Thomas R. Teehan
Senior Counsel

February 18, 2011

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4218 - Electric Infrastructure, Safety, and Reliability Plan FY 2012

Dear Ms. Massaro:

On behalf of both National Grid[1] and the Division of Public Utilities and Carriers ("Division"), I have enclosed ten (10) copies of responses that the Company made to three sets of data requests from the Division during the period that the Division reviewed and reached an agreement on the Company's proposed Electric Infrastructure, Safety and Reliability Plan ("Plan").

It is the intent that this material provide additional background and explanation relative to the Plan that has been submitted to the Commission.

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

Enclosure

cc: Docket 4218 Service List
Steve Scialabba
Leo Wold, Esq.

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

National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2012 Proposal

Copy of National Grid's Responses to Rhode Island Division Data Requests (Sets 1, 2, and 3)

February 18, 2011

Submitted to:
Rhode Island Public Utilities Commission
Docket No. 4218

Submitted by:
nationalgrid

National Grid's Proposed FY 2012

Electric

Draft Infrastructure, Safety, and Reliability Plan

National Grid Responses
to
Division's First Set of Data Requests

Issued by the Division on
September 1, 2010

Division 1-1

Request:

Referring to Section 5, Attachment 1, Page 1, please provide documentation supporting the Current Recovery of Vegetation I&M Expense on Line 14.

Response:

The current recovery of vegetation management ("VM") and inspection and maintenance ("I&M") expense is supported by the Rhode Island Public Utilities Commission's ("Commission") Decision and Order dated April 29, 2010 ("Order") with regard to the Company's application for approval of a change in electric base distribution rates in Docket No. 4065.

The Commission specifically allowed $5,081,368 for VM costs on line 2 of page 112 of its Order. This amount represents the five-year average of VM costs for the calendar years 2004 through 2008.

Page 116 of the Order also directs the Company to determine the allowance for I&M costs based on a four-year historical average of I&M using information provided in the Company's Supplemental Schedule NG-JP-1 submitted in Docket No. 4065 on February 9, 2010. This document is being provided as Attachment 1 to this response for ease of reference. As the Commission did not state the rate year allowance for I&M costs in its Order, nor was a four-year average provided in Supplemental Schedule NG-JP-1, the Company is providing this calculation in Attachment 2 to this response.

Prepared by or under the supervision of: David E. Tufts

nationalgrid

Thomas R. Teehan
Senior Counsel

February 9, 2010

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
Response to Data Request

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] supplemental Schedule NG-JP-1, which adds data from CY2005 through CY2007.

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").

The Narragansett Electric Company
Calculation of Inspection and Maintenance (I&M) O&M-Related Program Costs

			CY 2005 Costs	CY 2006 Costs	CY 2007 Costs	CY 2008 Costs		CY 2010 Costs
			(a)	(b)	(c)	(d)		(e)
	Operation and Maintenance Expenses:							
1	Opex Related to Capex	1/	$183,462	$1,312,745	$1,616,924	$1,806,357		$2,043,694
2	Repair - Related Costs		-	-	-	-		1,116,682
3	Inspections - Related Costs	1/	45,789	37,882	28,435	487,374	3/	986,259
4	Total Operation and Maintenance Expense		$229,250	$1,350,627	$1,645,359	$2,293,731		$4,146,635
6	Plus Inspections-Related Benefits and Taxes	2/	$27,070	$22,396	$16,811	$288,136		$529,537
7	Total Costs		$256,320	$1,373,023	$1,662,170	$2,581,867		$4,676,172

1/ Amounts reported above for CY 2005 to CY 2007 are based on fiscal year amounts per Data Request COMM 7-8, converted to calendar year basis. CY 2008 and CY 2010 are based on Schedule NG-JP-1. As noted in the response to COMM 12-3, comparable data is not available for CY2004 because National Grid did not conduct comparable activities, or track costs in a comparable manner for those activities that were similar in CY2004.

2/ Benefits reported for CY 2004 to 2007 are based on a assumed percentage of 59.12%, which is consistent with the assumption used for Schedule NG-JP-1.

3/ Amount for CY 2008 on Schedule NG-JP-1 reflects annualized amount to account for FTEs added in December 2008 for Overhead Distribution Inspection.

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Inspection & Maintenance Expenses
Amount Allowed in Base Distribution Rates
Per RIPUC Docket No. 4065

Line No.	Year	Inspection & Maintenance 1\
		(a)
1	2004	
2		
3	2005	$256,320
4		
5	2006	$1,373,023
6		
7	2007	$1,662,170
8		
9	2008	$2,581,867
10		
11	Total	$5,873,380
12		
13	Number of Years	4
14		
15	Average	$1,468,000

1\ Attachment 1 to Division 1-1, Page 2, Line 7, Columns (a) through (d) (Supplemental Schedule NG-JP-1)

Division 1-2

Request:

Referring to Section 5, Attachment 1, Page 2, please reconcile the plant additions on Line 2 to the Capital Forecast in Section 2.

Response:

As discussed in Section 5, the Company's revenue requirement is calculated based on amounts anticipated to be placed into service in FY 2012 rather than on the Company's proposed FY 2012 spending plan. Due to the multi-year nature of certain projects, current and prior year(s) capital spending may be included in the FY 2012 in-service amount when a project is placed into service during FY 2012. Similarly, the capital portion of a project included in the FY 2012 spending plan that will be placed into service in future fiscal periods will be included in subsequent revenue requirement calculations during that project's in-service year.

The Company estimates the in-service dates for capital to be placed into service during FY 2012 using a variety of methods. The Company's response to Division 1-4 includes a table that shows the prospective FY2012 capital outlays and plant in service amounts for FY2012 by project/program. This detail supports the prospective FY2012 capital outlays and plant in service amounts by spending category shown in the ISR Plan at Chart 6 from section 2 (reproduced below).

The company projects the in-service amounts using a variety of methods. For mandatory reserve items in the budget, the Company assumes that a percentage of the reserve will be placed into service based on the most likely timing of new mandatory projects that are likely to emerge during the fiscal year

For blanket programs such as meter and transformer purchase blankets, reliability and its asset replacement blankets, the Company estimates that 90percent to 100 percent of the projected capital outlays will be placed into service in the same fiscal year. In other words, the in-service estimate assumes that the construction work in progress ("CWIP") balance at the end of the fiscal year approximates the CWIP balance at the beginning of the year.

The Company uses a similar method to estimate the in-service amounts for other programs but for some engineering-intensive programs such as "pockets of poor performance" and EMS/RTU additions, the Company assumes that a smaller percentage of spending will be placed in service in the same year on the premise that some installs may still be in the engineering phase at the end of the year.

Division 1-2 (cont.)

For specific projects, the Company estimates in-service balance for the year based on the actual estimated in-service date when the budget is set.

Chart 6: Proposed FY2012 Capital Outlays, Investment Placed in Service and Cost of Removal

Spending Rationale	Proposed Capital Outlays FY2012 excluding Flood Related Capital Projects	New Capital Placed in Service FY2012	Estimated Cost of Removal	New Capital In Service Plus COR
Statutory/Regulatory	$21,636,500	$20,612,500	$2,432,000	$23,044,500
Damage/Failure	9,705,000	9,475,200	1,524,000	10,999,200
Asset Condition	11,118,050	7,186,000	1,192,000	8,378,000
Non-Infrastructure	278,000	278,000	-	278,000
System Capacity & Performance	17,962,450	14,548,300	1,780,000	16,328,300
Grand Total	$60,700,000	$52,100,000	$6,928,000	$59,028,000

Division 1-3

Request:

Referring to Section 5, Attachment 1, Page 2, please provide workpapers supporting the Depreciation Expense on Line 9.

Response:

The amount of depreciation expense included in Section 5 on Attachment 1, Page 2, Line 9 is the allowance for depreciation expense approved in Docket No. 4065 of $40,778,125 less the amount included in this allowance associated with general plant, which is not part of the Company's proposed ISR Plan. The allowance for depreciation expense in Docket No. 4065 was calculated in the Company's Second Amended Compliance Filing, Schedule NG-RLO-2 (C), page 28, Line 42. The Company is providing a calculation of the rate year depreciation expense associated with general plant in the attachment to this response, as shown in Column (e), Line 35. The result is $40,778,125 less $1,903,037, or $38,875,088.

Prepared by or under the supervision of: David E. Tufts

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Depreciation Expense

Line No.	Account	Account No.	Depreciable Plant as of 12/31/09	Depreciable Plant as of 12/31/10	Average	Composite Depreciation Rate	Depreciation Expense
			(a)	(b)	(c) ((a) + (b)) / 2	(d)	(e) (c) * (d)
1	Hydrolic Production Plant						
2	Land and Land Rights	330	$ -	$ -	$ -	3.4%	$ -
3	Structures & Improvements	331	-	-	-	3.4%	-
4	Reservoirs Dams & Waterways	332	-	-	-	3.4%	-
5	Total Hydro		$ -	$ -	$ -		$ -
6							
7	Distribution Plant						
8	Land and Land Rights	360	$ -	$ -	$ -	3.4%	-
9	Structures and Improvements	361	6,750,904	7,209,076	6,979,990	3.4%	237,320
10	Station Equipment	362	165,106,847	171,382,010	168,244,429	3.4%	5,720,311
11	Poles, Towers and Fixtures	364	178,942,645	185,433,441	182,188,043	3.4%	6,194,393
12	Overhead Conductors and Devices	365	254,781,219	265,852,501	260,316,860	3.4%	8,850,773
13	Underground Conduit	366	61,847,702	62,553,697	62,200,700	3.4%	2,114,824
14	Underground Conductors & Devices	367	130,005,865	136,128,814	133,067,340	3.4%	4,524,290
15	Line Transformers	368	153,931,717	160,479,724	157,205,721	3.4%	5,344,994
16	Services	369	70,503,258	72,434,901	71,469,080	3.4%	2,429,949
17	Meters	370	49,079,719	49,688,104	49,383,912	3.4%	1,679,053
18	Installations on Customer Premises	371	125,013	176,151	150,582	3.4%	5,120
19	Street Lighting & Signal Systems	373	51,389,033	52,967,503	52,178,268	3.4%	1,774,061
20	Asset Retire Costs for Dist Plant	374	-	-	-	3.4%	-
21	Total Distribution		$ 1,122,463,922	$ 1,164,305,922	$ 1,143,384,922		$ 38,875,087
22							
23	General Plant						
24	Land and Land Rights	389	$ -	$ -	$ -	3.4%	-
25	Structures and Improvements	390	23,532,145	23,532,145	23,532,145	3.4%	800,093
26	Office Furniture and Equipment	391	858,746	858,746	858,746	3.4%	29,197
27	Passenger Cars - Transp Equipment	392	646,123	646,123	646,123	3.4%	21,968
28	Stores Equipment	393	454,464	454,464	454,464	3.4%	15,452
29	Tools, Shop & Garage Equipment	394	2,678,097	2,678,097	2,678,097	3.4%	91,055
30	Laboratory Equipment	395	1,905,328	1,905,328	1,905,328	3.4%	64,781
31	Communications Equipment	397	25,774,317	25,774,317	25,774,317	3.4%	876,327
32	Miscellaneous Equipment	398	110,613	110,613	110,613	3.4%	3,761
33	Other Tangible Property	399	11,849	11,849	11,849	3.4%	403
34	Asset Retire Cost for Gen'l Plant	399.1	-	-	-	3.4%	-
35	Total General Plant		$ 55,971,682	$ 55,971,682	$ 55,971,682		$ 1,903,037
36							
37	Grand Total Plant - All Categories		$ 1,178,435,604 1/	$ 1,220,277,604 2/	$ 1,199,356,604 3/		$ 40,778,125 4/

1/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 29 in RIPUC Docket No. 4065
2/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 35 in RIPUC Docket No. 4065
3/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 37 in RIPUC Docket No. 4065
4/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 42 in RIPUC Docket No. 4065

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Depreciation Expense

Line No.	Account	Account No.	Depreciable Plant as of 12/31/08 (a)	Net Additions for Calendar Year 2008 Related to Depreciable Plant: Additions (b)	Retirements (c)	Net (d) (b) - (c)	Distribution % (e)	Net 2009 Distribution Additions (f) (e) * (f), Line 1	Depreciable Plant as of 12/31/09 (g) (a) + (f)	Net 2009 Distribution Additions (h) (e) * (h), Line 1	Depreciable Plant as of 12/31/10 (i) (g) + (h)
1	Net Plant Additions per NG-RLO-2 (C) - 2nd Amended							43,678,000		41,842,000	
2											
3	Hydrolic Production Plant										
4	Land and Land Rights	330	$ -	$ -	$ -	$ -			$ -		$ -
5	Structures & Improvements	331	-	-	-	-			-		-
6	Reservoirs Dams & Waterways	332	-	-	-	-			-		-
7	Total Hydro		$ -	$ -	$ -	$ -			$ -		$ -
8											
9	Distribution Plant										
10	Land and Land Rights	360	$ -	$ -	$ -	$ -	0%	$ -	$ -	$ -	$ -
11	Structures and Improvements	361	6,272,627	666,744	24,965	641,779	1%	478,277	6,750,904	458,172	7,209,076
12	Station Equipment	362	158,556,334	9,321,158	531,303	8,789,855	15%	6,550,513	165,106,847	6,275,163	171,382,010
13	Poles, Towers and Fixtures	364	172,167,037	9,900,308	808,408	9,091,900	16%	6,775,608	178,942,645	6,490,796	185,433,441
14	Overhead Conductors and Devices	365	243,224,137	19,266,447	3,758,491	15,507,956	26%	11,557,082	254,781,219	11,071,282	265,852,501
15	Underground Conduit	366	61,110,729	1,030,279	41,366	988,913	2%	736,973	61,847,702	705,995	62,553,697
16	Underground Conductors & Devices	367	123,614,245	9,748,723	1,172,080	8,576,643	15%	6,391,620	130,005,865	6,122,949	136,128,814
17	Line Transformers	368	147,096,387	9,614,101	442,063	9,172,038	16%	6,835,330	153,931,717	6,548,007	160,479,724
18	Services	369	68,486,855	2,842,656	136,931	2,705,725	5%	2,016,403	70,503,258	1,931,643	72,434,901
19	Meters	370	48,444,639	2,383,581	1,531,394	852,187	1%	635,080	49,079,719	608,385	49,688,104
20	Installations on Customer Premises	371	71,631	71,631	-	71,631	0%	53,382	125,013	51,138	176,151
21	Street Lighting & Signal Systems	373	49,741,301	2,520,295	309,273	2,211,022	4%	1,647,732	51,389,033	1,578,470	52,967,503
22	Asset Retire Costs for Dist Plant	374	-	-	-	-	0%	-	-	-	-
23	Total Distribution		$ 1,078,785,922	$ 67,365,923	$ 8,756,274	$ 58,609,649	100%	$ 43,678,000	$ 1,122,463,922	$ 41,842,000	$ 1,164,305,922
24											
25	General Plant										
26	Land and Land Rights	389	$ -	$ -	$ -	$ -			$ -		$ -
27	Structures and Improvements	390	23,532,145	-	-	-			23,532,145		23,532,145
28	Office Furniture and Equipment	391	858,746	-	-	-			858,746		858,746
29	Passenger Cars - Transp Equipment	392	646,123	-	-	-			646,123		646,123
30	Stores Equipment	393	454,464	-	-	-			454,464		454,464
31	Tools, Shop & Garage Equipment	394	2,678,097	-	-	-			2,678,097		2,678,097
32	Laboratory Equipment	395	1,905,328	-	-	-			1,905,328		1,905,328
33	Communications Equipment	397	25,774,317	-	-	-			25,774,317		25,774,317
34	Miscellaneous Equipment	398	110,613	-	-	-			110,613		110,613
35	Other Tangible Property	399	11,849	-	-	-			11,849		11,849
36	Asset Retire Cost for Gen'l Plant	399.1	-	-	-	-			-		-
37	Total General Plant		$ 55,971,682	$ -	$ -	$ -			$ 55,971,682		$ 55,971,682
38											
39	Grand Total Plant - All Categories		$ 1,134,757,604 1/	$ 67,365,923 2/	$ 8,756,274 2/	$ 58,609,649		$ 43,678,000 3/	$ 1,178,435,604 4/	$ 41,842,000 5/	$ 1,220,277,604 6/

1/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 9 in RIPUC Docket No. 4065
2/ Per Ferc Form 1
3/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 11 minus Line 12 in RIPUC Docket No. 4065
4/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 13 in RIPUC Docket No. 4065
5/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 31 minus Line 33 in RIPUC Docket No. 4065
5/ Agrees to Schedule NG-RLO-2 (C) - 2nd Amended, Page 28, Column (b), Line 35 in RIPUC Docket No. 4065

Division 1-4

Request:

Referring to Section 5, Attachment 1, Page 2, please provide workpapers supporting the Cost of Removal on Line 13.

Response

The detail to support the estimated COR is shown in the attached table. Please note that the Company budgets for the cost of removal prior to the installation of assets. We therefore estimate the COR based on the projected capital outlays, not on the expected capital to be placed into service in a particular year. The assumptions used to project the estimated COR are based on prior experience for a particular budget classification.

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual	FY 2009 Budget	FY 2009 Actual	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Forecast	FY 2012 Proposed
Statutory/ Regulatory	3rd Party Attachments	-	362,916	-	75,680	280,000	(123,199)	208,000	873,018	306,000	780,847	620,000	795,000	641,000
	Land and Land Rights - Dist	180,000	199,978	180,000	244,275	230,000	313,141	291,200	310,128	326,000	274,560	309,000	292,000	321,000
	Meters – Dist	1,976,000	1,609,398	1,900,000	1,768,581	1,950,000	2,194,959	2,101,000	2,135,191	2,690,000	2,042,048	2,040,000	2,150,000	1,803,000
	New Business - Commercial	6,192,000	6,178,305	4,425,000	7,782,725	7,210,000	7,602,534	5,691,500	6,993,422	5,801,000	4,705,078	5,550,000	5,100,000	6,157,500
	New Business - Residential	4,500,000	5,111,949	4,200,000	6,564,788	5,900,000	4,951,161	5,512,000	2,856,774	2,699,000	3,256,239	3,750,000	3,560,000	3,917,000
	Outdoor Lighting - Capital	400,000	523,859	400,000	573,758	1,000,000	712,535	1,001,200	1,236,779	945,000	941,164	680,000	700,000	718,000
	Outdoor Lighting - Capital MV	-	-		-	-	-	350,000	-	300,000	61,933	-	23,000	300,000
	Public Requirements	3,814,000	4,393,841	3,297,500	(790,093)	3,010,000	1,640,703	3,906,968	1,465,029	4,126,000	3,121,260	3,810,000	3,130,000	3,968,000
	Transformers & Related Equipment	3,240,000	4,504,947	3,500,000	4,812,334	5,050,000	6,595,658	4,960,800	5,301,415	6,533,000	4,128,756	4,255,000	3,100,000	3,811,000
Statutory/Regulatory Total		**20,302,000**	**22,885,193**	**17,902,500**	**21,032,048**	**24,630,000**	**23,887,492**	**24,022,668**	**21,171,756**	**23,726,000**	**19,311,885**	**21,014,000**	**18,850,000**	**21,636,500**
Damage/ Failure	Damage/ Failure	3,250,000	7,655,568	4,550,000	6,764,097	5,650,000	7,266,897	6,496,000	7,488,952	7,419,000	9,143,559	8,925,000	8,000,000	9,245,000
	Major Storms – Dist	-	609,088		678,175	10,000	375,380	100,000	856,490	500,000	(112,426)	440,000	3,400,000	460,000
Damage/Failure Total		**3,250,000**	**8,264,656**	**4,550,000**	**7,442,272**	**5,660,000**	**7,642,277**	**6,596,000**	**8,345,442**	**7,919,000**	**9,031,133**	**9,365,000**	**11,400,000**	**9,705,000**
Asset Condition	Woonsocket & Related	-	-		-	1,014,000	80,639	2,650,000	57,883	2,108,000	1,043,789	6,080,000	2,400,000	5,005,000
	Asset Replacement	9,323,000	5,828,465	8,241,000	8,314,885	8,631,000	12,381,390	7,050,732	10,793,745	10,847,000	11,530,572	721,000	3,500,000	4,732,050
	Asset Replacement - I&M (NE)	-	-	400,000	28,022	300,000	20,727	325,000	112,553	1,298,000	490,942	400,000	200,000	1,381,000
	Substation Capital - Dist	-	-		-		-	-	-	-	-	-	-	-
	Safety	-	-		-	75,000	76,680	65,000	(22,943)	-	-	-	-	-
Asset Condition Total		**9,323,000**	**5,828,465**	**8,641,000**	**8,342,907**	**10,020,000**	**12,559,436**	**10,090,732**	**10,941,238**	**14,253,000**	**13,065,303**	**7,201,000**	**6,100,000**	**11,118,050**
Non-Infrastructure	Corporate/Admin/General	-	(3,136,053)		2,441,291		(60,904)	-	(3,464)	-	(1,238,810)	-	-	-
	Facilities	693,000	742,137	890,000	563,836		121,166	-	134,036	-	256,800	-	200,000	-
	General Equipment	100,000	54,233	100,000	12,601	75,000	324,847	67,600	154,236	161,000	391,872	200,000	250,000	278,000
	Telecommunications Capital - Dist	-	143,386		23,333	-	-	175,000	-	7,000	-	485,000	350,000	-
Non-Infrastructure Total		**793,000**	**(2,196,297)**	**990,000**	**3,041,061**	**75,000**	**385,109**	**242,600**	**284,808**	**168,000**	**(590,138)**	**685,000**	**800,000**	**278,000**
System Capacity and Performance	Coventry & Related	-	-	-	-		4,345	950,000	89,324	1,128,000	558,222	300,000	100,000	1,000,000
	Hopkinton & Related	-	-	-	-		372	150,000	96,615	645,000	547,535	200,000	125,000	800,000
	Newport & Related	-	394	1,155,000	4,139	1,215,000	305,411	950,000	715,163	5,731,000	2,926,839	1,500,000	1,750,000	720,000
	West Warwick & Related	-	-	-	-		-		-	195,000	114,900	450,000	100,000	520,000
	Load Relief	5,964,000	7,306,395	4,648,000	6,694,784	5,030,000	3,486,228	4,335,500	5,988,143	6,780,000	4,650,580	1,958,000	4,225,000	6,492,920
	Reliability	2,922,500	3,022,794	5,745,000	3,529,889	5,104,000	5,446,383	5,667,500	3,878,186	3,641,000	5,768,069	2,214,000	3,750,000	5,199,430
	Reliability - FEEDER HARDENING	1,390,000	650,810	1,413,500	1,316,796	1,085,000	4,315,685	4,654,000	3,828,491	4,314,000	2,888,145	2,013,000	1,100,000	3,230,100
System Capacity and Performance Total		**10,276,500**	**10,980,393**	**12,961,500**	**11,545,608**	**12,434,000**	**13,558,424**	**16,707,000**	**14,595,922**	**22,434,000**	**17,454,290**	**8,635,000**	**11,150,000**	**17,962,450**
Grand Total		**43,944,500**	**45,762,410**	**45,045,000**	**51,403,896**	**52,819,000**	**58,032,738**	**57,659,000**	**55,339,166**	**68,500,000**	**58,272,473**	**46,900,000**	**48,300,000**	**60,700,000**

Division 1-5

Request:

Referring to Section 5, Attachment 1, Page 2, please provide workpapers supporting the Annual Tax Depreciation on Line 23.

Response:

Please see the attachment to this response for the calculation supporting the Annual Tax Depreciation included in Section 5 on Attachment 1, Page 2, Line 23. The amount of annual tax depreciation can be found on line 13.

Prepared by or under the supervision of: David E. Tufts

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Tax Depreciation

Line No.	Description	Reference	Fiscal Year 2012 (a)	Fiscal Year 2013 (a)	
1	Plant Additions	Section 5, Attachment 1, Page 2, Line 2	$52,100,000	$0	
2	Cost of Removal	Section 5, Attachment 1, Page 2, Line 13	$6,928,000	$0	
3					
4	20 YR MACRS Tax Depreciation Rates	Section 5, Attachment 1, Page 2, Line 20	3.75%	7.22%	
5	Capital Repairs Deduction	Section 5, Attachment 1, Page 2, Line 21	40.00%	40.00%	
6					
7	Calculation of Tax Depreciation:				
8					
9	Tax Depreciation Associated with Repairs	(Line 1 x Line 5)	$ 20,840,000	$ -	1\
10	Tax Depreciation Associated with All Other Plant Additions	(Line 1 - (Line 1 * Line 5) * Line 4	1,172,250	2,256,659	2\
11	Tax Depreciation Associated with Cost of Removal	(Line 2)	6,928,000	-	1\
12					
13	Total Tax Depreciation	Section 5, Attachment 1, Page 2, Line 23	$ 28,940,250	$ 2,256,659	

1\ Currently deductible for tax purposes
2\ Deductible according to MACRS rates

Division 1-6

Request:

Referring to Section 5, Attachment 1, Page 2, please provide workpapers supporting the Book Depreciation on Line 26.

Response:

Please see the attachment to this response for the calculation supporting the Annual Book Depreciation included in Section 5 on Attachment 1, Page 2, Line 26. The amount of annual book depreciation can be found on line 13.

Prepared by or under the supervision of: David E. Tufts

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Book Depreciation

Line No.	Description	Reference	Fiscal Year 2012	Fiscal Year 2013
			(a)	(a)
1	Plant Additions	Section 5, Attachment 1, Page 2, Line 2	$52,100,000	$0
2	Retirements	Section 5, Attachment 1, Page 2, Line 3	$8,242,220	$0
3	Net Depreciable Additions	Section 5, Attachment 1, Page 2, Line 4	$43,857,780	$0
4	Cumulative Net Depreciable Additions	Section 5, Attachment 1, Page 2, Line 5	$43,857,780	$43,857,780
5				
6	Composite Book Depreciation Rate	Section 5, Attachment 1, Page 2, Line 19	3.40%	3.40%
7				
8	Calculation of Book Depreciation:			
9				
10	Book Depreciation Year One	(Line 3 * Line 6) * 50%	$745,582	
11	Book Depreciation Year Two	(Prior Year Line 4 * Line 6) + (Current Year Line 3 * Line 6) * 50%		$1,491,165
12				
13	Total Tax Depreciation	Section 5, Attachment 1, Page 2, Line 26	$745,582	$1,491,165

Division 1-7

Request:

Referring to Section 5, Attachment 1, Page 2, please provide documentation for the amounts in Footnote 3.

Response:

Please see the attachment to this response for the calculation supporting the amounts in Footnote 3 in Section 5 on Attachment 1, Page 2.

Prepared by or under the supervision of: David E. Tufts

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Property Tax Rate
Calendar Year 2009

Line No.	Description	Distribution		Transmission		Total
		(a)		(b)		(c)
1	Plant in Service	$ 1,190,817,229		$ 240,870,644		$ 1,431,687,873
2						
3	Accumulated Provision for Depreciation & Amortization	505,832,095		80,534,846	1/	586,366,941
4						
5	Net Plant In Service	$ 684,985,134		$ 160,335,798		$ 845,320,932
6						
7	Distribution-Related Rate Year Property Tax Expense	$ 19,494,858	2/			
8						
9	Distribution-Related Property Tax Rate	2.85%				

Line Notes:

1 Column (a) = Page 2, Column (c), Line 49; Column (b) = - Page 2, Column (b), Line 49; Column (c) = Page 2, Column (a), Line 49
3 Column (a) = Column (c) - Column (b); Column (b) - See Note 1/ below; Column (c) = FERC Account 108000 per internal Company financials
5 Line 1 + Line 3
7 See Note 2/ below
9 Line 7 / Line 5

1/ Transmission-related Accumulated Depreciation:

Transmission	$ 79,811,907	
General	27,294,248	
12/31/09 IFA Salary Allocator for General Plant to Transmission	2.65%	
General Plant Allocable to Transmission	$ 722,939	
Total Transmission	$ 80,534,846	

2/ Distribution-related Operating Property Taxes per FERC Account 408140:

Distribution	$ 19,494,858	3/
Transmission	4,365,590	3/
Total	$ 23,860,448	3/

3/ Amounts agree to Intrastate Reporting from Annual Earnings Report per RIPUC Docket No. 3617

The Narragansett Electric d/b/a National Grid
Draft Infrastructure, Safety and Reliability Plan (ISR Plan)
Calculation of Property Tax Rate
Analysis of Calendar Year 2009 Plant in Service per FERC Form 1

Line No.	Acct No.	Account Title	Total Utility Plant	Transmission IFA		Distribution
			(a)	(b)		(c)
						(a) + (b)
1	330	Land and Land Rights	$ 6,989	$ -		$ 6,989
2	331	Structures & Improvements	1,993,757	-		1,993,757
3	332	Reservoirs Dams & Waterways	1,125,689	-		1,125,689
4		Total Hydro	$ 3,126,435	$ -		$ 3,126,435
5						
6	350	Land and Land Rights	$ 8,731,633	$ (8,731,633)	1/	$ -
7	352	Structures & Improvements	3,460,983	(3,460,983)	1/	-
8	353	Station Equipment	92,277,236	(92,277,236)	1/	-
9	354	Towers & Fixtures	1,482,419	(1,482,419)	1/	-
10	355	Poles and Fixtures	59,247,594	(59,247,594)	1/	-
11	356	Overhead Conductors & Devices	41,615,564	(41,615,564)	1/	-
12	357	Underground Conduit	4,830,086	(4,830,086)	1/	-
13	358	Underground Conductors & Devices	27,192,096	(27,192,096)	1/	-
14	359	Roads and Trails	492,181	(492,181)	1/	-
15		Total Transmission	$ 239,329,792	$ (239,329,792)	1/	$ -
16						
17	361	Structures and Improvements	$ 7,051,919	$ -		$ 7,051,919
18	362	Station Equipment	163,200,316	-		163,200,316
19		Total Substation	$ 170,252,235	$ -		$ 170,252,235
20						
21	360	Land and Land Rights	$ 9,121,940	$ -		$ 9,121,940
22	364	Poles, Towers and Fixtures	178,902,296	-		178,902,296
23	365	Overhead Conductors and Devices	250,729,162	-		250,729,162
24	366	Underground Conduit	62,268,171	-		62,268,171
25	367	Underground Conductors & Devices	134,155,171	-		134,155,171
26	368	Line Transformers	152,776,276	-		152,776,276
27	369	Services	72,310,709	-		72,310,709
28	370	Meters	49,129,233	-		49,129,233
29	371	Installations on Customer Premises	-	-		-
30	373	Street Lighting & Signal Systems	51,412,284	-		51,412,284
31	374	Asset Retire Costs for Dist Plant	-	-		-
32		Total Distribution	$ 960,805,242	$ -		$ 960,805,242
33						
34		Total Substation and Distribution	$ 1,131,057,477	$ -		$ 1,131,057,477
35						
36	389	Land and Land Rights	$ 975,637	(25,842)	2/	$ 949,795
37	390	Structures and Improvements	24,129,010	(639,102)	2/	23,489,908
38	391	Office Furniture and Equipment	792,498	(20,991)	2/	771,507
39	392	Passenger Cars - Transp Equipment	662,127	(17,538)	2/	644,589
40	393	Stores Equipment	458,566	(12,146)	2/	446,420
41	394	Tools, Shop & Garage Equipment	2,677,481	(70,918)	2/	2,606,563
42	395	Laboratory Equipment	1,969,330	(52,161)	2/	1,917,169
43	397	Communications Equipment	26,412,729	(699,591)	2/	25,713,138
44	398	Miscellaneous Equipment	84,648	(2,242)	2/	82,406
45	399	Other Tangible Property	12,143	(322)	2/	11,821
46	399.1	Asset Retire Cost for Gen'l Plant	-	-	2/	-
47		Total General Plant	$ 58,174,169	$ (1,540,852)	2/	$ 56,633,317
48						
49		Grand Total Plant - All Categories	$ 1,431,687,873	$ (240,870,644)		$ 1,190,817,229
50						
51		12/31/09 Salary Allocator for General Plant Allocable to Transmission per the IFA				2.65%

1/ Transmission plant is 100% allocable to transmission through the IFA
2/ General plant is allocable to transmission through the IFA based on a monthly salary allocator

National Grid's Proposed FY 2012

Electric

Draft Infrastructure, Safety, and Reliability Plan

National Grid Responses
to
Division's Second Set of Data Requests

Issued by the Division on
September 14, 2010

Division Data Request 2-1

Request:

For each capital improvement project for which the justification for upgrade or replacement is facility age and condition, please provide detailed explanation and the supporting documentation for those projects including, but not limited to, the age of the facilities and the identified condition of the facilities with all pole testing and infrared scan and other thermographic analyses completed on each project segment to be replaced, upgraded, or rebuilt.

Response:

As noted in the ISR Plan, Page 11, deteriorated equipment on the distribution system and substation equipment are the source of 26% of Customers Interrupted and 23% of Customer Minutes Interrupted. These are significant reliability impacts and are being addressed through line and station based programs.

Overhead Line asset condition data is generated through the Inspection and Maintenance Program, as discussed in the report, and is managed through that program. Condition codes are assigned to each situation found, using standard reference documents.

The asset condition element of the budget has the following significant components:

1. Construction of a new Substation at Woonsocket (Plan Page 24)

The new substation in Woonsocket will address a number of issues in the area, brought about by the following circumstances:

- The 345/115/13.8kV transformer at West Farnum Substation failed in 2001. A temporary 115-13.8kV transformer was installed at West Farnum to supply the two 13.8kV distribution feeders.
- In November 2006, one of the 115-13.8kV power transformers at Riverside failed. The failed 42 MVA transformer was replaced with a 33MVA transformer which results in reduced capacity during contingency conditions.
- Both West Farnum and Riverside 13.8kV systems provide service to the same general area.
- In 2007, Pascoag Municipality, which National Grid supplies, requested an increase in the capacity to their facilities in Burrillville, Rhode Island. This will require a second 13.8kV feeder to supply their projected load.

The installation of the 115-13.8kV substation at the Woonsocket Substation will address the asset condition issue at West Farnum, reliability issues at Riverside, and the need for additional capacity for Pascoag Municipal.

Division Data Request 2-1 (continued)

2. Substation Circuit Breaker Strategy and Program (Plan Page 25)

This program targets obsolete and unreliable breaker families to improve safety and reliability. Breakers targeted through the asset strategy include those with known mechanism issues that require high levels of maintenance, rely on air-magnetic technologies, and contain asbestos or are prone to arc flash issues. The program is designed to replace the breaker types listed in the table below. The Substation Circuit Breaker Strategy is described more fully in the attached strategy paper provided as Attachment 1 to DIV 2-1.

Breaker Type	Causes of obsolescence
Federal Pacific	These units are obsolete due to lack of spare parts, frequent rebuild requirements (every 5 years) and unreliability (slow or improper tripping).
GE AM	These units are obsolete due to lack of spare parts, frequent mechanism rebuild requirements (every 8-10 years), obsolescence of air-magnetic ("AM") interrupting technology, presence of asbestos in arc chutes and arc-flash problems.
GE VIR	These units are obsolete due to unavailability of spare parts, increasing maintenance requirements and increasing in-service failures.
ITE HK	These units are obsolete due to mechanism issues.
ITE KS	These units are obsolete due to mechanism issues.
ME VSA	Specific units within a given manufacture date range and serial number range are obsolete due to current interchanger issues.
WE DHP	These units are obsolete due to AM interrupting technology.

3. Ocean State Distribution Asset Replacement Blanket

The Company has established this spending program to provide the funding needed for on-going distribution work to replace line or substation assets based on inspections, asset condition and strategies.

4. Under Ground Cables (Plan Page 25)

The Company's present underground cable replacement program is a mixture of reactive "fix on fail" and proactive replacement based on type of construction, asset condition, and failure history for a specific asset and similar assets. Reactive "fix on failure" replacement, which the Company considers mandatory spending, often evolves into proactive replacement of an entire circuit or a localized portion of a circuit. Spending for proactive replacement can be further categorized by (1) work justified by the need to eliminate repeated in-service failures, (2) work justified by anticipated end-of-life based on historic performance or industry experience, and (3) work made necessary by other operational issues.

Division Data Request 2-1 (continued)

The Company's underground cable system is a mix of paper-insulated-lead-covered ("PILC") cable and solid dielectric cable. PILC cable has historically been very reliable, but does eventually reach end-of-life, generally either as a result of lead sheath deterioration resulting in loss of hermetic seal for the paper insulation, or as a result of degradation of the insulation's electrical properties due to load history and operating conditions to which the cable has been subjected over its lifetime.

The majority of the Company's solid dielectric cables that were installed in the 1970's are insulated with cross-linked polyethylene ("XLPE"). Historical performance throughout the industry for this particular vintage insulation is poor, and many cables reach end-of-life within 30 to 40 years. Often, where this type of cable was installed in Underground Residential Developments ("URDs"), the cable was direct-buried rather than installed in a manhole-and-duct system. Such installations require excavation to repair failures, and such limited repairs do not address overall deterioration of the cable system.

The underground cable projects targeted for FY 2012 replace assets in anticipation of end-of-life to avoid costly reactive construction and to eliminate repeated in-service failures which often result in customer interruptions. Some projects are multi-year efforts. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. The Company's Underground Cable Replacement Program is described more fully in the strategy paper provided in Attachment 2 to DIV 2-1.

A proposed project to construct a manhole/duct system on Governor Street in Providence will provide a route to bypass an existing duct-line on nearby Ives Street which is unusable due to severe deterioration of the ducts. The duct system on Ives Street is a critical underground corridor for four 11 kV feeders that supply Brown University and two 23 kV feeders that supply two substations on the East Side of Providence. The cables are a mix of PILC and solid dielectric construction. One of the four feeders supplying Brown University is early-1970's vintage XLPE and is targeted for replacement due to performance issues. The cable in this area on another feeder that supplies Brown and the two 23 kV feeders that supply substations on the East Side are approximately 40 years of age and will be future candidates for replacement as part of the Company's strategy to proactively replace cable to minimize the need for costly reactive construction and risk of customer interruptions. A suitable alternate route to the Ives Street duct-line does not exist and large-scale repair or addition to the existing duct-line is neither practicable nor cost-effective because of the number of circuits involved and physical constraints. In the event of in-service failure of any one of the feeders in this duct-line, emergency duct construction would be required. Such emergency construction would only address an immediate issue (cable failure repairs), and would not provide long-term benefit. This project will implement a proactive plan to install the underground facilities necessary for future cable replacement programs in the area, while limiting risk in the event of in-service failures.

Division Data Request 2-1 (continued)

Another proposed project to replace cable on feeder 1102A/1102B is part of the Company's strategy to proactively replace aged PILC cable before it reaches end-of-life. The majority of cable on this feeder is PILC construction between 70 and 80 years of age.

The cable replacement project targeted for Village Green in East Providence continues ongoing replacement of a direct-buried URD system that has experienced multiple in-service failures over several years. The most recent group of failures started in early July 2010. Repeated efforts to repair one of the main feeds into the complex were not successful, and the repair effort evolved into a replacement effort to install cable in conventional manhole/duct system. The project planned for FY 2012 continues this effort, working toward eventual replacement of the entire aged and failing direct-buried URD system. The construction sequence within the complex will be prioritized based on actual failure history.

As part of another proposed project, the Company will replace PILC cable on feeder 1158 on a heavily-loaded tie cable between Franklin Square and South Street substations. The majority of the targeted PILC cable is between 60 and 70 years of age. Three other feeders between Franklin Square and South Street are of similar age and construction and have a history of failures. Emergency mobilization and repairs are required to repair each failure, and system operation is constrained when any one of these feeders is forced out of service due to failure. The proposed project for FY 2012 is the first of a series of projects that will replace the cable on the entirety of all four feeders.

The underground cable plan as outlined above is subject to review and adjustment throughout the year, as evidenced by the Company's recent experience with two direct-buried URD systems in East Providence. At Village Green (discussed above) and Kent Farm, the scope of work evolved from repair of repeated in-service failures to major construction efforts to restore the URD systems to normal operation. Unplanned or reprioritized efforts such as these often require the shifting of resources and priorities to accomplish the required work.

5. Substation Batteries Replacement Strategy (Plan Page 27)

Substation battery replacement is in line with National Grid Substation Maintenance Standards and Procedures ("SMP's") and also reflects the latest substation battery strategy which incorporates the latest research and best practices from industry. Manufacturer warranties vary between 8 and 25 years, but industry research indicates 20 years is a valid upper limit for battery replacement (EPRI Study Report "Assessment of Alternatives to Lead-Acid batteries for Substations"). Please see the strategy paper provided in Attachment 3 to DIV 2-1 for more details.

Division Data Request 2-1 (continued)

6. Substation Metalclad Switchgear Replacement program (Plan Page 26)

The Company's Metalclad Switchgear Replacement program is described in the strategy paper contained in Attachment 4 to DIV 2-1. The project at Nasonville was originally identified in the ISR Plan as a metalclad replacement candidate based on routine monthly Visual and Operational Inspections but subsequent detailed partial discharge analyses have not revealed any significant sources; minor causes were addressed through maintenance. The Company is therefore, likely to substitute the Nasonville project with a project at another substation. The Company will perform the requisite tests on equipment at the Valley, Central Falls, Lippitt Hill and Front Street Substations to determine whether or not a replacement project is necessary to maintain reliability.

7. Substation RTU Program (Plan Page 27)

A Remote Terminal Unit ("RTU") is a device used to transfer operational information from a substation to an Energy Management System ("EMS") in a control center. An RTU allows for remote operation and management of the system to improve incident response and recovery and to thereby maintain reliable service to customers.

The Substation RTU program addresses Transmission and Distribution Substations where an RTU is not presently installed or an RTU is installed and expansion is required to maintain a reliable and sustainable network. For purposes of this program, RTU installation includes the RTU, associated wiring, device control requirements, data acquisition capability, and EMS configuration.

At a minimum, RTU control points include status and control of all automatic protective devices such as circuit breakers and circuit switchers. Additional points for monitoring the condition of equipment such as transformers, circuit breakers, circuit switchers, batteries, voltage regulators, etc. may be added to an RTU as needed provided the existing equipment has the necessary features allowing addition of a monitoring point.

This program offers a phased approach utilizing a priority list developed with System Operations and Distribution Planning to address key substations that require installation of an RTU or expansion of an existing RTU. The priority ranking was based on the following factors:

- substation loading,
- importance of the station related to customers served and impact the loss of this station has on the system,
- frequency of switching at the stations,
- stations that support the sub-transmission 23 kV network,
- substation status,

Division Data Request 2-1 (continued)

- whether metering and control would be most advantageous to regional control operators based on historical experience, mitigating customer outages or improving system integrity,
- the number of customers affected by outages/interruptions,
- the past fault/outage frequency and severity for a given area, as well as the customer sensitivity to outages in a given area.

New RTU's being installed are designed with the latest protocols and architecture and will be compatible to the new EMS being installed in National Grid Control Centers.

The Substation RTU program is designed to provide for a sustainable distribution system by enabling the following advantages:

- Enables Company personnel to operate a substation without having to travel to the substation.
- Enable the Company to fully exploit the wealth of information contained in existing substations.
- Enable Company personnel to access operational and non-operational data from substation without having to travel to the substation.
- Enables protection engineers and operations engineers to more quickly and more accurately diagnose faults and provides data for smarter analysis tools for asset managers.
- Improves asset management decisions based on hard statistical data and demand management profiles.
- Improves asset life cycle management and life extension.
- Actual field measurements obtained from substation data benefit the design and engineering functions related to: system protection, power factor monitoring and control, phase balancing, circuit reconfiguration and load balancing, load forecasting, and outage trending.

Division Data Request 2-1 (continued)

- Knowledge of the equipment condition, past performance, and historical loading and operations could be used to determine the remaining life of the equipment, future maintenance requirements, and ultimately the economic decision making criteria for retirement and life extension alternatives. The ability to perform these decisions more accurately is becoming increasingly important as the equipment population increases in age.
- Reduces the CAIDI contribution from non-SCADA stations by 15%.

Prepared by or under the supervision of: Tony McGrail and John Gavin

Distribution Substation Circuit Breaker and Recloser

Strategy Statement

The method for managing substation breakers and reclosers consists of periodic maintenance and 'replace on condition'. This approach is being augmented by a replacement program targeting aged/unreliable breaker families, units in poor condition and a formal spares policy as we first move to condition-based maintenance then risk/criticality-based maintenance. Aged units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement because their replacement would reduce the number of customer interruptions.

The total breaker population is in excess of 7,000 units consisting mainly of distribution assets with a few transmission assets managed by distribution (sub-transmission). Identified families of breakers targeted for replacement consist of approximately 940 units recommended for replacement in the next ten years. An additional 2,395 units are recommended for replacement in the next ten years based on a recently completed condition review.

The condition-based replacement program outlined in this strategy will be implemented over the next five years. This will permit the process of identifying and prioritizing the work to take place and allow for a smoother budgeting transition from the current to proposed state.

Once this strategy is in place, the annual capital budget is expected to be approximately $8M for the first four years increasing to $31M over the next six years. This sharp change after four years is due to the shift in replacement time frames between condition 3 (less than 5 years) and condition 2 (five to ten years) breakers. The high-level budget for the first ten years of the program is outlined in Table 1. These estimated costs are for breakers identified as likely one-for-one replacements and do not include breakers being replaced as part of a complete substation rebuild or replacement.

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 7,900,000		$ 7,900,000
2	$ 7,900,000		$ 7,900,000
3	$ 7,900,000		$ 7,900,000
4	$ 7,900,000		$ 7,900,000
5		$ 31,300,000	$ 31,300,000
6		$ 31,300,000	$ 31,300,000
7		$ 31,300,000	$ 31,300,000
8		$ 31,300,000	$ 31,300,000
9		$ 31,300,000	$ 31,300,000
10		$ 31,300,000	$ 31,300,000
Total	$ 31,600,000	$ 187,800,000	$ 219,400,000

Table 1 - Breaker Strategy High Level Budget

The performance target for this strategy is:

- Replace all breakers within the defined time-frame based on the condition codes

The primary benefits/risks associated with this strategy are the elimination of potentially hazardous/unreliable units from the system.

Additionally the following items require attention to better implement and manage these assets:

- Reconciliation of the spares population is needed to verify the spares population and support the creation of the spares policy. This is currently underway are part of the AIMMS conversion to Cascade that is expected to be complete by the end of 2009. The data in Cascade needs to be reviewed to confirm the reconciliation process has been completed and is accurate. This will be completed by the end of calendar year 2009.
- Support for condition codes and impact should be integrated into Cascade to provide a central location to store this information. This is currently underway as part of the AIMMS conversion to Cascade that is expected to be complete by the end of 2009.
- Condition codes must be reviewed annually and verified based upon breaker diagnostic test results and operational performance. This will support the improvement of the condition code process and insure accurate and reasonably current data is available for these assets.
- Substation Maintenance Standards (SMS) are required to document the conditions under which targeted families of breakers are replaced/refurbished. The Substation O&M Services group has agreed to begin reviewing the list of targeted families and create SMS's to support the replacement/refurbishment of the equipment. The target is to review two families annually and either create an SMS for the equipment or remove the family from the targeted list.

Table 2 - Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
2	10/14/2009	Updated data, added detail to breaker family descriptions, aligned benefits and risks to OSP objectives, added performance targets, added state specific sections	Jeffrey H. Smith Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Anthony McGrail Substation Engineering Services	John Pettigrew Executive Vice President, Electric Distribution Operations

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Strategy Justification

1.0 Purpose and Scope

This document sets out the asset management strategy for substation breakers and reclosers.

This document refers throughout to circuit breakers, or just breakers, as a generic way of identifying both circuit breakers and reclosers.

The method for managing substation breakers and reclosers consists of periodic maintenance and 'replace on condition'. This approach is being augmented by a replacement program targeting aged/unreliable breaker families, units in poor condition and a formal spares policy as we first move to condition-based maintenance then risk/criticality-based maintenance. Aged units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement because their replacement would reduce the number of customer interruptions.

