	4.0%		231	51%	3.3%		239	53%	2.6%		245	54%	2.4%		251	56%
	JOHNSTON 18	12.47	18F3	OH Line	336.4 Al	515	OH Line	336.4 Al	515	412	80%	5.5%		435	84%	2.8%		447	87%	3.7%		463	90%	4.0%		482	94%	3.3%		498	97%	2.6%		511	99%	2.4%		523	102%
	JOHNSTON 18	12.47	18F4	OH Line	477 Al Spca	530	Recloser	560 A	560			X	170	170	32%	2.8%		175	33%	3.7%		181	34%	4.0%		188	36%	3.3%		195	37%	2.6%		200	38%	2.4%		205	39%
	JOHNSTON 18	12.47	18F5	OH Line	477 Al Spca	530	Relay Safe C	720 A	612	455	86%	5.5%		480	91%	2.8%		493	93%	3.7%		512	97%	4.0%		532	100%	3.3%		550	104%	2.6%		564	106%	2.4%		578	109%
	JOHNSTON 18	12.47	18F6			515	OH Line	336.4 Al	515	398	77%	5.5%		420	82%	2.8%		432	84%	3.7%		448	87%	4.0%		466	90%	3.3%		481	93%	2.6%		493	96%	2.4%		505	98%
	JOHNSTON 18	12.47	18F7	OH Line	477 Al Spca	530	Relay Safe C	720 A	612	403	76%	5.5%	72	497	94%	2.8%		511	96%	3.7%		530	100%	4.0%		551	104%	3.3%		569	107%	2.6%		584	110%	2.4%		598	113%
	JOHNSTON 18	12.47	18F8	OH Line	477 Al Spca	530	Relay Safe C	720 A	612	266	50%	5.5%		281	53%	2.8%		288	54%	3.7%		299	56%	4.0%		311	59%	3.3%		321	61%	2.6%		330	62%	2.4%		338	64%
	JOHNSTON 18	12.47	18F9	OH Line	477 Al Spca	530	Relay Safe C	720 A	612	282	53%	5.5%		298	56%	2.8%		306	58%	3.7%		317	60%	4.0%		330	62%	3.3%		341	64%	2.6%		350	66%	2.4%		358	68%
	JOHNSTON 18	12.47	18F10			530			612									0	0%	3.7%		0	0%	4.0%		0	0%	3.3%		0	0%	2.6%		0	0%	2.4%		0	0%
	MANTON 69	12.47	69F1	OH Line	336.4 Al	515	OH Line	336.4 Al	515	412	80%	5.5%		435	84%	2.8%		447	87%	3.7%		463	90%	4.0%		482	94%	3.3%		498	97%	2.6%		511	99%	2.4%		523	102%
	MANTON 69	12.47	69F3	UG Cable	750 Al	502	OH Line	336.4 Al	515	500	100%	5.5%		528	105%	2.8%		542	108%	3.7%		562	112%	4.0%		585	116%	3.3%		604	120%	2.6%		620	123%	2.4%		635	126%
	PUTNAM PIKE 38	12.47	38F1	OH Line	477 Al Spca	530	OH Line	477 Al Spca	650	429	81%	5.5%		453	85%	2.8%		465	88%	3.7%		482	91%	4.0%		502	95%	3.3%		518	98%	2.6%		532	100%	2.4%		545	103%
	PUTNAM PIKE 38	12.47	38F2	OH Line	477 Al Spca	530	OH Line	477 Al Spca	650	361	68%	X		200	38%	2.8%		206	39%	3.7%		213	40%	4.0%		222	42%	3.3%		229	43%	2.6%		235	44%	2.4%		241	45%
	PUTNAM PIKE 38	12.47	38F3	OH Line	477 Al Spca	530	OH Line	477 Al Spca	650	387	73%	5.5%		408	77%	2.8%		420	79%	3.7%		435	82%	4.0%		453	85%	3.3%		468	88%	2.6%		480	91%	2.4%		491	93%
	PUTNAM PIKE 38	12.47	38F4	OH Line	336.4 Al	515	OH Line	336.4 Al	515	382	74%	5.5%		403	78%	2.8%		414	80%	3.7%		430	83%	4.0%		447	87%	3.3%		462	90%	2.6%		474	92%	2.4%		485	94%
	PUTNAM PIKE 38	12.47	38F5	OH Line	4/0 Al	395	OH Line	4/0 Al	395	377	95%	5.5%		398	101%	2.8%		409	104%	3.7%		424	107%	4.0%		441	112%	3.3%		456	115%	2.6%		467	118%	2.4%		479	121%
	PUTNAM PIKE 38	12.47	38F6	OH Line	477 Al Spca	530	Relay Safe C	720 A	612	378	71%	5.5%		399	75%	2.8%		410	77%	3.7%		425	80%	4.0%		442	83%	3.3%		457	86%	2.6%		469	88%	2.4%		480	91%
	WEST CRANSTON 21	12.47	21F2	OH Line	336.4 Al	515	OH Line	336.4 Al	515	432	84%	5.5%		456	88%	2.8%		469	91%	3.7%		486	94%	4.0%		505	98%	3.3%		522	101%	2.6%		536	104%	2.4%		548	106%
	WEST CRANSTON 21	12.47	21F4	OH Line	336.4 Al	515	OH Line	336.4 Al	515	380	74%	5.5%		401	78%	2.8%		412	80%	3.7%		427	83%	4.0%		444	86%	3.3%		459	89%	2.6%		471	91%	2.4%		482	94%
	WEST GREENVILLE 45	12.47	45F2	OH Line	336.4 Al	425	OH Line	336.4 Al	520	88	21%	5.5%		93	22%	2.8%		95	22%	3.7%		99	23%	4.0%		103	24%	3.3%		106	25%	2.6%		109	26%	2.4%		112	26%
	CENTREDALE 50	4.16	50J1	Regulator	250 Amp	285	Regulator	250 Amp	313	152	53%	5.5%		160	56%	2.8%		165	58%	3.7%		171	60%	4.0%		178	62%	3.3%		184	64%	2.6%		188	66%	2.4%		193	68%
	CENTREDALE 50	4.16	50J2	Regulator	187.5 kVA	295	Regulator	187.5 kVA	352		0%	5.5%		0	0%	2.8%		0	0%	3.7%		0	0%	4.0%		0	0%	3.3%		0	0%	2.6%		0	0%	2.4%		0	0%
	CENTREDALE 50	4.16	50J3	Relay/Fuse	Safe Carry - 408A	408	Relay/Fuse	Safe Carry - 408A	408	212	52%	5.5%		224	55%	2.8%		230	56%	3.7%		238	58%	4.0%		248	61%	3.3%		256	63%	2.6%		263	64%	2.4%		269	66%
PROVIDENCE																																							
	CLARKSON STREET 13	12.47	13F1	UG Cable/Reserv	1000 Cu/Reserved	400	UG Cable	1000 Cu	533	207	52%	3.2%		248	62%	0.4%		249	62%	1.0%		251	63%	1.3%		255	64%	0.9%		257	64%	0.4%		258	65%	0.3%		259	65%
	CLARKSON STREET 13	12.47	13F2	UG Cable	1000 Cu	540	Realy Setting	720 A	612	479	89%	3.2%	37	531	98%	0.4%		533	99%	1.0%		539	100%	1.3%		546	101%	0.9%		551	102%	0.4%		553	102%	0.3%		555	103%
	CLARKSON STREET 13	12.47	13F3	UG Cable	1000 Cu	425	Realy Setting	720 A	612	375	88%	3.2%		387	91%	0.4%		389	91%	1.0%		392	92%	1.3%		398	94%	0.9%		401	94%	0.4%		403	95%	0.3%		404	95%
	CLARKSON STREET 13	12.47	13F4	UG Cable	1000 Cu	520	Realy Setting	720 A	612	437	84%	3.2%		451	87%	0.4%		453	87%	1.0%		457	88%	1.3%		463	89%	0.9%		467	90%	0.4%		469	90%	0.3%		471	91%
	CLARKSON STREET 13	12.47	13F5	UG Cable	1000 Cu	455	Realy Setting	720 A	612	315	69%	3.2%		325	71%	0.4%		326	72%	1.0%		330	72%	1.3%		334	73%	0.9%		337	74%	0.4%		338	74%	0.3%		339	75%
	CLARKSON STREET 13	12.47	13F6	UG Cable	1000 Cu	415	UG Cable	1000 Cu	542	316	76%	3.2%		347	84%	0.4%		348	84%	1.0%		352	85%	1.3%		356	86%	0.9%		360	87%	0.4%		361	87%	0.3%		362	87%
	CLARKSON STREET 13	12.47	13F7	UG Cable	1000 Cu	436	UG Cable	1000 Cu	571	261	60%	3.2%		310	71%	0.4%		311	71%	1.0%		314	72%	1.3%		318	73%	0.9%		321	74%	0.4%		323	74%	0.3%		324	74%
	CLARKSON STREET 13	12.47	13F8	UG Cable	1000 Cu	437	UG Cable	1000 Cu	563	306	70%	3.2%		386	88%	0.4%		388	89%	1.0%		391	90%	1.3%		397	91%	0.9%		400	92%	0.4%		402	92%	0.3%		403	92%
	CLARKSON STREET 13	12.47	13F9	OH Line	477 Al Spca	530	Realy Setting	720 A	612	384	72%	3.2%		396	75%	0.4%		398	75%	1.0%		402	76%	1.3%		407	77%	0.9%		411	77%	0.4%		412	78%	0.3%		414	78%
	ELMWOOD 7 - OUTDOOR	12.47	7F1	OH Line	477 Al Spca	530	Realy Setting	720 A	612	316	60%	3.2%		326	62%	0.4%		327	62%	1.0%		331	62%	1.3%		335	63%	0.9%		338	64%	0.4%		339	64%	0.3%		340	64%
	ELMWOOD 7 - OUTDOOR	12.47	7F2	OH Line	477 Al Spca	530	Realy Setting	720 A	612	524	99%	3.2%		541	102%	0.4%	28	571	108%	1.0%		577	109%	1.3%		584	110%	0.9%		589	111%	0.4%		592	112%	0.3%		594	112%
	ELMWOOD 7 - OUTDOOR	12.47	7F4	OH Line	477 Al Spca	530	Realy Setting	720 A	612	404	76%	3.2%		417	79%	0.4%		419	79%	1.0%		423	80%	1.3%		428	81%	0.9%		432	82%	0.4%		434	82%	0.3%		435	82%
	LIPPITT HILL 79	12.47	79F1	UG Cable	1000 Al	451	UG Cable	1000 Cu	579	332	74%	3.2%		343	76%	0.4%		344	76%	1.0%		347	77%	1.3%		413	92%	0.9%		417	92%	0.4%		418	93%	0.3%		420	93%
	LIPPITT HILL 79	12.47	79F2	UG Cable	1000 Al	459	UG Cable	1000 Cu	579	328	71%	3.2%	21	359	78%	0.4%		361	79%	1.0%		365	79%	1.3%		369	80%	0.9%		373	81%	0.4%		374	82%	0.3%		375	82%
	POINT STREET 76	12.47	76F1	UG Cable	1000 Cu	484	OH Line	4/0 Cu	490	347	72%	3.2%		358	74%	0.4%		360	74%	1.0%		363	75%	1.3%		368	76%	0.9%		371	77%	0.4%		373	77%	0.3%		374	77%
	POINT STREET 76	12.47	76F2	UG Cable	1000 Cu	500	Realy Setting	720 A	612	370	74%	3.2%		382	76%	0.4%		383	77%	1.0%		387	77%	1.3%		392	78%	0.9%		396	79%	0.4%		397	79%	0.3%		399	80%
	POINT STREET 76	12.47	76F3	Regulator	333 kVA	546	Realy Setting	720 A	612	173	32%	3.2%		505	92%	0.4%		507	93%	1.0%		512	94%	1.3%		519		0.9%		523		0.4%		526		0.3%		527	
	POINT STREET 76	12.47	76F4	OH Line	477 Al Spca	530	Realy Setting	720 A	612	442	83%	3.2%		456	86%	0.4%		458	86%	1.0%		463	87%	1.3%		469	88%	0.9%		473	89%	0.4%		475	90%	0.3%		476	90%
	POINT STREET 76	12.47	76F5	UG Cable	2 X 4/0 Cu	497	Realy Setting	720 A	612	394	79%	3.2%	12	419	84%	0.4%		420	85%	1.0%		424	85%	1.3%		430	87%	0.9%		434	87%	0.4%		436	88%	0.3%		437	88%
	POINT STREET 76	12.47	76F6	UG Cable	1000 Cu	518	Realy Setting	720 A	612	398	77%	3.2%		411	79%	0.4%		412	80%	1.0%		417	80%	1.3%		422	81%	0.9%		426	82%	0.4%		427	83%	0.3%		429	83%
	POINT STREET 76	12.47	76F7	UG Cable	1000 Cu	525	Realy Setting	720 A	612	393	75%	3.2%		406	77%	0.4%		407	78%	1.0%		411	78%	1.3%		417	79%	0.9%		420	80%	0.4%		422	80%	0.3%		423	81%
	POINT STREET 76	12.47	76F8	OH Line	477 Al Spca	530	Realy Setting	720 A	612		0%	3.2%		0	0%	0.4%		0	0%	1.0%		0	0%	1.3%		0	0%	0.9%		0	0%	0.4%		0	0%	0.3%		0	0%
	FRANKLIN SQUARE 11	11.5	1112	Reactor Leads	425 Amp	280	Reactor Lead	425 Amp	280	39	14%	3.2%		40	14%	0.4%		40	14%	1.0%		41	15%	1.3%		41	15%	0.9%		42	15%	0.4%		42	15%	0.3%		42	15%
	FRANKLIN SQUARE 11	11.5	1121	UG Cable	500 PL	363	UG Cable	500 PL	383	60	17%	3.2%		62	17%	0.4%		62	17%	1.0%		63	17%	1.3%		64	18%	0.9%		64	18%	0.4%		64	18%	0.3%		65	18%
	FRANKLIN SQUARE 11	11.5	1123	Bus	350 Cu	404	Bus	350 Cu	404	46	11%	3.2%		47	12%	0.4%		48	12%	1.0%		48	12%	1.3%		49	12%	0.9%		49	12%	0.4%		49	12%	0.3%		50	12%
	FRANKLIN SQUARE 11	11.5	1125	Switch	Disconnect - 600A	678	Switch	Disconnect - 600A	834	344	51%	3.2%		355	52%	0.4%		356	53%	1.0%		360	53%	1.3%		365	54%	0.9%		368	54%	0.4%		369	54%	0.3%		371	55%
	FRANKLIN SQUARE 11	11.5	1126	UG Cable	500 Cu	327	UG Cable	500 Cu	450	264	81%	3.2%		272	83%	0.4%		274	84%	1.0%		276	84%	1.3%		280	86%	0.9%		282	86%	0.4%		284	87%	0.3%		284	87%
	SOUTH STREET 1	11.5	1151	UG Cable	500 Cu	322	UG Cable	500 Cu	375	196	61%	3.2%		202	63%	0.4%		203	63%	1.0%		205	64%	1.3%		208	65%	0.9%		210	65%	0.4%		210	65%	0.3%		211	66%
	SOUTH STREET 1	11.5	1152	UG Cable	500 Cu	326	UG Cable	500 Cu	389	195	60%	3.2%		201	62%	0.4%		202	62%	1.0%		204	63%	1.3%		207	63%	0.9%		209	64%	0.4%		209	64%	0.3%		210	64%
	ADMIRAL STREET 9	4.16	9J1	Regulator	250 Amp	297	Regulator	250 Amp	326	246	83%	3.2%		254	85%	0.4%		255	86%	1.0%		257	87%	1.3%		261	88%	0.9%		263	89%	0.4%		264	89%	0.3%		265	89%
	ADMIRAL STREET 9	4.16	9J2	Regulator	313 Amp	369	Regulator	313 Amp	441	153	41%	3.2%		158	43%	0.4%		159	43%	1.0%		160	43%	1.3%		162	44%	0.9%		164	44%	0.4%		164	45%	0.3%		165	45%
	ADMIRAL STREET 9	4.16	9J3	OH Line	1/0 Al	255	OH Line	1/0 Al	255	245	96%	3.2%	-35	218	85%	0.4%		219	86%	1.0%		221	87%	1.3%		224	88%	0.9%		226	89%	0.4%		227	89%	0.3%		227	89%
	ADMIRAL STREET 9	4.16	9J5	Regulator	250 Amp	297	Regulator	250 Amp	326	160	54%	3.2%		165	56%	0.4%		166	56%	1.0%		167	56%	1.3%		170	57%	0.9%		171	58%	0.4%		172	58%	0.3%		172	58%
	DYER STREET 2	4.16	2J1	Current Transform	400 Amp	408	Current Trans	400 Amp	408	363	89%	3.2%	-13	362	89%	0.4%		363	89%	1.0%		367	90%	1.3%		371	91%	0.9%		375	92%	0.4%		376	92%	0.3%		377	93%
	DYER STREET 2	4.16	2J10	Reactor	300 Amp	354	Reactor	300 Amp	354	160	45%	3.2%		165	47%	0.4%		166	47%	1.0%		167	47%	1.3%		170	48%	0.9%		171	48%	0.4%		172	49%	0.3%		172	49%
	DYER STREET 2	4.16	2J2	Regulator	250 Amp	285	Regulator	250 Amp	285	193	68%	3.2%		199	70%	0.4%		200	70%	1.0%		202	71%	1.3%		205	72%	0.9%		206	72%	0.4%		207	73%	0.3%		208	73%
	DYER STREET 2	4.16	2J3	Regulator	250 Amp	297	Regulator	250 Amp	297	147	49%	3.2%		152	51%	0.4%		152	51%	1.0%		154	52%	1.3%		156	52%	0.9%		157	53%	0.4%		158	53%	0.3%		158	53%
	DYER STREET 2	4.16	2J4	Relay/Fuse	Safe Carry - 340A	340	Relay/Fuse	Safe Carry - 340A	340	178	52%	3.2%		184	54%	0.4%		184	54%	1.0%		186	55%	1.3%		189	55%	0.9%		190	56%	0.4%		191	56%	0.3%		192	56%
	DYER STREET 2	4.16	2J5	Reactor	300 Amp	354	Reactor	300 Amp	354	123	35%	3.2%		127	36%	0.4%		127	36%	1.0%		129	36%	1.3%		130	37%	0.9%		132	37%	0.4%		132	37%	0.3%		132	37%
	DYER STREET 2	4.16	2J7	Reactor	300 Amp	354	Reactor	300 Amp	354	285	81%	3.2%		294	83%	0.4%		295	83%	1.0%		298	84%	1.3%		302	85%	0.9%		305	86%	0.4%		306	86%	0.3%		307	87%
	DYER STREET 2	4.16	2J8	Reactor	300 Amp	354	Reactor	300 Amp	354	205	58%	3.2%		212	60%	0.4%		212	60%	1.0%		215	61%	1.3%		217	61%	0.9%		219	62%	0.4%		220	62%	0.3%		221	62%
	DYER STREET 2	4.16	2J9	Relay/Fuse	Safe Carry - 340A	340	Relay/Fuse	Safe Carry - 340A	340	188	55%	3.2%		194	57%	0.4%		195	57%	1.0%		197	58%	1.3%		199	59%	0.9%		201	59%	0.4%		202	59%	0.3%		203	60%
	EAST GEORGE ST 77	4.16	77J1	UG Cable	750 Al	371	Relay/Fuse	Safe Carry - 408A	408	280	75%	3.2%		289	78%	0.4%		290	78%	1.0%		293	79%	1.3%		297	80%	0.9%		299	81%	0.4%		301	81%	0.3%		302	81%
	EAST GEORGE ST 77	4.16	77J2	UG Cable	750 Al	364	UG Cable	750 Al	495	343	94%	3.2%	-55	299	82%	0.4%		300	82%	1.0%		303	83%	1.3%		307	84%	0.9%		310	85%	0.4%		311	85%	0.3%		312	86%
	EAST GEORGE ST 77	4.16	77J3	UG Cable	750 Al	371	OH Line	4/0 Al	385	180	49%	3.2%		186	50%	0.4%		187	50%	1.0%		188	51%	1.3%		191	51%	0.9%		193	52%	0.4%		193	52%	0.3%		194	52%
	EAST GEORGE ST 77	4.16	77J4	UG Cable	750 Al	364	UG Cable	750 Al	495	293	80%	3.2%		302	83%	0.4%		304	83%	1.0%		307	84%	1.3%		311	85%	0.9%		313	86%	0.4%		315	86%	0.3%		316	87%
	GENEVA 71	4.16	71J1	Regulator	250 Amp	285	Regulator	250 Amp	313	217	76%	3.2%		224	79%	0.4%		225	79%	1.0%		227	80%	1.3%		230	81%	0.9%		232	81%	0.4%		233	82%	0.3%		234	82%
	GENEVA 71	4.16	71J2	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	110	29%	3.2%		114	30%	0.4%		114	30%	1.0%		115	30%	1.3%		117	31%	0.9%		118	31%	0.4%		118	31%	0.3%		118	31%
	GENEVA 71	4.16	71J3	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	160	42%	3.2%		165	44%	0.4%		166	44%	1.0%		167	44%	1.3%		170	45%	0.9%		171	45%	0.4%		172	45%	0.3%		172	45%
	GENEVA 71	4.16	71J4	Regulator	300 Amp	342	Relay/Fuse	Safe Carry - 408A	408	214	63%	3.2%		221	65%	0.4%		222	65%	1.0%		224	65%	1.3%		227	66%	0.9%		229	67%	0.4%		230	67%	0.3%		231	67%
	GENEVA 71	4.16	71J5	Regulator	300 Amp	342	Relay/Fuse	Safe Carry - 408A	408	293	86%	3.2%		302	88%	0.4%		304	89%	1.0%		307	90%	1.3%		311	91%	0.9%		313	92%	0.4%		315	92%	0.3%		316	92%
	HARRIS AVENUE 12	4.16	12J1	Regulator	250 Amp	285	Regulator	250 Amp	313	230	81%	3.2%		237	83%	0.4%		238	84%	1.0%		241	84%	1.3%		244	86%	0.9%		246	86%	0.4%		247	87%	0.3%		248	87%
	HARRIS AVENUE 12	4.16	12J2	Regulator	333 Amp	379	Regulator	333 Amp	416	280	74%	3.2%	-35	254	67%	0.4%		255	67%	1.0%		258	68%	1.3%		261	69%	0.9%		263	69%	0.4%		264	70%	0.3%		265	70%
	HARRIS AVENUE 12	4.16	12J3	Regulator	250 Amp	285	Regulator	250 Amp	313	87	31%	3.2%		90	32%	0.4%		90	32%	1.0%		91	32%	1.3%		92	32%	0.9%		93	33%	0.4%		93	33%	0.3%		94	33%
	HARRIS AVENUE 12	4.16	12J4	Regulator	250 Amp	297	Regulator	250 Amp	326	236	79%	3.2%		244	82%	0.4%		245	82%	1.0%		247	83%	1.3%		250	84%	0.9%		252	85%	0.4%		253	85%	0.3%		254	86%
	HARRIS AVENUE 12	4.16	12J5	Regulator	250 Amp	297	Regulator	250 Amp	326	103	35%	3.2%		106	36%	0.4%		107	36%	1.0%		108	36%	1.3%		109	37%	0.9%		110	37%	0.4%		111	37%	0.3%		111	37%
	HARRIS AVENUE 12	4.16	12J6	Regulator	250 Amp	297	Regulator	250 Amp	326	158	53%	3.2%	30	193	65%	0.4%		194	65%	1.0%		196	66%	1.3%		198	67%	0.9%		200	67%	0.4%		201	68%	0.3%		201	68%
	HUNTINGTON PARK 67	4.16	67J1	Regulator	300 Amp	342	Regulator	300 Amp	326	272	80%	3.2%		281	82%	0.4%		282	82%	1.0%		285	83%	1.3%		288	84%	0.9%		291	85%	0.4%		292	85%	0.3%		293	86%
	KNIGHTSVILLE 66	4.16	66J1	UG Cable	300 Cu	248	UG Cable	300 Cu	353	281	113%	3.2%	-40	250	101%	0.4%		251	101%	1.0%		254	102%	1.3%		257	104%	0.9%		259	104%	0.4%		260	105%	0.3%		261	105%
	KNIGHTSVILLE 66	4.16	66J2	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	312	82%	3.2%		322	85%	0.4%		323	85%	1.0%		327	86%	1.3%		331	87%	0.9%		334	88%	0.4%		335	88%	0.3%		336	89%
	KNIGHTSVILLE 66	4.16	66J3	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	303	80%	3.2%	40	353	93%	0.4%		354	93%	1.0%		358	94%	1.3%		362	96%	0.9%		366	96%	0.4%		367	97%	0.3%		368	97%
	KNIGHTSVILLE 66	4.16	66J4	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	283	75%	3.2%	-40	252	67%	0.4%		253	67%	1.0%		256	67%	1.3%		259	68%	0.9%		261	69%	0.4%		262	69%	0.3%		263	69%
	KNIGHTSVILLE 66	4.16	66J5	Regulator	333 Amp	379	Relay/Fuse	Safe Carry - 408A	408	240	63%	3.2%		248	65%	0.4%		249	66%	1.0%		251	66%	1.3%		254	67%	0.9%		257	68%	0.4%		258	68%	0.3%		259	68%
	OLNEYVILLE 6	4.16	6J1	Current Transform	300 Amp	306	Current Trans	300 Amp	354	217	71%	3.2%		224	73%	0.4%		225	73%	1.0%		227	74%	1.3%		230	75%	0.9%		232	76%	0.4%		233	76%	0.3%		234	76%
	OLNEYVILLE 6	4.16	6J2	Current Transform	300 Amp	306	Current Trans	300 Amp	354	210	69%	3.2%		217	71%	0.4%		218	71%	1.0%		220	72%	1.3%		223	73%	0.9%		225	73%	0.4%		226	74%	0.3%		226	74%
	OLNEYVILLE 6	4.16	6J3	Current Transform	300 Amp	306	Current Trans	300 Amp	354	171	56%	3.2%		176	58%	0.4%		177	58%	1.0%		179	58%	1.3%		181	59%	0.9%		183	60%	0.4%		184	60%	0.3%		184	60%
	OLNEYVILLE 6	4.16	6J5	Current Transform	300 Amp	306	Current Trans	300 Amp	354	89	29%	3.2%		92	30%	0.4%		92	30%	1.0%		93	30%	1.3%		94	31%	0.9%		95	31%	0.4%		96	31%	0.3%		96	31%

