Connecticut Cable Switching Transient Study for XLPE Alternative in Middletown to Norwalk Project

Final Report

December 2004

Prepared for:
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Foreword

This document was prepared by General Electric Company in Schenectady, New York. It is submitted to Northeast Utilities (NU). Technical and commercial questions and any correspondence concerning this document should be referred to:

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Executive Summary

GE Energy's Energy Consulting group has performed a switching transient study of an XLPE alternative (previously referred to as Case 5) in the Northeast Utilities (NU) Middletown to Norwalk 345 kV transmission cable project that is proposed in southwestern Connecticut. In this study, the two cables between Norwalk and Singer and the two cables between Singer and East Devon were represented as 3000 kcmil XLPE cables rather than 2500 kcmil HPFF cables, and one of the two HPFF cables between Plumtree and Norwalk was removed. The study considered three system loading levels, 40%, 50% and 70%, which determined the respective capacitor bank dispatch, shunt reactor dispatch, and load representation. The light post-project dispatch had most local generators off.

The objectives of this study were to investigate:

- the temporary overvoltages resulting from various fault clearing scenarios, and
- the effects of system load variations and line outages on temporary overvoltages under a range of fault conditions.

The study has focused on temporary overvoltages following fault clearing as a critical design factor due to their difficulty in mitigation. Unlike energization transients, which can be mitigated with special circuit breaker closing enhancements (such as pre-insertion resistors), fault clearing transients are difficult to mitigate. After circuit breakers open to clear a fault, nearby transformers will usually saturate due to trapped flux, and their inrush response contributes to temporary overvoltages that are distorted and sustained. The magnitude and duration of temporary overvoltages are compared with the capabilities of equipment to withstand them.

This study has considered over 1500 simulations with varying system conditions to evaluate temporary overvoltages resulting from fault clearing in the Middletown to Norwalk XLPE alternative configuration. Fault cases included the Plumtree – Long Mountain line, the E. Devon – Beseck line, the Plumtree – Norwalk cable, a Singer – E. Devon cable, a Singer-Norwalk cable, and various bus faults. The resulting TOVs observed at 345 kV appear to be within typical utility equipment TOV withstand capabilities. However, voltage magnification was observed at Rocky River 115 kV, as seen in previous studies, and is likely to be an existing issue that could be mitigated locally. For example, the capacitor bank at Rocky River could be replaced by a filter or a synchronous condenser.

The driving-point impedance was evaluated at Norwalk 345 kV under a variety of system loading and line outage conditions. It was found that the frequency of the first resonance varies between 2.1 pu (with 70% loading) and 3.6 pu of 60 Hz (with 40% loading), considering all lines in and various outages. With the large number of parameters that can vary in the system, it is likely that a variety of system conditions could result in resonance near 3rd harmonic, and with further contingencies (system weakening) or increased capacitance, the system could be resonant near 2nd harmonic. A concern would be if alternate conditions could cause a higher impedance resonance near the 2nd or 3rd

harmonics, which could potentially result in higher TOVs than those observed in this study. It is not feasible to study every possible scenario; however, the study did include a significant number of fault scenarios and resonance evaluation. It is recommended that the ability of equipment to withstand the voltages observed in the study be confirmed with manufacturers.

Introduction

GE Energy's Energy Consulting group has performed a switching transient study of an XLPE alternative (previously referred to as Case 5) in the Northeast Utilities (NU) Middletown to Norwalk 345 kV transmission cable project that is proposed in southwestern Connecticut. In this study, the two cables between Norwalk and Singer and the two cables between Singer and East Devon were represented as 3000 kcmil XLPE cables rather than 2500 kcmil HPFF cables, and one of the two HPFF cables between Plumtree and Norwalk was removed. The study considered three system loading levels, 40%, 50% and 70%, which determined the respective capacitor bank dispatch, shunt reactor dispatch, and load representation. The light post-project dispatch had most local generators off.

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The study has been performed with the Electromagnetic Transients Program (ATP/EMTP), which is recognized as an industry standard for simulating the transient performance and frequency response of electric utility systems [www.emtp.org].

System Model

The system model used in the Middletown to Norwalk study was used in this study with modifications. The pertinent portions of the system model are shown in Figure 1. The charging capacitance of the 3000 kcmil XLPE cables is approximately 60% of that of the 2500 kcmil HPFF cables. The parameters in Table 1 were used to represent the 3000 kcmil XLPE cables (per circuit in pu on a 100 MVA base).

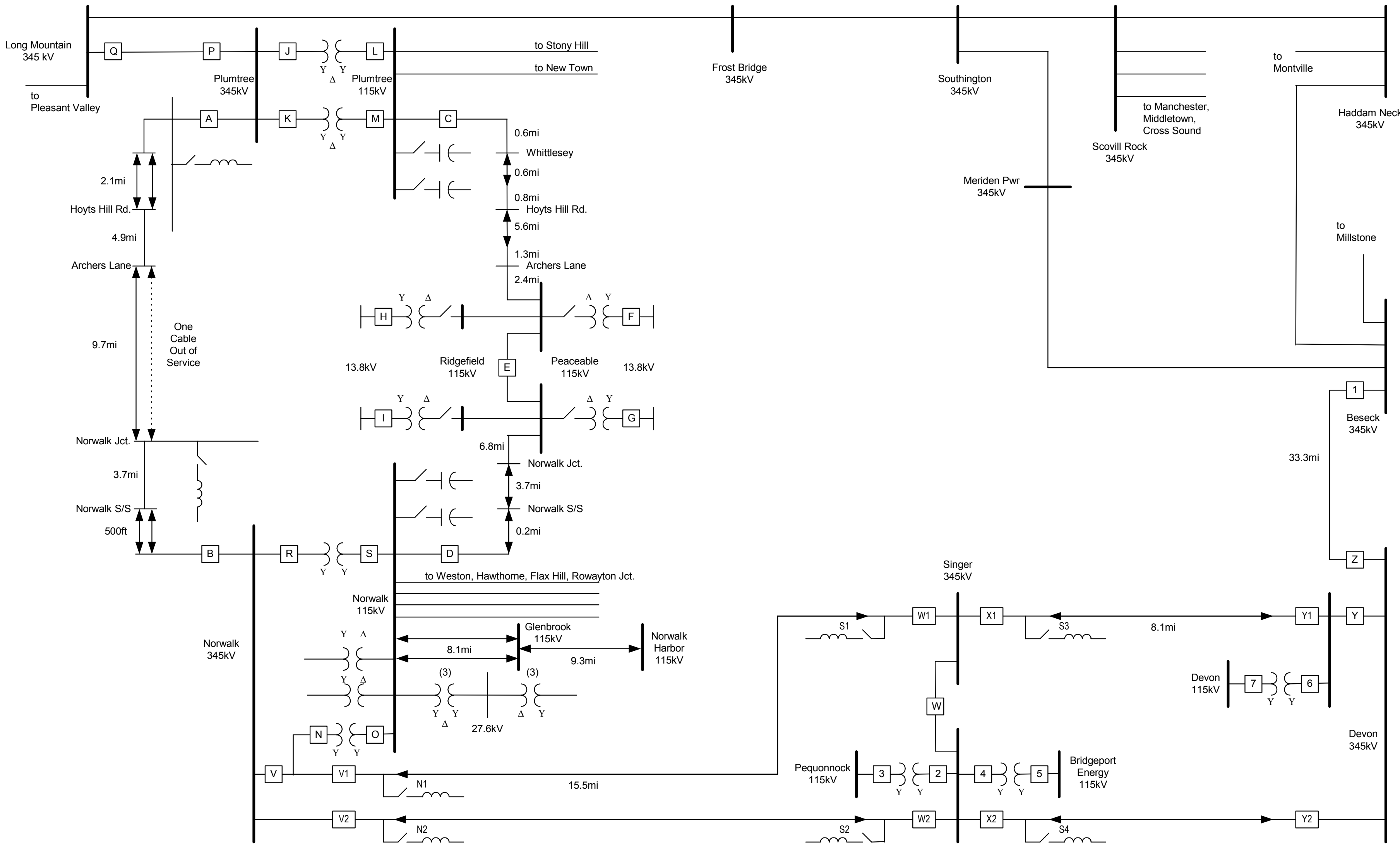

Figure 1. System Model

Table 1. XLPE 345 kV Cable Data (pu 100 MVA)

Cable	**Length**	**R1 (pu)**	**R0 (pu)**	**X1 (pu)**	**X0 (pu)**	**B1=B0 (pu)**
Singer - Norwalk	15.5 mi	0.0003477	0.003581	0.004162	0.002378	1.9637
E. Devon - Singer	8.1 mi	0.0001817	0.001872	0.002175	0.001243	1.0262

In addition to the above changes, one of the two 9.7-mile HPFF cable circuits between Plumtree and Norwalk was removed. The overhead line between East Devon and Beseck was the same as in the Middletown to Norwalk project.

NU determined that the two capacitor banks at Norwalk 115 kV would be removed with the addition of the Middletown to Norwalk project, and were removed from the model accordingly. Also, a 37.8 MVAR capacitor bank is being added at Branford 115 kV. Table 2 shows the capacitor bank dispatches used in this study, and indicates the total MVAR at each bus under the three studied load conditions.

Table 3 shows the generators included in the original ASPEN file, and the modified status originally provided for the Middletown to Norwalk (M/N) project, which indicates the generators that are on or off during peak and light load conditions. The "Light Post-Project" generator dispatch depicts a more realistic scenario with most local generation off. This study considered only the Light Post-Project dispatch with most local generation off.