2.0 Background

2.1 Substation Maintenance Procedures

Circuit breakers are inspected during the regular (at least bimonthly) Visual and Operational (V&O) check and annual Infrared (IR) rounds[1].

All breakers and reclosers undergo a mechanical check every three years, including a breaker timing diagnostic check. Oil breakers undergo a full diagnostic check at six-year intervals, while other units have a full diagnostic check at nine-year intervals[2].

2.2 Data

AIMMS has 7,129 operating breakers recorded, with 6,964 of those having either an install or manufacture date. The age profile, Figure 1, shows that about 24% of units are greater than 50 years old, with 11% at greater than 60 years old. There is an age peak at about 80 years, relating predominantly to indoor substations across the service territory. Approximately 82% of the operating breaker population is distribution assets (DxD) while 18% are transmission assets maintained by distribution (TxD). Older breakers though inherently not less reliable due to age, are more difficult to maintain, may not meet the specifications needed for modern electrical systems and may have no support in terms of replacements or spare parts.

AIMMS has 295 spare breakers recorded, with 270 of those having either an install or manufacture date. The age analysis indicates that about 28% of units are greater than 50 years old, with 15% at greater than 60 years old. The accuracy of the spares population stored in AIMMS has been called into question by field supervisors across the service territory. A reconciliation of the spares population is needed to verify the spares population and support the creation of the spares policy. The reconciliation process is underway as part of the AIMMS conversion to Cascade that is expected to be complete by the end of 2009. The data in

[1] Reference 1, SMS 400.06.1
[2] Reference 2, SMS 401.01.1 through SMS 401.07.1

Cascade needs to be reviewed to confirm the reconciliation process has been completed and is accurate. This will be completed by the end of calendar year 2009.

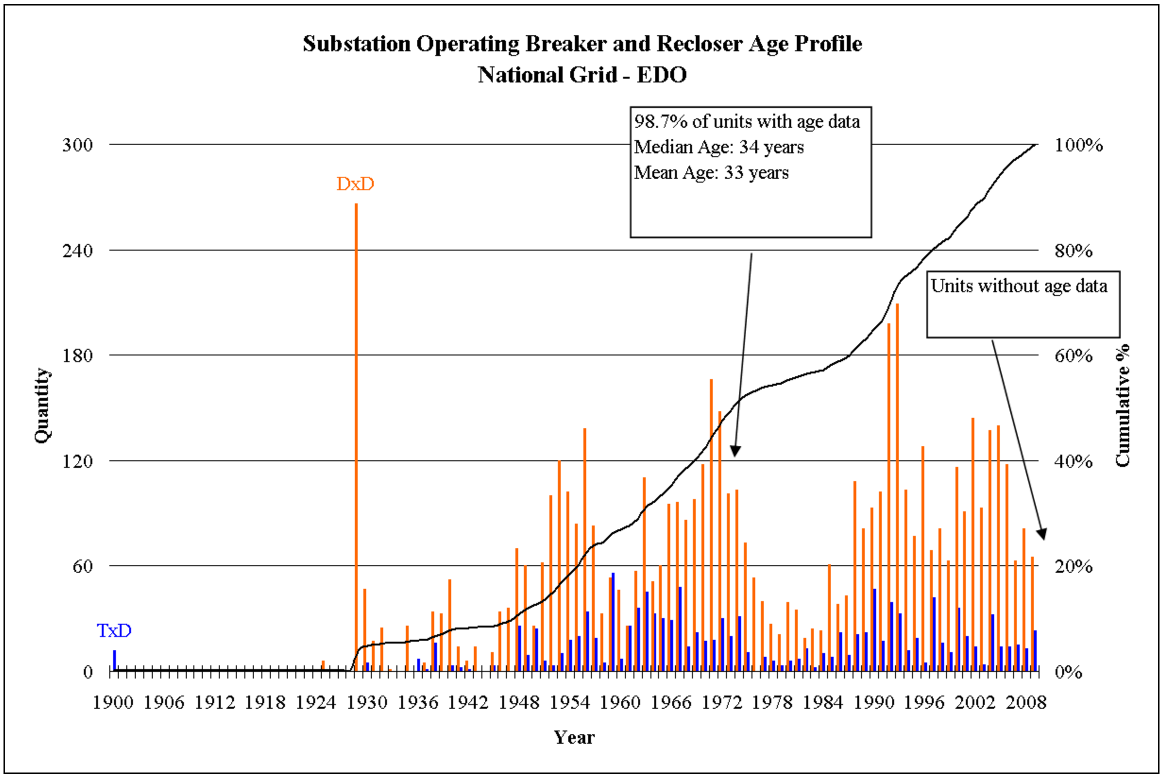


Figure 1 - Breaker and Recloser Age Profile

The distribution of breakers and reclosers by kV shows that most are 4 kV and 13 kV, Figure 2.

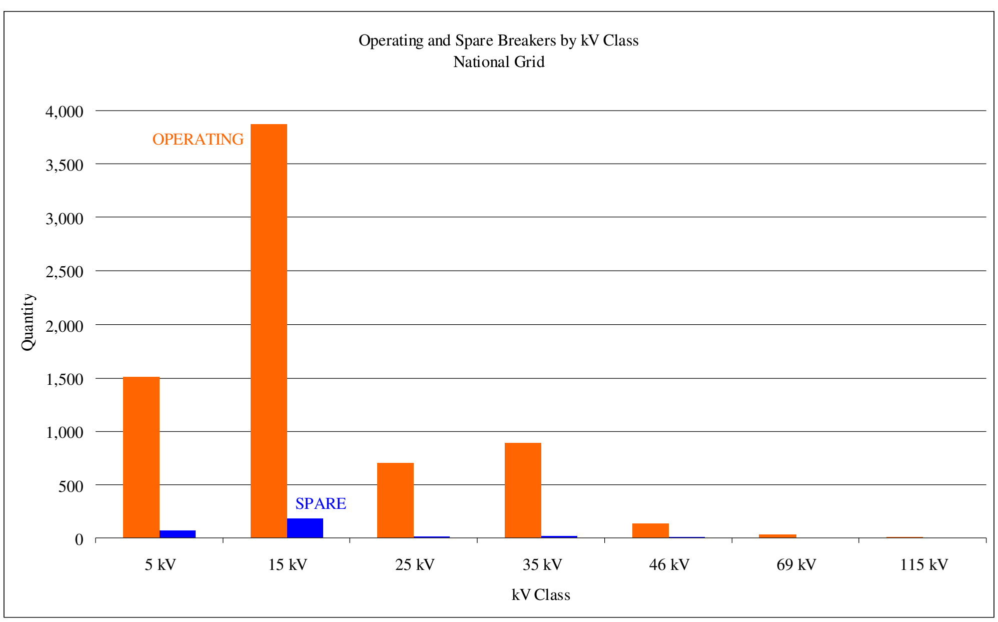


Figure 2 - Breakers and Reclosers by kV

2.3 Condition Assessment

The approach for breaker condition coding was based on engineering judgment and experience and was supported by discussion with local field staff. These condition codes were reviewed and updated in June of 2009. On-going breaker maintenance and inspection generates further knowledge and understanding of breaker condition.

Condition Code	Classification/Condition	Implication
1 Proactive	• Asset expected to operate as designed for more than 10 years	Appropriate maintenance performed; regular inspections performed
2 Proactive	• Some asset deterioration or known type/design issues • Obsolescence such that spares/replacement parts are not available • System may require a different capability at asset location	Asset likely to be replaced or refurbished in five to ten years; increased resources may be required to maintain/operate asset
3 Proactive	• Asset condition is such that there is an increased risk of failure • Test and assessment identifies definite ongoing deterioration	Asset likely to be replaced or refurbished in less than five years; increased resources may be required to maintain/operate asset
4 Reactive	• Asset has sudden and unexpected change in condition that is of immediate concern • This may be detected through routine diagnostics including inspections, annual testing, maintenance or following an event	Testing and assessment required to determine if asset may be returned to service or may be allowed to continue in service Following engineering analysis the asset will be either recoded to 1-3 or removed from the system

Table 3 - Substation Asset Condition Code Definitions

In addition to condition codes, many substations have impact codes representing the relative importance of interruptions at the substation. These impact codes are derived in part from feeder load shedding priorities established by the System Control Centers and the local knowledge and expertise of the O&M services group. The impact codes will be used to prioritize breakers within each condition code grouping.

Of the 7,129 operating breakers on the distribution system, 3,790 are condition 1, 2,496 are condition 2 and 843 are condition 3. The results of this condition assessment are summarized in Figure 3.

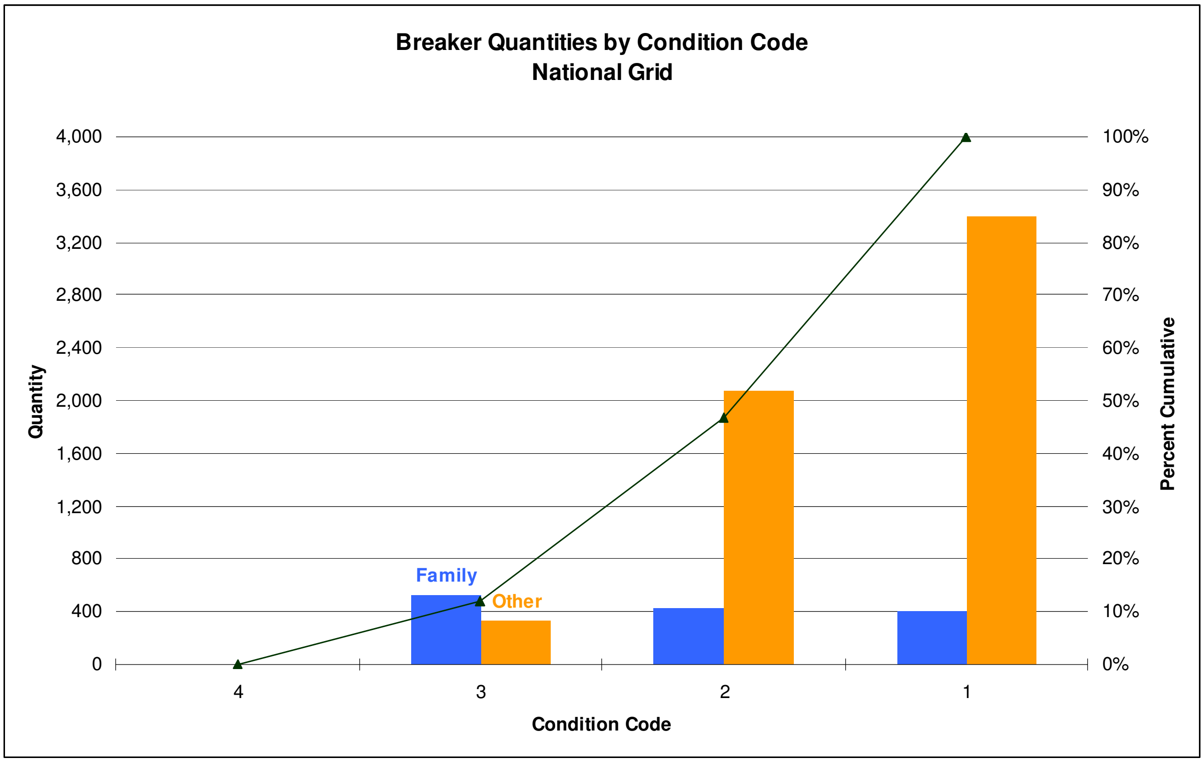


Figure 3 - Breaker Quantities by Condition Code

2.4 Targeted Breaker Families

The following section covers those breaker families that are recommended for accelerated replacement due to either age or poor reliability. A brief description of the issue follows along with a reference to the associated Substation Maintenance Standard (SMS), if available, covering the equipment replacement. Presently, many of these replacement groupings are based on anecdotal evidence that has not been completely documented. An action item to create SMS's for all targeted family replacements is being recommended by this strategy to formalize the replacement approach. Delaying these breaker family replacements will result in an increase in the possibility of the particular issue associated with the family occurring. The details of replacing targeted breakers is discussed in Section 4.0, but to summarize the approach, targeted breaker families will be replaced as part of both one-for-one replacements and larger substation projects. In general, most of the targeted families are at indoor or metalclad locations.

Condit breakers
78 units are currently in service with an average age of 69 years. These breakers are installed at indoor locations. These units are obsolete due to lack of spare parts and increasing maintenance costs. The units in this family are condition code 3 and recommended for replacement within the next five years. In general, these units will be replaced as part of a larger substation project.

Federal Pacific (FP) breakers
33 units are currently in service with an average age of 46 years. These breakers are primarily installed at indoor or metalclad locations. There are two types of FP breakers on the system, air-magnetic (AM) and oil, both of which are technologically obsolete. These units are obsolete due to lack of spare parts, frequent rebuild requirements (every 5 years) and unreliability (slow or improper tripping). The units in this family

are condition code 3 and recommended for replacement within the next five years. In general, these units will be replaced as part of one-for-one replacement projects.

General Electric (GE) Type AM breakers
526 units are currently in service with an average age of 45 years. These breakers are installed at metalclad locations. These units are obsolete due to lack of spare parts, frequent mechanism rebuild requirements (every 8-10 years), obsolescence of air-magnetic (AM) interrupting technology, presence of asbestos in arc chutes and arc-flash problems. It is possible to refurbish the interrupters with vacuum technology. Many of the breakers in this group have condition codes of 1, only the units with condition codes of 2 or 3 (179 breakers) are recommended for replacement at the present time. The remaining condition code 1 breakers will be monitored and the condition codes updated over time. The 179 units within this target group will be prioritized by condition and impact followed by age (due to the large quantity of target units). The targeted units in this family are recommended for replacement/refurbishment within the next ten years. In general, these units will be replaced as part of one-for-one replacement projects.

General Electric (GE) Type FH breakers
127 units are currently in service with an average age of 68 years. These breakers are installed at indoor locations. These units are obsolete due to lack of spare parts, slow operation (180 ms compared to modern 5-cycle breaker at ~ 80 ms) and the potential for failure. The units in this family are condition code 3 and recommended for replacement within the next five years. In general, these units will be replaced as part of a larger substation project.

General Electric (GE) Type VIR reclosers
50 units are currently in service with an average age of 38 years. These breakers are installed at outdoor locations. These units are obsolete due to unavailability of spare parts, increasing maintenance requirements and increasing in-service failures. The units in this family are condition code 3 and recommended for replacement within the next five years. SMS 401.40.1 provides the detailed conditions to justify unit replacement. In general, these units will be replaced as part of one-for-one replacement projects.

ITE Type HK breakers
215 units are currently in service with an average age of 40 years. These breakers are installed at metalclad locations. These units are obsolete due to mechanism issues. The units in this family are recommended for replacement within the next ten years, prioritized by condition and impact. As more information on this family of breakers is gathered, the replacement approach will be refined. In general, these units will be replaced as part of one-for-one replacement projects.

ITE Type KS breakers
114 units are currently in service with an average age of 40 years. These breakers are installed at outdoor locations. These units are obsolete due to mechanism issues. Many of the breakers in this group have condition codes of 1, only the units with condition codes of 2 or 3 (62 breakers) are recommended for replacement at the present time. The remaining condition code 1 breakers will be monitored and the condition codes updated over time. The 62 units in this target group are recommended for replacement within the next ten years, prioritized by condition and impact. As more information on this family of breakers is gathered, the replacement approach will be refined. In general, these units will be replaced as part of one-for-one replacement projects.

McGraw-Edison (ME) Type VSA reclosers
37 units are currently in service with an average age of 28 years. These breakers are installed at outdoor locations. Specific units within a given manufacture date range and serial number range are obsolete due to current interchanger issues. The units in this family are condition code 2 and recommended for replacement within the next five to ten years. SMS 401.41.1 provides the detailed conditions to justify unit replacement. In general, these units will be replaced as part of one-for-one replacement projects.

Westinghouse (WE) Type DHP breakers
167 units are currently in service with an average age of 37 years. These breakers are installed at metalclad locations. These units are obsolete due to AM interrupting technology. It is possible to refurbish the interrupters with vacuum technology. The units in this family are recommended for replacement/ refurbishment within the next ten years, prioritized by condition and impact. In general, these units will be replaced as part of one-for-one replacement projects.

2.5 Interruption Events

There have been approximately 123 interruption events attributed to breakers across our service territory over the last five years. These events resulted in a SAIFI of 0.008 and a SAIDI of 0.78 minutes on a five-year average basis from 2004 to 2008. The five-year average outage duration was 103 minutes.

3.0 Benefits

3.1 Safety and Environmental

Several of the targeted breaker families present opportunities to reduce potential hazards associated with safety and the environment (oil, asbestos).

3.2 Reliability

Breaker failures and mis-operations contribute a small number of events each year but these events typically involve a large number of customers (> 1000) per event. This strategy will help improve reliability by proactively replacing or refurbishing units with poor reliability or mitigate the risk of future unreliability. The overall five-year average reliability opportunity is a 0.008 reduction in system SAIFI and 0.78 minutes in system SAIDI.

3.3 Customer/Regulatory/Reputation

There are no significant benefits to external stakeholders beyond those outlined in the safety and environmental and reliability sections. Minimizing large-scale interruptions will help maintain favorable relationships with all external stakeholders.

3.4 Efficiency

There are no significant benefits to efficiency. Developing a long-range plan for managing the breaker population will avoid significantly increasing maintenance/repair costs associated with aged and obsolete equipment.

4.0 Estimated Costs

The estimates contained within this strategy are generic and only account for the costs associated with the breaker replacement (breaker installation and foundation work). Additionally these costs are high-level estimates intended to support long-range budgeting and are not intended to be used directly to support any near-term (12-18 months) budgeting. Consideration should be given to the condition of entire breaker system during replacements including relays, control cables and power supply systems. The overall condition of the substation should be reviewed prior to replacing breakers especially at indoor and metalclad locations. Additionally, a review of the future area needs (by Network Asset Planning) may be required at locations with significant concentrations of older equipment and/or older system designs as one-for-one replacement may not be the best long term strategy.

The following tables provide a high-level budget to support a ten-year plan including details for the targeted breaker families and the overall population. These estimates do not include indoor locations or locations identified for major rebuilds/replacements because the cost of breaker replacement at these locations is only a small component of the overall project. Breaker replacements at indoor locations or substation replacement locations will be covered under the specific project and/or program associated with the location. Approximately 900 of the more than 3,300 breakers identified for replacement are not included in the budgetary estimates below due to this assumption. These estimates are geared toward locations where one-for-one breaker replacements are likely to be required. The Network Asset Planning group will provide more detail for the first few years of the plan. This detail will include the specific units to be replaced and more accurate cost estimates.

Breaker Replacement Cost Estimate Groups		
Voltage Class (kV)	Construction Type	Capital Cost
15 kV	Metalclad	$ 35,000
15 kV	Outdoor	$ 110,000
25 kV	Outdoor	$ 130,000
35 kV	Outdoor	$ 160,000
46 kV	Outdoor	$ 190,000

Table 4 - Per Unit Breaker Replacement Cost Estimates

Breaker Family	Number of Units*	Per Unit Cost Estimate	Time Span	Annual Cost
Condit	12	$ 93,300	< 5 years	$ 280,000
FP	27	$ 76,900	< 5 years	$ 519,000
GE Type AM	174	$ 35,000	10 years	$ 609,000
GE Type VIR	44	$ 110,000	< 5 years	$ 1,210,000
ITE Type HK	209	$ 35,000	10 years	$ 732,000
ITE Type KS	62	$ 128,900	10 years	$ 799,000
ME Type VSA	37	$ 110,000	5 to 10 years	$ 678,000
WE Type DHP	167	$ 35,400	10 years	$ 592,000
All Other Condition 3	136	$ 112,200	< 5 years	$ 3,816,000
All Other Condition 2	1,547	$ 106,700	5 to 10 years	$ 27,519,000
*A small number of these units may already be in the process of being replaced.				

Table 5 – Summarized Breaker Replacement Cost Estimates by Family/Condition Code

Rearranging this information into a ten-year plan produces the following:

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 7,900,000		$ 7,900,000
2	$ 7,900,000		$ 7,900,000
3	$ 7,900,000		$ 7,900,000
4	$ 7,900,000		$ 7,900,000
5		$ 31,300,000	$ 31,300,000
6		$ 31,300,000	$ 31,300,000
7		$ 31,300,000	$ 31,300,000
8		$ 31,300,000	$ 31,300,000
9		$ 31,300,000	$ 31,300,000
10		$ 31,300,000	$ 31,300,000
Total	$ 31,600,000	$ 187,800,000	$ 219,400,000
At substations with a mixture of breaker conditions, all breakers should be replaced as part of the same project if change in scope is not significant. All costs in 2009 dollars without inflation.			

Table 6 - Estimated Ten-Year Capital Plan

5.0 Implementation

The condition-based replacement program outlined in this strategy will be implemented over the next five years. This will permit the process of identifying and prioritizing the work to take place and allow for a smoother budgeting transition from the current to proposed state. The estimated costs in Table 6 represent spending levels after the program has been fully implemented. Current capital spending levels for circuit breaker replacement is approximately $6M annually for one-for-one type replacements covering approximately 100 units. Specific substation projects typically replace an additional 10-20 units annually.

5.1 Performance Targets:

The performance target for this strategy is:

- Replace all breakers within the defined time-frame based on the condition codes

Achieving these performance targets will require a ramping up of the breaker replacements, which is expected to occur over the next five years.

6.0 Risk Assessment

6.1 Safety and Environmental

Failure to address the breaker families with identified issues will not reduce this potential hazard.

6.2 Reliability

Failure to address the breaker families and individual units with poor reliability performance will result in continued (and possibly more) interruptions involving large groups of customers (> 1000).

6.3 Customer/Regulatory/Reputation

There are no significant risks to external stakeholders beyond those outlined in the safety and environmental and reliability sections.

6.4 Efficiency

There are no significant risks to efficiency related to this strategy. Not proactively managing these assets will lead to less predictable spending associated with equipment failures.

7.0 Data Requirements

7.1 Existing/Interim:

- AIMMS
- Problem Identification Worksheet (PIW)
- IDS

7.2 Proposed:

- Cascade
- Problem Identification Worksheet (PIW)
- IDS

7.3 Comments:

- Cascade is currently being configured with the goal of replacing AIMMS as the source for substation and other asset system information over the course of 2009
- Support for condition and impact codes should be integrated into Cascade to provide a central location to store this information. This is currently underway are part of the AIMMS conversion to Cascade that is expected to be complete by the end of 2009.
- Condition codes must be reviewed annually and verified based upon breaker diagnostic test results and operational performance. This will support the improvement of the condition code process and insure accurate and reasonably current data is available for these assets.
- Substation Maintenance Standards (SMS) will be written to document the conditions under which targeted units are replaced/refurbished. The Substation O&M Services group has agreed to begin reviewing the list of targeted families and create SMS's to support the replacement/refurbishment of the equipment. The target is to review two families annually and either create an SMS for the equipment or remove the family from the targeted list.

8.0 References

1. SMS 400.06.1
2. SMS 401.01.1 thru SMS 401.07.1

Massachusetts Specifics

AIMMS has 2,117 operating breakers recorded, with 2,079 of those having an either an install or manufacture date. The age profile, Figure 4, shows that about 28% of units are greater than 50 years old, with 12% at greater than 60 years old. Approximately 94% of the operating breaker population is distribution assets (DxD) while 6% are transmission assets maintained by distribution (TxD). AIMMS has 149 spare breakers recorded.

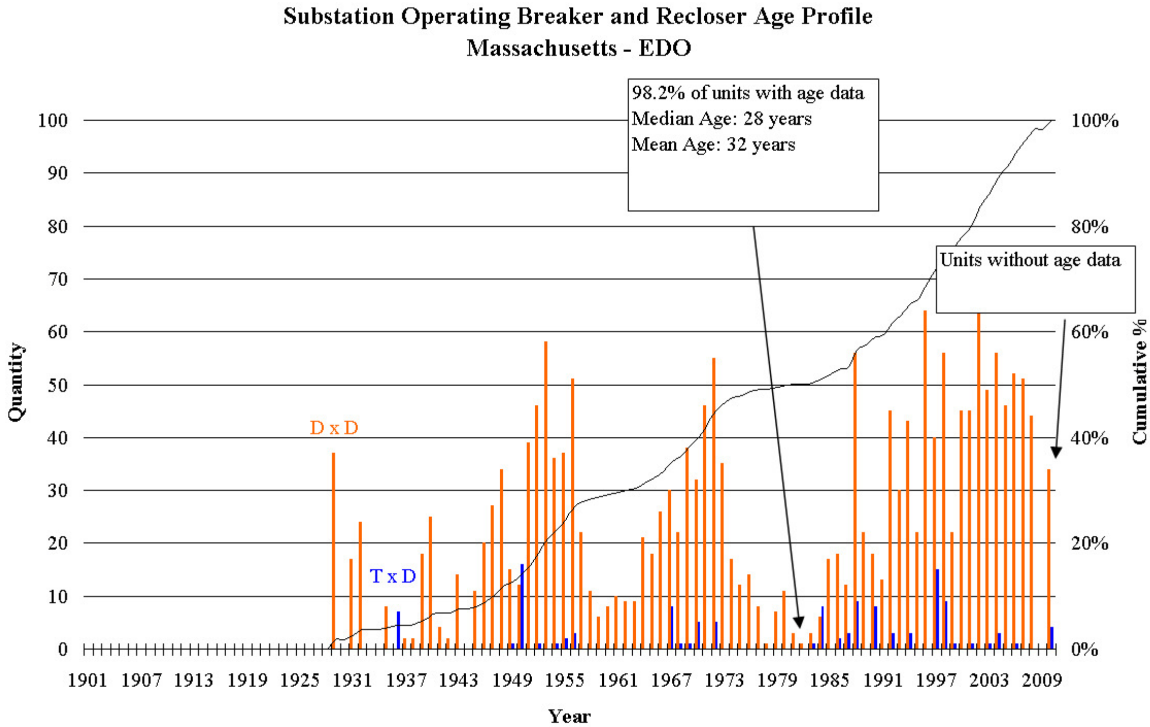


Figure 4 - Massachusetts Breaker Age Profile

Of the 2,117 operating breakers on the distribution system, 1,155 are condition 1, 648 are condition 2 and 314 are condition 3. The results of this condition assessment are summarized in the Figure 5.

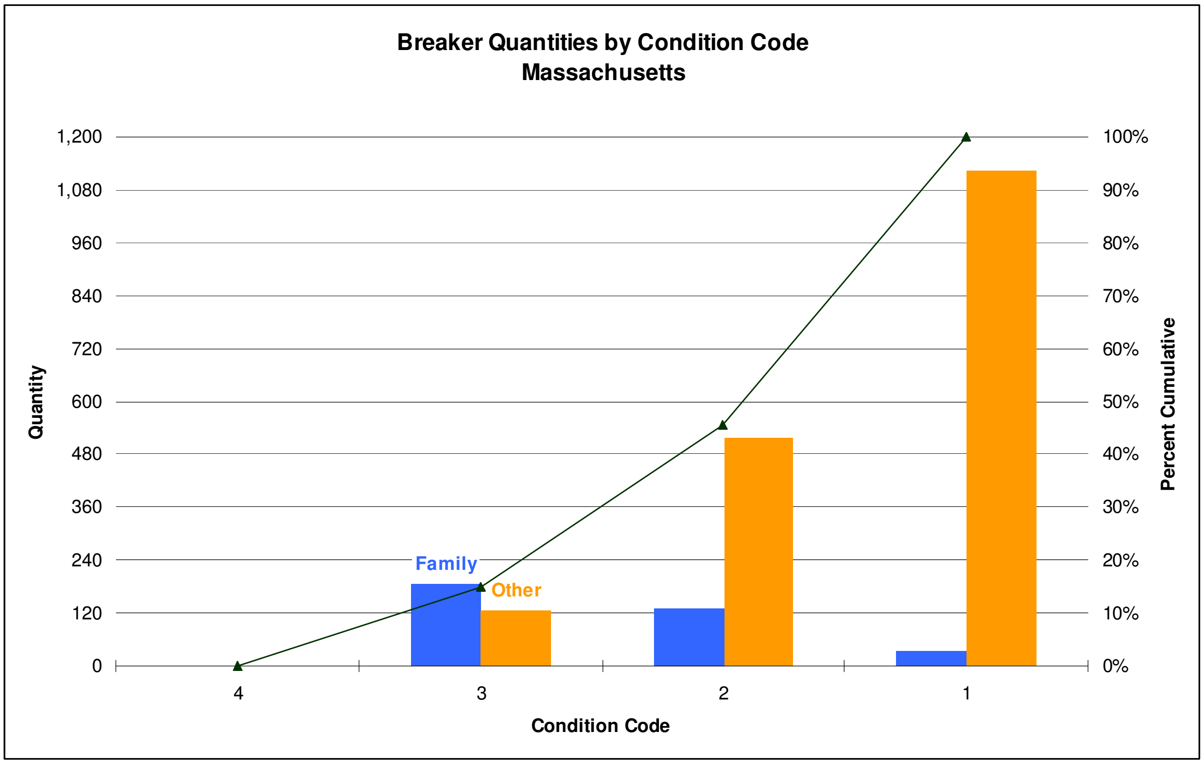


Figure 5 - Massachusetts Breaker Quantities by Condition Code

The following tables provide a high-level budget to support a ten-year plan including details for the targeted breaker families and the overall population (indoor and substation replacement locations are excluded as described in Section 4.0). The Network Asset Planning group will provide more detail for the first few years of the plan. This detail will include the specific units to be replaced and more accurate cost estimates.

Massachusetts				
Breaker Family	Number of Units*	Per Unit Cost Estimate	Time Span	Annual Cost
Condit	8	$ 122,500	< 5 years	$ 245,000
GE Type AM	105	$ 35,000	10 years	$ 368,000
GE Type VIR	21	$ 110,000	< 5 years	$ 578,000
ITE Type HK	31	$ 35,000	10 years	$ 109,000
ITE Type KS	1	$ 160,000	< 5 years	$ 32,000
ME Type VSA	27	$ 110,000	5 to 10 years	$ 495,000
WE Type DHP	47	$ 35,000	10 years	$ 165,000
All Other Condition 3	51	$ 122,500	< 5 years	$ 1,561,000
All Other Condition 2	294	$ 115,500	5 to 10 years	$ 5,658,000
*A small number of these units may already be in the process of being replaced.				

Table 7 - Massachusetts Summarized Breaker Replacement Costs by Family/Condition Code

Rearranging this information into a ten-year plan produces the following:

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 3,100,000		$ 3,100,000
2	$ 3,100,000		$ 3,100,000
3	$ 3,100,000		$ 3,100,000
4	$ 3,100,000		$ 3,100,000
5		$ 6,800,000	$ 6,800,000
6		$ 6,800,000	$ 6,800,000
7		$ 6,800,000	$ 6,800,000
8		$ 6,800,000	$ 6,800,000
9		$ 6,800,000	$ 6,800,000
10		$ 6,800,000	$ 6,800,000
Total	$ 12,400,000	$ 40,800,000	$ 53,200,000
At substations with a mixture of breaker conditions, all breakers should be replaced as part of the same project if change in scope is not significant. All costs in 2009 dollars without inflation.			

Table 8 - Massachusetts Estimated Ten Year Capital Plan

New Hampshire/Vermont Specifics

AIMMS has 79 operating breakers recorded, with 78 of those having an either an install or manufacture date. The age profile, Figure 6, shows that about 23% of units are greater than 50 years old, with 14% at greater than 60 years old. Approximately 61% of the operating breaker population is distribution assets (DxD) while 39% are transmission assets maintained by distribution (TxD). AIMMS has one spare breaker recorded.

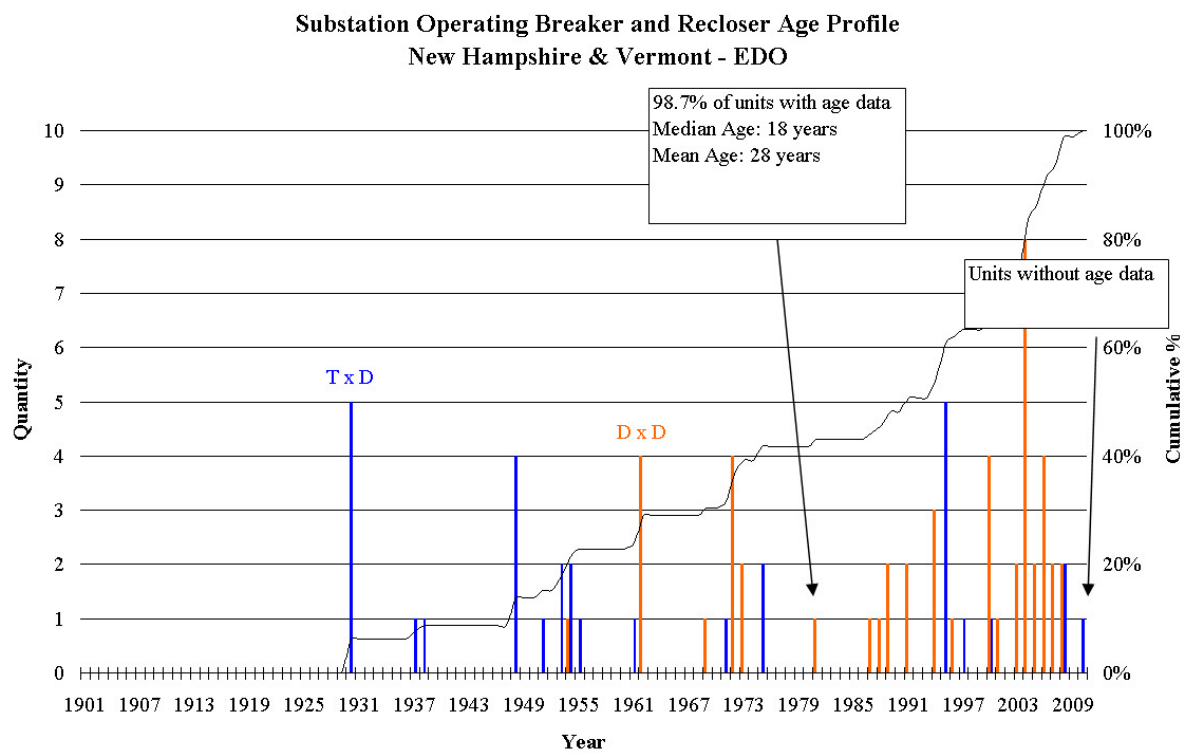


Figure 6 - New Hampshire/Vermont Breaker Age Profile

Of the 79 operating breakers on the distribution system, 46 are condition 1, 22 are condition 2 and 11 are condition 3. The results of this condition assessment are summarized in the Figure 7.

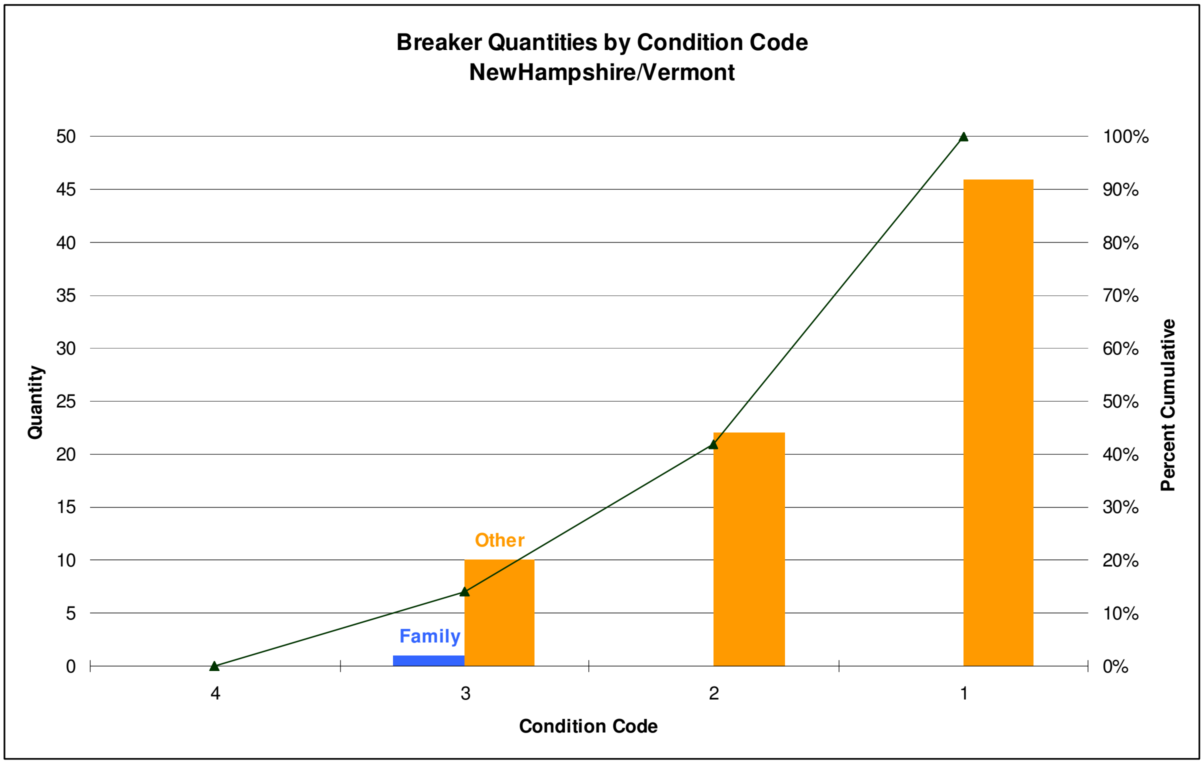


Figure 7 - New Hampshire/Vermont Breaker Quantities by Condition Code

The following tables provide a high-level budget to support a ten-year plan including details for the targeted breaker families and the overall population (indoor and substation replacement locations are excluded as described in Section 4.0). The Network Asset Planning group will provide more detail for the first few years of the plan. This detail will include the specific units to be replaced and more accurate cost estimates.

New Hampshire/Vermont				
Breaker Family	Number of Units*	Per Unit Cost Estimate	Time Span	Annual Cost
ME Type VSA	1	$ 110,000	5 to 10 years	$ 18,000
All Other Condition 3	10	$ 158,000	< 5 years	$ 395,000
All Other Condition 2	22	$ 131,800	5 to 10 years	$ 483,000
*A small number of these units may already be in the process of being replaced.				

Table 9 - New Hampshire/Vermont Summarized Breaker Replacement Costs by Family/Condition Code

Rearranging this information into a ten-year plan produces the following:

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 400,000		$ 400,000
2	$ 400,000		$ 400,000
3	$ 400,000		$ 400,000
4	$ 400,000		$ 400,000
5		$ 500,000	$ 500,000
6		$ 500,000	$ 500,000
7		$ 500,000	$ 500,000
8		$ 500,000	$ 500,000
9		$ 500,000	$ 500,000
10		$ 500,000	$ 500,000
Total	$ 1,600,000	$ 3,000,000	$ 4,600,000
At substations with a mixture of breaker conditions, all breakers should be replaced as part of the same project if change in scope is not significant. All costs in 2009 dollars without inflation.			

Table 10 - New Hampshire/Vermont Estimated Ten Year Capital Plan

New York Specifics

AIMMS has 4,093 operating breakers recorded, with 3,987 of those having an either an install or manufacture date. The age profile, Figure 8, shows that about 21% of units are greater than 50 years old, with 9% at greater than 60 years old. Approximately 73% of the operating breaker population is distribution assets (DxD) while 27% are transmission assets maintained by distribution (TxD). AIMMS has 108 spare breakers recorded.

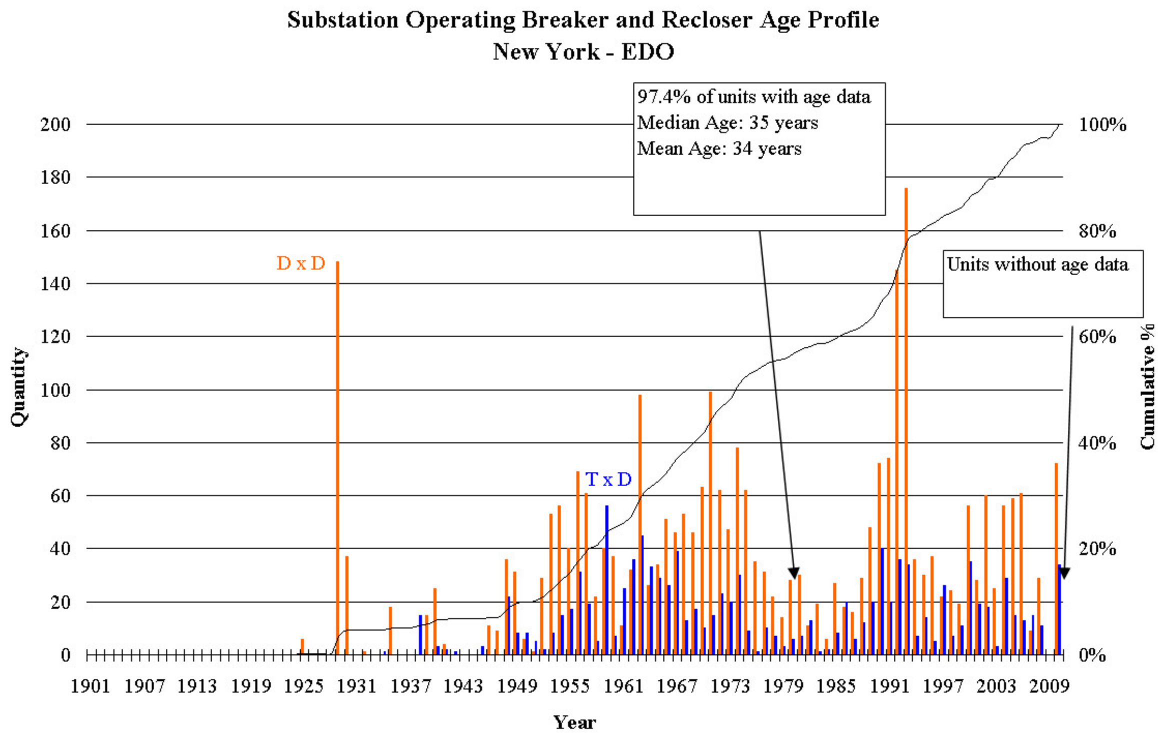


Figure 8 - New York Breaker Age Profile

Of the 4,093 operating breakers on the distribution system, 2,209 are condition 1, 1,670 are condition 2 and 214 are condition 3. The results of this condition assessment are summarized in the Figure 9.

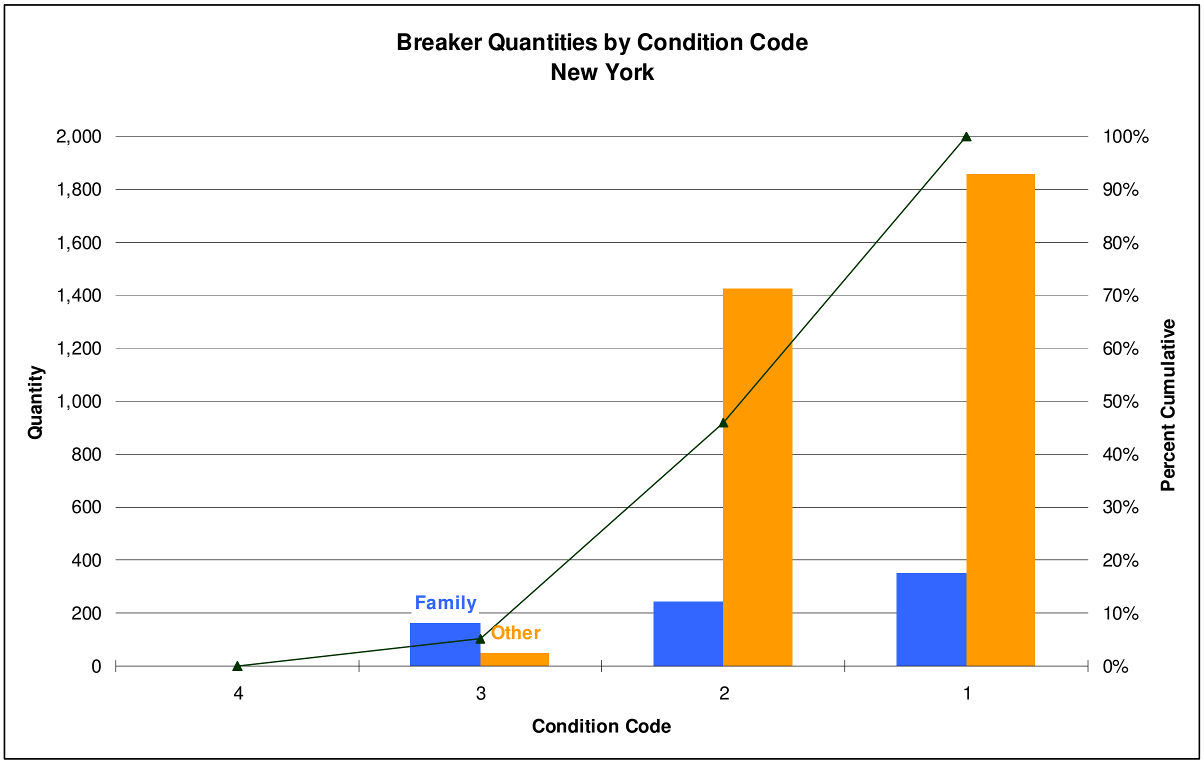


Figure 9 - New York Breaker Quantities by Condition Code

The following tables provide a high-level budget to support a ten-year plan including details for the targeted breaker families and the overall population (indoor and substation replacement locations are excluded as described in Section 4.0). The Network Asset Planning group will provide more detail for the first few years of the plan. This detail will include the specific units to be replaced and more accurate cost estimates.

New York				
Breaker Family	Number of Units*	Per Unit Cost Estimate	Time Span	Annual Cost
Condit	4	$ 35,000	< 5 years	$ 35,000
FP	22	$ 86,400	< 5 years	$ 475,000
GE Type AM	16	$ 35,000	10 years	$ 56,000
GE Type VIR	4	$ 110,000	< 5 years	$ 110,000
ITE Type HK	158	$ 35,000	10 years	$ 553,000
ITE Type KS	56	$ 125,500	5 to 10 years	$ 1,172,000
ME Type VSA	2	$ 110,000	5 to 10 years	$ 37,000
WE Type DHP	101	$ 35,700	5 to 10 years	$ 602,000
All Other Condition 3	43	$ 85,900	< 5 years	$ 924,000
All Other Condition 2	1,139	$ 104,200	5 to 10 years	$ 19,783,000
*A small number of these units may already be in the process of being replaced.				

Table 11 - New York Summarized Breaker Replacement Costs by Family/Condition Code

Rearranging this information into a ten-year plan produces the following:

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 2,300,000		$ 2,300,000
2	$ 2,300,000		$ 2,300,000
3	$ 2,300,000		$ 2,300,000
4	$ 2,300,000		$ 2,300,000
5		$ 22,100,000	$ 22,100,000
6		$ 22,100,000	$ 22,100,000
7		$ 22,100,000	$ 22,100,000
8		$ 22,100,000	$ 22,100,000
9		$ 22,100,000	$ 22,100,000
10		$ 22,100,000	$ 22,100,000
Total	$ 9,200,000	$ 132,600,000	$ 141,800,000
At substations with a mixture of breaker conditions, all breakers should be replaced as part of the same project if change in scope is not significant. All costs in 2009 dollars without inflation.			

Table 12 - New York Estimated Ten Year Capital Plan

Rhode Island Specifics

AIMMS has 840 operating breakers recorded, with 820 of those having an either an install or manufacture date. The age profile, Figure 10, shows that about 30% of units are greater than 50 years, with 17% at 60 years or greater. Approximately 97% of the operating breaker population is distribution assets (DxD) while 3% are transmission assets maintained by distribution (TxD). AIMMS has 37 spare breakers recorded.

