nationalgrid

Paige Graening
Counsel

April 17, 2006

VIA HAND DELIVERY

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

RE: The Application of Narragansett Electric Company d/b/a National Grid, Southern Rhode Island Transmission Project (Docket No. 3732)

Dear Luly:

I am enclosing for filing an original and nine (9) copies of National Grid's responses to the Division's First Set of Data Requests in the captioned docket.

We are sending hard copies to Ms. Wilson-Frias, Mr. Nault and Mr. Booth and are providing an electronic copy to the rest of the service list, which is attached, and to Mr. Krathwohl, counsel for ISO-New England.

Please acknowledge receipt on the enclosed copies of the filing and this letter and return to me via The enclosed self-addressed, stamped envelope.

Thank you for your cooperation.

Respectfully,

Paige Graening

Paige Graening

PG/mea
Enclosures

cc: Cynthia G. Wilson-Frias, Esq. (via Hand Delivery)
Mr. Alan Nault (Via Hand Delivery)
Mr. Gregory L. Booth (Via Federal Express)
Service List (Dkt. 3732)
Eric J. Krathwohl, Esq.

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CERTIFICATE OF SERVICE

I hereby certify that on April 17, 2006 I delivered a copy of the attached Responses to the Division's First Set of Data Requests prepared by The Narragansett Electric Company d/b/a National Grid to the Service List in PUC Docket 3732 by electronic mail, hand delivery and overnight delivery.

____

Mary E. Avery

Dated: April 17, 2006

Division Data Request 1-1

Request:

Provide the historical load data for the PSA used in the forecast.

Response:

See Attachment 1.

Prepared by or under the supervision of: Alan LaBarre, P.E.

PSA FORECAST 2004
NARRAGANSETT ELECTRIC COMPANY
WESTERN NECO PSA
SUMMER PEAK DEMAND WITH SPOT LOADS AT TIME OF COMPANY PEAK (MW)

		With Actual History				With Weather Adjusted History					
Year	Mo	Extreme Weather Scenario	Growth Rate	Normal Weather Scenario	Growth Rate	Extreme Weather Scenario	Growth Rate	Normal Weather Scenario	Growth Rate	Spot Loads	% of Load
1995	8	651.000	.	651.000	.	703.268	.	683.539	.	0.000	0.0%
1996	8	579.000	(11.1%)	579.000	(11.1%)	636.986	(9.4%)	617.042	(9.7%)	0.000	0.0%
1997	7	658.200	13.7%	658.200	13.7%	727.533	14.2%	707.331	14.6%	0.000	0.0%
1998	7	664.000	0.9%	664.000	0.9%	746.454	2.6%	725.884	2.6%	0.000	0.0%
1999	7	736.000	10.8%	736.000	10.8%	764.191	2.4%	743.275	2.4%	0.000	0.0%
2000	8	694.600	(5.6%)	694.600	(5.6%)	789.209	3.3%	767.806	3.3%	0.000	0.0%
2001	8	809.650	16.6%	809.650	16.6%	812.564	3.0%	790.706	3.0%	0.000	0.0%
2002	8	823.600	1.7%	823.600	1.7%	821.729	1.1%	799.692	1.1%	0.000	0.0%
2003	8	810.294	(1.6%)	810.294	(1.6%)	831.420	1.2%	809.194	1.2%	0.000	0.0%
Forecast											
2004	7	861.728	6.3%	839.233	3.6%	861.728	3.6%	839.233	3.7%	16.475	1.9%
2005	7	883.899	2.6%	861.128	2.6%	883.899	2.6%	861.128	2.6%	22.525	2.5%
2006	7	907.966	2.7%	884.991	2.8%	907.966	2.7%	884.991	2.8%	26.525	2.9%
2007	7	932.859	2.7%	909.724	2.8%	932.859	2.7%	909.724	2.8%	27.125	2.9%
2008	7	958.903	2.8%	935.581	2.8%	958.903	2.8%	935.581	2.8%	28.125	2.9%
2009	7	986.171	2.8%	962.663	2.9%	986.171	2.8%	962.663	2.9%	28.125	2.9%
2010	7	1,014.851	2.9%	991.173	3.0%	1,014.851	2.9%	991.173	3.0%	28.125	2.8%
2011	7	1,041.940	2.7%	1,018.093	2.7%	1,041.940	2.7%	1,018.093	2.7%	28.125	2.7%
2012	7	1,066.967	2.4%	1,042.945	2.4%	1,066.967	2.4%	1,042.945	2.4%	28.125	2.6%
2013	7	1,091.164	2.3%	1,066.981	2.3%	1,091.164	2.3%	1,066.981	2.3%	28.125	2.6%
2014	7	1,115.886	2.3%	1,091.559	2.3%	1,115.886	2.3%	1,091.559	2.3%	28.125	2.5%
2015	7	1,141.142	2.3%	1,116.672	2.3%	1,141.142	2.3%	1,116.672	2.3%	28.125	2.5%
2016	7	1,166.942	2.3%	1,142.334	2.3%	1,166.942	2.3%	1,142.334	2.3%	28.125	2.4%
2017	7	1,193.297	2.3%	1,168.628	2.3%	1,193.297	2.3%	1,168.628	2.3%	28.125	2.4%
2018	7	1,220.218	2.3%	1,195.538	2.3%	1,220.218	2.3%	1,195.538	2.3%	28.125	2.3%

Compound Annual Growth

1998-2003 Five Year	4.1%	4.1%	2.2%	2.2%
2003-2008 Five Year	3.4%	2.9%	2.9%	2.9%
2003-2013 Ten Year	3.0%	2.8%	2.8%	2.8%
2003-2018 Fifteen Year	2.8%	2.6%	2.6%	2.6%

Division Data Request 1-2

Request:

Provide the forecast models and the data that was used in developing the models.

Response:

The forecast models and the data that was used in developing the models are shown in working papers from the Area Study effort as Attachments 1 and 2. Attachment 1 shows historical summer peak loads at the substations in the Study Area. The conclusion drawn by reviewing this data was that the Study Area load has essentially grown at the same historical rate as the Western Narragansett Electric Company PSA. As such, the load forecast for this PSA could be used as a starting point for the development of the Study Area forecast.

The "With Spot Loads" columns in Attachment 2 is the 2004 Western Narragansett Electric Company PSA 5% probability summer coincident peak forecast prepared by the Planning and Financial Analysis Department, Distribution Finance New England. This forecast was then modified to exclude all anticipated PSA spot loads and is shown in the columns labeled "Without Spot Loads" in Attachment 2. Finally, the Western Narragansett Electric Company PSA forecast was modified to only include anticipated study area spot loads (2MW for American Power Conversion and 1.5 MW for South County Commons). This forecast is shown in the "With Study Area Spot Loads" columns of Attachment 2. The growth rate indicated in the final column of Attachment 2 was that assumed for the Study Area.

Attachment 3 provides graphical and tabular information of the actual and projected summer peak load for the South County East Study Area. This information was provided within the October 2004 distribution study report.

Prepared by or under the supervision of: Alan LaBarre, P.E.

Historical Area Load Growth (Station Loads Coincident W/ NECo Monthly Peaks)

Substation	1998 (Jul) MVA	1999 (Jul) MVA	2000 (Aug) MVA	2001 (Aug) MVA	2002 (Aug) MVA	2003 (Aug) MVA	
Kenyon	22.0	22.0	25.2	28.5	29.3	30.7	
Lafayette	14.7	17.2	11.1	14.5	14.9	15.9	
Old Baptist	28.0	34.0	28.1	37.0	35.9	31.6	
West Kingston	47.0	44.0	51.5	49.0	59.4	51.3	
Minus 68F3	-6.5	-6.3	-7.3	-7.6	-7.7	-7.8	
Bonnet Supplied by Davisville		7.7		9.5		9.5	
Total Area Load	105.20	118.59	108.57	130.88	131.77	131.14	**Average/yr**
Growth Rate (%)		12.72	-8.44	20.55	0.67	-0.47	**4.51**

Western NECO PSA	664.0	736.0	694.6	809.6	823.6	810.3	**Average/yr**
Growth Rate (%)		10.84	-5.63	16.56	1.73	-1.61	**4.06**

Kenyon 68F3 Feedes Outside Study Area

68F3	7.8	9.0	8.3	8.8	9.7	10.0
Station Load	26.4	31.3	28.7	32.9	36.8	39.3
% of Station Load for 68F3	29%	29%	29%	27%	26%	25%

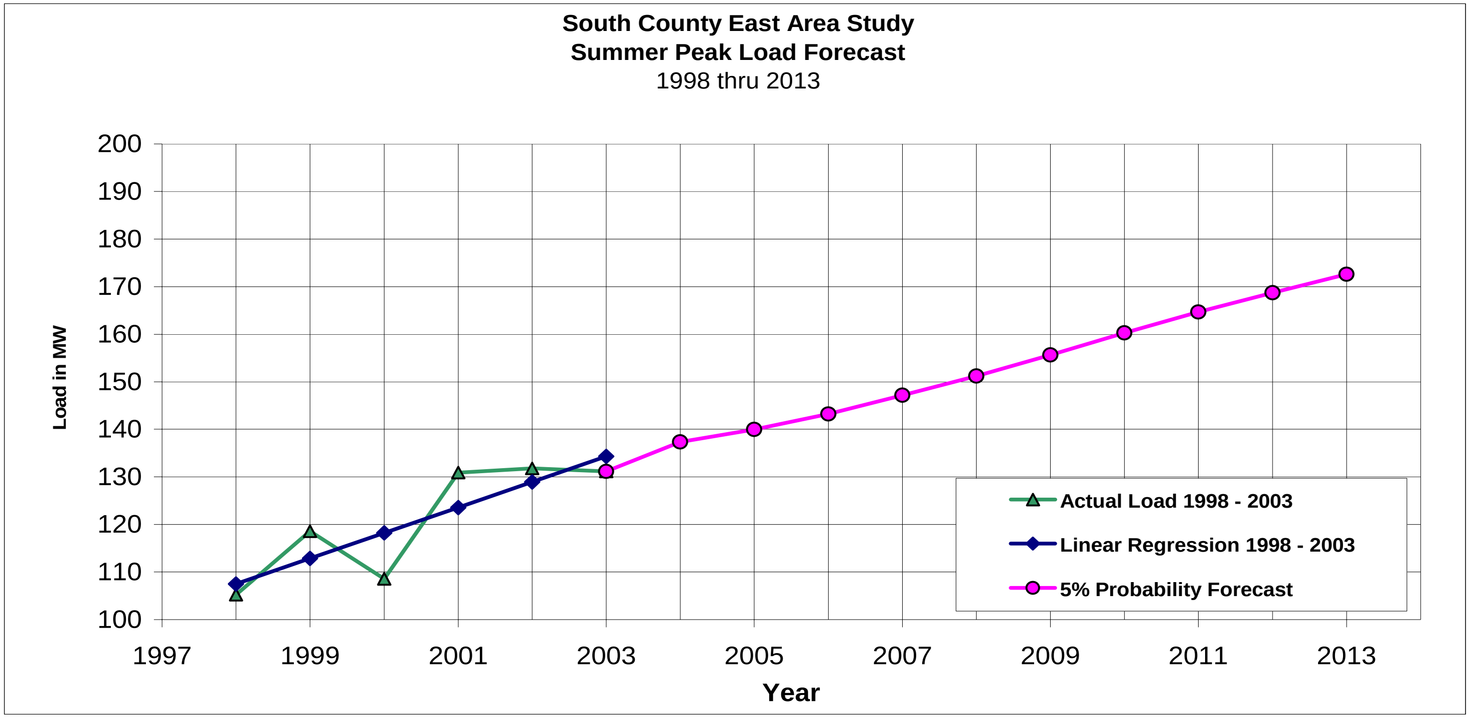
URI	6.0	7.0	6.0	7.0	9.0	9.9
Bonnet	7.4	(1)	8.6	(1)	10.0	(1)
Peacedale	27.0	31.1	28.9	33.0	35.8	32.1
Wakefield	10.2	11.4	10.7	12.4	12.8	20.8
West Kingston	50.6	49.5	54.2	52.4	67.6	62.8

(1) Bonnet Load Supplied By Davisville.