Table 2. Shunt Capacitor Dispatches used in Study

Shunt Capacitors		**70% Load**	**50% Load**	**40% Load**
Substation	**Voltage (kV)**	**MVAR**	**MVAR**	**MVAR**
Southington 1	115	157.2	52.4	
Southington 2	115	157.2	52.4	
Frost Bridge	115	262.0	52.4	
Berlin	115	132.0	39.8	
Plumtree	115	92.2		
Glenbrook	115	113.4	37.8	
Darien	115	39.6		
Waterside	115	39.6		
Norwalk (removed)	115			
East Shore	115	84.0	42.0	
No. Haven	115	42.0		
Sackett	115	42.0		
Rocky River	115	25.2		
Stony Hill	115	25.2	25.2	
Branford	115	37.8		
Cross Sound Filters	200	103.0 (61 – 25^{th}, 32 – 41^{st}, 10 – 21^{st})	103.0	103.0
Total MVAR		**1352**	**405**	**103**

Table 3. Generator Dispatch Definitions (Light Post Project used in Study)

GENERATOR	KV	ID	ST	STATUS (PEAK)	STATUS (LIGHT)	Light Post-Project	IDENTIFI-CATION NOTES
MILLSTON	22.8	1	1	on	on	On	
MILLSTON	22.8	1	1	on	on	On	
RESCO	115	1	1	on	on	On	Bridgeport
ROCKY RV	13.8	1	1	on	on	Off	
ROCKY RV	13.8	1	1	on	on	Off	
ROCKY RV	13.8	1	1	on	on	Off	
STEVENSO	6.9	1	1	off	off	Off	
NORWALK	27.6	1	0	off	off	Off	
BULLS BR	27.6	1	1	on	on	Off	
FORESTVI	13.8	1	1	on	on	On	
brdgphbr	18.4	2	1	off	off	Off	
brdgphbr	20.2	3	1	on	on	Off	
brdgphbr	13.68	jt	1	off	off	Off	
COSCOBGE	13.8	1	1	off	off	Off	
COSCOBGE	13.8	2	1	off	off	Off	
COSCOBGE	13.8	3	1	off	off	Off	
DEVON 11	13.8	1	1	off	off	Off	
DEVON 12	13.8	1	1	off	off	Off	
DEVON 13	13.8	1	1	off	off	Off	
DEVON 14	13.8	1	1	off	off	Off	
English	13.68	8	1	off	off	Off	
English	13.68	7	1	off	off	Off	
ESHOREGE	13.8	1	1	on	on	Off	New Haven
G1/G2	13.8	1	1	off	off	Off	Wallingford
G3/G4	13.8	1	1	off	off	Off	Wallingford
G5	13.8	1	1	off	off	Off	Wallingford
GT1 (11)	16	1	1	off	off	Off	BE
GT2 (12)	16	1	1	off	off	Off	BE
Middleto	22	1	1	on	off	Off	Middletown
Milford	20.9	1	1	on	on	Off	
Milford	20.9	1	1	off	off	Off	
one (Meriden)	21	1	1	on	off	Off	Meriden
Shepaug	13.8	1	1	on	on	Off	
so norwa	4.8	1	1	off	off	Off	
so norwa	4.8	1	1	off	off	Off	
so norwa	13.8	1	1	off	off	Off	
ST1 (10)	16	1	1	off	off	Off	BE
Temp Gen (Waterside)	13.8	3	0	off	off	Off	Waterside
Temp Gen (Waterside)	13.8	1	0	off	off	Off	Waterside
Temp Gen (Waterside)	13.8	2	0	off	off	Off	Waterside
three (Meriden)	21	1	1	on	off	Off	Meriden

GENERATOR	KV	ID	ST	STATUS (PEAK)	STATUS (LIGHT)	Light Post-Project	IDENTIFI-CATION NOTES
two (Meriden)	21	1	1	on	off	Off	Meriden
Unit 10	13.8	1	1	off	off	Off	Devon 10
Unit 6J- (Norwalk)	17.1	1	1	off	off	Off	Norwalk-1
Unit 6J- (Norwalk)	13.8	1	1	off	off	Off	Norwalk -10
Unit 6J- (Norwalk)	19	1	1	off	on	Off	Norwalk-2
Unit 7	13.2	1	1	on	off	Off	Devon
Unit 8	13.2	1	1	on	off	Off	Devon
walrecge	4.16	1	1	on	off	Off	

Table 4 shows the shunt reactor settings that were considered in the study. Note that there are no shunt reactors at East Devon.

Table 4. Shunt Reactor Dispatches used in Study

345 kV Cable	Shunt Reactor Location	Shunt Reactor Range	70% Load	50% Load	40% Load
Plumtree - Norwalk	Plumtree	75-150 MVAR	150	125	100
Plumtree - Norwalk	Norwalk	75-150 MVAR	150	125	100
Norwalk – Singer #1	Norwalk	50-100 MVAR	100	50	50
Norwalk – Singer #2	Norwalk	50-100 MVAR	100	50	50
Norwalk – Singer #1	Singer	50-100 MVAR	100	70	50
Norwalk – Singer #2	Singer	50-100 MVAR	100	70	50
Singer – E. Devon #1	Singer	50-100 MVAR	100	100	50
Singer – E. Devon #2	Singer	50-100 MVAR	100	100	50

Table 5 shows the load data that was provided for the study. Power wheeling through the system, particularly the large power transfer from Norwalk Harbor to Long Island, was excluded, because the physical load is not located in the Southwest Connecticut system nor is power flow through a system particularly relevant to the TOVs being studied.

Table 5. Load Data used in Study (MW, MVAR, MVA)

	ASPEN		100% Load				70% Load		50% Load		40% Load	
NAME	BUS #	KV	P	Q	S	pf	P	Q	P	Q	P	Q
Newtown	260	115	39.9	12.5	41.8	0.954	27.9	8.8	20.0	6.3	16.0	5.0
Sandy Hook	217	115	10.7	2.3	10.9	0.978	7.5	1.6	5.4	1.2	4.3	0.9
Stevenson	261	115	27.7	7.5	28.7	0.965	19.4	5.3	13.9	3.8	11.1	3.0
Baldwin A	256	115	30.3	8.1	31.4	0.966	21.2	5.7	15.2	4.1	12.1	3.2
Carmel Hill	218	115	14.7	3.5	15.1	0.973	10.3	2.5	7.4	1.8	5.9	1.4
Rocky River	212	115	31.8	10.2	33.4	0.952	22.3	7.1	15.9	5.1	12.7	4.1
Bulls Bridge	213	115	13.0	2.1	13.2	0.987	9.1	1.5	6.5	1.1	5.2	0.8
West Brookfield	211	115	42.6	11.9	44.2	0.963	29.8	8.3	21.3	6.0	17.0	4.8

	ASPEN		100% Load				70% Load		50% Load		40% Load	
NAME	BUS #	KV	P	Q	S	pf	P	Q	P	Q	P	Q
Stony Hill	199	115	41.5	4.1	41.7	0.995	29.1	2.9	20.8	2.1	16.6	1.6
Bates Rock	202	115	63.1	14.9	64.8	0.973	44.2	10.4	31.6	7.5	25.2	6.0
Middle River	205	115	79.1	19.5	81.5	0.971	55.4	13.7	39.6	9.8	31.6	7.8
Triangle	204	115	138.3	47.3	146.2	0.946	96.8	33.1	69.2	23.7	55.3	18.9
Ridgefield B	131	115	27.4	6.9	28.3	0.970	19.2	4.8	13.7	3.5	11.0	2.8
Peaceable	137	115	34.8	13.5	37.3	0.932	24.4	9.5	17.4	6.8	13.9	5.4
Ridgefield A	130	115	27.4	7.0	28.3	0.969	19.2	4.9	13.7	3.5	11.0	2.8
Norwalk	135	115	237.7	76.6	249.7	0.952	166.4	53.6	118.9	38.3	95.1	30.6
Flax Hill	134	115	48.8	11.7	50.2	0.972	34.2	8.2	24.4	5.9	19.5	4.7
Cedar Heights	113	115	36.5	10.5	38.0	0.961	25.6	7.4	18.3	5.3	14.6	4.2
Cedar Heights	15020	115	36.5	10.5	38.0	0.961	25.6	7.4	18.3	5.3	14.6	4.2
Waterside	101	115	71.4	20.1	74.2	0.963	50.0	14.1	35.7	10.1	28.6	8.0
COS COB	100	115	145.3	41.2	151.0	0.962	101.7	28.8	72.7	20.6	58.1	16.5
Tomac	105	115	35.5	9.3	36.7	0.967	24.9	6.5	17.8	4.7	14.2	3.7
South End	102	115	39.2	11.2	40.8	0.962	27.4	7.8	19.6	5.6	15.7	4.5
South End	103	115	38.9	11.1	40.5	0.962	27.2	7.8	19.5	5.6	15.6	4.4
South End	104	115	27.1	7.6	28.1	0.963	19.0	5.3	13.6	3.8	10.8	3.0
Darien	115	115	50.8	14.0	52.7	0.964	35.6	9.8	25.4	7.0	20.3	5.6
Compo	15022	115	39.2	8.6	40.1	0.977	27.4	6.0	19.6	4.3	15.7	3.4
Sasco Creek	126	115	12.9	1.8	13.0	0.990	9.0	1.3	6.5	0.9	5.2	0.7
Ash Creek	146	115	102.0	15.2	103.1	0.989	71.4	10.6	51.0	7.6	40.8	6.1
Weston	149	115	26.0	6.0	26.7	0.974	18.2	4.2	13.0	3.0	10.4	2.4
Weston	150	115	33.1	7.5	33.9	0.975	23.2	5.3	16.6	3.8	13.2	3.0
Hawthorne	140	115	62.7	5.8	63.0	0.996	43.9	4.1	31.4	2.9	25.1	2.3
Old Town	142	115	81.7	8.2	82.1	0.995	57.2	5.7	40.9	4.1	32.7	3.3
Pequonnock	145	115	39.8	1.8	39.8	0.999	27.9	1.3	19.9	0.9	15.9	0.7
E. MAINTAP 88	190	115	33.4	2.6	33.5	0.997	23.4	1.8	16.7	1.3	13.4	1.0
Baird 88	151	115	38.2	4.6	38.5	0.993	26.7	3.2	19.1	2.3	15.3	1.8
Barnum 88	157	115	30.1	2.7	30.2	0.996	21.1	1.9	15.1	1.4	12.0	1.1
Milvon 88	172	115	33.8	4.5	34.1	0.991	23.7	3.2	16.9	2.3	13.5	1.8
Woodmont 88	192	115	40.0	6.4	40.5	0.987	28.0	4.5	20.0	3.2	16.0	2.6
Allings 88	15009	115	31.8	4.7	32.1	0.989	22.3	3.3	15.9	2.4	12.7	1.9
Elm West 88	176	115	40.8	5.7	41.2	0.990	28.6	4.0	20.4	2.9	16.3	2.3
Water St	180	115	71.0	6.4	71.3	0.996	49.7	4.5	35.5	3.2	28.4	2.6
Shaws Hill	227	115	33.9	9.3	35.2	0.964	23.7	6.5	17.0	4.7	13.6	3.7
Bunker Hill	230	115	32.8	9.3	34.1	0.962	23.0	6.5	16.4	4.7	13.1	3.7
Bunker Hill	232	115	33.6	9.5	34.9	0.962	23.5	6.7	16.8	4.8	13.4	3.8
Freight	233	115	33.9	7.2	34.7	0.978	23.7	5.0	17.0	3.6	13.6	2.9
South Naugatuck	257	115	19.2	4.0	19.6	0.979	13.4	2.8	9.6	2.0	7.7	1.6
South Naugatuck	258	115	19.4	4.0	19.8	0.979	13.6	2.8	9.7	2.0	7.8	1.6
Baldwin B	262	115	30.5	8.4	31.6	0.964	21.4	5.9	15.3	4.2	12.2	3.4
Indian Well	265	115	65.0	9.2	65.6	0.990	45.5	6.4	32.5	4.6	26.0	3.7
Ansonia	263	115	23.9	2.6	24.0	0.994	16.7	1.8	12.0	1.3	9.6	1.0
Ansonia	266	115	23.6	2.5	23.7	0.994	16.5	1.8	11.8	1.3	9.4	1.0
Trap Falls	268	115	82.2	10.0	82.8	0.993	57.5	7.0	41.1	5.0	32.9	4.0
BEACON FALLS	259	115	60.1	15.4	62.0	0.969	42.1	10.8	30.1	7.7	24.0	6.2
Devon	15030	115	18.2	2.6	18.4	0.990	12.7	1.8	9.1	1.3	7.3	1.0
June St	269	115	54.6	4.4	54.8	0.997	38.2	3.1	27.3	2.2	21.8	1.8