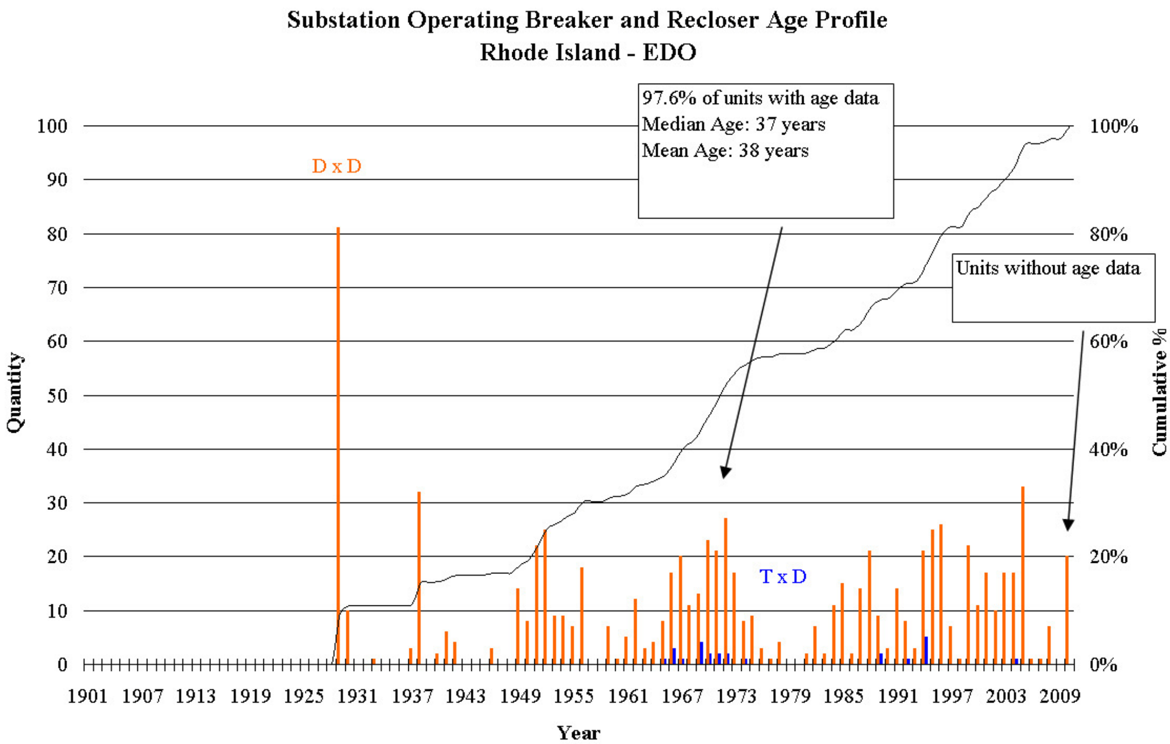


Figure 10 - Rhode Island Breaker Age Profile

Of the 840 operating breakers on the distribution system, 380 are condition 1, 156 are condition 2 and 304 are condition 3. The high percentage of condition 3 breakers is primarily associated with the aging sub-transmission system within downtown Providence. This area requires review by Network Asset Planning to determine the best course of action to address these breakers as a one-for-one replacement approach may not be the best long-term strategy. The results of this condition assessment are summarized in the Figure 11.

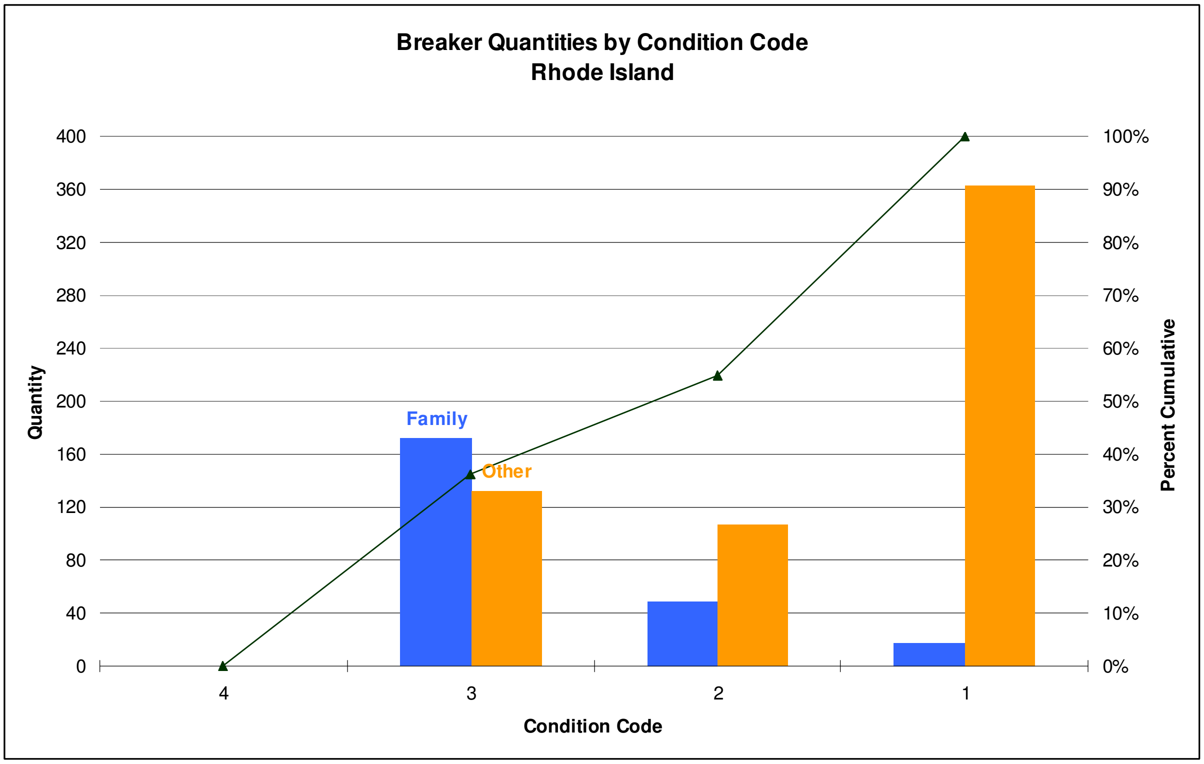


Figure 11 - Rhode Island Breaker Quantities by Condition Code

The following tables provide a high-level budget to support a ten-year plan including details for the targeted breaker families and the overall population (indoor and substation replacement locations are excluded as described in Section 4.0). More detail will be provided by the Network Asset Planning group for the first few years of the plan. This detail will include the specific units to be replaced and more accurate cost estimates.

Rhode Island				
Breaker Family	Number of Units*	Per Unit Cost Estimate	Time Span	Annual Cost
FP	5	$ 35,000	< 5 years	$ 44,000
GE Type AM	53	$ 35,000	10 years	$ 186,000
GE Type VIR	19	$ 110,000	< 5 years	$ 523,000
ITE Type HK	20	$ 35,000	< 5 years	$ 175,000
ITE Type KS	5	$ 160,000	< 5 years	$ 200,000
ME Type VSA	7	$ 110,000	5 to 10 years	$ 128,000
WE Type DHP	19	$ 35,000	10 years	$ 67,000
All Other Condition 3	32	$ 117,000	< 5 years	$ 936,000
All Other Condition 2	92	$ 104,000	5 to 10 years	$ 1,595,000
*A small number of these units may already be in the process of being replaced. These numbers represent the upper limit of breakers to be replaced.				

Table 13 - Rhode Island Summarized Breaker Replacement Costs by Family/Condition Code

Rearranging this information into a ten-year plan produces the following:

Estimated Ten Year Capital Costs for Breaker Strategy			
Plan Year	Condition 3 ($)	Condition 2 ($)	Total ($)
1	$ 2,100,000		$ 2,100,000
2	$ 2,100,000		$ 2,100,000
3	$ 2,100,000		$ 2,100,000
4	$ 2,100,000		$ 2,100,000
5		$ 2,000,000	$ 2,000,000
6		$ 2,000,000	$ 2,000,000
7		$ 2,000,000	$ 2,000,000
8		$ 2,000,000	$ 2,000,000
9		$ 2,000,000	$ 2,000,000
10		$ 2,000,000	$ 2,000,000
Total	$ 8,400,000	$ 12,000,000	$ 20,400,000
At substations with a mixture of breaker conditions, all breakers should be replaced as part of the same project if change in scope is not significant. All costs in 2009 dollars without inflation.			

Table 14 - Rhode Island Estimated Ten Year Capital Plan

Primary Underground Cable
Table of Contents

Strategy Statement

It is the intent of this strategy to eliminate all primary underground cable more than 60 years old from the system. It is the intent of this strategy to do so in fifteen years.

This strategy does not apply to URD cables or underground primary cables serving pad-mounted transformers or to sub-transmission cables. These applications are covered by other strategies.

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
1	01/03/2008	Initial Issue	John Teixeira Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

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.

This strategy is not intended to apply to primary cable used in URD systems or as supply to single or small groups of pad-mounted transformers (siphons). Nor is this strategy intended to apply to subtransmission cables. These cables are covered by other strategies.

2.0 Strategy Description

2.1 Background

National Grid currently has approximately 19,000 miles of underground primary cable, of all types, listed in the Smallworld GIS system. This data includes subtransmission cables in New England (but not New York) as well as URD cable and other cables not covered by this strategy. Smallworld GIS does not detail cable by application (URD, get-away, etc.). However, most URD cable and feeds to pad-mounted transformers are #2 cables and most #2 cable is used in these applications. For the purposes of this strategy, it is estimated that 75% of all #2 cable is used for URD and siphon applications.

After accounting for subtransmission cables and URD and siphon cables not managed by this strategy, a total of approximately 9,000 miles of cable are managed by this strategy as detailed in the table below.

Table 1- Cables Managed by This Strategy

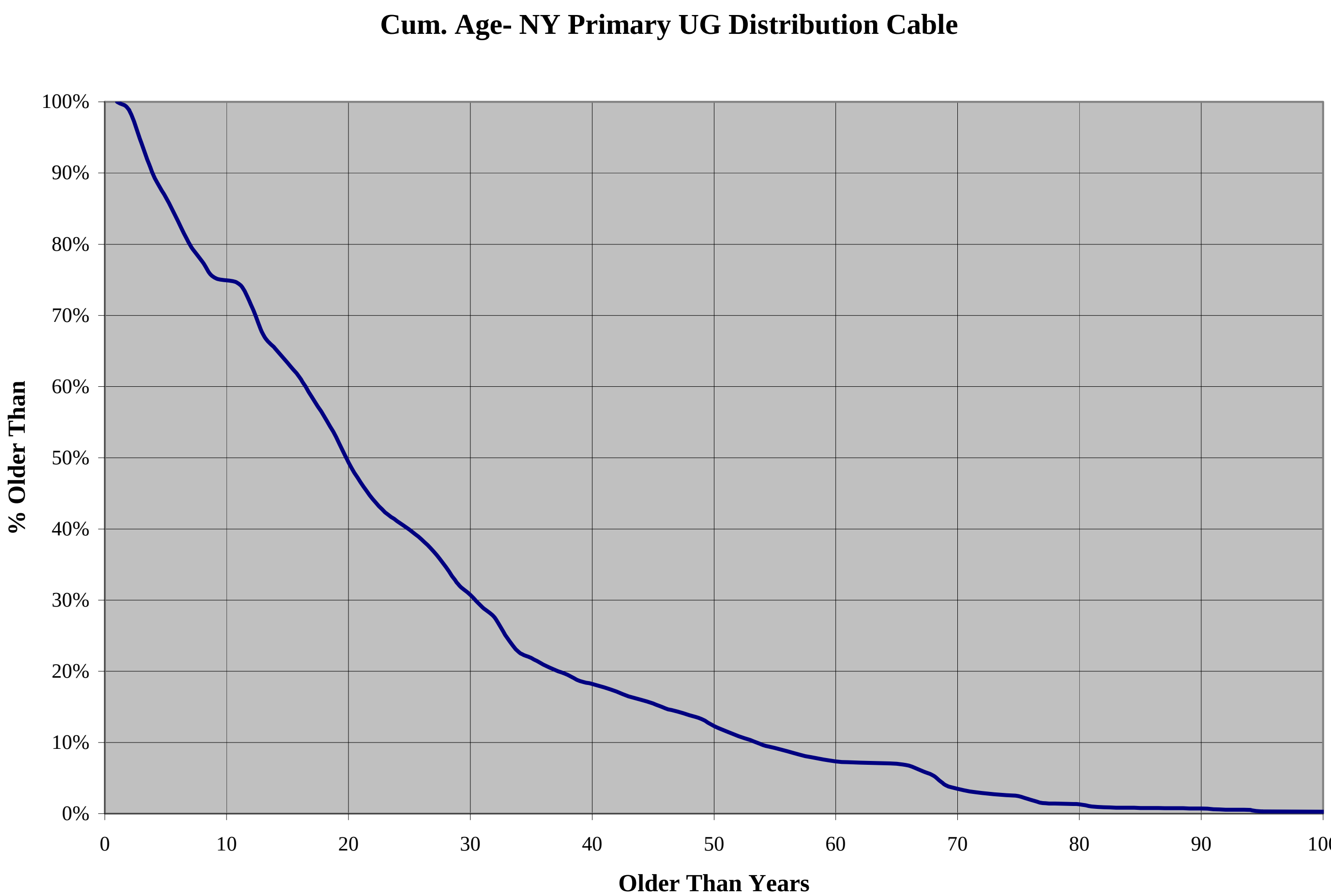
	NY	NE	Total	Notes
Total UG Primary Cable (Miles)	8,820	10,223	19,043	Source: Smallworld
Miles of #2	6,751	5,750	12,501	Source: Smallworld
% of #2 Assumed to be URD, etc.	75%	75%		Estimated
Miles of cable Excluding #2	3,757	5,910	9,667	
SubT cable in GIS	-	700		From Subtransmission cable strategy
Miles managed by this strategy	3,757	5,210	8,967	

There is no central repository of age data for primary underground cable. Age data for New York is contained in the Plant Accounting system (C-PAS). Due to the first in-first out retirement system used in New England, no reliable age data exists in the accounting systems for New England cables. No Age data exists in Smallworld prior to 2001. While there is no central repository for age data, limited age data may exist at the local level in both New York and New England.

Various cable insulations and configurations have been used through-out the years for underground primary cables. These range from multi-conductor paper-lead cables to single conductor solid dielectric cables. Expected cable life and reliability performance is likely linked to cable insulation. The Smallworld GIS system tracks cable insulation, however, the data currently in the GIS system is highly inaccurate and cannot be used for analysis.

Figure 1 below shows age data for the New York underground primary cable from the New York Plant Account system. As can be seen in Figure 1, approximately half of all primary underground cable currently in service is more than 20 years old. And nearly 8% is more than 60 years old. Considering the lack of age data for New England, for the purposes of this strategy, the age profile for underground primary cable in New England will be modeled as the same as New York.

Figure 1- Age Distribution of Underground Primary Cable



Accurate data on cable failures is not available in New York; however, failure data is available in New England from the IDS system. Over the five year period from calendar year 2002 to 2006 the contribution of cable failures to overall reliability is detailed below (based on IEEE criteria).

Table 2- Contribution of Cable Failures to Overall Reliability (New England- IEEE)

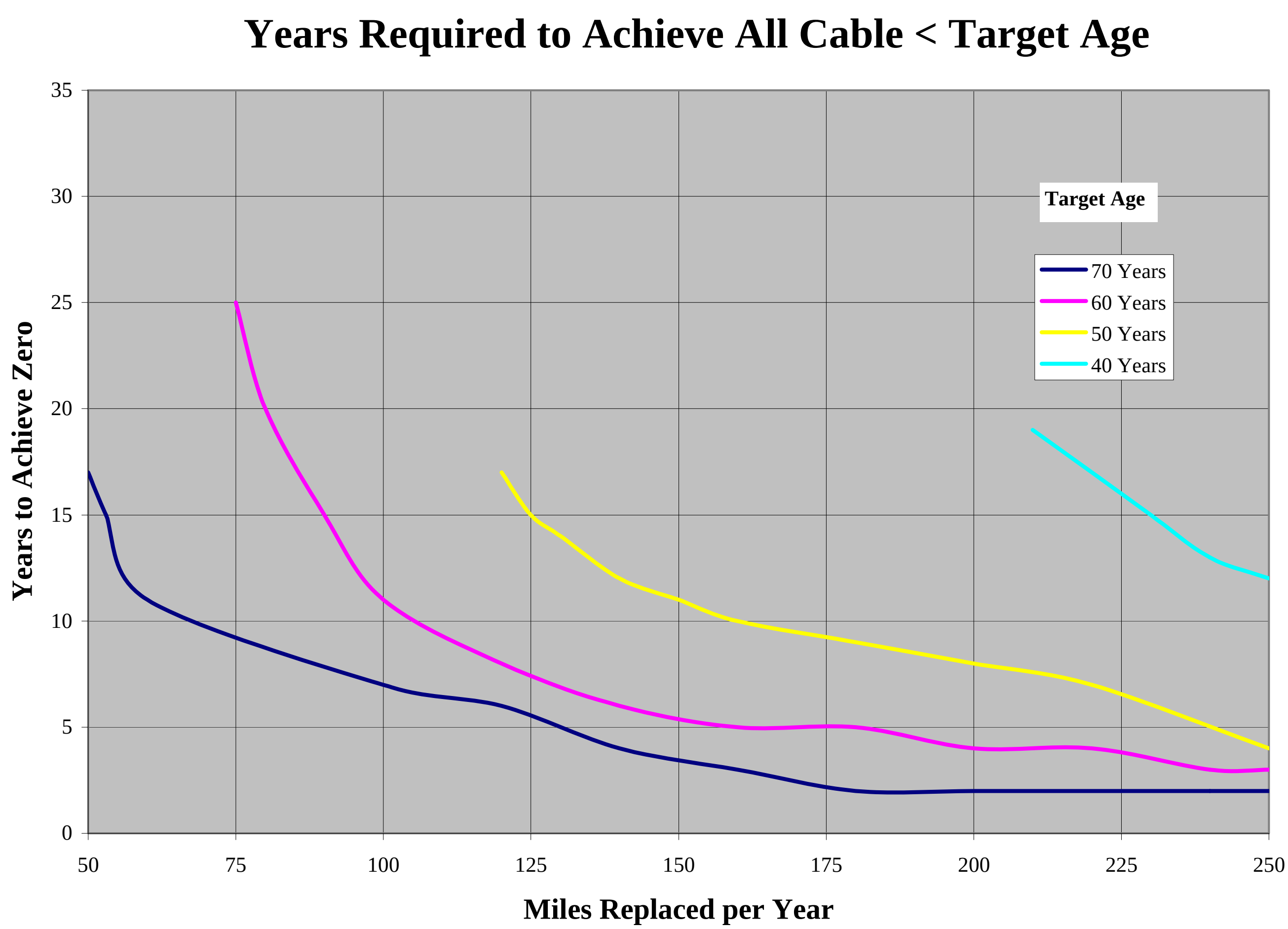
Year	Events	CI	CMI
2002	2%	5%	8%
2003	3%	6%	10%
2004	3%	6%	10%
2005	3%	6%	9%
2006	3%	5%	7%
Average	3%	6%	9%

The reliability data above includes contributions from all cables including cables not managed by this strategy. Existing systems do not accurately breakout cable failures by cable application. It should also be noted that no data is maintained that links cable age to failure data.

2.2 Infrastructure Management Alternatives

Several scenarios were reviewed for addressing the age of underground primary cable. Each scenario is based on setting a target for the maximum age of underground primary cable allowed and then determining the annual cable replacement required to achieve a condition of zero cable older than the target age within a fixed time frame. Figure 2 summarizes the potential scenarios.

Figure 2- Underground Primary Replacement Scenarios



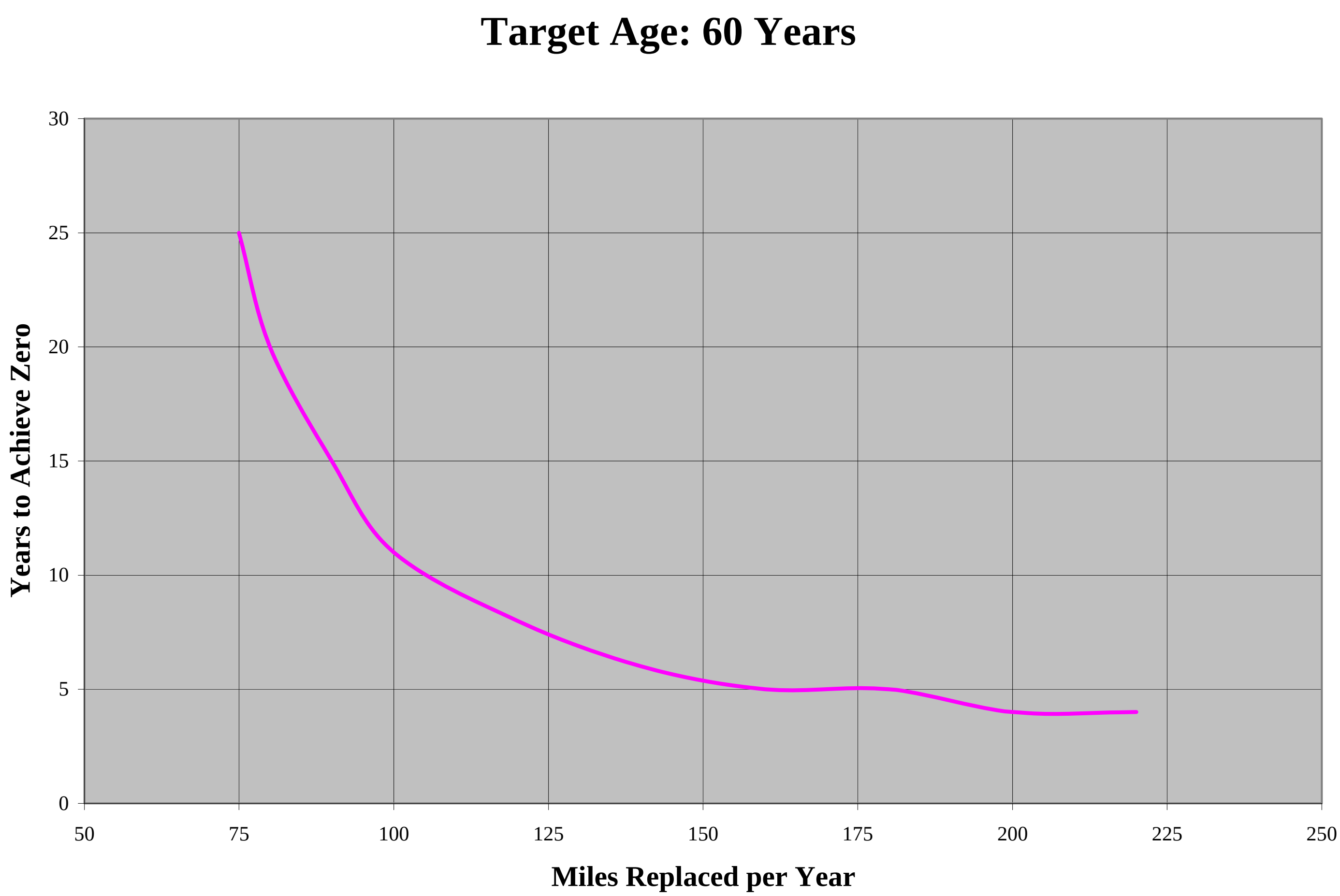
2.3 Proposed Plan

Considering the current age of the existing system and recognizing that efforts must be made to maintain this asset class within a certain maximum age, an upper age limit of 60 years was selected as a target. Using the 60 year age target, three programs were reviewed, aggressive, moderate, and sustained. These are detailed below.

Table 3- 60 Year Age Target- Replacement Rates

Program	Years To Achieve No Cable Older Than Target	Miles Replaced Each Year
Aggressive	10	105
Moderate	15	90
Sustained	20	80

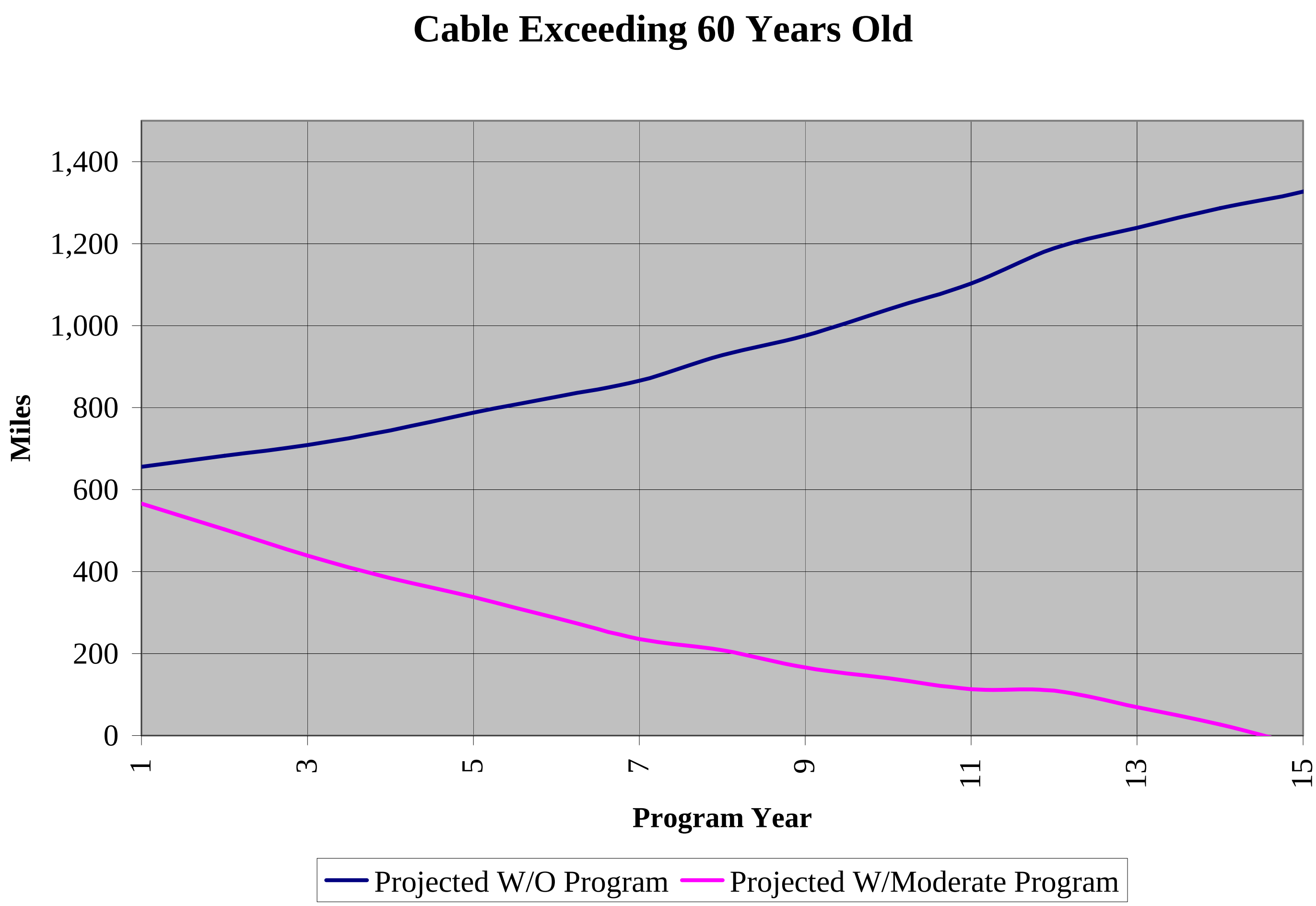
Figure 3- 60 Year Age Target



A moderate program is recommended. This program will require the installation of approximately 90 miles of cable per year and is expected to eliminate all underground primary cable older than 60 years in 15 years. This program should be reviewed and re-assessed at five year intervals.

Figure 4 details the projected miles of cable exceeding 60 years of age if a replacement program were not implemented versus projections with the proposed program.

Figure 4- Project Miles of Cable over Target Age



3.0 Benefits

3.1 Safety & Environmental

This strategy has no significant safety or environmental impact.

3.2 Reliability

Failures of underground primary cables, of all applications including those not managed by this strategy, contribute approximately 6% to CI and 9% to CMI annually. While this cannot be directly linked to cable age an age-based replacement program will likely decrease this contribution.

3.3 Regulatory/Reputation

While underground primary cable failures are a relatively small contributor to overall reliability, these failures typically take longer to repair than typical interruptions. In addition, underground primary cable is typically used in dense urban areas that are less tolerant of long interruptions. Considering these facts there is a greater risk of damage to reputation and subsequent regulatory intervention than associated with overhead distribution equipment.

3.4 Customer

Beyond any benefits stated above, this strategy has no significant direct customer benefit.

4.0 Estimated Costs

This program has expected costs of:

Table 4- Expected Annual Cost s (2007 Dollars) [2]

Capital	$53,000,000
O&M	$900,000
Removal	$6,300,000

The estimated costs are based on the following estimates and assumptions:

- Cable Installation/Mile in Existing Duct
  - $ 370,000 Capital
  - $ 10,000 O&M
  - $ 70,000 Removal
- Duct Installation/Mile
  - $2.2M per mile for manhole and duct installation (two-way, manholes at 350-400 foot intervals).
- For every mile of cable, 0.1 miles of duct line is required.
- Above costs include engineering and design

5.0 Implementation

Engineering and construction resources do not currently exist within National Grid to undertake this effort nor is it likely that adequate resources can be acquired through contractors or other sources to immediately implement this strategy.

Due to the lack of centralized, credible data as to cable type and age, a strenuous data collection effort is necessary before any large scale replacement program can begin. This strategy should be reviewed in light of age and type data collected and refined as required.

6.0 Risk Assessment

6.1 Safety & Environmental

This strategy presents no significant safety or environmental risk.

6.2 Reliability

The implementation of this strategy may require planned interruptions to replace cables.

6.3 Regulatory/Reputation

Failing to implement this strategy will not provide the benefits started above.

6.4 Customer

This strategy presents no significant customer risk.

7.0 Data Requirements

7.1 Existing/Interim:

Primary underground cable data is contained in the Smallworld GIS system however this data does not include age data and the quality of much of the other attribute data, including insulation type is highly inaccurate. Age data for New York is contained in the plant accounting system. That data is of questionable quality.

Significant amount of data may exist on the local level in paper based or independent computer databases.

7.2 Proposed:

In order to properly implement this strategy the age and type of cables must be know. Currently this data does not exist in a useable form but may exist in scattered paper and PC based documents at the district and division level.

An effort should be undertaken to capture cable data including age, insulation, size, etc. and that data should be entered into the Smallworld GIS system.

7.3 Comments:

The implementation of this strategy can take place in parallel with data collection efforts.

8.0 References

None

Batteries and Chargers Strategy Statement

The intent of this Strategy is to ensure batteries and chargers are sufficient and dependable in order to provide a reliable DC power supply in substations. Industry experience and National Grid's experience in managing battery systems support replacement of batteries after 20 years in service.

Battery systems (or sets) are a critical component necessary in a substation to ensure successful operation of equipment and control systems during routine and emergency conditions. In conjunction with an existing proactive battery inspection program and reactive Problem Identification Worksheet (PIW) process, this strategy supports a sustainable distribution system and maintains system reliability.

This Distribution strategy aligns with the Transmission Strategy SG 128 "Replacement Strategy for Substation Batteries in New York and New England" approved January 18, 2010.

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
3	03/31/10	Revised data and recommended replacement rate.	Alyne Silva Asset Strategy	Ellen Smith Chief Operating Officer US Electricity Operations Chairman of DCIG
2	08/06/08	Complete revision of data to reflect solely D operational and spare; up[dated analysis based on improved data; updated text to reflect PIW's, risk register and available projects	Tony McGrail Substations O&M	John Pettigrew Executive Vice President, Electric Distribution Operations
1	07/12/07	Initial Issue	Tony McGrail Substations O&M	John Pettigrew Executive Vice President, Electric Distribution Operations

Table 1 – Amendments Record

Battery and Chargers Strategy Justification

1.0 Purpose and Scope

This strategy supports the reliability of the system and the sustainability of the network. It identifies the replacement strategy for batteries and chargers in substations and augments the present approach of detecting poor systems and candidates for replacement through substation inspections.

2.0 Strategy Description

2.1 Background

Battery and charger systems are critical components that are required to ensure full substation operational capability during both normal and abnormal system conditions. The battery system provides the DC power source for most substation systems. This paper proposes a strategy to replace battery systems if the battery system is older than 20 years or if a need to replace is indicated by condition assessment, as described in Substation Maintenance Standard SMS 406.40.1.

Implementation of this strategy will deliver a sustained replacement program for substation batteries and their associated equipment. This will reduce the possibility of an unavailable or inadequate DC power source impacting the substation protection, monitoring, and control capabilities in an adverse manner. For example, when a battery system approaches its end of life there is a significant increase in the risk of battery cell connections and battery cell plates being unable to perform as originally designed.

As a practice, National Grid has discouraged battery load testing due to costs and the potential destructive nature of the test. An alternate, industry accepted, non-destructive method of testing is the impedance test which is performed by National Grid. Without battery load test data being available and few failures, National Grid has taken an age based approach to determine when replacement is required.

The useful life span for the typical lead-acid battery can vary by as much as 10 years. Studies indicate that at 80% of life, lead-acid battery performance drops off rapidly and the IEEE recommends a battery should be replaced when capacity reaches 80-85% of original performance.[1] A battery may prove itself inadequate only after failing to perform in an emergency.

Available battery life assumptions place the early onset of failure for a lead-acid battery at 20 years. Given this data, we believe batteries older than 20 years have entered a stage where true performance capability is uncertain. Along with this comes an elevated risk that the battery system will not perform as intended at a time when it is most needed.

The following are some estimates of lead-acid battery early onset of failure (end of life) from various sources:

EPRI:	15 years
National Grid (UK) Policy Statement:	20 years
Exide Manufacturer’s Battery Warrantee:	20 years
C&D Manufacturer’s Battery Warrantee:	20 years

[1] IEEE Report 10163, Technology Enhancements and Improved Practices for Existing Lead Acid Battery Systems

National Grid (US) Substation Maintenance Standard: 20 years
Handbook of Batteries[2] 6-25 years

2.2 Drivers

The driver for this strategy is to ensure this critical component capably performs its function as a reliable DC power source for the successful operation of equipment and protection schemes in substations when called upon. The National Grid philosophy regarding batteries is: batteries shall be replaced if either of the following conditions is met.; firstly if the battery system is older than 20 years based on installation date or secondly if the battery system replacement is identified by condition assessment, as described in Substation Maintenance Standard SMS 406.40.1.

Currently, 56 battery installations (15 NY and 41 NE) are greater than 20 years old and a further 30 have no associated age data. Analysis of the population of National Grid US substation batteries show the following distribution:[3]

OPERATING BATTERIES	NE				NY	Total
AGE	MA	NH	RI	NE Total		
<=5yrs	58	3	16	77	58	135
>5yrs & <=10yrs	20	2	8	30	39	69
>10yrs & <=15yrs	15	1	9	25	42	67
>15yrs & <=20yrs	20	2	12	34	30	64
>20yrs	32	0	9	41	15	56
Without age	1	0	3	4	26	30
State Total	146	8	57	211	210	421

Table 2 –Operating Batteries Age as of December 2009

The 56 battery installations that are already older than 20 years are at the end of useful life, and there are further 64 batteries that will reach 20 years old over the next 5 years. These batteries may not show visible signs of deterioration; however it is unknown whether they will perform adequately when needed. Since there is not a cost-effective way to adequately gauge the life left in these batteries, there is a significant degree of uncertainty as to how they will perform when needed in an emergency.

In addition to age driven replacements, some batteries in our network have endured less than perfect conditions (extreme temperatures where installed in non-temperature regulated rooms) and thus may be subject to premature failure modes such as sulfating and external corrosion. Other factors such as discharge rate, discharge depth and historical maintenance programs can influence battery failure rate. In most cases, premature failure will display visible signs of deterioration which is detectable via condition assessment or diagnostic testing. Substation Maintenance Standard SMS 406.01.1 and Substation Maintenance Procedure SMP 406.01.2, will identify any battery system replacement requirements based upon condition.

[2] David Linden and Thomas B Reddy, Handbook of Batteries, McGraw-Hill, New York, 2002
[3] Population listed does not reflect battery sets replaced in the Asset Replacement Program (ARP).

Adoption of this strategy will produce a comprehensive and sustained replacement program for substation battery systems which will reduce the possibility of an unavailable or inadequate continuous power source necessary for protection, monitoring and control of substations. Setting a replacement age allows for a continuous, planned replacement program which given the criticality of a battery system, as well as the unknown nature of its true end of life, manages the risk of battery systems that have entered a stage where true performance is unknown, or are determined to be at end of life by condition assessment.

2.3 Data

National Grid's Distribution substation batteries age profile is shown in Figure 1. Approximately 22% of batteries are greater than the 20 years of age.

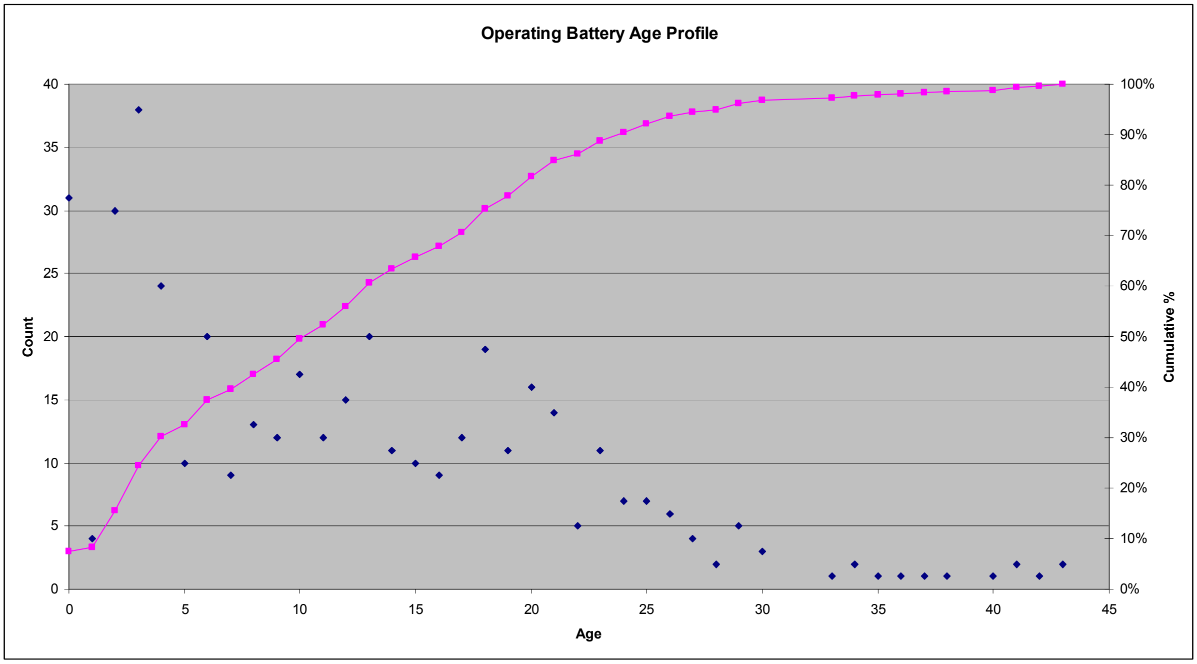


Figure 1 – Substation Battery Profile as of December 2009

Across NE and NY, 56 battery systems of known age are greater than 20 years, 64 between 15 and 20 years, and a further 30 battery systems without age (7% of the operating battery systems).

To replace all such units over a five year period would require a change out rate of approximately 18 units per year for five years.

With 217 systems over ten years old (including unknown age), requires a replacement rate of approximately 22 per year for ten years. There are 6 battery systems 30 or more years old; these should be given the highest replacement priority and are covered in the FY 11 budget.

The battery charger age profile is given in Figure 2. Approximately 65% of our battery charger systems are less than 20 years old, but there are some of up to 60 years of age. As these systems require little maintenance and have negligible impact on reliability, the age profile is not an issue.

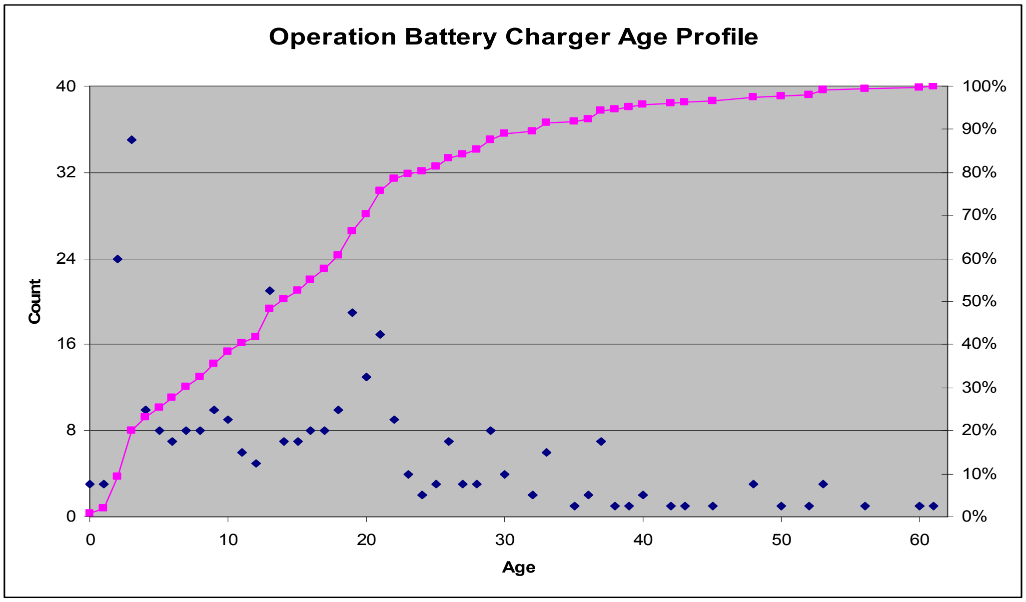


Figure 2 – Substation Battery Charger Age Profile as of December 2009

2.4 Events

For 1997-2009 IDS does not report any battery related events in NY.

In NE, from 1993-2009 there were no reported IDS events which related to batteries or had batteries as their root cause.

3.0 Benefits

3.1 Safety and Environmental

The current battery system housing arrangements are considered adequate. However, there are a number of hazards associated with lead-acid battery systems. Firstly, the fluid in lead acid batteries (electrolyte) is a mixture of sulfuric acid and distilled water. Contact with electrolyte can cause blindness, burn skin, and burn holes in clothing. Current operational and maintenance procedures for working on, or in the vicinity of, lead-acid batteries are designed to minimize this hazard. In addition, the use of proper PPE such as wearing acid proof gloves and aprons and a full face shield when inspecting or working on batteries provides additional protection from this hazard.

Lead-acid batteries emit hydrogen gas, which is explosive. The prohibition on smoking, open flames or sparks and the use of insulated tools when working on batteries mitigates this hazard. Standard ST.05.06.003, 'Battery Sizing' is used to engineer the proper ventilation needs of the battery area to less than the 2% hydrogen accumulation limit set by IEEE. As long as a battery room meets these ventilation requirements (less than 2%), it should not be considered a classified (hazardous) location; thus special electrical equipment enclosures to prevent fire or explosion are not necessary.

Substation batteries are capable of very high short-circuit currents. Accidentally shorting cells or batteries can result in severe burns and possibly battery explosions. The use of a disposable cover-up during maintenance of a 1,000 volt battery system mitigates this hazard.

The removed batteries will be disposed of in a safe environmental way, according to all State and Federal Laws and National Grid US guidelines.

3.2 Reliability

Replacement of battery systems that are at end of life as recommended by this strategy, is consistent with National Grid's goal of maintaining system reliability for the following reasons:

- Batteries close to end of life have a higher probability of not performing adequately when needed.
- Due to inherent battery system design there is no cost effective method to determine exactly when this probability becomes unacceptable. A conservative assumption of 20 years, based on well founded industry data, is the most cost effective way to ensure that all battery systems on the network are adequate.
- At all locations, a battery system that does not perform adequately could result in safety, reliability and financial consequences.

3.3 Customer/Regulatory/Reputation

There are no direct customer impacts associated with this strategy. Failure of a battery system and subsequent misoperation of equipment may impact National Grid's reputation if an event resulted in cascading outages.

3.4 Efficiency

Substation Batteries are not prone to failure.

4.0 Estimated Costs

There are approximately 120 battery sets of known age needing replacement in the next five years; with approximately 187 sets needing replacement within ten years.

By including 30 battery sets of unknown age, approximately 30 sets per year for the next 5 years or 19 sets per year for the next 10 years will require replacement.

Each battery and charger combination, complete with seismic rack, comes installed at about $60k.

- With a five year 30 per year replacement plan, we have an annual expenditure of approximately $1.85M.
- With a ten year 19 per year replacement plan, we have an annual expenditure of approximately $1.17M.

Table 3 shows the annual cost per state.

	Annual Rate of Replacement	Cost per Year
MA	7	$420,000
NH	1 every 3 yrs	$60,000 every 3 yrs
RI	3	$180,000
NY	9	$540,000

Table 3 – Annual Rate of Battery Replacement by State

5.0 Implementation

- Continue with V&O, annual diagnostic inspections, and the PIW process to identify batteries that may have condition issues per present SMS's for replacement.
- Bring all battery systems to ages less than 20 years within 10 years
- Identify dates of manufacture on all battery systems and chargers and ensure mobile battery trailers are identified in AIMMS/Cascade.
- Purchase mobile battery trailers for the NY Region.
- Monitor newer technologies which may allow for cost effective and beneficial monitoring and life extension of battery systems
- Ensure battery systems and chargers are considered during any related substation construction and maintenance
- The generic strategy for spares as per the SMS applies to batteries.

Given current costs and current replacement rates it is recommended we pursue a ten year replacement program.

6.0 Risk Assessment

6.1 Safety and Environmental

Risks are mitigated through adherence to the SMS standards.

6.2 Reliability

Failure to implement this strategy or deferring the replacement of batteries over 20 years of known age might lead to equipment operation failure negatively impacting the Company's system reliability.

As per the Transmission SC 128, batteries that have not been replaced, may fail during another natural disaster like the "ICE STORM of 2008". National Grids US reputation could be put to the test if our equipment fails to perform, as designed, due to lack of equipment asset health management.

6.3 Customer/Regulatory/Reputation

No significant customer or regulatory issues evident.

6.4 Efficiency

As this is a multiyear strategy, there is exposure to material, construction and engineering costs.

System conditions could impact schedules for installing and testing battery systems.

The age or condition of associated equipment at older substations may increase the scope of the project. On inspection these assets may have deteriorated over time and therefore may need to be replaced. Careful assessment at the preliminary engineering phase should minimize this impact.

Personnel will be working in and around substation battery systems. There is a risk that that during construction and testing that battery power may be interrupted due to human error. Proper coordination of personnel and review of company safe work practices, procedures and policies mitigates this risk.

There is a risk of scope creep in this battery replacement strategy. As the old battery systems are engineered up to today's standards of protection and operations/maintenance there will be a desire to upgrade other battery support equipment at the same time. This should be avoided.

7.0 Data Requirements

7.1 Existing/Interim:

AIMMS/Cascade holds battery and charger information. System event and interruption data are maintained in IDS. PIW's are dealt with through the Substation O&M PIW system.

7.2 Proposed:

Improve data relating to battery systems in CASCADE and related to battery trailers.

7.3 Comments:

None.