PSA Forecast 2004
Western NECO PSA
Summer Peak Demand At Time of Company Peak

Spot Loads 2004:	
South County Commons	1.5 MVA
Amer. Power Conversion	2.0 MVA
Total	3.5 MVA

	With Spot Loads			Without Spot Loads			With Study Area Spot Loads	
	Extreme Weather Scenario	Growth Rate	Spot Loads	Extreme Weather Scenario	Growth Rate	Study Area Spot Loads	Extreme Weather Scenario	Growth Rate
2003	810.294		0.000	810.294			810.294	
2004	861.728	6.35%	16.475	845.253	4.31%	3.500	848.753	4.75%
2005	883.899	2.57%	22.525	861.374	1.91%	3.500	864.874	1.90%
2006	907.966	2.72%	26.525	881.441	2.33%	3.500	884.941	2.32%
2007	932.859	2.74%	27.125	905.734	2.76%	3.500	909.234	2.75%
2008	958.903	2.79%	28.125	930.778	2.77%	3.500	934.278	2.75%
2009	986.171	2.84%	28.125	958.046	2.93%	3.500	961.546	2.92%
2010	1014.851	2.91%	28.125	986.726	2.99%	3.500	990.226	2.98%
2011	1041.940	2.67%	28.125	1013.815	2.75%	3.500	1017.315	2.74%
2012	1066.967	2.40%	28.125	1038.842	2.47%	3.500	1042.342	2.46%
2013	1091.164	2.27%	28.125	1063.039	2.33%	3.500	1066.539	2.32%



Year	Actual	% Growth	LR	% Growth	PSA 5% Forecast	PSA 5% Growth Forecast
1998	105.20		107.49			
1999	118.59	12.73	112.85	4.99		
2000	108.57	-8.45	118.21	4.75		
2001	130.88	20.55	123.58	4.54		
2002	131.77	0.68	128.94	4.34		
2003	131.14	-0.48	134.30	4.16	131.14	
2004					137.36	1.0475
2005					139.97	1.0190
2006					143.22	1.0232
2007					147.15	1.0275
2008					151.21	1.0275
2009					155.62	1.0292
2010					160.26	1.0298
2011					164.64	1.0274
2012					168.70	1.0246
2013					172.61	1.0232

Division Data Request 1-3

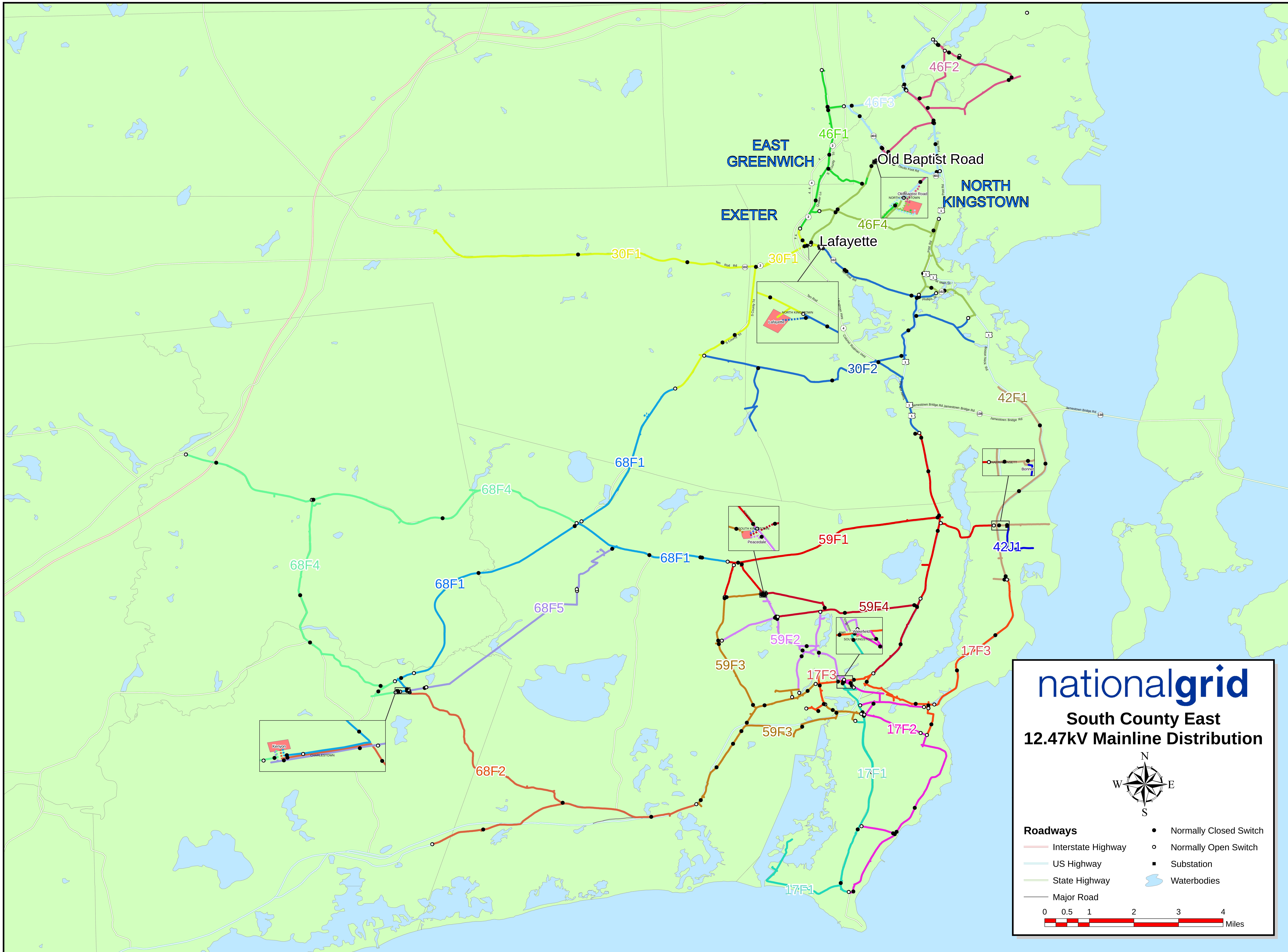
Request:

Please provide system maps showing distribution circuits as shown in Figures 1 and 2 of the Distribution Study. The maps should identify circuits by number (or other ID), substation source, conductor size, spot loads and any distribution switches that can be used to tie circuits or shift loads. Please note if switches are normally open or normally closed.

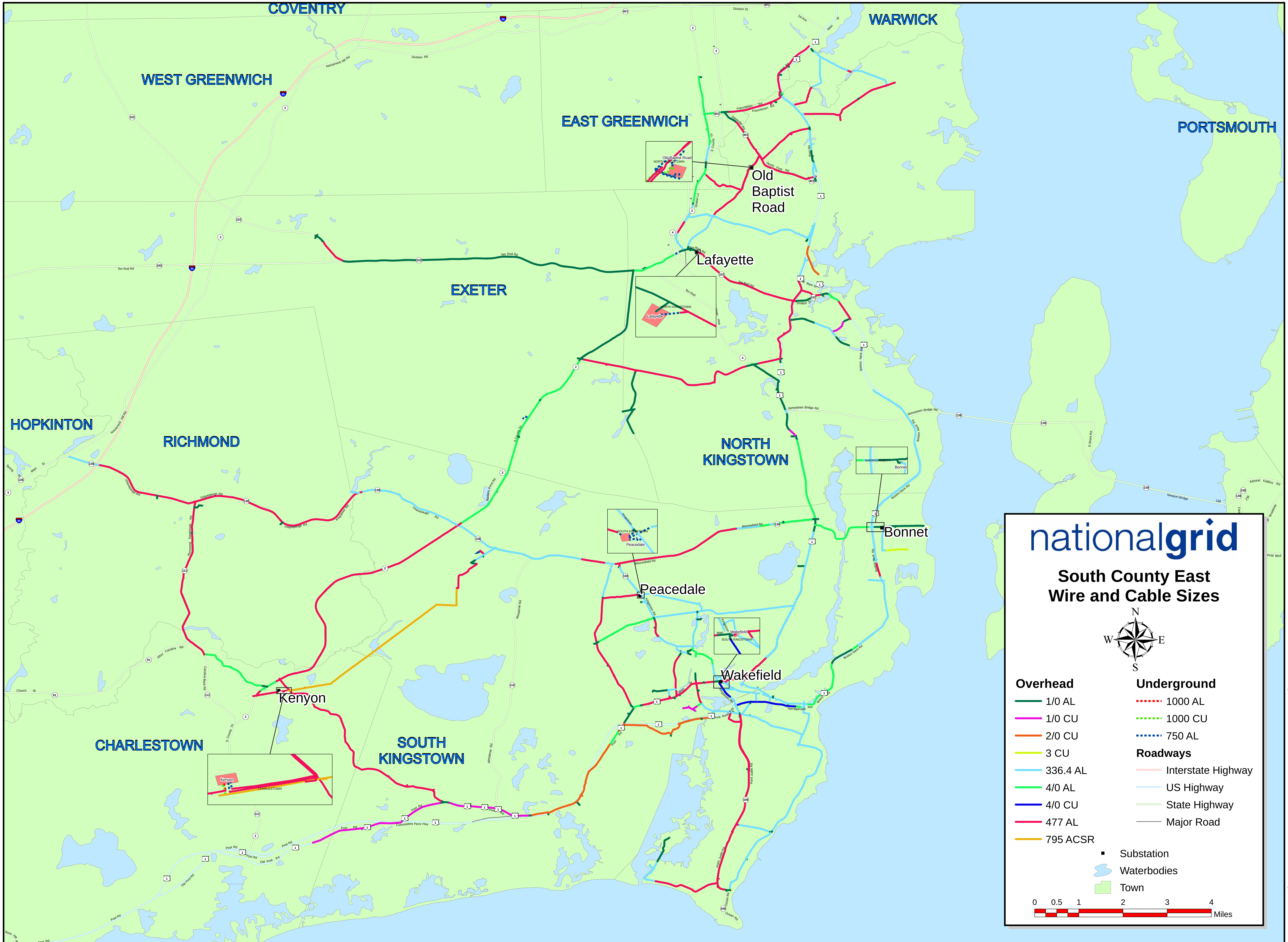
Response:

The map entitled "South County East Mainline Distribution" provides information on circuit ID, substation source, and distribution switches (including normal status). See Attachment 1. The map entitled "South County East Wire and Cable Sizes" provides information on the conductor sizes that make up the mainline of area circuits. See Attachment 2. In accordance with our agreement with Division Counsel, we have not provided information on "spot loads" on these maps. It should be noted that The Narragansett Electric Company does not regularly maintain maps of this type. They have been created utilizing information from our Geographical Information System for response to this data request.

Prepared by or under the supervision of: Alan LaBarre, P.E.