Study Area	Substation	Feeder Voltage (kV)	Feeder Number	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	Emergency Limiting Element	Emergency Element Specifics	SE Rating (Amps)	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	% SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN	Growth Rate	Spot Loads	Amps	%SN
	OLNEYVILLE 6	4.16	6J6	Current Transforn	300 Amp	306	Current Trans	300 Amp	354	166	54%	3.2%		171	56%	0.4%	-50	122	40%	1.0%		123	40%	1.3%		125	41%	0.9%		126	41%	0.4%		126	41%	0.3%		127	41%
	OLNEYVILLE 6	4.16	6J7	Current Transforn	300 Amp	306	Current Trans	300 Amp	354	206	67%	3.2%		213	69%	0.4%		213	70%	1.0%		216	70%	1.3%		218	71%	0.9%		220	72%	0.4%		221	72%	0.3%		222	73%
	OLNEYVILLE 6	4.16	6J8	Current Transforn	300 Amp	306	Current Trans	300 Amp	354	43	14%	3.2%		44	15%	0.4%		45	15%	1.0%		45	15%	1.3%		46	15%	0.9%		46	15%	0.4%		46	15%	0.3%		46	15%
	ROCHAMBEAU AVENUE 37	4.16	37J1	UG Cable	500 PL	329	Relay/Fuse	Safe Carry - 408A	408	216	66%	3.2%		223	68%	0.4%		224	68%	1.0%		226	69%	1.3%		229	70%	0.9%		231	70%	0.4%		232	71%	0.3%		233	71%
	ROCHAMBEAU AVENUE 37	4.16	37J2	UG Cable	300 PL	291	UG Cable	300 PL	349	232	80%	3.2%		239	82%	0.4%		240	83%	1.0%		243	83%	1.3%		246	85%	0.9%		248	85%	0.4%		249	86%	0.3%		250	86%
	ROCHAMBEAU AVENUE 37	4.16	37J3	UG Cable	500 PL	303	Relay/Fuse	Safe Carry - 408A	408	237	78%	3.2%		245	81%	0.4%		246	81%	1.0%		248	82%	1.3%		251	83%	0.9%		254	84%	0.4%		255	84%	0.3%		255	84%
	ROCHAMBEAU AVENUE 37	4.16	37J4	UG Cable	500 PL	278	UG Cable	500 PL	371	205	74%	3.2%		212	76%	0.4%		212	76%	1.0%		215	77%	1.3%		217	78%	0.9%		219	79%	0.4%		220	79%	0.3%		221	79%
	ROCHAMBEAU AVENUE 37	4.16	37J5	UG Cable	750 Al	347	Relay/Fuse	Safe Carry - 408A	408	228	66%	3.2%		235	68%	0.4%		236	68%	1.0%		239	69%	1.3%		242	70%	0.9%		244	70%	0.4%		245	71%	0.3%		246	71%
	SPRAGUE STREET 36	4.16	36J1	UG Cable	300 PL	236	UG Cable	300 PL	283	170	72%	3.2%		175	74%	0.4%		176	75%	1.0%		178	75%	1.3%		180	76%	0.9%		182	77%	0.4%		183	77%	0.3%		183	78%
	SPRAGUE STREET 36	4.16	36J2	UG Cable	300 PL	252	UG Cable	300 PL	299	176	70%	3.2%		182	72%	0.4%		182	72%	1.0%		184	73%	1.3%		187	74%	0.9%		188	75%	0.4%		189	75%	0.3%		190	75%
	SPRAGUE STREET 36	4.16	36J4	UG Cable	500 PL	344	UG Cable	500 PL	405	230	67%	3.2%		237	69%	0.4%		238	69%	1.0%		241	70%	1.3%		244	71%	0.9%		246	72%	0.4%		247	72%	0.3%		248	72%
	SPRAGUE STREET 36	4.16	36J5	OH Line	1/0 Cu	315	OH Line	1/0 Cu	315	165	52%	3.2%		170	54%	0.4%		171	54%	1.0%		173	55%	1.3%		175	56%	0.9%		176	56%	0.4%		177	56%	0.3%		178	56%
SOUTHCOUNTY EAST																																							
	BONNET 42	12.47	42F1	Transformer	7.5/9.375 MVA	525	Transformer	7.5/9.375 MVA	566	452	86%	5.5%		477	91%	2.8%		490	93%	3.7%		508	97%	4.0%		529	101%	3.3%		546	104%	2.6%		560	107%	2.4%		574	109%
	LAFAYETTE 30	12.47	30F1	Transformer	5.0 MVA - Lafayette 1	350	OH Line	4/0 Al (OXLIP) Bare	385	331	95%	5.5%		350	100%	2.8%		359	103%	3.7%		373	106%	4.0%		388	111%	3.3%		400	114%	2.6%		411	117%	2.4%		421	120%
	LAFAYETTE 30	12.47	30F2	Regulator	333 kVA 7.2 kV - 55C	546	Relay/Fuse	578 Amp Safe Carry	578	460	84%	5.5%		485	89%	2.8%		499	91%	3.7%		517	95%	4.0%		538	99%	3.3%		556	102%	2.6%		570	104%	2.4%		584	107%
	OLD BAPTIST ROAD 46	12.47	46F1	OH Line	477 Al Spacer Cable - 15kV	530	Relay/Fuse	612 Amp Safe Carry	612	490	92%	5.5%		517	98%	2.8%		531	100%	3.7%		551	104%	4.0%		573	108%	3.3%		592	112%	2.6%		607	115%	2.4%		622	117%
	OLD BAPTIST ROAD 46	12.47	46F2	OH Line	477 Al Spacer Cable - 15kV	530	Relay/Fuse	612 Amp Safe Carry	612	503	95%	5.5%		531	100%	2.8%		546	103%	3.7%		566	107%	4.0%		589	111%	3.3%		608	115%	2.6%		624	118%	2.4%		639	121%
	OLD BAPTIST ROAD 46	12.47	46F3	UG Cable	1C 1000Cu EPR CN	565	Relay/Fuse	612 Amp Safe Carry	612	393	70%	5.5%		415	73%	2.8%		427	76%	3.7%		442	78%	4.0%		460	81%	3.3%		475	84%	2.6%		488	86%	2.4%		499	88%
	OLD BAPTIST ROAD 46	12.47	46F4	UG Cable	1C 1000Cu EPR SWS	594	Relay/Fuse	612 Amp Safe Carry	612	488	82%	5.5%		515	87%	2.8%		530	89%	3.7%		549	92%	4.0%		571	96%	3.3%		590	99%	2.6%		605	102%	2.4%		620	104%
	PEACEDALE 59	12.47	59F1	Regulator	250 kVA 7.2kV - 55C	409	Relay/Fuse	476 Amp Safe Carry	476	376	92%	5.5%		397	97%	2.8%		408	100%	3.7%		423	103%	4.0%		440	108%	3.3%		454	111%	2.6%		466	114%	2.4%		477	117%
	PEACEDALE 59	12.47	59F2	Relay/Fuse	Relay Safe Carry Phase	515	Relay/Fuse	Relay Safe Carry Phase	515	317	62%	5.5%		335	65%	2.8%		344	67%	3.7%		357	69%	4.0%		371	72%	3.3%		383	74%	2.6%		393	76%	2.4%		403	78%
	PEACEDALE 59	12.47	59F3	UG Cable	1C 750 Al XLPE CN DB	521	Relay/Fuse	578 Amp Safe Carry	578	426	82%	5.5%		449	86%	2.8%		462	89%	3.7%		479	92%	4.0%		498	96%	3.3%		515	99%	2.6%		528	101%	2.4%		541	104%
	PEACEDALE 59	12.47	59F4	Regulator	3-250 kVA 7.2kV - 55C	409	Regulator	3-250 kVA 7.2kV - 55C	489	255	62%	5.5%		269	66%	2.8%		276	68%	3.7%		286	70%	4.0%		298	73%	3.3%		308	75%	2.6%		316	77%	2.4%		323	79%
	QUONSET 83	12.47	83F1	Circuit Recloser	560A (McGraw VSA) - VIR	560	OH Line	477 Al (COSMOS) Bare	645	151	27%	5.5%		159	28%	2.8%		163	29%	3.7%		169	30%	4.0%		176	31%	3.3%		182	33%	2.6%		187	33%	2.4%		191	34%
	QUONSET 83	12.47	83F2	OH Line	477 Al Spacer Cable - 15kV	530	OH Line	477 Al Spacer Cable - 15kV	650	336	63%	5.5%		354	67%	2.8%		364	69%	3.7%		378	71%	4.0%		393	74%	3.3%		406	77%	2.6%		417	79%	2.4%		427	80%
	QUONSET 83	12.47	83F3	Circuit Recloser	560A (McGraw VSA) - VIR	560	OH Line	477 Al (COSMOS) Bare	645	157	28%	5.5%		165	30%	2.8%		170	30%	3.7%		176	31%	4.0%		183	33%	3.3%		189	34%	2.6%		194	35%	2.4%		199	36%
	WAKEFIELD 17	12.47	17F1	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	439	85%	5.5%		463	90%	2.8%		476	92%	3.7%		494	96%	4.0%		513	100%	3.3%		530	103%	2.6%		544	106%	2.4%		557	108%
	WAKEFIELD 17	12.47	17F2	Relay/Fuse	Relay Safe Carry Phase	510	Relay/Fuse	Relay Safe Carry Phase	510	251	49%	5.5%		265	52%	2.8%		272	53%	3.7%		282	55%	4.0%		294	58%	3.3%		303	59%	2.6%		311	61%	2.4%		319	62%
	WAKEFIELD 17	12.47	17F3	Transformer	7.5/9.375 MVA - Wakefield T5	597	Transformer	7.5/9.375 MVA	626	470	79%	5.5%		496	83%	2.8%		510	85%	3.7%		529	89%	4.0%		550	92%	3.3%		568	95%	2.6%		583	98%	2.4%		597	100%
	TOWER HILL 88	12.47	88F1	OH Line	477 Al Spacer Cable - 15kV	530	OH Line	477 Al Spacer Cable - 15kV	650	289	55%	5.5%		305	58%	2.8%		314	59%	3.7%		325	61%	4.0%		338	64%	3.3%		350	66%	2.6%		359	68%	2.4%		367	69%
	TOWER HILL 88	12.47	88F3	UG Cable	88F3 1C 1000 Cu EPR	548	OH Line	477 Al (COSMOS) Bare	645	310	57%	5.5%		327	60%	2.8%		337	61%	3.7%		349	64%	4.0%		363	66%	3.3%		375	68%	2.6%		385	70%	2.4%		394	72%
	TOWER HILL 88	12.47	88F5	OH Line	477 Al Spacer Cable - 15kV	530	OH Line	477 Al Spacer Cable - 15kV	650	375	71%	5.5%		395	75%	2.8%		406	77%	3.7%		421	80%	4.0%		438	83%	3.3%		453	85%	2.6%		464	88%	2.4%		476	90%
SOUTH COUNTY WEST																																							
	ASHAWAY 43	12.47	43F1	Transformer	5.0/6.25 MVA	388	Transformer	5.0/6.25 MVA	423	307	79%	5.5%		324	83%	2.8%		333	86%	3.7%		345	89%	4.0%		359	93%	3.3%		371	96%	2.6%		381	98%	2.4%		390	100%
	HOPE VALLEY 41	12.47	41F1	Transformer	5.0 MVA	347	Transformer	5.0 MVA	430	240	69%	5.5%		253	73%	2.8%		260	75%	3.7%		270	78%	4.0%		281	81%	3.3%		290	84%	2.6%		298	86%	2.4%		305	88%
	KENYON 68	12.47	68F1	UG Cable	1C 1000Al XLPE DB	512	Relay/Fuse	612 Amp Safe Carry	612	341	67%	5.5%		359	70%	2.8%		369	72%	3.7%		383	75%	4.0%		398	78%	3.3%		412	80%	2.6%		422	82%	2.4%		432	84%
	KENYON 68	12.47	68F2	UG Cable	1C 1000Al XLPE DB	511	Relay/Fuse	612 Amp Safe Carry	612	351	69%	5.5%		370	72%	2.8%		380	74%	3.7%		394	77%	4.0%		410	80%	3.3%		424	83%	2.6%		435	85%	2.4%		445	87%
	KENYON 68	12.47	68F3	UG Cable	1C 1000Al XLPE DB	512	OH Line	336.4 Al (TULIP) Bare	515	419	82%	5.5%		442	86%	2.8%		454	89%	3.7%		471	92%	4.0%		490	96%	3.3%		506	99%	2.6%		519	101%	2.4%		531	104%
	KENYON 68	12.47	68F4	UG Cable	1C 1000Al XLPE DB	514	Relay/Fuse	612 Amp Safe Carry	612	251	49%	5.5%		264	51%	2.8%		272	53%	3.7%		282	55%	4.0%		293	57%	3.3%		303	59%	2.6%		311	60%	2.4%		318	62%
	KENYON 68	12.47	68F5	Relay/Fuse	612 Amp Safe Carry	612	Relay/Fuse	612 Amp Safe Carry	612	271	44%	5.5%		286	47%	2.8%		294	48%	3.7%		305	50%	4.0%		317	52%	3.3%		327	54%	2.6%		336	55%	2.4%		344	56%
	LANGWORTHY CORNER 86	12.47	86F1	Transformer	5.6/7 MVA	382	Transformer	5.6/7 MVA	429	292	76%	5.5%		308	81%	2.8%		317	83%	3.7%		328	86%	4.0%		342	89%	3.3%		353	92%	2.6%		362	95%	2.4%		371	97%
	WESTERLY 16	12.47	16F1	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	453	88%	5.5%		478	93%	2.8%		492	95%	3.7%		510	99%	4.0%		530	103%	3.3%		548	106%	2.6%		562	109%	2.4%		575	112%
	WESTERLY 16	12.47	16F2	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	443	86%	5.5%		467	91%	2.8%		480	93%	3.7%		498	97%	4.0%		518	101%	3.3%		535	104%	2.6%		549	107%	2.4%		562	109%
	WESTERLY 16	12.47	16F3	OH Line	336.4 Al (TULIP) Bare	515	OH Line	336.4 Al (TULIP) Bare	515	365	71%	5.5%		385	75%	2.8%		396	77%	3.7%		411	80%	4.0%		427	83%	3.3%		441	86%	2.6%		452	88%	2.4%		463	90%
	WESTERLY 16	12.47	16F4	OH Line	477 Al (COSMOS) Bare	645	OH Line	477 Al (COSMOS) Bare	645	249	39%	5.5%		262	41%	2.8%		270	42%	3.7%		280	43%	4.0%		291	45%	3.3%		300	47%	2.6%		308	48%	2.4%		316	49%
TIVERTON																																							
	TIVERTON 33	12.47	33F1	UG Cable	1000 Al	478	OH line	336 Al	515	249	52%	5.5%	0	263	55%	2.8%	0	270	56%	3.7%		280	59%	4.0%		291	61%	3.3%		301	63%	2.6%		309	65%	2.4%		316	66%
	TIVERTON 33	12.47	33F2	UG Cable	1000 Al	456	OH line	336 Al	515	305	67%	5.5%	0	322	71%	2.8%	0	331	73%	3.7%		343	75%	4.0%		357	78%	3.3%		369	81%	2.6%		378	83%	2.4%		387	85%
	TIVERTON 33	12.47	33F3	UG Cable	1000 Al	478	UG Cable	1000 Al	600	302	63%	5.5%	0	319	67%	2.8%	0	328	69%	3.7%		340	71%	4.0%		353	74%	3.3%		365	76%	2.6%		374	78%	2.4%		383	80%
	TIVERTON 33	12.47	33F4	UG Cable	1000 Al	456	UG Cable	1000 Al	576	384	84%	5.5%	0	405	89%	2.8%	0	416	91%	3.7%		432	95%	4.0%		449	98%	3.3%		464	102%	2.6%		476	104%	2.4%		487	107%

	Lower range	Upper range	Definition	
Feeder Loading		1.00000000	>100%	
	0.90000000	0.99999900	90%-100%	
		0.89999990	<90%	

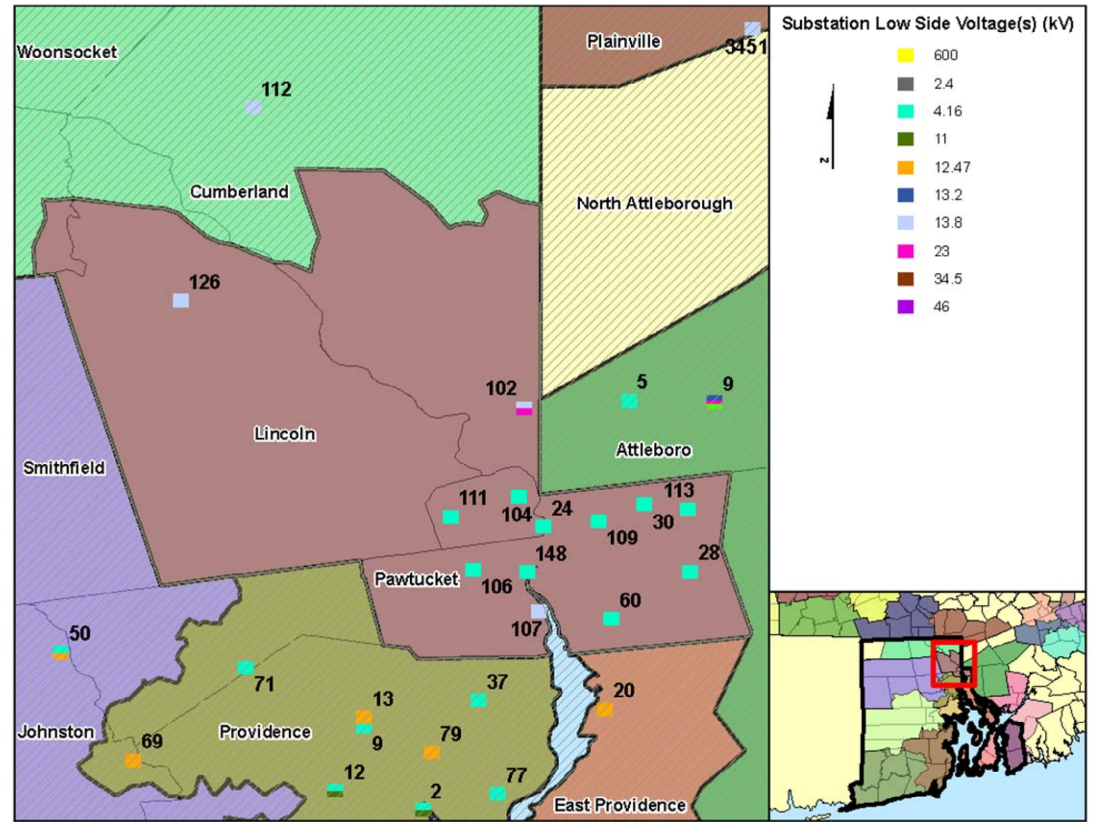
BLACKSTONE VALLEY NORTH



Major Electrical Facilities

Substations			
Nasonville 127	Riverside 108	Staples 112	West Farnum 17
Woonsocket 26	Farnum 105		

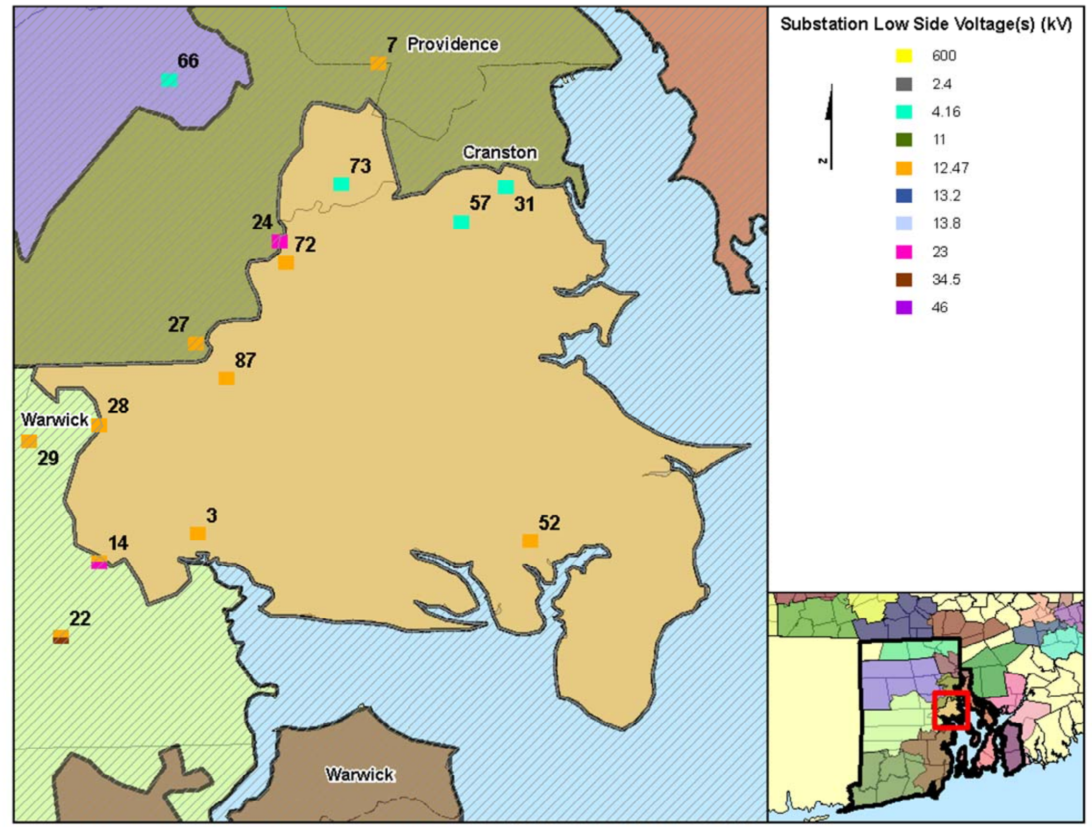
BLACKSTONE VALLEY SOUTH



Major Electrical Facilities

Substations			
Front Street #24	Valley #102	Pawtucket No. 1 #107	Daggett Avenue #113
Hyde Avenue #28	Central Falls #104	Cottage Street #109	Washington #126
Lee Street #30	Centre Street #106	Crossman Street #111	Pawtucket No.2 #148
Southeast #60			

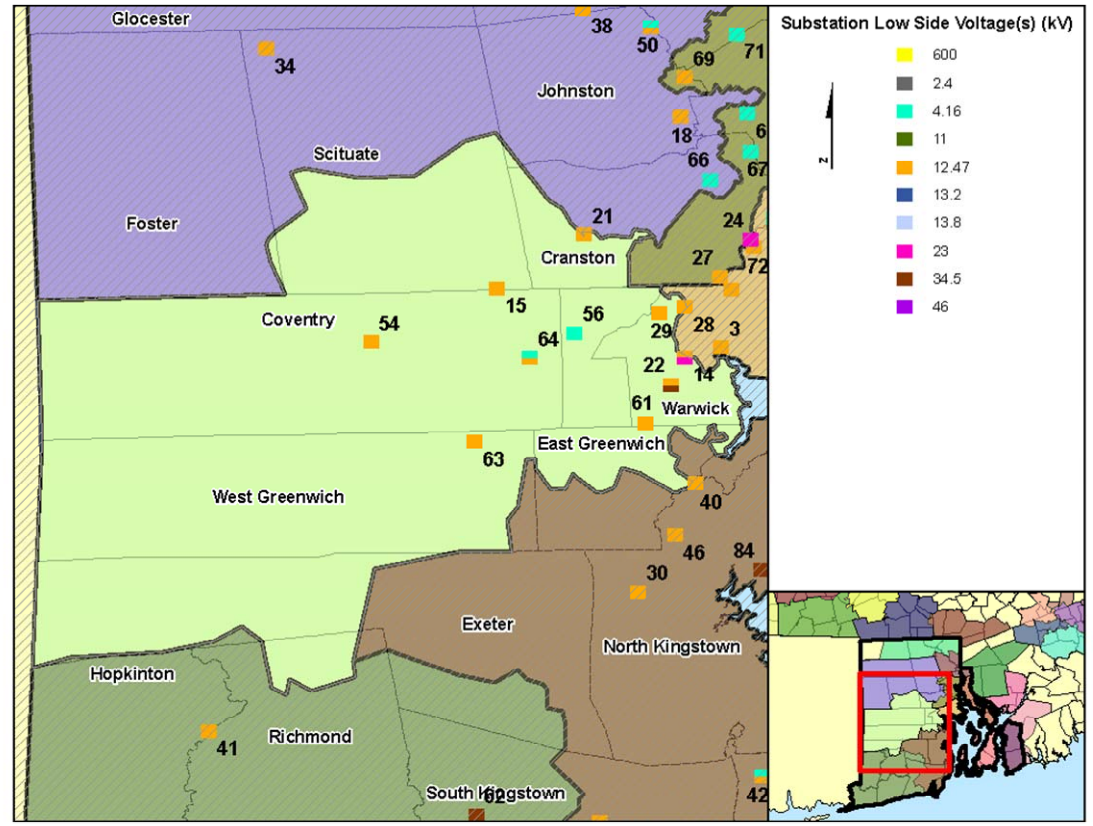
CENTRAL RI EAST



Major Electrical Facilities

Substations			
Apponaug 3	Kilvert Street 87	Lincoln Avenue 72	Pontiac 27
Warwick 52	Auburn 73	Lakewood 57	Pawtuxet 31
Drumrock 14			

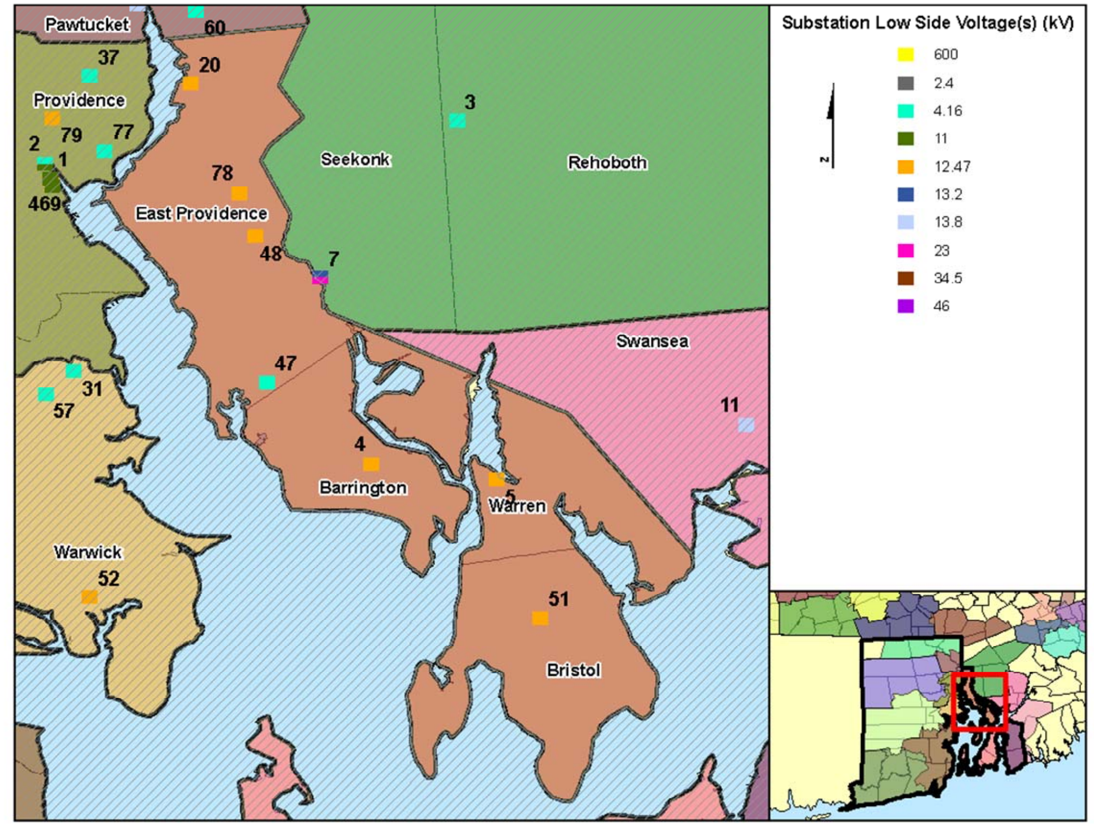
CENTRAL RI WEST



Major Electrical Facilities

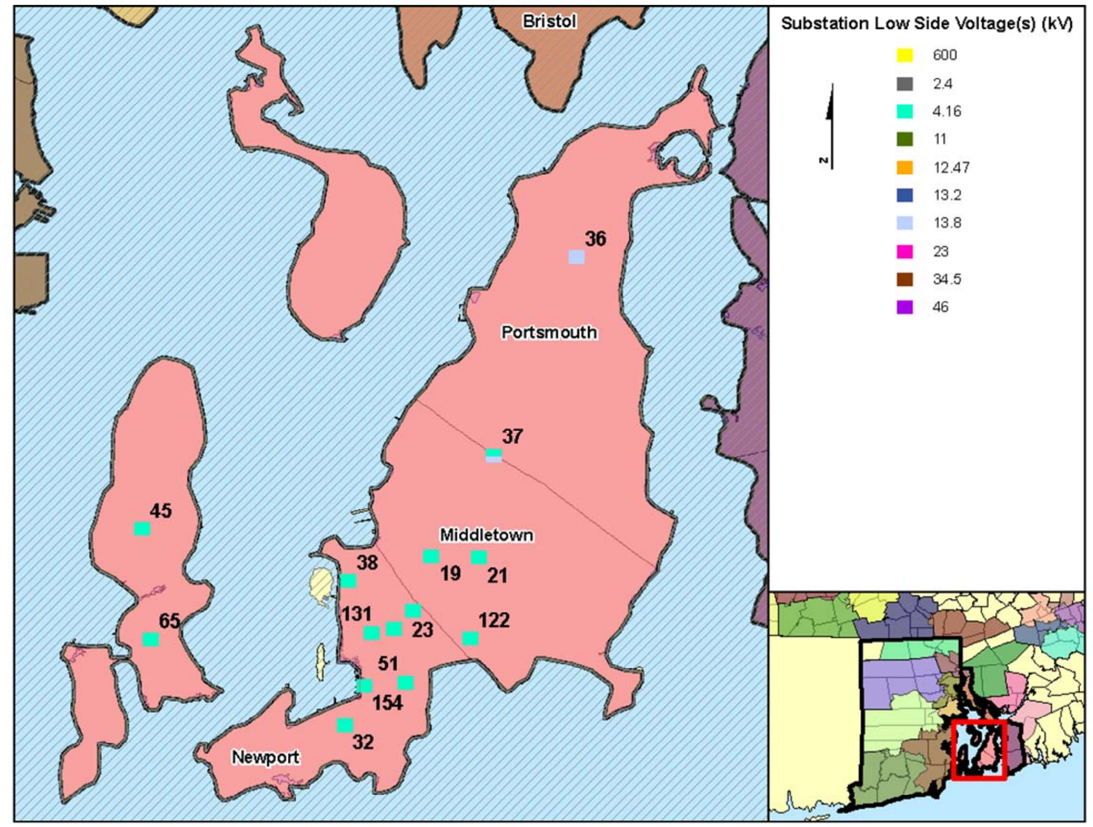
Substations			
ANTHONY 64	COVENTRY 54	DIVISION ST 61	HOPE 15
HOPKINS HILL 63	KENT COUNTY 22	NATICK 29	WARWICK MALL 28
ARCTIC 49			

EAST BAY



Major Electrical Facilities			
Substations			
BARRINGTON 4	BRISTOL 51	PHILLIPSDALE 20	WAMPANOAG 48
WARREN 5	WATERMAN AVENUE 78	KENTS CORNER 47	

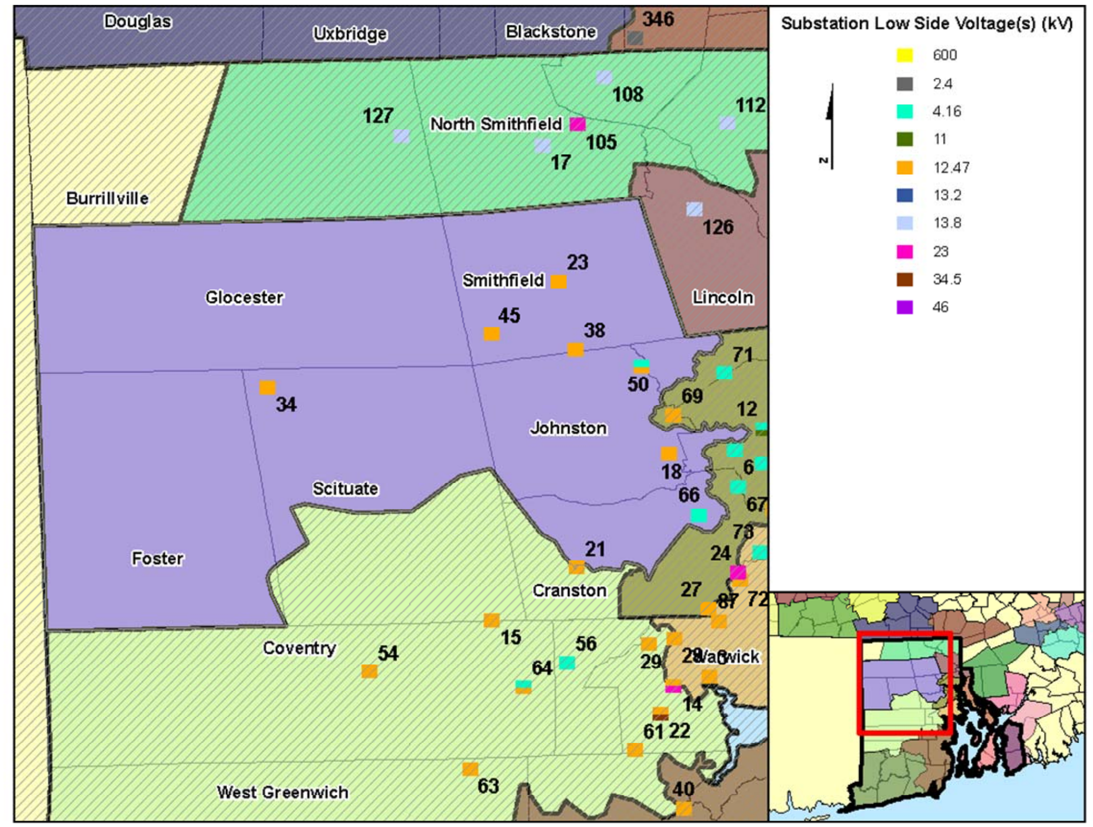
NEWPORT



Major Electrical Facilities

Substations			
Bailey Brook #19	Dexter #36	Merton #51	Kingston #131
North Aquidneck #21	Jepson #37	Clarke #65	Hospital #146
Vernon #23	Gate II #38	South Aquidneck #122	West Howard #154
Harrison #32	Eldred #45		