	ASPEN		100% Load				70% Load		50% Load		40% Load	
NAME	BUS #	KV	P	Q	S	pf	P	Q	P	Q	P	Q
Mix Avenue	296	115	98.4	14.9	99.5	0.989	68.9	10.4	49.2	7.5	39.4	6.0
Sackett	295	115	57.9	4.2	58.1	0.997	40.5	2.9	29.0	2.1	23.2	1.7
Elm West 89	177	115	41.0	5.7	41.4	0.990	28.7	4.0	20.5	2.9	16.4	2.3
Allings 89	15010	115	32.0	4.7	32.3	0.989	22.4	3.3	16.0	2.4	12.8	1.9
Woodmont 89	193	115	39.7	6.3	40.2	0.988	27.8	4.4	19.9	3.2	15.9	2.5
Milvon 89	173	115	33.7	4.4	34.0	0.992	23.6	3.1	16.9	2.2	13.5	1.8
Barnum 89	156	115	30.4	2.7	30.5	0.996	21.3	1.9	15.2	1.4	12.2	1.1
Baird 89	152	115	38.4	4.7	38.7	0.993	26.9	3.3	19.2	2.4	15.4	1.9
Congress 89	182	115	12.2	-0.3	12.2	1.000	8.5	-0.2	6.1	-0.2	4.9	-0.1
E.MAINTAP89	191	115	33.9	2.7	34.0	0.997	23.7	1.9	17.0	1.4	13.6	1.1
Congress 88	181	115	12.0	-0.3	12.0	1.000	8.4	-0.2	6.0	-0.2	4.8	-0.1
Mill River	15053	115	98.4	10.2	98.9	0.995	68.9	7.1	49.2	5.1	39.4	4.1
Broadway	15017	115	48.2	5.0	48.5	0.995	33.7	3.5	24.1	2.5	19.3	2.0
Quinnipiac	297	115	42.0	6.5	42.5	0.988	29.4	4.6	21.0	3.3	16.8	2.6
North Haven	274	115	24.8	1.8	24.9	0.997	17.4	1.3	12.4	0.9	9.9	0.7
Branford	272	115	82.9	19.9	85.3	0.972	58.0	13.9	41.5	10.0	33.2	8.0
Green Hill	293	115	77.5	23.4	81.0	0.957	54.3	16.4	38.8	11.7	31.0	9.4
Branford RR	225	115	4.9	0.8	5.0	0.987	3.4	0.6	2.5	0.4	2.0	0.3
East Shore	292	115	45.2	2.6	45.3	0.998	31.6	1.8	22.6	1.3	18.1	1.0
Southington A	241	115	44.5	10.7	45.8	0.972	31.2	7.5	22.3	5.4	17.8	4.3
Noera A	234	115	30.8	8.1	31.8	0.967	21.6	5.7	15.4	4.1	12.3	3.2
Noera B	235	115	31.1	8.0	32.1	0.968	21.8	5.6	15.6	4.0	12.4	3.2
Todd	238	115	34.1	7.5	34.9	0.977	23.9	5.3	17.1	3.8	13.6	3.0
Canal	240	115	27.8	7.0	28.7	0.970	19.5	4.9	13.9	3.5	11.1	2.8
Southington B	242	115	36.1	7.4	36.9	0.980	25.3	5.2	18.1	3.7	14.4	3.0
Hanover A	298	115	53.6	13.1	55.2	0.971	37.5	9.2	26.8	6.6	21.4	5.2
HanoverB	299	115	53.7	13.2	55.3	0.971	37.6	9.2	26.9	6.6	21.5	5.3
Colony	301	115	30.7	4.4	31.0	0.990	21.5	3.1	15.4	2.2	12.3	1.8
North Wallingford	252	115	27.0	3.9	27.3	0.990	18.9	2.7	13.5	2.0	10.8	1.6
East Meriden	290	115	49.7	12.2	51.2	0.971	34.8	8.5	24.9	6.1	19.9	4.9
Berlin	221	115	63.9	15.4	65.7	0.972	44.7	10.8	32.0	7.7	25.6	6.2
Wallingford	271	115	58.6	8.3	59.2	0.990	41.0	5.8	29.3	4.2	23.4	3.3
BLACKROCK 67	280	115	24.7	5.0	25.2	0.980	17.3	3.5	12.4	2.5	9.9	2.0
BLACKROCK 82	281	115	42.5	17.3	45.9	0.926	29.8	12.1	21.3	8.7	17.0	6.9
BLACKROCK 83	279	115	27.7	6.4	28.4	0.974	19.4	4.5	13.9	3.2	11.1	2.6
FORESTVILLE	246	115	80.2	21.0	82.9	0.967	56.1	14.7	40.1	10.5	32.1	8.4
BRISTOL	248	115	42.1	9.1	43.1	0.977	29.5	6.4	21.1	4.6	16.8	3.6
CHIPPEN HILL	247	115	17.9	3.7	18.3	0.979	12.5	2.6	9.0	1.9	7.2	1.5
CHIPPEN HILL	249	115	17.5	3.4	17.8	0.982	12.3	2.4	8.8	1.7	7.0	1.4
THOMASTON	406	115	24.6	5.4	25.2	0.977	17.2	3.8	12.3	2.7	9.8	2.2
CAMPVILLE	407	115	58.3	13.6	59.9	0.974	40.8	9.5	29.2	6.8	23.3	5.4
MILLSTONE	29	345	2.0	0.9	2.2	0.912	1.4	0.6	1.0	0.5	0.8	0.4
TOTAL			4370	911	4479		3059	638	2185	455	1748	364

Typically, in switching transient studies, load is not modeled, because it doesn't have a significant effect on overvoltages when the natural frequencies are in the many hundreds of Hz to kHz range. GE has done transient studies since the 1930's using a transient network analyzer (analog laboratory model), and load models were not typically used. These SWCT studies, however, are unique, having low-order harmonic resonances interacting with transformer non-linearities which can produce sustained overvoltages. Interaction of load with these temporary overvoltages (TOVs) is not easily defined due to the distributed nature and composition of the load, including the power delivery network, which is not normally modeled. The CIGRE paper 33-210 (1990), "Temporary Overvoltages: Causes, Effects, and Evaluation," states: "Actual data on loads and their effect on TOV are scarce." Lumping only linear R-L load at transmission buses is not an accurate representation of load. For these types of studies, the load must be modeled on a physical basis to account for large signal response. One approach is to utilize load models developed for harmonic studies, however these models do not typically include non-linearities of transformers nor do they accurately represent the response of motors or power electronics based load. Therefore, the modeling of no load or little load provides a conservative approach in determining the effect of the low-order resonant characteristics of the system on potential sustained overvoltages.

Nevertheless, an approach was taken to model higher levels of load primarily because the more critical cases were found under conditions corresponding to higher load levels, and with little load modeled, the overvoltages were assumed to be pessimistic. For example, high sustained overvoltages, with a large 2^{nd} harmonic resonance, were observed in fault clearing scenarios having prior line outages and all 115 kV capacitor banks in service. This condition is reasonable only for load conditions of about 70% or higher. Therefore, the approach was taken to model the load, capacitor bank dispatch, and shunt reactor dispatch corresponding to the load levels of 40%, 50%, and 70%. The modeling of load tends to add damping and reduce the magnitude of resonances, which should result in a more realistic simulation of the temporary overvoltages.

A physical load model approach is commonly used by GE in harmonic studies and is considered to be a reasonable approach to use in the NU cable project TOV analysis. The model includes a damped transformer, a resistive load component, a motor load component (locked rotor representation), and power factor correction capacitance. Note that there will always be uncertainty in the load representation because there is very little data (only P,Q) on the actual loads. Also, note that these models do not include non-linearities of transformers nor do they include power electronics based load. Further details of the physically-based load model are included in Appendix A.

Cases Studied

Case scenarios included fault application and clearing of the 345 kV cables and adjacent transmission lines as well as bus faults. Table 6 shows the case scenarios that were considered in the study.