8.0 References

8.1 Substation Maintenance Standards and Procedures

Substation Maintenance Standards and Substation Maintenance Procedures relating are shown in Table 4.

Standard or Procedure	Number	Description
SMS	400.12.1	Spare Equipment
SMS	400.06.1	Visual And Operational (V&O) Inspection Standard
SMP	400.06.2	Visual And Operational (V&O) Inspection Procedure
SMS	400.87.1	Earthquake Response
SMS	406.01.1	Lead/Acid Battery Standard
SMP	406.01.2	Lead/Acid Battery Procedure
SMP	406.01.3	Lead/Acid Battery Inspection Card
SMS	406.02.1	Nickel-Cadmium Battery Standard
SMP	406.02.2	Nickel-Cadmium Battery Procedure
SMP	406.02.3	Nickel-Cadmium Battery Inspection Card
SMS	406.03.1	Battery Charger Standard
SMP	406.03.2	Battery Charger Procedure
SMP	406.03.3	Battery Charger Inspection Card
SMS	406.10.1	Battery Eyewash Stations
SMS	406.40.1	Substation Battery Replacement

Table 4 – Substation Maintenance Standards & Procedures

In addition there are specific maintenance related bulletins, as per Table 5; bulletins may relate to specific battery types and also recommends a generic maintenance kit to lessen the likelihood of follow up work:

Substation Maintenance Alert Number	Description
01-06	Battery Maintenance Kit to Eliminate Follow Up Work
02-07	Excide Type 3CC Vintage 1990-2000 Below Cover Connection Corrosion
05-07	C&D Type 3DJ-110 Cracks on Cover: Manufacturing Defect

Table 5 – Substation Maintenance Bulletins: Battery Related

8.2 Industry Reference Data

Battery life is a subject of debate and research; the value stated may be as low as 8 years, or as high as 25 years, depending on sources. New batteries may come with a 20 year warranty.

Storage Battery Systems Product Information, http://www.sbsbattery.com/subpage_index.php?_subp_=93
EPRI Study, “Assessment of Alternatives to Lead-Acid batteries for Substations”,
http://www.battcon.com/PapersFinal2004/KamathPaper2004.pdf

9.0 Massachusetts

The Massachusetts State funding blanket for battery/charger replacement is

- C32015 – Batts/Chargers – NE North MA
- C32016 – Batts/Chargers – NE North MA BSW
- C32018 – Batts/Chargers – NE South MA

Massachusetts has 67 battery systems over 10 years old. This strategy recommends the battery/charger replacement rate in MA to be 7 batteries per year for an annual cost of $420k.

10.0 New Hampshire

The New Hampshire State funding blanket for battery/charger replacement is

- C32020 – Batts/Chargers – NY North NH

New Hampshire has 3 battery systems over 10 years old. This strategy recommends the battery/charger replacement rate in NH to be 1 battery every three years for an annual cost of $60k every three years.

11.0 Rhode Island

The Rhode Island State funding blanket for battery/charger replacement is

- C32019 – Batts/Chargers – NE South OS RI

Rhode Island has 30 battery systems over 10 years old. This strategy recommends the battery/charger replacement rate in RI to be 3 batteries per year for an annual cost of $180K.

12.0 New York

The New York State funding blanket for battery/charger replacement is

- C32012 – NY ARP Batts/Chargers Repl. Prog.
- C32013 – NY ARP Batts/Chargers Repl. Prog.
- C32014 – NY ARP Batts/Chargers Repl. Prog.

New York has 87 battery systems over 10 years old. This strategy recommends the battery/charger replacement rate in NY to be 9 batteries per year for an annual cost of $540k.

13.0 Appendix A – Location of Batteries Over 20 Years of Age (includes batteries without age)

This list is obtained from CASCADE which shows batteries over 20 years of age. This list is likely to change based on field operations.

State	Substation	Age	No. of Batt.
Massachusetts	Bancroft Street 3	21	1
	Bates 115	25	1
	Beach Road 7	26	1
	Bridge 6	29	1
	Burrill 2	27	1
	Chandler Street 2	30	1
	Clara Street 6	23	1
	Foxboro 1 3431	23	1
	King Street 5	26	1
	Lincoln Plaza 15	30	1
	Mansfield 16	24	1
	Melrose 4	23	1
	Millbury Training Center	null	1
	North Beverly 18	28	1
	North Lawrence 6	43	1
	Norton 4	26	1
	Plainville 3451	25	1
	Pleasant Street 8	22	1
	Rehoboth 3	23	1
	Riverside 17	21	1
	Rockland Street 39	29	1
	Salem 3 Boston St	41	1
	Somerset Switching Yard	24	1
	South Bellingham 346	26	1
	South Weymouth 3	29	1
	Squantum Street 14	21	1
	Stearns Street 7	30	1
	Topsfield 26	21	1
	Western 4	23	1
	Winthrop 22	40	1
	Wollaston 2	29	1
	Wood Hill Shelter	22	2
Massachusetts Total			33

New York	Albion Station 80	23	1
	Arnold Station 656	null	1
	Ashley Station 331 (Port PDS 7 East)	null	1
	Bolton Station 284	25	1
	Central Avenue Station 235	null	1
	Chestertown Station 42	null	1
	Commerce Avenue Station 235	null	1
	Conkling Station 652	21	1

	Delaware Avenue Station 330	null	1
	ERCC	21	2
	Liberty Street Station 94	null	1
	McBride Street Station 123	null	1
	Mechanicville Station 971	null	1
	Mill Street Station 748	21	1
	MOBILE SUB 3 EAST	null	1
	MOBILE SUB 4 EAST	null	1
	MOBILE SUB 5 WEST	null	1
	Nassau Station 113	null	1
	Northville Station 332	22	1
	Pleasant Station 664	27	1
	Poland Station 621	null	1
	Saint Johnsville Station 335	null	1
	Saint Peters Hospital 411	null	2
	Schoharie Station 234	null	1
	Seminole Station 339	null	1
	Seventh Avenue Station 244	null	1
	Sherman Station 54	null	1
	State Street Station 954	null	1
	Station 021	null	1
	Station 043	21	1
	Station 058	21	1
	Station 089 - Ransomville	21	1
	Station 122 - Tonawanda News	null	1
	Station 126 - Gibson St	21	1
	Station 127 - Delaware Rd	25	1
	Trenton Station 627	29	1
	Union Falls Station 844	null	1
	Watt Street Station 380	24	1
	Weaver Street Station	null	1
New York Total			41

Rhode Island	Apponaug 3	24	1
	Arctic 49	21	1
	Auburn 73	25	1
	Bailey Brook 19	23	1
	Barrington 4	24	1
	Clarke Street 65	21	1
	Dyer Street 2	23	1
	Eldred 45	null	1
	Knightsville 66	26	1
	Rochambeau Avenue 37	24 null	1 1
	Sayles Hill Microwave	null	1
Rhode Island Total			12

Metal Clad Switchgear
Table of Contents

Strategy Statement

Rolling replacement program for less reliable and aged for metal clad gear identified; spares strategy to be formalized.

Strategic aims:
Remove older and less reliable units; apply new technologies to detect onset of unreliability

Strategic opportunities:
AIMMS data better recorded
Replacement of older and less reliable metal clads
Addition of animal incursion prevention equipment
Gain additional data through acoustic emission (AE) discharge surveys

Strategic areas:
This strategy supports reliability and a sustainable network

Costs:
$16M pa for 5 years

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	01/03/2008	Initial Issue	Anthony McGrail Substation Engineering Services	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This document notes that the present strategy for metalclad switchgear is adequate. However, new technologies relating to AE and PD should be implemented to improve our knowledge and understanding of the assets.

2.0 Background

2.1 Substation Maintenance Standards

Metal clad switchgear is surveyed using Visual and Operational (V&O) surveys and InfraRed (IR) inspections. Replacement is performed based on age and type using AIMMS data. This needs to be formalized into a rolling asset replacement program. Animal based outages should be addressed through an animal incursion prevention program.

Newer methods of detecting onset of unreliability, using AE PD detection, should be pursued. These have yielded benefits in breakers already and are applicable to metal clad.

2.2 Data

There is a significant lack of data in AIMMS relating to metal clad gear; it is not recorded as such.

However, there are about 80 units in the field, approximately half of which have issues relating to deterioration of the equipment.

2.3 Events

13 events on metal clad equipment in NY in the last ten years included 6 animal incursions. Non-animal events lead to 22,719 customer interruptions at an average duration of 193 minutes. Animal based incursions tended to be shorter, at about 63 minutes on average.

3.0 Benefits

Fewer outages related to metal clad switchgear; by using AE and PD surveys we should identify units at risk before failure and be able to replace them in a controlled manner. Formal spares strategy allows for identification of replacement units ahead of problems.

4.0 Estimated Costs

40 unreliable and poor condition metal clad systems to be replaced over 5 years. $4M per site.

$16M pa for 5 years.

5.0 Implementation

Rolling program over 5 years

6.0 Risk Assessment

6.1 Safety & Environmental

No significant environmental implications.
Some safety implications as the failure mode is not overt.

6.2 Reliability

Failure may lead to significant outages and interruptions.

6.3 Regulatory

N/A.

6.4 Customer

N/A.

7.0 Data Requirements

Data mining in IDS required to prioritize issues and locations, backed up by local knowledge. Data from AE and PD surveys needs to be added in to improve decision making capability

7.1 Existing/Interim:

AIMMS, PIWS, IDS

7.2 Proposed:

No change.

7.3 Comments:

N/A.

8.0 References

Unpublished AE/PD surveys in NYE July/August 2007.

Division Data Request 2-2

Request:

For each capital improvement project for which the justification is the need for additional capacity, please provide all existing circuit capacity information, peak loading details, projected load growths, and all justifications for the system upgrade project identified in the planning process. National Grid should provide for each of these projects the engineering assessment completed that would indicate future load growth that would justify an upgrade to facility capacity and why in the current significant economic downturn National Grid would anticipate any significant level of load growth that would stress the component of the system.

Response:

As described in the FY 2012 ISR Plan (page 29), the projected load growth used to identify the need for system upgrade projects is based on projected economic activity (employment, household formation) and projected peak-day weather conditions as opposed to current economic and weather conditions.

The Company's load growth model is based on a forecast of employment and household information provided by Moody's Investor Services, a leading economic forecasting firm. The economic forecast used for planning purposes anticipates a slow recovery from the recent recession in 2010 followed by a fairly sharp rebound in 2011, 2012, and 2013. Indeed, Moody's expects all the jobs that were lost in Rhode Island during the recession to be regained by 2014. The planned upgrades to the distribution network are required to make sure that the system has sufficient capacity to support the economic recovery in Rhode Island and acknowledges the time required to build this capacity.

The load forecast used to identify the need for capacity upgrades is also based on an "extreme weather" scenario so that there is only a 5% chance that the Company's actual load will exceed the forecasted peak load. This approach helps to ensure that the Company can meet its obligation to provide safe and reliable service to customers and optimize the service life of distribution assets. This approach is essential because weather conditions are highly variable year-to-year. For example, following a very mild summer in 2009, the system-wide peak load for the Company in July 2010 was 95% of its all time peak and the load on several parts of the network established new highs.

The attachment to this response provides the assumed load growth, normal capacity, projected 2010 loading, and year of forecasted overload for the key components that comprise the most important system upgrade projects in the Company's FY 2012 ISR Plan. The attachment also identifies which projects are related and why each project has been included in the Company's Plan. The attachment shows that these projects address heavy loads on equipment regardless of whether economic growth will occur in these areas in 2010 or 2011.

Prepared by or under the supervision of: Rob Sheridan

RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	Normal Load Growth Percentage (Summer 2010-Summer 2011)	Element Overloaded	Normal Capacity of Element (Amps or MVA)	Summer 2010 Projections (Amps or MVA)	Loading as a percentage of Normal rating	Year of Forecasted Overload	Normal or Contingency Concern	MWhr at Risk (if Contingency)	Associated Projects	Justification
Coventry & Related	C24179	Coventry MITS (Dist Sub)	41									C24180: Distribution Line Project C24179: Distribution Substation Project	Projected loading in the Central RI West area, on both feeders & transformers, exceed normal ratings. Additionally, projected loading on the 2228, 2230 & 2232 distribution supply circuits exceed emergency rating for the loss of any one line. These three lines supply a number of stations in the Central Rhode Island West area and operate in a closed looped system.
	C24180	Coventry MITS (Dist Line)	41										
		Coventry Projects		1.5%	54F1	385 A	445 A	116%	2010	Normal Concern			
				1.5%	61F1	450 A	523 A	116%	2010	Normal Concern			
				1.5%	61F2	450 A	493 A	110%	2010	Normal Concern			
Coventry & Related Total													
Hopkinton & Related	C24176	Hopkinton Substation (Dist Sub)	36									C33050: Transmission Substation Project C24176: Distribution Substation Project	Concerns in the South County West area include both transformers and feeders projected to be loaded above their summer normal rating. In addition to normal loading concerns, several transformers and distribution supply lines are projected to exceed their summer emergency ratings. Due to the recent flood activity at Westerly Substation, the Hopkinton substation project scope will be revised to include additional recommendations.
	C33050	New Hopkinton RI Substation	36										
		New Hopkinton RI Projects		2.8%	Wood River T10	52.44 MVA	65.9 MVA	126%	2015	Contingency	480 MWHr		
				2.8%	Westerly T2/T4	26.7 MVA	35 MVA	130%	2015	Contingency	288 MWHr		
				2.8%	Ashaway T1	8.4 MVA	7.7 MVA	92%	2012	Normal Concern			
				2.8%	16F1	515 A	535 A	104%	2010	Normal Concern			
				2.8%	16F2	515 A	403 A	78%	2019	Normal Concern			
				2.8%	68F3	512 A	495 A	97%	2011	Normal Concern			
				2.8%	43F1	388 A	359 A	92%	2012	Normal Concern			
				2.8%	85T2	39 MVA	41 MVA	107%	2010	Contingency			
				2.8%	85T3	24 MVA	24 MVA	101%	2010	Contingency			
Hopkinton & Related Total													
Newport & Related	C11578	Newport, RI. Land Purchase	41	0.90%	38J4	440 A	401 A	91%	2016	Normal		C11578, C15158,C24159,C32401	A new 69/13.8kV substation is recommended in the City of Newport to provide distribution capacity to relieve the heavily loaded 23kV supply and 4.16kV distribution systems. In addition, this new station will reduce the load exposure for the loss of the 69/13.8kV transformer at Jepson substation and the 115/13.8kV transformer at Dexter substation.
	C15158	Newport Mall Substation	41	0.90%	32J12	372 A	328 A	88%	2023	Normal			
	C24l 59	Newport Sub Transmission Line Tap	41	0.90%	32J14	327 A	294 A	90%	2019	Normal			
				0.90%	122J4	480 A	404 A	84%	2012	Normal			
	C3240l	Construct Newport Mall Substation	41										
				0.90%	154J8	380 A	331 A	87%	2026	Normal			
				0.90%	Vernon T231	3.6 MVA	3.9 MVA	106%	2010	Normal			
				0.90%	37K21	12.5 MVA	11.5 MVA	91%	2026	Normal			
				0.90%	Dexter T364	44.6 MVA	23.0 MVA	52%	2016	Contingency	480 MWHr		
				0.90%	Jepson T374	42.9 MVA	25.4 MVA	59%	2013	Contingency	483 MWHr		
Newport & Related **Total**													
West Warwick & Related	C28920	Install Distr. Sub - West Warwick	39										
	C28921	Install 4 dist. Fdrs West Warwick	39										
	C32002	W. Warwick 115/12.5kV Sub	39										
				1.5%	64F2	361 A	295 A	82%	2017	Normal Concern			
				1.5%	54F1	385 A	445 A	116%	2010	Normal Concern			
				1.5%	14F4	515 A	394 A	77%	2021	Normal Concern			
				1.5%	15F2	476 A	392 A	82%	2017	Normal Concern			

RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	Normal Load Growth Percentage (Summer 2010-Summer 2011)	Element Overloaded	Normal Capacity of Element (Amps or MVA)	Summer 2010 Projections (Amps or MVA)	Loading as a percentage of Normal rating	Year of Forecasted Overload	Normal or Contingency Concern	MWhr at Risk (if Contingency)	Associated Projects	Justification
		West Warwick Projects C28920, C28921, C32002		1.5%	22F3	530 A	447 A	84%	2017	Normal Concern		C28920: Distribution Substation Project C28921: Distribution Line Project C32002: Transmission Substation Project	There are a number of distribution circuits, transformers and supply lines projected above their normal and emergency ratings in the City of Warwick and Towns of West Warwick, Scituate and West Greenwich. This project provides distribution capacity to address these overloads.
				1.5%	22F4	586 A	455 A	78%	2020	Normal Concern			
				1.5%	29F1	526 A	426 A	81%	2018	Normal Concern			
				1.5%	29F2	408 A	303 A	74%	2022	Normal Concern			
				1.5%	21F1	515 A	504 A	98%	2011	Normal Concern			
				1.5%	Anthony T1	7.8 MVA	7.3 MVA	94%	2012	Normal Concern			
				1.5%	2230	35.5 MVA	35.9 MVA	101%	2010	Contingency			
				1.5%	2232	15.3 MVA	15.5 MVA	101%	2010	Contingency			
				1.5%	3310	44.8 MVA	48.4 MVA	108%	2010	Contingency			
				1.5%	3311	53.2 MVA	68.2 MVA	128%	2010	Contingency			
Warwick & Related **Total**													

RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	Normal Load Growth Percentage (Summer 2010-Summer 2011)	Element Overloaded	Normal Capacity of Element (Amps or MVA)	Summer 2010 Projections (Amps or MVA)	Loading as a percentage of Normal rating	Year of Forecasted Overload	Normal or Contingency Concern	MWhr at Risk (if Contingency)	Associated Projects	Justification
Load Relief	004484	Fdr 1131 Mars Plastics - Olneyville	50	1%	Asset Condition	N/A	N/A	N/A	N/A	N/A	N/A		Leaking single phase 200 kVA 11 kV-600 V transformer at Mars Plastics industrial sub on feeder 1131 in Olneyville. Transformer is obsolete with no direct replacement and no suitable stock transformer to use as replacement. Replacing transformer with standard equipment requires addressing other obsolete equipment at this industrial sub and two other locations on radial tap of underground feeder 1131 in Providence. In addition, PCB-contamination is present under transformer foundation and must be remediated.
	C05505	IE - OS Dist Transformer Upgrades	30										This project provides the relief or replacement of overloaded distribution transformers.
	C13967	PS&I Activity - Rhode Island	36										This is used to fund study work in RI. As capital projects are developed and budgeted, costs are transferred to appropraite capital projects.
	C230l2	63F6 Ext 2 P11 down Ten Rod Rd	48	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		This project extends two additional phases down Ten Rod Rd in Exeter from Nooseneck Hill Rd to Escohead Hill Rd. This will resolve reoccuring voltage issues in the area.
	C24221	Load Relief to 9J3 - Brown Street	36	1%	Underground getaway cable 750 Al Cable on 77J2.	313 A	364 A	97%	2013	Normal	N/A		The 9J3, 77J2, 37J4 and 2J1 feeders all converge at Olney and Hope Streets in Providence. There is a large single load of approx. 70 A on the 77J2 feeder at this point, which will overload any feeder that it is transferred to. Options were investigated to transfer loads to other feeders to make capacity available, but with limited capacity in area this was not a feasible option. Conversion of a section of the 9J3 will provide capacity on the 4 kV system in area to alleviate all projected 4 kV overloads for forseeable future. Install three phases of 1/0 spacer cable on the 79F2 feeder from Pole 11 Camp St, across Olney St and extending to Pole 26 Brown Street. Replace the existing single phase 4 kV construction on Brown Street between Pole 26 and Pole 11 with three phase 1/0 spacer 15 kV class construction and convert load to 12.47 kV.
	C27245	Relocate 23kV 2227 & 22230 NEEWS	34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		This project will relocate the 23kV 2227 and 2230 circuits as part of the relocation of the transmission line T172N. (NEEWS Transmission Project Requirement)
	C28615	BRISTOL 51F1 Load Relief	36	2.0%	51F1	502 A	531 A	106%	2016	Normal	N/A		It was identified that projected 2010 peak load on feeder 51F1 would be if 106% of SN ratings.This project provides distribution capacity to address these overloads. The project will consist into: reconductoring 1,500' 750 Al DB getaway cable with 3-1/C 1000Kcmil CU EPR 15kV, installing manhole and ductline system, installing UG getaway consisting of 1,500' of 3-1/C 1000Kcmil CU EPR 15kV and removing the existing 750Al direct buried cable.
	C28627	WAMPANOAG 48F3 Load Relief	36	2.0%	48F3	510 A	551A	108%	2011	Normal	N/A	**C36304 -** Wampanoag #48 115/12.47 kV substation is projected to be loaded to 59.7 MVA by the summer peak of 2015. The proposed project is the replacement of T3 at Phillipsdale #20 substation.	It was identified that projected 2010 peak load on feeder 48F3 would be of 108% of SN ratings. This project provides distribution capacity to address these overloads. A new UG cable will be installed as well as 2-miles upgrade of the 336AL and 4/0 Al section with 477 Al.
	C28851	Recon. 38F5 and 2227 Greenville Ave	27	2.80%	38F5	395 A	409A	104%	2010	Normal	N/A	N/A	The projected 2010 load on the 38F5 feeder is exceed its normal rating. Install 1.4 mi of 477 Al to address the overloads. Improves tie capacibility in the area as well.

RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	Normal Load Growth Percentage (Summer 2010-Summer 2011)	Element Overloaded	Normal Capacity of Element (Amps or MVA)	Summer 2010 Projections (Amps or MVA)	Loading as a percentage of Normal rating	Year of Forecasted Overload	Normal or Contingency Concern	MWhr at Risk (if Contingency)	Associated Projects	Justification
	C28900	Recond. 2228 Johnston sub - Randall	36	3.70%	Supply line - 336AL OH conductor	21 MVA	21.4 MVA (SN); 31 MVA (SE)	104%	2010	Normal & Contingency	240MWhr		The 2228 line is projected to exceed its normal rating. This line forms a closed loop to Drumrock and is also significantly overloaded during a contingency on the 23 kV system involving the 2226, 2230 and 2232 lines. Load transfers are blocked where possible however there are still contingencies that overload the line that cannot be blocked . Load has to be dropped quickly to prevent damage to the line should these events occur.
	C28932	Recon. 0.5 Miles Segment of 2232	21	1.5%	2232	15.3 MVA	14.6 MVA	95%	2012	Contingency Concern			The 2232 line has a 0.5 segment of 477 kcmil Al on streets that is the limiting section between Drumrock and Arctic substations. This segment is overloaded on a contingency involving the 2230 line. The new West Warwick substation will reduce the contingency overload in 2011 however it will still be necessary to drop load during a contingency after the new station is in service. This reconductoring eliminates the need to shed load.
	C32256	Replace Getaways 107W53 and 107W65	50	0.6%	None	No Overload	All area feeders and substation transformers within ratings through 2026.	All area feeders and substation transformers within ratings through 2026.	beyond 2026	None	None		This work is required as part of the reconductoring of the 107W53 and 107W65 circuits across the Seekonk River. This project covers the replacement of poles, including the riser poles, on either side of the river to accommodate the reconductoring. The reconductoring of the two feeder segments (on transmission structures) across the river is complete.
	C32363	Inst. Mainline Cond. 6J6 and Cony.	30	1%	Underground getaway cable 750 Al Cable 69F3	502 A	542 A	108%	2009	Normal			The Manton 69F3 is projected to exceed its thermal limits in 2011. Load was switched to adjacent feeders in 2009 to previously off load the feeder. There are no other feeders with availble capacity that tie to the Manton 69F3 so the 18F9 has to be extended by utilizing a small conversion of the 6J6 feeder.
	C32450	Nasonville 127W43	31	0.20%	127W43	545 A	545 A	100%	2010	Normal	N/A	N/A	The Nasonville 127W43 feeder is overloaded and this circuit is the source to the Pascoag Municipal Light Department.

RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	Normal Load Growth Percentage (Summer 2010-Summer 2011)	Element Overloaded	Normal Capacity of Element (Amps or MVA)	Summer 2010 Projections (Amps or MVA)	Loading as a percentage of Normal rating	Year of Forecasted Overload	Normal or Contingency Concern	MWhr at Risk (if Contingency)	Associated Projects	Justification
	C33535	Johnston Sub 1247 kV Expansion	35	3.70%									failed in the spring of 2009. It was replaced with a spare 2-winding 115/23 kV transformer. The No. 2 transformer along with the No.1 transformer supplied a 2-bay, 4-feeder breaker and a half outdoor 12.47 kV distribution substation dating back to the 1960's. The 12.47 kV substation includes obsolete GE VIR circuit reclosers. Within the past 10 years 115/ 12.47 kV transformers No.3 and No.4 were added to the substation along with a second 12.47 kV outdoor breaker and a half substation supporting an additional 5 feeders. The ultimate design of this addition was for it to eventually replace the older distribution equipment. The loss of the 12.47 kV supply with the replacement of the No.2 transformer leaves the old 12.47 kV substation with a single source. As in interim measure a bus tie has been constructed from the new substation to the old to protect against loss of the only remaining supply from the No.1 transformer. Bus transfer of the old substation is presently inhibited with this configuration.
				3.70%	Johnston Sub - 18F3	515A	515 A	100%	2012	Normal		C28884, C34002, C33535	In addition to the asset condition related needs expressed above, there is also a capacity related need for expansion of the new 12.47 kV yard. A new industrial park was established in 2007 adjacent to interstate I-295, west of Johnston substation. Several new tenants have located there in the last two years and there are additional lots available for further development.
				3.70%	Johnston Sub - 18F5	530A	543 A	102%	2010	Normal			The area west of Johnston substation is supplied by three feeders from Johnston substation and one from West Cranston substation. Two of the feeders are projected to be in excess of 100% of their normal summer rating by 2012 and the other two are projected in excess of 94% of rating. Due to the heavy loading of the feeders, switching is not a viable option to reduce loading on the feeders above their normal rating and new capacity is required in the area. It is proposed that a new feeder be developed out of Johnston Substation.
				3.70%	Johnston Sub - 21F2 (adjacent ckt)	515A	513 A	100%	2010	Normal			The addition of substation capacitors for transformer reactive loss compensation is also recommended at this time. Along with the expansion of the new 12.47 kV switchgear it is recommended that the 40 MVA T3 transformer (DxT Asset) be replaced with a 55 MVA unit in order to satisfy the planning design criteria for a loss of transformer contingency.
	C 35870	Staples New Breaker	34	0.20%	108W55	510 A	468 A	92%	2013	Normal	N/A	There are also projects for D station and D Line (2) regarding the customer SFS	Install new breaker at Staples to supply new feeder which will relieve the Riverside 108W55 and Staples 112W43 and 112W41 due to spot load at the CVS Park.
				0.20%	112W41	515 A	468 A	91%	2013	Normal			
				0.20%	112W43	515 A	489 A	95%	2013	Normal			
	C36522	Kilvert St 87- Install TB2	39	2.60%	Kilvert T1	67 A	22 A	32%	2012	Contingency	480 MWHr	OS-C36515 Distribution Station Project OS-C36516 Distribution Line Project	loaded to 21.6 MVA, or 32% of its summer normal rating (67 MVA) and 26% of its summer emergency rating (84 MVA), during the summer peak of 2009. A failure of the existing Kilvert TB#1 will result in outages, yielding approximately 17.5 MVA of unserved load. The installation of a new feeder 87F3 at Kilvert St in 2010 further supports the need for
	COSO16	Ocean St-Dist-Load Relief Blanket	50										This funding project is for load relief work requests that are under $100,000 and is based historic spending in this category.
	RESERVE 049 016 LINE	Reserve for Load Relief Unidentified Specifics & Schedule Changes	34										

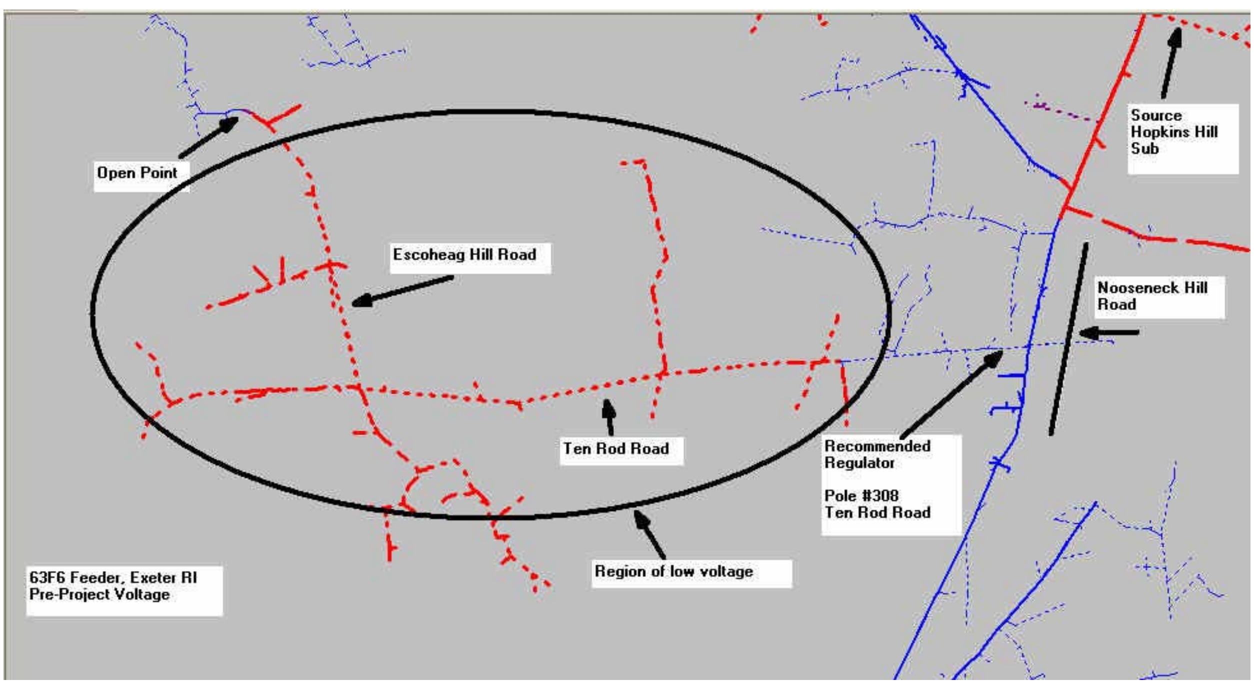
Division Data Request 2-3

Request:

For each capital improvement project which is justified by low voltage conditions, please provide the voltage profile information for the feeder or line section involved and what alternative voltage enhancement and mitigation alternatives were considered including, but not limited to, application of voltage regulators or capacitors in lieu of line upgrade.

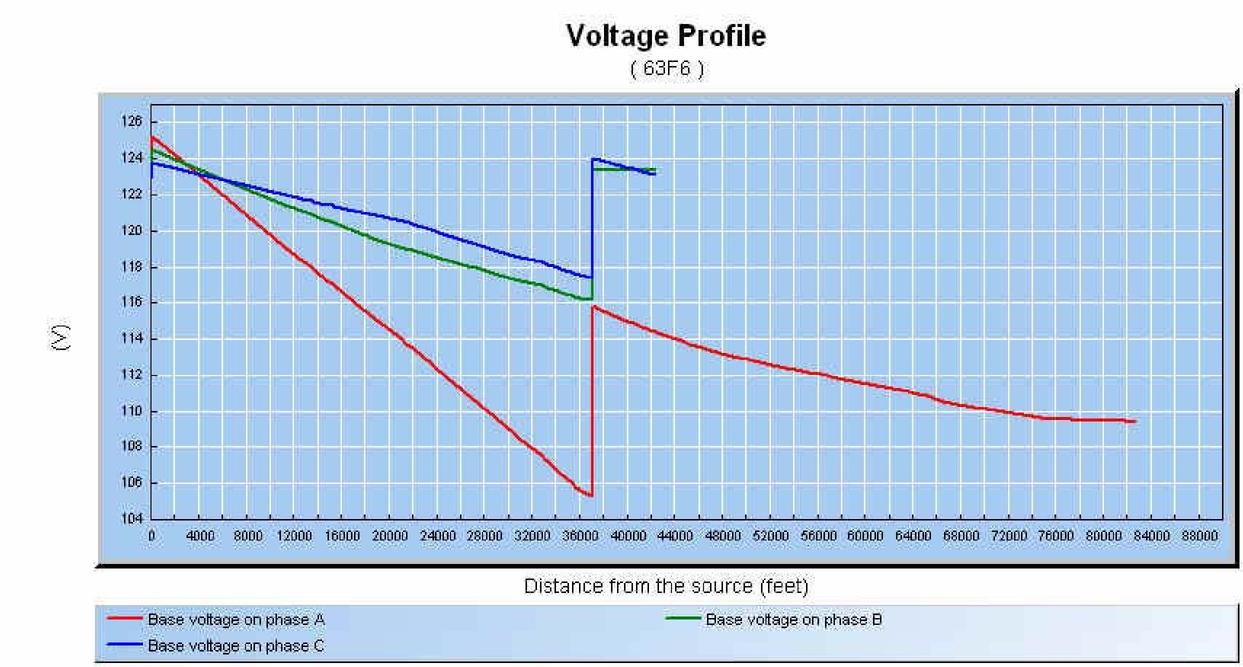
Response:

The ISR plan includes only one project that is motivated by low voltage conditions; project # C23012 – "63F6 Ext 2 P11 down Ten Rod Road." In response to low voltage concerns this past summer, the Company has already established new settings for four existing switched capacitors and for four voltage regulators to improve the voltage profile of the feeders. These changes improved but did not fully ameliorate the low voltage conditions. So, the Company has decided to install two phases on Ten Rod Road and two new switched capacitors These changes will also improve the voltage profile of the Hopkins Hill 63F6 feeder.



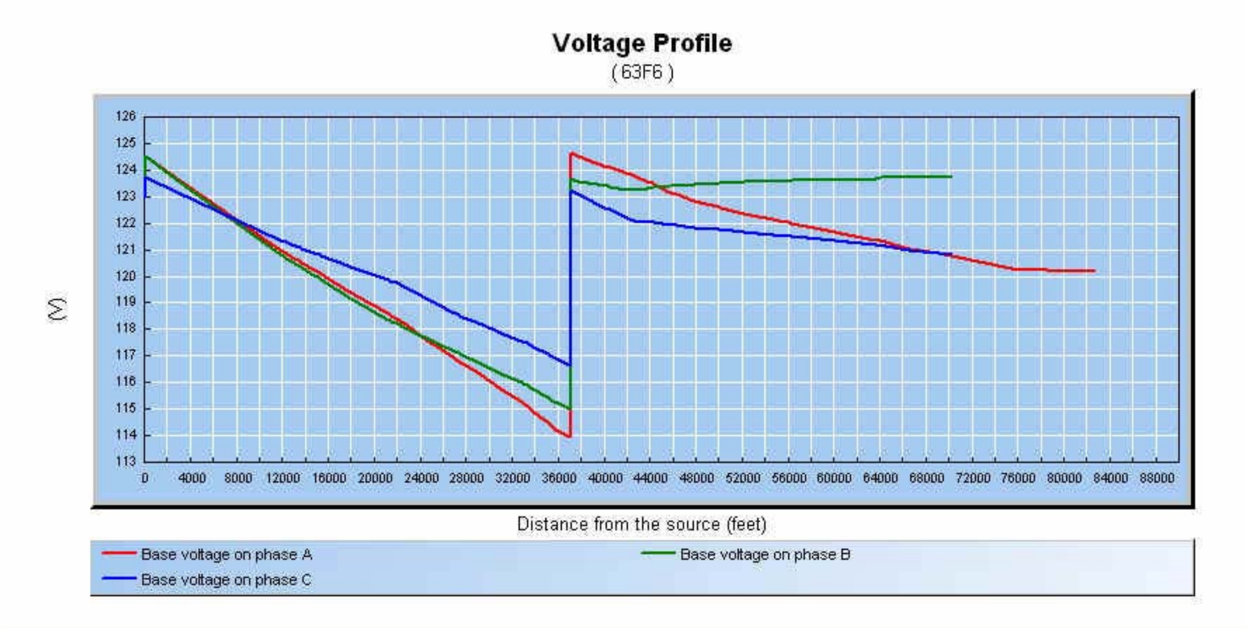
Division Data Request 2-3 (continued)

The diagram above shows the current feeder layout with Ten Rod Road. The solid areas are three phase and the dashed areas are single phase. The source station is just off of the picture on the right. The red lines (dark black in grayscale) indicate voltages below 115 volts.

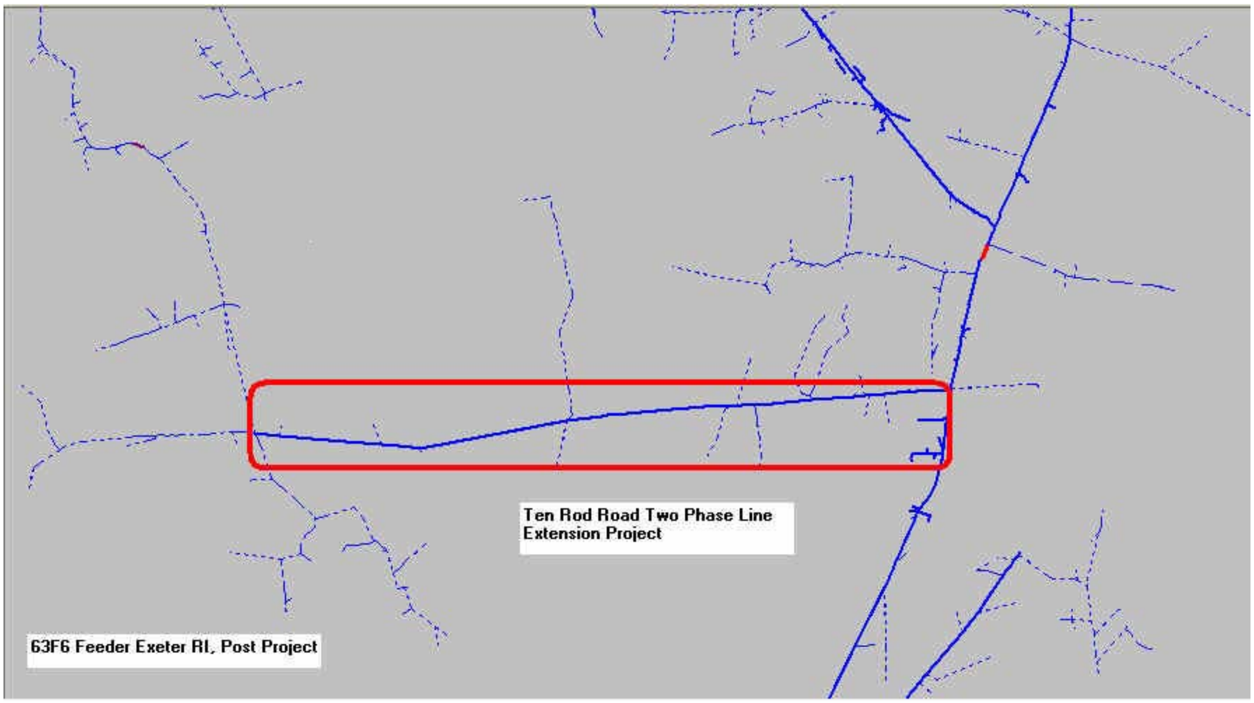


The present voltage profile shown above begins at the station shown on the left (upper right of the of the feeder diagram) and extends to the end of the Ten Rod Road. The single phase area (Phase A – red/bottom line) of Ten Rod is shown above. The low voltage situation is clear from this profile since the base voltage for the primary is 120 Volts. It is important to note that part of the voltage sag is due to the approximately 2500 kVA of load on a 3 mile section of single-phase 1/0 Al conductor, an overload of the existing conductor. Adding the two phases from Nooseneck Hill Road to Escohead Hill Road along Ten Rod Road and rebalancing the load will improve the situation.

Division Data Request 2-3 (continued)



The chart above shows the expected voltage profile after the addition of two additional phases (15,000 circuit feet) (Extension of blue and green lines in diagram) down Ten Rod Road from Nooseneck Hill Road to Escoheag Hill Road and moving several side taps off A phase to B and C phases. The chart above also demonstrates the impact of the new switched capacitors.



Division Data Request 2-3 (continued)

The circle in the diagram above identifies the location of the two phase extension project (15,000 circuit feet) on Ten Rod Road and the impact of re-allocating load from the former single A phase line to the extended B and C phases.

Prepared by or under the supervision of: Rob Sheridan

Division Data Request 2-4

Request:

For each item as requested in 1, 2, and 3 above, please provide all other associated projects, such as line switch additions, system protective device replacement or upgrades, or other items associated with a particular capital project enhancement.

Response:

For the asset condition and system capacity projects, associated line switch additions, protective device replacement and other related items are included in the particular capital projects.

Prepared by or under the supervision of: Tony McGrail, John Gavin, and Rob Sheridan

Division Data Request 2-5

Request:

Please provide a summary of the number of miles and percent of system that has been hardened under the previous system hardening, grounding, and lightning enhancement programs and as outlined in all of the previous reliability reports. Then explain why, with the previous historical aggressive programs, that National Grid is not in a position to begin to reduce the annual expenditures associated with this program. Furthermore, National Grid should explain when it believes this program will reach its conclusion, since it is an overall enhancement program which should have a defined completion date. Additionally, explain why, based on all of the reliability reports prepared by National Grid, this program has not in fact already reached its conclusion predicated on previous anticipated percentage of system to be hardened and enhanced each year.

Response:

The intent of the Feeder Hardening Program is to identify overhead feeders with the most potential for reliability performance improvement related to deteriorated equipment and lightning interruptions. The Company uses a feeder hardening ranking model to determine which feeders meet the criteria for hardening. The Feeder Hardening program was not intended to address all 5,236 miles of the overhead distribution system.

To date, the Company has completed 1,372 miles of Feeder Hardening in Rhode Island, or 26% of the system. Table 1 below shows the breakdown of miles hardened since the program's inception in FY 2006.[1]

Table 1. Feeder Hardening Program

	FY06	FY07	FY08	FY09	FY10	FY11	FY12	Total FH Miles	Total OH Miles	% Total Feeder Miles
FH Miles To Date	70	191	379	417	263	52	0	1372	5236	26%
Complete FH Program	70	191	379	417	263	212	275	1807	5236	35%

The Company plans to continue the Feeder Hardening program as a distinct program through the end of FY 2012. In the current fiscal year, FY 2011, the Company will complete an additional 160 miles for a total of 212 miles. In FY 2012, the Company will harden an additional 275 miles so that when the program ends at the end of FY2012, 1807 miles or 35% of the system will have been hardened.

The Company chose to extend the Feeder Hardening Program through FY 2012, instead of FY 2011 as previously anticipated, to complete work that had already been designed but postponed in response to the Commission's Order in R.I.P.U.C. Docket No. 4065.

[1] Please note that the pre-filed testimony of John Pettigrew in the rate case erroneously stated that the feeder hardening began in 2007

Division Data Request 2-5 (continued)

This work will be completed by the end of FY 2012 at which time work similar in nature to that of the Feeder Hardening Program will be subsumed by the Company's Inspection and Maintenance Program.

Prepared by or under the supervision of: John Gavin

Division Data Request 2-6

Request:

Please provide a copy of the current vegetation management program cycle and the number of miles of line which are affected by vegetation growth. To the extent that different areas of the system contain different vegetation management cycles, provide that detail, including the number of miles of line which are affected by vegetation with each specific program cycle and why any cycle is shorter than another.

Response:

The optimal pruning cycle for all lines is 4 years. The only lines not currently on the optimal cycle are those that were deferred from the vegetation work plan this year, FY 2011, due to budget cuts in response to the Commission's ruling in the Company's latest electric distribution rate case.

The table in Attachment 1 to this response contains a list of all distribution and sub-transmission lines which need vegetation management work[1] and identifies the lines where pruning was deferred. The table also shows the total miles of line, the number of miles that need to be pruned each year to maintain the optimal 4 year cycle, and how continuing to defer necessary work will result in more than a six year pruning cycle.

Prepared by or under the supervision of: Sara Sankowich

[1] Please note: a very small number of feeders, less than 25 total miles in length, do not need vegetation management work.