Attachment 1 to Response to Division Data Request 1-3


nationalgrid
South County East
Wire and Cable Sizes
N
S
E
W
Overhead
1/0 AL
1/0 CU
2/0 CU
3 CU
336.4 AL
4/0 AL
4/0 CU
477 AL
795 ACSR
Underground
1000 AL
1000 CU
750 AL
Roadways
Interstate Highway
US Highway
State Highway
Major Road
Substation
Waterbodies
Town
0
0.5
1
2
3
4
Miles
COVENTRY
WARWICK
WEST GREENWICH
EAST GREENWICH
PORTSMOUTH
Old
Baptist
Road
Lafayette
EXETER
HOPKINTON
RICHMOND
NORTH
KINGSTOWN
Bonnet
Peacedale
Wakefield
Kenyon
CHARLESTOWN
SOUTH
KINGSTOWN

Division Data Request 1-4

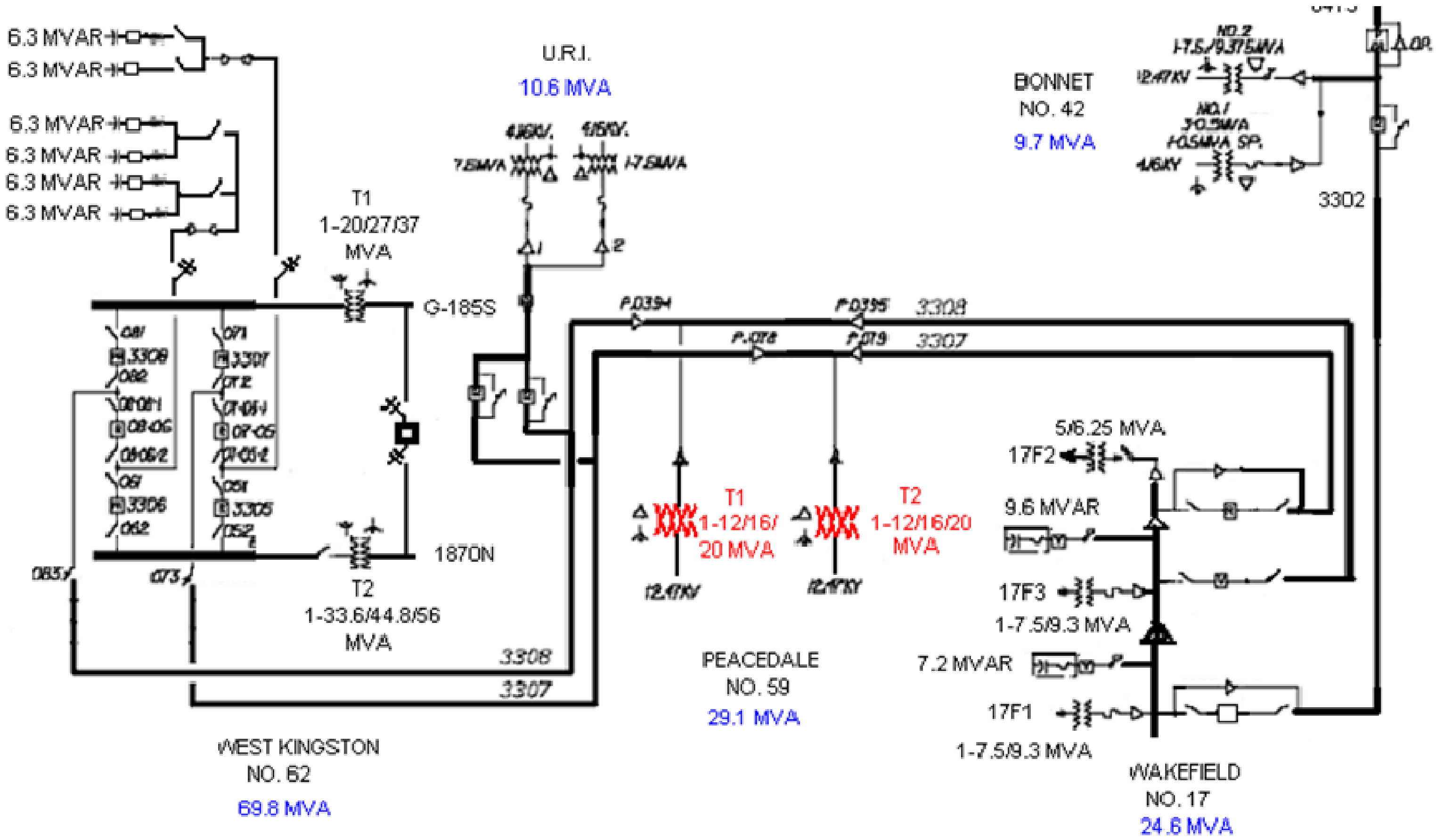
Request:

The Distribution Study identified overloaded circuits in Figures 5 and 6 to be in red. Please provide a color copy of Figures 5 and 6.

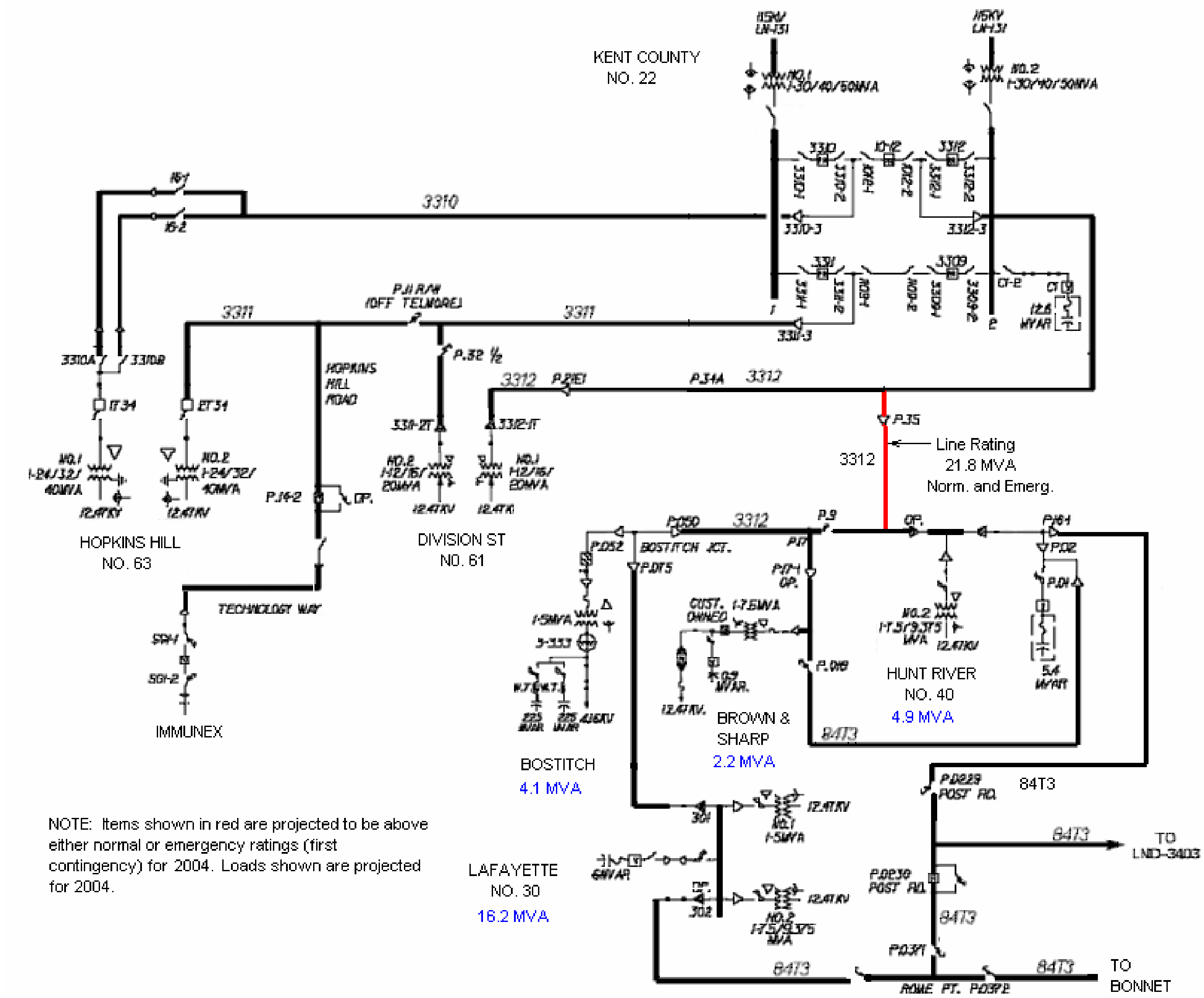
Response:

Color copies of study report figures 5 and 6 are provided as Attachments 1 and 2 respectively.

Prepared by or under the supervision of: Alan LaBarre, P.E.



NOTE: Items shown in red are projected to be above either normal or emergency ratings (first contingency) for 2004. Loads shown are projected for 2004.



NOTE: Items shown in red are projected to be above either normal or emergency ratings (first contingency) for 2004. Loads shown are projected for 2004.

Division Data Request 1-5

Request:

Provide copy of Transmission Planning Guide for the New England Power Company as sited on page 8 of Appendix A in the Environmental Report Volume I.

Response:

The Transmission Planning Guide used for the October, 2003 Study was the Transmission Planning Guide Revision 1.1, Issue Date 3/20/2001 and is attached. The current edition of the National Grid Transmission Planning Guide Revision 2.1, Issue Date 6/29/04 is filed as an attachment to Melissa Scott's pre-filed testimony.

Prepared by or under the supervision of: Melissa Scott, P.E.

National Grid

New England Power Company
part of National Grid Transmission USA

TRANSMISSION PLANNING GUIDE

TRANSMISSION PLANNING GUIDE

National Grid

Procedure No. NEP 1.0

New England Power Company
part of National Grid Transmission USA

Title:	TRANSMISSION PLANNING GUIDE	Revision No.: 1.1	Issue Date: 03/20/01
Section:	**A. Introduction**	Revised By: PJT (Initials)	Approved By: TJG (Initials)

1.0 OBJECTIVE OF TRANSMISSION PLANNING GUIDE

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the adequacy of the existing and future New England Power (NEP) transmission system for all reasonably anticipated conditions and to provide guidance in the design of future modifications or upgrades to the transmission system. As such, the guide is a design tool that may not always address unusual or unanticipated operating conditions.

2.0 PLANNING AND DESIGN CRITERIA

All NEP facilities that are part of the Bulk Power System and part of the interconnected NEP system shall be designed in accordance with the latest versions of the New England Power Pool (NEPOOL) standards and the Northeast Power Coordinating Council (NPCC) criteria and the NEP criteria. The fundamental guiding documents are the "Reliability Standards for the New England Power Pool," the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Bulk Power System Protection Criteria" (NPCC Document A5), and this document.

All NEP facilities that are not part of the Bulk Power System, but are part of the interconnected NEP system shall be designed in accordance with the latest versions of this document.

All NEP or NEP Transmission customers' facilities which are served by transmission suppliers other than NEP shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NEPOOL and NPCC documents.

Detailed design of facilities may require additional guidance from industry or technical standards which are not addressed by any of the documents referenced in this guide.

3.0 OPERATIONAL CONSIDERATIONS IN PLANNING AND DESIGN

The system should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- minimization of post contingency switching operations
- minimization of the use of Special Protection Systems (SPSs)

1.0 BASIC TYPES OF STUDIES

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Load Flow, Stability, Short Circuit, and Protection.