Table 6. Case Scenarios Studied

Case Scenario Name	Fault Clearing	Fault Location	Fault Type
plmlmt3ph	Plumtree – Long Mountain 345 kV Line	Plumtree 345 kV	3ph
plmlmt2ph	Plumtree – Long Mountain 345 kV Line	Plumtree 345 kV	2ph
plmlmt1ph	Plumtree – Long Mountain 345 kV Line	Plumtree 345 kV	1ph
devbsk3ph	E. Devon – Beseck 345 kV Line	E. Devon 345 kV	3ph
devbsk2ph	E. Devon – Beseck 345 kV Line	E. Devon 345 kV	2ph
devbsk1ph	E. Devon – Beseck 345 kV Line	E. Devon 345 kV	1ph
norplm3ph	Norwalk – Plumtree 345 kV Cable	Norwalk 345 kV	3ph
norplm2ph	Norwalk – Plumtree 345 kV Cable	Norwalk 345 kV	2ph
norplm1ph	Norwalk – Plumtree 345 kV Cable	Norwalk 345 kV	1ph
sngdev3ph	Singer – E. Devon 345 kV Cable	Singer 345 kV	3ph
sngdev2ph	Singer – E. Devon 345 kV Cable	Singer 345 kV	2ph
sngdev1ph	Singer – E. Devon 345 kV Cable	Singer 345 kV	1ph
nor3ph	Bus Fault	Norwalk 345 kV	3ph
nor2ph	Bus Fault	Norwalk 345 kV	2ph
nor1ph	Bus Fault	Norwalk 345 kV	1ph
plm3ph	Bus Fault	Plumtree 345 kV	3ph
plm2ph	Bus Fault	Plumtree 345 kV	2ph
plm1ph	Bus Fault	Plumtree 345 kV	1ph
nor1153ph	Bus Fault	Norwalk 115 kV	3ph
plm1153ph	Bus Fault	Plumtree 115 kV	3ph
sngnor3ph	Singer – Norwalk 345 kV Cable	Singer 345 kV	3ph
sngnor2ph	Singer – Norwalk 345 kV Cable	Singer 345 kV	2ph
sngnor1ph	Singer – Norwalk 345 kV Cable	Singer 345 kV	1ph

Each of the case scenarios defined above was simulated under a range of conditions including various prior line outages and load levels, which defined the capacitor bank dispatch, shunt reactor dispatch, and load model. Faults were applied at voltage zero, and fault duration was varied between 3.5 and 4.0 cycles. Table 7 shows the conditions that were simulated in each of the above case scenarios. Each case scenario simulated 24 or 30 conditions.

Table 7. Conditions Simulated in Case Scenarios

	Variations	Number of Variations
Line Outages	1. All Lines in Service 2. E. Devon – Beseck 345 kV Line Out 3. Plumtree – Long Mountain 345 kV Line Out 4. Long Mountain – Pleasant Valley 345 kV Line Out 5. Norwalk Harbor – Long Island 138 kV Cables Out	5
Load Level	1. 40% 2. 50% 3. 70%	3
Fault Duration	1. 3.5 cycles 2. 4.0 cycles	2
	Total Combined Variations:	30[1]

Switching Transient Results

For each case scenario, voltages were monitored at Plumtree, Norwalk, E. Devon, and Beseck, 345 kV and at Plumtree, Norwalk, East Shore, Frost Bridge, Stony Hill, and Rocky River 115 kV. The temporary overvoltage (TOV), which is a sustained overvoltage lasting more than two cycles, was measured as the peak value of the voltage from about two cycles after fault clearing to the end of the simulation (250 ms) in three time windows. The three time windows (0.13 to 0.17 s, 0.17 to 0.21 s, and 0.21 to 0.25 s) provide insight into the decay or growth of the TOV magnitude following fault clearing. The TOVs were tabulated for all variations of each case scenario and are found in Appendix B. The highest TOVs for each case scenario, along with the system conditions, are given in Table 8. Plots for these cases are given in Appendix E.

[1] Case scenarios involving fault clearing of Plumtree – Long Mountain line or E. Devon – Beseck line had 24 variations, since that line was excluded from pre-fault line outage conditions.

Table 8. Highest TOVs for each Case Scenario

Fault Clearing	Fault & Location	Case	Load Level	Lines Out	Fault Clear	Max 2C TOV & Location	Max 4C TOV & Location	Max 6C TOV & Location
Plum-Lmtn	3ph fault Plum	13	40%	ALL IN	3.5 cy	1.34 PLUM345	1.30 PLUM345	1.28 PLUM345
Plum-Lmtn	2ph fault Plum	13	40%	ALL IN	3.5 cy	1.32 PLUM345	1.28 PLUM345	1.26 PLUM345
Plum-Lmtn	1ph fault Plum	10	70%	ED-BS	4.0 cy	1.18 RRVR115	1.11 BSCK345	1.11 BSCK345
Edvn-Bsck	3ph fault Edvn	13	40%	ALL IN	3.5 cy	1.31 EDVN345	1.38 EDVN345	1.37 EDVN345
Edvn-Bsck	2ph fault Edvn	13	40%	ALL IN	3.5 cy	1.48 EDVN345	1.44 EDVN345	1.38 EDVN345
Edvn-Bsck	1ph fault Edvn	1	40%	ALL IN	4.0 cy	1.34 EDVN345	1.29 EDVN345	1.24 EDVN345
Nrwk-Plum	3ph fault Nrwk	26	70%	ALL IN	3.5 cy	1.62 RRVR115	1.66 RRVR115	1.66 RRVR115
Nrwk-Plum	2ph fault Nrwk	2	40%	ED-BS	4.0 cy	1.66 EDVN345	1.53 EDVN345	1.47 EDVN345
Nrwk-Plum	1ph fault Nrwk	15	70%	NH-LI	4.0 cy	1.30 RRVR115	1.17 RRVR115	1.17 RRVR115
Sngr-Edvn	3ph fault Sngr	11	70%	ALL IN	4.0 cy	1.35 RRVR115	1.41 RRVR115	1.41 RRVR115
Sngr-Edvn	2ph fault Sngr	18	40%	PL-LM	3.5 cy	1.48 PLUM345	1.47 PLUM345	1.43 PLUM345
Sngr-Edvn	1ph fault Sngr	17	40%	ED-BS	3.5 cy	1.37 EDVN345	1.38 EDVN345	1.35 NRWK345
Nrwk Fault	3ph fault Nrwk	14	70%	LM-PV	4.0 cy	1.42 RRVR115	1.29 RRVR115	1.25 RRVR115
Nrwk Fault	2ph fault Nrwk	2	40%	ED-BS	4.0 cy	1.48 EDVN345	1.44 EDVN345	1.41 EDVN345
Nrwk Fault	1ph fault Nrwk	17	40%	ED-BS	3.5 cy	1.31 EDVN345	1.27 EDVN345	1.23 EDVN345
Plum Fault	3ph fault Plum	11	70%	ALL IN	4.0 cy	1.43 RRVR115	1.39 RRVR115	1.39 RRVR115
Plum Fault	2ph fault Plum	11	70%	ALL IN	4.0 cy	1.40 RRVR115	1.33 RRVR115	1.29 RRVR115
Plum Fault	1ph fault Plum	11	70%	ALL IN	4.0 cy	1.24 RRVR115	1.16 RRVR115	1.14 RRVR115
Nrwk Fault	3ph flt Nrw115	17	40%	ED-BS	3.5 cy	1.36 EDVN345	1.32 EDVN345	1.28 EDVN345
Plum Fault	3ph flt Plm115	11	70%	ALL IN	4.0 cy	1.35 RRVR115	1.24 RRVR115	1.22 RRVR115
Sngr-Nrwk	3ph fault Sngr	11	70%	ALL IN	4.0 cy	1.41 RRVR115	1.47 RRVR115	1.49 RRVR115
Sngr- Nrwk	2ph fault Sngr	26	70%	ALL IN	3.5 cy	1.51 RRVR115	1.50 RRVR115	1.50 RRVR115
Sngr- Nrwk	1ph fault Sngr	11	70%	ALL IN	4.0 cy	1.33 RRVR115	1.35 RRVR115	1.34 RRVR115

Figure 2 shows TOV capability curves for typical arresters, as given by IEEE Std. C62.22-1997 (IEEE Guide for the Application of Metal Oxide Surge Arresters for Alternating-Current Systems). The curves define the magnitude (in per unit on base of nominal system voltage) and duration of TOVs that the arrester can withstand. The two curves indicate that the withstand capability is reduced when considering a prior energy dissipation. These curves assume an MCOV (maximum continuous operating voltage) rating that is 1.1 times nominal voltage. The curves would vary somewhat with manufacturer and selected arrester rating. It should be pointed out that the failure mode of a surge arrester exposed to excess TOV is to become a short circuit; thus a fault causing an excessive TOV could be followed by a consequential fault elsewhere in the system. This type of correlation between faults is not normally considered in system planning.

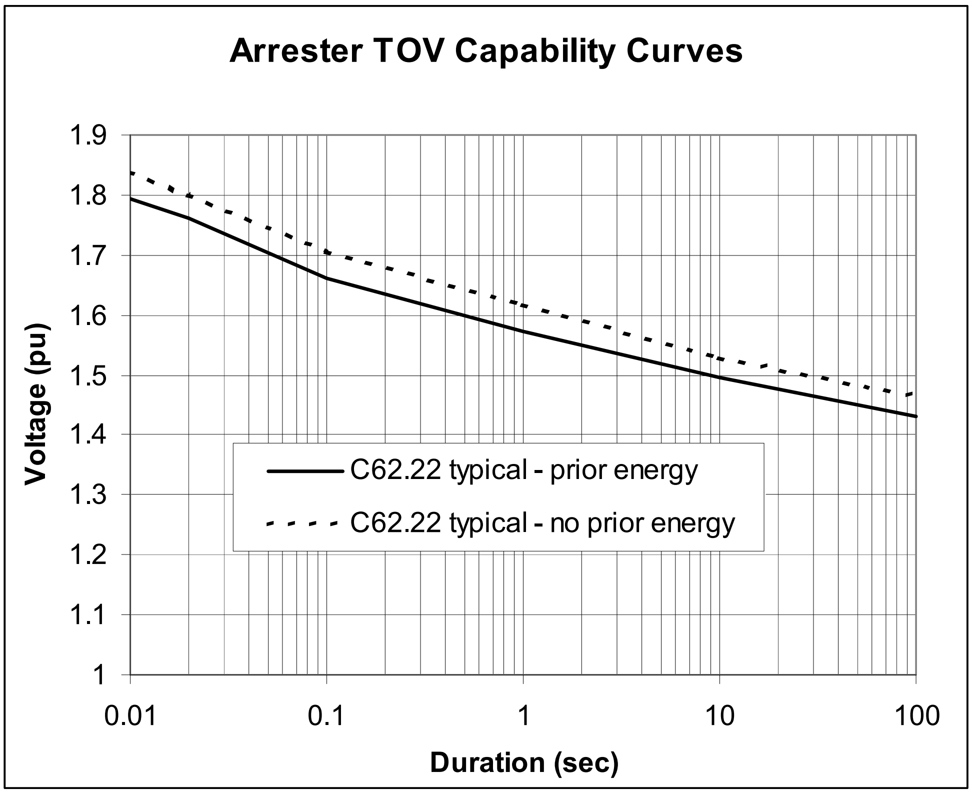

Figure 2. TOV Capability Curves for Typical Surge Arresters

Figure 3 shows guideline TOV withstand characteristics for sample EHV equipment, as given by CIGRE Working Group 33.10 on Temporary Overvoltages[2]. The graph summarizes data gathered from various manufacturers on transformers and shunt reactors and information from IEEE and IEC standards on shunt capacitors and voltage transformers.