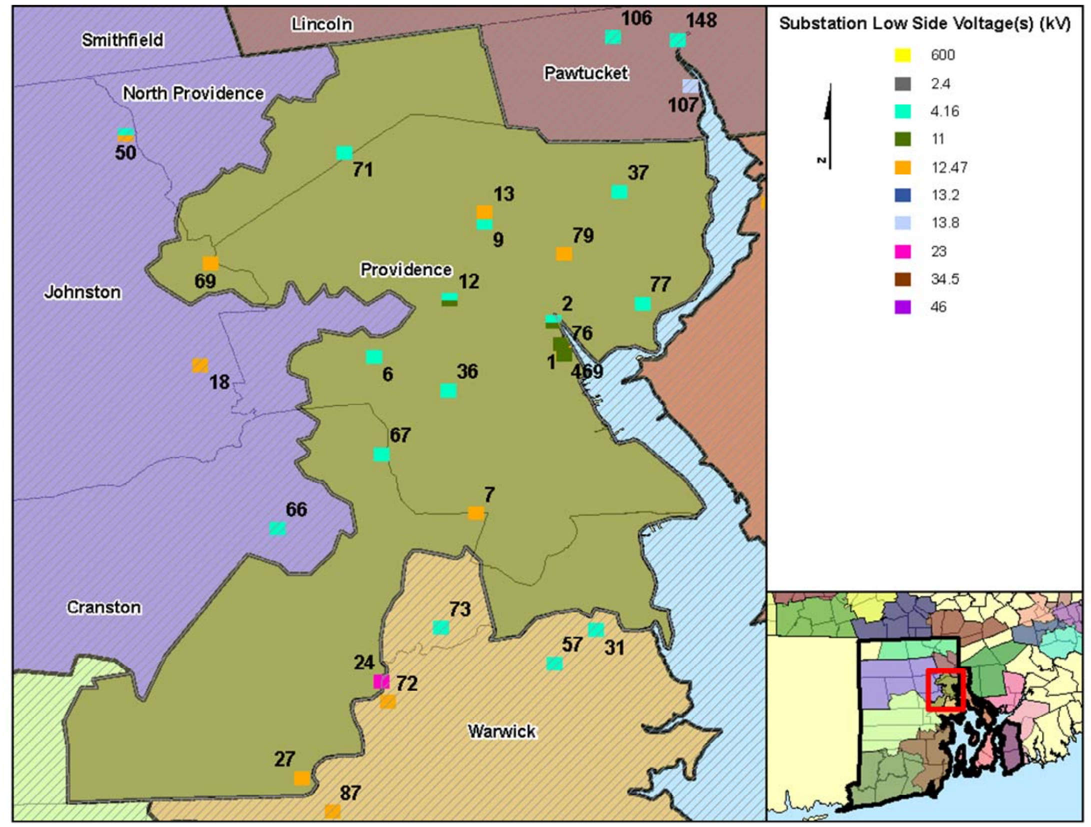
NORTH CENTRAL RI



Major Electrical Facilities

Substations			
Johnston #18	Farnum Pike #23	Putnam Pike #38	Centredale #50
Wolf Hill #19	Chopmist #34	West Greenville #45	Manton #69
West Cranston #21			

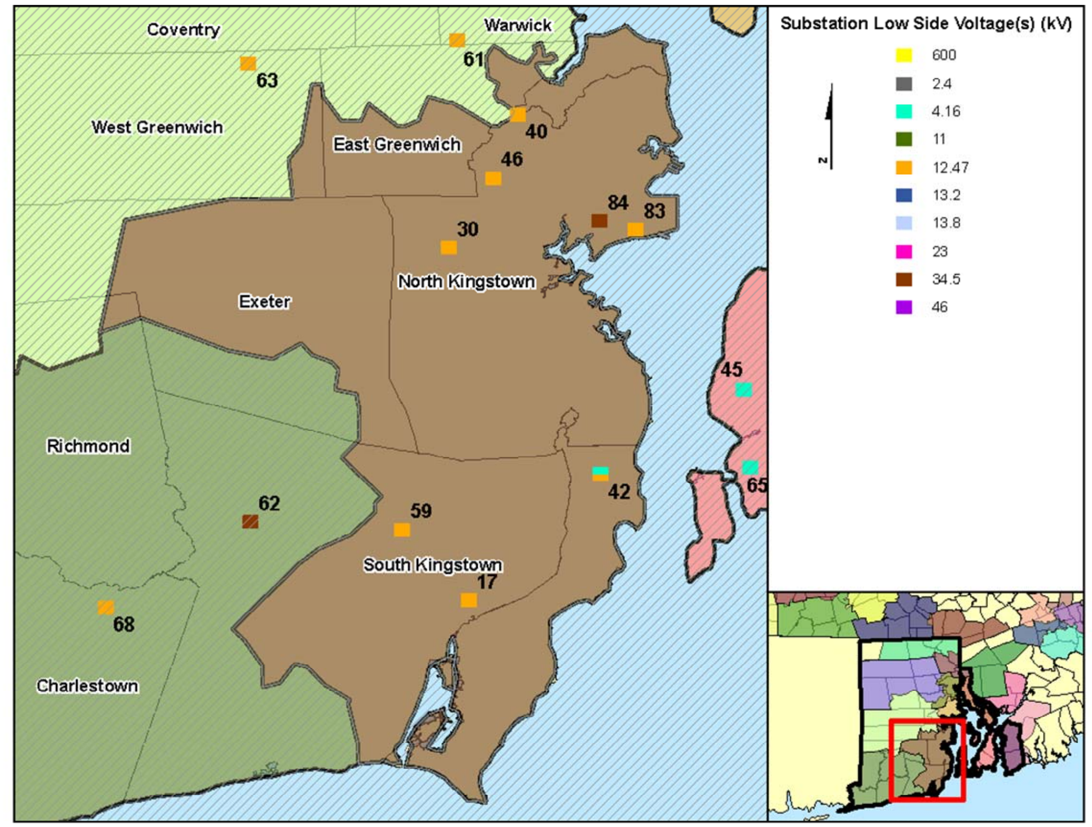
PROVIDENCE



Major Electrical Facilities

Substations			
South Street #1	Admiral Street #9	Sprague Street #36	Geneva #71
Dyer St #2	Franklin Square #11	Rochambeau Ave #37	Point Street #76
Olneyville #6	Harris Ave #12	Knightsville #66	East George #77
Elmwood #7	Clarkson Street #13	Rochambeau Ave. #67	Lippitt Hill #79

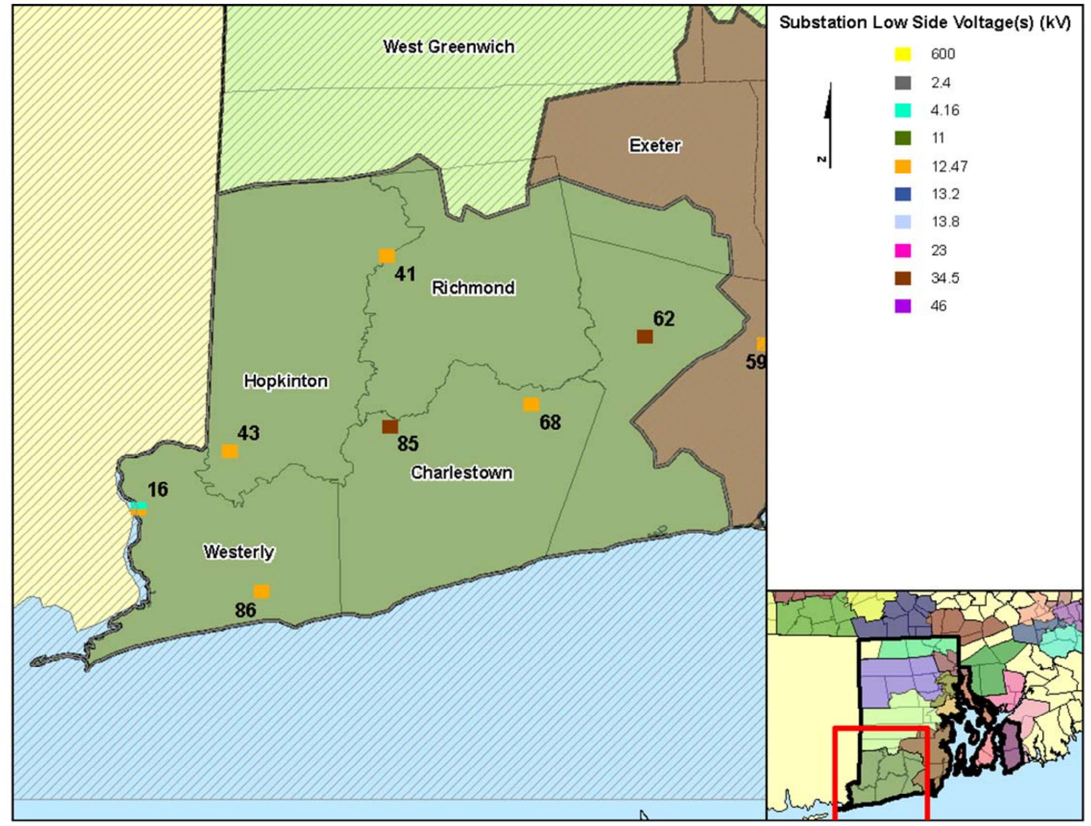
SOUTH COUNTY EAST



Major Electrical Facilities

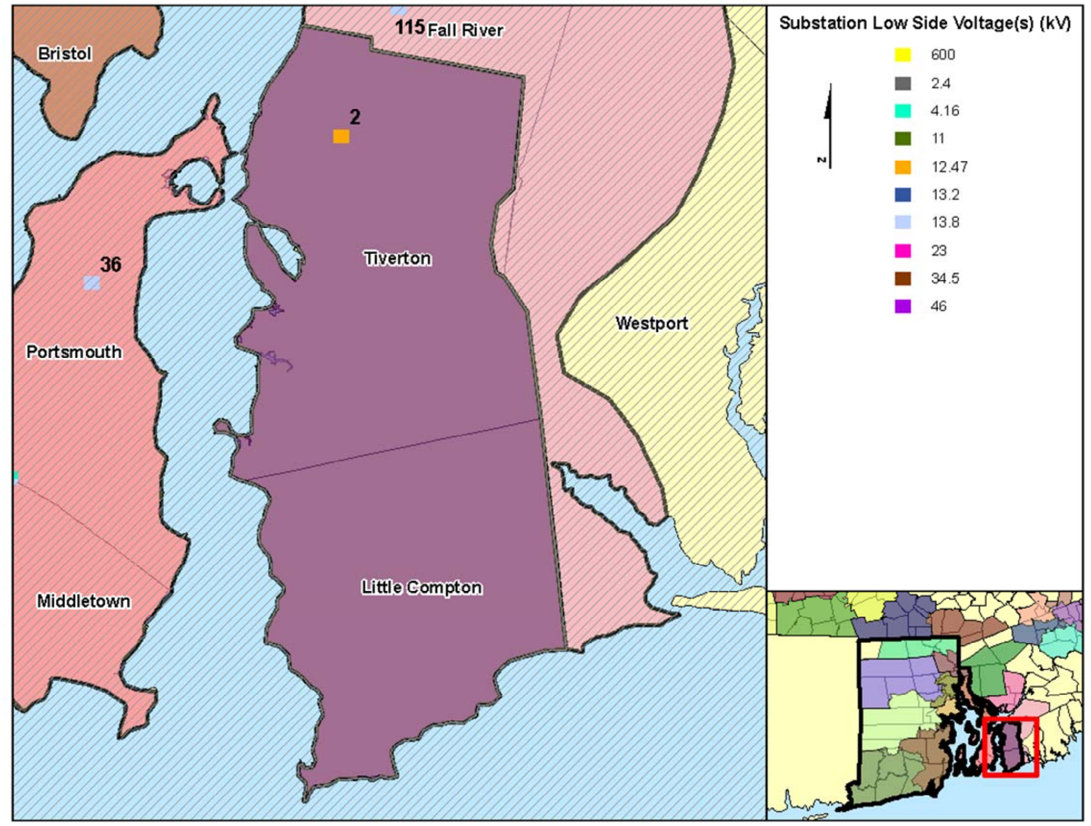
Substations			
BONNET 42	DAVISVILLE 84	LAFAYETTE 30	OLD BAPTIST ROAD 46
PEACEDALE 59	QUONSET 83	WAKEFIELD 17	WEST KINGSTON 62
TOWER HILL 88			

SOUTH COUNTY WEST



Major Electrical Facilities			
Substations			
ASHAWAY 43	HOPE VALLEY 41	KENYON 68	LANGWORTHY 86
WESTERLY 16	WOOD RIVER 85		

TIVERTON



Major Electrical Facilities			
Substations			
Tiverton #33			

Division Data Request 14-3

Request:

What standards does the company use to determine a voltage violation, meaning a voltage level on the primary electric distribution system that is lower than is acceptable to the company and its customers?

Response:

The Division of Public Utilities and Carriers maintains current rules prescribing standards for electric utilities. Standards, rules and regulations were first published on May 11, 1956 by the Public Utility Administrator in accordance with Section 42, Chapter 122 of the General Laws of Rhode Island with Amendments and other sections and chapters as may apply.

The most recent update to these rules and regulations were published on September 21, 2004 and posted on the RIPUC website. The rules and regulations include a table with established standard service voltages and also show both minimum and maximum acceptable service voltages. When voltages in use by National Grid are not included in table in the above referenced document, ANSI C84.1-1989 is used as a guide in determining acceptable service voltages.

The section of the rules related to service voltage is shown below.

B. Service Voltage - The following service voltage standards shall be maintained at the point where the electrical system of the supplier and the electrical system of the user are connected.

Table I [These values are ANSI C84.1 (1989). Values shall change if ANSI adopts new standards.]

Established Standard Service Voltage	Minimum Voltage	Maximum Voltage	Type of Service
120	114	126	Single Phase
120/240	114/228	126/252	Single or Polyphase
208Y/120	197Y/114	218Y/126	Single or Polyphase
240	228	252	Single or Polyphase
480Y/277	456Y/263	504Y/291	Single or Polyphase
480	456	504	Single or Polyphase
600	570	630	Single or Polyphase
2400	2340	2520	Single or Polyphase
4160Y/2400	4050Y/2340	4370Y/2520	Single or Polyphase
12470Y/7200	12160Y/7020	13090Y/7560	Single or Polyphase

For distances exceeding a 2-mile radius from any distribution sub-station serving the customer, the minimum permissible voltage shall not be less than 97% of the minimum values shown in Table I.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-4

Request:

What standard does the company use to establish what they believe is a thermal loading violation or problem that needs to be rectified on its system? This means what percentage of loading of a conductor is acceptable during the summer and what percentage of loading of a conductor is acceptable during the winter for each electric distribution conductor size used by National Grid in Rhode Island.

Response:

A distribution circuit (feeder) consists of a number of series elements. For each element, the Company assigns a normal rating based on factors such as ambient temperature; wind speed; earth temperature; pre-loading of the equipment, etc. The lowest rated element is identified as the limiting element of the circuit.

The standard that the Company uses to establish a thermal loading violation that needs to be rectified is when the projected peak loading of the limiting element on a distribution feeder exceeds 100% of its normal rating.

Division Data Request 14-5

Request:

Does National Grid perform a dissolved gas analysis on all power transformers on an annual basis or on some other systematic rotation? If the answer to this question is yes, provide a detailed description of how the information gathered from the dissolved gas analysis is utilized in determining potential power transformer replacement.

Response:

Please refer to Substation Maintenance Standard SMS 400.10.8 Dissolved Gas Analysis – Transformers, provided as Attachment DIV 14-5 for requested information. DGA test results are used as part of the overall health condition assessment of power transformers and not the sole criteria.

Prepared by or under the supervision of: John Pettigrew

nationalgrid	SUBSTATION MAINTENANCE STANDARD	**SMS 430.10.8** **Version 1.0** **Date 10/14/2008** **Page 1 of 4**

DISSOLVED GAS ANALYSIS - TRANSFORMERS

INTRODUCTION

National Grid USA uses Dissolved Gas Analysis (DGA) as one of the criteria to determine the asset condition of power transformers.

Transformers and transformer banks rated 2.5MVA, or above are sampled for dissolved gases at defined intervals based on MVA rating and voltage class. The intervals are specified in the Transformer Maintenance Standards.

If transformers are equipped with Load Tap Changers (LTC's), the LTC tank is also sampled. LTC sampling intervals are based on time and LTC manufacturer's type. These intervals are specified in the Load Tap Changer Maintenance Standard.

Mobile equipment is also sampled at defined intervals based on in service or out of service, time, and MVA rating. Intervals are specified in the Mobile Substations and Portable Transformers Maintenance Standard.

REFERENCE

Environmental Procedure EP-14 – Oil Filled Electrical Equipment Management

SMS 400.04.1 – Priority Based Maintenance System (PBM)

SMS 402.01.1—Transformer 15MVA and Above Maintenance Standard

SMS 402.02.1 – Transformer 2.5 To 14.9 Maintenance Standard

SMS 412.01.1– Load Tap Changer (LTC) Maintenance Standard

SMS 418.01.1– Mobile Substation and Portable Transformer Maintenance Standard

SMP 430.10.4 –Transformer Oil Sampling Procedure

SMS 430.10.7 –Transformer Dissolved-Gas-In-Oil Limits Maintenance Standard

PROCEDURE

DGA samples are prioritized by critical number in the Priority Based Maintenance System (PBM).

The Asset Information Maintenance Management System (AIMMS) creates equipment specific DGA sampling work orders.

These work orders are assigned to field Substation Operations and Maintenance (O&M) crews to sample specific transformers and transformer load tap changers.

Samples are sent, by the field O&M offices, to National Grid USA approved oil laboratories for dissolved gas analysis.

Dissolved gas analysis laboratory reports are sent to Substation O&M Services where results are reviewed by a Substation O&M Services Maintenance Engineer and entered into the AIMMS system.

Acceptable dissolved gas levels are determined by the evaluation done by a maintenance engineer. These determinations are based on IEEE, Duval, Roger's Ratio, Cigre and other criteria.

If analysis and review of a sample indicates increased/abnormal gas levels or ratios, the reviewing engineer will make a determination of any action to be taken.

Actions taken may include re-sample to verify results, an increase or decrease the sample frequency, or removal of the unit from service for additional evaluation, or replacement.

On a quarterly basis, DGA results from AIMMS are entered into a DGA Scoring System. The DGA Scoring System was developed at National Grid UK, more than six years ago, by John Lapworth.

An algorithm is used to calculate the individual score for each unit. This algorithm focuses on combustible gases and uses ratios of gases to provide an individual score for each unit.

The algorithm is presently optimized for UK transformers (conservator, free breathing) and set so a score below 60 is good, and a score above 150 is a serious alert. When applied to US transformers, which are generally sealed, higher values are expected. Currently a score of 100 or above warrants further investigation.

After the results are entered into the DGA Scoring System, Substation O&M Service Engineers meet to discuss and review the list focusing on units which have the highest values. During this meeting, action plans are developed for units of concern.

Action plans may include re-sampling to verify results, an increase or decrease the sample frequency, or removal of the unit from service for additional evaluation, or replacement.

The results of the review are also used as an input into the transformer asset replacement program for the Transmission and Distribution system.

OIL DEGASIFICATION AND OIL REPLACEMENT

Oil found with greater than 500 ppm PCB content should be replaced for oil reclassification purposes and oil greater than 50 but less than 500 ppm should be considered for replacement. (See Environmental Procedure EP-14).

Transformers or load tap changers that have experienced internal faults (example: bushing failures, lead failures, DETC contact problems or LTC problems) that were successfully repaired shall undergo oil degasification or oil replacement to establish a new baseline for dissolved gas analysis. Based on system operating needs (customer outages, reliability requirements, system configuration) oil degasification or oil replacement should be scheduled as soon as practicable after repair.

Transformers internally inspected as a result of DGA analysis will be reviewed and a determination made by Substation O&M Services whether oil requires degasification or replacement. This determination will be based on combustible gas levels, and/or the need for further trend analysis.

AIMMS transformer and load tap changer records must be promptly updated to document when oil has been degasified or replaced. The maintenance engineer shall note this in the DGA and Screen notes field for first samples done after oil replacement or degasification.

1. Record of Revisions

Revision	Changes
10/14/2008	New Standard

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Division Data Request 14-6

Request:

What transformer loading standards does National Grid utilize for its power transformers and how did it develop those standards, this meaning what is the generally accepted maximum level National Grid will load a power transformer, what is the maximum level that National Grid will load a transformer for four hours during peak, and what is the level of loss of life of power transformer National Grid will accept as a result of short time overloads.

Request:

National Grid utilizes the EPRI PTLoad 6.1.1 program to determine power transformer peak loading criteria using factory test reports on new transformers and upon requests of System Electric Planning. The program determines normal, short term, and long-term emergency ratings. National Grid power transformer loading standards are not restricted by loss of life factors. The Company uses temperature calculations with operating requirements not to exceed 140º C for hot spot winding temperature and 110º C for top oil temperature. Please see Attachment 14-6 for a copy of the Company's transformer loading guide.

Prepared by or under the supervision of: John Pettigrew

nationalgrid	SUBSTATION MAINTENANCE STANDARD	**SMS 402.40.1** **Version 1.0** **Date 06/11/2007** **Page 1 of 4**

TRANSFORMER LOADING GUIDE

INTRODUCTION

This document provides transformer load ratings for normal and emergency operation of substation power transformers that have 55ºC or 65ºC temperature rise ratings. For load ratings for other transformers contact O&M Substation Services.

The ratings in this document are generic and to be used as a guide.

If operation is required above these generic ratings a review of the specific transformer's ratings and asset condition is required.

All pumps, fans, winding and oil temperature gauges, and coolers, must be fully functional to use the ratings in this document.

For transformers having any secondary winding of 69kV, or greater, refer to Loading Criteria For Transmission Transformers dated June 2006 and authored by Dean Latulipe.

RESPONSIBILITIES

1. **Division Substation Operations Responsibilities**
   - 1.1 Proper operation of transformer alarms
   - 1.2 Proper operation of fans, pumps, and other transformer cooling components.
     - 1) This includes:
       - a) Winding temperature and liquid temperature gauges.
       - b) Fans, pumps, coolers and their controls.
       - c) Cooling control settings (Manual/Auto, operation of cooling stages).
   - 1.3 Correct Oil Levels in main and conservator tanks, and load tap changer (LTC).
   - 1.4 Timely response to transformer alarms, including notification, and monitoring if required.
   - 1.5 Notification to National Grid Substation O&M Services and System Control of:
     - 1) Top Oil Temperature, Maximum Hot Spot Winding Temperature alarms.
       - a) Document all Transformer High Temperature Alarms on SMP 402.05.3 - Transformer High Temperature Alarm Report and forwarded to Substation O&M Services.
   - 1.6 Monitoring or increasing of alarm points if temperature alarms points are exceeded.
   - 1.7 Returning alarm points to normal settings if they are changed.

1.8 Follow-up of infrared inspections of transformers identified with possible:
   1) Blocked radiators or fins
   2) Incorrect oil levels.
   3) LTC tank temperature hotter than main tank temperature.

2. <u>National Grid Substation O&M Services</u>

2.1 Technical support to Division Substation Operations if limits in this Standard need to be exceeded.
2.2 Dissolved Gas Analysis Review.
2.3 Calculation of Individual Transformer Ratings for transformers with secondary voltage less than 69kV. Example: 115kV to 23kV.
   1) Transmission Planning provides ratings for transmission transformers with secondary voltages of 69kV and above.
2.4 Review of asset condition of transformers whose ratings may be exceeded during peak periods.
2.5 Selecting cooling options if additional cooling of a transformer is required.
2.6 Provide increased transformer temperature set points for emergency use.

3. <u>National Grid System Planning</u>

3.1 Identification of transformers whose ratings may be exceeded during peak periods.
3.2 Blocking of Auto Transfer schemes, if required.
3.3 System reconfiguration to address transformers ratings that may be exceeded.

4. <u>System Control</u>

4.1 Notification to Division Substation Operations or Power Delivery of transformer alarms and loading issues.
4.2 System reconfiguration to address transformers where ratings may be exceeded.
4.3 Monitor transformer temperatures where remote temperature monitoring is available.

5. <u>Requirements if Operating Above Normal Alarm Points</u>

5.1 If the transformer is to be operated at temperatures above the Normal ratings in the Oil and Winding temperature Limits Table one of the following must be complied with.
   1) Hourly monitoring of the transformer by standby personnel to:
      a) Insure limits in the Oil and Winding Temperature Limits Table, or those agreed to with Substation O&M Services, are not exceeded.
      b) All fans, pumps and gauges continue to operate properly.
      c) Record all available transformer ampere readings, temperatures, oil levels, and ambient (outside) temperatures hourly for use in future planning. Send to Substation O&M Services.
   2) Increase temperature alarm set points to temperatures agreed to by Substation O&M Services.
      a) Easily done on transformers with electronic temperature alarms by reprogramming.
      b) Some gauge/micro-switch alarms may have unused micro-switches that could be set in advance, and the alarm wires switched in the cabinet, when required.

DEFINITIONS

Emergency –	The maximum equipment rating, for a specific period of time without excessive Loss of Life. Ratings are affected by peak load cycle and ambient temperature cycles. In emergencies equipment will typically be allowed to run hotter for short time periods. Loss of Life can be greater during emergency conditions than during normal conditions since emergency loading will be infrequent.
Generic –	A rating used on a class or type of equipment when load is not close to the equipment rating and individual rating does not need to be determined.
Hot Spot Temperature –	The temperature at the hottest spot in the transformer winding.
Individual –	Ratings that are calculated for specific situations for a specific piece of equipment. Transformer ratings can be based on asset condition, specific test report data, load, and ambient temperature cycles.
Long Term Emergency – New England	Emergency loading that exceeds 12 hours in summer and 4 hours in winter
Long Term Emergency – New York	Emergency loading that exceeds 4 hours in summer or winter.
Loss of Life –	A calculated value used to estimate transformer life based on an expected normal life span. It is not an actual loss of life. Operation at elevated temperatures results in loss of life. Life at other than rated temperature is calculated using the equations for transformer insulation life expectancy.
Normal –	A maximum rating for daily operation without excessive Loss of Life.
Short Term Emergency –	Emergency loading type with a duration of less than 15 minutes.
Ratings –	All ratings shall be stated in amperes (A) or in apparent power (MVA), not in real power (MW).
Top Oil Temperature –	The temperature of the oil at the top of the tank.

OIL AND WINDING TEMPERATURE LIMITS

Loading Type	Duration	55 ºC Rise Transformers		65 ºC Rise Transformers	
		Maximum Top Oil Temperature (ºC)	Maximum Winding Temperature (ºC)	Maximum Top Oil Temperature (ºC)	Maximum Winding Temperature (ºC)
Normal	Continuous	95	105	105	120
Long Term Emergency	Summer – 12 hours (NE) Winter – 4 hours (NE) Summer/Winter 4 hours (NY)	100	140	110	140
Short Term Emergency	15 minutes NE and NY	100	150	110	150

For transformers having any secondary winding of 69kV, or greater, refer to Loading Criteria For Transmission Transformers dated June 2006 and authored by Dean Latulipe.

BACKGROUND

Substation power transformers thermal ratings are based on the Top Oil Temperature, Maximum Hot Spot Winding Temperature, and calculated value of percent Loss of Life (LOL).

LOL is a prediction of winding insulation life. It is a function of the Maximum Hot spot Winding Temperature, and the time duration of operation at that temperature. Loss of Life is a calculated prediction, not loss of actual transformer life.

Gassing may occur in the insulation and oil at winding hot spots above 140°C.

Exceeding maximum Top Oil and Hot Spot Winding temperatures will reduce transformer life.

If Top Oil Temperatures exceed 105 °C there is a possibility that expansion will cause the oil volume to exceed capacity of the main tank. This will cause the pressure relief device to operate and loss of oil.

Reliable operation of the transformer for its intended life is dependent on proper control of top oil temperature and winding temperatures.

Record of Revisions

Revision	Changes
06/11/2007	New Standard

Division Data Request 14-7

Request:

What standards does National Grid utilize for loading distribution transformers, that is to say what percentage of the nameplate rating of a distribution transformer is considered an acceptable loading level by National Grid and how did it develop this standard?

Response:

National Grid uses its internal Construction Standards for loading distribution transformers. ANSI/IEEE C57.91 and C57.92 "Guidelines for Loading Mineral Oil Immersed Transformers" along with recent IEEE Papers were used to determine maximum loading for single and three-phase transformers. National Grid's criteria for loading of different types of distribution transformers under different types of customer loads are noted below.

OVERHEAD DISTRIBUTION TRANSFORMERS

Serving Residential Customer Loads

Residential customers have one of three basic load profiles:

1. Oil or Gas Heat – 8kW diversified per residence (includes electric range, dryer, and window air conditioner units)
2. Oil or Gas Heat w/ Central Air – 10kW per residence
3. Electric Heat – 20kW per residence

The following table provides a guide to determine the maximum number of residential customers that can be served on a secondary crib by a single overhead distribution transformer. The table assumes multi-family homes or single-family homes smaller than 3,500 square feet.

Maximum Number of Residential Customers				
Transformer KVA Size	**Oil or Gas Heat**	**Oil or Gas Heat w/ Central Air**	**Electric Heat**	**50% Electric Heat 50% Oil/Gas Heat**
25 KVA	9	5	2	3
50 KVA	12	8	5	6

Commercial and Industrial Customer Loads

The loading of overhead distribution transformers serving commercial and industrial customers should not exceed 100% of the transformer nameplate rating where the customer's daily load factor is 100% and summer ambient temperature is 30°C/86°F or winter ambient temperature is 0°C/32°F. However, transformer loading may be increased 0.3% for each 1% decrease in the customer's load factor to a maximum of 115% of the transformer nameplate

Division Data Request 14-7 (cont.)

rating at 50% customer load factor. In addition, if peak loads occur at ambient temperatures other than 30°C/86°F or 0°C/32°F, loading may be increased 1% for each 1°C/1.8°F decrease or decreased 2% for each 1°C/1.8°F increase in ambient temperature.

UNDERGROUND DISTRIBUTION TRANSFORMERS

Single Phase Customer Loads

Based on load research data for actual customer loading, single-phase transformers are pre-loaded to approximately 40-60% and the peak load duration is about 2 hours. For ambient temperatures in summer of 95°F and 32°F in the winter, the respective peak load limits of 140% and 160% of the transformer nameplate rating are used.