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
1	Admiral Street	0022	SubT	4	1.91	
2	Valley	102K22	SubT	4	6.90	
3	Valley	102W41	Dist	4	2.40	
4	Valley	102W42	Dist	4	6.66	
5	Valley	102W44	Dist	4	11.85	
6	Valley	102W50	Dist	4	1.56	
7	Valley	102W51	Dist	4	20.03	
8	Valley	102W52	Dist	4	4.39	
9	Valley	102W54	Dist	4	19.71	
10	Central Falls	104J1	Dist	4	1.19	
11	Central Falls	104J3	Dist	4	2.36	
12	Central Falls	104J5	Dist	4	3.01	
13	Central Falls	104J7	Dist	4	3.35	
14	Farnum	105K1	SubT	4	6.96	
15	Centre St	106J1	Dist	4	2.36	
16	Centre St	106J3	Dist	4	3.02	
17	Centre St	106J7	Dist	4	1.06	
18	Pawtucket	107W43	Dist	4	7.37	
19	Pawtucket	107W50	Dist	4	3.78	
20	Pawtucket	107W51	Dist	4	4.46	
21	Pawtucket	107W53	Dist	4	6.95	
22	Pawtucket	107W60	Dist	4	3.35	
23	Pawtucket	107W61	Dist	4	5.68	
24	Pawtucket	107W62	Dist	4	10.54	
25	Pawtucket	107W63	Dist	4	17.41	
26	Pawtucket	107W65	Dist	4	8.00	
27	Pawtucket	107W66	Dist	4	2.63	
28	Pawtucket	107W80	Dist	4	4.49	
29	Pawtucket	107W81	Dist	4	5.02	
30	Pawtucket	107W83	Dist	4	7.69	
31	Pawtucket	107W84	Dist	4	8.92	
32	Pawtucket	107W85	Dist	4	1.76	Y
33	Riverside	108W51	Dist	4	5.80	Y
34	Riverside	108W53	Dist	4	12.65	Y
35	Riverside	108W55	Dist	4	9.46	Y
36	Riverside	108W60	Dist	4	1.38	
37	Riverside	108W61	Dist	4	15.08	
38	Riverside	108W62	Dist	4	18.02	
39	Riverside	108W63	Dist	4	18.19	
40	Riverside	108W65	Dist	4	18.70	Y
41	Cottage Street	109J1	Dist	4	3.05	
42	Cottage Street	109J3	Dist	4	3.67	
43	Cottage Street	109J5	Dist	4	4.40	
44	Dyer Street	1103	SubT	4	-	
45	Admiral Street	1117	Dist	4	0.28	
46	Admiral Street	1119	Dist	4	0.83	
47	Crossman Street	111J1	Dist	4	4.08	
48	Crossman Street	111J3	Dist	4	5.83	
49	Franklin Square	1121	SubT	4	0.04	
50	Franklin Square	1123	Dist	4	2.19	
51	Franklin Square	1125	Dist	4	3.74	
52	Staples	112W41	Dist	4	28.74	
53	Staples	112W42	Dist	4	23.56	
54	Staples	112W43	Dist	4	14.37	
55	Staples	112W44	Dist	4	51.03	
56	Harris Avenue	1131	Dist	4	0.78	
57	Harris Avenue	1133	Dist	4	0.56	
58	Daggett	113J1	Dist	4	3.86	
59	Daggett	113J2	Dist	4	4.17	
60	Washington	126W40	Dist	4	5.76	
61	Washington	126W41	Dist	4	29.07	

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
62	Washington	126W42	Dist	4	9.76	
63	Washington	126W50	Dist	4	20.97	
64	Washington	126W51	Dist	4	27.11	
65	Washington	126W54	Dist	4	14.24	
66	Nasonville	127W40	Dist	4	55.61	
67	Nasonville	127W41	Dist	4	34.48	
68	Nasonville	127W42	Dist	4	14.46	Y
69	Nasonville	127W43	SubT	4	5.20	
70	Harris Avenue	12J1	Dist	4	0.67	
71	Harris Avenue	12J2	Dist	4	1.71	
72	Harris Avenue	12J3	Dist	4	0.15	
73	Harris Avenue	12J4	Dist	4	2.14	
74	Harris Avenue	12J5	Dist	4	0.78	
75	Harris Avenue	12J6	Dist	4	1.25	
76	Clarkson Street	13F2	Dist	4	18.36	
77	Clarkson Street	13F3	Dist	4	10.66	
78	Clarkson Street	13F4	Dist	4	19.58	
79	Clarkson Street	13F5	Dist	4	12.09	
80	Clarkson Street	13F9	Dist	4	16.34	
81	Pawtucket	148J1	Dist	4	4.64	
82	Pawtucket	148J3	Dist	4	2.66	
83	Pawtucket	148J5	Dist	4	1.85	
84	Pawtucket	148J7	Dist	4	4.82	
85	Hope	15F1	Dist	4	23.07	
86	Hope	15F2	Dist	4	61.80	
87	West Farnum	17W42	Dist	4	19.95	
88	West Farnum	17W43	Dist	4	13.20	Y
89	Johnston	18F1	Dist	4	17.38	
90	Johnston	18F2	Dist	4	5.05	
91	Johnston	18F3	Dist	4	24.02	
92	Johnston	18F4	Dist	4	1.91	
93	Johnston	18F5	Dist	4	14.24	
94	Johnston	18F6	Dist	4	28.14	
95	Johnston	18F7	Dist	4	15.54	
96	Johnston	18F8	Dist	4	12.96	
97	Johnston	18F9	Dist	4	9.78	
98	Phillipsdale	20F1	Dist	4	6.64	Y
99	Phillipsdale	20F2	Dist	4	13.29	Y
100	West Cranston	21F1	Dist	4	34.58	
101	West Cranston	21F2	Dist	4	22.54	Y
102	West Cranston	21F4	Dist	4	19.99	Y
103	Franklin Square	2207	SubT	4	0.77	
104	Johnston	2211	SubT	4	8.46	
105	Elmwood	2213	SubT	4	1.76	
106	Wolf Hill	2219	SubT	4	5.22	
107	Wolf Hill	2221	SubT	4	8.85	
108	Johnston	2226	SubT	4	5.83	
109	Johnston	2227	SubT	4	18.28	
110	Johnston	2228	SubT	4	18.59	
111	Hope	2229	SubT	4	2.49	
112	Elmwood	2235	SubT	4	7.15	
113	Phillipsdale	2242	SubT	4	6.13	
114	Phillipsdale	2243	SubT	4	3.30	
115	Admiral Street	2254	SubT	4	1.25	
116	Franklin Square	2260	SubT	4	3.27	
117	Warren	2291	SubT	4	5.59	
118	Warren	2295	SubT	4	4.19	
119	Farnum Pike	23F1	Dist	4	15.06	
120	Farnum Pike	23F2	Dist	4	23.30	
121	Farnum Pike	23F3	Dist	4	26.30	
122	Farnum Pike	23F4	Dist	4	5.18	
123	Farnum Pike	23F5	Dist	4	2.70	
124	Farnum Pike	23F6	Dist	4	23.67	

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
125	Front St	24J1	Dist	4	1.38	
126	Pontiac	27F1	Dist	4	19.23	Y
127	Pontiac	27F2	Dist	4	1.99	Y
128	Pontiac	27F3	Dist	4	0.96	Y
129	Pontiac	27F4	Dist	4	8.40	Y
130	Pontiac	27F5	Dist	4	14.35	
131	Pontiac	27F6	Dist	4	23.18	
132	Hyde	28J1	Dist	4	4.70	
133	Hyde	28J2	Dist	4	4.64	
134	Dyer Street	2J1	Dist	4	1.22	
135	Dyer Street	2J3	Dist	4	0.41	
136	Dyer Street	2J4	Dist	4	0.26	
137	Dyer Street	2J5	Dist	4	0.60	
138	Dyer Street	2J7	Dist	4	1.88	
139	Dyer Street	2J8	Dist	4	0.05	
140	Dyer Street	2J9	Dist	4	0.08	
141	Lee Street	30J1	Dist	4	3.95	
142	Lee Street	30J3	Dist	4	4.06	
143	Lee Street	30J5	Dist	4	3.10	
144	Franklin Square	3320	SubT	4	-	
145	Franklin Square	3324	SubT	4	-	
146	Chopmist	34F1	Dist	4	168.71	
147	Chopmist	34F2	Dist	4	81.74	
148	Chopmist	34F3	Dist	4	49.00	
149	Sprague Street	36J1	Dist	4	2.15	
150	Sprague Street	36J2	Dist	4	1.83	
151	Sprague Street	36J4	Dist	4	2.71	
152	Sprague Street	36J5	Dist	4	1.75	
153	Rochambeau Avenue	37J1	Dist	4	2.12	Y
154	Rochambeau Avenue	37J2	Dist	4	2.85	
155	Rochambeau Avenue	37J3	Dist	4	3.80	
156	Rochambeau Avenue	37J4	Dist	4	2.41	
157	Rochambeau Avenue	37J5	Dist	4	3.57	
158	Putnam Pike	38F1	Dist	4	70.46	
159	Putnam Pike	38F2	Dist	4	6.58	
160	Putnam Pike	38F3	Dist	4	24.34	
161	Putnam Pike	38F4	Dist	4	15.21	
162	Putnam Pike	38F5	Dist	4	40.36	
163	Putnam Pike	38F6	Dist	4	16.66	
164	West Greenville	45F2	Dist	4	11.53	
165	Kents Corner	47J1	Dist	4	0.29	
166	Kents Corner	47J2	Dist	4	5.45	
167	Kents Corner	47J3	Dist	4	6.14	
168	Kents Corner	47J4	Dist	4	6.27	
169	Wampanoag	48F1	Dist	4	15.79	
170	Wampanoag	48F2	Dist	4	4.95	
171	Wampanoag	48F3	Dist	4	21.43	
172	Wampanoag	48F4	Dist	4	12.52	
173	Wampanoag	48F5	Dist	4	17.06	
174	Wampanoag	48F6	Dist	4	10.97	
175	Barrington	4F1	Dist	4	20.54	
176	Barrington	4F2	Dist	4	28.89	
177	Centredale	50F2	Dist	4	6.94	
178	Centredale	50J1	Dist	4	2.97	
179	Centredale	50J2	Dist	4	0.18	
180	Centredale	50J3	Dist	4	3.30	
181	Bristol	51F1	Dist	4	26.54	
182	Bristol	51F2	Dist	4	20.63	
183	Bristol	51F3	Dist	4	18.60	
184	Warren	5F1	Dist	4	24.85	
185	Warren	5F2	Dist	4	25.51	
186	Warren	5F3	Dist	4	20.34	
187	Warren	5F4	Dist	4	19.03	

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
188	Southeast	60J1	Dist	4	1.95	
189	Southeast	60J3	Dist	4	3.07	
190	Southeast	60J5	Dist	4	3.33	
191	Knightsville	66J1	Dist	4	2.46	
192	Knightsville	66J2	Dist	4	4.17	
193	Knightsville	66J3	Dist	4	4.55	
194	Knightsville	66J4	Dist	4	3.18	
195	Knightsville	66J5	Dist	4	3.14	
196	Huntington Park	67J1	Dist	4	3.41	
197	Manton	69F1	Dist	4	19.35	
198	Manton	69F3	Dist	4	14.98	
199	Olneyville	6J1	Dist	4	2.16	
200	Olneyville	6J2	Dist	4	2.63	
201	Olneyville	6J3	Dist	4	0.95	
202	Olneyville	6J5	Dist	4	1.33	
203	Olneyville	6J6	Dist	4	1.39	
204	Olneyville	6J7	Dist	4	2.37	
205	Olneyville	6J8	Dist	4	0.18	
206	Geneva	71J1	Dist	4	3.21	
207	Geneva	71J2	Dist	4	1.67	
208	Geneva	71J3	Dist	4	2.07	
209	Geneva	71J4	Dist	4	2.59	
210	Geneva	71J5	Dist	4	5.34	
211	Auburn	73J1	Dist	4	2.60	
212	Auburn	73J2	Dist	4	1.91	
213	Auburn	73J3	Dist	4	2.45	
214	Auburn	73J4	Dist	4	1.32	
215	Auburn	73J5	Dist	4	4.82	
216	Auburn	73J6	Dist	4	2.79	
217	Point Street	76F1	Dist	4	10.86	
218	Point Street	76F2	Dist	4	11.24	
219	Point Street	76F4	Dist	4	15.71	
220	Point Street	76F5	Dist	4	11.38	
221	Point Street	76F6	Dist	4	11.64	
222	Point Street	76F7	Dist	4	14.42	
223	Point Street	76F8	Dist	4	3.17	
224	East George St	77J1	Dist	4	1.07	
225	East George St	77J2	Dist	4	3.40	
226	East George St	77J3	Dist	4	2.43	
227	East George St	77J4	Dist	4	1.18	
228	Waterman Ave	78F3	Dist	4	8.96	
229	Waterman Ave	78F4	Dist	4	8.58	
230	Lippitt Hill	79F1	Dist	4	0.07	Y
231	Lippitt Hill	79F2	Dist	4	6.74	Y
232	Elmwood	7F1	Dist	4	15.86	
233	Elmwood	7F2	Dist	4	16.77	
234	Elmwood	7F4	Dist	4	12.94	
235	Admiral Street	9J1	Dist	4	4.31	
236	Admiral Street	9J2	Dist	4	1.93	
237	Admiral Street	9J3	Dist	4	2.61	
238	Admiral Street	9J5	Dist	4	1.32	
239	South Aquidneck	122J2	Dist	4	5.20	
240	South Aquidneck	122J4	Dist	4	9.67	
241	South Aquidneck	122J6	Dist	4	1.24	
242	Kingston	131J12	Dist	4	1.50	
243	Kingston	131J14	Dist	4	0.27	
244	Kingston	131J2	Dist	4	1.80	
245	Kingston	131J4	Dist	4	1.92	
246	Kingston	131J6	Dist	4	1.54	
247	Hospital	146J14	Dist	4	0.95	
248	Hospital	146J2	Dist	4	2.52	
249	Drumrock	14F1	Dist	4	24.21	
250	Drumrock	14F2	Dist	4	16.33	

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
251	Drumrock	14F3	Dist	4	7.63	
252	Drumrock	14F4	Dist	4	7.15	
253	West Howard	154J14	Dist	4	1.27	
254	West Howard	154J16	Dist	4	0.14	
255	West Howard	154J18	Dist	4	3.92	
256	West Howard	154J2	Dist	4	0.77	
257	West Howard	154J6	Dist	4	0.40	
258	West Howard	154J8	Dist	4	2.61	
259	Westerly	16F1	Dist	4	33.40	
260	Westerly	16F2	Dist	4	26.61	
261	Westerly	16F3	Dist	4	11.71	
262	Westerly	16F4	Dist	4	18.00	
263	Wakefield	17F1	Dist	4	27.89	
264	Wakefield	17F2	Dist	4	29.54	
265	Wakefield	17F3	Dist	4	14.69	
266	Bailey Brook	19J14	Dist	4	2.32	
267	Bailey Brook	19J16	Dist	4	0.43	
268	Bailey Brook	19J2	Dist	4	2.61	
269	North Aquidneck	21J2	Dist	4	1.95	
270	North Aquidneck	21J4	Dist	4	12.02	
271	North Aquidneck	21J6	Dist	4	2.46	
272	Drumrock	2222	SubT	4	7.27	
273	Drumrock	2224	SubT	4	5.23	
274	Drumrock	2230	SubT	4	14.99	
275	Drumrock	2232	SubT	4	17.42	
276	Sockanosset	2233	SubT	4	7.86	
277	Drumrock	2262	SubT	4	4.56	
278	Drumrock	2264	SubT	4	1.16	
279	Drumrock	2266	SubT	4	2.58	
280	Kent County	22F1	Dist	4	16.68	
281	Kent County	22F2	Dist	4	16.55	
282	Kent County	22F3	Dist	4	16.97	
283	Kent County	22F4	Dist	4	19.94	
284	Vernon	23J12	Dist	4	2.17	
285	Vernon	23J14	Dist	4	2.94	
286	Vernon	23J2	Dist	4	2.96	
287	Vernon	23J4	Dist	4	4.42	
288	Vernon	23J6	Dist	4	0.55	
289	Natick	29F1	Dist	4	21.57	
290	Natick	29F2	Dist	4	3.24	
291	Lafayette	30F1	Dist	4	54.16	
292	Lafayette	30F2	Dist	4	25.38	Y
293	Pawtuxet	31J1	Dist	4	0.71	
294	Pawtuxet	31J2	Dist	4	5.15	
295	Harrison	32J12	Dist	4	7.26	
296	Harrison	32J2	Dist	4	3.66	
297	Harrison	32J4	Dist	4	2.29	
298	Wakefield	3302	SubT	4	5.47	
299	West Kingston	3305	SubT	4	0.06	
300	West Kingston	3307	SubT	4	9.69	
301	West Kingston	3308	SubT	4	6.97	
302	Kent County	3309	SubT	4	7.17	
303	Kent County	3310	SubT	4	6.44	
304	Kent County	3311	SubT	4	7.45	
305	Kent County	3312	SubT	4	10.47	
306	Tiverton	33F1	Dist	4	28.09	
307	Tiverton	33F2	Dist	4	25.37	
308	Tiverton	33F3	Dist	4	76.80	
309	Tiverton	33F4	Dist	4	89.20	
310	Dexter	36W41	Dist	4	18.05	Y
311	Dexter	36W42	Dist	4	20.19	Y
312	Dexter	36W43	Dist	4	18.24	Y
313	Dexter	36W44	Dist	4	29.21	Y

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
314	Jepson	37J2	Dist	4	1.48	
315	Jepson	37J4	Dist	4	3.30	
316	Jepson	37K21	SubT	4	4.41	
317	Jepson	37K22	SubT	4	6.12	
318	Jepson	37K33	SubT	4	9.41	
319	Jepson	37W41	Dist	4	10.21	
320	Jepson	37W42	Dist	4	12.60	
321	Jepson	37W43	Dist	4	29.22	
322	Gate Two	38J2	Dist	4	2.90	
323	Gate Two	38J4	Dist	4	2.87	
324	Gate Two	38K21	SubT	4	0.41	
325	Gate Two	38K23	SubT	4	5.69	
326	Apponaug	3F1	Dist	4	20.90	
327	Apponaug	3F2	Dist	4	17.72	
328	Hunt River	40F1	Dist	4	13.11	
329	Hope Valley	41F1	Dist	4	61.79	
330	Bonnet	42F1	Dist	4	31.24	
331	Ashaway	43F1	Dist	4	67.64	
332	Eldered	45J2	Dist	4	7.50	Y
333	Eldered	45J4	Dist	4	11.68	Y
334	Eldered	45J6	Dist	4	8.64	Y
335	Old Baptist Road	46F1	Dist	4	22.16	Y
336	Old Baptist Road	46F2	Dist	4	36.59	
337	Old Baptist Road	46F3	Dist	4	20.77	
338	Old Baptist Road	46F4	Dist	4	19.42	Y
339	Arctic	49J1	Dist	4	3.61	
340	Arctic	49J2	Dist	4	1.89	
341	Arctic	49J3	Dist	4	3.78	
342	Arctic	49J4	Dist	4	2.50	
343	Merton	51J12	Dist	4	0.86	
344	Merton	51J14	Dist	4	0.35	
345	Merton	51J16	Dist	4	2.99	
346	Merton	51J2	Dist	4	3.12	
347	Warwick	52F1	Dist	4	11.60	Y
348	Warwick	52F2	Dist	4	12.68	Y
349	Warwick	52F3	Dist	4	25.62	
350	Coventry	54F1	Dist	4	115.84	
351	Lakewood	57J1	Dist	4	2.28	
352	Lakewood	57J2	Dist	4	5.31	
353	Lakewood	57J3	Dist	4	7.63	
354	Lakewood	57J4	Dist	4	5.80	
355	Lakewood	57J5	Dist	4	6.13	
356	Peacedale	59F1	Dist	4	23.69	
357	Peacedale	59F2	Dist	4	18.37	
358	Peacedale	59F3	Dist	4	56.53	
359	Peacedale	59F4	Dist	4	16.05	
360	Division St	61F1	Dist	4	7.35	
361	Division St	61F2	Dist	4	14.53	
362	Division St	61F3	Dist	4	13.74	
363	Division St	61F4	Dist	4	3.55	
364	Hopkins Hill	63F2	Dist	4	28.29	
365	Hopkins Hill	63F3	Dist	4	39.34	
366	Hopkins Hill	63F4	Dist	4	14.02	
367	Hopkins Hill	63F5	Dist	4	27.85	
368	Hopkins Hill	63F6	Dist	4	125.99	
369	Anthony	64F1	Dist	4	20.83	
370	Anthony	64F2	Dist	4	14.77	
371	Anthony	64F5	Dist	4	0.10	
372	Clarke Street	65J12	Dist	4	11.03	Y
373	Clarke Street	65J2	Dist	4	12.14	Y
374	Kenyon	68F1	Dist	4	83.09	
375	Kenyon	68F2	Dist	4	79.66	
376	Kenyon	68F3	Dist	4	84.37	

Line No.	Substation Name	Feeder No.	Asset Class	Cycle Length	Total OH Miles	FY11 Deferred ?
377	Kenyon	68F4	Dist	4	50.70	
378	Lincoln Avenue	72F1	Dist	4	9.69	Y
379	Lincoln Avenue	72F2	Dist	4	20.42	Y
380	Lincoln Avenue	72F3	Dist	4	15.15	Y
381	Lincoln Avenue	72F4	Dist	4	23.92	Y
382	Lincoln Avenue	72F5	Dist	4	22.88	
383	Lincoln Avenue	72F6	Dist	4	16.08	
384	Quonset	83F1	Dist	4	0.53	
385	Quonset	83F2	Dist	4	23.94	
386	Quonset	83F3	Dist	4	1.56	
387	Davisville	84T1	Dist	4	2.09	
388	Davisville	84T2	SubT	4	1.55	
389	Davisville	84T3	SubT	4	19.49	
390	Davisville	84T4	SubT	4	1.63	
391	Wood River	85T1	Dist	4	34.69	
392	Wood River	85T2	SubT	4	17.41	
393	Wood River	85T3	Dist	4	64.64	
394	Langworthy Corner	86F1	Dist	4	25.88	
395	Kilvert St.	87F1	Dist	4	8.86	
396	Kilvert St.	87F2	Dist	4	4.90	
397	Kilvert St.	87F4	Dist	4	4.29	
398	Tower Hill	88F1	Dist	4	45.27	
399	Tower Hill	88F3	Dist	4	41.43	
400	Tower Hill	88F5	Dist	4	44.83	

Total RI Miles:	**5,238.48**	**475.1**	**= Total FY11 Deferred Mileage ****
Annual Goal Mileage for 4 year cycle:	**1,309.62**	**834.52**	**= Goal mileage if deferral continues annually**
Optimal Cycle Length	**4.00**	**6.28**	**= New cycle length if deferral continues**

** varies slightly from initial 472 miles due to small feeder additions

Division Data Request 2-7

Request:

It is our understanding that National Grid's feeder health program and line inspection program are substantially identical to the program outlined in the early phases of the reliability program and annual reporting to the Division. To the extent that the program has undergone any significant change where the comment by National Grid is that it has increased the expense associated with implementing the program, please outline in detail.

Response:

Historically, distribution components have typically been addressed on a fix-on-fail basis with trees, animals, lightning, and deteriorated equipment being the primary influences on reliable system performance. The Reliability Enhancement Program ("REP") was developed in 2006 to address reliability trending that was unfavorable on specific feeders. 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

In late 2009, National Grid began the Inspection and Maintenance ("I&M") Program. This strategy builds on the lessons learned from REP and is a comprehensive program, which will replace the Feeder Hardening program and some of the distribution line asset replacement programs. I&M focuses on a systematic inspection and maintenance schedule, which is proactive, and establishes a work plan for assets based upon actual condition assessments. As part of the I&M strategy the Company performs:

1. Cyclical inspections of the entire population of overhead, underground and sub-transmission line assets on the distribution system, and
2. Repair and/or upgrade projects identified through the inspections for all Level 1 and Level 2 priorities.

With the I&M Program, the Company takes a more holistic approach to capital spending, in that capital investment will be informed and motivated by inspection data, field conditions and systematic repair and replacement schedules, rather than arising from performance failures or deficiencies. The key to the I&M Program is that it is a systematic inspection of the distribution system on a six-year cycle with maintenance derived from those inspections. This cyclical inspection and maintenance program will play a significant role in maintaining a sustainable and reliable system as well as meeting regulatory requirements. The data compiled from field inspection provides the Company with an accurate assessment of the condition of its assets,

Division Data Request 2-7 (continued)

which will help optimize its budget, determine work priorities, and improve service quality to customers.

The inspections will also help the Company capture other asset information and asset conditions as needed, which will be used for asset strategies or assets decision-making. The I&M process is efficient as it introduces the use of a new computer-based handheld device that captures the field notes, which are entered by the inspector, and synchronizes automatically into The Company's work order system. The concepts contained within this program are consistent with accepted asset management principles.

The following table shows the historical capital costs and associated expenses for I&M activities since FY 2008. It is important to note from this table that the proposed level of capital spending for I&M activities in FY 2012 (with the revised I&M program) is approximately $1 million dollars less than the average level of spending for I&M activities during the period FY 2008-to-FY 2010. Under the revised I&M program, the repair of all Level 3 issues will be postponed until FY 2015. The O&M associated with the capital outlays for these activities is comparable to the outlays in the historical period.

Inspection and Maintenance Activities

Capex

PROGRAM	Sum of FY2007	Sum of FY2008	Sum of FY2009	Sum of FY2010	Sum of FY2011 - Budget	FY2012 - Proposed
OH I&M	$ -	$ -	$ -	$ -	$ -	$ 781,000
CUTOUT	$ 959,811	$ 457,141	$ 621,929	$ 1,114,306	$ 1,264,000	$ 1,714,000
FEEDER HARDENING	$ 1,074,488	4,311,391	3,828,491	2,888,145	1,100,000	$ 3,230,100
POLES	$ 742,664	$ 2,463,041	$ 2,879,787	$ 2,550,510	$ -	$ -
UG Inpsect incl Equip Structures	$ 118,797	$ 462,823	$ 1,098,349	$ 1,230,066	$ 200,000	$ 600,000
Grand Total	**$ 2,895,760**	**$ 7,694,396**	**$ 8,428,555**	**$ 7,783,026**	**$ 2,564,000**	$ 6,325,100

O&M Related to Capex

PROGRAM	Sum of FY2007	Sum of FY2008	Sum of FY2009	Sum of FY2010	Sum of FY2011 - Budget	FY2012 - Proposed
OH I&M	$ -	$ -	$ -	$ -	$ -	$ 273,350
CUTOUT	$ 16,222	$ 4,366	$ 42,430	$ 198,700	$ 126,400	$ 171,400
FEEDER HARDENING	$ 1,539,708	$ 1,250,322	$ 1,618,127	$ 1,084,850	$ 385,000	$ 1,130,535
POLES	$ 111,822	$ 308,122	$ 157,391	$ 226,988	$ -	$ -
UG Inpsect incl Equip Structures	$ 1,281	$ 36,744	$ 59,521	$ 309,146	$ 50,000	$ 150,000
Grand Total	**$ 1,669,033**	**$ 1,599,554**	**$ 1,877,469**	**$ 1,819,684**	**$ 561,400**	**$ 1,725,285**

Division Data Request 2-8

Request:

With the feeder hardening and inspection program which, per our understanding is now a very mature program, explain in detail why the cost of continuing this program should not be lower and more efficient than the cost associated with the program in its early inception. In particular, explain once a feeder has gone through a detailed assessment why would there be repetitive detailed assessments required, rather than simply a more compressed evaluation of any changes from previous assessments.

Response:

As shown on Chart 2 on page 65 of the Company's Infrastructure, Safety, and Reliability Plan ("ISR Plan"), the Company proposed a $6,325,100 capital and $2,479,230 expense plan for inspection and maintenance activities in FY 2012. Approximately half of the funds will be devoted to feeder hardening—a program that addresses equipment issues on approximately 6% of overhead ("OH") feeder miles each year and that will be subsumed by the Company's Inspection and Maintenance ("I&M") Program as of FY 2013.

In the original scope of the Inspection and Maintenance ("I&M") Program, a proactive program designed to replace the feeder hardening and some other asset replacement programs[1], the Company proposed to inspect 20% of its system (1,047 miles of its OH system plus 1,020 manholes each year) and to replace components that were slated to fail within 5 years (Level l, 2, & 3 issues).[2] The I&M program would begin with the remaining 66% of OH feeder miles that were not already addressed as part of the feeder hardening program and the manholes that were not already inspected as part of its underground maintenance program. The scope of work to be performed on each "non-hardened" feeder as part of the I&M program was similar to the work performed as part of the feeder hardening and underground maintenance program. The expected cost to implement this I&M program was commensurate with the three-fold increase in the number of feeder miles and manholes that would be addressed each year relative to the feeder hardening and underground maintenance program. This cost was expected to drop considerably in the out years after all the Level 1, 2 and 3 issues on the "non-hardened" feeder miles and in the underground system had been addressed.

In response to the Commission Ruling in R.I. P.U.C Docket No. 4065, the Company has since modified the scope of the I&M program. First, the Company has extended the cycle time for inspections to six years so that 837 miles (16%) of its system would be inspected each year. Second, the Company has postponed work to address Level 3 issues on the "non-hardened"

[1] In addition to feeder hardening, the Pro-active I&M program is also designed to replace the targeted pole replacement and the miscellaneous underground and overhead deteriorated equipment programs.
[2] Because Level 1 issues need to be complete within one week, the costs associated with these repairs are part of the Damage/Failure Budget.

Division Data Request 2-8 (continued)

feeder miles until FY 2015. With these changes, the projected capital budget to address Level 2 issues on 837 miles of "non-hardened" feeder and in 824 manholes is $1.5 million.

Looking forward, the Company currently anticipates that its $6,325,000 million proposed FY 2012 capital budget for the I&M Program, as shown on Chart 2 of the ISR Plan (page 65), will drop to approximately $3,100,000 in FY 2013 with the sunset of the feeder hardening program assuming that the Level 3 work on the "non-hardened feeders" is postponed until FY 2015. This budget includes approximately $1,700,000 to remove potted porcelain cutouts ("PPCs")—a program that the Company expects to complete by the end of FY 2013. The proposed I&M Program budget is anticipated to therefore decline again in FY 2014 as the PPC program ends but only if the Company continues to postpone the Level 3 work on the "non-hardened feeders".

The 34% of feeders that were already addressed as part of the feeder hardening program will not be inspected or addressed again as part of the I&M program until the Level 1, 2 and 3 issues on all of the "non-hardened" feeders have been addressed. Based on the current plan, this will not occur until FY 2016 at the earliest. Moreover, because the major issues on the "hardened feeders" would have already been addressed as part of the feeder hardening program, the Company expects to find fewer issues on these feeders compared with the "non-hardened" feeders. With this in mind, the cost of the I&M program should decrease after all the Level 2 and 3 work has been completed on all "non-hardened" feeders and manholes.

Prepared by or under the supervision of: Catherine McDonough and John Gavin

Division Data Request 2-9

Request:

Please provide the annual labor rate increase in percent for the company utility workers historically and what the projected increase would be under any existing union contract. Additionally, provide the annual percent increase and decrease associated with the cost of material and supply acquisitions by category as follows:

a. Poles
b. Line transformers
c. Conductor
d. Utility hardware such as insulators and crossarms
e. Any other outside contracting costs, labor costs, or material costs data that would justify the increase associated with the expenditures proposed in the ISP Plan over historical costs from the annual reliability filings

Response:

The proposed capital budget for FY 2012 is 8% greater than the average level of spending between FY 2008 and FY 2010. Much of the increase is due to proposed increase in line work on several projects and the required spending for several large substation projects that was delayed from FY 2011 due to the reduced budget in response to the Commission's Order in R.I.P.U.C Docket No. 4065. The substation projects include Newport, Coventry, West Warwick, Woonsocket, and Hopkinton, which were separately broken out from their traditional "budget classifications" to highlight their impact on increased budget levels as compared to some historical years. Inflation accounts for only part of the increase in the proposed Infrastructure, Safety, and Reliability ("ISR") Plan spending in FY 2012

The historical and contractual labor rates are shown below. The current labor contract was scheduled to expire on 5/11/11, but was extended through 5/11/2013. The past and prospective general annual wage increases effective in May of each year, as per the contracts are as follows.

Year	Increase
2007	3.0%
2008	3.0%
2009	3.0%
2010	3.0%
2011	2.5%
2012	2.5%

Division Data Request 2-9 (continued)

The Company does not separately apply inflation factors to poles, conductor, or hardware, rather it is accounted for in terms of commodity increases. The Company's method to account for inflation in its cost estimates is as follows:

- "Purchase Only" Blanket Projects - For pre-capitalization of meters and line transformers, the Company has separate purchase blanket projects where these items are purchased into. Net "inflation" for transformers was a decrease of 10%. This is a combination of a decrease of 22% for estimated purchase efficiencies and a commodity inflation increase estimated at 12%.

- "Non-Purchase" Blanket Projects - Within the Company's non-purchase blanket project category, which represent the remaining blanket projects, the Company breaks cost types into three categories and inflates each with a weighted average inflationary figure as follows for FY 2012:

    - Labor – Labor is usually about 65-75% of a blanket project and was inflated at 3% for FY 2012.

    - Materials – Materials typically represents about 15-25% of a blanket project cost and was inflated at 12%, based upon a composite of forward indexes for commodities including aluminum copper, steel, and oil.

    - Other – All other costs typically represent approximately 10-15% of a blanket project cost and were inflated at 2%

- Specific Projects – The expected costs for specific projects are based on historic costs and are not adjusted for inflation.

Prepared by or under the supervision of: Mark Smith and Chris Brouillard

Division Data Request 2-10

Request:

Please provide a detailed description of how the "Risk Score" system is utilized. What criteria is used to score a project? Does a specific score denote if a project is funded or is it a prioritization system and subject to availability of funds?

Response:

Annual Work Plan Overview

Each year, the Company develops an Annual Work Plan to maintain and improve the safety and reliability of the distribution system. From an overall perspective, the Company's objective with respect to the capital plan is to arrive at a capital budget that is the optimal balance in terms of making the investments necessary to maintain the performance of the system, ensure a cost-effective use of the Company's available resources, manage the overall risk on the system, and minimize the impact on customer bills.

The specific combination of work undertaken by the Company in any given year is a function of both the internal investment plan and external drivers. There are five basic capital work categories for the installation of new facilities that are required to ensure safe and reliable service: (1) activities required by statutory or regulatory requirements, (2) activities required to address damage/failures, (3) activities to address system capacity needs and performance, (4) activities to address asset conditions, and (5) non-infrastructure activities to support capex construction and operations. Generally, activities conducted in the categories of statutory or regulatory requirements and damage/failure are dictated by circumstances external to the Company and are considered to be mandatory type construction. Construction work in the System Capacity and Performance and Asset Condition categories is considered policy-driven. Internal capital-spending priorities relating to system capacity or asset replacements arise from the investment-planning strategy employed by the Company. Non-infrastructure expenditures are projects that are necessary to support construction and operations.

Annual Work Plan Development

The Company uses a risk-scoring system that assigns a value to each project or strategy relative to the objectives of safety, reliability, and environmental responsibility to guide investment decisions. The risk scoring methodology is applied to the Company's distribution improvement projects that are expected to be ongoing within a 5-year planning horizon. These projects include new substations, substation upgrades, and upgrades to the distribution and sub-transmission systems. The risk scoring method employs a risk/opportunity matrix, as shown in Figure 1, below. The matrix is applied across all projects within National Grid's lines of business and is discussed in more detail below. All projects new to the plan are reviewed and scored using the risk/opportunity matrix. Projects are scored based on the prioritization ranking process described below and is applied to the entire capital portfolio consisting of Blanket Projects, Programs, Mandatory and Policy Driven Specific Projects, and Fiscal Year Carryover Project Spending.

Division Data Request 2-10 (continued)

Projects are then selected for funding based upon the magnitude of the mandatory category work, the relative risk score of each project, the maturity of the project, the availability of resources to undertake the work, and the funding levels for that fiscal year.

Prioritization Ranking Process

The Company includes in the risk scoring exercise all capital projects and programs identified by the Distribution Asset Planning group that stem from Company strategies, plans, and operating requirements. The 5-Year spending plan is developed based upon the risk score and category of the work, as well as other factors including the maturity of the project. The spending plan is then cast into a fiscal year work plan that is managed on a monthly basis by personnel from the Program Management, Distribution Asset Management, Finance, and Construction Delivery departments. Resources are allocated based upon the project risk score, need date, and type and schedule of resources.

The project risk score is calculated using a project risk decision support matrix that assigns a project risk score based upon the estimated consequence and likelihood 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 risk score takes into account key performance areas including safety, environmental, and reliability, including system equipment performance criteria such as thermal loading, voltage, and asset performance and condition. The overall objective of the approach is to establish a capital project ranking that optimizes the overall portfolio via specific investments in the distribution system based upon the measure of risk or improvement opportunity associated with a project. Projects undertaken to meet franchise, regulatory, statutory, or damage/failure requirements are designated as "Mandatory" and are given a score of 50, outside of the scoring matrix exercise. Such projects reflect little or no discretion with respect to the scope and timing of the work. Projects that are policy driven are scored in terms of their impact to safety, reliability, and environmental responsibility and the probability of the impact occurring. The result is a project impact, probability, and overall risk score for each project within an overall risk scored capex portfolio. The portfolio can, therefore, be optimized in terms of its impact to individual risk categories and on overall portfolio risk.

Division Data Request 2-10 (continued)

Figure 1 below represents a detailed view of a sample project risk scoring matrix used to estimate the probability and consequences of a potential distribution system event for projects in the five-year portfolio.

Figure 1

Project Risk Score – Reliability Example

Impact

Risk Score

Loss to 50,000 customers; more than 20M CMI, loss of more than 10 (13KV) feeders; loading: 120%; Voltage (P.U.): less than 0.85; loss of supply greater than 1,000 MWs	Very High	25	32	38	43	47	48	49
Loss to 25,000-50,000 customers 5M to 20M CM; Loss of 6-10 (13KV) feeder: Loading: 115-120% : Voltage (P.U.): 0.85-0.87; Significant increase in transmission constraint costs ($15m):; Loss of supply between 250 – 1,000MWs	High	20	29	33	40	44	45	46
Loss to 10,000-25,000 customers 1M to 5M CMI; Loss of 3-6 (13KV) feeder; Loading: 110-115%; Voltage (P.U.): 0.87-0.90; Significant increase in transmission constraint costs ($5m); Loss of supply between 50 - 250MWs	Moderately High	15	22	26	35	39	41	42
Loss to 5,000-10,000 customers 500K to 1M CMI; Loss of 1-3 (13 KV) feeder Loading: 105-110%; Voltage (P.U.): 0.90-0.9 Significant increase in transmission constraint costs ($1m); Loss of supply up to 50 MWs	Moderate	9	17	19	28	34	36	37
Loss to 500-5,000 customers 50K to 500K CMI Loss of 0.5-1 (13KV) feeder Loading: 100-105%: Voltage (P.U.): 0.92-0.93; Major disruption to outage & maintenance/ construction programs	Moderately Low	5	10	14	21	27	30	31
Loss to less than 500 customers; Less than <50K CMI; Loss of 0.5 (13KV) feeder: Loading: 95-100%: Voltage (P.U.): 0.93-0.95; Disruption to outage & maintenance/ construction programs	Low	3	6	8	16	18	20	24
Loss of 0.5 (13KV) feeder:	Very Low	1	2	4	7	11	12	13
		>100 yrs	20-100 Years	10-20 Years	5-10 Years	3-5 Years	1-3 Years	< 1Year

10

Likelihood

Division Data Request 2-11

Request:

Please explain the difference, as Narragansett defines it, between routine weather events, minor storm events, and major storm events.

Response:

Major events are defined according to the IEEE criterion, i.e. those events occurring on days during which the natural log of SAIDI for each respective day is greater than a value (beta) that is 2.5 standard deviations above the most recent 5 year average of the natural log of daily SAIDI.

Minor events are defined, for internal purposes only at National Grid, as those events that satisfy two criteria. The first criterion is that such events occur on days during which the natural log of SAIDI for each respective day is between values that are 1.5 and 2.5 standard deviations (inclusive) above the most recent 5 year average of the natural log of daily SAIDI. The second criterion is that the number of events occurring on each such day is 3 or more times the most recent 5 year average number of daily events.

Normal events are all other events that do not meet the criteria of major or minor events.

Prepared by or under the supervision of: Jon Gonynor

Division Data Request 2-12

Request:

Please provide Planning Criteria used by Narragansett.

Response:

Please see Attachment DIV 2-12, the Company's "Guide for Area Supply and Distribution Planning" (EDP-PLN-1), Revision 1 dated 9/21/1998.

Prepared by or under the supervision of: Rob Sheridan

National Grid

Engineering/Design Procedure

Procedure	**EDP-PLN-1**	Issue Date	**January 1, 1977**		
Title	**Guide For Area Supply And Distribution Planning**	Revision No.	**1**	Date	**9/21/98**
		Page No.	**1**	of	**13**

Sharad Y. Shastry
Prepared by

Charles H. Moser
Approved by

1.0 INTRODUCTION

The goal of supply and distribution planning is to provide adequate capacity for each element of the electrical system and to ensure reliable service to the customer on an economic basis. The objective is the optimum use of capital while maintaining acceptable standards of service[1]. This guide has been prepared to help planning engineers consistently meet this objective.

This guide applies to National Grid Companies' local area supply and distribution facilities (below 69 kV) which are not a critical portion of the interconnected bulk transmission network and do not connect major generation to the transmission network. In the latter cases, planning guidance is provided by the New England Power (NEP) Transmission Planning Guide[2], which establishes minimum requirements for transmission system reliability, and which does not necessarily apply to area supply problems.

Since many area plans may directly affect the interconnected system, the Transmission provider (NEP) has complete responsibility for ensuring that regional Transmission planning criteria are not violated; National Grid Retail Companies provide the load and interconnection information to facilitate the required Transmission interconnection and adequacy studies.

2.0 SUPPLY AND DISTRIBUTION DESIGN CRITERIA

The design of supply and distribution facilities should preclude equipment loadings above emergency capabilities, and voltage regulation beyond acceptable limits, which could otherwise cause damage to our own or customers' equipment.

The following sections list several basic criteria that will guide the analysis and design of the supply and distribution system.

2.1 Load Forecasts

The Power Supply Area (PSA) load forecast is updated annually[3]. The PSA is the smallest unit for which forecasts are developed. Further apportioning of the PSA load if required, is done proportionally to the coincident peak demands of areas within the PSA by the planning engineers.

After area plans are developed, their economic sensitivity to change in load growth is tested. The results of this testing are included in the study report.

2.2 Thermal Capabilities of Equipment

Thermal limits must be recognized for all system elements in conducting planning studies. Thermal capabilities are determined so that maximum use can be made of all equipment. Several factors are taken into account, including ambient temperatures, load cycles, wind velocities, and potential loss of life of equipment.

Definitions of thermal capabilities of various system elements are provided in the following sections.

2.2.1 Overhead Conductors[4,5,6]

The current carrying capacity (ampacity) of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe Summer or Winter ambient conditions.

The sag of a conductor increases due to elastic elongation as its temperature increases. If the operating time at elevated temperatures is long enough, inelastic elongation (creep) occurs. Both effects must be considered to determine sag limitations on the conductor ampacity. Elevated temperature operation also increases the loss of tensile strength of the conductor, thus reducing its life.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous), Long-Time Emergency (LTE), Short-Time Emergency (STE), and Drastic Action Limit (DAL) operations for summer and winter conditions. Other short duration ratings, if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information.

2.2.2 Underground Cables[7]

Ampacities are defined for underground cables as follows:

Normal Ampacity

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle.

One-Hour to 24-Hour Emergency Ampacities

These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the 100-hour ampacity (defined below). The length of the emergency time period refers to the total duration of the emergency loading, not to the duration of the peak on the normal load cycle.

100-300 Hour Ampacity

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

2.2.3 Transformers[8,9,10]

Thermal capabilities of transformers are based on IEEE Guide for Loading Oil-Immersed Power Transformers for up to 100 MVA (C57.92-1981) and in excess of 100 MVA (C57.115-1991). Three categories of transformer capabilities are defined below:

Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle, and on the maximum 24-hour average ambient temperature for the period involved. Loading at these levels does not result in significant reduction of expected life on the transformer.

Short-Time Emergency Capability (1/2 hour or less)

A negligible loss of life is incurred if the transformer load is limited to twice nameplate rating for 30 minutes or less.

Long-Time Emergency Capabilities (1 hour to several days)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. A cumulative loss of life may be accepted under these conditions so long as the maximum allowable top oil temperature or hot spot temperature in the winding are not exceeded. A 5% loss of life per event and an average of 2-1/2 percent loss of life per year may be allowed for emergency loading conditions only, as long as the maximum allowable top oil temperature or the hot spot winding temperature are not exceeded.

2.2.4 Other Equipment[4,5,6]

Normal and emergency capabilities of all other series equipment must be calculated and considered. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life.

However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, etc. or even current transformers at the two terminals of the circuit. These ratings are generally based on the allowable maximum temperature of the equipment.

2.3 Application of Equipment Capabilities

In the application of thermal capabilities, it is assumed that load relief is attained by automatic or manual switching, generation adjustments, or other means, within allowable time limits.

Normal Equipment Capabilities Must Not Be Exceeded

N For normal operating conditions

N For the loss of a transformer where a mobile unit cannot be utilized.

N For the loss of generation on which area supply and distribution is dependent.

Emergency Equipment Capabilities Must Not Be Exceeded As Follows:

N For the loss of an overhead line, do not exceed:

a. The 1 hour to 24 hour emergency ampacity of underground cable circuits;

b. The long-time emergency capability of transformers;

c. The long-time emergency ampacity of overhead circuits;

d. The long-time emergency capability of auxiliary equipment.

N For the loss of a transformer where a mobile unit can be utilized, or for the loss of a cable operating at less than 115 kV in a duct bank, do not exceed:

a. The 24-hour emergency ampacity of underground cable circuits;

b. The long-time emergency capability of transformers;

c. The long-time emergency ampacity of overhead circuits;

d. The long-time emergency capability of auxiliary equipment.

N For the Loss of a Direct Buried or Submarine Cable Rated at Less Than 115 kV, or a 115 kV Cable in Duct, do not exceed:

a. The 100-hour emergency ampacity of underground cables;

b. The long-time emergency capability of transformers;

c. The long-time emergency ampacity of overhead circuits;

d. The long-time emergency capability of auxiliary equipment.

N For the Loss of 115 kV (and above) Direct Buried, Submarine, or Pipe Type Cables, do not exceed:

a. The 300-hour emergency ampacity of underground cables;

b. The long-time emergency capability of transformers, taking into account duration of outage and available methods of load relief;

c. The long-time emergency ampacity of overhead circuit;

d. The long-time emergency capability of auxiliary equipment.

2.4 Voltage Regulation

The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most substation regulating equipment has a range of 20 percent. Under normal conditions, therefore, half the regulator range can compensate for variations in supply voltage, leaving the other half available for voltage drops on the distribution feeders. The substation transformer taps should be chosen to allow this control.

The voltage regulation at substation busses without regulating equipment should be within 5 percent for normal and 10 percent for emergency conditions.

2.5 Service Reliability

The supply and the distribution systems in the National Grid Companies are designed to limit the interruption of energy (MWh) delivery for a loss of any single element.

In planning the development of the system, it is recognized that some highly improbable events involving loss of more than one element, such as multiple and common mode outages, may occur resulting in a much larger interruption of energy delivered.

The indices of service reliability are the annual frequency of customer interruption (f) and the average duration of interruption (Di). The product of these two indices is the average annual duration of interruption per customer served (Ds). Since the total system is involved in supplying the customer, ensuring an acceptable reliability of service to all customers requires designing the supply and the distribution systems in an integrated manner to limit the interruption of energy delivery.

The design criteria report[1] establishes the criteria for designing the system to ensure an acceptable reliability of service for all National Grid Companies' customers. The applicable guide[11] illustrates the reliability evaluation techniques.

2.5.1 Distribution Design Criteria

For system design, transmission lines (69 kV and above) and the associated substation transformers should be considered as part of the supply system. The subtransmission lines (below 69 kV) and the distribution feeders, which are similar in construction to each other and have a higher outage rate compared to transmission lines, should be considered as part of the distribution system.

The design criteria, reformulated to maintain the current service reliability for National Grid Companies, are as follows:

Supply Design Criterion (SDC):

The supply system should be designed to limit the interruption caused by an outage of a single supply line or substation element to 480 MWh, based upon peak load.

Feeder Design Criterion (FDC):

The distribution system should be designed to limit the interruption caused by an outage of a single distribution feeder to 20 MWh, based upon peak load.

Duration Design Criterion (DDC):

The supply and the distribution systems should be designed so that the five-year average annual duration of interruption per customer served (Ds) on a feeder basis, excluding severe weather related events, does not exceed 200 minutes per year

2.5.2 Multiple Outages

Simultaneous outage of both circuits on overhead double circuit structures may result in the loss of an entire area load. Since these outages are nearly always due to faults caused by lightning, it is reasonable to assume that both circuits will not be permanently faulted, and that at lease one circuit can be restored to service quickly by a successful reclosure. The effect on the rest of the interconnected system must be evaluated, however, even for temporary simultaneous outages.

Planning for supply to secondary underground networks could consider the consequences of overlapping outages on the supply cables.

The loss of two transformers should be considered at locations where a mobile or spare transformer is not available or does not have sufficient capability to carry the entire load, and then only with the concept that the second transformer may fail while the first unit is being repaired. The interruption should be limited to 480 MWh, after allowing for load transfers.

The outage of a local generating unit or supply facility while one generator is already out due to failure or maintenance, should not result in loss of load. It is reasonable to interrupt 480 MWh or less if a third generating unit is forced out of service.

The probability of independent, overlapping outages of two underground cables or two overhead supply circuits is extremely low. For this reason, facilities should not be planned to protect against this condition. In some cases, it may be advisable to evaluate the consequences.

2.5.3 Common Mode Events

Some single events on the system may result in the outage of more than one element. Examples include loss of the common oil supply to parallel pipe-type cables, a dig-in to closely spaced cables in a common duct bank or trench, or loss of a common cooling system to multiple substation transformers.

These occurrences are sufficiently rare so that firm capability need not be provided to protect against them. However, no load should be interrupted for more than 24 hours by such an event. Shorter outages may be indicated by the nature of the load interrupted.

2.5.4 Maintenance of Facilities

Although maintenance is usually performed at off-peak periods, an outage of an element (other than a generator) while another element is out for maintenance may result in some loss of load. The system should be designed, however, such that loss of an entire major urban load center or other large block of load for greater than a few hours does not occur following such an event.

2.5.5 Operation During Construction

Some of these guidelines may need to be relaxed during construction in order to accomplish the work. Each situation should be reviewed individually. As a guide, however, the possible loss of an entire major urban load center or other large block of load for several hours following a single contingency should be avoided. The risk should be weighed in terms of customer sensitivity, a season of year, weather forecasts, and other relevant factors.

2.6 Sizing of New Facilities

All equipment should be sized based on economics and operating requirements. Spreadsheet computer programs can be readily created and used to determine the economic size of conductors and transformers based on total owning costs.