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[2] "Temporary Overvoltage Withstand Characteristics of Extra High Voltage Equipment," published in Electra No. 179, August 1998

The TOV withstand characteristics are not standardized for all equipment, but the data could be used to estimate TOV withstand characteristics when actual equipment data is unknown.

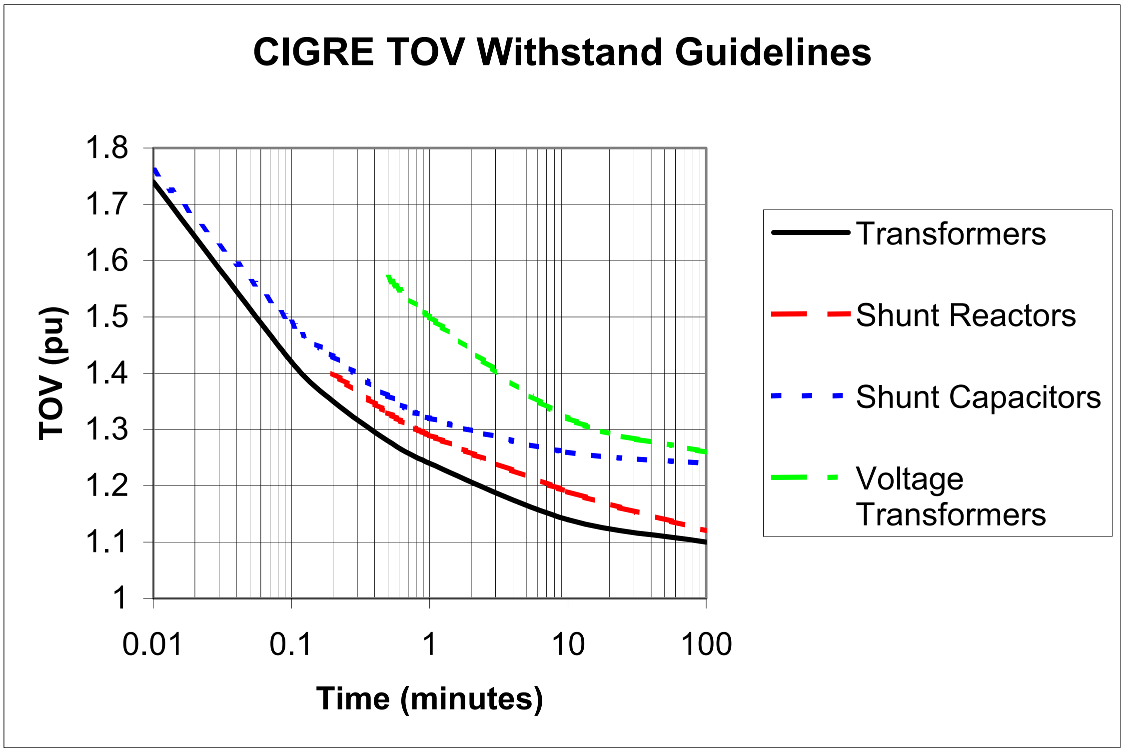

Figure 3. CIGRE TOV Withstand Guidelines for EHV Equipment

It is anticipated that the surge arresters at locations adjacent to the 345 kV cables will be rated 294 kV and those at other 345 kV locations are rated 276 kV. Figure 4 shows TOV capability curves for typical 294 kV and 276 kV arresters, based on a GE surge arrester guide. Also included is the CIGRE transformer TOV withstand guideline from Figure 3. Note that for shorter duration TOVs, the surge arrester is more limiting, and for longer duration TOVs, the transformer is more limiting.

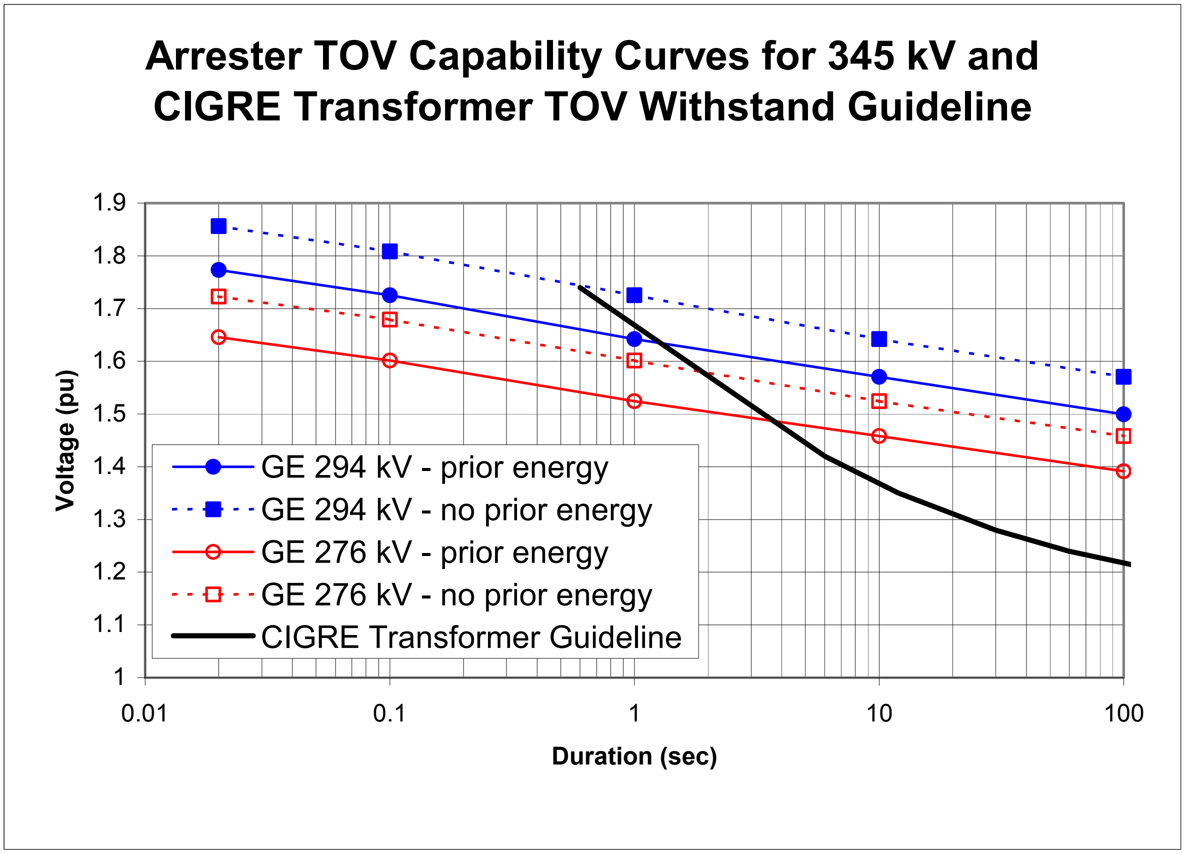

Figure 4. Estimated TOV Limitations for 345 kV

The highest TOV observed in the study on the 345 kV cable system was 1.66 pu at E. Devon 345 kV, with an estimated duration of 50 ms, as shown in Figure 5. In this case, the E. Devon – Beseck line was out, the load level was 40%, and the Norwalk – Plumtree cable was tripped following a 2phg fault. The TOV decayed to 1.53 pu during the next 40 ms time window and to 1.47 pu during the following 40 ms time window. The arrester TOV capability curve defines the duration and magnitude of TOVs that may be applied before the arrester voltage must be reduced to its MCOV capability. Therefore, a slowly decaying TOV that follows the TOV capability curve would actually exceed the TOV capability of the arrester. However, since the simulated TOV decays much faster than the TOV capability curve, it is expected to be within the capability of a typical 294 kV surge arrester at E. Devon 345 kV.

TOVs observed on the 345 kV system outside of the cable system were lower than those on the cable system. The highest TOV observed on the overhead 345 kV loop was 1.35 pu at Long Mountain.

A high TOV of 1.66 pu was also observed at Rocky River 115 kV in a different case, as has been observed in previous studies, and is shown in Figure 6. In this case, all lines were in service, the load level was 70%, and the Norwalk – Plumtree cable was tripped following a 3phg fault. Voltage magnification was observed at the Rocky River 115 kV capacitor bank with a magnitude that was higher than the voltage at the 345 kV disturbance location and appears to be growing in magnitude. This resonant condition with the Rocky River capacitor bank should be addressed. For example, the capacitor bank could be replaced by a filter or a synchronous condenser. A TOV of 1.45 pu was also observed at Stony Hill 115 kV, which is another location where voltage magnification has been observed. TOVs at other 115 kV capacitor bank locations were below 1.4 pu.

The maximum circuit breaker transient recovery voltage (TRV) observed in the study was 718 kV, when the Plumtree – Long Mountain line was tripped following a 1phg fault. The 718 kV TRV occurs on an unfaulted phase and is within the capability defined for 362 kV breakers in ANSI C37.06. The circuit breaker voltages and currents are shown in Figure 7. A table of maximum TRVs for each case is included in Appendix C.