Three Phase Customer Loads

Loading limits are based on not exceeding a maximum hot spot transformer winding temperature of 140°C. This corresponds to a top oil temperature of approximately 110°C, which is safely below the flash point of mineral oil. Based on these temperature limits, an 8-hour overload cycle and a pre-existing transformer load of 100% of the transformer nameplate rating, peak load limits of 120% of nameplate in the summer and 140% of nameplate in the winter are used.

Division Data Request 14-8

Request:

Does National Grid have a conductor loading table and has National Grid performed an economic conductor study?

Request:

National Grid's Overhead Construction Standards contain maximum electrical current ratings for its standard primary conductors. These ratings are published for normal and emergency operating conditions for summer and winter weather conditions. Conductors are selected for specific line projects to meet present and anticipated future summer and winter peak loading conditions under normal operating conditions and any anticipated abnormal or emergency operating conditions.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-11

Request:

Provide a copy of each of the last five years of annual reliability reports and asset management reports provided to the division and its consultant, Gregory L. Booth, PE, as required as part of the reliability assessment process. Provide the name and business address for the individual in the company that is most knowledgeable and has for most of the last five years been responsible for leading the reliability initiative for National Grid, including potentially chairing national organizations such as IEEE subcommittees.

Response:

The annual reporting requirements of reliability assessment process defined by the Division and recommended by Gregory L. Booth, PE, have changed over the course of the last five years. The annual reports and the documents that define the reporting requirements are contained in Attachments DIV 14-11-1 through DIV 14-11-8 to this response.

The requirements for the report filed in 2009 were defined by the Division and Gregory L. Booth, PE in a letter dated September 26, 2008, as contained in Attachment 14-11-1. The annual report filed by National Grid on June 30, 2009 is contained in Attachment 14-11-2.

The requirements for the reports filed in 2008, 2007 and 2006 were defined by Gregory L. Booth, PE in the Conclusions of the Final Assessment Report of Narragansett Electric Company, dated March 31, 2006. The conclusions of this report are contained in Attachment 14-11-3. The annual reports subsequently filed by National Grid in 2008, 2007, and 2006 are contained in Attachments 14-11-4, 14-11-5, and 14-11-6, respectively.

Prior to 2006, the requirements for reliability assessment reports were defined by the Division and Gregory L. Booth, PE in March of 2003, as contained in Attachment 14-11-7. This reliability assessment process involved a number of different action items and reports. An annual report that was filed by National Grid in 2005 regarding Contingency Analysis is contained in Attachment 14-11-8.

The name and business address of the person currently responsible for leading the reliability initiative for National Grid is

Bruce Walker
VP Asset Strategy & Policy
National Grid
40 Sylvan Road
Waltham, MA 02451

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-12

Request:

Provide a copy of the latest asset management plan and feeder health ranking by feeder for all feeders, including the detail for establishing the feeder health ranking.

Request:

Please see Attachment DIV 14-12-1 for National Grid's current Asset Management Policy. This document outlines the overall National Grid philosophy and approach using strategic inputs to asset management. The policy was initially approved in January 2008 and revised in June 2008. The Asset Management Policy was updated as follows:

- Updated Section 3 (AM objectives) to align with updated Organization Strategic Plan objectives
- Updated Section 4 (AM Plans) to conform with new terminology
- Replaced DOC with DCIG in Sections 6 and 8
- Edited department names based on new organizational structure

Please see Attachment 14-12-2 for a ranked list of feeders by SAIFI for calendar years 2004 through 2008. This is the same criteria that National Grid uses to generate the quarterly reports that it files with the PUC with an expanded time-scale, i.e., yearly instead of quarterly.

This is just one method to rank feeders for possible reliability projects. National Grid also uses the Engineering Reliability Review process and the Feeder Hardening Program to identify and perform reliability focused reviews and construction.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-13

Request:

As part of providing the feeder health ranking for all feeders on the National Grid system in Rhode Island, include the SAIDI and CAIDI statistics for each of these feeders for each of the last five years.

Response:

Please refer to the Company's response DIV 14-12 for SAIDI and CAIDI statistics. These two data fields have been added to the feeder health ranking by SAIFI.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-14

Request:

Provide a copy for 2001 through 2008, the IEEE 1366-2003 comparisons for SAIDI, CAIDI, SAIFI, MAIFI and CADI and other reliability indices as part of National Grid's participation in the subcommittee which produces this statistical information. Provide for each category, chart, and data the identification of National Grid as it compares to all of the other participates (utility companies).

Response:

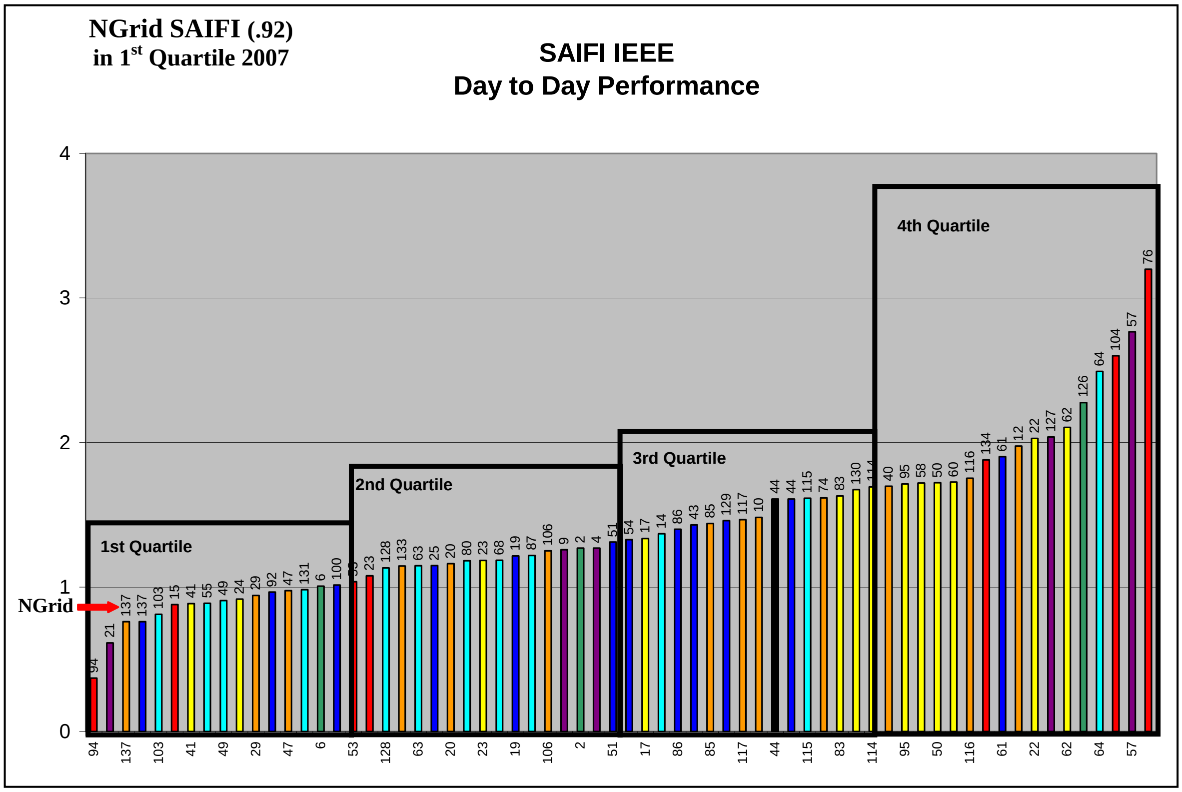
National Grid participates in the annual IEEE 1366-2003 Benchmarking Survey conducted by the IEEE Working Group on Distribution Reliability. This published survey does not list the participating utilities by name. Survey results prior to 2004 were not available in graphical form.

The most recent IEEE 1366-2003 survey results that are available include data for the year, 2007. In this survey, National Grid's SAIFI, SAIDI, and CAIDI statistics fell within the first quartile, as shown in charts 1, 2, and 3 below. These statistics exclude major storms.

Prepared by or under the supervision of: John Pettigrew

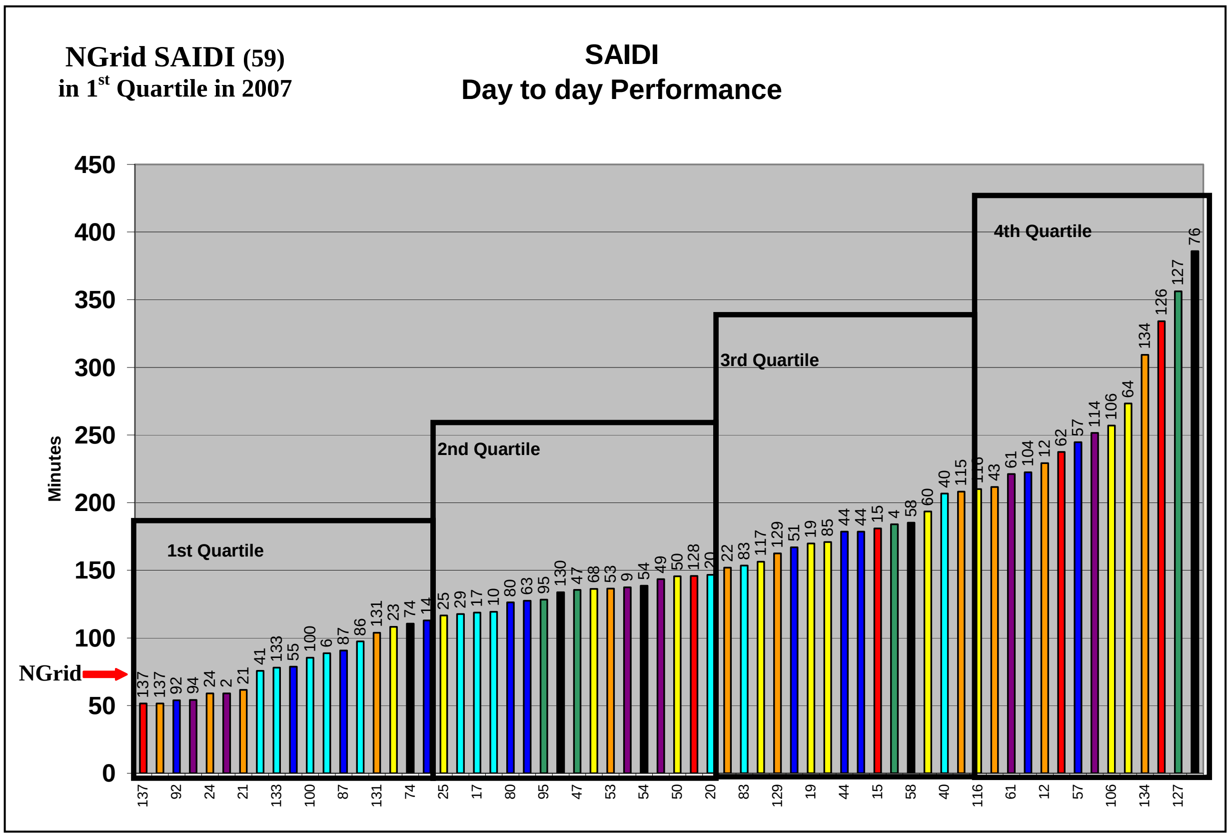
Division Data Request 14-14 (cont.)

Chart 1



Division Data Request 14-14 (cont.)

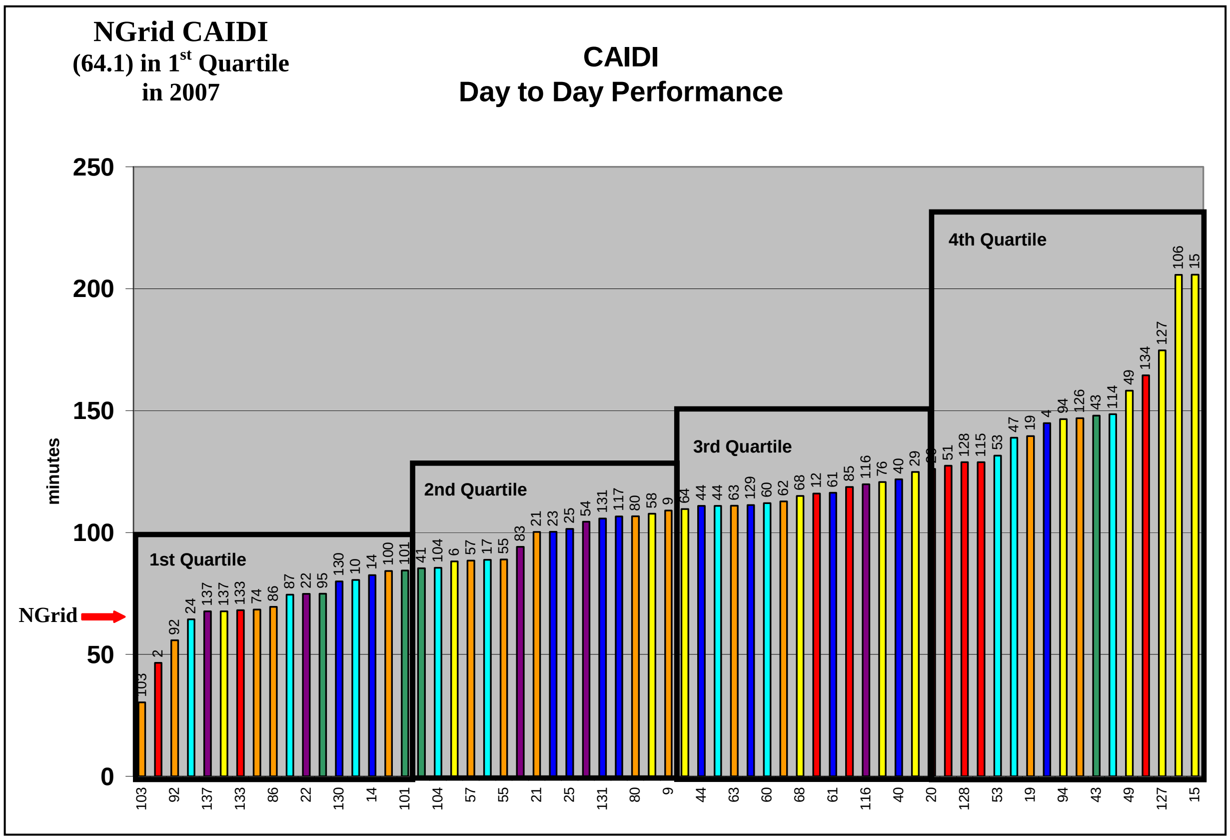
Chart 2



Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-14 (cont.)

Chart 3

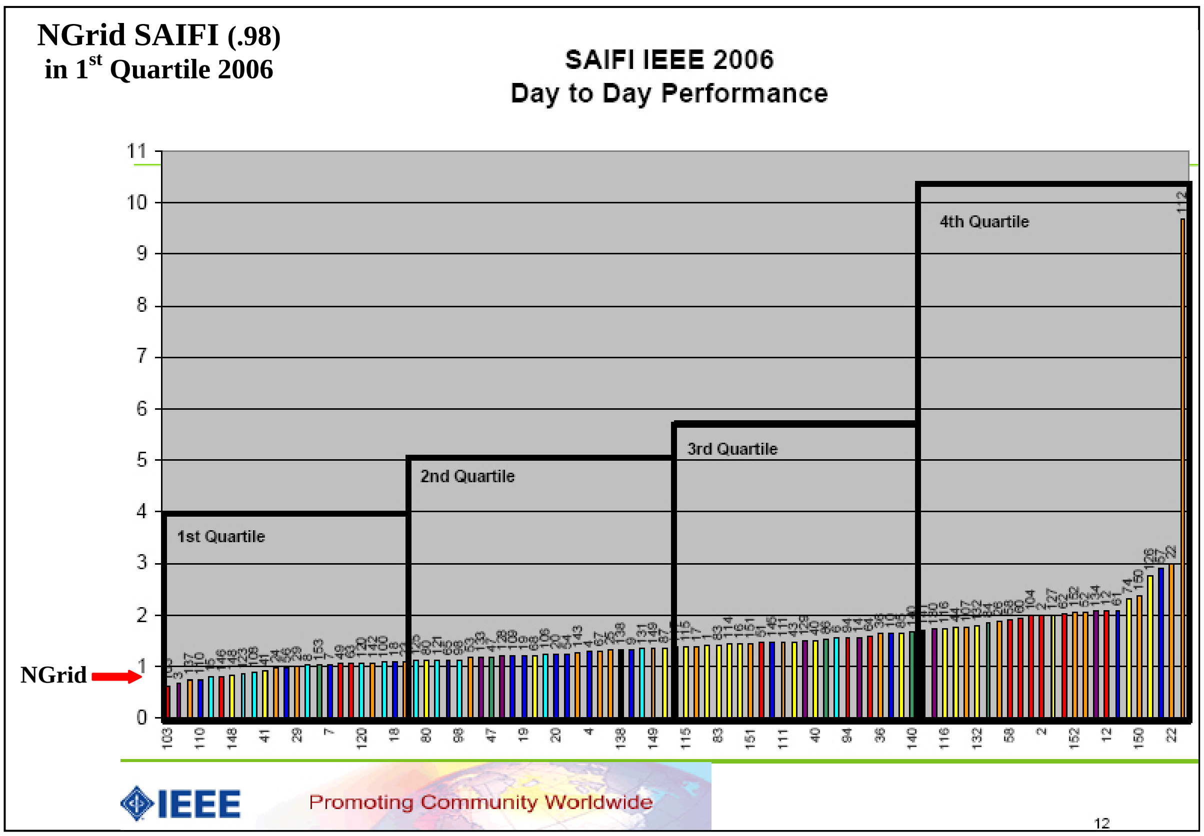


Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-14 (cont.)

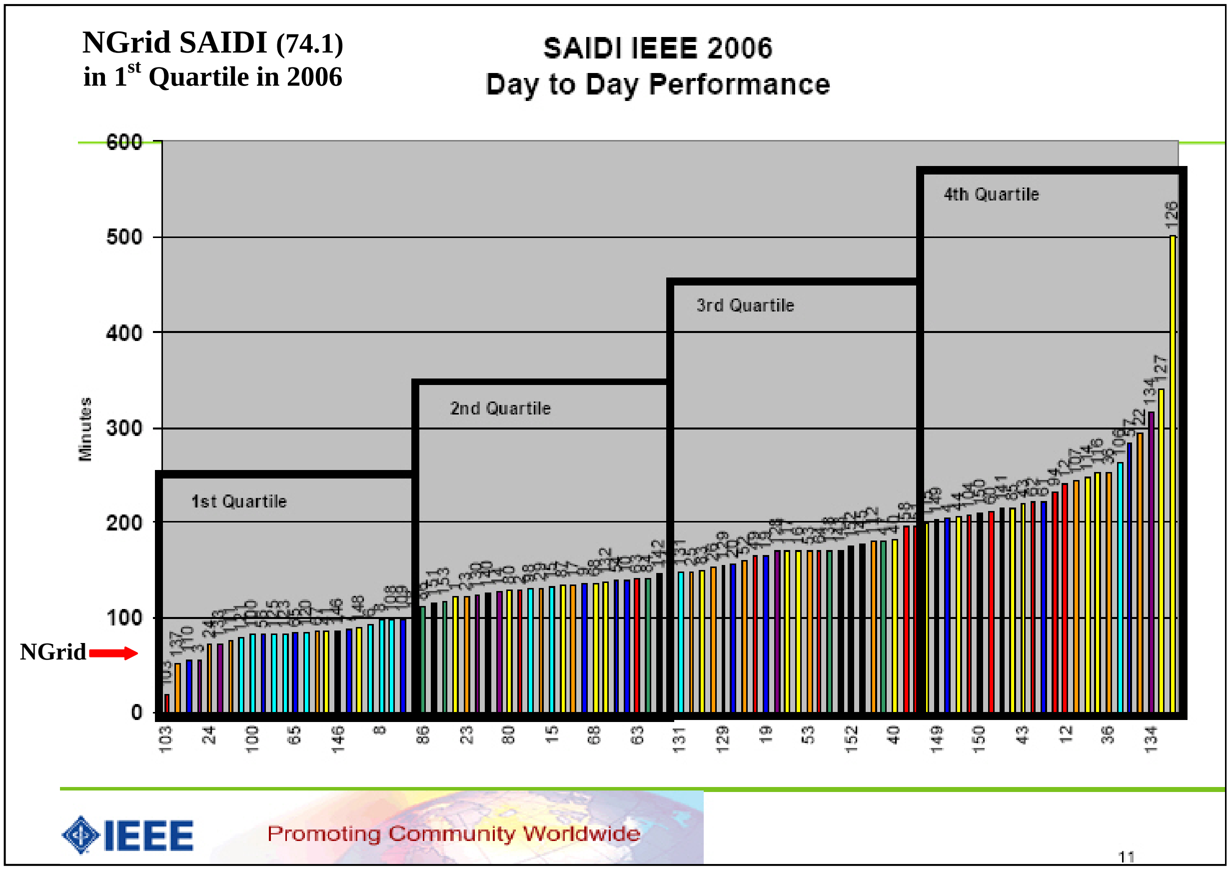
National Grid's SAIFI, SAIDI, and CAIDI statistics relative to the IEEE 1366-2003 survey results for the year, 2006 are shown in charts 4, 5, and 6 below. National Grid fell within the first quartile of performance. These statistics exclude major storms.

Chart 4



Division Data Request 14-14 (cont.)

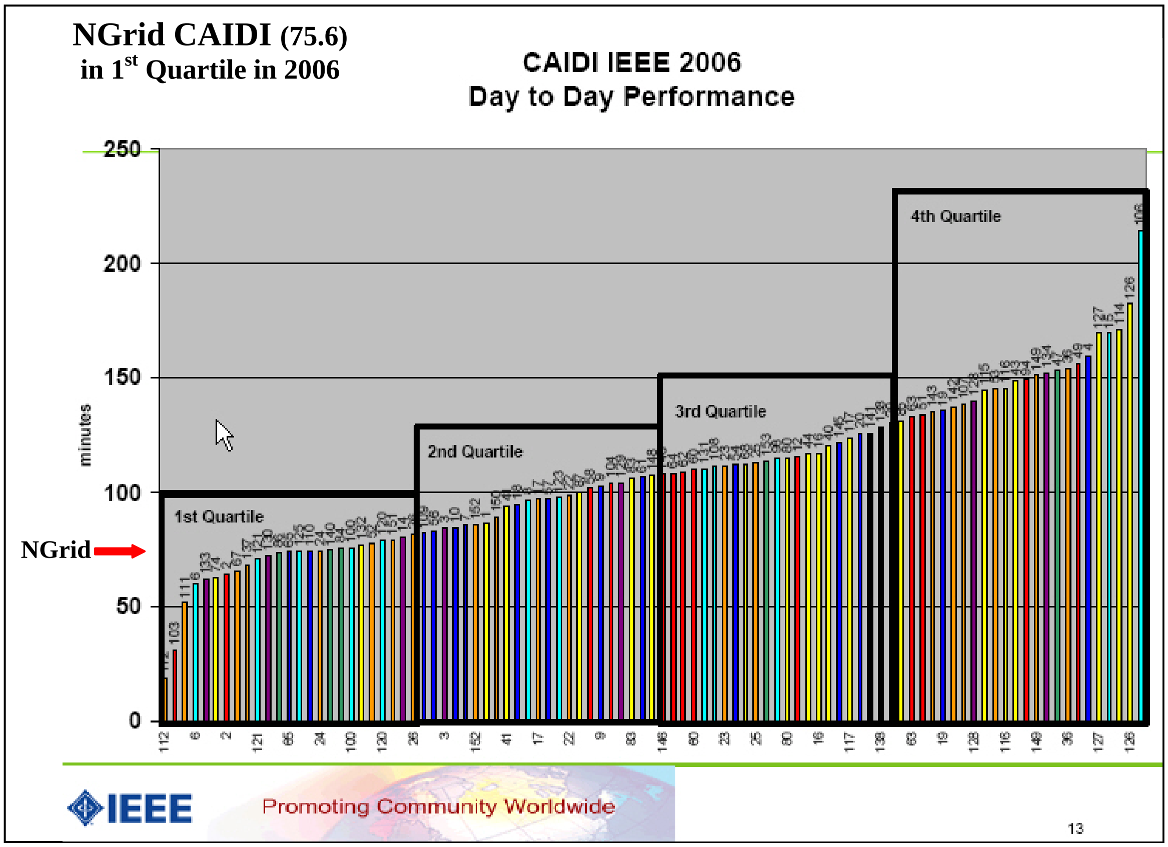
Chart 5



Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-14 (cont.)

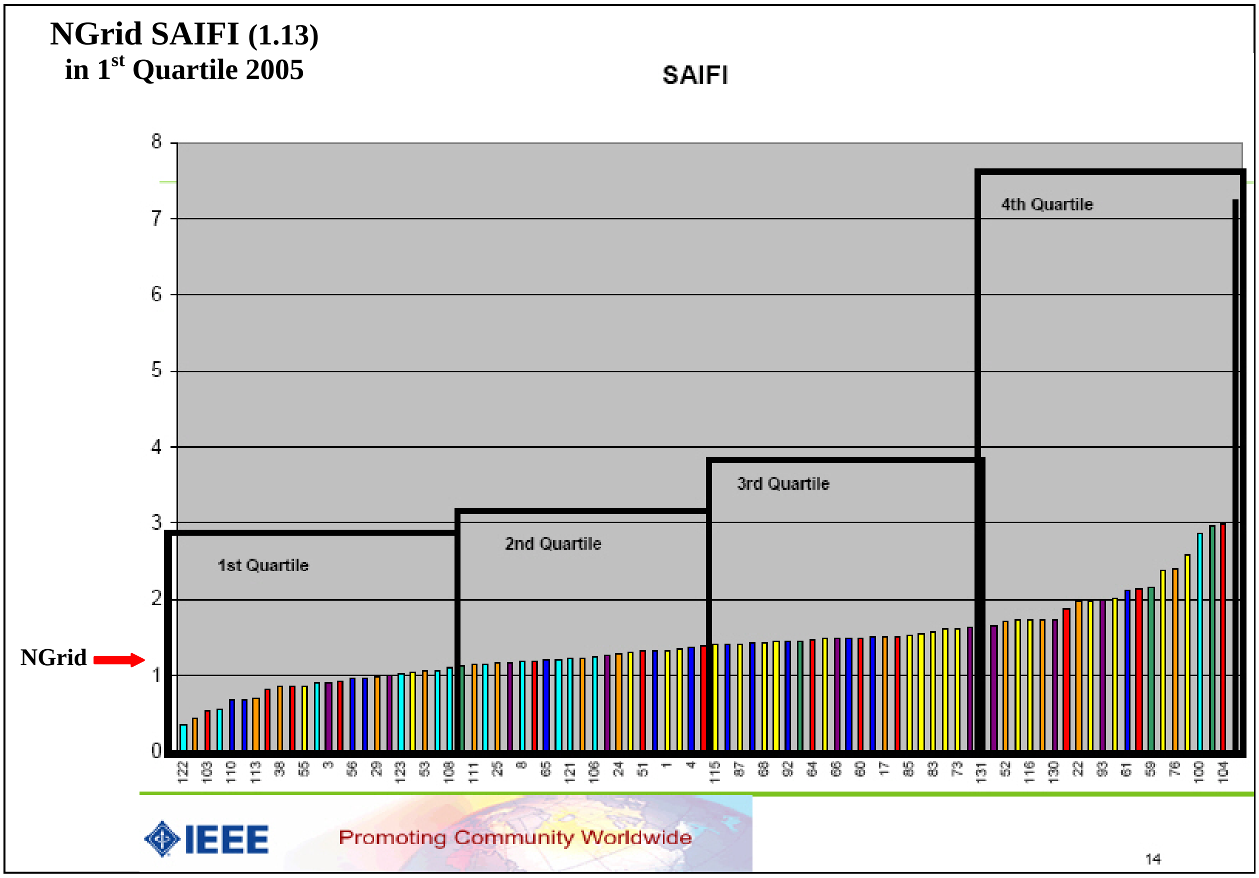
Chart 6



Division Data Request 14-14 (cont.)

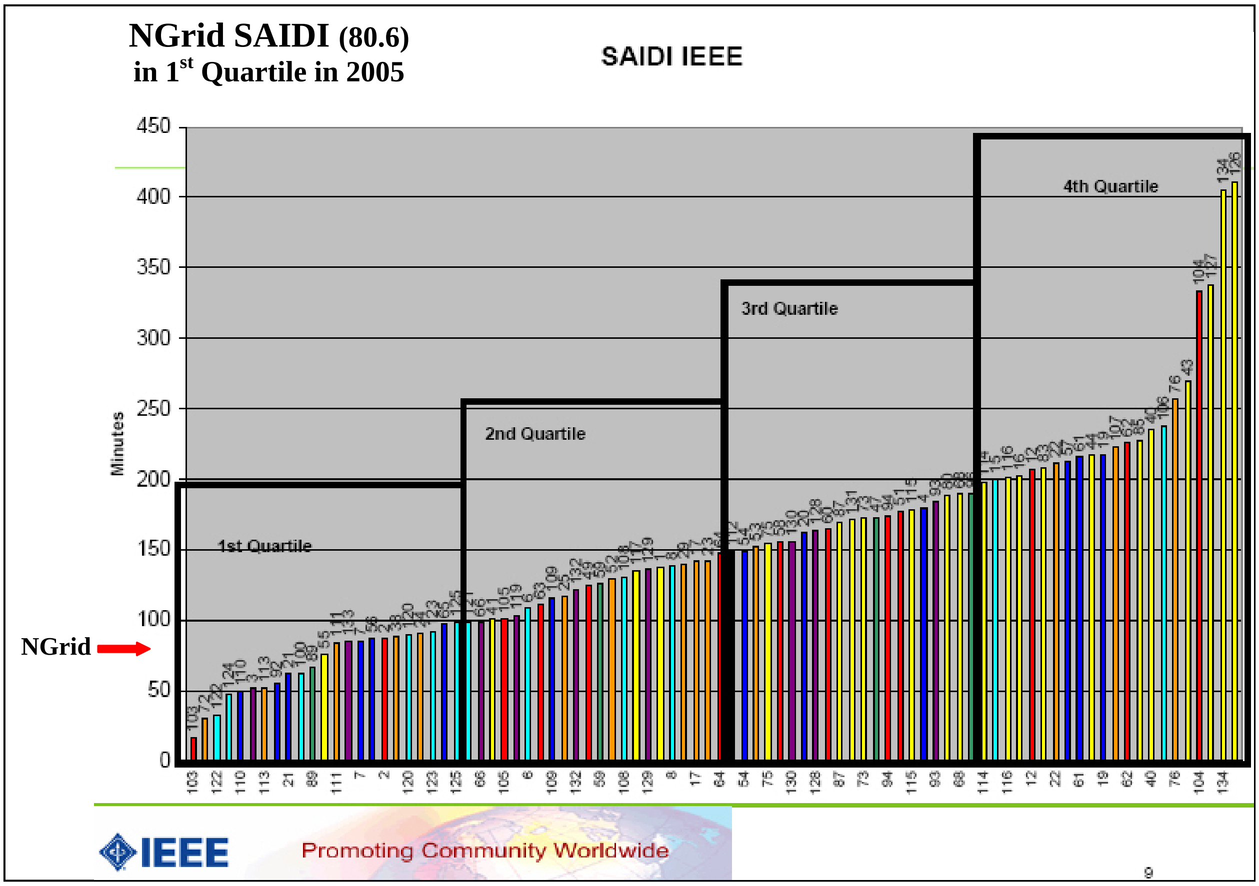
National Grid's SAIFI, SAIDI, and CAIDI statistics relative to the IEEE 1366-2003 survey results for the year, 2005 are shown in charts 7, 8, and 9 below. National Grid fell within the first quartile of performance. These statistics exclude major storms.