2.0 STUDY HORIZON

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to ten-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six to ten years). Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.0 FUTURE FACILITIES

Planned facilities should not automatically be assumed to be in-service for study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

4.0 EQUIPMENT THERMAL RATINGS

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing ratings are based on guidance provided by the NEPOOL System Design Task Force (SDTF) and industry standards. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Even though different equipment types have different time-current relationships, equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Actions must be taken to relieve equipment loadings within the time periods specified.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)
Overhead Transmission	Continuous	12 hours summer 4 hours winter	15 minutes	requires immediate action
Underground Cables	Continuous	12 hours summer 4 hours winter (some cables may need to be rated for up to 300 hours)	15 minutes (some cables may need to be rated for up to one hour)	requires immediate action
Transmission Transformers	Continuous	12 hours summer 4 hours winter	30 minutes	requires immediate action

4.1 OTHER EQUIPMENT

The SDTF and industry standards should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

4.2 HIGH VOLTAGE DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

5.0 MODELING FOR LOAD FLOW STUDIES

The modeling representation for load flow studies should include impedance and admittance of transmission lines, generators, reactive sources, and any other equipment which can affect power flow or voltage (e.g. capacitors or reactors). The representation should include voltage or angle taps, tap ranges, and control points for fixed-tap, load-tap-changing, and phase shifting transformers. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

5.1 FORECASTED LOAD

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Local generation should be modeled separately.

The Point of Delivery for load flow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between NEP and the Transmission Customer.

Every forecast involves uncertainty. To address the uncertainty, the peak load forecast should include an associated high and low range forecast. Due to the lead time required to construct new facilities, planning should be based conservatively on the high range forecast.

5.2 LOAD LEVELS

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the high range peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the associated generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

5.3 BALANCED LOAD

Balanced three-phase 60 Hz ac loads should be assumed at each Point of Delivery unless a customer specifies otherwise. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase to phase is less than 3%
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

- Harmonic voltage distortion is within limits recommended by the current version of IEEE Std. 519

If the customer specifies that they have an unbalanced load, then special conditions not addressed in this guide may apply.

5.4 LOAD POWER FACTOR

Load Power Factor in each area should be consistent with the limits set by the requirements developed under NEPOOL Criteria, Rules, and Standards No.30 (CRS-30) for that area.

5.5 REACTIVE COMPENSATION

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. NEP should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator output for each generator connected to the transmission system.

5.6 GENERATION DISPATCH

Analysis of generation sensitivity is necessary to model the variations in dispatch which routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation which should account for seasonal variation in the availability of water. A reasonable generation dispatch should closely relate to an economic dispatch. When biased economic dispatches are used to reasonably stress the transmission, the resulting transfers are considered normal.

NEPOOL interface limits can be used as a reference for stressing the transmission. Dispatching to the interface limits may stress the transmission system in excess of an economic based dispatch.

5.7 FACILITY STATUS

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section B, paragraph 3.0.

6.0 MODELING FOR STABILITY STUDIES

6.1 DYNAMIC MODELS

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained through cooperation with NEPOOL and NPCC.

6.2 LOAD LEVEL AND LOAD MODELS

Stability studies within NEPOOL typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed with a system load level of 45% of peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within NEPOOL are usually modeled as constant admittances for both active and reactive power, but other load models may be used as needed. Loads outside NEPOOL are modeled consistent with the practices of the individual areas. Appropriate load models for other areas are available through NEPOOL and NPCC.

6.3 GENERATION DISPATCH

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched economically. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

7.0 MODELING FOR SHORT CIRCUIT STUDIES

The Short Circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed.

Short Circuit studies for determining impedances for unbalanced faults typically assume all generators are on line. Switching sequences associated with the contingency should be accounted for in the calculation.

8.0 MODELING FOR PROTECTION STUDIES

Conceptual protection system design should be performed to develop cost estimates for use in economic comparison of alternatives. The conceptual design is performed to ensure adequate fault detection and clearing in accordance with the "NEES Protection Philosophy" and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from load flow, stability, and short circuit studies to ensure feasibility of the conceptual design.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements below the required circuit rating.

9.0 DEVELOPMENT AND EVALUATION OF ALTERNATIVES

If the performance or reliability of the forecasted system does not conform with the applicable criteria, then alternative solutions based on performance, reliability, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation which is summarized concisely in a report.

9.1 PERFORMANCE

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

9.2 RELIABILITY

This guide assesses reliability deterministically by defining conditions that the transmission system must be capable of withstanding. This deterministic approach is consistent with NEPOOL and NPCC practice. Generically defined outage conditions that the system must be designed to withstand are listed in Section C. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

The level of reliability provided through this approach may vary between customers or between groups of customers. To some degree this is acceptable due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment. When the level of reliability provided to a customer or group of customers is significantly lower than the average customer, alternatives are developed to improve the reliability.

When assessing customer reliability, the engineer compares the reliability of comparable facilities at different locations on the system. This comparison considers factors such as age, condition, style, and failure rates of equipment. The cause of poor reliability also influences the recommended action. Therefore, the engineer must assess the specific conditions affecting the reliability of service to particular customer(s).

If remedial actions are taken, historical performance data over an appropriate period of time may need to be re-established prior to assessing the need for additional remedial actions.

9.3 TECHNICAL PREFERENCE

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement.

9.4 ECONOMICS

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. However, engineering economic analysis is typically required to compare total NEP cost of each alternative in terms of cumulative present worth of revenue requirements. The cumulative present worth analysis should include the annual charges on investments, losses, and all other expenses related to each alternative.

If the plan with the lowest present worth of revenue requirements has a higher initial capital investment than any other alternative, the annual revenue requirements of the higher initial capital investment should be less than the other alternatives within five years. Also, the cumulative present worth of revenue requirement of the higher initial capital investment alternative should be less than the other alternatives within 10 years.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should show full recovery of the investment within 5 years.

9.5 SIZING

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least ten (10) years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

10.0 RECOMMENDATION

A recommended action should result from every study that identifies a potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as the forecasted performance and reliability, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, environmental impacts of facilities, and complexity to license and permit.

11.0 REPORTING STUDY RESULTS

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

National Grid New England Power Company part of National Grid Transmission USA	Procedure No. NEP 1.0	
Title: TRANSMISSION PLANNING GUIDE	Revision No.: 1.1	Issue Date: 03/20/01
Section: **C. Design Criteria**	Revised By: PJT (Initials)	Approved By: TJG (Initials)

1.0 OBJECTIVE OF DESIGN CRITERIA

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

2.0 DESIGN CONTINGENCIES

The Design Contingencies used to assess the performance of the transmission system are generically defined in Table 1. In association with the design contingencies, this table also includes information on fault type, fault clearing, allowable facility loading, acceptable loss of load, and acceptable transmission restoration time. Control actions may be available to mitigate some contingencies listed in the Section C, Table 1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NPCC and NEPOOL systems. Where this is the case, the system performance requirements for the local area under NEP design contingencies may be less stringent than what is required by NPCC criteria or NEPOOL reliability standards.

2.1 FAULT TYPE

As specified in Section C, Table 1, some contingencies may be modeled without a fault; others should be modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

2.2 FAULT CLEARING

Design criteria contingencies involving ac system faults are simulated with the fault clearing time based on a single protection system failure occurring in conjunction with the designated contingency.

For facilities protected by two independent protection groups, fault clearing for design criteria contingencies is based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

For facilities protected by a single protection group, fault clearing for design criteria contingencies is based on the worst single contingency failure in the protection group. This typically consists of failure of the station battery at one terminal resulting in fault clearing initiated by protection groups at remote terminals or, where applicable, failure of the communication system resulting in fault clearing initiated by backup (possibly with an intentional time delay) protection groups at each terminal.

2.3 ALLOWABLE FACILITY LOADING

The normal rating of a facility defines the maximum allowable pre- or post-contingency loading to which the equipment can operate during a normal load cycle. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section B, System Studies, paragraph 4.0 "Equipment Thermal Ratings").

As a planning practice, the system should be designed to avoid loading equipment above the LTE rating. Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating for momentary conditions provided automatic actions are in place to quickly reduce the loading of the equipment below the LTE rating. These guides recognize that as an operating practice, equipment may be loaded up to the STE rating. The DAL was created as an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. The DAL limit is not used in planning studies. In some cases, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

2.4 ACCEPTABLE LOSS OF LOAD - DIRECT SUPPLY

The NEP transmission system is designed to accept loss of load during the failure of a single supply or some of the less likely design contingencies which directly affect the ability to serve a particular load. However, the acceptability of the loss of load is conditioned on the expected restoration time defined in Section C, paragraph 2.6. The Acceptable Loss of Load values referenced in Section C, Table 1 reflect load by station and by total system (whichever is most limiting) that cannot be promptly restored with manual or automatic actions. This load is actual customer load. Actual customer load may be different from metered load if there were generators operating on the load side of the meter at the time of the loss of service.

The probability of a loss of customer load is acceptably higher during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages or catastrophic failures resulting from contingencies more severe than those defined by the Design Contingencies may acceptably result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

2.5 ACCEPTABLE LOSS OF LOAD - LOAD SHED

NEPOOL and NPCC require that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region.

Manual or automatic load shedding of any load connected to the NEP Transmission system for disturbances on the NEP system is also acceptable, based on the conditions and limits noted in Section C, Table 1. In the case of automatic load shedding, the protective relaying should be designed, to the extent practical, to minimize unnecessary operation by sensing the actual conditions which require action.

If there is a direct loss of load, then that loss of load should be included in the limit for load shedding. Therefore, the total loss of load respects the limits for load shedding.

2.6 ACCEPTABLE RESTORATION TIME

Acceptable transmission restoration time for design contingencies is typically considered to be within 24 hours, but for unlikely contingencies that could take longer to restore, acceptable restoration time is extended to within 3 days as noted in Section C, Table 1.

2.7 GENERATION REJECTION OR RAMP DOWN

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system conditions are maintained following such action
- the alternative is not economically justified
- the interconnection agreement with the generator permits such action
- when exposed to the conditions which may require generation rejection or ramp down the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require NEPOOL and NPCC review and approval.

2.8 PRIORITY

Serving load has priority over serving generation. Therefore, if there is an option to trip generation or trip load, the plan should be to trip generation.

2.9 EXCEPTIONS

These Design Criteria do not apply if a customer receives service from NEP and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, NEP has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

NEP is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, NEP does not have to provide redundant transmission supplies.

3.0 VOLTAGE RESPONSE

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Section C, Table 2), and in terms of percent voltage change from pre-contingency to post-contingency (Section C, Table 3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.0 STABILITY

Typically, acceptable stability response is demonstrated by positively damped oscillations. In addition, other factors also may be considered in specific situations. At the discretion of NEP, isolated generator instability may be acceptable, if it is limited to a particular unstable generator. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

National Grid

Procedure No. NEP 1.0

New England Power Company
part of National Grid Transmission USA

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Section: C. Design Criteria		Revised By: PJT (Initials)	Approved By: TJG (Initials)

Table 1: Design Contingencies

Ref #	CONTINGENCY (Loss or failure of:)	Fault Type	Allowable Facility Loading	Acceptable Loss of Load Direct Supply (MW)	Acceptable Loss of Load Shed (MW)	Acceptable Transmission Restoration Time
0	None (All Transmission Elements In-Service)	None	Normal	None	None	N/A
1	Open switching device w/ or w/o a Generator	None	LTE	30/Station	None	24 hours
2	Generator	None, 1Ø-Grd or 3Ø	LTE	None	None	N/A
3	Transmission Element (w/ or w/o a Generator)	None, 1Ø-Grd or 3Ø	LTE	30/Station 60/Cont.	None	3 days UG or Tfmrs, else 24 hours
	w/ failure of a circuit breaker & loss of additional associated transmission element(s)	1Ø-Grd		30/Station 100/Cont.	60	
4	Circuit Breaker fault & loss of Associated Transmission Element(s)	1Ø-Grd	LTE	30/Station 100/Cont.	60	24 hours
5	Double Circuit on Common Tower (>1mile)	(2)1Ø-Grd	LTE	30/Station 100/Cont.	60	24 hours
6	Non functionally redundant SPS w/ a Transmission Element	1Ø-Grd or 3Ø	LTE	30/Station 60/Cont.	None	3 days for UG or Tfmrs, else 24 hours
7	Common system to multiple Transmission Elements (i.e. cooling oil)	None	LTE	90/Station 100/Cont.	60	24 hours
8	Two cables in a common duct bank or trench	1Ø-Grd	LTE	90/Station 100/Cont.	60	3 days

Notes:

a. **Transmission Elements** are transmission circuits, transformers, and/or bus sections which are isolated by circuit switchers or breakers.
b. **1Ø-Grd** is Single Phase to Ground, **3Ø** is Three Phase, and **(2) 1Ø-Grd** is two simultaneous Single Phase to Ground faults on different phases on different lines.
c. **N/A** is not applicable, **UG** is Underground, **Tfmrs** is Transformers, **w/ or w/o** is with or without, and **Cont.** is Contingency.
d. Acceptable Loss of Load for Direct Supply and Load Shed are "either or", not "and".