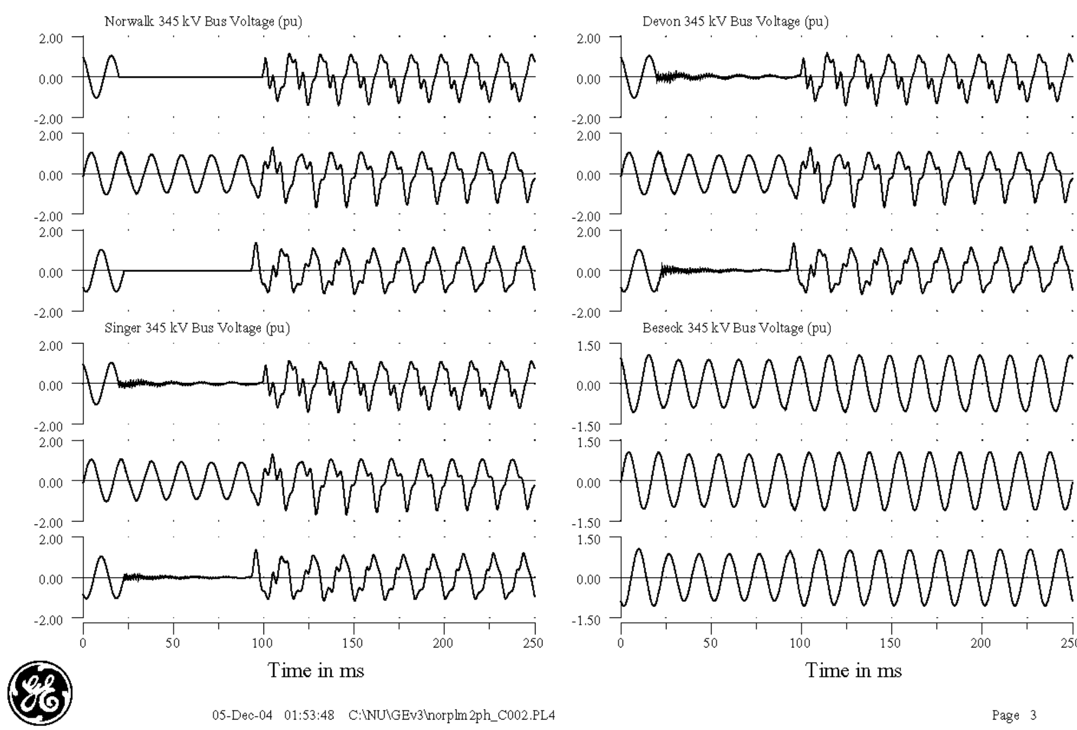

Figure 5. 2ph Fault at Norwalk 345 kV and Clearing Norwalk – Plumtree Cable

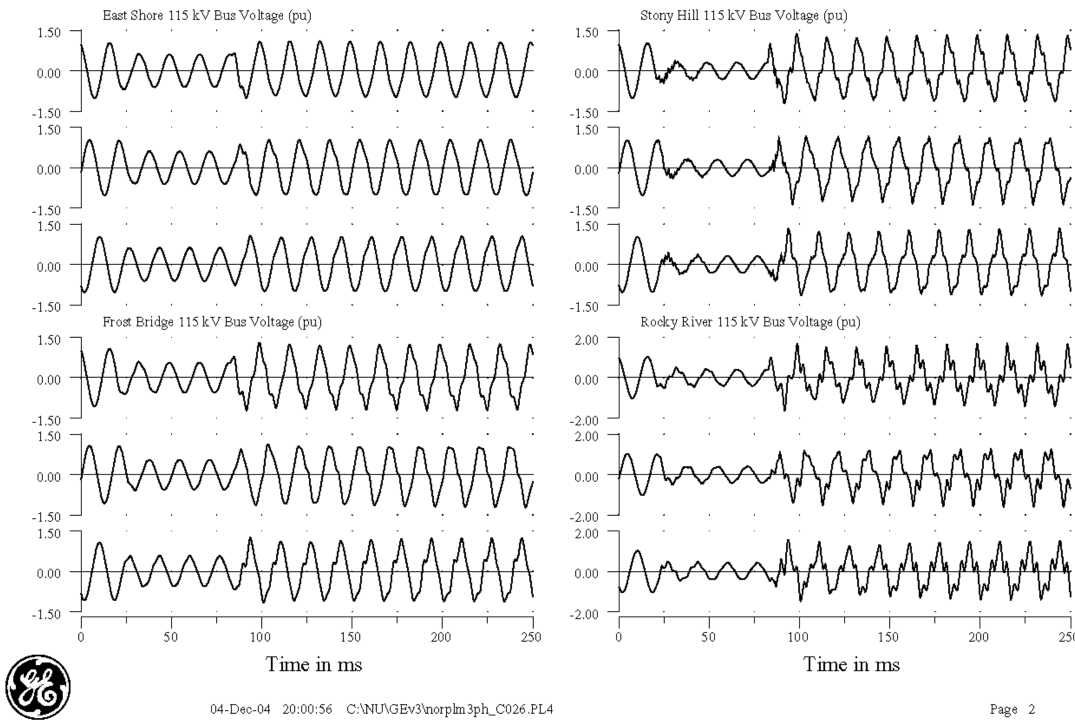

Figure 6. 3ph Fault at Norwalk 345 kV and Clearing Norwalk – Plumtree Cable

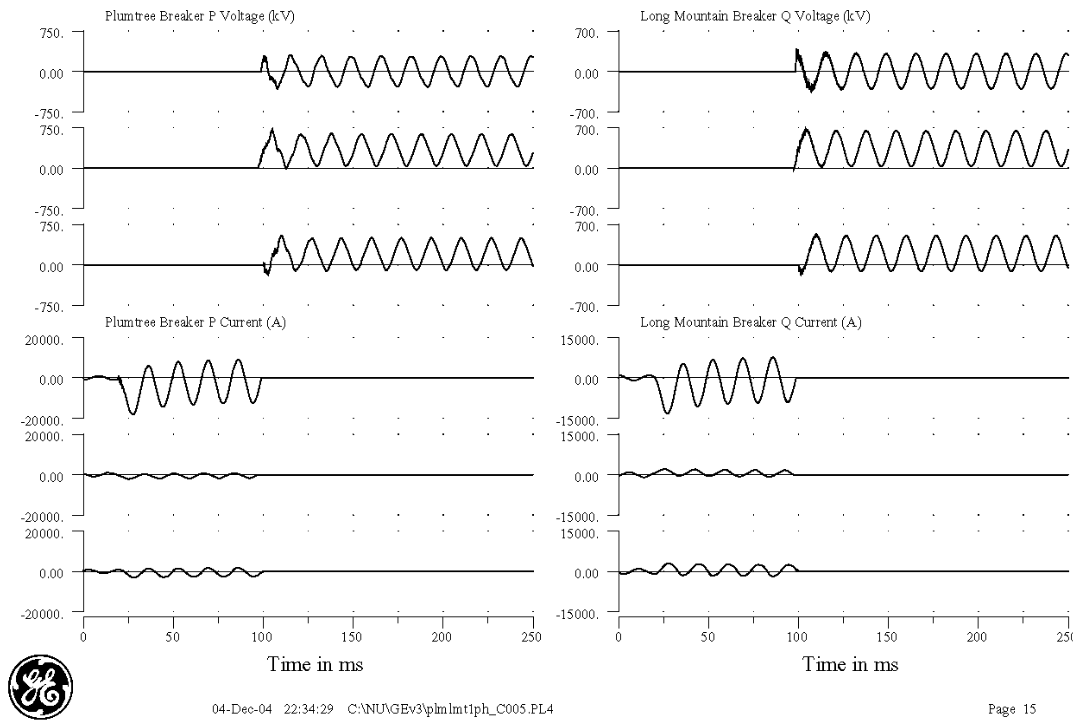

Figure 7. Breaker TRV While Clearing 1phg Fault on Plumtree – Long Mountain Line

Resonance Evaluation

Resonance screening simulations were performed to calculate the positive-sequence driving-point impedance versus frequency at Norwalk 345 kV under various line outage and load level conditions. Table 9 shows the conditions that were evaluated and the frequency and magnitude of the first resonance. The conditions included 40%, 50%, and 70% load levels, with corresponding capacitor bank dispatch, shunt reactor dispatch, and load model. The no load condition was the same as the 40% load level condition, except that there was no load model. The resonant frequency is given in pu of 60 Hz, and the magnitude is given in ohms. The driving-point impedance plots are provided in Appendix D. The highest TOV cases appear to occur when resonances are just below 3rd harmonic and of relatively high magnitude, with 40% or 50% system loading. With the frequencies of the first resonance varying between 2.1 pu (with 70% loading) and 3.4 pu of 60 Hz (with 40% loading), it is likely that there could be many conditions that result in a resonance near 3rd harmonic. It is also possible that with further contingencies (system weakening), the resonance could be at 2nd harmonic or below.

Table 9. Driving-Point Impedance of First Resonance at Norwalk 345 kV

Condition	70% Load		50% Load		40% Load		No Load	
Lines and Cables In/Out	**f (pu)**	**Z (Ω)**	**f (pu)**	**Z (Ω)**	**f (pu)**	**Z (Ω)**	**f (pu)**	**Z (Ω)**
All Lines In	2.5	74.6	3.0	121.6	3.1	153.3	3.1	279.0
E. Devon - Beseck Line Out	2.4	100.5	2.8	160.9	2.8	196.0	2.8	337.5
Plumtree - Long Mountain Line Out	2.4	97.7	2.7	149.5	2.8	180.4	2.7	311.3
Long Mountain - Pleasant Valley Line Out	2.3	82.0	2.6	124.8	2.7	152.3	2.7	269.4
Norwalk Harbor - Northport LI Cables Out	2.3	67.6	2.8	102.3	2.9	124.7	2.9	212.7
Norwalk - Plumtree Cable Out	2.6	97.8	3.0	171.9	3.1	220.3	3.2	397.5
Singer - E. Devon Cable Out	2.6	72.8	3.1	119.0	3.2	151.3	3.3	281.4
Norwalk - Singer Cable Out	2.6	69.0	3.2	109.8	3.4	140.5	3.5	269.0
E. Devon - Beseck Line Out & Plumtree - Long Mountain Line Out	2.1	143.2	2.3	199.9	2.3	228.8	2.2	372.9
Norwalk - Plumtree Cable Out & E. Devon - Beseck Line Out	2.4	181.3	2.6	282.9	2.6	332.4	2.5	542.2
Singer - E. Devon Cable Out & Plumtree - Long Mountain Line Out	2.4	96.8	2.8	149.3	2.8	181.4	2.8	317.0
Plumtree - Long Mountain Line Out & Norwalk - Singer Cable Out	2.4	93.6	2.9	143.3	3.0	176.0	3.0	314.6
Norwalk - Plumtree Cable Out & Singer - E. Devon Cable Out	2.6	93.9	3.1	165.6	3.3	215.2	3.4	400.8
Norwalk - Plumtree Cable Out & Norwalk - Singer Cable Out	2.6	86.1	3.3	144.1	3.5	189.0	3.7	368.8
E. Devon - Beseck Line Out & Norwalk - Singer Cable Out	2.5	90.0	3.0	144.7	3.1	180.6	3.1	326.9
Norwalk - Singer Cable Out & Singer - E. Devon Cable Out	2.6	67.1	3.3	106.1	3.5	136.5	3.6	268.6
Singer - E. Devon Cable Out & E. Devon - Beseck Line Out	2.7	64.1	3.2	100.1	3.3	125.7	3.4	232.4
2 Norwalk - Singer Cables Out	2.6	78.8	3.3	115.1	3.6	142.9	3.8	271.6
2 Singer - E. Devon Cables Out	2.6	100.5	3.0	172.8	3.1	218.7	3.1	385.0

Sensitivity Analysis

A sensitivity analysis was performed to consider the effect of a weakened system, additional capacitor bank installations at 115 kV, short additions of 345 kV XLPE cable, reduced load (30%), and point-on-wave variations of fault application.