Chart 7



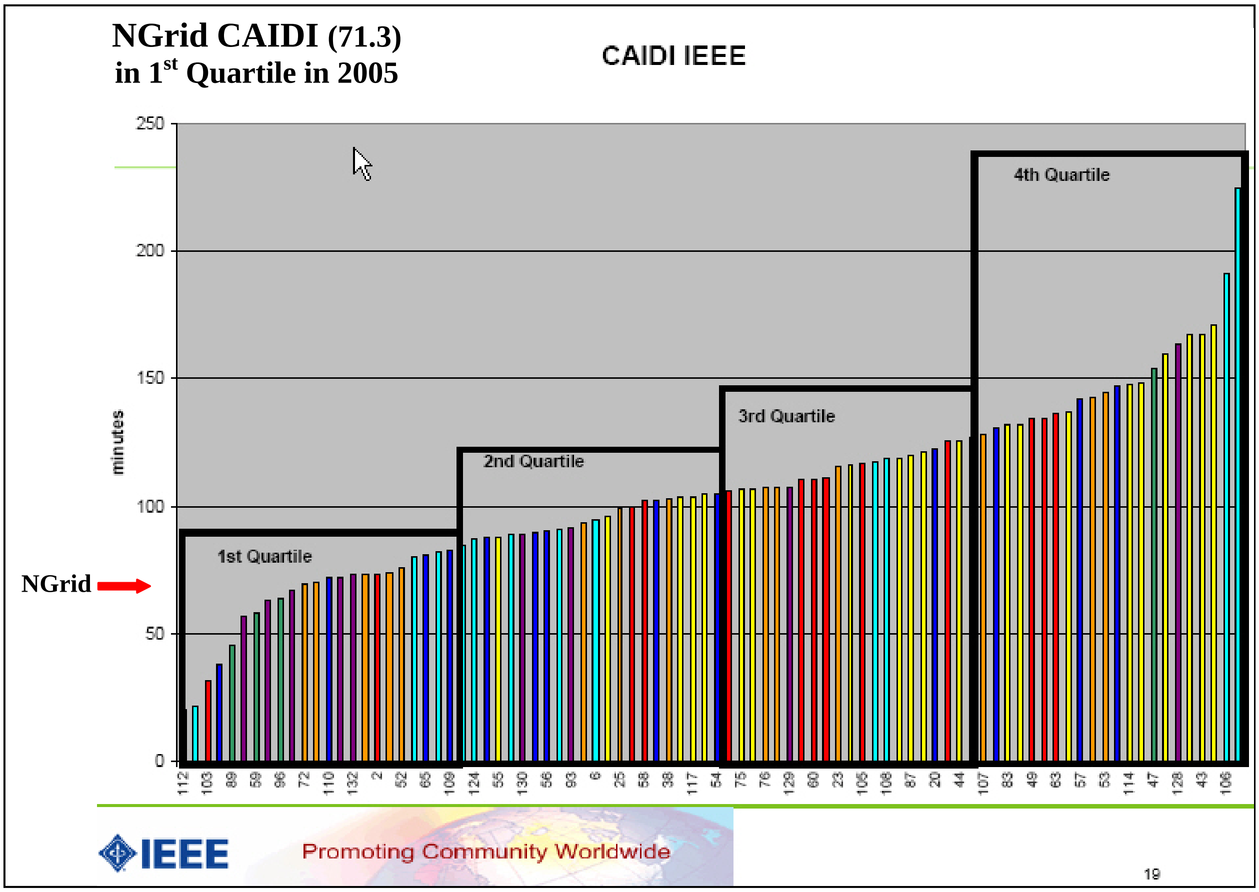
Division Data Request 14-14 (cont.)

Chart 8



Division Data Request 14-14 (cont.)

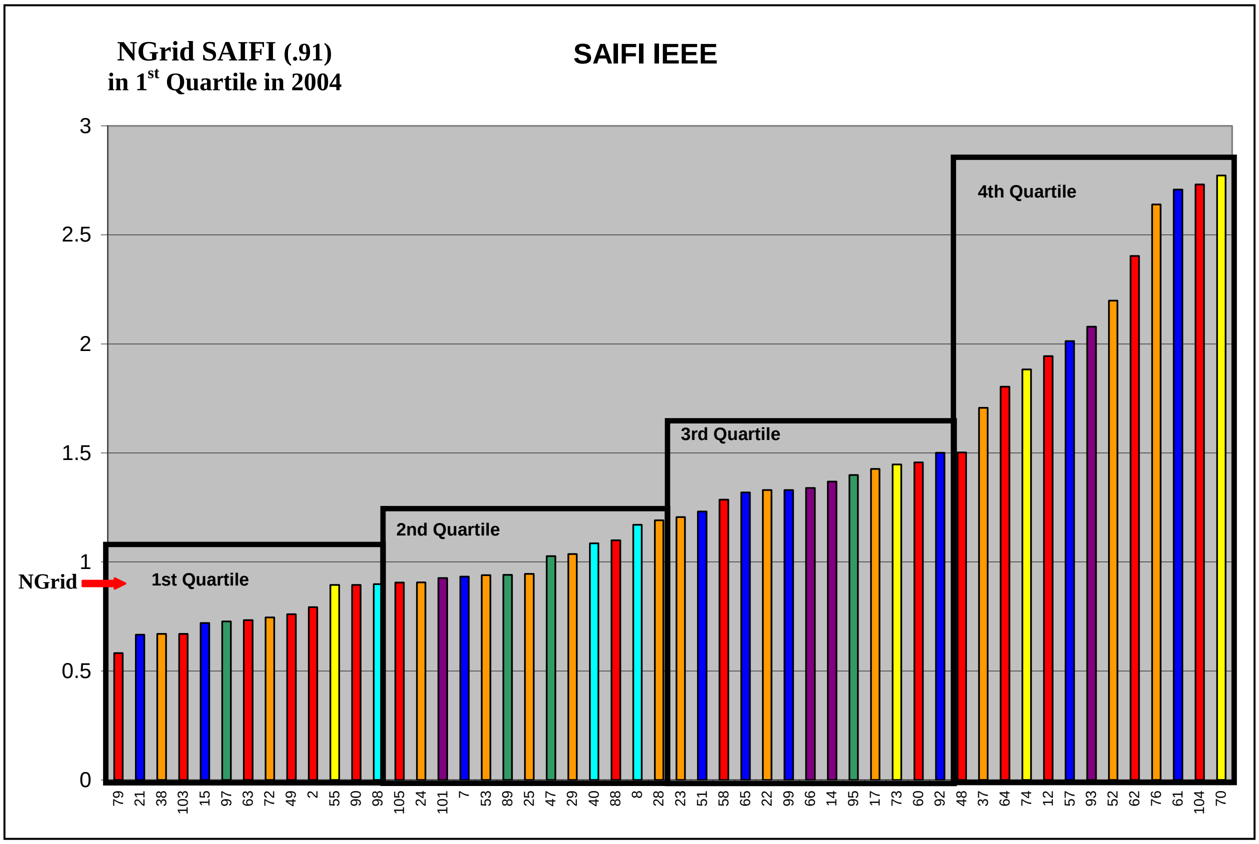
Chart 9



Division Data Request 14-14 (cont.)

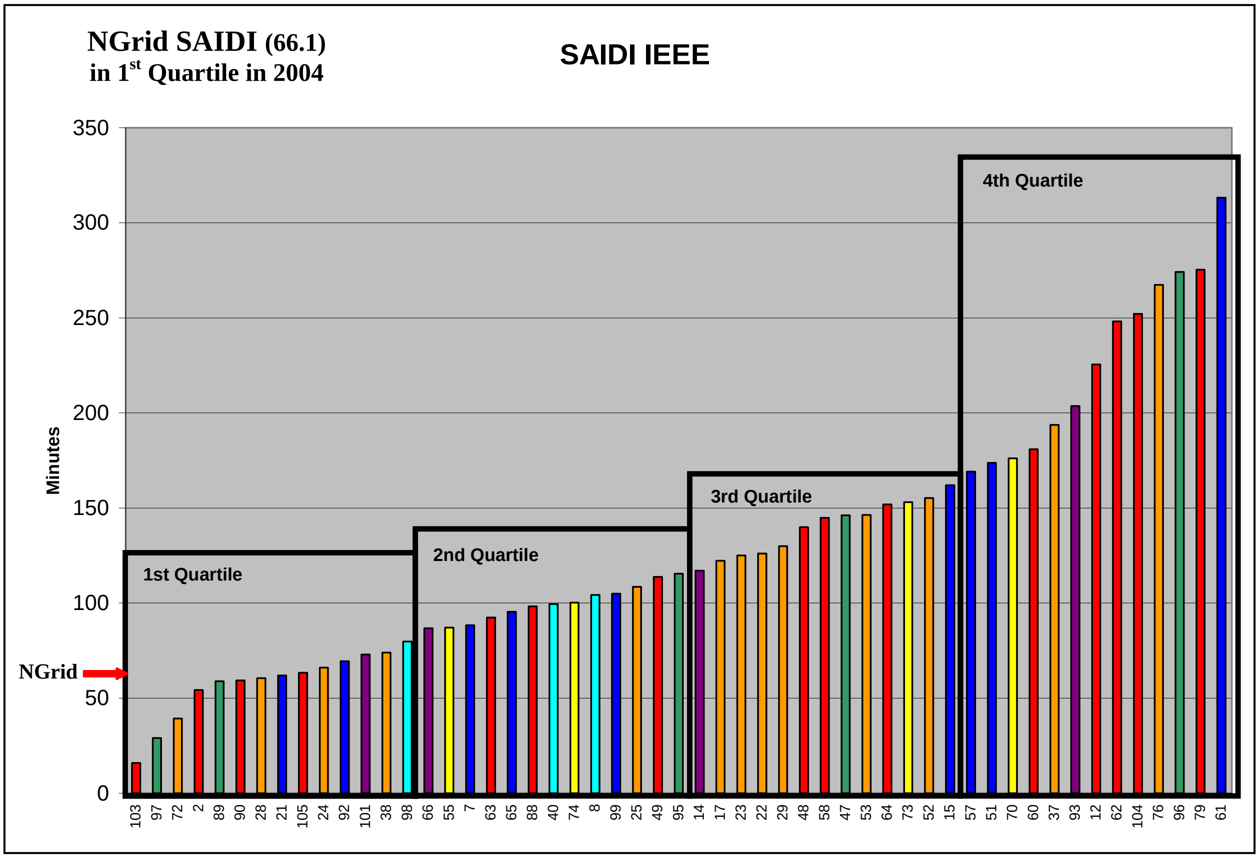
National Grid's SAIFI, SAIDI, and CAIDI statistics relative to the IEEE 1366-2003 survey results for the year, 2004 are shown in charts 7, 8, and 9 below. National Grid fell within the first quartile of performance. These statistics exclude major storms.

Chart 10



Division Data Request 14-14 (cont.)

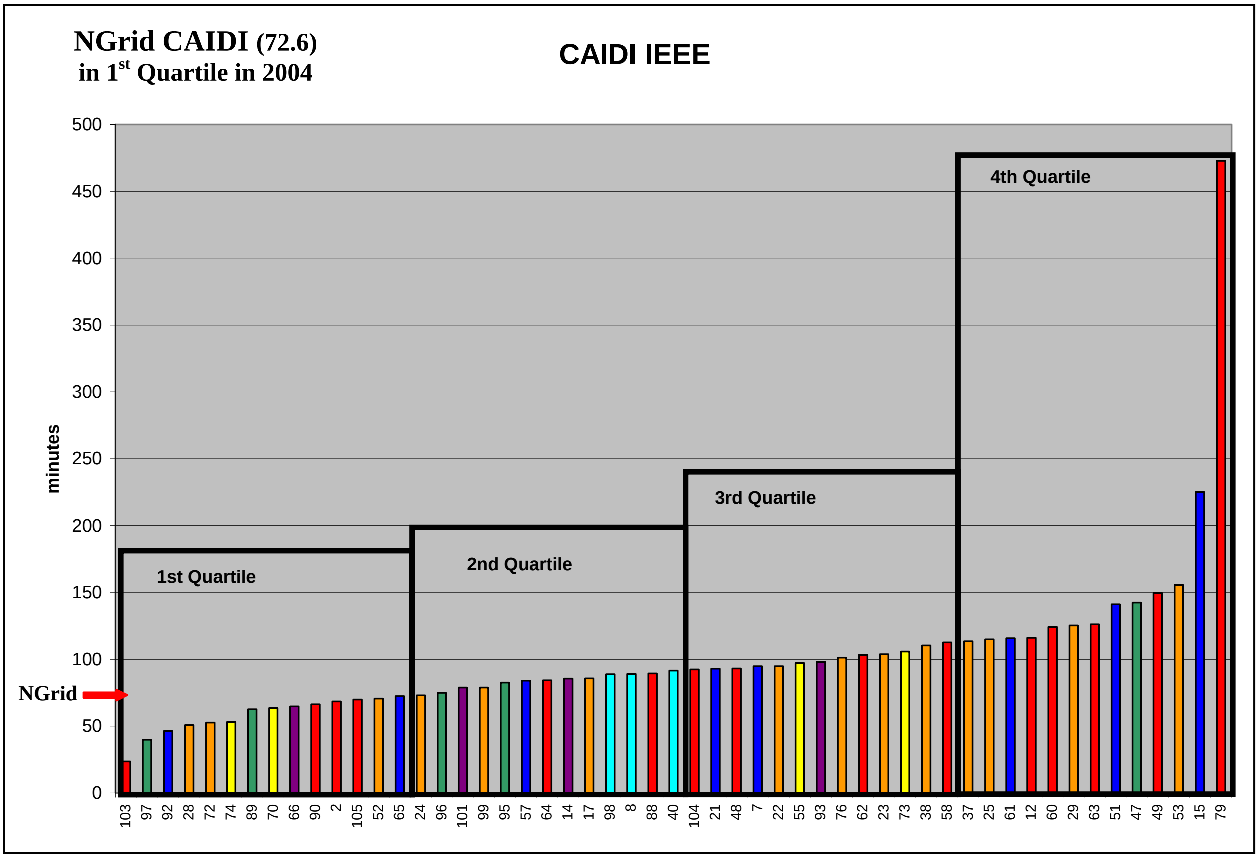
Chart 11



Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-14 (cont.)

Chart 12



Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-16

Request:

What percentage of lightning and storm hardening of the electric distribution system has been completed by National Grid to date?

Request:

As of the end of July, 2009, approximately 1,040 miles (37 feeders) of overhead primary has been feeder hardened with an additional 300 miles (7 feeders) planned for the remainder of FY10. These 1,040 completed miles represent approximately 22% of the overhead distribution system.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-17

Request:

What percentage of supervisory control and data acquisition implementation in the distribution substation has been completed by National Grid to date? Additionally, provide the percent of substations that have been enhanced with National Grid's latest technologies standards.

Request:

There are a total of 102 distribution substations in service in Rhode Island of which 73.5% are deployed with SCADA.

Of the total number of distribution substations with SCADA, 32.5% have been upgraded with new or replacement RTU's with microprocessor based relays.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-18

Request:

Provide a detailed description as to how the company's feeder hardening plan has changed from 2001 to present, specifically describing each change and the year in which such change took place.

Request:

Feeder Hardening is part of the Reliability Enhancement Program (REP) and it has changed in three main areas between FY06 (pilot year) to FY11 (last year of program):

1. *How feeders are selected for the program*:

   - FY06 (pilot year) - Feeders were selected for the program based on an internal poor performing feeder list.
   - FY07 (first year of REP) – The selection method was improved to select feeders experiencing only distribution line deteriorated equipment and lightning interruptions from a ranked list based on $/Delta CMI.
   - FY08 – Selection method was improved to use four metrics to determine ranking (instead of just $/Delta CMI). Due to the variability of cost per mile, $/Delta CMI was not the best method to select feeders. The four metrics are:
     - Number of Customers Served, used to model future value of avoided outage
     - CMI/Event, used to model historic severity of interruption events
     - Events/Mile, used to model historic density of interruption events
     - $/Delta CMI, used to model the cost effectiveness of the mitigation
   - FY09 – 'Hybrid' Approach developed, emphasizing work on three phase sections of the feeder (due to larger impact of these interruptions). Selection model was changed to support 'hybrid' approach using existing four metrics.

2. *What and how work is performed on the selected feeders*:

   All work was initially performed by local field forces including work identification, work order creation and work execution. In FY08, a centralized 'Pod' was created to handle all aspects of work from the initial survey through to QA/QC of the completed work. This was needed to insure consistency of the process across New England. In FY09, the

Division Data Request 14-18 (cont.)

‘hybrid’ approach was implemented changing the scope of the work performed on the three phase and non-three phase sections of the feeder.

3. *Feeder mileage levels:*

The base feeder mileage levels were initialing defined in FY07 when the REP was approved. These levels have gone up and down slightly year to year but have averaged around 300 to 400 miles annually (excluding the pilot year). The expected total mileage of this program is approximately 1,700 miles by the end of FY11. Currently approximately 1,000 have been completed with another 300 either under construction or planned for the remainder of FY10.

The Feeder Hardening Strategy is provided in Attachment DIV 14-18.

Feeder Hardening Strategy
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Strategy Statement

The intent of this strategy is to provide a method to identify feeders with characteristics indicating the potential for significant reliability performance improvements related to overhead deteriorated equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

After identification and local review by Distribution Field Engineering, the feeders become part of the Feeder Hardening Program. Feeders in this program are surveyed for deteriorated equipment and non standard grounding/bonding. All poles on which work is performed are brought up to current standards as part of the program.

This work is expected to reduce the five-year average National Grid USA SAIDI by 11 minutes on an IEEE 1366 basis by FY 2011. This improvement is based on a reduction in the number and magnitude of deteriorated equipment, lightning and animal related interruptions in upgraded sections.

This is one of the four major strategies designed to improve National Grid's reliability performance as measured by state regulatory service quality targets. The short term goal is to meet state regulatory targets by 2008 and attain first quartile reliability performance compared to a select group of peers in SAIDI, SAIFI and CAIDI by 2012.

The main benefits/risks are reliability and regulatory.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	07/02/2008	Updated Sections 3 (Benefits) and 6 (Risk Assessment) to align with updated OSP objectives Added Section 2.3 (Performance and/or Condition Targets)	Jeffrey H. Smith Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

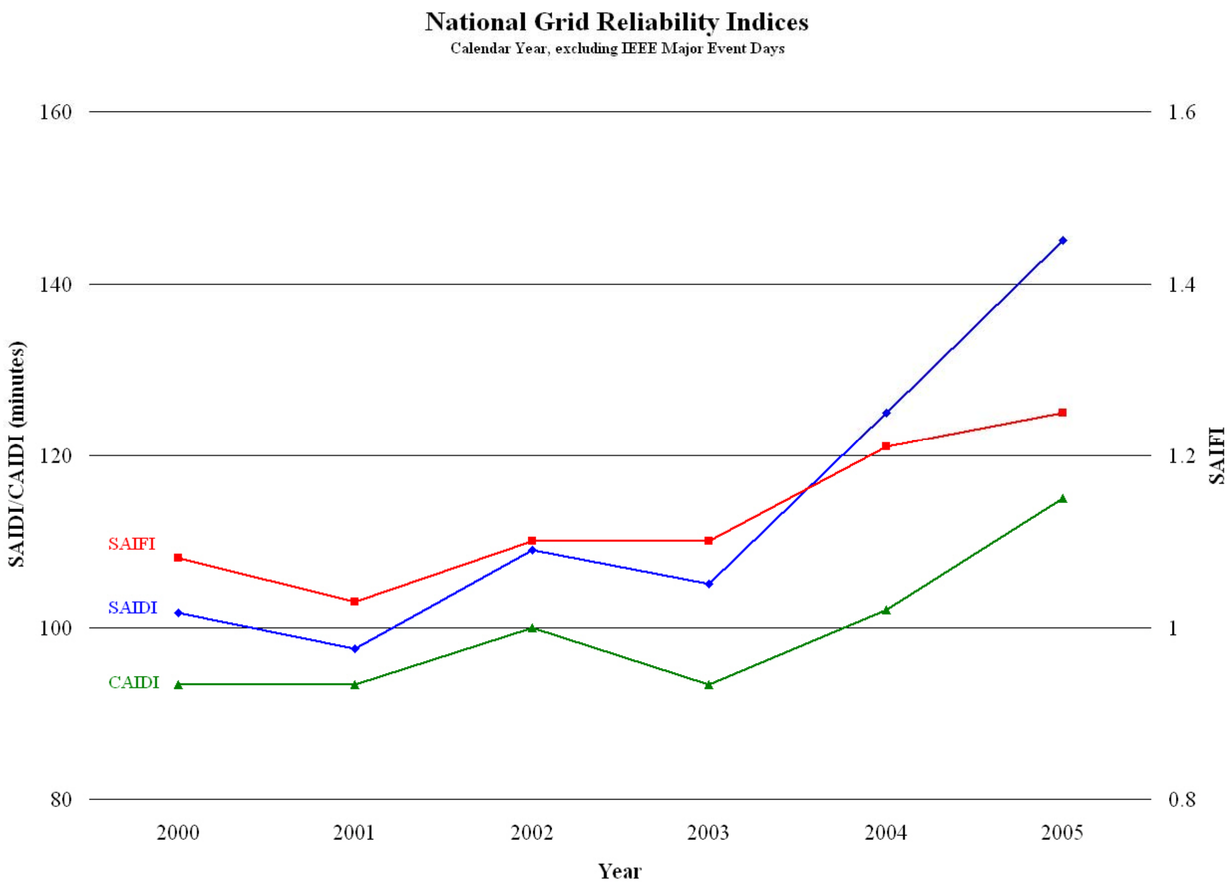
1.0 Purpose and Scope

This strategy sets forth a Feeder Hardening program to remediate deteriorated equipment and improve lightning protection on primarily overhead distribution feeders. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

2.0 Strategy Description

2.1 Background

Trees, animals, lightning and deteriorated equipment are the major drivers in National Grid's reliability performance. Since approximately 2001, the distribution reliability performance in these areas has been steadily worsening. Along with this deteriorating reliability performance, the company has been assessed steadily increasing financial penalties from state regulators due to our poor performance against the regulatory service quality targets.



The Reliability Enhancement Program (REP) was developed to reverse this trend. This program consists of four major initiatives:

1. Feeder Hardening/Engineering Reliability Reviews
2. Incremental Asset Replacement
3. Incremental Vegetation Management
4. Inspection and Maintenance

The goal of the REP is to meet state regulatory targets by 2008 and attain first quartile reliability performance compared to a select group of peers in SAIDI, SAIFI and CAIDI by 2012.

Feeder Hardening was developed to specifically address overhead deteriorated equipment and lightning related interruptions on distribution feeders. Feeder Hardening utilizes remediation measures, such as replacement of fuse cutouts, crossarms, poles and transformers; lightning protection with bonding, grounding and lightning arrester installations; and installation of animal guards. Equipment is inspected and replaced as needed on the selected Feeder Hardening circuits under the "Hybrid" approach which optimizes the program by focusing remediation on three phase areas of the feeder, as shown in the table below.

Feeder Hardening Remediation – Hybrid Approach

Three-Phase Areas	**Non- Three Phase Areas**
Line and Transformer Cutouts Lightning Arresters Animal Guards Crossarms, Armless Brackets and Pole Top Pins Poles, Guys and Anchors Equipment Grounding and Bonding Insulators Switches	Line and Transformer Cutouts Lightning Arresters Animal Guards NOTE: While only pole locations which require animal guards, lightning arresters and cutouts will be addressed in non-three phase areas, that pole then should be brought up to current standards, including all items shown for three phase areas.

2.2 Feeder Hardening Ranking Model

Three reliability models are used to create a feeder rank for all feeders meeting the Feeder Hardening filtering criteria. These three models are the Overhead Deteriorated Equipment (OHDE) Model, Lightning Model and Feeder Hardening Optimization Model.

The OHDE Model and the Lightning Model each extract data from the reliability source systems related specifically to deteriorated overhead equipment interruptions and lightning interruptions, respectively. Additionally, regional IEEE 1366 Major Event Days and supply and substation related events are excluded from the analysis. This reliability data is combined with feeder asset data to create a framework to assess the performance of the feeder and determine the potential for reliability improvement through the Feeder Hardening Program.

The filtering criteria for inclusion in each model are:

- Customers Served > 0
- Number of interruption events in last three years > 1
- Total Customer Minutes Interrupted (CMI) > 500
- Overhead circuit mileage > 1000 feet

The filters are designed to exclude only the obvious feeders which should not be selected.

The results of the OHDE and Lighting Models are combined by the Feeder Hardening Optimization Model to create a combined ranking. This combined ranking is used to select the feeders to be included in each fiscal year's program.

A brief description of the model ranking process follows:

The Overhead Deteriorated Equipment (OHDE) Model analyzes the last three calendar year interruption events related to failed overhead equipment and combines this information with customer served and overhead feeder mileage data to calculate a combined ranking of all the feeders across New England/New York that meet the model filtering criteria (described above).

Four separate rankings are calculated for each feeder. A ranking of 1 in each metric represents the most desirable feeder:

- Customers Served
  - Ranked highest to lowest customers served
  - Based on the last calendar year's customers served (not a historic multi-year average)
  - Used to model the future value of the avoided interruption

- CMI/Event
  - Ranked highest to lowest CMI per event
  - Based on the last three years of interruption events
  - Used to model the historic severity of the interruption events

- Events/Mile
  - Ranked highest to lowest events per mile of overhead exposure
  - Based on the three year average interruption events and the current year's miles of overhead exposure
  - Used to model the historic density of the interruption events

- Dollars/Change in Customer Minutes Interrupted ($\$/\Delta CMI$)
  - Ranked lowest to highest $\$/\Delta CMI$
  - Based on the three year average ΔCMI assuming a fixed improvement percentage and a fixed cost per mile to mitigate the interruptions
  - The lower the $\$/\Delta CMI$, the more cost effective the mitigation

The above four ranks are combined (and sorted low to high) as follows:

- Overall Rank = Customer Served Rank + CMI/Event Rank + Events/Mile Rank + $\$/\Delta CMI$ Rank

The Lightning Model is basically the same as the OHDE Model, principal differences:

- Three years of interruption events related to lightning are used

The Feeder Hardening Optimization Model simply combines the OHDE and Lightning rankings to produce the Feeder Hardening Ranking. If a feeder is ranked in one model but not the other, a value equal to the largest ranking (worst feeder) plus one is inserted into the calculation.

The above two ranks are combined (and sorted low to high) as follows:

- Feeder Hardening Rank = Overhead Deteriorated Equipment Rank + Lightning Rank

The data from the models below are combined with the Feeder Hardening ranked data to provide an estimated total cost and benefit for the Feeder Hardening Program:

- Animal Model — Feeders ranked based on $/Δ CMI
- Cutout Model — Estimated number of potted porcelain cutouts on the feeder
- Pole Model — Estimated number of poles targeted for replacement on the feeder

Feeders are initially selected for each company of National Grid based on the budgets established in the five year plan. These circuits are reviewed and adjusted based on the expertise of the division engineers. A review is also performed to ensure that work is done in both urban and rural areas. Feeders are reviewed not only across all of National Grid, but also on a State by State basis. Recent significant changes or near-term planned changes to a selected feeder are typical reasons for skipping a feeder and moving to the next best candidate.

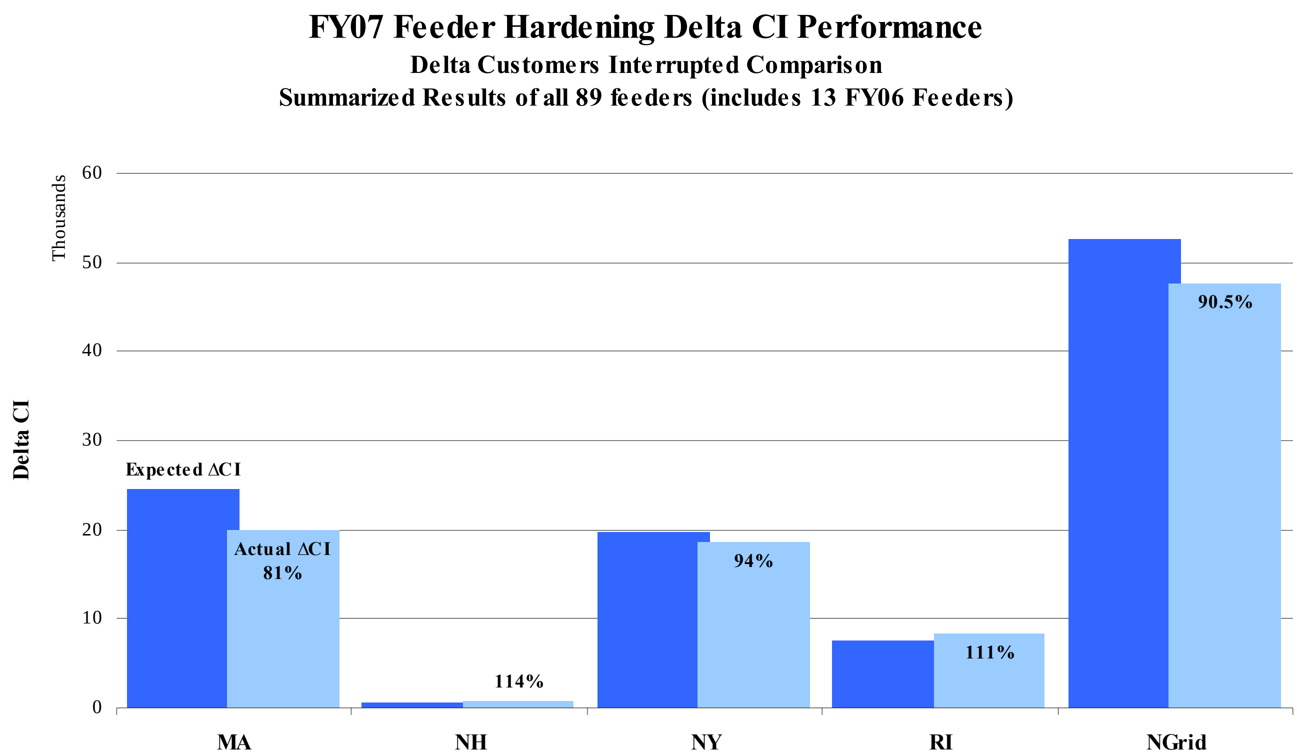
While the company has been doing Feeder Hardening since 2006, the above designed model was first used to select the FY08 feeders for the Feeder Hardening Program. Prior to the adoption of the described model, a similar process involving only the $/ΔCMI and judgment was used to select the feeders. Due to the variability of the cost/mile on a feeder by feeder basis, the new four-metric approach was developed.