2.7 System Stability

Consideration must be given to system stability if major transmission and substation facilities are altered to accommodate the supply circuits. The supply system must then comply with the stability requirements for the interconnected power system as specified in the Transmission Planning Guide[2].

2.8 Other Major Considerations

The planning engineer must consider the effect of each plan on all aspects of system design. These include:

Short Circuit Duty

Protection

Operation and Maintenance

Transmission Planning

3.0 ECONOMICS[12]

Engineering economics should be used to compare all plans on a common basis. Annual charges on investments, losses, rentals, and all other expenses should be determined for each plan.

The cumulative present worth of annual revenue requirement through the end of the study period for each plan provides one input for comparing plans.

If the plan with the lowest long-range cost has a higher initial investment than one or more of the others, a year-by-year analysis should be made for the first few years.

Some studies involve investments proposed to reduce or eliminate an annual expense. In these cases, a year-by-year analysis must justify the investment alternative.

4.0 REPORTS AND REVIEWS

A supply and distribution study should culminate in a concise report describing the assumptions, procedures, economic comparison, conclusions, and recommendations resulting from the study. Reviews of area planning studies should be made when condition changes justify them. Justification for review of a study might include a new load forecast, change in load distribution, major new loads, availability of new line routes, loss of a proposed route, or other condition changes. Area planning studies should be reviewed periodically to permit adequate overlap in the study periods.

5.0 REFERENCES

1. Report: "Reformulated Distribution Design Criteria", by V. D. Antoniello, S. Y. Shastry, R. D. Sheridan and R. G. Wheeler, dated November, 1997.

2. Procedure No: NEP – 1.0 titled "Transmission Planning Guide", approved by Dana Walters, issued on November 17, 1977 or later version.

3. Report: "New England Electric System Retail Companies 1998 PSA Forecast", by Regional Economic Research Inc. or latest version.

4. Capacity Rating Procedure By The System Design Task Force of the NEPOOL Planning Committee, dated October 1990.

5. Reliability Standards in The New England Power Pool, dated April 1991.

6. National Grid Companies' Computer Programs 65 (Circuits), 92 (OH Conductor Normal Capabilities) and 108 (OH Conductor Emergency Capabilities).

7. National Grid Companies' Computer Programs 10 and 20 (UG Cable Ampacities).

8. IEEE C57.92-1981 (Reaff. 1991), Guide for Loading Mineral-Oil-Immersed Power Transformers Up To and Including 100 MVA with 55°C and 65°C Average Winding Rise.

9. IEEE C57.115-1991 (Redesignation of IEEE Std. 756, Trial Use May 1984), Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65°C Winding Rise).

10. National Grid Companies Computer Programs 4, 156, 157 and 158 (Transformer Capabilities).

11. The "Guide for the Application of Distribution Design Criteria", by S. Y. Shastry and J. M. Thompson.

12. Memo: "Revenue Requirements Factors, and Cost of Losses Update", to C. H. Moser by D. K. Pantalone, dated September 20, 1996 or latest version.

Division Data Request 2-13

Request:

How does the Net Book Value compare to the aging assets recommended for replacement? Are the assets being replaced fully depreciated?

Response

The Company targets specific assets for intervention based upon their current and forecasted performance or condition. Age alone, is not a reliable indicator of condition but is an important factor when considering the volume of assets that need to be managed to ensure long-term sustainability with acceptable reliability performance.

The Company did review several programs and performed a comparison of assets retired, as part of those programs, with average depreciable life. Retirement data from the following Rhode Island programs were reviewed:

- C05461 - Feeder Hardening
- C05524 - Cutout Replacements
- C06644 - Pole Replacements
- C08512 - Battery Replacements
- C32019 - Battery/Chargers

The Company determined the weighted average vintage year retirement by utility account for the above projects, and compared them to the expected average depreciable life with the following results:

- Acct 364 - Poles
  Average vintage retired - 29 years (1980)
  Expected life - 25 years

- Acct 365 – Overhead ("OH") Conductor
  Average vintage retired - 30 years (1979)
  Expected life - 35 years

- Acct 368 - Line Transformers
  Average vintage retired - 41 years (1968)
  Expected life - 25 years

- Acct 369 - OH/Underground ("UG") Services
  Average vintage retired - 43 years (1966)
  Expected life - 25 years

Division Data Request 2-13 (continued)

In most cases the average age of assets retired exceed the expected life. The only exception was the average retirement vintage for OH conductor of 30 years, which is less than the expected life of 35 years. The quantity of OH conductor retired as part of these projects is small and is generally related to sections of conductor removed to accommodate longer sections of conductor as the result of increased pole heights to meet current standards.

Prepared by or under the supervision of: John Gavin and John Currie

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Division Data Request 2-13 - Supplemental

Request:

How does the Net Book Value compare to the aging assets recommended for replacement? Are the assets being replaced fully depreciated?

Response

The Company targets specific assets for intervention based upon their current and forecasted performance or condition. Age alone, is not a reliable indicator of condition but is an important factor when considering the volume of assets that need to be managed to ensure long-term sustainability with acceptable reliability performance.

The Company did review several programs and performed a comparison of assets retired, as part of those programs, with average depreciable life. Retirement data from the following Rhode Island programs were reviewed:

- C05461 - Feeder Hardening
- C05524 - Cutout Replacements
- C06644 - Pole Replacements
- C08512 - Battery Replacements
- C32019 - Battery/Chargers

The Company determined the weighted average vintage year retirement by utility account for the above projects, and compared them to the expected average depreciable life (Note 1) with the following results:

- Acct 364 - Poles
  Average vintage retired - 29 years (1980)
  Expected life - 38 years

- Acct 365 – Overhead ("OH") Conductor
  Average vintage retired - 30 years (1979)
  Expected life - 40 years

- Acct 368 - Line Transformers
  Average vintage retired - 41 years (1968)
  Expected life - 31 years

- Acct 369 - OH/Underground ("UG") Services
  Average vintage retired - 43 years (1966)
  Expected life - 40 years

Division Data Request 2-13 - Supplemental (cont.)

In most cases the average age of assets retired exceed the expected life

Poles are one exception. Poles have an average retirement vintage of 29 years compared to an expected life of 38 years. This outcome is due to the Company's practice of retiring poles as part of projects when the height of the pole does not meet current electrical clearance standards.

OH Conductor is another exception. An OH conductor has an average retirement vintage of 30 years versus an expected life of 40 years. This outcome is caused by the need to replace conductor with longer sections of conductor when taller poles are installed to meet current clearance standards. The quantity of OH conductors retired as part of these projects is small.

Note 1: The Company is revising its prior response to 2-13 to use the expected asset lives for each utility account from the 2009 depreciation study conducted by Foster Associates.

Prepared by or under the supervision of: John Gavin and John Currie

Division Data Request 2-14

Request:

Please provide the location and 100 Year Flood Maps for the substations recommended for upgrades based on 2010 Flooding. Also, please provide the equipment capacity, age and annual peak loading on the devices recommended for upgrades or relocation.

Response:

As a result of the 2010 Flooding in Rhode Island, the Company conducted a Flood Mitigation Study. Twenty (20) substations, listed below, were identified as being in the 100 year flood plain and consequently categorized as high risk. These substations are being assessed to determine possible options to mitigate the affects of floods. Options for each location include an upgrade option and a relocation option.

Substation	BFE
Anthony No. 64	220
Farnum Sub No. 105	-
Front Street No. 24	38
Gate II No. 38	13
Hope Valley No. 41	83
Hunt River No. 40	-
Kent County No. 22	-
Pawtucket 1 No. 107	16
Pawtucket 2 No. 148	33
Pawtuxet No. 31	16
Pontiac No. 31	26
Quonset No. 83	13
Riverside No. 8	128
Sockanosset No. 24	23
S. Aquidneck No. 122	13
Warren No. 5	13
Warwick Mall No. 28	35
West Howard No. 154	11
Westerly No. 16	11
Woonsocket No. 26	229

BFE - Base Flood Elevation

Division Data Request 2-14 (continued)

Attachment 1 to this response provides flood maps for the above locations. Abbreviations used in Attachment 1 are as follows:.

- X500 (FEMA) - An area inundated by 500-year flooding; an area inundated by 100-year flooding with average depths of less than 1 foot or with drainage areas less than 1 square mile; or an area protected by levees from 100-year flooding.

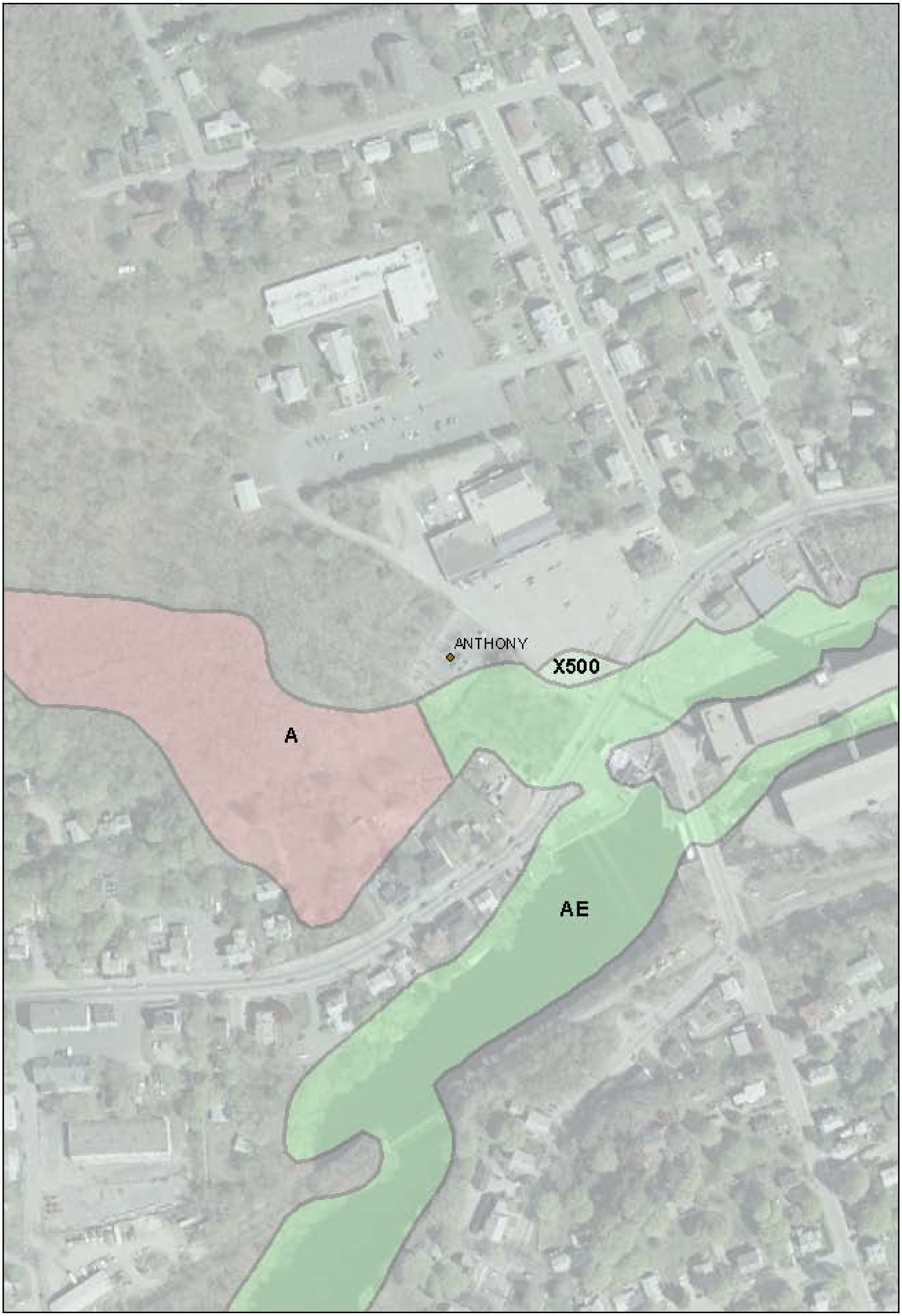
- AE (FEMA) - An area inundated by 100-year flooding, for which BFEs have been determined.

- VE (FEMA) - An area inundated by 100-year flooding with velocity hazard (wave action); BFEs have been determined.

Attachment 2 to this response provides a list of equipment located at each location, age, and where available, capacity. Since the Company is still evaluating alternative flood mitigation options, the devices recommended for upgrade or relocation are not yet available.

Attachment 3 to this response provides loading on the transformers for the 20 locations in 2010.

Prepared by or under the supervision of: John Gavin and Jeff Pires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A
AE


X500
AE
X500
PAWTUCKET
X500
X500
AE


X500
X500
VE
X500
PAWTUCKET
Pawtucket
AE
X500
X500
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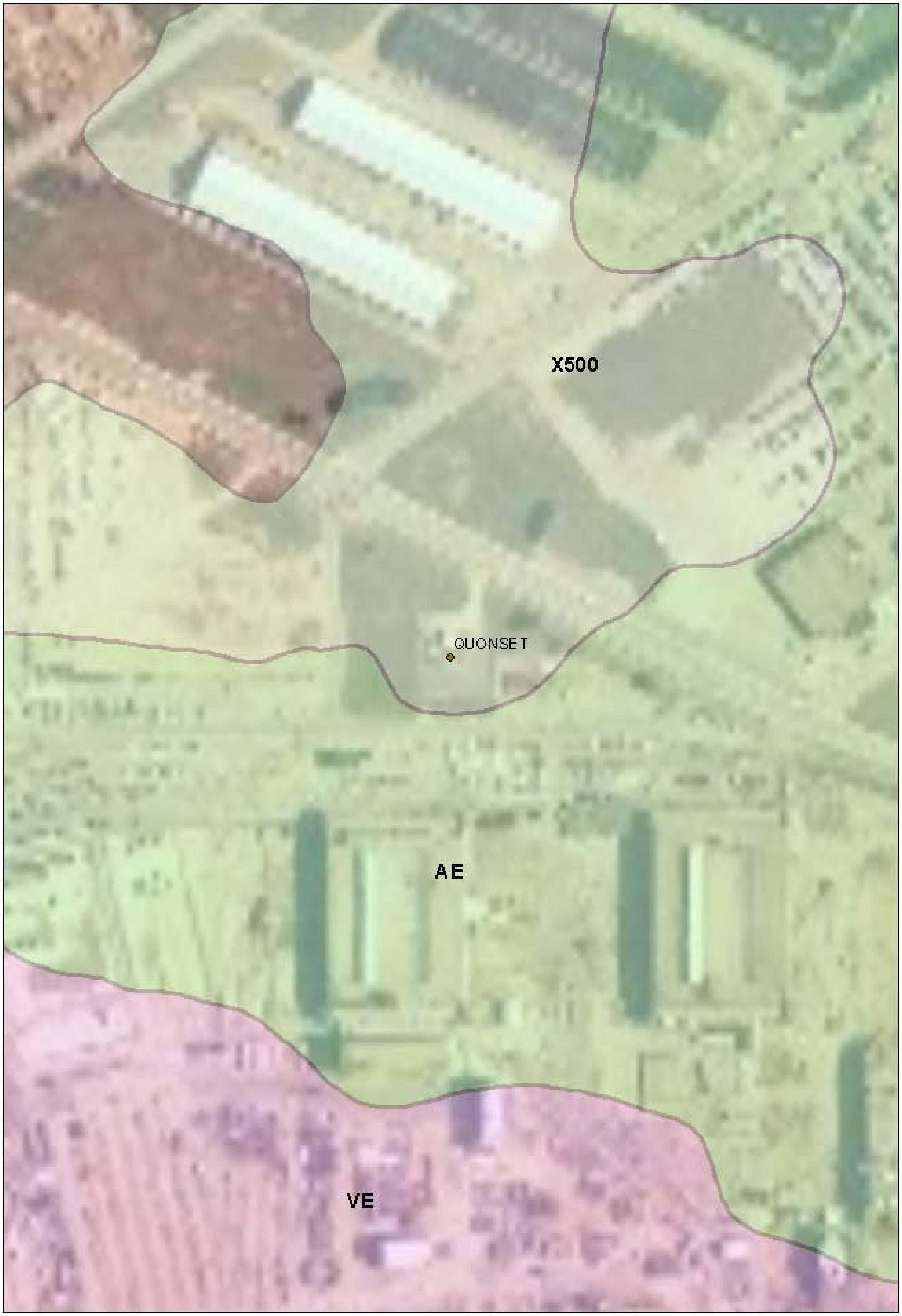
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QUONSET
AE
VE


AE
RIVERSIDE
RIVERSIDE
X500
X500


AE
AE
AE
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VE
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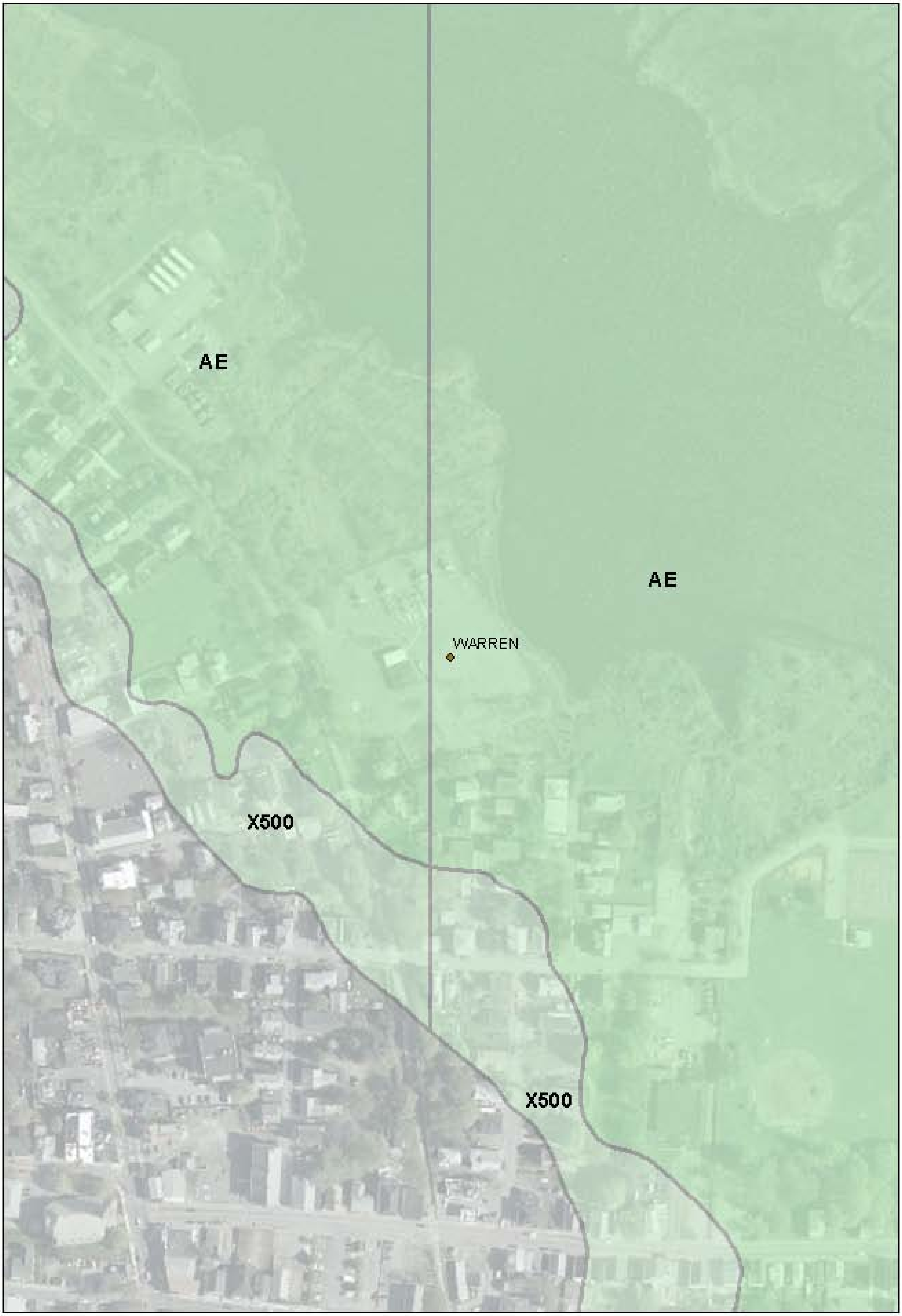
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AE
WARREN
X500
X500


X500
AE
X500
AE
WARWICK MALL
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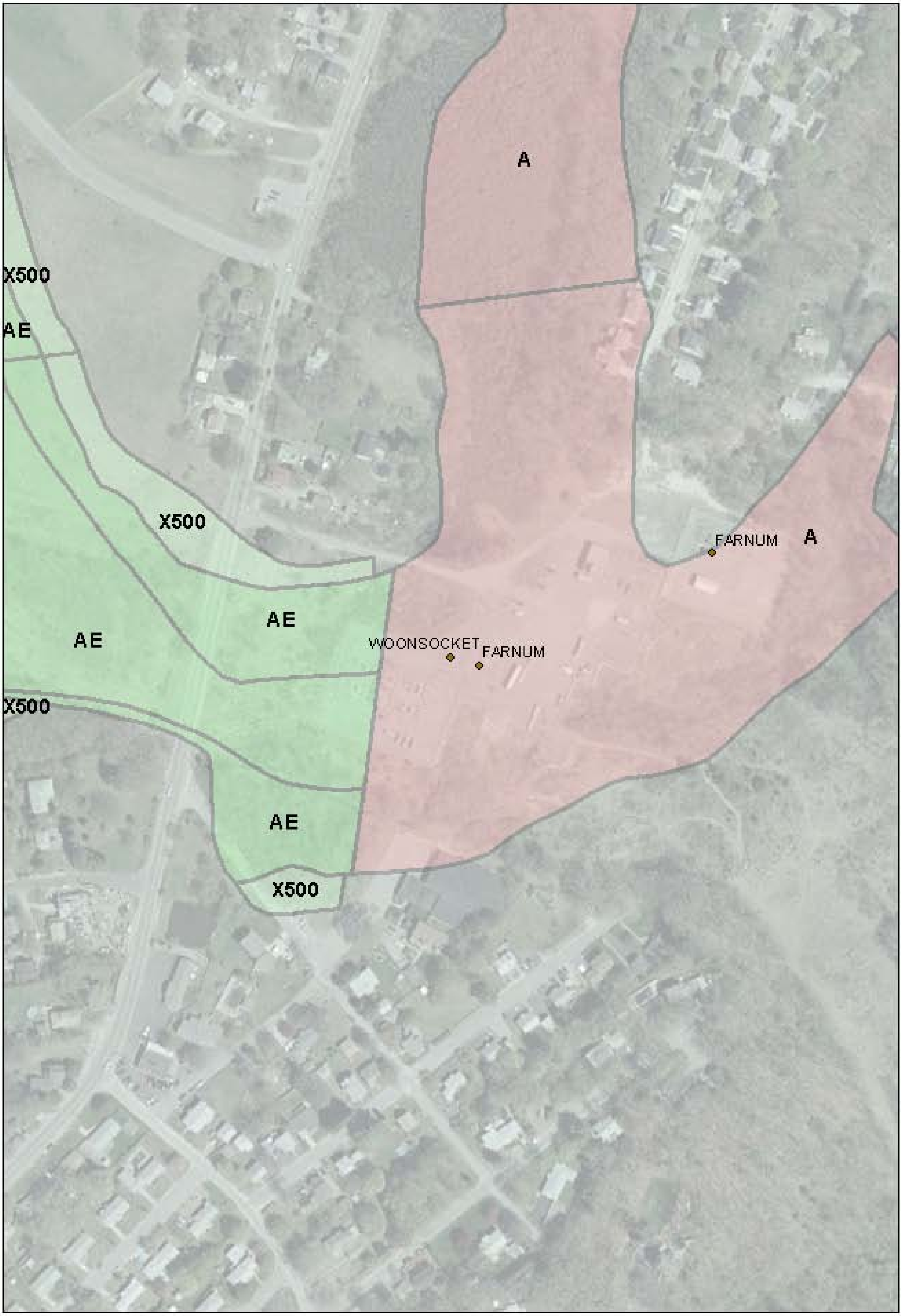
X500


X500
AE
WEST HOWARD
VE
X500
AE


X500
X500
AE
X500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X500
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FARNUM
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WOONSOCKET
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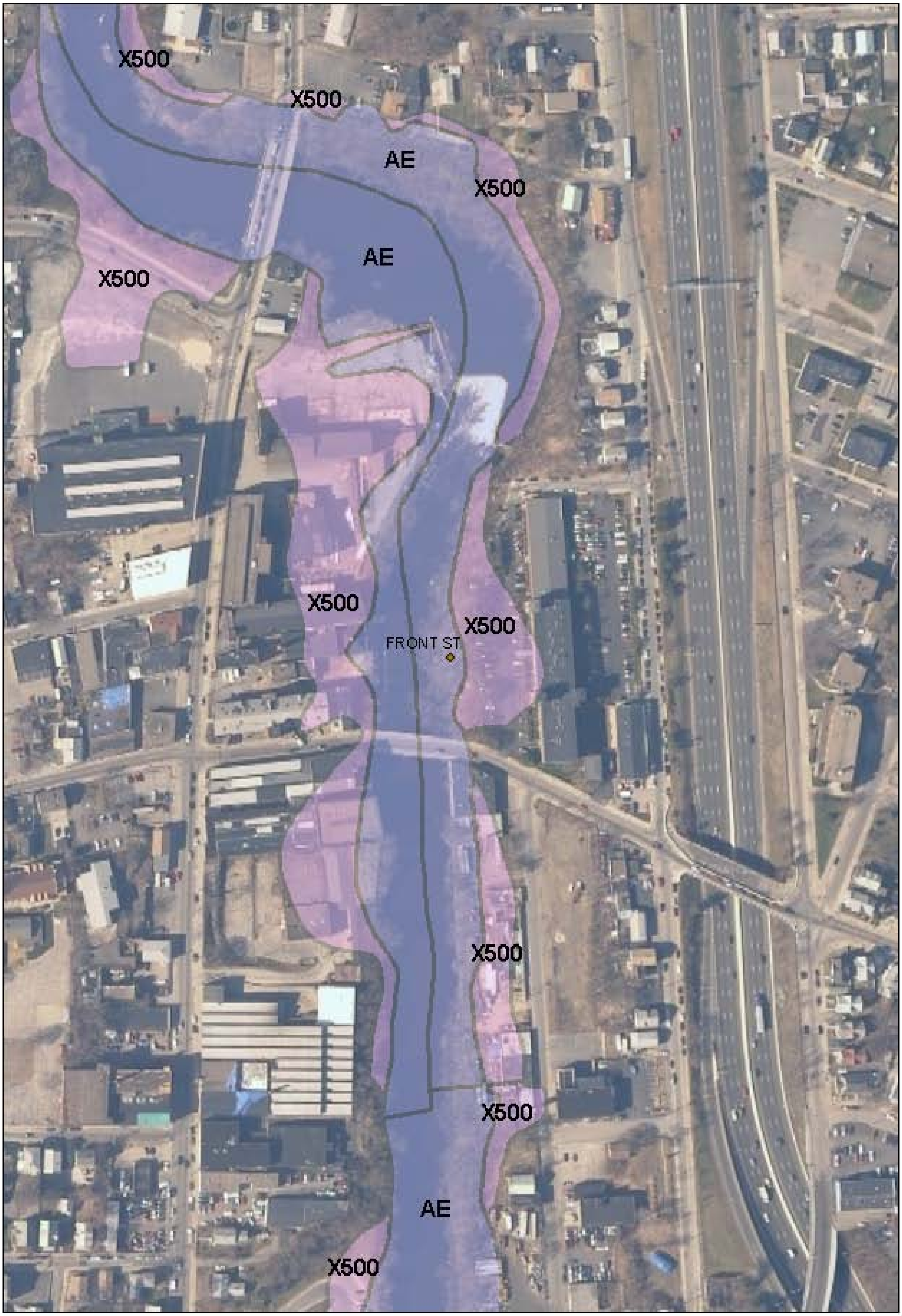
X500
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AE
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AE
X500
X500
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FRONT ST
X500
X500
AE
X500


X500
VE
GATE TWO
X500
AE
X500
X500


AE
HOPE VALLEY
AE
X500


A
HUNT RIVER
A
A


KENT COUNTY
A

location	equip category	equip type	equip class	equipment description	equip position	nominal kv	manufacturer	model	mfg date	install date	street	town	state	amperage current rating	basic impulse level	maximum design voltage
Anthony 64	CB	VCR	15kV	VSA	64F2 VCR	12.4	McGRAW EDISON	VSA	01/01/1972 00:00:00	01/01/1972 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island	560	110	15.5
Anthony 64	TRF	TRF	22.9-13.2kV	22.9-13.2 kV 6.17/7.712 MVA	1 3PH TRF	23	GENERAL ELECTRIC		01/01/1972 00:00:00	01/01/1989 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island		110	
Anthony 64	CB	OCB	25kV	41-23KS500-6B	2230 OCB	23	ITE CIRCUIT BREAKER CO	41-23KS500-6B	01/01/1966 00:00:00	01/01/1968 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island	600	150	25.8
Anthony 64	CB	OCB	25kV	41-23KS500-6B	2232 OCB	23	ITE CIRCUIT BREAKER CO	41-23KS500-6B	01/01/1966 00:00:00	01/01/1968 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island	600	150	25.8
Anthony 64	TRF	TRF	22.9-13.2kV	22.9-13.2 kV 5/6.25 MVA	2 3PH TRF	23	GENERAL ELECTRIC		01/01/1972 00:00:00	12/01/1972 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island		110	
Anthony 64	CB	VSW	25kV	VBM	C1 VSW	23	JOSLYN HI-VOLTAGE CORPORATION	VBM	01/01/1989 00:00:00	10/01/1989 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island	300		34.5
Anthony 64	CB	VCR	15kV	VSA	64F1 VCR	12.4	McGRAW EDISON	VSA	01/01/1972 00:00:00	01/01/1972 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island	560	110	15.5
Anthony 64	CAP	CAP	23kV	36F310G2	C-1 CAP	23	GENERAL ELECTRIC	36F310G2		10/01/1983 00:00:00	643 WASHINGTON ST	COVENTRY	Rhode Island			
Farnum Sub 105	CB	OCB	25kV	23KS500-12B	SPARE BREAKERS	23	ITE CIRCUIT BREAKER CO	23KS500-12B	01/01/1963 00:00:00	01/01/1963 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	1,200	150	25.8
Farnum Sub 105	TRF	TRF		112-24.kV 20/26.6/33.3 MVA	51 BANK TRF	115	WESTINGHOUSE ELECTRIC CORP		11/06/1963 00:00:00	11/06/1963 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island		550	
Farnum Sub 105	CB	VCB	25kV	RMAG 27kV	105K1 VCB	23	ASEA-BROWN BOVERI	RMAG	02/11/2008 00:00:00	08/01/2008 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	1,200	150	27
Front St 24	TRF	LTCs		13.8/2.52 kV 0/0/0 MVA	6249 LTC	13.8	ALLIS - CHALMERS COMPANY	TLF		08/01/1954 00:00:00	1 CARNATION ST	PAWTUCKET	Rhode Island	0		
Front St 24	TRF	LTC		13.8/2.52 kV 0/0/0 MVA	6249 LTC	13.8	ALLIS - CHALMERS COMPANY		08/01/1954 00:00:00	08/01/1954 00:00:00	1 CARNATION ST	PAWTUCKET	Rhode Island		110	
Front St 24	CB	AMCB	5kV	MA75C	24J1 ACB	4.16	ALLIS - CHALMERS COMPANY	MA75C	01/01/1969 00:00:00	01/11/2001 00:00:00	1 CARNATION ST	PAWTUCKET	Rhode Island	1,200	60	4.76
Gate II 38	TRF	LTCs		23 kV 7/0/0 MVA	731 BANK LTC	23	GENERAL ELECTRIC	LRT-200A-2		08/01/1986 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	0		
Gate II 38	TRF	LTCs		69-24 kV 25/33.3/46.6 MVA	381 BANK LTC	69	GENERAL ELECTRIC	LRT-200-2VAC		04/29/1983 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	0		
Gate II 38	CB	OCB	25kV	SDO 30 12.5	3823 OCB	23	SIEMENS ENERGY AND AUTOMATION	SDO 30 12.5	09/01/1984 00:00:00	09/01/1984 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	150	30
Gate II 38	CB	OCB	72kV	CG 48	3863 OCB	69	McGRAW EDISON	CG 48	01/01/1984 00:00:00	01/01/1984 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	350	72.5
Gate II 38	CB	OCB	25kV	SDO 30 12.5	3821 OCB	23	SIEMENS ENERGY AND AUTOMATION	SDO 30 12.5	09/01/1984 00:00:00	08/30/2006 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	150	30
Gate II 38	CB	OCB	25kV	SDO 30 12.5	3822 OCB	23	SIEMENS ENERGY AND AUTOMATION	SDO 30 12.5	09/01/1984 00:00:00	09/01/1984 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	150	30
Gate II 38	CB	OCB	25kV	SDO-30-12.5	3800 OCB	23	SIEMENS ENERGY AND AUTOMATION	SDO-30-12.5	05/01/1984 00:00:00	05/01/1984 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	150	0
Gate II 38	CB	OCB	25kV	SDO 30 12.5	3824 OCB	23	SIEMENS ENERGY AND AUTOMATION	SDO 30 12.5	09/01/1984 00:00:00		1 MEYERCORD ROAD	NEWPORT	Rhode Island	1,200	150	0
Gate II 38	TRF	TRF		23 kV 0.265/0/0 MVA	381 GRND. TRF	23	WESTINGHOUSE ELECTRIC CORP				1 MEYERCORD ROAD	NEWPORT	Rhode Island		0	
Gate II 38	CB	VSW	38kV	VBM	3826 CAP VSW	34.5	JOSLYN HI-VOLTAGE CORPORATION	VBM	01/01/1985 00:00:00	01/01/1985 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island			24.9
Gate II 38	CB	OCR	15kV	VWE	38J2 RCL	14.4	McGRAW EDISON	VWE	11/01/1985 00:00:00	11/09/2000 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island			0.01
Gate II 38	TRF	LTC		23 kV 7/0/0 MVA	731 BANK LTC	23	GENERAL ELECTRIC		08/01/1986 00:00:00	08/01/1986 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island		150	
Gate II 38	TRF	LTC		69-24 kV 25/33.3/46.6 MVA	381 BANK LTC	69	GENERAL ELECTRIC		04/29/1983 00:00:00	04/29/1983 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island		350	
Gate II 38	CB	VSW	38kV	VBM	3827 CAP VSW	34.5	JOSLYN HI-VOLTAGE CORPORATION	VBM			1 MEYERCORD ROAD	NEWPORT	Rhode Island	300		
Gate II 38	CB	OCR	15kV	WE	38J4 CR	12.4	McGRAW EDISON	WE		07/01/2001 00:00:00	1 MEYERCORD ROAD	NEWPORT	Rhode Island	560	110	15.5
Hope Valley 41	TRF	TRF		33.6-12.47 kV 5 MVA	2 TRF	34.5	WESTINGHOUSE ELECTRIC CORP		01/01/1970 00:00:00	03/01/1973 00:00:00	1152 MAIN ST., Rte 3	HOPKINTON	Rhode Island		200	
Hope Valley 41	CB	VCR	15kV	VSA-12	41F1 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	12/01/2009 00:00:00	04/15/2010 00:00:00	1152 MAIN ST., Rte 3	HOPKINTON	Rhode Island	800	110	15.5
Hunt River 40	CB	VSW	38kV	VBM	CAP VSW	34.5	JOSLYN HI-VOLTAGE CORPORATION	VBM	01/02/1991 00:00:00	05/01/1996 00:00:00	5890 POST RD	WARWICK	Rhode Island	400		
Hunt River 40	CB	OCR	15kV	PR	40F1 CR	12.4	WESTINGHOUSE ELECTRIC CORP	PR	01/01/1963 00:00:00	01/01/1963 00:00:00	5890 POST RD	WARWICK	Rhode Island	560	110	15.5
Hunt River 40	TRF	TRF		34.5 kV MVA	2 3PH TRF	34.5	WESTINGHOUSE ELECTRIC CORP		01/01/1970 00:00:00	06/26/2006 00:00:00	5890 POST RD	WARWICK	Rhode Island		200	
Kent County 22	TRF	AUTO	345-115kV	345-115 kV 240/320/400 MVA	3 3PH AUTO	345	McGRAW EDISON		01/01/1971 00:00:00	06/01/1973 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		900	
Kent County 22	TRF	AUTO		345-115-24kV AUTO 268.8/358/448 MVA	T4	345	Hyundai		06/01/2009 00:00:00	12/22/2009 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		1,050	
Kent County 22	CB	GCB	115kV	121PM50-30	8510 GCB	115	ASEA-BROWN BOVERI	121PM50-30	01/01/1995 00:00:00	08/09/2006 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	TRF	TRF	115-34.5kV	115-34.5 kV 30/40/50 MVA	1 3PH TRF	115	WESTINGHOUSE ELECTRIC CORP		01/01/1969 00:00:00	01/01/1969 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		450	
Kent County 22	TRF	TRF	115-34.5kV	115-34.5 kV 33.6/44.8/56 MVA	2 3PH TRF	115	McGRAW EDISON		01/01/1972 00:00:00	06/01/1973 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		350	
Kent County 22	CB	GCB	115kV	TCP-121-50-2000	8589 GCB	115	SIEMENS ENERGY AND AUTOMATION	TCP-121-50-2000	01/01/1995 00:00:00	12/13/1995 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	2,000	550	115
Kent County 22	CB	VCB	38kV	FVR3122020A	7T34 VCB	34.5	S&C ELECTRIC	FVR3122020A	03/20/2003 00:00:00	04/16/2003 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	VCB	15kV	FVR1121120A	22F3 VCB	12.47	S&C ELECTRIC	FVR1121120A	12/01/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Kent County 22	CB	VCB	15kV	FVR1121120A	C4 VCB	12.47	S&C ELECTRIC	FVR1121120A	12/06/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Kent County 22	CB	OCB	38kV	345GS1500	10-12 OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345GS1500	01/01/1972 00:00:00	01/01/1973 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	OCB	115kV	FK-121-43000-1	8910 OCB	115	GENERAL ELECTRIC	FK-121-43000-4	01/01/1972 00:00:00	11/01/1972 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	2,000	550	121
Kent County 22	CB	OCB	38kV	345GS1500	3311 OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345GS1500	01/01/1971 00:00:00	01/01/1971 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	OCB	38kV	345GS1500	3312 OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345GS1500	01/01/1972 00:00:00	01/01/1973 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	OCB	115kV	FK-121-43000-1	9085 OCB	115	GENERAL ELECTRIC	FK-121-43000-4	01/01/1972 00:00:00	11/01/1972 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	2,000	550	121
Kent County 22	CB	OCB	38kV	345GS1500	3309 OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345GS1500	01/01/1972 00:00:00	01/01/1973 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	OCB	38kV	34.5KS1500 12B	3310 OCB	34.5	ITE CIRCUIT BREAKER CO	34.5KS1500 12B	01/01/1969 00:00:00	01/01/1969 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	34.5
Kent County 22	CB	VCB	15kV	FVR1121120A	22F1 VCB	12.47	S&C ELECTRIC	FVR1121120A	12/01/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Kent County 22	TRF	LTCs		115-13.2 kV 12/16/20 MVA	SPARE TRF	115	ALLIS - CHALMERS COMPANY	TLH-21			700 COWESETT RD	WARWICK	Rhode Island	1,300		
Kent County 22	TRF	LTCs		115-34.5 kV LTC 33/44/55 MVA	SPARE TRF	115	WAUKESHA ELECTRIC SYSTEM			07/01/2008 00:00:00	700 COWESETT RD	WARWICK	Rhode Island			
Kent County 22	TRF	LTC	115-34.5kV	115-34.5 kV LTC 33/44/55 MVA	SPARE TRF	115	WAUKESHA ELECTRIC SYSTEM		06/01/2007 00:00:00	07/01/2008 00:00:00	700 COWESETT RD	WARWICK	Rhode Island			
Kent County 22	TRF	LTC	115-13.2kV	115-13.2 kV 12/16/20 MVA	SPARE TRF	115	ALLIS - CHALMERS COMPANY		01/01/1970 00:00:00	01/01/1970 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		450	
Kent County 22	TRF	TRF	115-34.5kV	115-34.5 kV 33/44/55 MVA	7 TRF	115	WAUKESHA ELECTRIC SYSTEM		02/04/2003 00:00:00	05/13/2003 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		350	
Kent County 22	TRF	TRF	115-13.2kV	115-13.2 kV 24/32/40 MVA	6 3PH TRF	115	KUHLMAN ELECTRIC		04/01/2001 00:00:00	05/16/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island		350	
Kent County 22	CB	GCB	345kV	300-SFMT-50HE	4T59 GCB	345	MITSUBISHI	300-SFMT-50HE		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	1,300	362
Kent County 22	CB	GCB	345kV	300-SFMT-50HE	359 GCB	345	MITSUBISHI	300-SFMT-50HE		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	1,300	362
Kent County 22	CB	GCB	345kV	300-SFMT-50HE	4T GCB	345	MITSUBISHI	300-SFMT-50HE		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	1,300	362
Kent County 22	CB	GCB	115kV	121PMI 63-30	4T3T GCB	115	ASEA-BROWN BOVERI	121PMI63-30		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	CB	GCB	115kV	121PMI 63-30	4T20 GCB	115	ASEA-BROWN BOVERI	121PMI63-30		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	CB	GCB	115kV	121PMI 63-30	9020 GCB	115	ASEA-BROWN BOVERI	121PMI63-30		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	CB	GCB	115kV	121PMI 63-30	C-2 GCB	115	ASEA-BROWN BOVERI	121PMI63-30		06/05/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	CB	GCB	115kV	121PMI 63-30	8520 GCB	115	ASEA-BROWN BOVERI	121PMI63-30		05/01/2010 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	3,000	550	121
Kent County 22	CB	VCB	38kV	FVR3122020A	11-09 VCB	34.5	S&C ELECTRIC	FVR3122020A	12/19/2002 00:00:00	04/16/2003 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	200	38
Kent County 22	CB	VCB	15kV	FVR1121120A	C3 VCB	12.47	S&C ELECTRIC	FVR1121120A	12/06/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Kent County 22	CB	VCB	15kV	FVR1121120A	22F4 VCB	12.47	S&C ELECTRIC	FVR1121120A	12/01/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Kent County 22	CB	VCB	15kV	FVR1121120A	22F2 VCB	12.47	S&C ELECTRIC	FVR1121120A	10/10/2001 00:00:00	05/01/2002 00:00:00	700 COWESETT RD	WARWICK	Rhode Island	1,200	110	15.5
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W62 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	02/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	107W83 ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	73T MAIN B ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	01/01/1964 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	2,000	95	15
Pawtucket 1 107 Sub	TRF	LTC		110-14.4 kV 28/37.3/46.66 MVA	74 BANK LTC	115	GENERAL ELECTRIC		09/01/1998 00:00:00	09/01/1998 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island		550	
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W61 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	05/01/1969 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W49 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1973 00:00:00	05/01/2000 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 123	107W2 OCB	13.8	GENERAL ELECTRIC	FH 123	01/01/1942 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	0	0
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 126-1000	731 BT	14.4	GENERAL ELECTRIC	FH 126-1000	01/01/1965 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	2,000	0	0
Pawtucket 1 107 Sub	CB	OCB	115kV	GM-4	738 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-4	02/02/1949 00:00:00	02/02/1949 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	800	550	0
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 126	00S 7200 TRANS OCI	13.8	GENERAL ELECTRIC	FH 126	01/01/1942 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	0	0
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 123	C1 OCB	13.8	GENERAL ELECTRIC	FH 123	01/01/1942 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	0	15
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 123	107W3 OCB	13.8	GENERAL ELECTRIC	FH 123	01/01/1942 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	0	0
Pawtucket 1 107 Sub	CB	OCB	115kV	GM-4	704 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-4	02/02/1949 00:00:00	02/02/1949 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	800	550	0
Pawtucket 1 107 Sub	CB	OCB	115kV	BZO-115-5000-4	702 OCB	115	ALLIS - CHALMERS COMPANY	BZO-115-5000-4	08/23/1971 00:00:00	08/23/1971 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	550	121
Pawtucket 1 107 Sub	CB	OCB	115kV	GM-4	7118 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-4	02/02/1949 00:00:00	02/02/1949 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	800	550	0
Pawtucket 1 107 Sub	CB	OCB	15kV	FH 128	71T MAIN B OCB	13.8	GENERAL ELECTRIC	FH 128	01/01/1942 00:00:00	01/01/1942 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	2,000	0	0
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	107W81 ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	TRF	LTCs		110-14.4 kV 28/37.3/46.66 MVA	73A BANK LTC	115	WESTINGHOUSE ELECTRIC CORP	UTT-B		06/22/1976 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	0		
Pawtucket 1 107 Sub	TRF	LTCs		112-14.4 kV 28/37.3/46.6 MVA	71A BANK LTC	115	OHIO TRANSFORMER	RMV-II-1500-15PREV		01/01/1998 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	1,500		
Pawtucket 1 107 Sub	CHRG	SLDST		ARE-130AC12F	1 CHRG	0	C&D POWER SYSTEMS	ARE-130AC12F			6 THORNTON ST	PAWTUCKET	Rhode Island	18		
Pawtucket 1 107 Sub	CB	GCB	15kV	FG2-15050-12	C3 VCB	13.8	SQUARE "D" ELECTRIC	FG2-15050-12			6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	0	15
Pawtucket 1 107 Sub	TRF	LTCs		110-14.4 kV 28/37.3/46.66 MVA	74 BANK LTC	115	GENERAL ELECTRIC	RMV-II-1500-15PREV		09/01/1998 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	1,500		
Pawtucket 1 107 Sub	CB	LREC	15kV	GV	S-102 LREC	13.8	McGRAW EDISON	GV	01/01/1990 00:00:00	01/01/1990 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island			0.01
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W1 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1973 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	BT13 Breaker	13.8	GENERAL ELECTRIC	VIB-H	01/01/1972 00:00:00	01/01/1972 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W43 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1972 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W50 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1972 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0

Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W51 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1972 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	VCB	15kV	VIB-H	107W53 VCB	13.8	GENERAL ELECTRIC	VIB-H	01/01/1972 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	0
Pawtucket 1 107 Sub	CB	GCB	115kV	100-SFMT-40HE	778 GCB	115	MITSUBISHI	100-SFMT-40HE	06/01/2008 00:00:00	10/22/2009 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	3,000	550	123
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	74T MAIN B ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00	07/01/1971 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	2,000	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	107W80 ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	C2 AMCB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	107W84 ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	107W85 ACB	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W60 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	05/01/1969 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W63 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	10/01/1966 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	150DH-P500	7473 BT	13.8	WESTINGHOUSE ELECTRIC CORP	150DH-P500	07/01/1971 00:00:00	07/01/1971 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island	2,000	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W65 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	01/01/1964 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	CB	AMCB	15kV	15HK	107W66 ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	01/01/1964 00:00:00		6 THORNTON ST	PAWTUCKET	Rhode Island	1,200	95	15
Pawtucket 1 107 Sub	TRF	LTC		110-14.4 kV 28/37.3/46.66 MVA	73A BANK LTC	115	WESTINGHOUSE ELECTRIC CORP		06/22/1976 00:00:00	06/22/1976 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island		350	
Pawtucket 1 107 Sub	TRF	LTC		112-14.4 kV 28/37.3/46.6 MVA	71A BANK LTC	115	OHIO TRANSFORMER		01/01/1998 00:00:00	01/01/1998 00:00:00	6 THORNTON ST	PAWTUCKET	Rhode Island		350	
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	480T ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	TRF	LTC		13.8/4.16 kV 5.6/7/0 MVA	16730-TRAN LTC	13.8	WESTINGHOUSE ELECTRIC CORP		01/01/1967 00:00:00	01/01/1967 00:00:00	34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island		110	
Pawtucket 2 Station 148	TRF	LTCs		13.8/4.16 kV 5.6/7/0 MVA	16731-TRAN LTC	13.8	WESTINGHOUSE ELECTRIC CORP	UTS		01/01/1967 00:00:00	34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	0		
Pawtucket 2 Station 148	TRF	LTC		13.8/4.16 kV 5.6/7/0 MVA	16731-TRAN LTC	13.8	WESTINGHOUSE ELECTRIC CORP		01/01/1967 00:00:00	01/01/1967 00:00:00	34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island		110	
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	481T ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	482T ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	148J1 ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	148J3 ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	148J5 ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	148J7 ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00		34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	CB	AMCB	5kV	AM-4.16-250-7H	HYDRO BKR. ACB	4.16	GENERAL ELECTRIC	AM-4.16-250-7H	06/01/1967 00:00:00	06/01/1967 00:00:00	34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	1,200	60	4.76
Pawtucket 2 Station 148	TRF	LTCs		13.8/4.16 kV 5.6/7/0 MVA	16730-TRAN LTC	13.8	WESTINGHOUSE ELECTRIC CORP	UTS		01/01/1967 00:00:00	34 ROOSEVELT AVE.	PAWTUCKET	Rhode Island	0		
Pawtuxet 31	TRF	TRF		11-2.3 kV 1 MVA	1 BK TRF C	23	ALLIS - CHALMERS COMPANY				70 BELLOWS ST	WARWICK	Rhode Island		150	
Pawtuxet 31	TRF	TRF		11-2.3 kV 1 MVA	1 BK TRF A	23	ALLIS - CHALMERS COMPANY				70 BELLOWS ST	WARWICK	Rhode Island		150	
Pawtuxet 31	TRF	TRF		11-2.3 kV 1 MVA	1 BK TRF B	23	ALLIS - CHALMERS COMPANY				70 BELLOWS ST	WARWICK	Rhode Island		150	
Pawtuxet 31	CB	VCR	5kV	VSA-12	31J1 VCR	4.16	COOPER POWER SYSTEMS		04/01/2009 00:00:00	04/03/2010 00:00:00	70 BELLOWS ST	WARWICK	Rhode Island	800	110	15.5
Pawtuxet 31	CB	VCR		VSA-12	31J2 VCR	4.16	COOPER POWER SYSTEMS		05/01/2009 00:00:00	04/02/2010 00:00:00	70 BELLOWS ST	WARWICK	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	27F1 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	01/01/1991 00:00:00	06/01/1991 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	TRF	LTCs		115-13.2 kV 24/32/40 MVA	2 3PH LTC	115	COOPER POWER SYSTEMS	V2A		06/01/1991 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island			
Pontiac 27	CB	VCR	15kV	VSA	27F3 VCR	12.4	McGRAW EDISON	VSA	01/01/1987 00:00:00	11/01/1988 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	TRF	LTCs		115-13.2 kV 24/32/40 MVA	1 3PH LTC	115	GENERAL ELECTRIC	LRT-200		06/01/1977 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800		
Pontiac 27	CB	VCB	15kV	FVR1121120A	27F5 VCB	12.4	S&C ELECTRIC	FVR1121120A	06/01/2004 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	1,200	110	15.5
Pontiac 27	CB	VCB	15kV	FVR1121120A	27F6 VCB	12.4	SQUARE "D" ELECTRIC	FVR1121120A	03/01/2004 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	1,200	110	15.5
Pontiac 27	CB	VCB	15kV	FVR1121120A	27F6 VCB	12.4	S&C ELECTRIC	FVR1121120A	10/01/2000 00:00:00	02/05/2001 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	1,200	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12		12.4	COOPER POWER SYSTEMS	VSA-12	07/01/2007 00:00:00	06/29/2009 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	27F4 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	05/01/2009 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	27F3 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	04/01/2009 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	3-4 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	05/01/2009 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	1-2 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	05/01/2009 00:00:00	04/01/2010 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA	27F4 VCR	12.4	McGRAW EDISON	VSA	01/01/1987 00:00:00	11/01/1988 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	1-2 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	01/01/1991 00:00:00	02/25/2001 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	CB	VCR	15kV	VSA-12	3-4 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	01/01/1991 00:00:00	02/25/2001 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island	800	110	15.5
Pontiac 27	TRF	LTC	115-13.2kV	115-13.2 kV 24/32/40 MVA	2 3PH LTC	115	COOPER POWER SYSTEMS		01/01/1990 00:00:00	06/01/1991 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island		350	
Pontiac 27	TRF	LTC	115-13.2kV	115-13.2 kV 24/32/40 MVA	1 3PH LTC	115	GENERAL ELECTRIC		01/01/1977 00:00:00	06/01/1977 00:00:00	14 ROSS SIMON DRIVE	CRANSTON	Rhode Island		350	
Quonset 83	TRF	LTCs		34.5-12.470 kV 12/16/20 MVA	1 3PH LTC	34.5	GENERAL ELECTRIC	LRT-200			1135 ROGER WILLIAMS WAY	NORTH KINGSTOWN	Rhode Island	800		
Quonset 83	TRF	LTC		34.5-12.470 kV 12/16/20 MVA	1 3PH LTC	34.5	GENERAL ELECTRIC		01/01/1974 00:00:00	12/01/1974 00:00:00	1135 ROGER WILLIAMS WAY	NORTH KINGSTOWN	Rhode Island		200	
Quonset 83	CB	VCR	15kV	VSA-12	83F1 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	03/01/2003 00:00:00	09/14/2007 00:00:00	1135 ROGER WILLIAMS WAY	NORTH KINGSTOWN	Rhode Island	800	110	15.5
Quonset 83	CB	VCR	15kV	VSA-12	83F3 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	03/01/2003 00:00:00	09/19/2007 00:00:00	1135 ROGER WILLIAMS WAY	NORTH KINGSTOWN	Rhode Island	800	110	15.5
Quonset 83	CB	VCR	15kV	VSA-12	83F2 VCR	12.4	COOPER POWER SYSTEMS	VSA-12	03/01/2003 00:00:00	09/26/2007 00:00:00	1135 ROGER WILLIAMS WAY	NORTH KINGSTOWN	Rhode Island	800	110	15.5
Riverside 8	TRF	LTCs		115-13.8 kV 20/26.7/33.3 MVA	81 TR LTC	115	McGRAW EDISON	550-B		05/10/2006 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,800		
Riverside 8	CB	OCB	115kV	GM-6B	842 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-6B	01/01/1961 00:00:00	01/01/1961 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	550	0
Riverside 8	CB	OCB	115kV	GM-6B	892 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-6B	03/03/1961 00:00:00		1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	550	0
Riverside 8	CB	OCB	115kV	BZO-115-10000-2	898 OCB	115	ALLIS - CHALMERS COMPANY	BZO-115-10000-2	02/02/1969 00:00:00	02/02/1969 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,600	550	121
Riverside 8	CB	OCB	115kV	GM-6B	878 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-6B	02/02/1961 00:00:00	02/02/1961 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	550	0
Riverside 8	CB	OCB	115kV	GM-6B	848 OCB	115	WESTINGHOUSE ELECTRIC CORP	GM-6B	03/03/1961 00:00:00	03/03/1961 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	550	0
Riverside 8	TRF	LTCs		115-14.4 kV 25/33.3/41.6 MVA	82 TR LTC	115	SOUTHWEST ELECTRIC	RMV-1		06/04/2003 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	2,000		
Riverside 8	CAP	CAP	<23kV	58L129RC43	C81 CAP	0	GENERAL ELECTRIC	58L129RC43		01/23/2002 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island			
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W51 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-750-3000-58	82T VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-750-3000-58	01/01/1995 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	3,000	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W60 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W61 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	10/15/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W62 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W63 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	C82 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00		1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W65 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-750-3000-58	812 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-750-3000-58	01/01/1995 00:00:00		1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	3,000	95	15
Riverside 8	CB	VCB	15kV	15-GMI-750-3000-58	81T VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-750-3000-58	01/01/1995 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	3,000	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W50 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	10/02/2001 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	TRF	LTC		115-14.4 kV 25/33.3/41.6 MVA	82 TR LTC	115	SOUTHWEST ELECTRIC		04/28/2003 00:00:00	06/04/2003 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island		450	
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W52 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/02/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W53 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	C81 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00		1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	VCB	15kV	15-GMI-500-1200-37	108W55 VCB	13.8	SIEMENS ENERGY AND AUTOMATION	15-GMI-500-1200-37	10/01/1999 00:00:00	03/06/2000 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	CB	AMCB	15kV	15HK	SPARE ACB	13.8	ITE CIRCUIT BREAKER CO	15HK	12/01/1970 00:00:00	12/01/1970 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island	1,200	95	15
Riverside 8	TRF	LTC	115-13.8kV	115-13.8 kV 20/26.7/33.3 MVA	81 TR LTC	115	McGRAW EDISON		01/01/1973 00:00:00	05/10/2006 00:00:00	1000 FLORENCE DR. EXTENSION	WOONSOCKET	Rhode Island		350	
Sockanosset 24	TRF	TRF	115-23kV	115-23 kV 24/32/40 MVA	2 3PH TRF	115	GENERAL ELECTRIC		01/01/1972 00:00:00	08/01/1974 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island		350	
Sockanosset 24	TRF	TRF	115-23kV	115-23 kV 24/32/40 MVA	1 3PH TRF	115	GENERAL ELECTRIC		01/01/1972 00:00:00	03/01/1977 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island		350	
Sockanosset 24	CAP	CAP	23kV	CEB81463B0314D2	C-1 CAP	23	McGRAW EDISON	CEB81463B0314D2	01/01/1982 00:00:00	06/01/1982 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island			
Sockanosset 24	CAP	CAP	23kV	CEB87221B0221D1	C-2 CAP	23	McGRAW EDISON	CEB87221B0221D1	01/01/1987 00:00:00	01/01/1991 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island		150	
Sockanosset 24	CB	VCB	25kV	RMAG 27kV	2233 VCB	23	ASEA-BROWN BOVERI	RMAG	02/01/2010 00:00:00	04/01/2010 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island	1,200	150	27
Sockanosset 24	CB	VCB	25kV	RMAG 27kV	2235 VCB	23	ASEA-BROWN BOVERI	RMAG	02/01/2010 00:00:00	04/06/2010 00:00:00	19 ELECTRONIC DRIVE	WARWICK	Rhode Island	1,200	150	27
Sockanosset 24	CB	VCB	25kV	RMAG 27kV	33-35 VCB	23	ASEA-BROWN BOVERI	RMAG	02/01/2010 00:00:00	08/18/2010 09:06:33	19 ELECTRONIC DRIVE	WARWICK	Rhode Island	1,200	150	27
Sockanosset 24	CB	VCB	25kV	RMAG 27kV	C12 VCB	23	ASEA-BROWN BOVERI	RMAG	02/01/2010 00:00:00	08/18/2010 09:08:14	19 ELECTRONIC DRIVE	WARWICK	Rhode Island	1,200	150	27
Sockanosset 24	CB	VSW	25kV	VBM	C-1 VSW	23	JOSLYN HI-VOLTAGE CORPORATION	VBM			19 ELECTRONIC DRIVE	WARWICK	Rhode Island	400		34.5
South Aquidneck 122	CB	AMCB	5kV	5HK	122J2 FDR ACB	4.16	ITE CIRCUIT BREAKER CO	5HK	11/01/1982 00:00:00	04/01/2001 00:00:00	1220 AQUIDNECK AVE.	MIDDLETOWN	Rhode Island	1,200	60	4.76
South Aquidneck 122	TRF	LTC		23-4.16 kV 5.6/7 MVA	221 BANK LTC	23	McGRAW EDISON		01/01/1988 00:00:00	01/01/1988 00:00:00	1220 AQUIDNECK AVE.	MIDDLETOWN	Rhode Island		150	
South Aquidneck 122	TRF	LTCs		23-4.16 kV 5.6/7 MVA	221 BANK LTC	23	McGRAW EDISON			01/01/1988 00:00:00	1220 AQUIDNECK AVE.	MIDDLETOWN	Rhode Island	0		
South Aquidneck 122	CB	AMCB	5kV	5HK	122J4 FDR ACB	4.16	ITE CIRCUIT BREAKER CO	5HK	11/01/1982 00:00:00	04/01/2001 00:00:00	1220 AQUIDNECK AVE.	MIDDLETOWN	Rhode Island	1,200	60	4.76
South Aquidneck 122	CB	AMCB	5kV	5HK	122J6 FDR ACB	4.16	ITE CIRCUIT BREAKER CO	5HK	11/01/1982 00:00:00	04/01/2001 00:00:00	1220 AQUIDNECK AVE.	MIDDLETOWN	Rhode Island	1,200	60	4.76
Warren 5	CB	OCB	25kV	345G1500	2295 OCB	23	WESTINGHOUSE ELECTRIC CORP	345G1500	01/01/1966 00:00:00	01/01/1967 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200		38
Warren 5	CB	OCB	25kV	34.5KS1500 12D	2291 OCB	23	ITE CIRCUIT BREAKER CO	34.5KS1500 12D	01/01/1973 00:00:00	03/01/1997 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	200	
Warren 5	CB	OCB	25kV	345G1500	6 TR OCB	23	WESTINGHOUSE ELECTRIC CORP	345G1500	01/01/1966 00:00:00	01/01/1968 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	200	38
Warren 5	CB	OCB	25kV	FKA-38-22000-6Y	5 TR OCB	23	GENERAL ELECTRIC	FKA-38-22000-6Y	01/01/1975 00:00:00	03/01/1976 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	200	38
Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	5F2 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5

Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	5F1 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5
Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	5F4 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5
Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	5F3 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5
Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	1-2 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5
Warren 5	CB	VCB	15kV	PVDB1 15.5-20-2	3-4 VCB	12.4	GENERAL ELECTRIC	PVDB1 15.5-20-2	02/21/1996 00:00:00	10/01/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island	1,200	110	15.5
Warren 5	TRF	TRF	115-13.2kV	115-13.2 kV 24/32/40 MVA	2 TRF	115	KUHLMAN ELECTRIC		04/01/2001 00:00:00	07/30/2001 00:00:00	34 NORBERT STREET	WARREN	Rhode Island		350	
Warren 5	TRF	TRF	115-13.2kV	115-13.2 kV 24/32/40 MVA	1 TRF	115	NORTH AMERICAN TRANSFORMER		09/01/1996 00:00:00	10/17/1996 00:00:00	34 NORBERT STREET	WARREN	Rhode Island		350	
Warren 5	TRF	TRF	115-24kV	115-24 kV 30/40/50 MVA	5 TRF	115	MAGNETEK ELECTRIC INC		01/01/1993 00:00:00	10/01/1994 00:00:00	34 NORBERT STREET	WARREN	Rhode Island		450	
Warren 5	TRF	TRF	115-24kV	115-24 kV 30/40/50 MVA	6 TRF	115	MAGNETEK ELECTRIC INC		08/16/1993 00:00:00	03/01/1994 00:00:00	34 NORBERT STREET	WARREN	Rhode Island		450	
Warwick Mall 28	CB	VCR	15kV	VIR-15.5-10000-3	28F1 VCR	12.4	GENERAL ELECTRIC	VIR-15.5-10000-3	01/01/1970 00:00:00	01/01/1970 00:00:00	400 BALD HILL RD	WARWICK	Rhode Island	560	110	15.5
Warwick Mall 28	CB	VCR	15kV	VIR-15.5-10000-3	28F2 VCR	12.4	GENERAL ELECTRIC	VIR-15.5-10000-3	01/01/1970 00:00:00	01/01/1970 00:00:00	400 BALD HILL RD	WARWICK	Rhode Island	560	110	15.5
Warwick Mall 28	TRF	TRF	22.9-13.2kV	22.9-13.2 kV 5/6.25 MVA	2 3PH TRF	23	FEDERAL PACIFIC		01/01/1969 00:00:00	01/01/1970 00:00:00	400 BALD HILL RD	WARWICK	Rhode Island		150	
Warwick Mall 28	TRF	TRF	22.9-13.2kV	22.9-13.2 kV 5/6.25 MVA	1 TRF	23	GENERAL ELECTRIC		01/01/1979 00:00:00	06/01/1994 00:00:00	400 BALD HILL RD	WARWICK	Rhode Island			
West Howard 154	CB	VCB	5kV	5-MSV-250	542T (BANK VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	09/01/1985 00:00:00	09/01/1985 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	2,000	60	4.76
West Howard 154	TRF	LTCs		22.9-4.16 kV 9.375/10.5/0 MVA	541 BANK LTC	23	McGRAW EDISON			01/01/1984 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	0		
West Howard 154	TRF	LTCs		22.9-4.16 kV 9.375/10.5/0 MVA	542 BANK LTC	23	McGRAW EDISON	55OLS		01/01/1986 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,267		
West Howard 154	TRF	LTC		22.9-4.16 kV 9.375/10.5/0 MVA	542 BANK LTC	23	McGRAW EDISON		01/01/1986 00:00:00	01/01/1986 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island		150	
West Howard 154	TRF	LTC		22.9-4.16 kV 9.375/10.5/0 MVA	541 BANK LTC	23	McGRAW EDISON		01/01/1984 00:00:00	01/01/1984 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island		150	
West Howard 154	CHRG	SLDST		CR24A3	SPARE CHRG	0	OTHER	CR24A3			447 THAMES ST.	NEWPORT	Rhode Island			
West Howard 154	CB	VCB	5kV	5-MSV-250	154J16 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	09/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	15-MSV-250	154J18 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	15-MSV-250	09/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	15-MSV-250	5400 (BUS VCB	4.16	SIEMENS ENERGY AND AUTOMATION	15-MSV-250	02/01/1985 00:00:00	02/01/1985 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	15-MSV-250	154J12 FDR VCB OO:	4.16	SIEMENS ENERGY AND AUTOMATION	15-MSV-250	09/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	15-MSV-250	154J14 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	15-MSV-250	09/01/1994 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	5-MSV-250	154J8 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	02/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	5-MSV-250	541T (BANK VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	02/01/1985 00:00:00	02/01/1985 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	2,000	60	4.76
West Howard 154	CB	VCB	5kV	5-MSV-250	154J2 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	02/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	2,000	60	4.76
West Howard 154	CB	VCB	5kV	5-MSV-250	154J4 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	02/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	5kV	5-MSV-250	154J6 FDR VCB	4.16	SIEMENS ENERGY AND AUTOMATION	5-MSV-250	02/01/1985 00:00:00	04/01/2001 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	60	4.76
West Howard 154	CB	VCB	38kV	V23	5421 VCB	34.5	WESTINGHOUSE ELECTRIC CORP	V23	06/01/1987 00:00:00	06/01/1987 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	150	38
West Howard 154	CB	VCB	38kV	V23	5422 VCB	34.5	WESTINGHOUSE ELECTRIC CORP	V23	06/01/1987 00:00:00	06/01/1987 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	150	38
West Howard 154	CB	VCB	38kV	V23	5423 VCB	34.5	WESTINGHOUSE ELECTRIC CORP	V23	06/01/1987 00:00:00	06/01/1987 00:00:00	447 THAMES ST.	NEWPORT	Rhode Island	1,200	150	38
Westerly 16	CB	OCB	5kV	SD4T	3TR 4 OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	1,200		7.5
Westerly 16	CB	OCB	38kV	345G1500	3 TR OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345G1500	01/01/1969 00:00:00	03/11/1996 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	1,200	200	38
Westerly 16	CB	OCB	5kV	SD4T	SS OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	600		15
Westerly 16	CB	OCB	5kV	SD4T	1TR 4 OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	600		15
Westerly 16	CB	OCB	38kV	345G1500	1 TR OCB	34.5	WESTINGHOUSE ELECTRIC CORP	345G1500	01/01/1996 00:00:00	02/01/1996 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	1,200	200	38
Westerly 16	CB	OCB	5kV	SD4T	16J3 OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	600		15
Westerly 16	CB	OCB	5kV	SD4T	16J2 OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	600		15
Westerly 16	CB	OCB	5kV	SD4T	16J1 OCB	4.16	GENERAL ELECTRIC	SD4T	01/01/1929 00:00:00		69 CANAL ST	WESTERLY	Rhode Island	600		15
Westerly 16	TRF	TRF		34.5-2.4 kV 5 MVA	1 3PH TRF	34.5	ALLIS - CHALMERS COMPANY				69 CANAL ST	WESTERLY	Rhode Island		200	
Westerly 16	TRF	TRF		34.5-2.4 kV 5 MVA	3 3PH TRF	34.5	ALLIS - CHALMERS COMPANY				69 CANAL ST	WESTERLY	Rhode Island		200	
Westerly 16	CB	VCR	15kV	VSA-12	16F2 VCR	15.5	COOPER POWER SYSTEMS	VSA-12	05/01/2009 00:00:00	05/06/2010 10:08:27	69 CANAL ST	WESTERLY	Rhode Island	800	110	15.5
Westerly 16	TRF	LTC		34.5-12.47 kV 12/16/20 MVA	2 3PH LTC	34.5	GENERAL ELECTRIC		01/01/1974 00:00:00	01/01/1991 00:00:00	69 CANAL ST	WESTERLY	Rhode Island		200	
Westerly 16	CAP	CAP	<23kV	CEB96006B0118C1	C1 CAP	12.47	COOPER POWER SYSTEMS	CEB96006B0118C1	01/01/1996 00:00:00	02/01/1997 00:00:00	69 CANAL ST	WESTERLY	Rhode Island		150	
Westerly 16	CAP	CAP	<23kV	CEB96006B0118C1	C-2 CAP	12.47	COOPER POWER SYSTEMS	CEB96006B0118C1	01/01/1996 00:00:00	02/01/1997 00:00:00	69 CANAL ST	WESTERLY	Rhode Island		150	
Westerly 16	CB	GCB	38kV	70-SFMT-40LE-A	4T-34 GCB	34.5	MITSUBISHI		01/01/2010 00:00:00	04/30/2010 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	2,000	550	72.5
Westerly 16	CB	VCR	15kV	VSA-12	16F4 VCR	12.47	COOPER POWER SYSTEMS	VSA-12 800A	05/01/2009 00:00:00	05/06/2010 10:15:26	69 CANAL ST	WESTERLY	Rhode Island	800	110	15.5
Westerly 16	CB	VSW	15kV	VBM	C1 VSW	12.47	JOSLYN HI-VOLTAGE CORPORATION	VBM	01/01/1996 00:00:00	02/19/1997 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	400	150	15.5
Westerly 16	CB	VSW	15kV	VBM	C2 VSW	12.47	JOSLYN HI-VOLTAGE CORPORATION	VBM	01/01/1996 00:00:00	02/01/1997 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	400	150	15.5
Westerly 16	TRF	LTCs		34.5-12.47 kV 12/16/20 MVA	4 3PH LTC	34.5	GENERAL ELECTRIC	LRT-200		01/01/1985 00:00:00	69 CANAL ST	WESTERLY	Rhode Island	800		
Westerly 16	TRF	LTCs		34.5-12.47 kV 12/16/20 MVA	2 3PH LTC	34.5	GENERAL ELECTRIC	LRT-200			69 CANAL ST	WESTERLY	Rhode Island	800		
Westerly 16	TRF	LTC		34.5-12.47 kV 12/16/20 MVA	4 3PH LTC	34.5	GENERAL ELECTRIC		01/01/1974 00:00:00	01/01/1985 00:00:00	69 CANAL ST	WESTERLY	Rhode Island		200	
Woonsocket 26	CB	OCB	115kV	FK-121-43000-5	4348 OCB	115	GENERAL ELECTRIC	FK-121-43000-5	01/01/1973 00:00:00	01/01/1973 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	1,600	550	121
Woonsocket 26	CB	GCB	115kV	121PM40-30	4471 GCB	115	ASEA-BROWN BOVERI	121PM40-30	04/05/2001 00:00:00	04/16/2002 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	3,000	550	121
Woonsocket 26	CB	GCB	115kV	121PM40-30	4372 GCB	115	ASEA-BROWN BOVERI	121PM40-30	08/27/2001 00:00:00	02/25/2002 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	3,000	550	121
Woonsocket 26	CB	GCB	115kV	121PM40-30	4472 GCB	115	ASEA-BROWN BOVERI	121PM40-30	08/27/2001 00:00:00	03/19/2002 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	3,000	550	121
Woonsocket 26	CB	GCB	115kV	121PM40-30	71-48 GCB	115	ASEA-BROWN BOVERI	121PM40-30	08/27/2001 00:00:00	04/10/2002 00:00:00	76 GREENVILLE RD.	NORTH SMITHFIELD	Rhode Island	3,000	550	121

Rhode Island Division Data Request 2-14 Attachment #3

The Narragansett Electric Company

		System Voltage (kV)		Maximum	Rating (MVA)		Summer 2010 Projection (MVA)	
							2010	
Substation	Tranf. ID.	From	To	Nameplate Rating	SN	SE	MVA	% SN
ANTHONY 64	1	23	12.47	1-6.15/7.687	7.8	8.1	7.3	94%
ANTHONY 64	2	23	12.47	1-5/6.25	7.8	8.1	6.4	82%
FARNUM #105	T1	115	23	37.3	37.30	37.30	3.2	9%
GATE 2	381	69	23	46.7	54.2	63.7	20.2	37%
GATE 2	731	23	4.16	7.0	8.1	8.7	4.3	53%
HOPE VALLEY 41	1	34.5	12.47	5.0	7.3	9.3	5.4	75%
HUNT RIVER	2	34.5	12.47	9.38	11.2	12.7	4.7	42%
KENT COUNTY 22	1*	115	34.5	50	57.3	67.6	31.0	54%
KENT COUNTY 22	2*	115	34.5	50	66.3	69.9	32.1	48%
KENT COUNTY 22	6	115	12.47	40	50.7	58.9	34.8	69%
KENT COUNTY 22	7*	115	34.5	56	57.3	68.8	32.3	56%
PAWTUCKET No.1 #107	T71	115	13.8	25.0/33.3/41.7/46.7	48.00	48.00	29.5	61%
PAWTUCKET No.1 #108	T73A	115	13.8	28.0/37.33/46.67	48.00	48.00	42.0	87%
PAWTUCKET No.1 #109	T74	115	13.8	28.0/37.33/46.67	48.00	48.00	28.7	60%
PAWTUCKET No.2 #148	T1	13.8	4.16	5/6.25	7.60	9.36	2.4	0%
PAWTUCKET No.2 #148	T2	13.8	4.16	5/6.25	7.60	9.36	2.2	0%
PAWTUXET 31	1	23	4.16	3-1.0	4.3	5.1	3.6	84%
PONTIAC 27	1	115	12.47	1-24/32/40	50.7	53.3	17.5	35%
PONTIAC 27	2	115	12.47	1-24/32/40	46.5	51.9	22.3	48%
QUONSET 83	1	34.5	12.47	20.0	25.6	26.7	13.82	54%
RIVERSIDE #108	T82	115	13.8	41.67	49.62	58.74	41.1	83%
RIVERSIDE #108	T81	115	13.8	33.3	41.83	45.23	27.0	64%
SOCKANOSSET 24	1	115	23	24/32/40	47	55	12	25%
SOCKANOSSET 24	2	115	23	24/32/40	47	55	16	31%
SOUTH AQUIDNECK	221	23	4.16	7.0	7.9	9.6	3.9	49%
WARREN 5	1	115	12.47	1-24/32/40	48.3	53.4	15.0	31%
WARREN 5	2	115	12.47	1-24/32/40	50.6	59.6	16.5	33%
WARREN 5	5	115	23	50.0	61.0	65.1	7.3	12%
WARREN 5	6	115	23	50.0	59.6	64.2	21.9	37%
WARWICK MALL 28	1	23	12.47	1-5/6.25	8.8	8.9	3.0	34%
WARWICK MALL 28	2	23	12.47	1-5/6.25	8.7	9.1	2.0	23%
WEST HOWARD	541	23	4.16	10.5	12.6	14.8	5.0	40%
WEST HOWARD	542	23	4.16	10.5	13.1	13.6	5.5	42%
WESTERLY 16	2*	34.5	12.47	20.0	25.6	26.7	19.7	77%
WESTERLY 16	4*	34.5	12.47	20.0	25.6	26.7	14.9	58%
WOONSOCKET				None				

Division Data Request 2-15

Request:

Why are the 2007-2008 and 2009-2010 Actual Expenditures in the ISP Plan document different than those filed in the annual reports to the RIDPUC on reliability?

Response:

Differences occurred in totals between the ISP Plan document and the RIDPUC Reliability report as the RIDPUC Reliability report is prepared using a Management Reporting spreadsheet, while the ISP Plan document used total Finance spending figures. In certain cases, as will be shown below, Management Reporting documents may include/exclude certain categories of spending whereas Finance amounts would include total spend which agrees to the total Electric Distribution Capital Spending Financial Statements.

The small difference between the reports for FY 2007/2008 was related to the Capital Allocation Pool Project (CAP049), which was not included in the Management Report (by choice), partially offset by a small capital adjustment on the general ledger which also did not affect project spending in the Management Report as shown in the reconciliation below:

	FY2007/08 Capital (000's)
TOTAL PER RIDPUC RELIABILITY REPORT	**58,179**
TOTAL PER ISP PLAN DOCUMENT	**58,032**
DIFFERENCE	147
Non-Operations Accounting Entry	134
CAP Allocation project excluded from Management Report	(285)
Other	4
Unexplained difference	-

Division Data Request 2-15 (continued)

The difference between the reports for FY 2009/2010 was comprised of two primary items:

1) Write-offs of capital spending within work orders, which would not be progressing as a capital project, must be periodically written off to expense. The Management Report excluded these reductions to capital since they were not included in the normal capital spending of the construction projects which were moving forward.

2) The Management Report missed a late year-end accounting accrual adjustment of $801,000 due to the timing of running reports for spending. This type of item is usually included in the management reports and was only missed due to timing.

The reconciliation between the ISP Plan document and the RIDPUC Reliability report for Fiscal Year 2009/2010 is shown below:

	FY10 Capital (000's)
TOTAL PER RIDPUC RELIABILITY REPORT	**60,952**
TOTAL PER ISP PLAN DOCUMENT	**58,272**
DIFFERENCE	2,680
Writeoffs of capital spending within work orders which will not progress. Excluded from Management Report Spending for FY10.	(1,934)
Late March Capital Accrual Adjustment not contained in Management Reports.	(801)
Other	55
Unexplained difference	-

Regarding differences on a category by category basis, the ISP Plan was prepared using current reporting categories of project spending regardless of the year in which it occurred. The RIDPUC Reliability Reports are a snapshot of categories at that point in time, which may differ slightly from the current categories. This is due to the fact that new categories may be added over time to help clarify spending (e.g. Feeder Hardening) or a project's spend may have been changed over time to reflect more up-to-date information (e.g. cutouts).

Prepared by or under the supervision of: Chris Brouillard

National Grid's Proposed FY 2012

Electric

Draft Infrastructure, Safety, and Reliability Plan

National Grid Responses
to
Division's Third Set of Data Requests

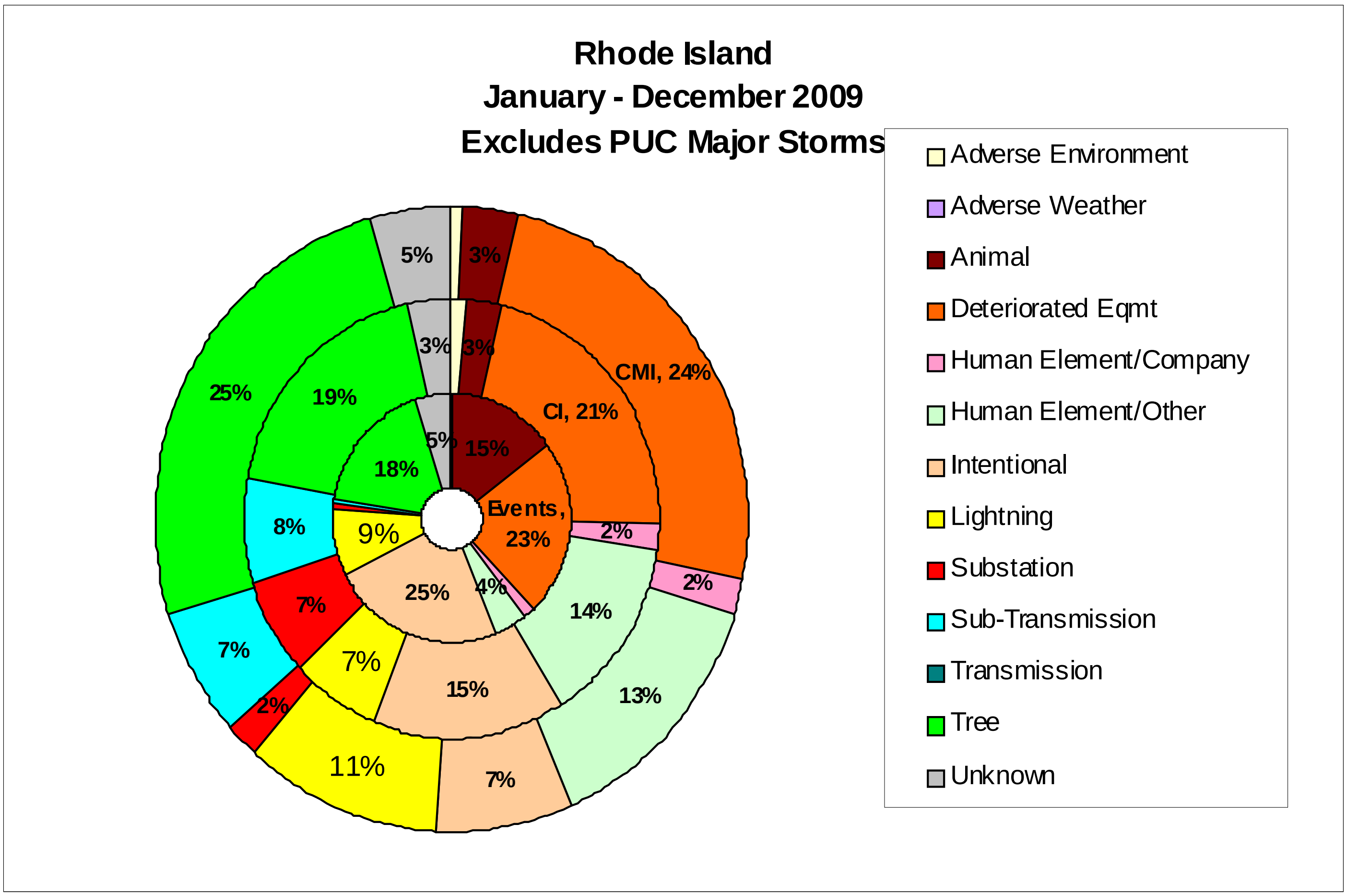
Issued by the Division on
October 20, 2010

Division 3-1

Request:

Page 47, Chart 1 of the ISR Plan includes Major Storm Events. Please provide data excluding major storms in the same format.

Response:



Prepared by or under the supervision of: Jon Gonynor

Division 3-2

Request:

Please provide the Vegetation Management budget and actual expenses from 2003-2006.

Response:

Please see the table below for Vegetation Management budget and expenses from fiscal year 2003 through 2006. Please note that budget data for fiscal years 2003 and 2004 is unavailable as the Company operated under a different system which is unavailable today.

Year	Actuals	Budget
FY 2003	$3,575,283	N/A*
FY 2004	$3,300,059	N/A*
FY 2005	$3,015,186	$4,593,612
FY 2006	$3,937,950	$4,347,212

* As noted above, budget data is unavailable for FY 2003 and FY 2004 due to change in systems.

Prepared by or under the supervision of: Sara Sankowich

Division 3-3

Request:

Please provide the 5 year projection for Vegetation Management expenses.

Response:

Please see the following chart for the 5 year projection for Vegetation Management expenses. Please note that the first two years are recovery years and include a $1.3M increase and a $0.7M increase from base costs respectively. After the recovery period, costs return to base levels in FY14. From FY14 forward the only projected increases are for 3% inflation.

Business Plan FY 2012 - FY 2016

Distribution Veg Mgmt REP View - Rhode Island

$'000	FY 2012 Recovery Forecast	FY 2013 Recovery Forecast	Notes on Recovery Forecasts	FY 2014 Forecast	FY 2015 Forecast	FY 2016 Forecast
OPEX - VM						
Cycle Trimming	5,902	6,079	472 mi deferred at cost of $1,402 in FY11 - estimated cost of $750K in FY12 and $773 in FY13	5,465	5,629	5,798
Hazard Tree	1,811	1,256	$592k increase in FY12 only, for deferred hazard tree work in FY11	1,294	1,332	1,372
Sub-T (on-road portion only)	91	94		96	99	102
Police/Flagman Detail	585	603		621	640	659
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	1,261	1,299		1,338	1,378	1,420
OPEX - VM Total	**9,650**	**9,330**	$1.3M increase FY12, $773K increase FY13 to recover from budget reduction in FY11	**8,814**	**9,078**	**9,351**

Prepared by or under the supervision of: Sara Sankowich

Division 3-4

Request:

Page 51 of the ISR Plan refers to "pruning specifications in 2007 to create additional clearance between conductors and trees or tree limbs." Please provide the clearance specifications before 2007 and after.

Response:

Please see Attachment 1, *NE Lump Sum Distribution Line Clearance Specifications* for the New England specifications prior to 2007, and Attachment 2, *NGRID-NE Dist Spec 12 18 07* for the New England Specifications since 2007.

Some of the changes between the two specifications were to enhance clarity, to ensure current clearances are maintained, and improve clearance overhead. For example, the new specifications include a definitions section for added clarity on Mature Tree Line and Maintenance Corridor clearance. Section 4.4 of the 2007 specification document includes new wording on removing all dead or damaged overhead limbs capable of falling onto the conductors as part of the bid and section 4.5 includes a new policy that increased clearance on pine species for ice and snow loading protection.

Prepared by or under the supervision of: Sara Sankowich

nationalgrid

Appendix "A"

NATIONAL GRID NEW ENGLAND DISTRIBUTION LINE CLEARANCE SPECIFICATIONS

Program Objective: The goals and objectives of the Distribution Line Clearance program are to provide safe, reliable, electric service through a cost effective, integrated vegetation management program. These specifications are designed to address:

- the minimum clearance requirements necessary to sustain safe, reliable electric service while striving to satisfy the concerns of sensitive customers,
- and the routine clearance requirements necessary to maintain the greater clearance conditions which have been achieved in previous trim cycles.

I. Scope of Specification

1.1 These specifications cover the clearing, pruning and removal of vegetation along overhead electric distribution lines.

II. Intent

The intent of this specification is to:

2.1 Define the minimum clearance between the conductors and trees acceptable to the Corporation for the purpose of maintaining and improving reliable overhead electric distribution line service.

III. Scope of Work

3.1 Within cities, villages, residential areas, and the yard areas (maintained) of rural homes and seasonal camps, the lines shall be pruned to provide a minimum of ten (10) feet of overhead clearance, six (6) feet of side clearance and ten (10) feet of clearance below the primaries. These clearances apply to all 3 phase construction types. Likewise, these clearance standards (10'-6'-10') will also apply to all single phase construction types. Express Cable shall be pruned to provide six (6) feet of circular clearance around the cable.

The main trunk of the tree, together with major limbs that are structurally sound and healthy, may be left growing within these distances when removal would adversely affect the health, vigor and aesthetics of the street or residential tree. All branches shall be pruned in accordance with recognized, arboricultural pruning standards (ANSI A300), and pruned so as to grow away from the overhead conductors to the extent practical. This may result in clearances beyond the dimensions noted above. In addition, where greater clearances have been achieved in previous pruning operations, the work shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearances.

3.2 All slash from pruning in residential areas (maintained) shall be disposed of through chipping. Large diameter wood, that is too big to chip, may remain on site provided it is cut to easily handled lengths, and piled neatly. Small debris shall be raked up and removed so as to leave the property in a condition equal to the start of work.

3.3 When pruning the 3 phase primary beyond or outside the yard area (un-maintained) of a residence, the lines shall be pruned so as to provide a minimum of fifteen (15) feet of overhead clearance and six (6) feet of side clearance. All types of single phase construction shall be pruned so as to provide a minimum of ten (10) feet of overhead clearance and six (6) feet of side clearance. The Contractor shall ground cut all undesirable tree and shrub species which have the capability of interfering with the conductor (capable species), for a minimum distance of ten (10) feet either side of centerline. Along individual spans that have been previously maintained using National Grid's eight (8) foot targeted ground cutting specification (trimming or removal) the same approach shall be utilized. Otherwise, stumps shall be cut flat and as close to grade as possible. Regardless of the ground cutting method used, trees shall be removed back to the tree line, including the removal of any stems back inside the tree line, which are growing out or leaning into the right-of-way.

Again, where greater clearances have been achieved in previous cycles, the pruning and ground cutting shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

3.4 For un-maintained areas, all slash along the highway or near residences shall be disposed of by chipping or mowing/mulching. Where practical, chips may be blown back onto the site without creating large chip piles. On off-road, un-maintained sites, slash and wood shall be mowed/mulched and/or neatly windrowed to the edge of the right-of-way and cut to lie close to the ground, away from sensitive locations. Whole trees or large branches dropped along or into a wooded area shall be limbed or cut to lie as flat as possible. No debris shall be left so as to block or significantly alter any drainage or water resource.

3.5 In a continued effort to minimize outages from above the conductor, National Grid has begun to implement ground to sky clearances on mainly rural, 3 phase segments of higher voltage - wye circuits. This practice may be pre-identified as areas or individual trees on the bid copy of the feeder maps or identified in the field by the Arborist/Forester or his designee at any time during the pruning project. This work will be billed hourly.

3.6 All dead or damaged overhead limbs, branches or leads that are capable of falling onto overhead primary wires from above or along side the right-of-way and potentially causing a tree outage shall be removed at the time of pruning and included in the lump sum price.

3.7 Additionally, when pruning the primary outside of residential yard areas, the lump sum price shall include the removal of any tree up to and including an eight (8) inch D.B.H., that is located within the right-of-way or located along the edge of the right-of-way.

3.8 Other than work required in the above section, the removal of any hazard tree over 8 inches D.B.H. within the right-of-way shall be considered a hazard tree removal, and is outside the lump sum price.

3.9 The contractor shall provide a unit price per tree by diameter class for the removal of potential hazard trees. National Grid reserves the right to award**,** in whole or in part, the removal of hazard trees on any circuit using the contractor's unit price for removals, their current hourly rates, or to another contractor.

3.10 While pruning the circuit, the contractor's personnel shall perform a visual inspection of each tree to identify potential defects and determine the potential risk for the tree to cause an outage over the length of the trim cycle. The crew shall work closely the National Grid Arborist/Forester to determine potential hazard trees, preparing a list of trees in accordance with National Grid's Hazard Tree Reporting Form. The completed lists of hazard trees shall be regularly provided to the supervising Arborist/Forester, before the completion of the feeder. If the hazard poses a high potential to cause an outage the Contractor shall immediately notify the Arborist.

3.11 Hazard trees that are approved for removal through unit price may be removed at the time of pruning. Removals done hourly will generally be cut following the completion of trim work on a feeder. Exceptions to this procedure may be approved to enable the removal of trees that pose an imminent risk or to authorize hazard tree removals in off road areas where the skidder bucket or climbing crew is already available and on site.

3.12 When the crew completes the removals at the time of pruning, they shall compile a list of hazard trees that were removed by road, pole, species and diameter class in either a rural or urban setting. This list shall be submitted to the supervising arborist/forester on a weekly basis utilizing National Grid's Unit Price Hazard Tree Reporting form provided by the arborist/forester. Once approved, the contractor shall submit the unit price removals on the same invoice as the unit price trimming for that feeder. Where National Grid cannot verify tree diameter, we will deduct 2 inches from the average stump diameter to establish the payable "D.B.H." class.

3.13 All secondary lines shall be pruned to provide a minimum of eighteen (18) inches of clearance.

3.14 At the time of the bid meeting or with the distribution of bid materials the National Grid Arborist or his designated representative will determine and communicate to the bidders whether all services drops are to be pruned on a feeder or if the 2” rule will prevail.

Where the 2” rule is specified the following will apply: Trees shall be pruned to provide 18 inches of clearance for the entire service wire whenever any 2 inch or larger limb is resting or rubbing on the service. In these cases the entire service will be pruned, not just the 2”+ limb.

Otherwise, all service wires shall be pruned to provide 18 inches of clearance, unless the property owner requests that the service not be pruned. When the owner requests that a service not be pruned, the contractor shall provide the customer’s names and address to the Company. All service drops will be pruned to provide a minimum of eighteen (18) inches of clearance.

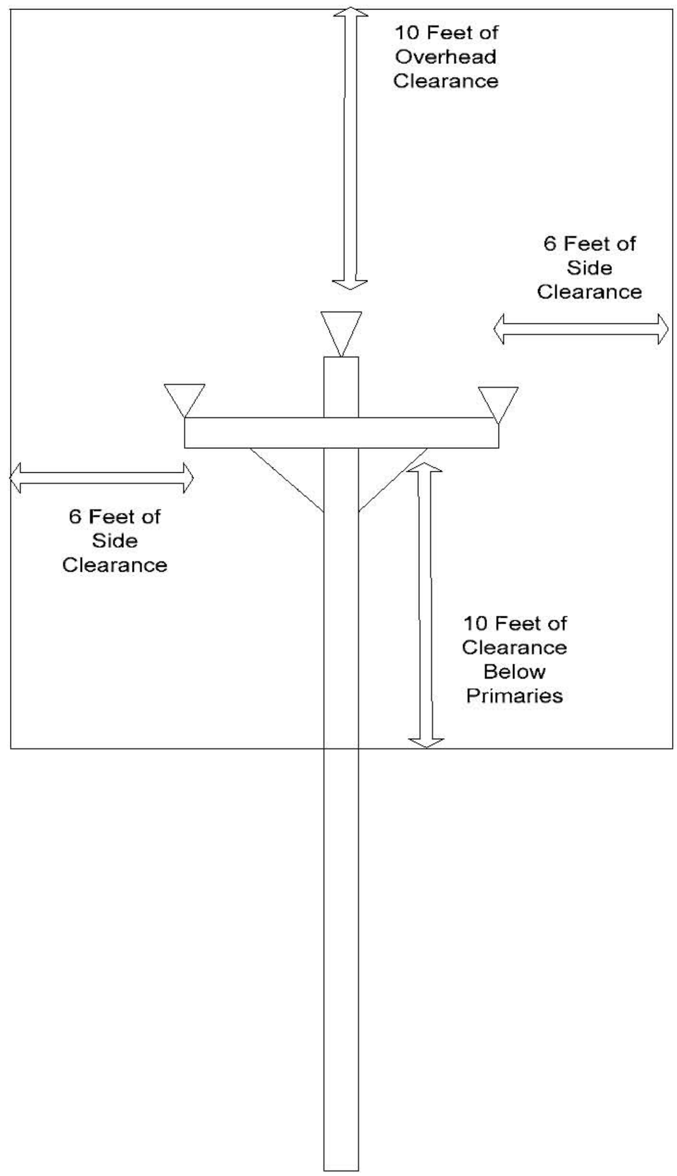
3.15 When pruning, all cuts shall be made at a parent branch or limb, so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch or node where the branch remaining is at least one-third the diameter of the parent limb. All pruning cuts shall be made in accordance with proper collar cutting methods, utilizing drop crotch principles to minimize the number of pruning cuts, promote natural growth patterns, and maintain tree health and vigor (ANSI A300). Climbing irons or spurs shall not be used in pruning a shade/ornamental tree to be saved. Tree wound dressings shall not be applied.