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Table 2: Voltage Range

CONDITION	345 & 230 kV		115 kV & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions (#1 - #3)	0.95	1.05	0.90	1.05
Post Contingency & Automatic Actions (#4 - #8)	0.90	1.05	0.90	1.05

Table 3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV & Below (%)
Post Contingency & Automatic Actions (#1 - #3)	5.0	10.0
Post Contingency & Automatic Actions (#4 - #8)	10.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 2 and 3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific REMVEC or NEPEX operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to NEP facilities.

Bulk Power System
The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant effect outside the local area.

Contingency
An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Economic Dispatch
The selection and operation of resources to provide the lowest total cost to serve customers' electrical demand.

Element
Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, phase angle regulating transformer, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its current transformer(s).

Fault Clearing - Delayed
Fault Clearance consistent with correct operation of a breaker failure scheme and its associated breakers or of a backup relay scheme with an intentional time delay.

Fault Clearing - Normal
Fault Clearance consistent with correct operation of the protective relay scheme designed to clear the Fault without unnecessary delay and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that relay scheme and without the operation of any other protective or switching equipment.

High Voltage dc (HVdc) System, Bipolar
An HVdc system with two poles of opposite polarity and negligible ground current.

Interface
A collection of transmission lines connecting two areas of the transmission system.

Load Cycle
Refers to the hourly facility loading over a 24 hour period.

Load Level
A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)

Loss of service to one or more customers excluding automatic switching time.

Point(s) of Delivery
The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems
A Special Protection System (SPS) is a protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding is not considered an SPS.

Supply Transformer
Transformers that only supply distribution load to the same customer.

Transfers
The flow of electrical power across a transmission circuit or interface.

Transmission Customer
Any entity that has an agreement to receive wholesale service from the NEP Transmission system.

Transmission Transformer
Any Transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.

Division Data Request 1-6

Request:

Provide additional detail or supporting data used to develop study grade cost estimates for the transmission upgrades and proposed substation additions and upgrades.

Response:

See the following seven memoranda (Attachments 1 through 7) which discuss estimated costs for the transmission upgrades and proposed substation additions and upgrades.

Attachment 1. Memo to Melissa Scott from David Beron, 4/18/02 and workpapers, 4/16/02 (5 pages)

Attachment 2. Memo to Melissa Scott from David Beron, 10/16/03 and workpapers, 10/03/03 (9 pages)

Attachment 3. Memo to Melissa Scott from Kieu Nguyen 10/16/03 (2 pages)

Attachment 4. Memo to K. Horelik from J. Vaz, 2/03/04 (1 page)

Attachment 5. Memo to J. Vaz from Kathy M. Horelik, 2/21/04 (4 pages)

Attachment 6 Memo to D. Beron from J. Vaz, 3/31/04 (4 pages)

Attachment 7. Memo to Jack Vaz from David Beron, 8/10/04 (2 pages)

Prepared by or under the supervision of: Melissa Scott, P.E and Al LaBarre, P.E.

National Grid

Memorandum

National Grid USA Service Company, Inc.

To: Melissa Scott

From: David Beron

Date: 04/18/02

Subject: **Study Grade Estimates**
Southwestern Rhode Island Transmission Study

Per your request, we have prepared Study Grade Estimates for two alternatives under consideration in your "Southwestern Rhode Island Transmission Study". The alternatives, their estimated costs and implementation timeframes are as follow:

Alternative to Extend L-190 115 kV Line to West Kingston Substation

Scope: Extend the L-190 115 kV transmission line a distance of 12.3 miles, from the Old Baptist Road Tap point to the West Kingston Substation. The new portion of the line would be constructed in a single circuit davit arm configuration, using 795 kcm ACSR conductors rated for 140 C.

Cost: The estimated cost of this work is $6,000,000

Time: We estimate that it would take approximately 24 months to complete this project following issuance of a Project Data Sheet

Alternative to Reconductor G-185S Line

Scope: Reconductor the existing G-185S 115 kV transmission line a distance of 12.3 miles, from the Old Baptist Road Tap point to the West Kingston Substation. The reconductored line would carry 795 kcm ACSR conductors rated for 140 C.

Cost: The estimated cost of this work is $2,800,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

Notes

1. These estimates are in year 2002 dollars.
2. These estimates are based upon National Grid USA Service Company, Inc. performing the construction during normal working hours.
3. **STUDY ESTIMATES** are prepared with only a conceptual understanding of the project. They are prepared using historical cost data, data from similar projects and other stated assumptions of the Project Engineer. The accuracy of **STUDY ESTIMATES** is expected to be ±25% (reference EDP-GEN-2, Section 2.1.2).

David Beron

c: Frank Barys
Mark Browne

David J. Beron, P.E.
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Westborough, MA 01582
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DATE 4.16.02
PAGE NO. 1
BY BERGM

STUDY GRADE ESTIMATE

EXTEND L-190 LINE FROM OLD BAPTIST RD TAP PT. TO W. KINGSTON SUB

LENGTH OF EXTENSION ≅ 12.3 MILES

DEVELOP CONSTRUCTION COSTS FOR A "TYPICAL" LINE MILE OF 115 KV DAVIT ARM CONSTRUCTION WITH 795 KSR CONDUCTORS
INCLUDE 2 LOADBREAK SWITCHES AT OLD BAPTIST TAP POINT.
ASSUME 450 +/- SPANS = 12 STRUCTURES PER MILE
2 STEEL STRUCTURE DEADEND / ANGLES PER MILE
10 WOOD POLE DAVIT ARM SUSPENSION STRUCTURES PER MILE.

	M	L	O	TOTAL
WOOD POLES	30	11	10	51
MAT'L ASSUME 10 - 90' CL H1 @ $3,000				
LABOR 20 MH / POLE				
EQUIP $1000 / POLE				
STEEL DAVIT ARMS	11	13	3	27
MAT'L 30 ARMS @ $360				
LABOR 8 MH / ARM				
EQUIP $100 ARM				
STEEL STRUCTURES	40	11	4	55
MAT'L 2 STRUCTURES @ $20,000				
LABOR 100 MH / STR				
EQUIP $2000 / STR				
FOUNDATIONS FOR STEEL STRUCTURES	5	28	3	36
MAT'L USE $2500 FOUNDATION				
LABOR 250 MH / FOUNDATION				
EQUIP $1500 / FOUNDATION				
DISC INSULATORS	11	5	2	18
MAT'L 420 DISCS @ $25 / DISC				
LABOR 2 MH / STRING				
EQUIP $50 / STRING				

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BY BERON

	M	L	O	TOTAL
MISCELLANEOUS HARDWARE & WORK	6	2	2	10
MAT'L ALLOW $500/STR				
LABOR 40 MH				
EQUIP $2000				
CONDUCTOR	23	30	4	57
MAT'L ~17000' @ $1.35				
LABOR ASSUME 500 MH/MILE + 24 MH/DE				
EQUIP $4000/MILE				
SHIELDWIRE	2	11	1	14
MAT'L ~6000' @ $0.30				
LABOR 200 MH/MILE				
EQUIP $1000/MILE				
ACCESS IMPROVEMENTS	2	7	1	10
ENVIRONMENTAL/COMPLIANCE	3	10	2	15
SWITCHING/GROUNDING	–	5	–	5
SUPERVISION	–	13	2	15
R/W CLEARING	–	–	40	40
CONTINGENCIES	15	22	10	47
TOTAL COSTS PER MILE	148	168	84	400

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BY ____________

DEVELOP L-190 EXTENSION ESTIMATE:

12.3 MILES LINE @ $400,000/MILE	=	$4,920,000
2 SWITCHES @ $75,000/SWITCH INSTALLED	=	150,000
LICENSING + PERMITTING, [illegible]	=	500,000
ENGINEERING/PRELIM ENG/PROJ MGMNT	=	400,000
MISC PUBLIC RELATIONS AND INITIATIVES	=	30,000
TOTAL ESTIMATED COST	=	6,000,000

DATE 4.16.02
PAGE NO. 1
BY FERON

STUDY GRADE ESTIMATE
RECONDUCTOR G-185S LINE FROM OLD BAPTIST TAP TO W. KINGSTON

RECONDUCTOR G-185S LINE A DISTANCE OF 12.3 MILES FROM OLD BAPTIST RD. TAP POINT TO WEST KINGSTON SUBSTATION. USE 795 KCM ACSR CONDUCTORS FOR 140°C MCOT.

SIMILAR 115KV RECONDUCTORING PROJECTS HAVE BEEN COSTING-OUT AT $250,000 - $300,000 PER MILE.

BECAUSE A REHABILITATION PROJECT WAS PERFORMED ON G185S LINE SEVERAL YEARS AGO, ASSUME PER MILE COSTS OF G-185S RECONDUCTORING WILL BE TOWARD THE LOWER END OF THIS RANGE.

USE $225,000 / MILE x 12.3 MILES = $2,767,500

SAY $2,800,000 TOTAL COST.

National Grid

Memorandum

National Grid USA Service Company, Inc.

To: Melissa Scott

From: David Beron

Date: 10/16/03

Subject: **Supplemental Study Grade Estimates**
Southwestern Rhode Island Transmission Study

Per your request, we have prepared supplemental Study Grade Estimates for various options being evaluated in connection with your "Southwestern Rhode Island Transmission Study". The alternatives, their estimated costs and implementation timeframes are as follow:

Reconductor L-190 Line 795 AAC between Kent County Sub and Davisville Tap using 1,113 ACSR

Scope: Reconductor approximately 2 miles of existing L-190 Line 795 AAC conductors between the Kent County Substation and the Davisville Tap. This portion of the line would be reconductored using 1,113 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature to achieve a rating of at least 325 MVA.

Cost: The estimated cost of this work is $700,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

Reconductor L-190 Line 795 AAC between Kent County Sub and Davisville Tap using 1,590 ACSR

Scope: Reconductor approximately 2 miles of existing L-190 Line 795 AAC conductors between the Kent County Substation and the Davisville Tap. This portion of the line would be reconductored using 1,590 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature.

Cost: The estimated cost of this work is $750,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

Reconductor L-190 Line 795 ACSR between Kent County Sub and Davisville Tap using 1,113 ACSR

Scope: Reconductor approximately 3.26 miles of existing L-190 Line 795 ACSR conductors between the Kent County Substation and the Davisville Tap. This portion of the line would be reconductored using 1,113 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature to achieve a rating of at least 325 MVA.

Cost: The estimated cost of this work is $1,100,000

Time: We estimate that it would take approximately 24 months to complete this project following issuance of a Project Data Sheet

<u>Reconductor L-190 Line 795 ACSR between Kent County Sub and Davisville Tap using 1,590 ACSR</u>

Scope: Reconductor approximately 3.26 miles of existing L-190 Line 795 ACSR conductors between the Kent County Substation and the Davisville Tap. This portion of the line would be reconductored using 1,590 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature.