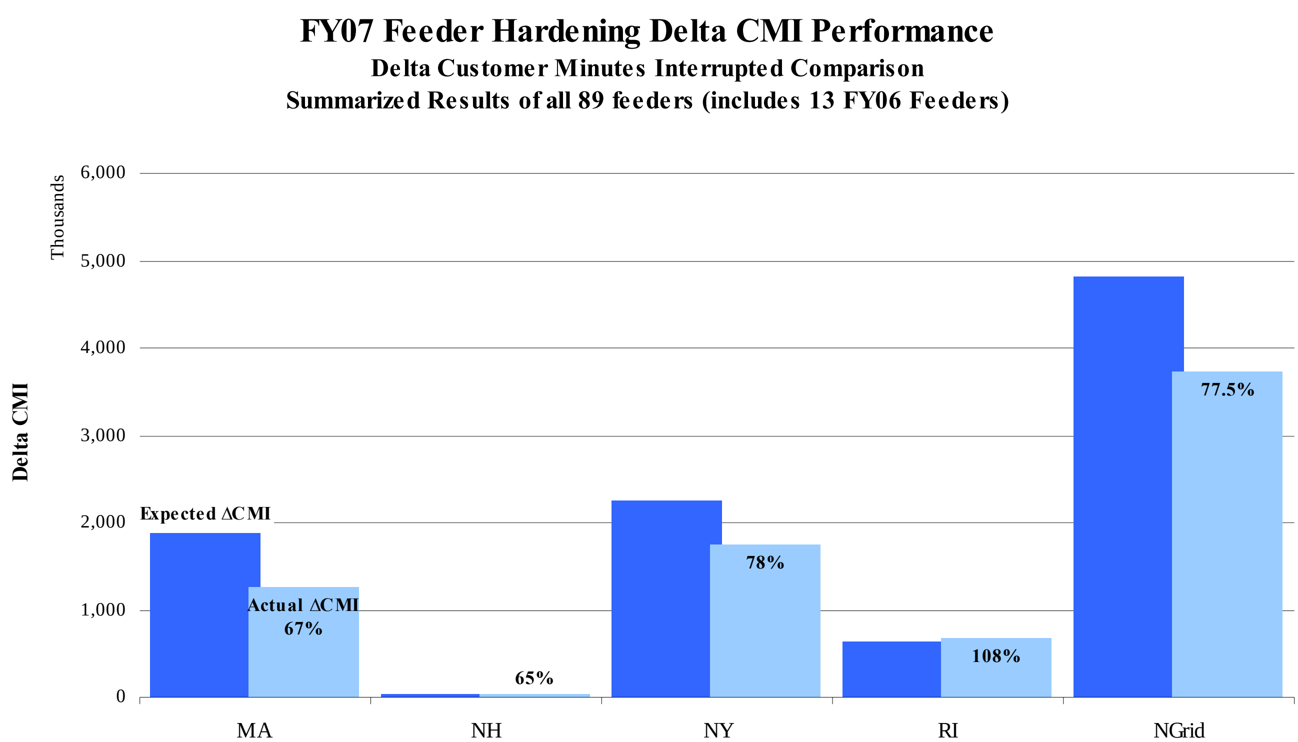
In the initial program, the scope of work was the same on both three-phase and non-three phase feeder segments, including all items listed for three phase in the "Hybrid" approach described above. The new approach, known as the "Hybrid" approach, reduces the scope of the construction on the non three-phase portions of the selected feeders. The scope of work on the three-phase has remained the same. Non three-phase construction is now limited to locations requiring an animal guard, lightning arrester or cutout. At these locations all components on the pole are brought up to current standards.

The models described above have been modified to support the new "Hybrid" approach. This modification essentially creates two separate paths within the model, one for three-phase and another for non three-phase. Each path handles a subset of the interruptions with different reliability improvement percentages and costs. These paths are combined to create the same four rankings used in the original model.

2.3 Performance and/or Condition Targets

The Feeder Hardening Strategy is designed to support the reliability objective of meeting service quality requirements for all states by 2008 and attaining first quartile performance by 2011. The specific strategy performance targets by state (and overall) are illustrated in the graphic in Section 3.2. Current performance against these targets for the first year of the program (including FY2006 New England pilot) is shown below:


FY07 Feeder Hardening Delta CI Performance
Delta Customers Interrupted Comparison
Summarized Results of all 89 feeders (includes 13 FY06 Feeders)
Thousands
Delta CI
60
50
40
30
20
10
0
Expected ΔCI
Actual ΔCI
81%
114%
94%
111%
90.5%
MA
NH
NY
RI
NGrid


FY07 Feeder Hardening Delta CMI Performance
Delta Customer Minutes Interrupted Comparison
Summarized Results of all 89 feeders (includes 13 FY06 Feeders)
Thousands
Delta CMI
6,000
5,000
4,000
3,000
2,000
1,000
0
Expected ΔCMI
Actual ΔCMI
67%
65%
78%
108%
77.5%
MA
NH
NY
RI
NGrid

Additionally, service quality targets were met in Massachusetts and Rhode Island in 2007, with significant progress being made in New Hampshire (1 of 2 targets met) and New York (1 of 2 targets met). New Hampshire did not have service quality standards when this program was first developed but has since adopted them without a financial penalty.

While the Feeder Hardening Program was not solely responsible for meeting these state regulatory targets, the program is a significant component which performed within reasonable expectations.

3.0 Benefits

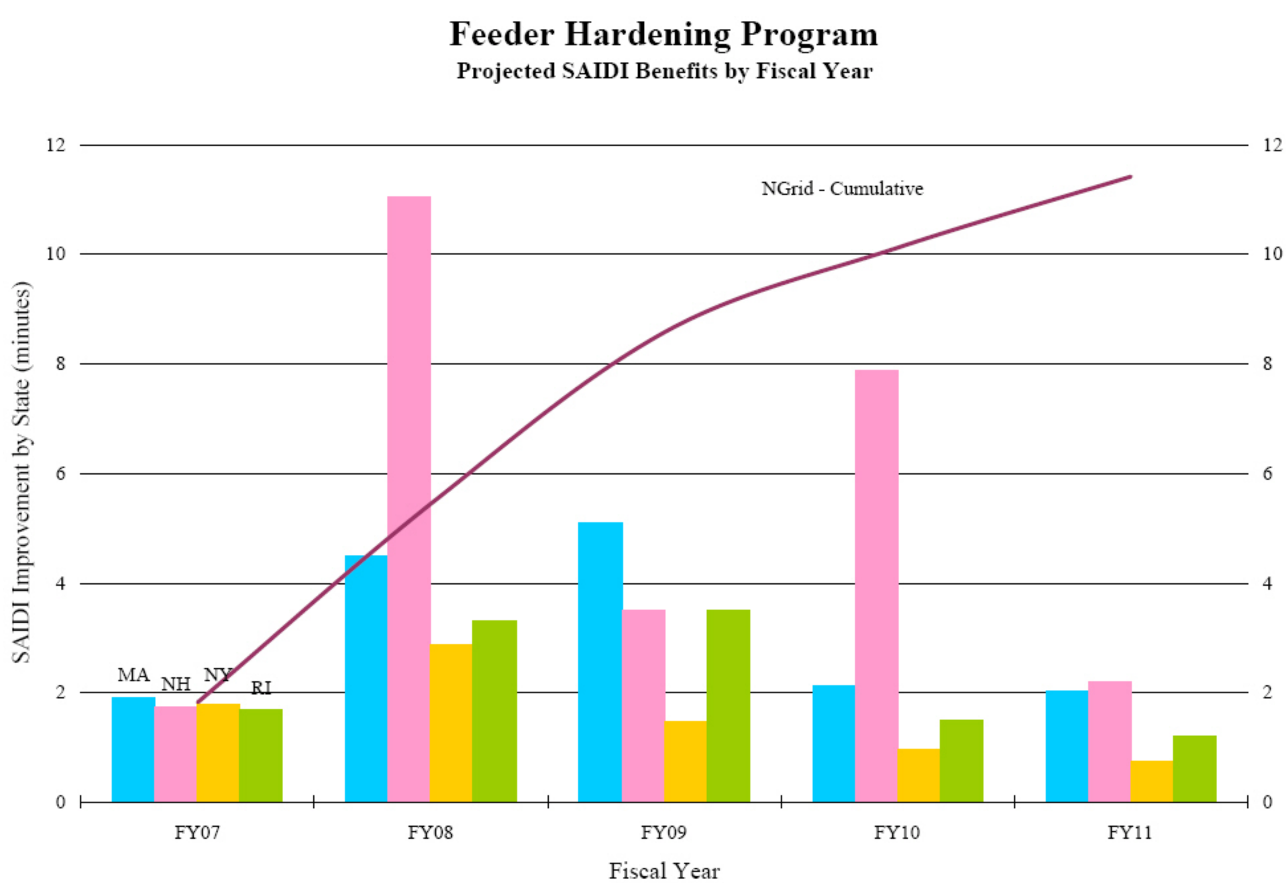
The principal benefits of the Feeder Hardening Strategy are reliability and regulatory.

3.1 Safety & Environmental

This strategy has no direct safety or environmental impact. As feeders are brought up to current standards, safety will be improved.

3.2 Reliability

This work is expected to reduce the five-year average National Grid USA SAIDI by 11 minutes on an IEEE basis by FY 2011. This improvement is based on a reduction in the number and magnitude of deteriorated equipment, lightning and animal related interruptions in upgraded sections.



3.3 Customer/Regulatory/Reputation

This is one of the four major strategies designed to improve National Grid's reliability performance as measured by state regulatory service quality targets. The overall goal is to meet state regulatory targets by 2008. Meeting our state regulatory service quality standards will eliminate financial penalties and improve our relationship with the regulators. While this is not a customer focused strategy, customers on the feeders in the program will experience a significant reliability improvement.

3.4 Efficiency

The programmatic, model-based approach used in this strategy ensures feeders selected for the Feeder Hardening Program present the best opportunity to meet the strategy's objectives. Additionally, combining the overhead deteriorated equipment, lightning and animal initiatives into one program maximizes the design, scheduling and crew time by addressing all programs with one visit to the pole.

4.0 Estimated Costs

Approximately 14,500 miles of overhead distribution will be "hardened" over the next five fiscal years. The program is expected to continue through at least FY 2011. The figures below represent the program as originally justified in FY 2007:

Total $ and $/year CAPEX and OPEX

Fiscal Year	CAPEX (Millions $)	OPEX (Millions $)	Total (Millions $)
2007	9.4	9.7	**19.1**
2008	14.9	15.4	**30.3**
2009	19.8	20.9	**40.7**
2010	21.6	22.4	**44.0**
2011	22.2	22.9	**45.1**
Total	**87.9**	**91.3**	**179.2**

Approximate $/ΔCMI for Feeder Hardening Program*

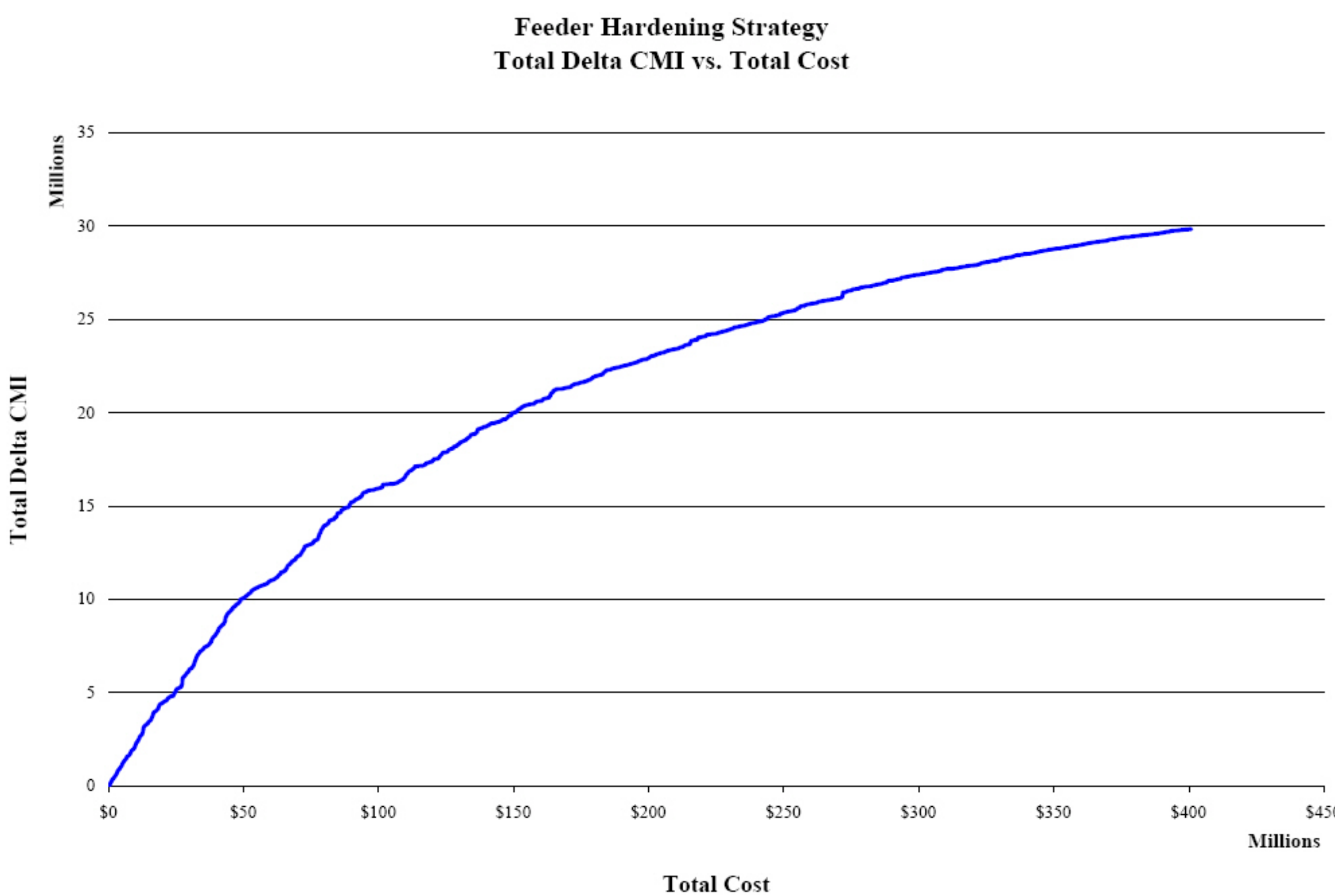
Fiscal Year	Feeder Hardening Only $/ΔCMI	FH plus Animals, Cutouts & Poles $/ΔCMI
2006 (NE Only)	3.19	2.47
2007	3.05	2.28
2008	3.44	2.32
2009	4.05	4.21
2010	6.68	6.70
2011	7.86	8.12
Total	4.50	4.09

* Hybrid Approach used for FY 2009 – FY 2011

5.0 Implementation

The program was piloted in New England in FY 2006 and adopted in New York in FY 2007. FY 2008 will be the first year the above described model has been used to select the feeders to be included in the program. The new "Hybrid" approach will be applied to feeders not yet designed in FY 2008 and all future feeders selected for inclusion in the program. This program is expected to continue through at least FY 2011.

The chart below represents the scalability of the program if additional reliability improvements are desired. Feeders recommended through FY 2008 are not represented on the chart.



6.0 Risk Assessment

The principal risks of the Feeder Hardening Strategy are reliability and regulatory.

6.1 <u>Safety & Environmental</u>

This strategy has minimal safety or environmental risk.

6.2 Reliability

Deteriorated equipment and lightning related interruptions have been on the rise since 2001. The average number of customer minutes interrupted (CMI) has increased by 10% annually (approximately 3.5 million CMI/year) for the last four years. Without taking action on deteriorated equipment and lightning related interruptions, the increasing trend is expected to continue.

6.3 Customer/Regulatory/Reputation

Maintaining a favorable working relationship with state regulators is key to the future success of National Grid. Continued poor performance against state regulatory service quality standards puts this relationship in jeopardy and results in financial penalties. Additionally, continued poor reliability performance will be result in negative customer satisfaction and increased complaints to state regulators.

6.4 Efficiency

Failing to implement this strategy will likely result in an uncoordinated, suboptimal approach to improving National Grid's reliability performance and would be a missed opportunity to create efficiencies by prioritizing and combining the work.

7.0 Data Requirements

The data necessary to manage the Feeder Hardening Strategy is currently available and a set of models has been developed to support the strategy. The main areas open for improvement are cost tracking for better CAPEX/OPEX estimating.

7.1 Existing/Interim:

- Smallworld/ArcSDE – Feeder asset data
- PowerOn/IDS/SIR – Feeder reliability data

7.2 Proposed:

Same

7.3 Comments:

Improved data quality in both feeder asset and reliability areas will support the refinement of the modeling process.

8.0 References

None

Division Data Request 14-19

Request:

Does the company perform pole testing on a systematic regular cyclical basis? If the answer is yes, provide the details associated with how many poles are tested each year, how the poles are tested and what the company does with the test results.

Request:

National Grid has not traditionally performed pole testing on a systematic or cyclical basis. However, the Company has conducted condition-based pole replacements as part of the Reliability Enhancement Program implemented in 2006.

In 2008, the Company formalized an asset strategy. As part of the Wood Pole Strategy the replacement of wood poles is based on the output of a "Pole Model," which rates poles based on age, equipment loading, dielectric fluid, and proximity to wetlands as described in the strategy document provided in Attachment DIV 14-19. The candidates identified by the model are visually inspected (along with adjacent poles) and poles in poor condition are replaced up to the budgeted amount on a division basis. Additionally, poles on Feeder Hardening feeders are replaced if they have been identified by the model and are in poor condition. National Grid is in the process of transitioning from a model-based replacement approach to an inspection-based replacement approach. The budgetary figures in the current strategy reflect this transition. Prior to the strategy-based approach, individual districts/divisions would typically replace poles in poor condition up to the annual budget amount.

Going forward, with the implementation of the new Inspection and Maintenance strategy, National Grid will inspect poles on a five-year cycle as part of the inspection program.

Prepared by or under the supervision of: John Pettigrew

Wood Pole Strategy
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Strategy Statement

The intent of this strategy is to provide an approach for managing our distribution and sub-transmission wood poles. This strategy is designed to provide for a sustainable distribution and sub-transmission system. This is a very large asset class (2.4 million poles) and is the foundation of the overhead distribution system. Reasonable age data is available for sub-transmission and distribution poles.

The Inspection Program has been updated to improve the consistency of the equipment condition reporting. Enhanced pole inspection has been added to the program which includes both a visual and structural review of all poles on a five year cycle. The Inspection Program is identifying and assigning a priority code (1-3) to poles in need of replacement. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle as per EOP D004 and T007.

Interruptions caused by pole related issues are not significant; most pole problems are safety and environment related. While we have not experienced a large number of pole failures, the few we have experienced are getting more media attention. Maintaining or slightly improving our pole age profile is recommended to hold steady at our current level of failures.

The strategy for pole replacements is to use the Inspection Program results to generate replacement candidates based on condition.

The estimated replacement cost (2008 dollars) is $4,000/pole for distribution and $15,000/pole for sub-transmission. Estimated budgetary quantities and costs for the first two cycles are in the table below:

Estimated System-wide Pole Replacements based on Inspection Data*

Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	2,507	7,211	9,718	$38,872,000	24	246	270	$4,050,000	$42,922,000
FY11	2,507	7,982	10,489	$41,956,000	24	428	452	$6,780,000	$48,736,000
FY12	2,507	9,492	11,999	$47,996,000	24	428	452	$6,780,000	$54,776,000
FY13	2,507	10,005	12,512	$50,048,000	24	428	452	$6,780,000	$56,828,000
FY14	1,595	10,918	12,513	$50,052,000	15	428	443	$6,645,000	$56,697,000
FY15	827	9,018	9,845	$39,380,000	8	263	271	$4,065,000	$43,445,000
FY16	827	5,574	6,401	$25,604,000	8	140	148	$2,220,000	$27,824,000
FY17	827	3,894	4,721	$18,884,000	8	140	148	$2,220,000	$21,104,000
FY18	827	3,686	4,513	$18,052,000	8	140	148	$2,220,000	$20,272,000
FY19	827	3,586	4,413	$17,652,000	8	140	148	$2,220,000	$19,872,000

*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY16 all of Level 3 distribution poles are included in the plan (including backlog from FY10 - FY15). Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

The main benefits/risks are safety, environmental and maintaining sustainability of overhead system. Conducting pole inspections and associated repairs are regulatory requirements in several states.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	12/20/2008	Added Sub-transmission detail to Section 2 (Strategy Description) Added Section 2.3 (Inspection Results) discussing results from partial year inspections in NY Revised Sections 2.4, 4.0 & 5.0 (Pole Strategy, Estimated Costs, & Implementation) based on inspection results Updated Sections 3.0 & 6.0 (Benefits & Risk Assessment) to align with Strategic Business Plan objectives Added Section 5.1 (Performance Targets) Added State specific sections to address age profile and estimated costs	Jeffrey H. Smith Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

The intent of this strategy is to provide an approach for managing our distribution and sub-transmission wood poles. This strategy is designed to provide for a sustainable distribution system. This is a very large asset class and is the foundation of the overhead distribution system.

2.0 Strategy Description

2.1 Background

National Grid has approximately 2.4 million distribution and sub-transmission poles. Reasonable age data is available for both distribution and sub-transmission poles. Figure 1 is a chart of the combined age profile of distribution and sub-transmission poles across the system:

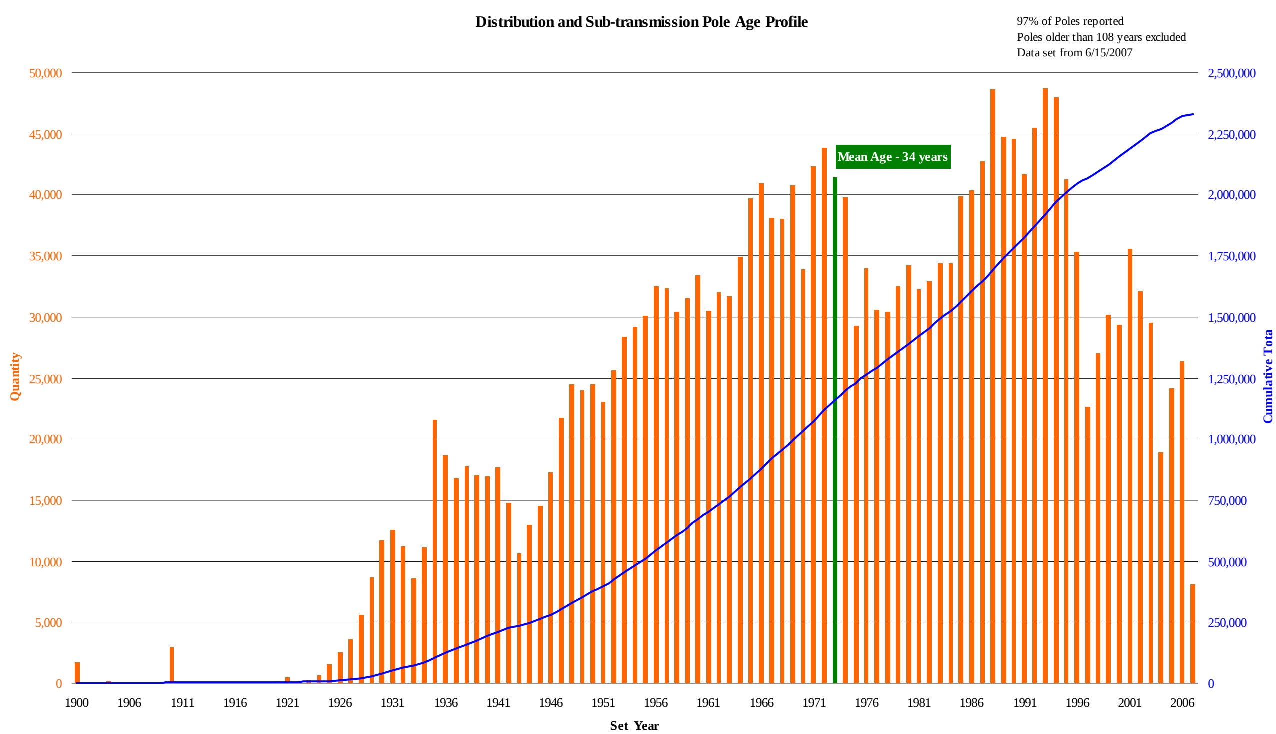

Figure 1

Sub-transmission pole data is currently being captured by a helicopter survey. This data is expected to be available within the GIS by the end of FY09. The availability of this information electronically will support quicker access to the information and the ability to better analyze the data.

The Inspection Program has been updated to improve the consistency of the equipment condition reporting. Enhanced pole inspection has been added to the program which includes both a visual and structural (using a hammer and screwdriver) review of all poles on a five year cycle. The Inspection Program is identifying and assigning a priority code (1-3) to poles in need of replacement. A brief description of the priority code levels follows:

- Level 1 An identified pole that must be repaired/replaced within five days
- Level 2 An identified pole that must be repaired/replaced within six months
- Level 3 An identified pole that must be repaired/replaced within two years

Photographs of poles with different priority codes are provided to support consistent priority code collection. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle as per EOP D004 and T007.

Due to the dynamic nature of the overhead distribution system, distribution poles are typically replaced before a condition based review would target them for replacement. This is due to a number of reasons including, load growth, circuit re-configuration, road re-building, and other routine changes to the overhead system. This statement does not apply to the majority of the sub-transmission poles as these assets are in a more static environment.

Interruptions caused by pole related issues are not significant (analysis of New York data revealed 0.06% of poles are involved in outages, with 60% of these related to motor vehicles); most pole problems are safety and environment related. While we have not experienced a large number of pole failures, the few we have experienced are getting more media attention. Maintaining or slightly improving our pole age profile is recommended to hold steady at our current level of failures. The majority of the reliability impact is related to external factors like motor vehicle accidents, tree fells (not limbs) and customer related activity.

2.2 Pole Model

The Pole Model which ranks poles for replacement is available to provide pole ranking information. Figure 2 is diagram of the model and brief description of the model follows:

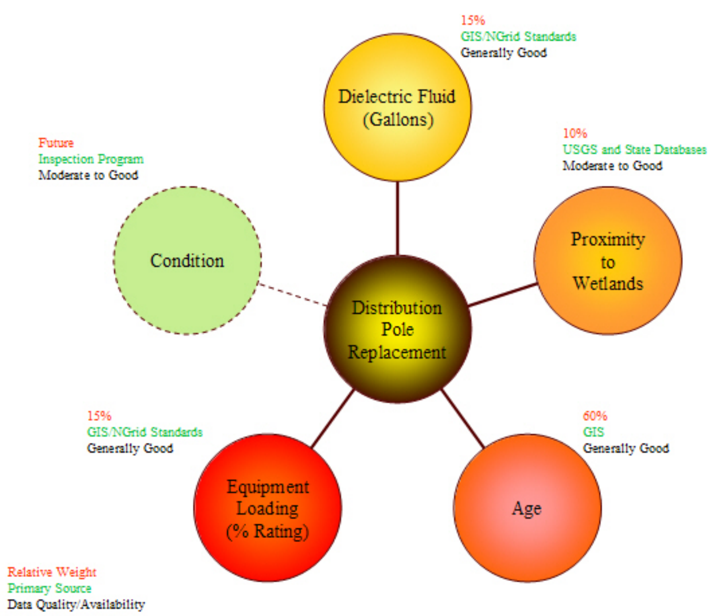

Figure 2

- Uses four unequally weighted measures to score poles
- Each measure is scored from 0 to 2
- Scores are combined by multiplying each measure score by the relative weight than adding the four scores together to create an overall weight from 0 to 2
- Poles scoring at or above 1.2 are candidates for replacement
- All poles more than 80 years old are automatically selected for replacement
- Condition data from the Inspection Program will be integrated beginning in FY10

2.3 Inspection Results

Distribution

A review of distribution pole inspection data was completed for inspections between 01/01/08 and 08/31/08. In this time frame, approximately 271,500 poles were inspected across New York. Approximately 1,500 of the inspected poles had Level 1 or 2 codes and 6,500 had Level 3 codes. This represents 0.55% of the inspected population for Level 1 and 2 codes and 2.40% for Level 3 codes. Figure 3 shows both the poles inspected and poles to be replaced by install year:

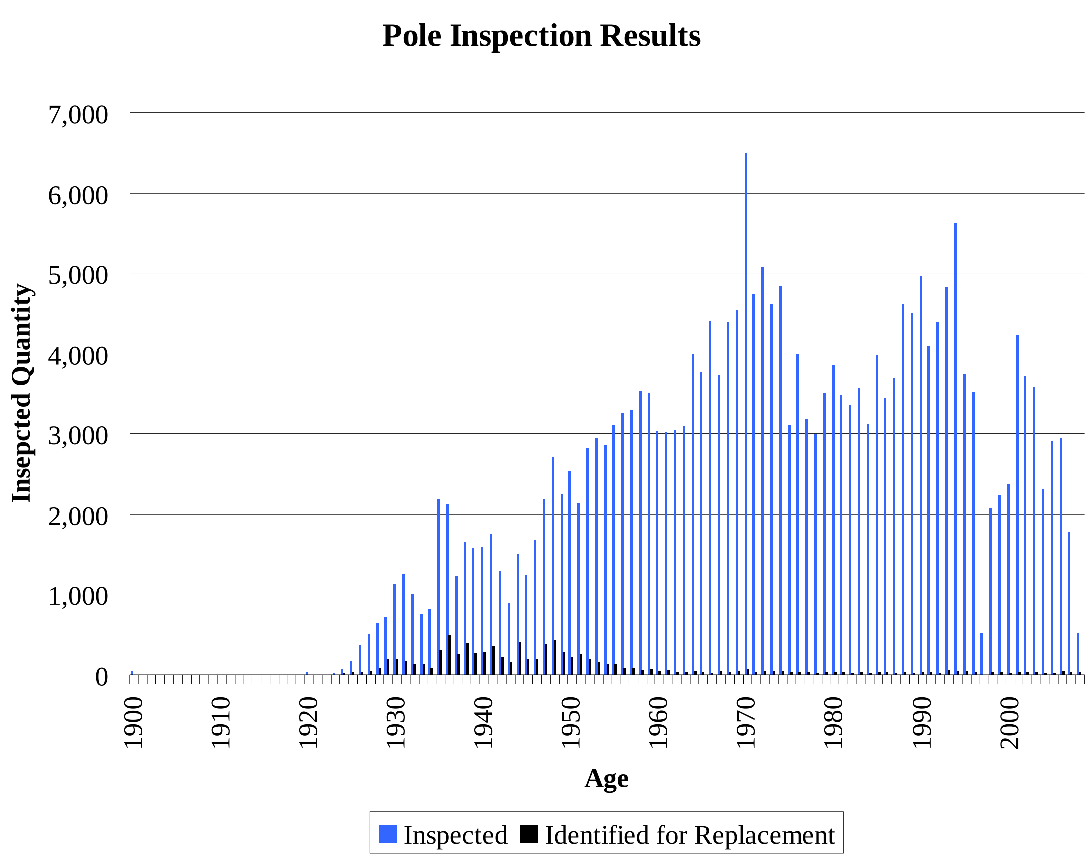

Figure 3

As Figure 3 illustrates, the quantities of poles replaced are much smaller than the total poles inspected. Additionally, reviewing the install year distribution between Figure 1 and Figure 3, the partial year inspection data in Figure 3 is roughly representation of the entire population. Reviewing the age of poles to be replaced by the Inspection Program, a steep increase in replacements is visible beginning at approximately 50 years (Figure 4). This increase tapers off at approximately 80 years.