3.16 All vines growing on poles, guy wires, stub poles or towers shall be cut so as to create a “growth gap” and treated (where appropriate) with a herbicide approved by the Company. Contactors should not attempt to remove vines from any structure. Prior to removing any vine that appears to have been planted by the property owner, the Contractor shall notify that landowner. The Contractor shall refer any landowner concerns to the Arborist/Forester.

Revision Date: 9/1/05

Urban / Rural Maintained Properties

3 Phase Clearances

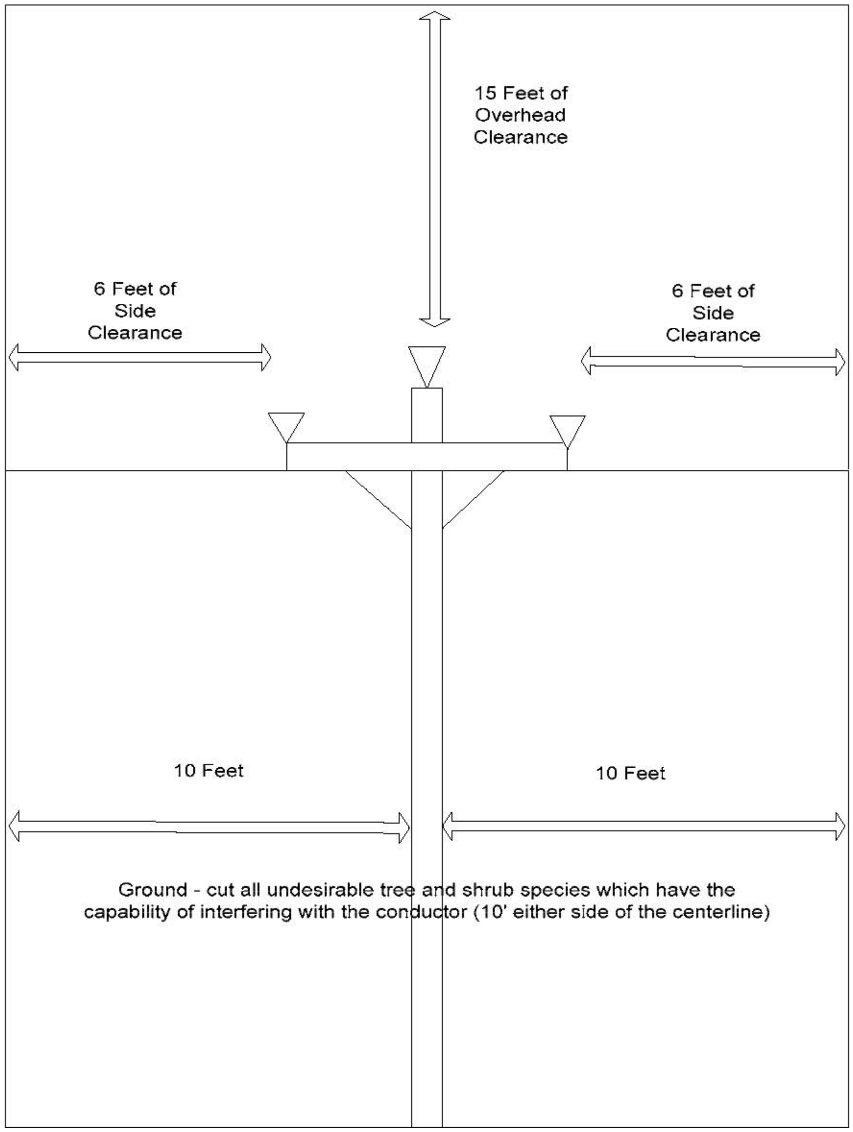


The above diagram depicts the clearance requirements for all 3 phase construction types (except Spacer/Hendricks Cable) when working in cities, villages, residential, and maintained yard areas.

(Proper Arboricultural pruning may exceed the specifications depicted above)

Rural / Un-maintained Properties

3 Phase Clearances

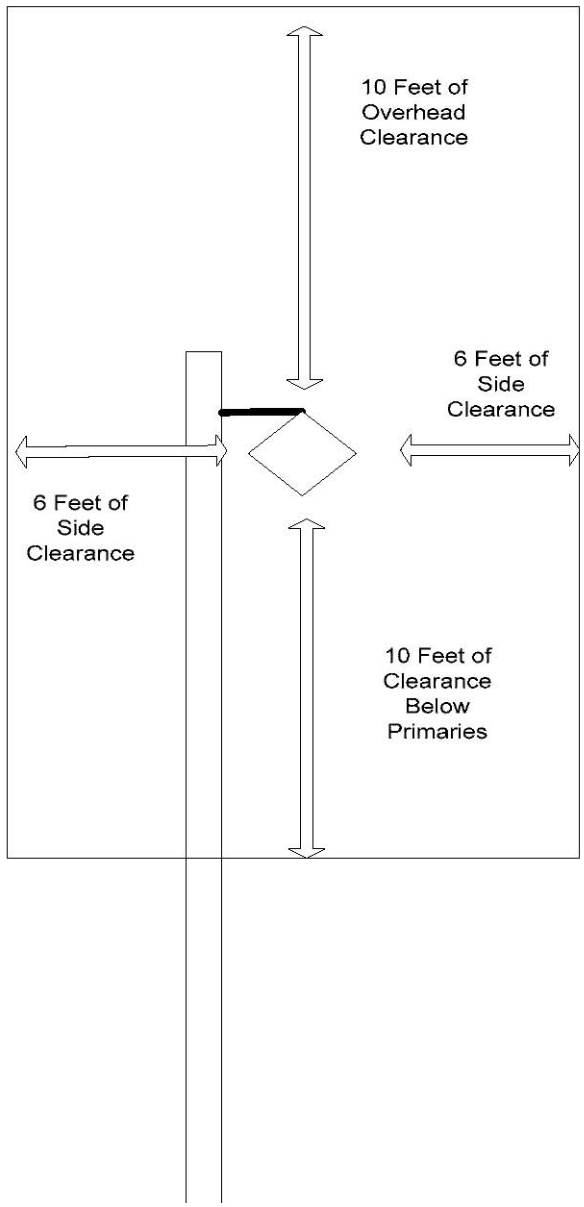


The above diagram depicts the clearance requirements for all 3 phase construction types outside or beyond the yard area (un-maintained)

(Proper Arboricultural pruning may exceed the specifications depicted above)

Urban / Rural Maintained Properties

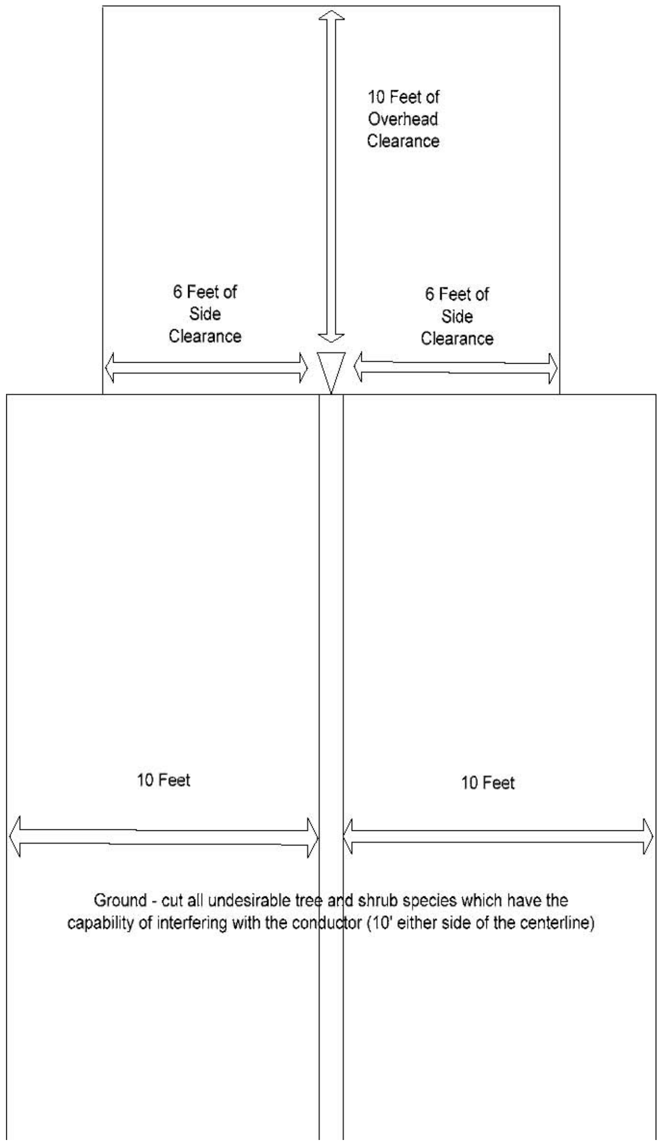
3 Phase Hendricks Cable and Single Phase Clearances



The above diagram depicts the clearance requirements for 3 phase Spacer/Hendricks Cable and all single phase construction types when working in cities, villages, residential, and maintained yard areas.

(Proper Arboricultural pruning may exceed the specifications depicted above)

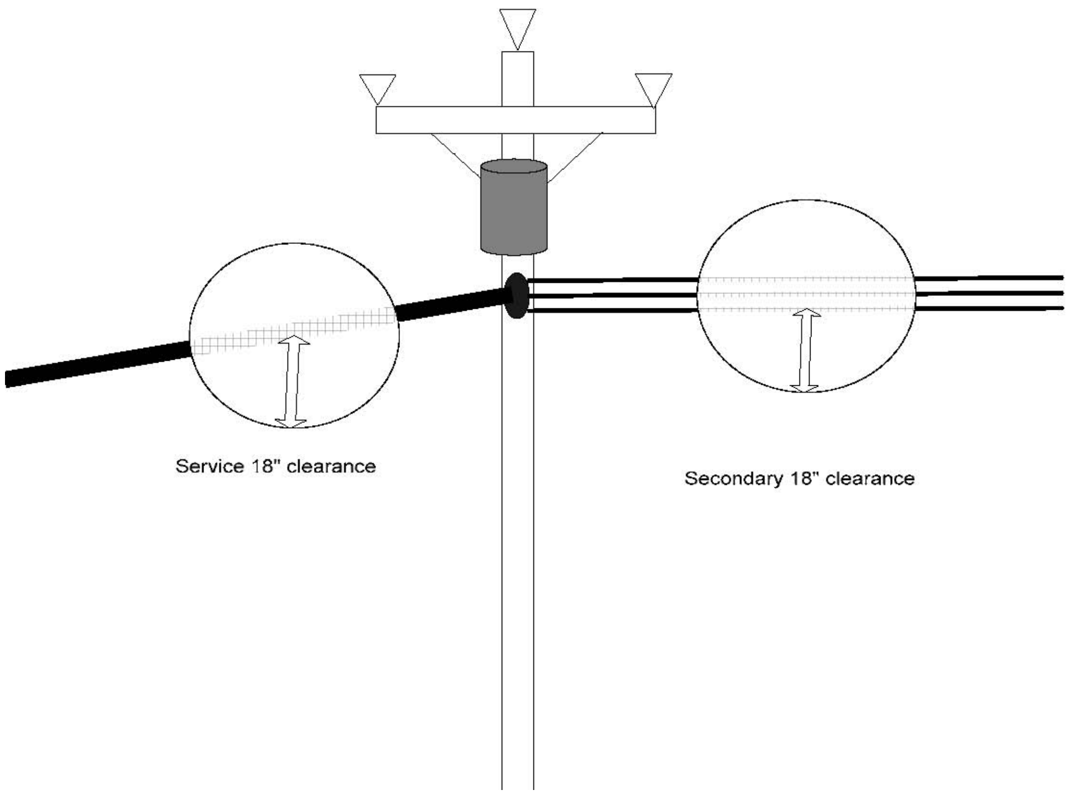
Rural / Un-maintained Properties
Single Phase Clearances



The above diagram depicts the clearance requirements for single phase construction outside or beyond the yard area (un-maintained)

(Proper Arboricultural pruning may exceed the specifications depicted above)

Secondary and Service Clearances



The above diagram depicts the clearance requirements for secondary and services

Service is defined as the last span from pole to the house.

Secondary is defined as between poles. (Triplex or open wire)

Clearance Requirements by Voltage and Construction Type

Construction Type	Above	Side	Below	Gound cut	Maintained	Un-Maintained
3 Phase Crossarm	10	6	10	No	X	
3 Phase Spacer / Hendricks	10	6	10	No	X	
Single Phase all Construction	10	6	10	No	X	
3 Phase Crossarm	15	6	10	Yes		X
3 Phase Spacer / Hendricks	10	6	10	Yes		X
Single Phase all Construction	10	6	10	Yes		X
Secondary	18 inches of clearance around wires					
Service	18 inches of clearance around wire					

nationalgrid

NE DISTRIBUTION LINE CLEARANCE SPECIFICATIONS

Updated 12/18/07

I. Scope/Intent

1.1 These specifications cover the cutting, clearing, pruning, tree removal and herbicide treatment of vegetation along overhead electric distribution lines and the corresponding substations. The intent is to define the minimum clearances to be obtained between the overhead conductors and vegetation that will be acceptable to National Grid. These specifications are strictly for use on overhead line maintenance pruning projects. This is not a specification to be used for enhanced hazard tree removal, new construction clearing or rebuild construction clearing.

II. Program Objectives:

2.1 The goals and objectives of the NGRID Distribution Line Clearance program are to provide safe, reliable, electric service through a cost effective, integrated vegetation management program. NGRID acknowledges differences in the manner in which various landowners respond to the need for routine line clearance activities, together with occasional differences in easement rights. Therefore, these specifications are designed to address:

- the minimum clearance requirements necessary to sustain safe, reliable electric service while striving to satisfy the concerns of sensitive customers,
- and the optimum clearance requirements necessary to sustain an appropriate level of safety and reliability.

III. Definitions:

Maintained Area: Generally defined as an area where the landowner or occupant is mowing the lawn and/or caring for gardens, ornamental shrubs or trees in the area under and immediately adjacent to the distribution poles. It includes commercial land uses such as business areas, parking lot edges and the tree lawn areas along urban and suburban streets. Un-maintained areas, of course, hold the opposite of these characteristics. It should be noted that within residential (maintained) areas there may be small sections of un-maintained property between yards or along the roadside of residential front lawns, etc. These small sections shall be treated as maintained areas for the purposes of this specification.

Mature Tree Line: A generally straight and contiguous line of trees nine (9) inches d.b.h. or greater, that mark the boundary between the forested edge and the maintenance corridor. In the case of an existing mature tree line, there may be individual mature trees that are rooted closer to the pole centerline than the common mature tree line. In these instances the mature tree line continues behind those individual trees.

Maintenance Corridor: The area physically located under and alongside the overhead distribution feeder bounded by the mature tree line when one exists. In the absence of a mature tree line the maintenance corridor is defined as the area that is at least ten (10) feet either side of the pole centerline or equal to the previously maintained dimensions if greater than ten (10) feet.

Service Drop or Service Line: The last span of triplex or open three wire extending to the building or meter pole or a multi-span run of either triplex or open three wire that serves a single customer. This does not include street light services.

Secondary: The conductor, either triplex or open wire, which extends from the transformer to the Service Drop. Secondary spans may run along under primary spans or separately.

Street Light Secondary: The conductor, either triplex or open wire, which leaves the primary pole to pole configuration and extends out to service a street light or lights.

IV. Scope of Work:

4.1 Pruning Standards: All pruning shall be performed in accordance with ANSI A300 standards as well as the Best Management Practices – Tree Pruning publication. All cuts shall be made at a parent branch or limb, so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch or node where the branch being removed is at least one-third the diameter of the parent limb. All pruning cuts shall be made in accordance with proper collar cutting methods, utilizing drop crotch principles to minimize the number of pruning cuts, promote natural growth patterns, and maintain tree health and vigor (ANSI A300). Climbing irons or spurs shall not be used in pruning a shade/ornamental tree to be saved. Tree wound dressings shall not be applied.

4.2 Line Clearance within Maintained Areas: All overhead primary lines shall be pruned to provide a minimum of ten (10) feet of overhead clearance, a minimum of six (6) feet of side clearance from the outermost phase and a minimum of ten (10) feet of clearance below the wires. The contractor shall recognize that the use of ANSI A300 standards and techniques will result in clearances beyond the dimensions noted above.

4.2.1 The main trunk of the tree or major leads which are structurally sound and healthy may be left growing within these distances as long as none of the smaller diameter end branches are within the clearance dimensions. In that case the lead must be removed.

4.2.2 Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.2.3 The contractor shall ground cut any new volunteer growth capable of growing into the wires from around poles, guys, fences, etc. within the maintained yard areas after notifying the property owner.

4.2.4 It is an objective of National Grid's program to continually strive to reduce the number of under-wire tree and branch growth that will continually require pruning, by removing as many stems and growth as possible on each cycle. The Contractor is expected to emphasize this type of removal through the landowner contacts made by their customer contact personnel.

4.2.5 All slash from pruning in maintained areas shall be disposed of through chipping. Large diameter wood may remain on site provided it is cut into manageable lengths and piled neatly. Smaller debris shall be raked up and removed so as to leave the property in a condition equal to the start of work.

4.3 Line Clearance Outside of Maintained Areas: All overhead lines shall be pruned to provide a minimum of fifteen (15) feet of overhead clearance and six (6) feet of side clearance from the outermost phase. Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.3.1 The contractor shall ground cut all trees and shrubs which have the ability to interfere with the conductor out to the limits of the existing maintenance corridor. Where a maintenance corridor does not already exist, ground cutting shall be performed for a minimum distance of ten (10) feet either side of centerline. Ground cutting shall include stems of eight (8) inches d.b.h. or less, all as part of the fixed price bid. Along individual spans that have been previously maintained using National Grid's past eight (8) foot targeted ground cutting specification (trimming and removal) the same approach shall be utilized.

4.3.2 Along off-road sections the contractor shall completely remove all side branches that extend into the maintenance corridor from below and beside the lines in order to "box out" the maintenance corridor. This practice will minimize future pruning efforts as well as improve storm restoration and line inspection efficiencies.

4.3.3 Where trees beyond the limits of the maintenance corridor are extending into the corridor, the contractor shall either prune those limbs back or have the option to remove the tree as part of the fixed price bid. For trees, eight (8) inches d.b.h. or less, where the top of the tree is leaning out into the corridor so that topping would be the only possible correction, the contractor shall ground cut that tree as part of the fixed price bid.

4.3.4 Stumps shall be cut flat and as close to grade as possible.

4.3.5 All slash along the roadway or near residences shall be disposed of by chipping or mowing/mulching. Where practical, chips may be blown back onto the site without creating large chip piles. On off-road, un-maintained sites, slash shall be mowed/mulched or neatly windrowed to the edge of the maintenance corridor and cut to lie close to the ground, away from sensitive locations. No debris shall be left anywhere that will potentially block access, significantly alter any drainage or water resource, or create any unsafe conditions for the public. Alternatives to these practices must be approved by National Grid's Forestry representative and by the current landowner.

4.4 All dead or damaged overhead limbs, branches or leads that are capable of falling onto overhead primary wires from above or along side the right-of-way and potentially causing a tree outage, shall be removed at the time of pruning, and included in the fixed price bid.

4.5 For all pine species growing above the overhead clearance limits with boughs overhanging primary conductor - the contractor shall shorten all overhanging boughs so to reduce the length of the branch by approximately 1/3 without removing all needle growth from the entire branch. This shall be done in a progressive manner beginning at the upper clearance dimension (10 or 15 feet) and working upwards generally two (2) whorls in the tree as necessary to reduce the likelihood of a long pine bough loaded with ice or wet snow, drooping down or breaking onto the conductors.

4.6 Pruning Clearance for Secondary and Service Lines:

4.6.1 All secondary wire (triplex and open wire), other than that serving street lights only, shall be pruned to provide a minimum of eighteen inches of clearance from wire to vegetation.

4.6.2 All service wires (triplex or open wire) and street light secondary on the circuit shall be inspected during the pruning process. For branches that are either making hard contact with the service wire, pushing on or creating tension enough to force the wire out of a natural arc, or redirecting the wire out of a straight line run, the vendor shall do whatever pruning is necessary to correct that situation. The entire service drop need not be pruned, only the point of conflict.

4.6.3 For open wire services, pruning is required for all the situations noted in 4.6.2 as well as anytime vegetative growth is forcing the three wires out of their normal configuration. The vendor must take extra care when pruning around open wire services so not to cause a service interruption to our customers.

4.7 Multiple Circuits and Under-builds: The contractor shall prune all distribution circuits on a pole unless otherwise called out on the bid documents. Where a distribution circuit is under-built below either a sub-transmission or transmission line the contactor is not responsible for the pruning of that portion of the circuit unless otherwise directed in the bid documents. However, the contractor is responsible for work on any primary, secondary or service tap running off the sub-transmission or transmission pole line as long as the bid circuit is under-built. Any exceptions to the above will be explained at the time of bidding.

4.8 Circuits along Transmission Rights-of-Way: The contractor shall employ this specification on all sections of distribution circuits that run along segments of transmission rights-of-way except for areas where the distribution circuit is actually under-built on the same pole. In those cases the above section will apply. Any exceptions to the above will be explained at the time of bidding.

4.9 Substation Clearances: All vegetation within 10' of the substation fence shall be pruned, from ground to sky, removed and chipped and no overhanging branches shall be allowed to remain. Where shrubs and trees have been planted for screening purposes and are rooted within the 10' distance, only the fence side branches shall be removed. Any volunteer growth (natural regeneration) rooted within the 10' distance shall be removed.

4.10 Vine Control: All vines growing on poles, guy wires, stub poles or towers shall be cut so as to create a “growth gap” of 2 feet and treated (where appropriate) with a herbicide approved by the company.. Contactors should not attempt to remove vines from any structure.

4.11 Hazard Tree Inspection and Removal: Other than work required in previous sections, the removal of any tree over 8 inches d.b.h. within the maintenance corridor or outside the maintenance corridor shall be considered a hazard tree removal and is outside the fixed price bid.

4.11.1 While pruning the circuit, the contractor's personnel shall perform a visual inspection of each tree along the circuit in order to identify potential defects and determine the potential risk for the tree to cause an interruption over the length of the pruning cycle. The crew shall work closely with National Grid Forestry representative to determine potential hazard trees, preparing a list of trees in accordance with National Grid's Hazard Tree Reporting Form. The completed lists of potential hazard trees shall be regularly provided to the Forestry representative for review and approval prior to removing any of those specific trees. Exceptions to this procedure may be approved to enable removals of trees that have been pre-identified as hazard trees by National Grid representatives, trees that pose an imminent risk, or to authorize hazard tree removals in off-road areas where a skidder bucket is already on site.

4.11.2 Once a crew completes the removals on an approved list they shall note the completion details on the Hazard Tree Reporting Form. This form shall be submitted to the Forestry representative on a timely basis. Once the list is audited the contractor may submit an invoice for that specific work.

V. Contractor Requirements

5.1 The Contractor shall do all work and furnish all labor including supervision, tools, machinery and transportation necessary for the pruning, removal and herbicide treatment of trees to provide acceptable vegetation clearance for overhead lines of National Grid. Work at the fixed price rates will be designated on the distribution circuit maps, and identified in the pre-bid documents. Work at the fixed price is based on overhead primary miles of line, and includes pruning, tree and lead removal and herbicide treatment to all primary, secondary, service drops, and substation fence areas as clarified in the Work Scope section of this specification. Work at unit prices and/or hourly rates as also defined in the Work Scope section will be designated at the pre-bid meeting or by a National Grid Forestry representative as required.

VI. Contractor's Responsibility

6.1 The Contractor shall provide all necessary supervision, labor, material, tools and equipment for the safe execution of all work covered by these specifications.

6.2 The Contractor shall employ a competent field supervisor and customer contact person(s) acceptable to the Corporation, in addition to the crew Foreman and senior Company management. The supervisor shall be available to the Corporation at all reasonable times during the entire extent of the project and/or contract. In addition, at least one member of each stand-alone crew or unit of crews shall be fluent in the English language.

6.3 The Contractor shall comply with all building and sanitary laws and all Federal, State, County, Town and Municipal laws, ordinances and regulations pertaining to the work. The contractor shall be responsible for obtaining all permits necessary to perform the work unless otherwise provided by National Grid

6.4 The Contractor shall notify each landowner and inform them of the clearing, removal, pruning and herbicide work to be done, and where appropriate, agree on access point(s), before crossing the property and then abide by the same. The Contractor shall designate a Customer Contact Person(s) for each project they are awarded and communicate that name and phone contact information for that person to the National Grid forestry representative for that project.

6.5 In the event that the Contractor cannot locate the landowner after using all reasonable measures, or upon locating them is aware of an objection to the work to be performed, the Contractor shall document the landowners concern and then notify the National Grid's forestry representative in a timely fashion in order to obtain specific instructions and/or their permission prior to commencing work on that property.

6.6 In addition to the above notifications, where herbicide applications will be made, the Contractor must follow any and all current notification requirements of any applicable regulations.

6.7 The Contractor shall be held solely liable and indemnify National Grid fully for any and all claims and legal expenses for damage to crops, land, trees or otherwise resulting from such violations, failure or damages arising out of the Contractor's negligence. The Contractor shall not be liable for claims or suits for damage to property if the work causing such damage is done under specific direction from NGRID.

6.8 The Contractor shall replace or make necessary repairs to all property destroyed or damaged in the course of the work and exercise due care and diligence in adequately protecting all properties, both real and personal, from damage of whatsoever nature whenever crossed over, on, or in the vicinity of the work. If the contractor neglects or fails to promptly make said repairs or make good of said destruction, the Corporation may make any and all necessary repairs to the satisfaction of the property owner and the Contractor agrees to promptly reimburse the Corporation the amount of its incurred cost and expenses.

6.9 The contractor shall inform the National Grid Forestry representative of their intent to start work at least two weeks prior to the start of any action on a feeder.

6.10 The Contractor shall implement and provide the required training and certification programs necessary to provide fully qualified Line Clearance Tree Trimmers or Line Clearance Tree Trimmer Trainees. A single Foreman may supervise multiple bucket trucks on the same project. In that case however, the minimum qualifications for the "lead" person on each of the other trucks shall be a certified qualified Line Clearance Tree Trimmer. At least one other employee on the truck shall be at least a qualifying Line Clearance Tree Trimmer Trainee, in accordance with all applicable OSHA requirements.

6.11 The Contractor shall submit a weekly time report to the National Grid Forestry representative, indicating the labor and equipment assigned to the project, amount of work accomplished, quantities and location of herbicide applications and location of the work.

6.14 The Contractor shall provide a monthly summary report to Distribution Forestry, identifying crew staffing and equipment by area as of the first of each month, to be submitted by the 5th of each month or the following Monday should the 5th fall on the weekend. The report shall also identify work type (e.g., such as hourly, new construction, danger trees, mowing; lump sum or unit price) by project, percentage complete for all fixed price projects, and anticipated completion dates.

6.15 The Contractor shall provide a monthly OSHA injury summary report in a format supplied by National Grid for the previous month, no later that the 10th of the month or the following Monday should the 10th fall on the weekend. The data in the report shall be separated by state as well as reported for the overall Contractor Company for any and all United States operations.

6.16 By April 10th of each year, the contractor shall provide a list of employees that could reasonably be expected to work on National Grid's property to Distribution Forestry. This listing shall include:

- identify the current pay classification of each employee, together with their union certification level,
- the date of their progression to their current pay level,
- the dates each employee completed their required OSHA safety and other training, or retraining, including any annual refreshers,
- the date each employee last demonstrated their tree rescue and climbing proficiency
- the date each employee completed first aid and CPR training,
- identify each certified pesticide applicator and their certification number.

6.17 The contractor shall provide a unit cost per tree for the removal of potential hazard trees from the three phase portions of the circuit, as well as "high risk target" hazard trees from the single-phase portions. See the attached Addendum # 1, Hazard Tree Tree Removal, Unit Price Schedule to be bid separately from the fixed price project. National Grid reserves the right to award**,** in whole or in part, the removal of hazard trees for each bid package on the basis of these unit price costs, or to do the work at the contractor's current hourly rates.

VII. Acceptance of Work

7.1 At appropriate intervals, the Contractor shall report and review the work completed to date with National Grid's Forestry representative. The Contractor may then invoice for the percentage of the work completed and approved by National Grid.

7.2 Near completion of the work, the Contractor shall notify the National Grid Forestry representative that the entire project has been reviewed by the contractor's supervision and is now ready for inspection. Upon review and acceptance of all required work including the resolution of any and all required corrective actions as well as any outstanding damage claims, the NGRID Forestry representative will give the Contractor permission to submit a final invoice for payment.

7.3 The contractor shall understand, per their signed Master Purchase order with NGRID that time is of the essence with respect to the performance of this work. The contractor shall take all appropriate actions necessary to complete the work on schedule. Those actions shall include among other things, the use of overtime, the use of supplemental labor crew resources from outside areas, and the use of subcontractors, not withstanding the NGRID requirement for advanced approval of all subcontractors. All actions employed by the contractor to meet schedules are at their cost and shall not affect the lump sum contract amount. In the event of extenuating circumstances defined by NGRID, the company reserves the right to extend project completion dates.

Revision Date: 12/18/07

Addendum #1

Hazard Tree Removal

Unit Price Category Definitions:

Removal-Maintained Area: Normally within city town or village settings in areas where lawn and ornamental tree and shrub care is evident. The contractor will safely fell the tree, limb and chip all brush and flush the stump as low as is practical. The wood will be cut to manageable lengths and yard cleanup performed.

Removal-Roadside Area: Normally, outside of any maintained areas as described above. The contractor will safely fell the tree, limb and chip all brush, flush the stump as low as is practical, and leave the wood to lie where it is felled. Minimal cutting should be required other than to allow the wood to lie flat against the ground.

Removal-Unmaintained Area: Outside of any maintained area along a wooded roadside or off-road section of line. The contractor will safely fell the tree and make the necessary cuts on the tree to have the wood and brush lie relatively flat against the ground (drop and lop).

Unit Price Schedule

Diameter Class	**Removal-Maintained**	**Removal-Roadside**	**Removal-Unmaintained**
8 inches or less	Lump Sum	Lump Sum	Lump Sum
>9 – 12 inches	________	________	_________
>13 – 18 inches	________	________	_________
>19 – 24 inches	________	_________	_________
>25 and up inches	__T&M__	__T&M__	__T&M___

Note: For hazard trees that have been removed and the D.B.H. cannot be determined, NGRID will deduct 2 inches from the average stump diameter to determine payable size.

Complete removal of wood will be performed on a T&M basis.

Removals above 24 inches D.B.H. shall be performed on a T&M basis.

Unit prices will be bid separately from the lump sum bids. National Grid reserves the right, when awarding fixed price pruning projects, to add an estimated price for hazard trees removals based on the prices submitted on this form for removal, and award the total project based on the sum of both prices.

Revision Date: 12/18/07

Addendum #2

National Grid Distribution Forestry
Herbicide Application Procedure

In order to ensure consistent herbicide applications the following procedure and expectations will apply to all tree crews working on distribution line clearance work at National Grid-Rhode Island

The ability to control brush growth on our distribution system is a critical part of achieving our overall line clearance cyclic program objectives. It is important to understand that appropriate herbicide application will benefit National Grid's service reliability by significantly reducing the amount of re-sprouting that occurs after ground cutting is performed. As professional pesticide applicators, the contractor has an obligation to be educated, prepared and conduct themselves in a professional manner to achieve successful applications on line clearance projects.

- All crews and/or notification personnel will have clean copies of all appropriate notification materials such as labels, MSDS sheets.
- Application logs are to be maintained and available for field review. Copies must accompany the weekly time sheets submitted to the Company. If a customer rejects the use of herbicide it should be noted on the customer log.
- All crews engaging in ground cutting must apply a stump treatment application at the time of cutting. Cutters should carry an applicator bottle on them to ensure a thorough and timely application.
- The primary stump treat product will be Pathway. During periods of frozen ground the vendor shall switch to a Garlon 4/Stalker mix. Finally, the vendor shall also have a glyphosate stump treatment product available on the project for usage in wet areas or other sensitive sites. Equivalent substitutes are acceptable with the approval of the National Grid Forestry Representative.
- Mowed areas are exempt from a stump treatment application; however, these areas will receive an aggressive follow-up foliar application. Stems cut by hand as part of the mowing process shall be stump treated. Cut stubble treatments are also acceptable.
- Herbicide notifications should be incorporated into the general customer notification for pruning and ground cutting. Notification personnel must be knowledgeable of the products being used and present the use of herbicide in a positive, professional and proactive manner. Taking time to fully explain the application technique and product will produce results.
- If a customer refuses an application and there is a significant amount of brush to control you must notify the National Grid Forestry representative prior to proceeding with the work.
- If an inspection or audit occurs you must notify the National Grid Forestry representative immediately.
- Any operations found to be out of compliance will be shut down and payment held until issues are corrected.

Stump treatment is a low profile, customer compatible, target specific technique that ensures effective brush control. A thorough stump treatment also makes the follow-up foliar job easier and more effective.

Revision Date: 12/18/07

Division 3-5

Request:

Does Chart 3 on Page 57 of the ISR Plan include major storm events?

Response:

The Chart 3 on page 57 includes major storm events but the Company has since discovered that errors were made in pulling the data used to generate this Chart. The corrected chart including major storms is shown below as Chart A.

Chart A

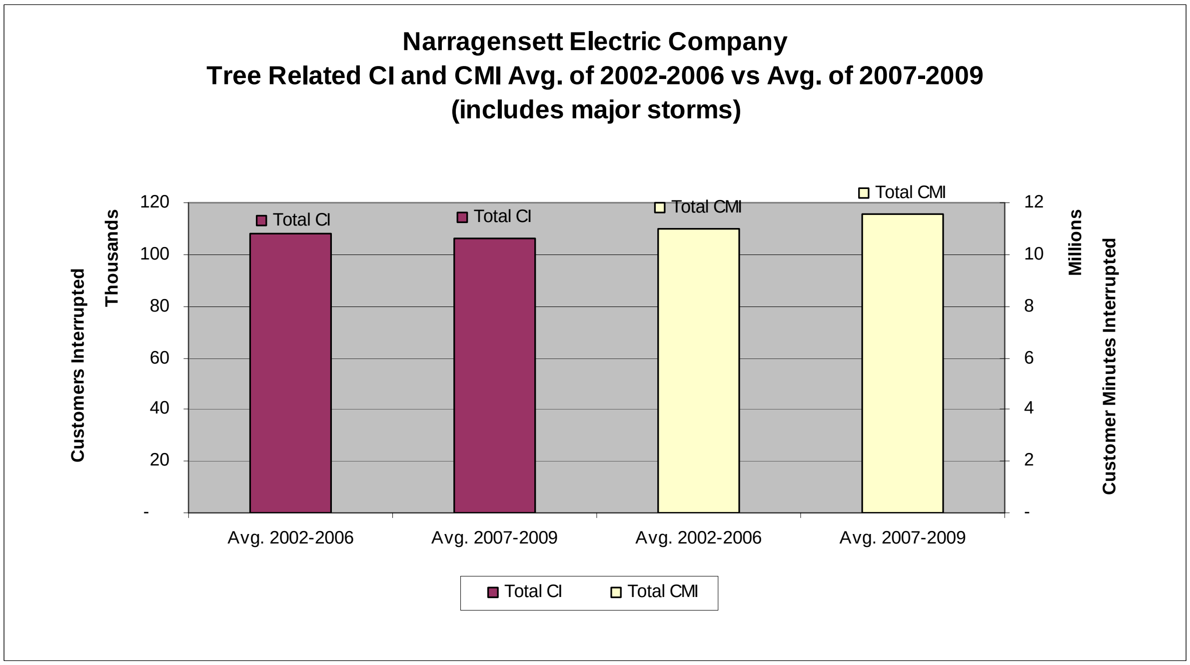


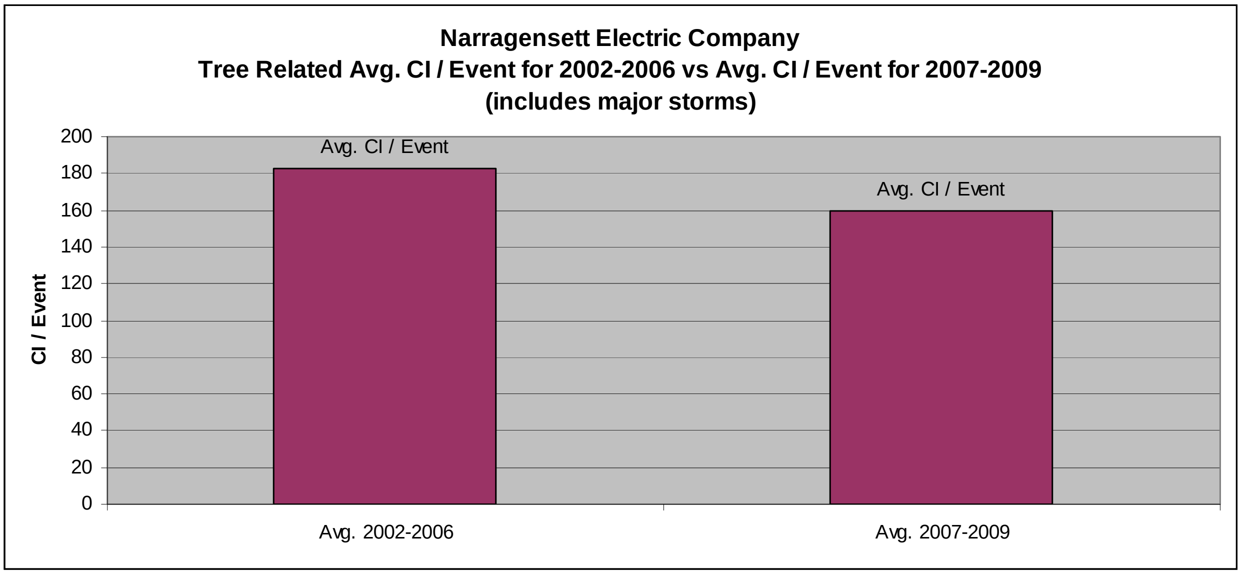
Chart A shows that the average number of customers interrupted ("CI") due to trees is down 2,091 since the Company has improved its vegetation management programs in 2007. But the Company believes that this decline understates the gain from improvements to its vegetation management program as it suspects that severe weather in 2008 boosted the number of tree-related CI. The effectiveness of the Company's vegetation management program since 2007 is more evident in Chart B which shows a 10% reduction in the average number of tree-related CI per Event since the Company improved its vegetation management programs.

Tree-related CI per Event is the preferred metric to evaluate the effectiveness of the Company's vegetation management program, especially the Enhanced Hazard Tree Mitigation program ("EHTM"). This metric is helpful because EHTM strives to reduce interruptions on the mainline sections of the feeder where the most customers are served. If two tree removal candidates have

Division 3-5 (continued)

the same risk of failure but one is outside the substation and the other is on a single phase fused tap, the EHTM protocol would prioritize the tree outside the substation for removal since the potential customers interrupted from the failed tree outside the substation is greater than that of a failed hazard tree located on the single phase side tap. If the hazard tree on the side tap failed and caused an event, the CI per Event would be lower than if the hazard tree outside the substation failed and locked on the substation. The reduction in average number of tree-related CI per Event since 2007 suggests that EHTM protocol is helping to reduce the number of customers impacted by tree failures.

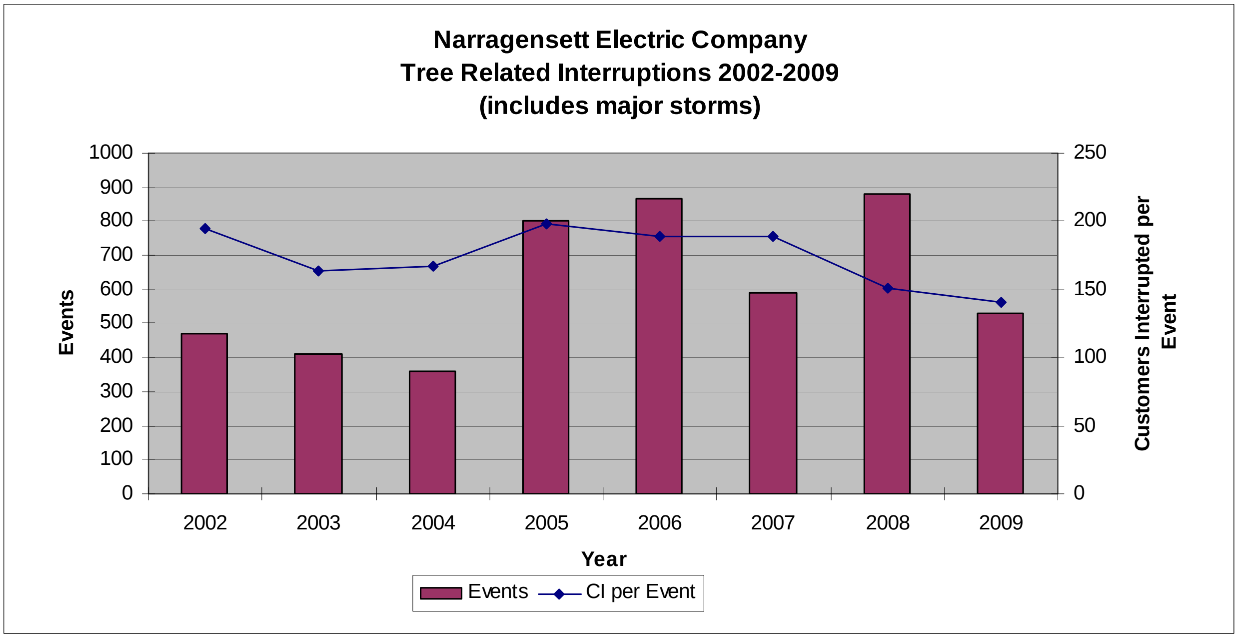
Chart B



The effectiveness of the EHTM protocol in protecting the mainline section of the feeder is also evident in the relationship between number of events and CI per Event as shown in Chart C. The number of events on the system is variable year-to-year due to weather. It is impossible to completely safeguard the system from catastrophic tree failures when weather exceeds normal conditions. Since the data are not normalized for weather, it is difficult to draw inferences about the effectiveness of vegetation management programs from making year-to-year comparisons. Comparing the number of events to the CI per Event is helpful in overcoming this problem. A low CI per Event even when the number of events is higher than normal indicates that the sections of the feeder with the highest amount of customers served are performing better. The year 2008 shows the program's effectiveness and is encouraging in this regard. Severe thunderstorms and other weather events drove the tree-related interruption events up in 2008 but CI per Event remained low.

Division 3-5 (continued)

Chart C



Note: The Company generally does not use Customer Minutes Interrupted ("CMI") as a metric to evaluate the effectiveness of its vegetation management programs because CMI is impacted by several variables that are not directly connected to the vegetation management program including the number of concurrent events, the availability of replacement equipment, resource availability, and the Company's ability to isolate faults and switch customers.

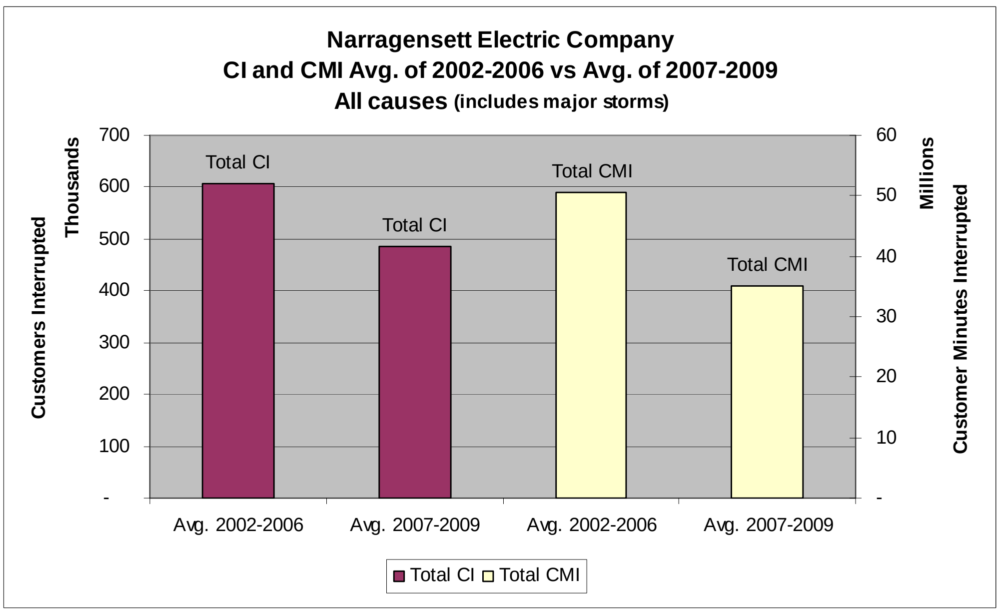
Prepared by or under the supervision of: Sara Sankowich

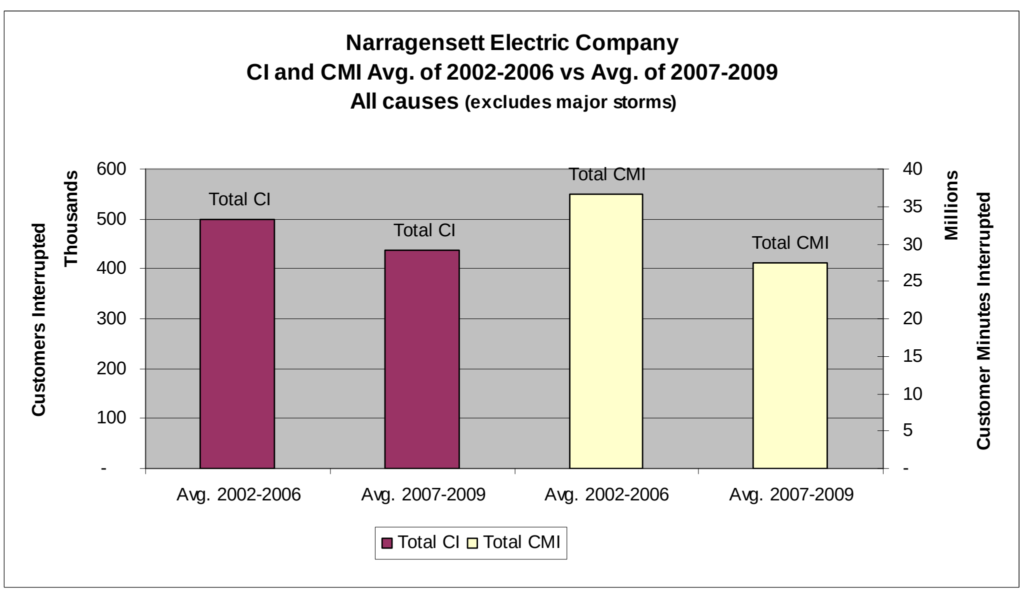
Division 3-6

Request:

Page 57, Chart 3 of the ISR Plan provides Customer Minutes Interrupted and Customer Interruptions Caused by Trees. Please provide similar format for all interruptions, both with Major Storms and Without Major Storms.

Response:





Prepared by or under the supervision of: Sarah Sankowich

Division 3-7

Request:

What is the estimated cycle time for danger tree removal?

Response:

Cycle time for the hazard tree program is dictated by the reliability performance of the circuit and by field inspection. This is generally between 3 and 5 years. Annually, the performance of all circuits is assessed and those circuits with poor performance for the last 3 years are reviewed for recent work completed, need for additional work, and actual conditions after field inspection. A circuit may be re-visited for hazard tree removal sooner than average if reliability and field conditions warrant more work. An example would be for insect or pest invasion in an area, or rapid decline / mortality from a large weather event. A portion of a circuit could also be revisited if "pockets of poor performance" are found with reliability issues in additional areas after initial hazard tree work was completed on the circuit.

Prepared by or under the supervision of: Sara Sankowich