Cost: The estimated cost of this work is $2,100,000

Note: Use of alternative conductors such as ACSS conductor or ACCR conductors to achieve the desired line ratings could potentially produce some savings for the reconductoring of this portion of the L-190 Line, however significant analysis would be required in order to make this determination.

Time: We estimate that it would take approximately 24 months to complete this project following issuance of a Project Data Sheet

<u>Reconductor 1870N Line 795 AAC between West Kingston Sub and Kenyon Sub using 954 ACSR</u>

Scope: Reconductor approximately 4.3 miles of existing 1870N Line 795 AAC conductors between the West Kingston Substation and the Kenyon Substation. This portion of the line would be reconductored using 954 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature.

Cost: The estimated cost of this work is $1,400,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

<u>Reconductor 1870N Line 795 AAC between West Kingston Sub and Kenyon Sub using 1,113 ACSR</u>

Scope: Reconductor approximately 4.3 miles of existing 1870N Line 795 AAC conductors between the West Kingston Substation and the Kenyon Substation. This portion of the line would be reconductored using 1,113 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature.

Cost: The estimated cost of this work is $1,600,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

<u>Reconductor 1870 Line 795 AAC between Kenyon Sub and Wood River Sub using 795 ACSR</u>

Scope: Reconductor approximately 3.9 miles of existing 1870 Line 795 AAC conductors between the Kenyon Substation and the Wood River Substation. This portion of the line would be reconductored using 795 kcm ACSR conductors rated for 140 °C maximum conductor operating temperature.

Cost: The estimated cost of this work is $1,200,000

Time: We estimate that it would take approximately 18 months to complete this project following issuance of a Project Data Sheet

Notes

1. These estimates are in year 2003 dollars.
2. These estimates are based upon National Grid USA Service Company, Inc. performing the construction during normal working hours.
3. **STUDY ESTIMATES** are prepared with only a conceptual understanding of the project. They are prepared using historical cost data, data from similar projects and other stated assumptions of the Project Engineer. The accuracy of **STUDY ESTIMATES** is expected to be ±25% (reference EDP-GEN-2, Section 2.1.2).

c: Mark Browne

DATE 10/03/05
PAGE NO. 1
BY BERON

STUDY GRADE ESTIMATES

UPGRADE 2 MILES OF L-190 795 AAC BETWEEN KENT COUNTY SUB AND DAVISVILLE TAP TO 1,113 ACSR AT 140°C TO ACHIEVE RATING OF 325 MVA

- SUBSTANTIAL RECONSTRUCTION OF L-190 WOULD BE REQUIRED (POLE AND ARM REPLACEMENTS) B/C AGE, CONDITION AND CLEARANCE CONSIDERATIONS.

USE $350,000/MILE ≈ $700,000

UPGRADE 3.26 MILES OF L-190 795 ACSR BETWEEN KENT COUNTY AND DAVISVILLE TAP TO 1,113 ACSR AT 140°C

- ASSUME SOME DOUBLE CIRCUIT STEEL STRUCTURES WILL REQUIRE REPLACEMENT (~25%)
- HUNT RIVER CROSSING WILL REQUIRE NEW STRUCTURES

USE $300,000/MILE x 3.26 MILE = 978,000
+ RECONSTRUCTION OF HUNT RIVER = $125,000

TOTAL = $1,100,000

DATE

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BY

UPGRADE THE 4.3 MILES OF 1870 + 795 AAC BETWEEN WEST KINGSTON AND KENYON TO 954 ACSR AT 140 °C

USE RECONDUCTOR + REHAB COSTS OF $300,000 / MILE

ADD IN SPECIAL TENSION CHANGE STR AT KENYON

$300,000 / MILE X 4.3 MILES = $1,290,000

+ ~ $100,000 + ~100,000

1,390,000

SAY $1,400,000

DATE

PAGE NO. 3

BY

UPGRADE THE 3.9 MILES OF 1870 LINE 795 AAC BETWEEN KENYON AND WOOD RIVER TO 795 ACSR OPERATING AT 140°C

USE \$275,000 /MILE = \$1,075,000

+ TENSION CHANGE - 100,000

\$1,175,000

SAY \$1,200,000

DATE 10/16/03

PAGE NO.

BY

STUDY GRADE ESTIMATE

UPGRADE 3.26 MILES OF L-190 LINE 795 ACSR BETWEEN KENT COUNTY AND DAVISVILLE TAP TO 1590 ACSR AT 140°C MCOT.

- ASSUME APPROXIMATELY 1/2 OF DOUBLE CIRCUIT STRUCTURES WILL REQUIRE REPLACEMENT
- HUNT RIVER CROSSING WILL REQUIRE NEW STRUCTURES

USE $600,000 / MILE x 3.26 MILE = 1,956,000

+ RECONSTRUCTION OF HUNT RIVER = 150,000

TOTAL = $2,106,000

SAY $2,100,000

DATE

PAGE NO.

BY

STUDY GRADE ESTIMATE

UPGRADE 4.3 MILES OF THE 1870N 795 ACSR BETWEEN WEST KINGSTON AND KENYON SUBSTATIONS TO 1,113 ACSR CABLE @ 140°C MCOT

USE BASE COST OF $350,000 / MILE AND ADD IN SPECIAL TENSION CHANGE STRUCTURE AT KENYON

$350,000 MILE × 4.3 MILE = $1,505,000

+ TENSION CHANGE = 100,000

$1,605,000

SAY $1,600,000

DATE 10/16/03

PAGE NO. 1

BY BERON

STUDY GRADE ESTIMATES

UPGRADE 2 MILES OF L190 795 AAC BETWEEN KENT COUNTY SUBSTATION AND DAVISVILLE TAP TO 1,590 ACSR AT 140°C

- AS WITH RECONDUCTORING THIS SEGMENT TO 1,113 ACSR, SUBSTANTIAL RECONSTRUCTION OF L190 WOULD BE REQD IN THE FORM OF POLE AND ARM REPLACEMENTS, DUE TO AGE, CONDITION AND CLEARANCE CONSIDERATIONS

USE $350,000 / MILE x 2 ≅ $700,000

+ PLUS COST DIFFERENCE BETWEEN 1,113 AND 1,590 ACSR CABLES @ ~ $0.60 / FOOT

$0.60 / FT x 5280 FT / MILE x 2 MILE x 3 PHASES = 19,000

+ SOME TALLER POLES REQ'D @ ~ $30,000

SAY ESTIMATED COST – $750,000

National Grid

National Grid USA Service Company, Inc.

Memorandum

To: Melissa Scott

From: Kieu Nguyen

Date: 10/16/2003

Subject: Study Estimate-West Kingston-Install Breaker for 115 kV 190 line.

As requested, estimates have been prepared for:

W. KINGSTON SUBSTATION-Install a 115 kV circuit breaker for line L 190. (Option 2):

Installing a 115 kV bus structure/termination for the new line 190 from Kent County Substation. Line 190 will supplies to T2 transformer. Installing a new 115 kV breaker between the line 190 and the existing line 1870.
Automation will be provided for 115 kV circuit breakers. The new addition to the 115 kV yard will need permits.

Plant Addition :	900,000.00
TOTAL PLANT ADDITION	**900,000.00**
O&M	25,000.00
Removal	35,000.00

Engineering Design & Construction is to be done by NEPSCo during normal business hours.

W. KINGSTON SUBSTATION-Install two 115 kV circuit breakers (Option 1a):

Rebuild the 115 kV bus structure/termination for the new line 190 and 185 from Kent County Substation. Line 190 will supplies to T2 transformer. Installing a new 115 kV breaker between the line 190 and the existing line 1870, and a new 115 breaker between the line 185 and 1870.
Automation will be provided for 115 kV circuit breakers. The new addition to the 115 kV yard will need permits.

Plant Addition :	1,200,000.00
TOTAL PLANT ADDITION	**1,200,000.00**
O&M	25,000.00
Removal	80,000.00

Engineering Design & Construction is to be done by NEPSCo during normal business hours.

55 Bearfoot Road
Northborough, MA 01532
508/421-7647 Fax: 508/421-7520
Kieu.Nguyen@us.ngrid.com

3) Upgrade the 795 Al conductor/bus for 1870 N line at West Kingston to 1113 ACSR

Plant Addition :	20,000.00
Removal:	5,000.00

4) Upgrade the 795 Al conductor/bus for 1870 N and 1870 lines at Kenyon to 113 ACSR.

Plant Addition :	30,000.00
Removal:	5,000.00

5) Upgrade the 795 Al conductor/bus for 1870 line at Wood River to 113 ACSR.

Plant Addition :	20,000.00
Removal:	5,000.00

STUDY GRADE ESTIMATES are developed with only a conceptual understanding of the project. They are prepared using historical cost data, data from similar projects and other stated assumptions. The accuracy of STUDY GRADE ESTIMATES is expected to be +/- 25%. (Reference EDP-GEN-2, Section 2.1.2)

Cc: C. Kelly D.R. Ethier M. Scott.

Narragansett Electric
A National Grid Company

Memorandum

To: K. Horelik

From: J. Vaz

Date: 2/03/04

Subject: South County East Distribution Study Estimates

Kathy,

I am currently involved in a study encompassing the eastern section of the South County area in Rhode Island. One plan under consideration is to construct a new 115/12.47 kV low profile substation off Tower Hill Road in North Kingstown. I would like to received substation estimates for two options.

Option 1: As shown in Figure 1, the substation would initially be equipped with a single transformer and three regulated feeders. The ultimate layout would provide for two transformers and six regulated feeders.

Option 2: As shown in Figure 2, the substation would initially be equipped with a single transformer and two regulated feeders. Again, the ultimate layout would provide for two transformers and six regulated feeders.

I am also investigating the feasibility of installing a 5th feeder at Old Baptist Road. As shown in Figure 3, I would like to receive an estimate to install the 5th feeder and a 7.2 MVAR capacitor bank with two 3.6 MVAR stages.

Finally, I would like an estimate to replace three VIR reclosers at Peacedale substation, as shown on Figure 4, with three 800 Amp VSA reclosers.

Thanks for your help.

Jack

280 Melrose St
Providence, RI 02901-1438
401-784-7517

National Grid

MEMORANDUM

To:	J Vaz	**Date:**	February 21, 2004
From:	Kathy M. Horelik	**File:**	South County East
Subject:	Study Grade Estimates for New Substations, Old Baptist and Peacedale		

REFERENCE

(a) Memorandum, J. Vaz to K Horelik, "South County East Distribution Study Estimates," dated 2/3/04

DISCUSSION

In response to your request, study grade estimates have been developed for the four options specified in Reference (a) as follows:

Option 1: New Substation, three feeders

Transmission Cost	$ 2,100,000
Distribution Cost	1,900,000
Total Estimate	$ 4,000,000

The above estimate includes material, construction, engineering and design costs for:

- Typical land preparation and permitting for new substation with 6 feeder ultimate layout
- Control house, relays and control per LPS 03 design
- Purchase and install one 115 kV-13.2 kV, 24/32/40 MVA transformer
- Purchase and install one 115 kV, 1200 A circuit switcher
- Purchase and install one 15 kV, 3000A airbreak switch
- Purchase and install three 15 kV regulated feeders consisting of 3-1200 A bus breakers, 9-333 KVA step voltage regulators, 36 disconnects
- Install foundations and buses 1 & 2 for ultimate layout
- 15 kV load break switch for bus tie
- 7.2 MVAr capacitor with bus breaker, 2-3.6 MVAr stages and PLC control

This estimate does not consider real estate costs or unusual site conditions such as ledge or wetland reclamation.