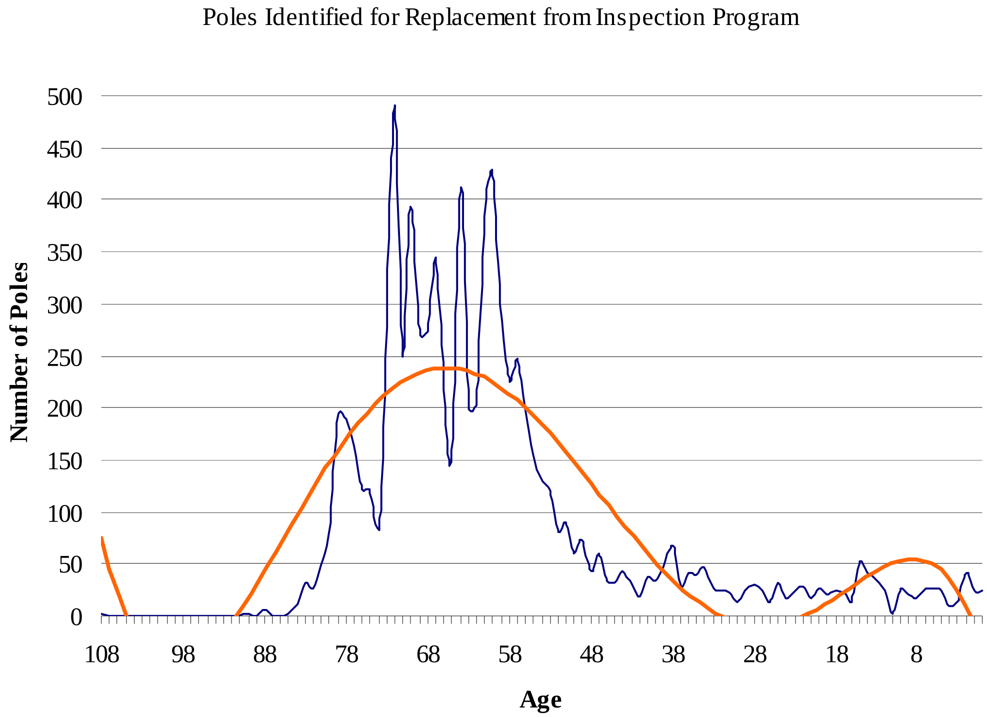

Figure 4

The percent replaced versus inspected is approximately 0.9% from 0 to 50 years of age and approximately 9% from 51 years of age to the end of the data set. The small jump at the beginning of the curve (0 to 10 years old) is likely associated with poles partially damaged by snow removal or minor motor vehicle damage not resulting in an outage.

These results (Level 1 & 2, 0.55%; Level 3, 2.40%) are the basis for the distribution budgetary estimates discussed in Section 4.0.

Sub-transmission

A review of sub-transmission pole inspection data was completed for inspections between 01/01/08 and 08/31/08. In this time frame, approximately 10,100 poles were inspected across New York. Ten of the inspected poles had Level 1 or 2 codes and 178 had Level 3 codes. This represents 0.10% of the inspected population for Level 1 and 2 codes and 1.76% for Level 3 codes. Install year data is not available for sub-transmission poles on a pole by pole basis, only in aggregate so comparison charts cannot be created.

These results (Level 1 & 2, 0.10%; Level 3, 1.76%) are the basis for the sub-transmission budgetary estimates discussed in Section 4.0.

2.4 Pole Strategy

The strategy for pole replacements is to use the Inspection Program results to generate replacement candidates based on condition.

The Pole Model will be updated in FY10 to include the output of the Inspection Program. This model analyzes other aspects of the pole replacement beyond condition (wetlands, dielectric fluid, loading, etc.) and will remain in place to provide ranking information for Level 3 pole replacement as well as any ad hoc requests.

3.0 Benefits

The principal benefits to pole replacement are in the safety and environmental areas.

3.1 Safety & Environmental

Existing work procedures based on the EOP's and construction standards provide for a safe work environment on and around existing pole plant. Pole replacement prior to failure provides an incremental public safety benefit and avoids the potential environmental problems related to dielectric fluid releases.

3.2 Reliability

The reliability benefit associated with pole replacement is small. However, poles are the foundation of the distribution and sub-transmission systems and maintaining acceptable reliability performance without a sound foundation is not sustainable. The programmatic replacement of poles under the Inspection Program supports the creation of a sustainable distribution system and will enable National Grid's objective of first quartile reliability performance.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with pole replacement is small. In several states we have regulatory requirements prescribing cyclic inspection of overhead equipment (including poles) and associated repair timeframes based on the severity of the problem. The Inspection Program meets or exceeds these regulatory requirements. Replacing poles through the Inspection Program has the benefit of maintaining our regulatory compliance for overhead equipment inspection and maintenance.

3.4 Efficiency

The programmatic replacement of poles under the Inspection Program supports a predictable replacement rate and avoids unexpected changes to replacement rates in the absence of inspection data. This predictable replacement rate better supports long term budgeting, packaging of work for internal and/or external crews, and combining pole replacement with line rebuilds or voltage conversions.

4.0 Estimated Costs

Applying the percentages determined in Section 2.3 across the system the high level quantities and budgets for distribution and sub-transmission (Table 1) yield the following quantities:

Estimated System-wide Pole Replacements based on Inspection Data*

Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	2,507	7,211	9,718	$38,872,000	24	246	270	$4,050,000	$42,922,000
FY11	2,507	7,982	10,489	$41,956,000	24	428	452	$6,780,000	$48,736,000
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FY13	2,507	10,005	12,512	$50,048,000	24	428	452	$6,780,000	$56,828,000
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FY18	827	3,686	4,513	$18,052,000	8	140	148	$2,220,000	$20,272,000
FY19	827	3,586	4,413	$17,652,000	8	140	148	$2,220,000	$19,872,000

*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY16 all of Level 3 distribution poles are included in the plan (including backlog from FY10 - FY15). Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

Table 1

The estimated replacement cost (2008 dollars) is $4,000/pole for distribution and $15,000/pole for sub-transmission. The large cost differential between distribution and sub-transmission poles reflects the increased cost associated with gaining access to poles in the right-of-way and environmental safeguards needed to work in these areas. For distribution poles the estimated cost is based on FY08 actuals from the Targeted Pole Replacement Programs. For Sub-T, the estimated costs represent the high end of the possible cost for long range budget forecasting. Additionally, the annual cost has been averaged over the five year cycle. These budgetary figures are not definitive and serve only to establish an approximate funding level for the long term program. As the near term budget (12 -18 months) is developed, more detail will be added regarding both the actual quantities and costs.

Reviewing the latest FY10 budget, approximately $36.25 million has been allocated to distribution pole replacements between the Inspection Program, Targeted Pole Replacement Program and Feeder Hardening Program. For sub-transmission poles, approximately $4.7 million has been allocated in the Inspection Program. According to EOP D004 all Level 3 poles are to be replaced within two years. Meeting this requirement would require approximately $53.5 million beginning in FY11. A phased approach to spanning the $17 million gap is proposed to reach compliance with EOP D004 by FY19 across the system. Level 1 and 2 distribution poles and all sub-transmission poles will be in compliance in FY10.

In addition to pole replacements associated with programs, approximately $5.2 million is allocated to specific projects. 90% of this is related to the sub-transmission system. This strategy is not designed to include or address specific project level work, these types of projects are to be justified and budgeted independently.

These estimates include poles identified by the Overhead Inspection Program, Targeted Pole Replacement Program and the Feeder Hardening Program. Beginning in FY10, the Feeder Hardening feeder selections have been coordinated with the New York inspection cycle to maximize the use of the inspection resources and bring Feeder Hardening and the Inspection Program into alignment. A similar effort can take place for the FY11 Feeder Hardening feeder selection. Based on the scope of this pole replacement effort, the Targeted Pole Replacement Programs in New York and New England can be phased out in the near future as inspection results become the driver for pole replacements.

5.0 Implementation

This strategy is being implemented using condition data collected by the Inspection Program. This method will maintain or slightly improve the overall age profile. Consideration for use of an external vendor to evaluate a targeted sample of poles that have been inspected by the Inspection Department is recommended after pole data from New England has been collected to ensure the criteria is reasonable.

A confounding factor in addressing pole replacements is jointly owned poles in areas set by the local telephone company. The division design departments will need to work with their telephone company counterparts to insure these poles are replaced in as timely a manner as possible.

Additionally, Problem Identification Worksheets, Feeder Hardening, Engineering Reliability Reviews and Pockets of Poor Performance may identify additional pole replacement work.

5.1 Performance Targets

The performance of this strategy will be measured by conformance to Inspection Program (EOP D004 & T007) specifically:

- maintaining the inspection cycle (20% of system annually)
- replacing poles in accordance with the priority codes and associated replacement time frames as adjusted in the long term compliance plan

6.0 Risk Assessment

Main risks are safety and environmental.

6.1 Safety & Environmental

Existing work procedures based on the EOP's and construction standards provide for a safe work environment on and around existing pole plant. The risk associated with not replacing poles prior to failure is the increased possibility of a safety related incident to an employee or layperson and an increased potential for environmental problems related to dielectric fluid releases.

6.2 Reliability

The near term reliability risk associated with poles is small. The long term risk of non-programmatic condition based pole replacements is the erosion of the sustainability of the distribution system. This will negatively impact the system's long term reliability.

6.3 Customer/Regulatory/Reputation

The customer risk associated with pole replacement is small. In several states we have regulatory requirements prescribing cyclic inspection of overhead equipment (including poles) and associated repair timeframes based on the severity of the problem. The Inspection Program meets or exceeds these regulatory requirements. Failing to inspect and replace poles would result in noncompliance with our regulatory requirement for overhead equipment inspection and maintenance.

6.4 Efficiency

The risk associated with non-programmatic condition based pole replacement is unpredictable long term budgeting and loss of efficiency with the construction groups.

7.0 Data Requirements

7.1 Existing/Interim:

Smallworld/ArcSDE – distribution pole data
Computapole – pole inspection data
Helicopter Survey – sub-transmission pole data

7.2 Proposed:

Smallworld/ArcSDE – all pole data
Computapole – pole inspection data

7.3 Comments:

Conversion from Computapole to a different inspection tool is being evaluated as part of the Transformation Program.

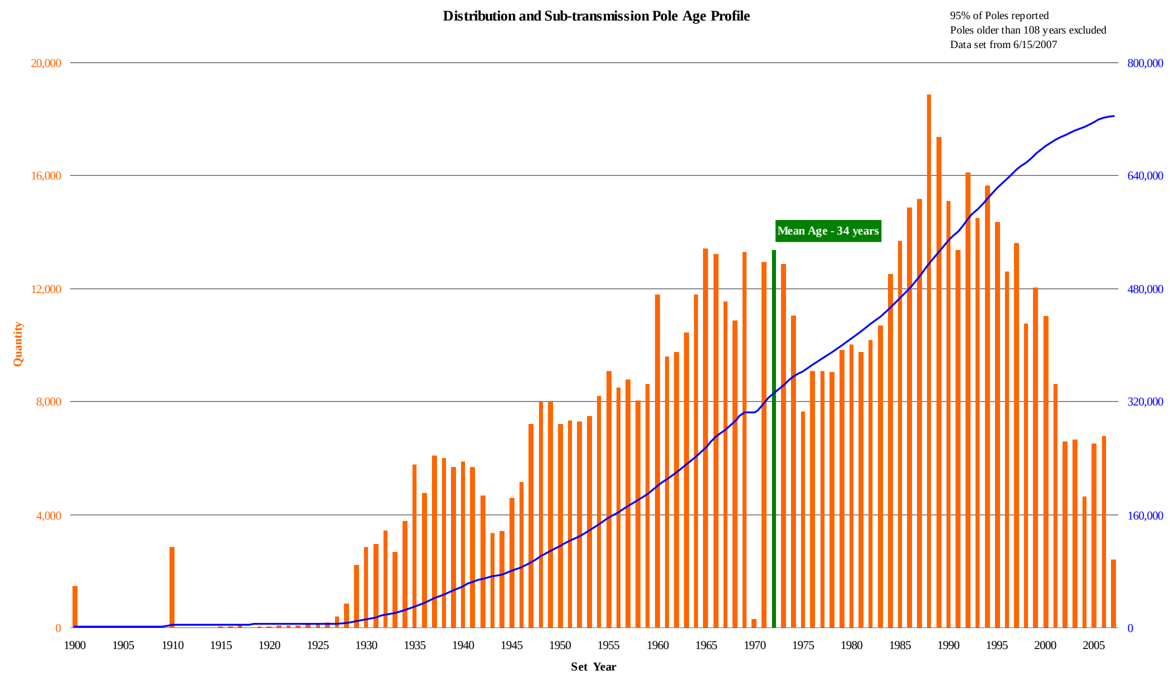
8.0 References

EOP D004 – Distribution Line Patrol and Maintenance
EOP T007 – Transmission Line Patrol 23kV – 345kV
DAM – 012, Engineering Reliability Review Process Guideline
DAM – 016, Problem Identification Worksheet (PIW) Process for Distribution Lines
Feeder Hardening Strategy
Pockets of Poor Performance Strategy

Massachusetts Specifics

Pole Age Profile

National Grid has approximately 750,600 distribution and sub-transmission poles in Massachusetts. Reasonable age data is available for both distribution and sub-transmission poles. A chart of the combined age profile of distribution and sub-transmission poles is below:



Estimated Costs

Estimated Massachusetts Pole Replacements based on Inspection Data*

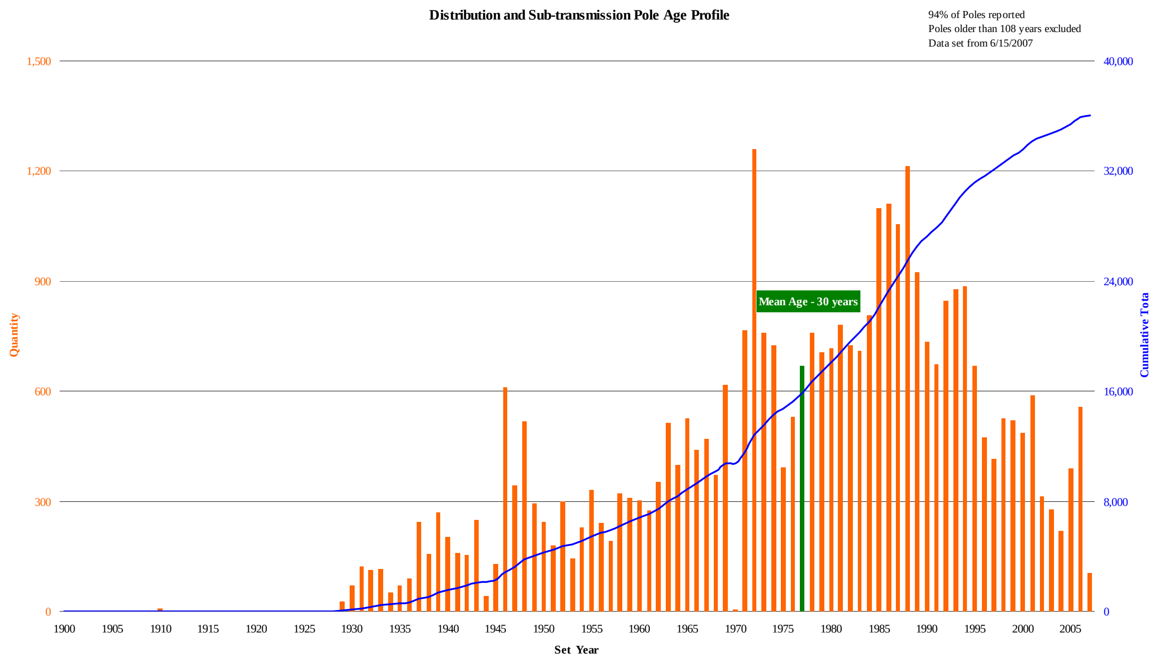
Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	796	1,671	2,467	$9,868,000	6	0	6	$90,000	$9,958,000
FY11	796	2,000	2,796	$11,184,000	6	113	119	$1,785,000	$12,969,000
FY12	796	2,500	3,296	$13,184,000	6	113	119	$1,785,000	$14,969,000
FY13	796	3,000	3,796	$15,184,000	6	113	119	$1,785,000	$16,969,000
FY14	796	3,500	4,296	$17,184,000	6	113	119	$1,785,000	$18,969,000
FY15	263	3,500	3,763	$15,052,000	2	113	115	$1,725,000	$16,777,000
FY16	263	2,000	2,263	$9,052,000	2	37	39	$585,000	$9,637,000
FY17	263	1,350	1,613	$6,452,000	2	37	39	$585,000	$7,037,000
FY18	263	1,138	1,401	$5,604,000	2	37	39	$585,000	$6,189,000
FY19	263	1,138	1,401	$5,604,000	2	37	39	$585,000	$6,189,000

*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY17 all of Level 3 distribution poles are included in the plan (including backlog from FY10 - FY16). Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

New Hampshire Specifics

Pole Age Profile

National Grid has approximately 38,000 distribution and sub-transmission poles in New Hampshire. Reasonable age data is available for both distribution and sub-transmission poles. A chart of the combined age profile of distribution and sub-transmission poles is below:



Estimated Costs

Estimated New Hampshire Pole Replacements based on Inspection Data*

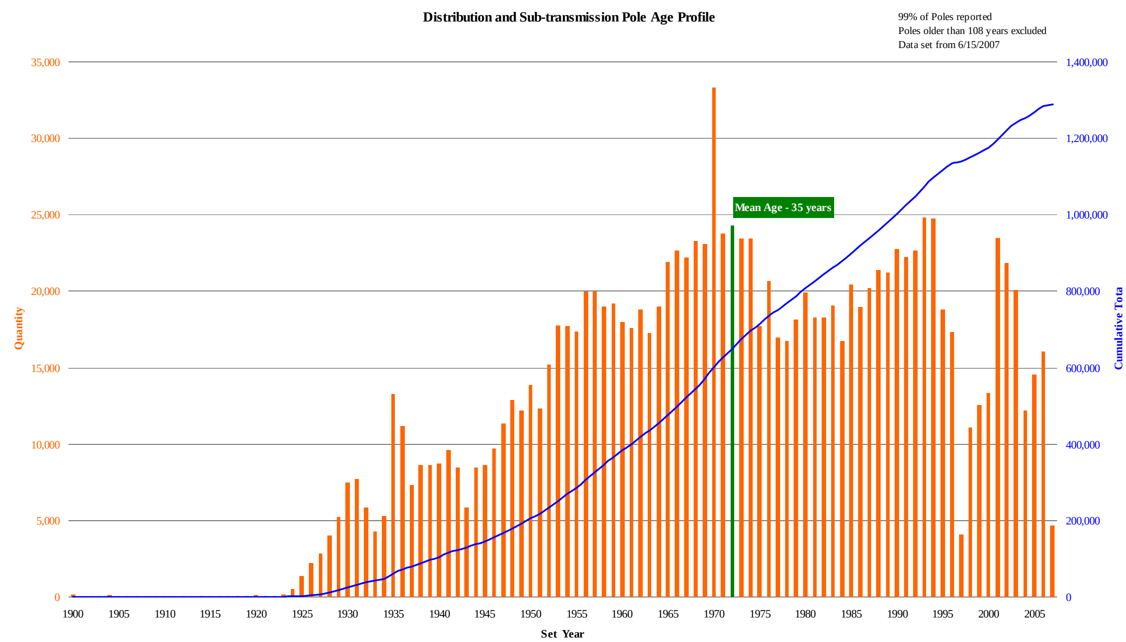
Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	40	0	40	$160,000	0	0	0	$0	$160,000
FY11	40	147	187	$748,000	0	7	7	$105,000	$853,000
FY12	40	147	187	$748,000	0	7	7	$105,000	$853,000
FY13	40	160	200	$800,000	0	7	7	$105,000	$905,000
FY14	40	173	213	$852,000	0	7	7	$105,000	$957,000
FY15	13	173	186	$744,000	0	7	7	$105,000	$849,000
FY16	13	130	143	$572,000	0	2	2	$30,000	$602,000
FY17	13	100	113	$452,000	0	2	2	$30,000	$482,000
FY18	13	80	93	$372,000	0	2	2	$30,000	$402,000
FY19	13	57	70	$280,000	0	2	2	$30,000	$310,000

*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY16 all of Level 3 distribution poles are included in the plan (including backlog from FY10 - FY15). Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

New York Specifics

Pole Age Profile

National Grid has approximately 1.3 million distribution and sub-transmission poles in New York. Reasonable age data is available for both distribution and sub-transmission poles. A chart of the combined age profile of distribution and sub-transmission poles is below:



Estimated Costs

Estimated New York Pole Replacements based on Inspection Data*

Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	1,361	5,015	6,376	$25,504,000	14	246	260	$3,900,000	$29,404,000
FY11	1,361	5,015	6,376	$25,504,000	14	246	260	$3,900,000	$29,404,000
FY12	1,361	5,500	6,861	$27,444,000	14	246	260	$3,900,000	$31,344,000
FY13	1,361	5,500	6,861	$27,444,000	14	246	260	$3,900,000	$31,344,000
FY14	449	5,900	6,349	$25,396,000	5	246	251	$3,765,000	$29,161,000
FY15	449	4,000	4,449	$17,796,000	5	81	86	$1,290,000	$19,086,000
FY16	449	3,000	3,449	$13,796,000	5	81	86	$1,290,000	$15,086,000
FY17	449	2,000	2,449	$9,796,000	5	81	86	$1,290,000	$11,086,000
FY18	449	2,024	2,473	$9,892,000	5	81	86	$1,290,000	$11,182,000
FY19	449	1,947	2,396	$9,584,000	5	81	86	$1,290,000	$10,874,000

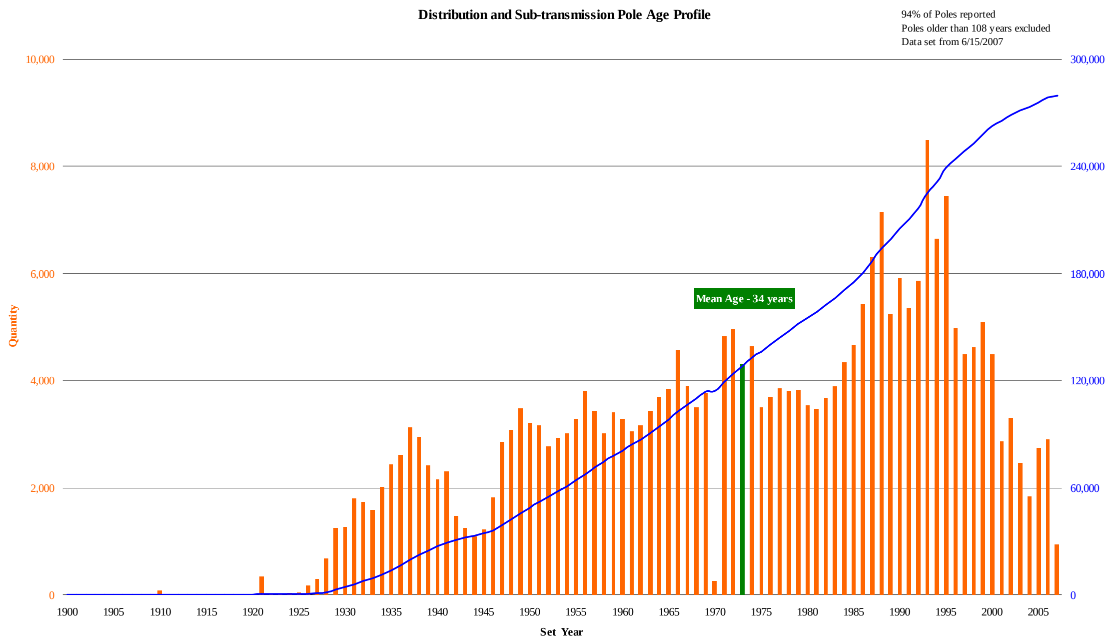
*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY16 all of Level 3 distribution poles are included in the plan (including backlog from FY10 - FY15). Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

Cyclic inspection and repair of poles is a regulatory requirement in New York.

Rhode Island Specifics

Pole Age Profile

National Grid has approximately 298,000 distribution and sub-transmission poles in Rhode Island. Reasonable age data is available for both distribution and sub-transmission poles. A chart of the combined age profile of distribution and sub-transmission poles is below:



Estimated Costs

Estimated Rhode Island Pole Replacements based on Inspection Data*

Year	Distribution				Sub-transmission				Total Cost
	Level 1 & 2	Level 3	Total	Estimated Cost	Level 1 & 2	Level 3	Total	Estimated Cost	
FY10	310	525	835	$3,340,000	4	0	4	$60,000	$3,400,000
FY11	310	820	1,130	$4,520,000	4	62	66	$990,000	$5,510,000
FY12	310	1,345	1,655	$6,620,000	4	62	66	$990,000	$7,610,000
FY13	310	1,345	1,655	$6,620,000	4	62	66	$990,000	$7,610,000
FY14	310	1,345	1,655	$6,620,000	4	62	66	$990,000	$7,610,000
FY15	102	1,345	1,447	$5,788,000	1	62	63	$945,000	$6,733,000
FY16	102	444	546	$2,184,000	1	20	21	$315,000	$2,499,000
FY17	102	444	546	$2,184,000	1	20	21	$315,000	$2,499,000
FY18	102	444	546	$2,184,000	1	20	21	$315,000	$2,499,000
FY19	102	444	546	$2,184,000	1	20	21	$315,000	$2,499,000

*Assumes replacements begin in FY10. All Level 1 & 2 poles are replaced in same fiscal year as identified. Level 3 distribution poles will be phased in over the first two cycles to ramp up spending always maintaining the 85% threshold required by the EOP. By FY10 all of Level 3 distribution poles are included in the plan. Beginning in FY10 Level 3 sub-transmission poles will be replaced during the fiscal year following their identification. After first full cycle (5 years) quantities are reduced to 33% of first cycle values. All estimates in 2008 dollars.

Division Data Request 14-20

Request:

Provide a copy of the pole testing summary reports from the last five years delineating the total number of poles tested, the total number of defective poles identified and the total number of defective poles that were replaced, and the total number of defective poles replaced and the total number of defective poles remediated including how the remediation was accomplished for each of the last five years.

Request:

As stated in DIV 14-19, National Grid does not have any record of pole testing on a systematic regular cyclical basis.

The Targeted Pole replacement program has been a component of the Reliability Enhancement Program since 2006. Prior to 2006, pole inspections and replacements occurred as a result of local engineering decisions and ad-hoc queries. The table below shows poles replaced in Rhode Island since 2005.

Year	Poles Replaced
FY06 (2005)	120
FY07 (2006)	131
FY08 (2007)	465
FY09 (2008)	417

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-21

Request:

Has the Company compared its vegetation management program with other utilities and what were the results of such a comparison?

Request:

Yes, the Company continually evaluates its vegetation management program in comparison to other utilities. Some of these ongoing comparisons include, UAA System Foresters Summit, Northeast US Electric Utility Vegetation Management Benchmark Committee, PSE&G Benchmarking Studies, PPL Danger – Hazard Tree Survey 2008, EUCG (electric utility cost group) Vegetation Management Practices- Storm Impact Reduction benchmarking group 2007.

Please see the following attachments for the results of the comparisons.

Attachment DIV 14-21-1: NE Benchmark Data 3 25 08

Attachment DIV 14-21-2: PPL Danger-Hazard Tree Survey

Attachment DIV 14-21-3: Electric Distribution Benchmark Report-National Grid-Consolidation *2009*

Prepared by or under the supervision of: John Pettigrew

Division Data Request 14-22

Request:

Provide a list delineating each projected voltage violation by circuit and location for each of the next five years.

Request:

Please see response to Division Data Request 14-2.

Division Data Request 14-23

Request:

Provide a detailed listing of each of the projected thermal violations by substation, piece of equipment, and circuit for each of the next five years.

Request:

Please see response to Division Data Request 14-2.

Division Data Request 14-24

Request:

Provide a detailed description as to how the company reflects the joint ownership relationship with Verizon and others on the cost for pole replacement, repairs and other O&M cost.