Since the first resonance is just above 2^{nd} harmonic (2.1 pu of 60 Hz) with the E. Devon – Beseck and Plumtree – Long Mountain lines out, additional simulations were performed to shift the resonance just below 2^{nd} harmonic and evaluate the impact on TOVs. The resonance could shift below 2^{nd} harmonic if the system is weaker and/or if further capacitance is added. The system was weakened by modifying the equivalent source driving-point impedances, reducing their short-circuit contributions to 80%; i.e., the impedances were increased by 1.25 (1/0.8). Capacitor banks which are potential future installations at

115 kV stations were added at Ansonia (40 MVAR), Bunker Hill (52.4 MVAR), and Hawthorne (40 MVAR). Further increases in capacitance were considered by adding 1 mile, 2 miles, and 5 miles of XLPE cable (three parallel sets) at E. Devon 345 kV going toward Beseck. Table 10 shows the resulting frequencies and magnitudes of the resonances.

Table 10. Driving-Point Impedance of First Resonance at Norwalk 345 kV
Sensitivity Analysis with E. Devon – Beseck and Plumtree – Long Mountain Lines Out
(70% Load)

Weakened Equivalent Sources (80%)	115 kV Capacitor Bank Addition	345 kV XLPE Cable Addition (miles)	f (Hz)	Z (Ω)
Default Condition (from Table 9 above)			127	143.2
X			125	138.0
	X		125	137.9
X	X		123	133.0
X	X	1 mi	121	134.3
X	X	2 mi	120	135.5
X	X	5 mi	116	138.4

The fault cases were repeated for the Plumtree – Long Mountain line, with all variations of load level, line outages and fault clearing times, for the 2-mile and 5-mile cable additions, including the weakened sources and 115 kV capacitor bank additions. The resulting TOVs are shown in Figure 8 as a function of the time windows at 2-cycles, 4-cycles, and 6-cycles following the fault. The highest TOVs with the 2-mile and 5-mile cable additions were observed with the prior outage of the E. Devon – Beseck line and either 40% load or 70% load and were 1.45 pu and 1.67 pu, respectively, as compared to 1.32 pu in the default condition. This sensitivity analysis indicates that relatively small changes in resonance conditions near 2nd harmonic can have significant effects on TOVs. However, the highest magnitude observed (1.67 pu) was similar to the highest TOV observed in all of the other cases summarized in Table 8 (1.66 pu).

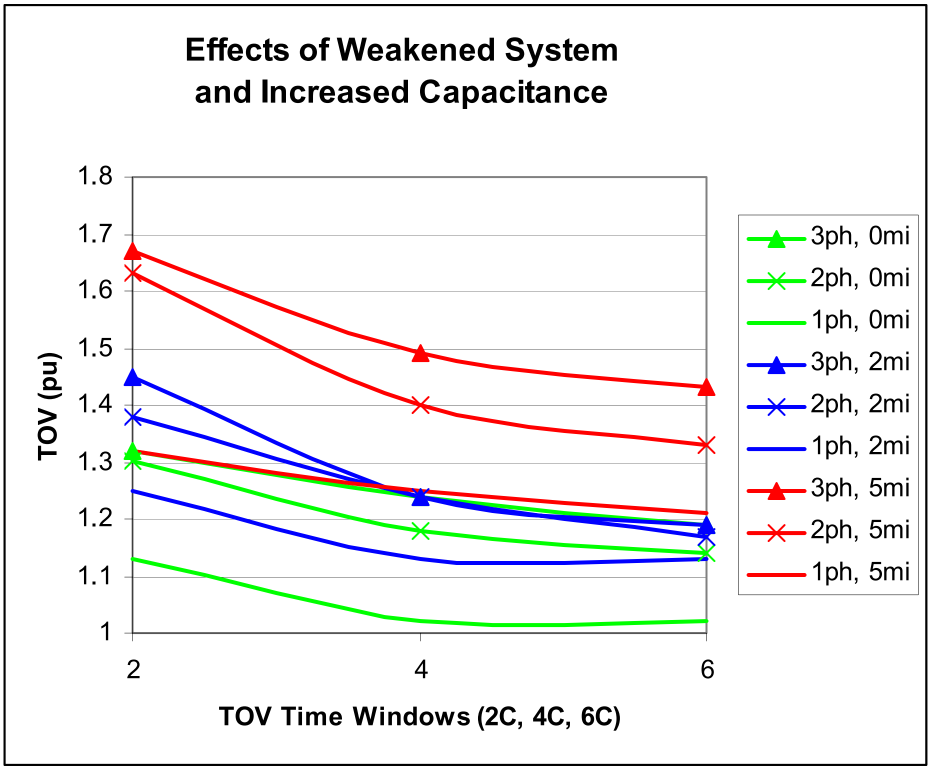

Figure 8. Effects of Weakened System and Increased Capacitance for Faults on Plumtree – Long Mountain Line

Another sensitivity analysis was performed to evaluate the effect of reduced load (30%). Faults were repeated for cases where the higher TOVs were observed at 40% load. These included 2-phase faults on the Norwalk – Plumtree cable, the E. Devon – Beseck line, Singer – E. Devon cable, and the Norwalk bus, with all variations of line outages and fault clearing times. Shunt capacitor dispatch and shunt reactor dispatch were the same as the 40% load level, but the load was changed from 40% to 30%. The resulting TOVs are shown in Figure 9 as a function of the time windows at 2-cycles, 4-cycles, and 6-cycles following the fault. The TOVs in these cases increased by about 0.1 pu. The highest TOV observed was 1.75 pu at Singer 345 kV for a fault on the Norwalk – Plumtree cable with the E. Devon – Beseck line out of service (Figure 10).

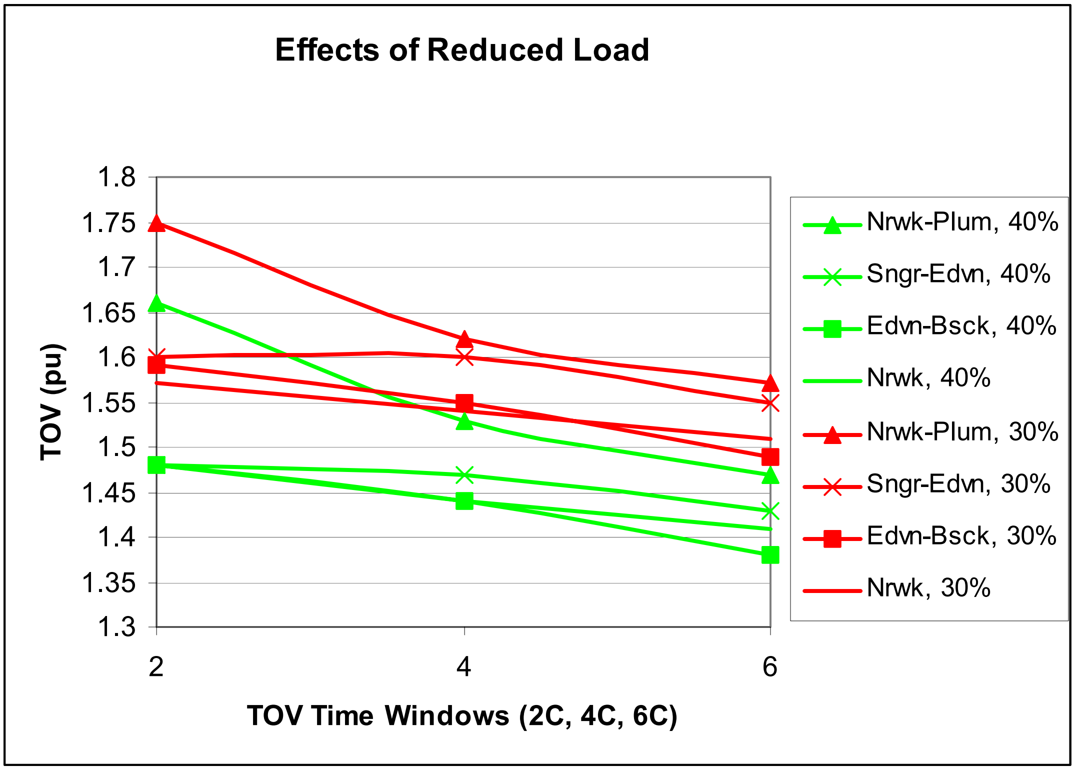

Figure 9. Effects of Reduced Load for Selected Faults

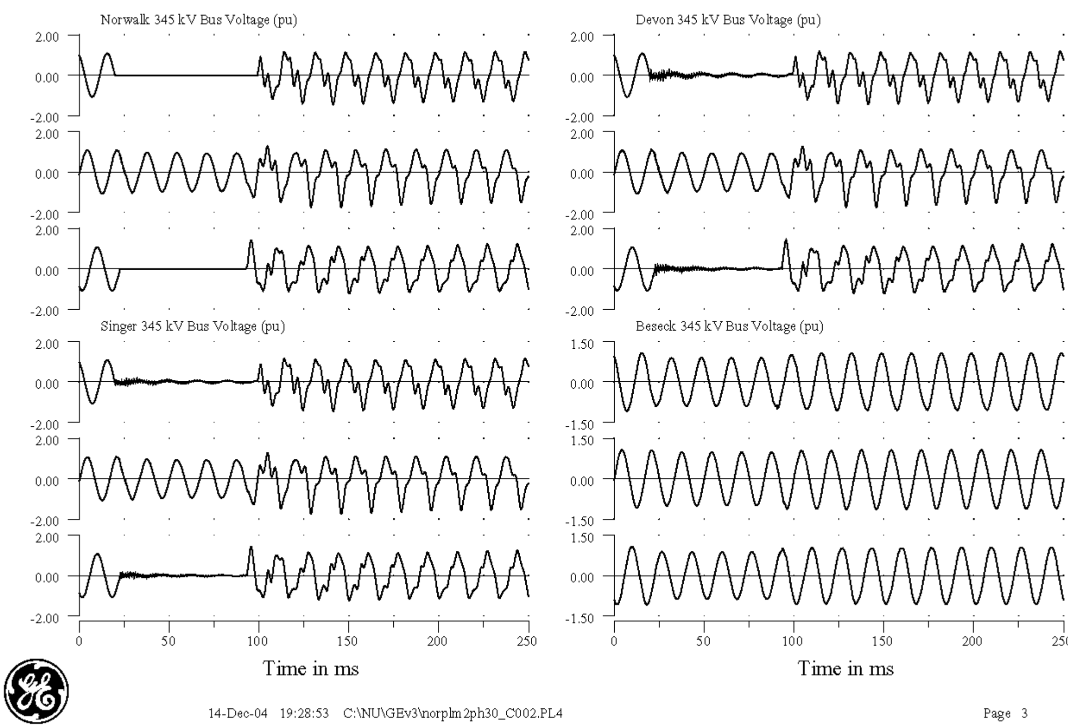

Figure 10. 2ph Fault at Norwalk 345 kV and Clearing Norwalk – Plumtree Cable, 30% Load