55 Bearfoot Road
Northboro, MA 01532
508-421-7678 Fax: 508-421-7520
kathy.horelik@us.ngrid.com

Option 2: New Substation, two feeders

Transmission Cost	$ 2,100,000
Distribution Cost	1,100,000
Total Estimate	$ 3,200,000

The above estimate includes material, construction, engineering and design costs for:

- Typical land preparation and permitting for substation with 6 feeder ultimate layout
- Control house, relays and control per LPS 03 design
- Purchase and install one 115 kV-13.2 kV, 24/32/40 MVA transformer
- Purchase and install one 115 kV, 1200 A circuit switcher
- Purchase and install one 15 kV, 3000A airbreak switch
- Purchase and install two 15 kV regulated feeders consisting of 2-1200 A bus breakers, 6-333 KVA step voltage regulators, 24 disconnects
- Install foundations for Bus 1 build-out
- Single Stage 3.6 MVAr capacitor with bus breaker

This estimate does not consider real estate costs or unusual site conditions such as ledge or wetland reclamation.

Option 3: Add Feeder and Capacitor at Old Baptist Road Substation

Capital	$ 925,000
O&M	15,000
Removal	10,000
Total Estimate	$ 950,000

The above estimate includes material, construction, engineering and design costs to:

- Purchase and install one 15 kV regulated feeder consisting of 1-1200 A relayed breaker, 1-1200 A tie breaker, 3-333 KVA step voltage regulators, 21 disconnects
- Provide full feature EMS automation of new feeder and tie breaker
- Install foundations and bus work for ultimate 6 feeder layout (Note: Bus 1 bay size is 12' x 23' , Bus 2 bay size is 16' x 23')
- 7.2 MVAr capacitor with bus breaker, 2-3.6 MVAr stages and PLC control

This estimate assumes adequate space exists in the control house for a PLC and required accessories. This estimate assumes no extra ordinary bus work.

Adder to distribution costs to retrofit the 46F3, F4 and 34 tie breakers with SEL 351S and 501 relays for automation is:

O&M	$ 75,000
Removal	5,000
Total Estimate	$ 80,000

Adder to transmission cost to automate the 115 kV circuit switchers and provide EMS telemetry for Transformers No 1 & 2:

Capital	$ 45,000
O&M	2,000
Removal	3,000
Total Estimate	$ 50,000

Option 4: Replace GE VIR reclosers at Peacedale Substation

Capital	$ 210,000
O&M	10,000
Removal	20,000
Total Estimate	$ 240,000

The above estimate includes material, construction, engineering and design costs to:

- Purchase and install 3-15 kV VSA reclosers for 59F1, F2 and 12 Tie reclosers
- Remove GE VIR reclosers
- Provide full feature EMS automation and telemetry of 59F1, F2 and 12 Tie reclosers

This estimate assumes the existing foundations and conduit will be used.

Adder to distribution costs to automate 59F3, F4 and 34 ties VSA reclosers via FORM 6 control retrofit:

O&M	$ 60,000
Removal	10,000
Total Estimate	$ 70,000

Adder to transmission costs to replace the transformer sacrificial airbreaks with circuit switchers and add EMS telemetry to Transformers No. 1 & 2:

Capital	$ 290,000
O&M	10,000
Removal	20,000
Total Estimate	$ 320,000

Please note that replacement of the air breaks with circuit switchers at Peacedale is not currently included in the proposed scope of the 5 year sacrificial airbreak program. The cost for transformer telemetry only is $30,000.

This study grade estimate has been prepared in accordance with Engineering Department Procedure EDP-GEN-2.1.2, which states:

"A STUDY ESTIMATE is based on a conceptual understanding of a project. STUDY ESTIMATES are prepared using historical cost data, data from similar projects and other stated assumptions. They are prepared to ensure that they would be within +/- 25 % of the final project cost."

Please call me at ext. 57678 if you have any questions or require additional information regarding these estimates.

Cc:
C. Kelly
A. LaBarre

Narragansett Electric
A National Grid Company

Memorandum

To: D. Beron

From: J. Vaz

Date: 3/31/04

Subject: South County East Distribution Study Estimate

Dave,

Enclosed are 3 possible locations for a new 115/12.47 kV low profile substation. These locations are identified as Option A, B or C. In all options the substation would initially be equipped with a single transformer and three regulated feeders. The ultimate layout would provide for two transformers and six regulated feeders.

Two locations are off Tower Hill Road in North Kingstown and are identified as "Option A" and "Option B". Can you please provide an estimate to extend either the G-185S/L-190 Lines and an estimate to extend both lines. All three possibilities will be evaluated prior to making a final recommendation.

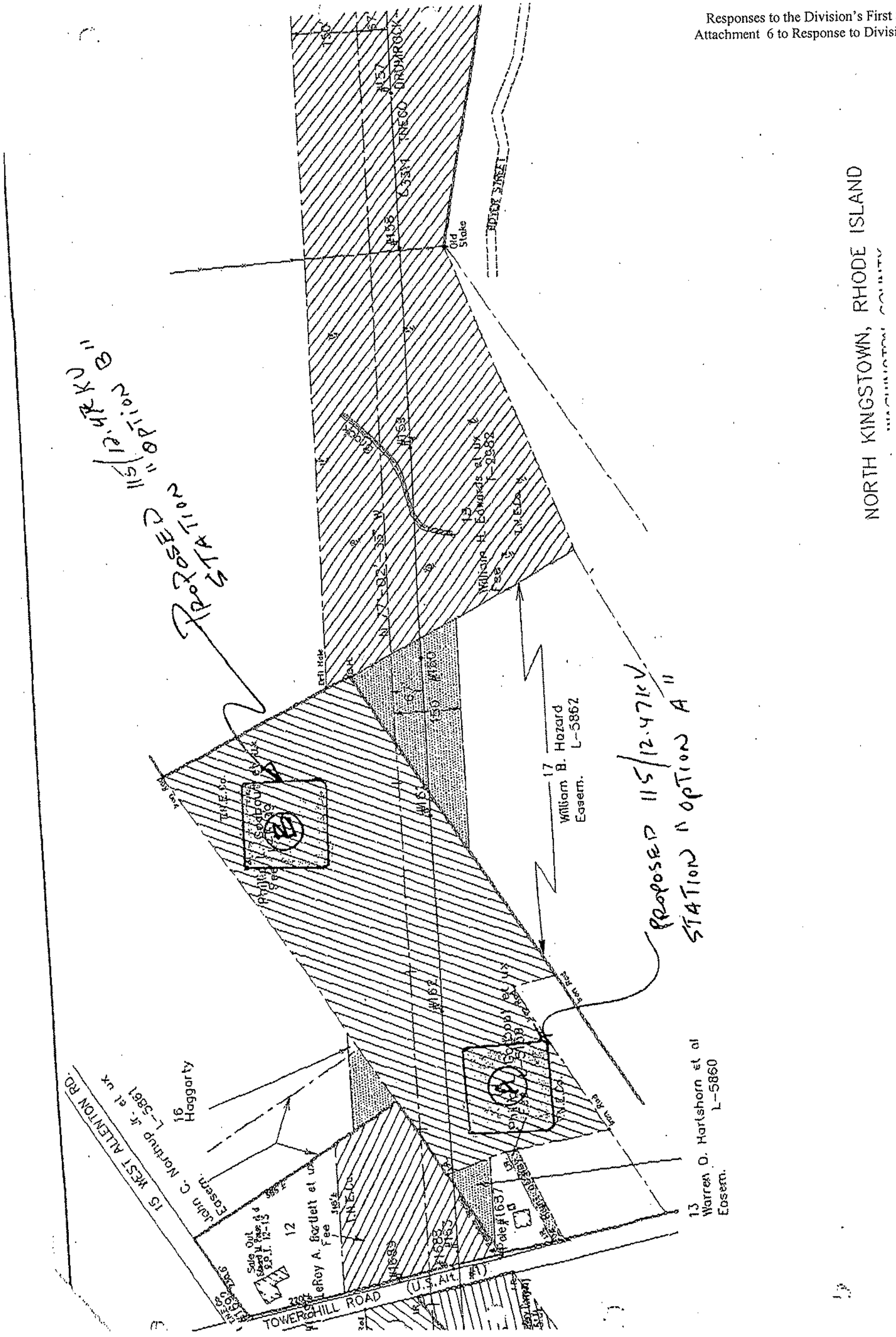
The third location is off Indian Corner Rd in North Kingstown and is identified as "Option C". This station would require NECo to acquire land adjacent to the Drumrock to West Kingstown ROW. Can you please provide an estimate to tap either the G-185S or L-190 Line.

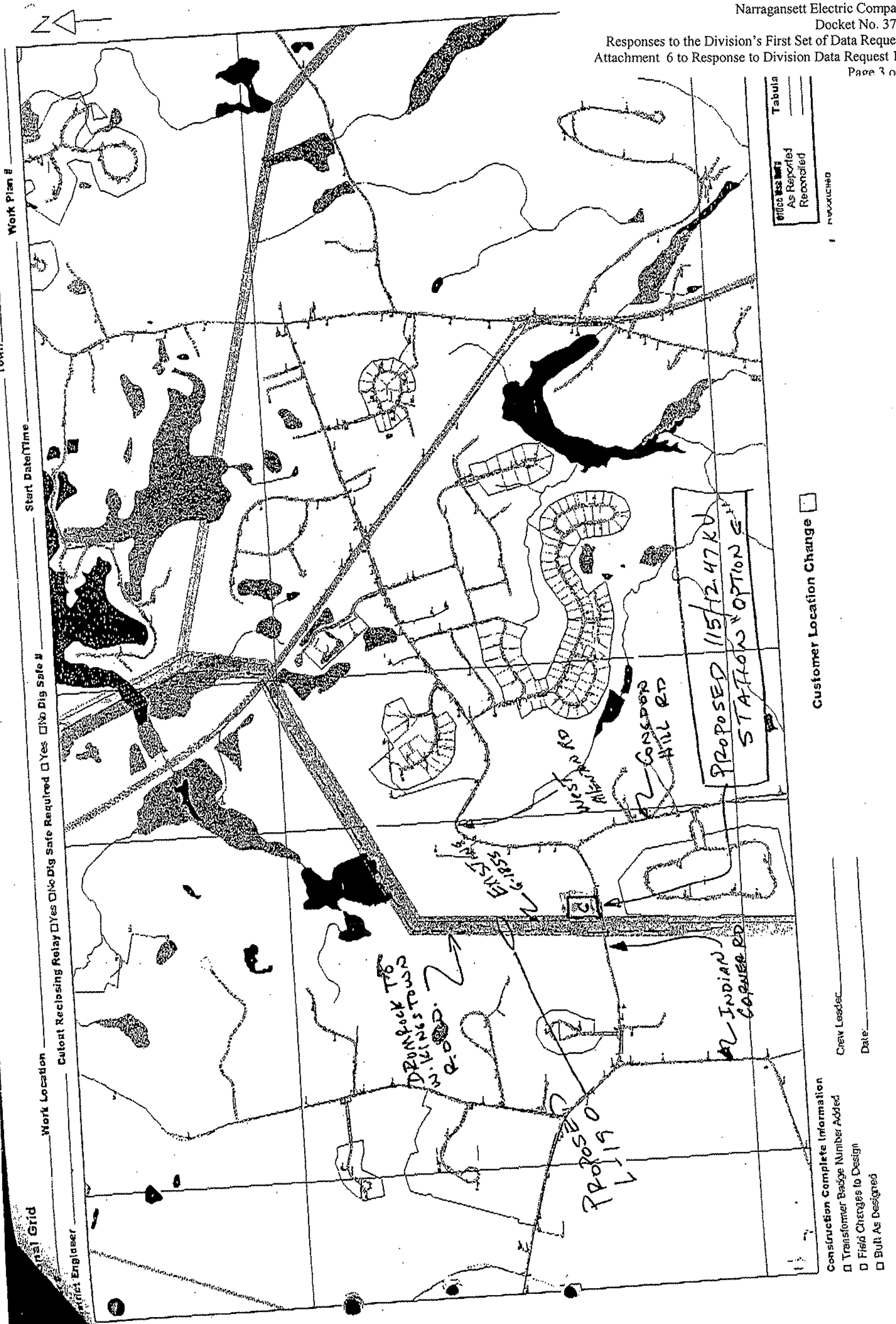
Finally, common to all plans is the installation of a 5th feeder at Old Baptist Road. Because we presently have double 12 kV circuits on Old Baptist Road, adding a 5th circuit would require building major duct line infrastructure unless we could use the Davisville Tap transmission right of way. This would require building approximately 1,400 feet on mainline on the right of way. I have indicated a preferred routing for the new feeder on the attached sketch. Can you please review this option and let me know if you have any objections.