National Grid Response:

In Rhode Island, National Grid joint pole ownership exists with Verizon only. Regarding jointly owned pole replacements, pole ownership payments from Verizon are recorded as a contribution against the pole cost and accordingly, the booked cost is reduced by the value of the payment received. National Grid payments to Verizon for joint pole ownership are booked at the value paid.

Generally, there is no contribution received or paid for O&M costs incurred by either joint pole owner (either National Grid or Verizon). Each company bears 100% of O&M costs relating to their facilities installed on the joint owned pole. O&M costs relating specifically to the "pole" are borne by the assigned Custodian under the Joint Pole Ownership Agreement. Custodianship for the common service area with Verizon has been assigned such that there exists an approximate 50-50 distribution of the common service area. On exception and with mutual agreement, certain O&M costs relating to the pole (e.g., pole treatment/pole reinforcement) if performed, would be shared equally.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 16-16

Request:

Re: page 8 of 15, lines 9-13, of the testimony of witness Fields. Please provide the total dollars that National Grid has expended in support of its economic development programs in New York State since 2003 including all associated utility operating, administrative, and overhead costs.

Response:

Since 2003, National Grid has expended a total of $8.4 million in support of its economic development programs in New York State. This total includes all direct administrative and operating costs expended to support the Company's economic development activities. The total does not include labor overheads such as pensions and benefits, and also does not include the value of the economic development incentives made in the form of customer grants and discount amounts.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 17-1

Request:

Please explain the activities conducted by Narragansett employees and those conducted by the National Grid Service employees that are booked in accounts 580, 588, 598, and 594: this should include an explanation as to why a high proportion of Narragansett's costs appear to result from Service Company charges.

Response:

The amounts recorded in Accounts 580, 588, 598, and 594 align with the types of costs to be reflected in these accounts pursuant to FERC's Code of Federal Regulations ("CFR"). Brief definitions are as follows, representing guidance provided in FERC's CFR:

Account 580: This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the distribution system.

Account 588: This account shall include the cost of labor, materials used and expenses incurred in distribution system operation not provided for elsewhere.

Account 598: This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in accounts 371, Installations of Customers' Premises, and 372, Leased Property on Customers' Premises, and any other plant the maintenance of which is assignable to the distribution function and is not provided for elsewhere.

Account 594: (Major only) This account shall include the cost of labor, materials used and expense incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services.

Please see Attachment DIV 17-1, which shows the activities recorded in these accounts. This schedule represents all charges in the respective accounts originating from the Company and the National Grid USA Service Company.

The Company employs the services of the National Grid USA Service Company under the terms and conditions of their mutual service agreement, and is billed accordingly for the services provided. Please see the service agreement contracts as provided in the response to Division Data Request 12-1.

Prepared by or under the supervision of: Robert L. O'Brien

Narragansett Electric
Summary by Activity for Regulatory Accounts 580, 588, 594 and 598
Charges Originating from Narragansett Electric and National Grid Service Company
Calendar 2008

				Orig Business Unit		
Line	Regulatory	Regulatory Acct Descr	Activity Descr	Narragansett Electric	NG USA Service Co.	Grand Total
1	580000	Dist Oper-Supervision & Eng	Dispatch Crews - Distribution	336	17,150	17,486
2			Eng Analysis/OM Proj Work-Dist		1,914	1,914
3			Engineer / Develop PLC/HMI -		2,316	2,316
4			Engineer/Develop Control Schem		25,385	25,385
5			Engineer/Develop Protection Sc		2,639	2,639
6			Engineer/Develop Wireless Sche		3,067	3,067
7			IS Development - Distribution	40	138,005	138,046
8			IS Enhance - Distribution Ops		0	0
9			IS Support - Distribution Ops	81	74,120	74,201
10			Lab Admin & Genl Services		162,861	162,861
11			NPCC/ISO Studies & Support - D		60	60
12			Perform CATV Make Ready Survey	(511,906)	95,130	(416,775)
13			Perform Detailed Design - Non-	202,414	2,966	205,380
14			Perform Distribution Overhead	18,629		18,629
15			Perform Engineering Surveys -	67,469	127,257	194,726
16			Perform Engineering System Pla	12,158	106,783	118,941
17			Perform Interconnection Engine	(3,143)	45,726	42,583
18			Perform Reliability/Contingenc	624	147,188	147,812
19			Perform Special Project/Study-	406	56,048	56,454
20			Perform Technical Support Oper	1,723	2,480	4,203
21			PLC/HMI support - Distribution		801	801
22			Protection Coordination Sys Re		6,651	6,651
23			Shared Telecom Billing - Distr	353		353
24			Standards and Committees		28	28
25			Supervision&Engineering OH	238,009	113,595	351,603
26			Update Sub Design Records	644	430	1,074
27	580000 Total			27,836	1,132,600	1,160,436
28	588000	Dist Oper-Misc Expenses	Attend Distribution Safety Mee	296,255	21,462	317,717
29			Attend Distribution Safety Tra	137,702	26,997	164,699
30			Attend Other Employee Meetings	520,248	73,974	594,223
31			Attend Training Other Than Saf	656,746	140,270	797,016
32			Building Expenses and Small To	401,552	907,584	1,309,136
33			Chemical Lab Activities		14	14
34			Clean/Stock Distribution Vehic	373,434	25	373,459
35			Connect/Disconnect Taps - Dist	51,653		51,653
36			Connect/Disconnect Taps-Distri	145,113		145,113
37			Electric Distribution Financia		185,030	185,030
38			Employee Communications		35	35
39			Facilities Rent-Elim	35,983		35,983
40			Failure Analysis/Special Testi		2,283	2,283
41			IEEE Comm Standards Work-Dist		5,760	5,760
42			Inclement Weather - Distributi	977,722	2,572	980,294
43			Install Rubber Cover/Service/C	81,749		81,749
44			Misc Ops Supv and Admin	1,012,931	2,498,369	3,511,299
45			Miscellaneous Field Investigat	345	33,624	33,969
46			Perform Distribution Accident	16,672	3,134	19,806
47			Perform Distribution Police Pr	61,204	44,050	105,254
48			Perform DOT Drug Testing - Dis	11,202	179	11,380
49			Perform Emergency Standby - Di	337,422	6,440	343,862
50			Perform Light Duty - Distribut	514,382	47	514,428
51			R&D Distribution Operations		10	10
52			Repair Engineering Lab Instrum		183	183
53			Respond to Fire/Emergency Call	117,111		117,111
54			Test Boom Trucks	144	3,970	4,114
55			Test Engineering Lab Instrumen		3,647	3,647

Narragansett Electric
Summary by Activity for Regulatory Accounts 580, 588, 594 and 598
Charges Originating from Narragansett Electric and National Grid Service Company
Calendar 2008

				Orig Business Unit		
Line	Regulatory	Regulatory Acct Descr	Activity Descr	Narragansett Electric	NG USA Service Co.	Grand Total
56			Test Live Line Tools	320	10,703	11,023
57			Test Miscellaneous Dielectric		1,826	1,826
58			Test Rubber Gloves		73,953	73,953
59			Test Rubber Sleeves		7,205	7,205
60			Training Center-Rent-Elim		73,328	73,328
61			Update Maps/Records-Distributi	236,139	46,005	282,145
62			Wait for Vehicle Breakdown Ass	69,785	406	70,191
63	588000 Total			6,055,813	4,173,084	10,228,896
64	594000	Dist Maint-Underground Lines	Environmental-Haz Waste-DUG	52,042	6,964	59,006
65			Maintain Cable - Direct Buried	7,926	11	7,937
66			Maintain Cable - Submarine - D	3,980		3,980
67			Maintain Cable in Conduit - Le	14,230	7,787	22,017
68			Maintain Cable in Conduit-XLPE	30,888	1,773	32,661
69			Maintain Cathodic Protection -		105	105
70			Maintain Conduit/Riser - Distr	33,360	11,881	45,241
71			Maintain Conventional Secondar	6,906		6,906
72			Maintain Distribution Ground E	1,201		1,201
73			Maintain Distribution Undergro	36,066	5,462	41,528
74			Maintain Manhole/Handhole - Di	103,878	12,862	116,740
75			Maintain Network - Secondary -	856		856
76			Maintain Network Protector - D	88,717	436	89,153
77			Maintain Oil Fused Cutout - Di	205		205
78			Maintain Other Underground Swi	4,516	312	4,828
79			Maintain Outdoor Light Cable -	29,820	33	29,853
80			Maintain Padmount Switch - Dis	7,732	35	7,767
81			Maintain Sidewalk/Building Vau	15,874	41,366	57,240
82			Maintain Underground Splice	2,566		2,566
83			Maintain Underground Terminati	398		398
84			Maintain URD - Secondary - Dis	3,546	474	4,019
85			Maintain URD Cable - In Condui	3,863		3,863
86			Maintain URD Cable Direct Buri	35,000	210	35,210
87			MMT Materials Dist UGL Mnt	(1,592,409)	2,078,381	485,972
88			Perform 3rd Party Make Ready W	899		899
89			Perform Site Restoration - Dis	3,343		3,343
90			Refuse Underground Protective	261		261
91			Supervision & Administration D	391	99	490
92	594000 Total			(1,103,944)	2,168,192	1,064,248
93	598000	Dist Maint-Misc Distr Plant	Bldg Exp & Small Tools - Distr	75	121	196
94	598000 Total			75	121	196
95	Grand Total			4,979,779	7,473,997	12,453,776

Division Data Request 17-2

Request:

Please provide data on the proportion of activities booked in accounts 594 (Maintenance of Underground Lines) and 598 (Maintenance of Miscellaneous Plant) which are conducted in Rhode Island, and explain whether and how these activities are performed by Service Company employees.

Response:

Please see Attachment DIV 17-2, which shows the proportion of activities booked in Accounts 594 and 598 between the Company and the Service Company. Page 1 indicates the activity being performed while page 2 identifies the type of expense charged to the two FERC accounts. It should be noted that the credit of $1.6 million in activity "MMT Materials" is a result of work orders being completed and closed, resulting in warehouse inventory being reclassified and/or charged to specific work order accounting; the offsetting activity is either another O&M FERC account or capital.

The activities that originate from National Grid USA Service Company are performed and billed under the terms and conditions of their mutual service agreement.

Prepared by or under the supervision of: Robert L. O'Brien

Narragansett Electric
Summary by Activity for Regulatory Accounts 594 and 598
Charges Originating from Narragansett Electric and National Grid Service Company
Calendar 2008

				Orig Business Unit		
Line	Regulatory Acct	Regulatory Acct Descr	Activity Descr	Narragansett Electric	NG USA Service Co.	Total
1	594000	Dist Maint-Underground Lines	Environmental-Haz Waste-DUG	52,042	6,964	59,006
2			Maintain Cable - Direct Buried	7,926	11	7,937
3			Maintain Cable - Submarine - D	3,980		3,980
4			Maintain Cable in Conduit - Le	14,230	7,787	22,017
5			Maintain Cable in Conduit-XLPE	30,888	1,773	32,661
6			Maintain Cathodic Protection -		105	105
7			Maintain Conduit/Riser - Distr	33,360	11,881	45,241
8			Maintain Conventional Secondar	6,906		6,906
9			Maintain Distribution Ground E	1,201		1,201
10			Maintain Distribution Undergro	36,066	5,462	41,528
11			Maintain Manhole/Handhole - Di	103,878	12,862	116,740
12			Maintain Network - Secondary -	856		856
13			Maintain Network Protector - D	88,717	436	89,153
14			Maintain Oil Fused Cutout - Di	205		205
15			Maintain Other Underground Swi	4,516	312	4,828
16			Maintain Outdoor Light Cable -	29,820	33	29,853
17			Maintain Padmount Switch - Dis	7,732	35	7,767
18			Maintain Sidewalk/Building Vau	15,874	41,366	57,240
19			Maintain Underground Splice	2,566		2,566
20			Maintain Underground Terminati	398		398
21			Maintain URD - Secondary - Dis	3,546	474	4,019
22			Maintain URD Cable - In Condui	3,863		3,863
23			Maintain URD Cable Direct Buri	35,000	210	35,210
24			MMT Materials Dist UGL Mnt	(1,592,409)	2,078,381	485,972
25			Perform 3rd Party Make Ready W	899		899
26			Perform Site Restoration - Dis	3,343		3,343
27			Refuse Underground Protective	261		261
28			Supervision & Administration D	391	99	490
29	594000 Total			(1,103,944)	2,168,192	1,064,248
30			Percent to Total	-104%		
31						
32	598000	Dist Maint-Misc Distr Plant	Bldg Exp & Small Tools - Distr	75	121	196
33	598000 Total			75	121	196
			Percent to Total	38%		

Narragansett Electric
Summary by Activity for Regulatory Accounts 594 and 598
Charges Originating from Narragansett Electric and National Grid Service Company
Calendar 2008

					Orig Business Unit		
Line	Regulatory Acct	Regulatory Acct Descr	Expense Type	Expense Type Descr	Narragansett Electric	NGUSA Service Co.	Total
1	594000	Dist Maint-Underground Lines	100	Consultants		13,437	13,437
2			110	Contractors Services	213,544	1,266	214,809
3			200	Employee Expenses	281	108	389
4			400	Other	0		0
5			A40	Construction Reimbursement	467		467
6			A42	Bill Interface Expense Type	(5,747)		(5,747)
7			A60	Supervision & Admin	478		478
8			A65	Service Co Operating Costs		52	52
9			A70	Sales Tax	(100,557)	139,772	39,215
10			M10	Materials Outside Vendor	86,137	11,205	97,343
11			M20	Materials From Inventory	(1,519,117)	1,998,452	479,335
12			M50	Materials Stores Handling	47,880		47,880
13			P10	Regular Pay Weekly	73,322	1,596	74,918
14			P15	Regular Pay Monthly	12,377	908	13,285
15			P20	Base OT Pay Weekly	20,910	46	20,956
16			P21	Incremental OT Pay Weekly	11,683	23	11,706
17			P25	Base OT Pay Monthly	2,575	266	2,841
18			P26	Incremental OT Pay Monthly	1,150	112	1,262
19			P30	Bonus & Misc Pay	4,350	260	4,610
20			P50	Time Not Worked	24,056	463	24,519
21			T10	Transportation	22,268	225	22,493
22	594000 Total				(1,103,944)	2,168,192	1,064,248
23							
24							
25	598000	Dist Maint-Misc Distr Plant	200	Employee Expenses	75	121	196
26	598000 Total				75	121	196

Division Data Request 17-3

Request:

Follow up to DIV 1-29, regarding Account 583:

(a) When did the new survey and inspection program begin?

(b) Do the survey and inspection program costs included in the cost of service include startup and planning costs?

(c) Please provide detail on the costs, by activity, included in the 2008 costs of the survey and inspection program.

(d) Are the costs of the survey and inspection program charged to the Company by the National Grid or KeySpan Service Companies?

(e) If the Service Companies charge for the survey and inspection program, please provide detail of these charges.

Response:

(a) The survey and inspection program referenced and accounted for in Account 583 is also referred to as The New England Geographic Information System (GIS) Survey Project, which began in summer of 2005. The objective of this program was to field verify, collect and update information on the overhead electric distribution facilities GIS data. Please note that the Inspection and Maintenance strategy that is outlined in the pre-filed testimony is different from the New England Geographic Information System (GIS) Survey Project.

(b) The survey and inspection programs costs include startup and planning costs.

(c) Nearly 97% of the costs associated with the New England GIS Survey Project in 2008 were for services performed by outside vendors/contractors. These services involved the collection of field data for overhead electric distribution assets, updating the data in National Grid's GIS, and performing Quality Assurance/Quality Control for field data and data delivered in GIS

(d) The costs of the New England Geographic Information System (GIS) Survey Project are charged to the Company by National Grid USA Service Company.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 17-3 (cont.)

(e) Please see Attachment DIV 17-3 (e), which provides a breakdown of charges for the Survey and Inspection program from the National Grid USA Service Company to Narragansett Electric.

Narragansett Electric Company
Analysis of FERC 583 - Calendar 2008
NE Survey and Inspection Program
Charges Originating from National Grid Service Company

							Charges from Affiliates
Line	Project	Project Descr	Activity	Activity Description	Expense Type	Expense Type Descr	NGUSA Service Company
1	X04782	NE Inventory Survey & Inspection	DO1100	Perform Distribution Overhead Patrol & Inspection	110	Contractors Services	2,233,960
2					200	Employee Expenses	2,692
3					300	Hardware	508
4					400	Other	337
5					A60	Supervision & Admin	3,395
6					A65	Service Co Operating Costs	115
7					M10	Materials Outside Vendor	876
8					M20	Materials From Inventory	0
9					M50	Materials Stores Handling	0
10					P15	Regular Pay Monthly	43,159
11					P30	Bonus & Misc Pay	3,479
12					P50	Time Not Worked	7,349
13					T10	Transportation	9,217
14		NE Inventory Survey & Inspection Total					2,305,085

Division Data Request 17-6

Request:

Follow up to DIV 1-29, with regard to account 903:

a) Please describe the new Interactive Voice Response system.

b) What was the cost of the Interactive Voice Response system?

c) Over what period is this cost being amortized?

d) Is this cost billed by the Service Companies?

e) If this cost is billed by the Service Companies, was the entire cost or an amortized amount billed in 2008?

f) What is the total amount of costs associated with customer calls?

g) Provide any analysis by which the Company determined that $2.7 million related to increased call volume.

h) Does the Service Company bill the Company for customer calls activities or are these costs directly incurred?

Response:

(a) The Interactive Voice Response (IVR) system allows customers to complete self service transactions and provides account-specific information as well as general information of interest to customers. For more complex transactions and needs, the calls are routed to a live representative.

Customers can navigate the IVR by using speech. Touch-tone functionality also is offered when needed, and as a fall-back for those who prefer to use touch-tone.

Features available on the IVR include:

- English and Spanish options for self service as well as account and general information
- Information regarding Consumer Information (supplier information and pricing) and Payment Agents.

Division Data Request 17-6 (cont.)

- Report an Outage
- Account information (Billing Summary and Billing Details)
- General Billing Information (Why Is My Bill So High, Payment Assistance)
- Payments (Report Payment, Electronic Payments/Pay By Phone, Enroll in Budget Billing, Short or Long Term Payment Plans, enroll in Direct Pay)
- Update Account Information (telephone number, payment mailing address)
- Stop Service
- Meter Reading: (Hear meter reading instructions, provide monthly meter reading or a reading to complete a Start or Stop Service Order)
- Consumer Information (Retail Access, Alternative Supplier Lists, Supply Pricing)
- Power Outage Application (Report an outage and hear information on restoration time, causes of the problem and affected areas)

(b) The cost of the Interactive Voice Response was $4,763,955.14.

(c) The cost of the Interactive Voice Response system is being amortized over a period of 60 months.

(d) The amortization costs are billed to Narragansett Electric Company by National Grid USA Service Company.

(e) The amount charged in 2008 was the annual amortization.

(f) In 2008, the total amount of costs associated with responding to customer calls and inquiries in FERC Account 903 was $2,617,794.

(g) The Company cannot determine the source of the reference to the $2.7 million quoted. It is not an amount contained in the Company's response to DIV 1-29.

(h) The majority of the costs billed for customer calls and inquiries originate from National Grid USA Service Company, but costs may also be directly incurred or originate from other National Grid affiliates.

Prepared by or under the supervision of: Rudolph L. Wynter

Navy Data Request 3-1

Request:

Referring to Schedule NG-HSG-1, page 30 of the Company's filing:

(a) Please provide a complete description and detailed breakdown of all costs included in A&G – Miscellaneous Expenses.

(b) Please provide a detailed explanation of the Company's rationale for allocating A&G – Miscellaneous Expenses on the basis of loss adjusted energy consumption.

Response:

(a) Please see Attachment NAVY 3-1 (a), which details costs included in A&G-Miscellaneous Expenses. The amount on page 30 is the amount functionalized to Secondary and classified to Demand.

(b) A&G – Miscellaneous Expenses, Account 930200 includes an annual amount of $3,078,000, for environmental response, as well as another $310,000 for costs related to environmental compliance. These costs, which represent approximately 87% of the account balance, are causally related to MWh- Generation (i.e., energy consumption before losses).

Prepared by or under the supervision of: Howard S. Gorman

Costs included in A&G - Miscellaneous Expenses
Regulatory Account 930200
Calendar 2008

Line	Activity	Activity Description	Total
1	930200	A&G-Misc Expenses	$30,984
2	AG0100	Acquire/Maintain Environmental Regulatory Licenses/Permits	13,802
3	AG0105	Support Environmental Compliance	261,905
4	AG0109	Def Cr-Hazardous Waste Payroll	224
5	AG0110	Environmental Site Assess & Remediation	112,391
6	AG0210	Economic Development Plan	92
7	AG0230	Environmental Legal Services	802
8	AG0233	Environmental Reserve Fund	3,078,000
9	AG0245	Corporate Matters/Contracts	356,549
10	AG0246	Nant Reimb_Nant-Meco Elimination	92
11	AG0435	Meter Data Services Operations	157,591
12	AG0746	Executive Directors Fees & Exp	5
13	Subtotal		4,012,435
14			
15	Known & Measurable Adjustment - IFA Agreement		(185,533)
16	Pro Forma adjustment - Salary & Wage expense Adjustment		38,888
17	Pro Forma adjustment - Inflation Adjustment		2,193
18			
19	Total		$3,867,983

Navy Data Request 3-7

Request:

Referring to the direct testimony of Company witness Howard S. Gorman, page 38, lines 11-12:

(a) Please clarify whether the Company is proposing to use demands at the time of the Company's monthly peak, the New England Power system peak or the ISO-NE system peak as the basis for the allocation of transmission costs.

(b) Please clarify whether the proposed allocation of transmission costs is on an annual 12 CP basis or other basis.

(c) Please provide a detailed narrative explanation of the methodology and rationale supporting the Company's proposed allocation of transmission costs.

(d) Please provide all schedule and workpapers supporting the Company's proposed allocation of transmission costs, in Microsoft Excel format with all formulas intact.

Response:

(a) (b) (c) The Company is proposing to allocate transmission costs based on the contribution of each rate class to New England Power's ("NEP's") monthly peak. However, Schedule NG-HSG-7 was prepared based on the contribution of each rate class to the Company's monthly peak (12 CP). Although any differences will be minor, the Company will revise Schedule NG-HSG-7 to reflect the correct allocator to better align with how the Company incurs these costs.

As is discussed on page 36 of Mr. Gorman's testimony, NEP determines the Company's share of transmission costs based on the Company's load ratio, which is determined, along with NEP's other transmission customers, by comparing the Company's demand at the time of NEP's monthly transmission system peak as a percentage of all of NEP's customers' demand at the time of NEP's system peak. The Company is proposing that transmission costs are allocated among the rate classes based on their respective contributions to the system peak of NEP. The Company believes this is an appropriate, cost-based allocation of transmission costs among the rate classes.

(d) The Company is providing Schedule NG-HSG-7 and page 30 of Schedule NG-HSG-2 in Microsoft Excel format.

Prepared by or under the supervision of: Howard S. Gorman

Demand-2
30

Test Year 2008 Class Contributions to 12 CP at Voltage Levels

			1	2	3	4	5	8	10
Line	**Rate Class**	**Includes**	**Test Year 12 CP at Customer**	**% at 115 kV**	**% at Primary**	**% at Secondary**	**Test Year 12 CP at Secondary**	**Test Year 12 CP at Primary Before Losses**	**Test Year 12 CP at 115kV Before Losses**
1	Residential	A16-A60	554,463			100%	554,463	582,629	604,653
2	Small C&I	C06-R2	101,467			100%	101,467	106,621	110,651
3	General C&I	G02-E40	225,131		1%	99%	222,879	236,453	245,391
4	200 kW Demand	B32-G32	306,559		100%	0%	0	306,559	318,146
5	3000 kW Demand	B62-G62	77,435		100%	0%	0	77,435	80,362
6	Lighting	S10-S14	8,227			100%	8,227	8,645	8,972
7	Propulsion	X01	6,298		100%	0%	0	6,298	6,536
8	**Total**		**1,279,579**				**887,036**	**1,324,640**	**1,374,712**
								7	**9**
9			Loss Multipliers					1.0508	1.0378

2010 Retail Transmission Rates

Line		Total	A16	A60	C6	G2	B32 / G32	B62 / G62	S10 / S14	X1
	Retail Tranmsission Revenue at Current Rates									
1	Current Retail Transmission Charges - per kW					$1.40	$1.27	$1.39		$1.34
2	Current Retail Transmission Charges - per kWh		$0.01500	$0.01402	$0.01600	$0.01064	$0.01064	$0.01064	$0.01323	$0.01064
3A	Forecast Billed 2010 Demand- kW	11,145,124				3,747,594	5,901,279	1,301,916		194,335
3B	Forecast Actual 2010 Demand- kW	11,826,124				4,428,594	5,901,279	1,301,916		194,335
4	Forecast 2010 Deliveries- kWh X 1000	7,662,969	2,842,814	194,799	552,429	1,371,694	2,041,538	565,378	68,382	25,935
5	Retail Transmission Revenue at Current Rates	$112,536,532	$42,642,210	$2,731,084	$8,838,862	$19,841,452	$29,216,592	$7,825,284	$904,689	$536,360
	Allocation of Revenue to Rate Classes									
6	Coincident Peak with NEP's Peak- kW	1,374,712	604,653		110,651	245,391	398,509		8,972	6,536
7	Coincident Peak Allocator	100.00%	43.98%		8.05%	17.85%	28.99%		0.65%	0.48%
8	Allocated 2010 Total Transmission Revenue	$112,536,532	$49,498,029		$9,058,124	$20,088,164	$32,622,698		$734,441	$535,076
	Retail Transmission Rates									
9	**Proposed kW-based Transmission Rate**					**$2.29**	**$2.28**			**$2.01**
10	Retail kW-Based Transmission Revenue	$26,955,379				$10,141,480	$16,423,286			$390,613
11	Revenue to be Recovered on kWh-basis	$85,581,153	$49,498,029		$9,058,124	$9,946,684	$16,199,412		$734,441	$144,463
12	**Proposed kWh-based Transmission Rate**		**$0.01630**		**$0.01640**	**$0.00725**	**$0.00621**		**$0.01074**	**$0.00557**
13	Retail kWh-based Transmission Revenue	$85,585,534	$49,513,094		$9,059,834	$9,944,779	$16,188,949		$734,419	$144,459
	Retail Tranmsission Revenue Proof at Proposed Rates									
14	Retail Transmission Revenue at Proposed Rates	$112,540,912	$49,513,094		$9,059,834	$20,086,259	$32,612,235		$734,419	$535,073
15	Difference from Revenue at Current Rates	$4,380	$15,065		$1,709	($1,905)	($10,463)		($22)	($3)

Line Notes

(1), (2)	Per current tariff	(9)	Proposed rates
(3)	A) Schedule NG-HSG-2, Page 7, plus X01; B) Add 681,000 kW below 10kW-month for G2	(10)	Line (3B) x Line (9)
(4)	Schedule NG-HSG-2, Page 8	(11)	Line (8) - Line (10)
(5)	[Line (1) x Line (3A] + [Line (2) x Line (4)]	(12)	Line (11) ÷ Line (4) (5 decimal places)
(6)	Schedule NG-HSG-2, Page 30	(13)	Line (4) X Line (12)
(7)	Line (6) ÷ Line (6) Total	(14)	Line (10) + Line (13)
(8)	Line (7) x Line (5) Total	(15)	Line (14) - Line (8)

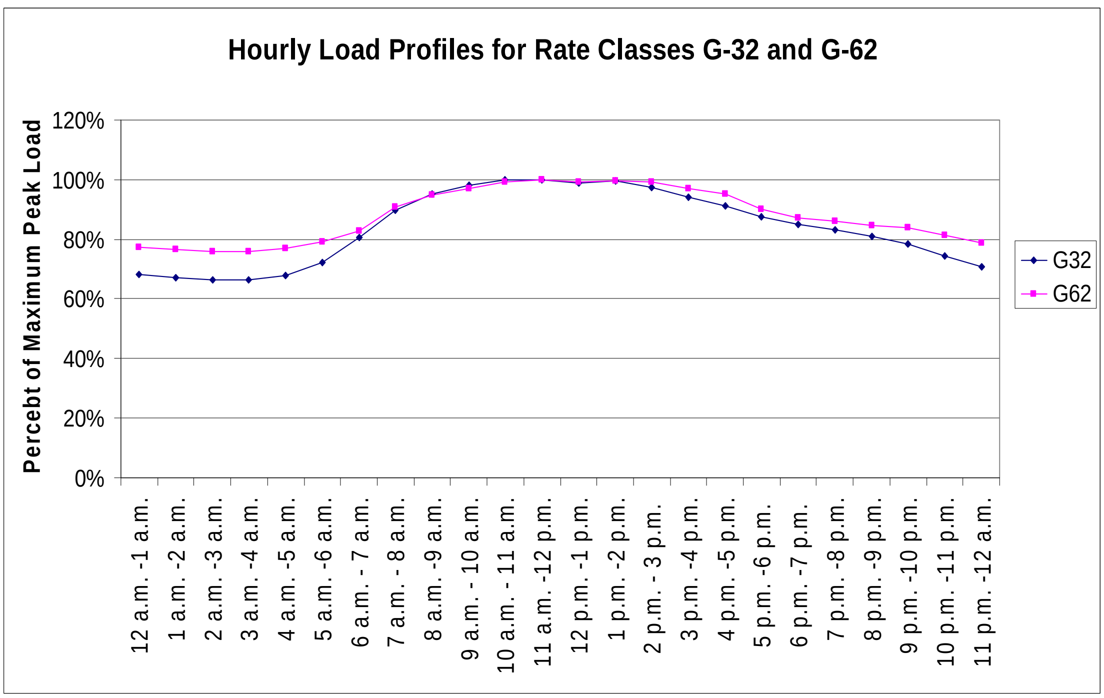
Navy Data Request 3-8

Request:

Referring to the direct testimony of Company witness Howard S. Gorman, page 20, lines 3-7, please provide all studies, analyses or other support available to the Company for the statement that the B-32, G-32, B-62 and G-62 classes have similar usage profiles.

Response:

The Company's analysis of the annual hourly data for rate classes G-32/B-32 and G-62/B-62 indicates that these two classes have very similar load factors[1] and load shapes. Both have annual average load factors of approximately 60% for calendar year 2008. The chart below presents the average load shapes for G-32 and G-62 for 2008.



As shown on page 47 of Schedule NG-NSG-1, Unitized Requirements, Rate Base and Costs, the similarity in usage profiles of these two classes results in demand based unit cost components that are very comparable.

[1] Load factor is defined as average usage for a given period of time divided by maximum usage during the same time period.

Prepared by or under the supervision of: Howard S. Gorman