Selected cases were used to evaluate point-on-wave variations of fault application and the effect on TOVs. All faults in the study were applied at successive voltage zeros to obtain a high inrush condition for nearby transformers. Two cases were selected as sample cases to test different fault application timing – a 2-phase fault case and a 3-phase fault case. A 2-phase fault is likely to occur simultaneously in each phase if lightning is the cause. The Norwalk – Plumtree fault case (1.66 pu TOV in Case 2), with 40% load and the E. Devon – Beseck line out of service, was selected for point-on-wave variation. The fault application time was varied over ½ cycle in steps of 100 µs. Simultaneous faults to ground were applied on phases A and B, B and C, and C and A with breaker clearing at 3.5 and 4.0 cycles. Figure 11 shows the effect of the varying fault application time on the TOVs. The plot illustrates the high degree of variability in the TOVs with fault application time, ranging from 1.15 to 1.68 pu. It also shows that the initial assumption of fault application at successive voltage zeros was reasonable, since the 1.66 pu TOV was similar to the maximum observed in the sensitivity case.

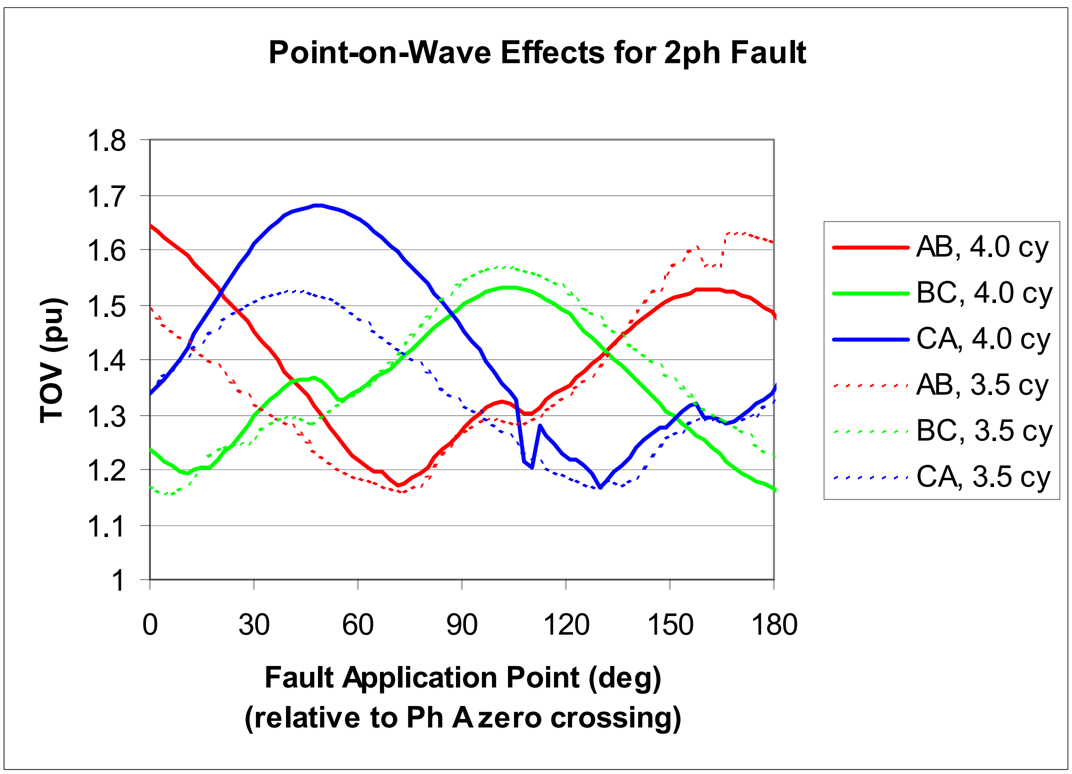

Figure 11. Effect of Point-on-Wave Fault Application for
2ph Fault at Norwalk 345 kV and Clearing Norwalk – Plumtree Cable

A 3-phase fault is likely to occur at varying times between phases if a breaker closes into a fault due to grounding straps left on equipment. The Norwalk bus fault case (1.40 pu TOV at

E. Devon in Case 16), with 40% load and all lines in service, was selected for point-on-wave variation. The pole span was assumed to be 90°. The closing time on Phase A was varied over ½ cycle and Phases B and C were closed with variation of ±45° relative to Phase A, resulting in over 600 fault application times. With a constant fault clearing time, the faults lasted approximately 3.5 to 4.0 cycles. Figure 12 shows the statistical distribution of TOVs resulting from the varying fault application times. The plot illustrates the high degree of variability in the TOVs with fault application time, ranging from 1.14 to 1.51 pu. In a statistical analysis, it is common to exclude the outliers at the extremes and use a TOV level that is exceeded only 2% of the time (or is below that level 98% of the time). In this case, the TOVs exceed 1.47 pu in 2% of fault events. This is slightly higher than the TOV found by using successive voltage zeros (difference of 0.07 pu).

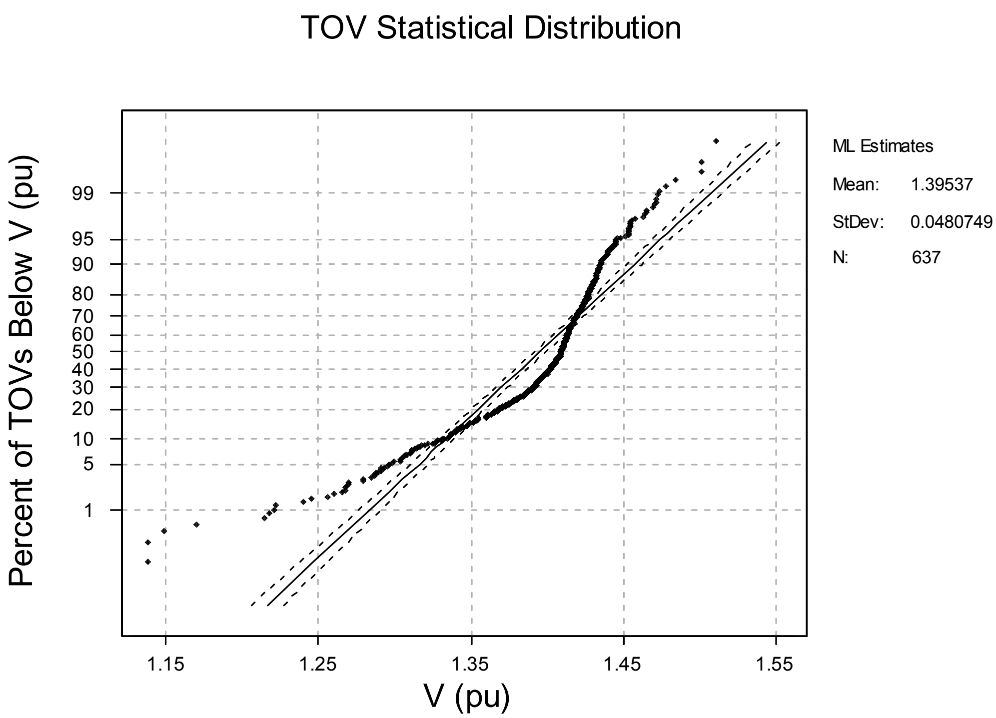

Figure 12. Effect of Point-on-Wave Fault Application for 3ph Fault at Norwalk 345 kV

Conclusions

This study has considered over 1500 simulations with varying system conditions to evaluate temporary overvoltages resulting from fault clearing in the Middletown to Norwalk XLPE alternative configuration. Fault cases included the Plumtree – Long Mountain line, the E. Devon – Beseck line, the Plumtree – Norwalk cable, a Singer – E. Devon cable, a Singer-

Norwalk cable, and various bus faults. The resulting TOVs observed at 345 kV appear to be within typical utility equipment TOV withstand capabilities. However, voltage magnification was observed at Rocky River 115 kV, as seen in previous studies, and is likely to be an existing issue that could be mitigated locally. For example, the capacitor bank at Rocky River could be replaced by a filter or a synchronous condenser.

The driving-point impedance was evaluated at Norwalk 345 kV under a variety of system loading and line outage conditions. It was found that the frequency of the first resonance varies between 2.1 pu (with 70% loading) and 3.6 pu of 60 Hz (with 40% loading), considering all lines in and various outages. With the large number of parameters that can vary in the system, it is likely that a variety of system conditions could result in resonance near 3rd harmonic, and with further contingencies (system weakening) or increased capacitance, the system could be resonant near 2nd harmonic. A concern would be if alternate conditions could cause a higher impedance resonance near the 2nd or 3rd harmonics, which could potentially result in higher TOVs than those observed in this study. It is not feasible to study every possible scenario; however, the study did include a significant number of fault scenarios and resonance evaluation. It is recommended that the ability of equipment to withstand the voltages observed in the study be confirmed with manufacturers.

Appendix A Physical Load Model Description

Appendix B Table of TOVs Observed in Case Scenarios

Appendix C Table of TRVs Observed in Case Scenarios

Appendix D Driving-Point Impedance Plots

Appendix E Selected Plots of TOVs Observed in Case Scenarios