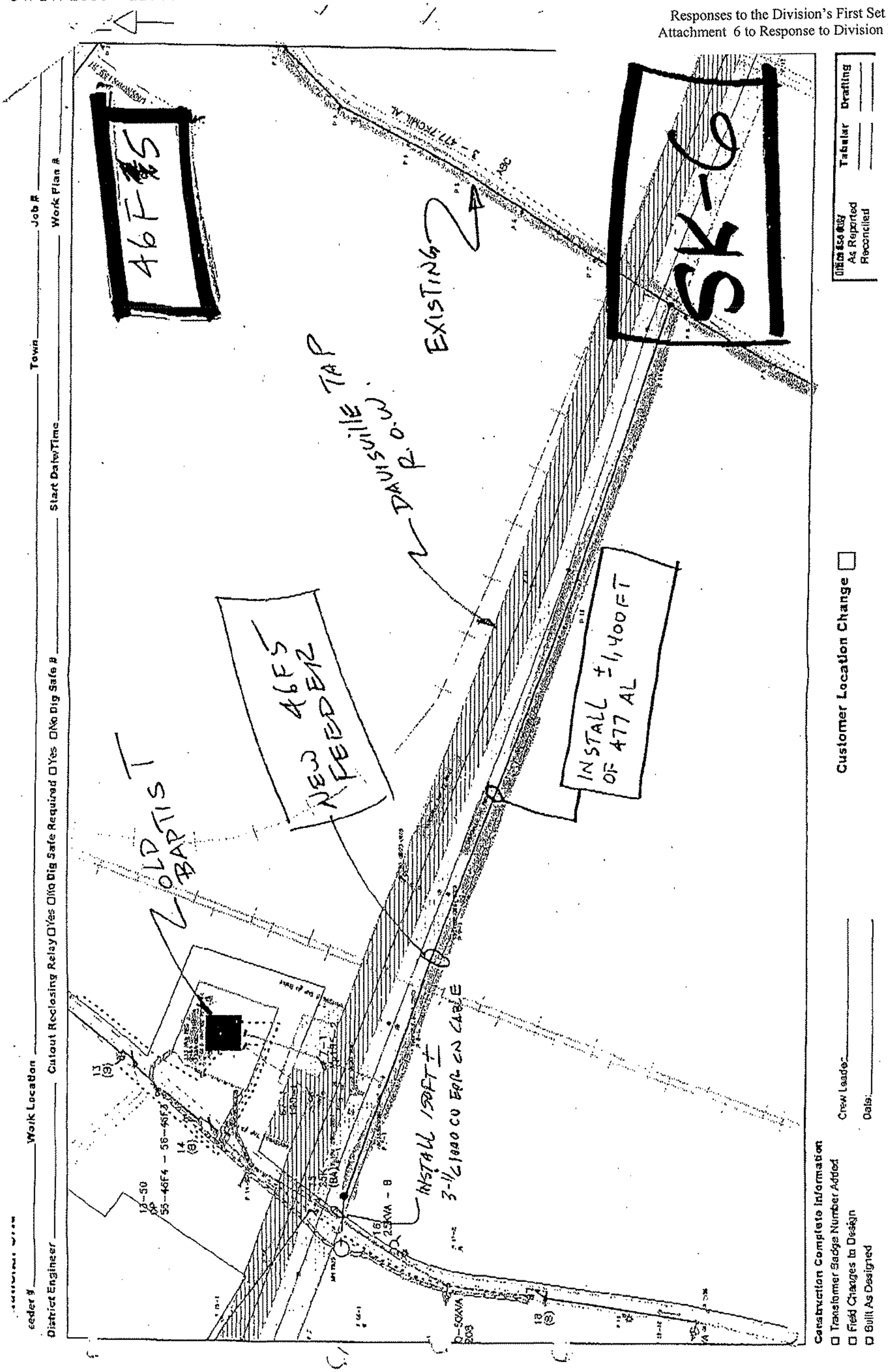
Thanks for your help.

Jack

280 Melrose St
Providence, RI 02901-1438
401-784-7517


PROPOSED 115/12.47KV STATION "OPTION B"
PROPOSED 115/12.47KV STATION "OPTION A"
NORTH KINGSTOWN, RHODE ISLAND
17 William B. Hazard Easem. L-5862
13 Warren D. Hartshorn et al Easem. L-5860
16 Haggarty
John C. Northup Jr. et ux Easem. L-5861
15 WEST ALLENTON RD.
TOWER HILL ROAD (U.S. Alt. #1)
12 LeRoy A. Bartlett et ux Fee
William H. Edwards et ux Fee L-2882
BRIDGE STREET
Old Stake
Drill Hole
L33M
TREGO DRUMROCK


Job #
Work Plan #
Town
Start Date/Time
No Dig Safe #
Cutout Reclosing Relay
Work Location
Customer Location Change
PROPOSED 115/12.47KV
STATION OPTION C
CONGDON HILL RD
West Allenton RD
EXISTING G185
DRUMROCK TO W. KINGSTOWN ROAD
INDIAN CORNER RD
PROPOSE L190
Construction Complete Information
Transformer Badge Number Added
Field Changes to Design
Built As Designed
Crew Leader
Date
As Reported
Reconciled
Tabula


46F5
SK-6
EXISTING
DAVISVILLE TAP R.O.W
NEW 46F5 FEEDER
OLD BAPTIST
INSTALL ±1,400FT OF 477 AL
INSTALL 150FT ± 3-1/C 1000 CU EPR CN CABLE
District Engineer
Work Location
Town
Job #
Work Plan #
Start Date/Time
Cutout Reclosing Relay ☐Yes ☐No Dig Safe Required ☐Yes ☐No Dig Safe #
Customer Location Change
Construction Complete Information
☐ Transformer Badge Number Added
☐ Field Changes to Design
☐ Built As Designed
Crew Leader
Date
As Reported
Reconciled
Tabular
Drafting

National Grid

National Grid USA Service Company, Inc.

Memorandum

To: Jack Vaz

From: David Beron

Date: 08/10/04

Subject: South County Area Study
Study Grade Estimate for 115 kV Tap Line to Potential Tower Hill Substation and Feasibility Assessment for Establishing Distribution Feeder(s) on Davisville Tap Right-of-Way

---

Per your request, we have prepared a Study Grade estimate of the cost to construct a new 115 kV transmission tap line to serve a new substation under consideration in the vicinity of Tower Hill Road in North Kingstown, Rhode Island. The new transmission line would tap either the existing G-185S Line or the planned L-190 Line Extension and extend approximately 0.75 miles easterly along the Rome Point right-of-way to the substation site(s) under consideration. Three loadbreak switches would be installed as part of this project, with one being located in the 115 kV main line north of the tap point, one located in the 115 kV main line south of the tap point, and one being located in the tap line itself. The estimated transmission line costs of this alternative are as follow:

Capital	$ 650,000
Removal	15,000
O&M	10,000
Total	$ 675,000

You have also requested a feasibility assessment for establishing new 12.47 kV feeder(s) at Old Baptist Road Substation and utilizing a 1400' section of the Old Baptist Road to Davisville transmission line right-of-way for the overhead feeder routing.

We have no engineering objection to this proposal. Because the Davisville Substation is radially fed by two existing 115 kV circuits, we do not envision a need to establish additional transmission facilities on the right-of-way in the future; additionally, because the right-of-way narrows considerably in the vicinity of Post Road, establishing additional transmission circuits on the right-of-way would be somewhat impractical.

We recommend that if you pursue the option of establishing distribution feeders on this portion of the Davisville right-of-way, the distribution lines be located at the very edges of the right-of-way. Once the feeder design is advanced, you must request a review of the proposal from Transmission Line Engineering to ensure that adequate clearances and separation will exist between the transmission and distribution facilities. Further, we recommend that you request that the Property Assets and/or Legal departments perform a review of the U.S. Navy and the General Services Administration easement documents to ensure that the existing easements provide rights for use at lower distribution voltages. Lastly, we would note that establishing distribution feeders on this portion of the right-of-way will require a license from Amtrak due

to the crossing of the Amtrak's main Northeast Corridor and electrified catenary system adjacent to the Old Baptist Road Substation.
If you have any questions on these findings, or if you require additional information at this time, please contact me.

Notes:

1. This estimate is in 2004 dollars.
2. This estimate is based upon National Grid USA Service Company personnel performing the work during normal working hours.
3. **STUDY ESTIMATES** are prepared with only a conceptual understanding of the project. They are prepared using historical cost data, data from similar projects and other stated assumptions of the Project Engineer. The accuracy of **STUDY ESTIMATES** is expected to be ±25% (reference EDP-GEN-2, Section 2.1.2).

c: Mark Browne
Michael DiNezza
Brian Reynolds
Melissa Scott
Slawomir Szymanowski

David J. Beron, P.E.
25 Research Drive
Westborough, MA 01582
Telephone: (508) 389-2935
Facsimile: (508) 389-2890
E-mail: david.beron@us.ngrid.com

Division Data Request 1-7

Request:

Provide detailed cost estimates of the proposed substation improvements.

Response:

See response to Division Data Request 1-6.

Prepared by or under the supervision of: Melissa Scott, P.E. and Al LaBarre, P.E.

Division Data Request 1-8

Request:

Provide circuit loading on new and expanded substations, both initial and long range.

Response:

The table in Attachment 1, prepared as part of the study, provides anticipated circuit loading (from 2008 through the study horizon year of 2013) on all feeders included within the electrical scope of the South County East Area Supply and Distribution Study.

Prepared by or under the supervision of: Alan LaBarre, P.E.

Plan 1 - Projected Loads

	Feeders	Limit		2008		2009		2010		2011		2012		2013	
		MVA	Device	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%	MVA	%
Bonnet	42F1	11.12	OH Line	8.4	76	8.7	78	8.9	80	9.2	82	9.4	84	9.6	86
Kenyon	68F1	11.06	UG Cable	9.3	84	9.6	86	9.8	89	10.1	91	10.4	94	10.6	**96**
	68F2	11.06	UG Cable	9.3	84	9.6	87	9.9	89	10.1	92	10.4	94	10.6	**96**
	68F4	8.32	OH Line	6.4	77	6.6	80	6.8	82	7.0	84	7.2	86	7.3	88
	68F5	11.45	OH Line	8.6	75	8.9	77	9.1	80	9.4	82	9.6	84	9.8	86
Lafayette	30F1	7.56	Transformer	4.4	59	4.6	60	4.7	62	4.8	64	4.9	65	5.1	67
	30F2	11.77	Regulator	5.2	44	5.3	45	5.5	47	5.7	48	5.8	49	5.9	50
Old Baptist	46F1	11.36	4/0 kcmil Cu	9.8	86	10.1	89	10.4	91	10.6	94	10.9	**96**	11.2	**98**
	46F2	11.36	4/0 kcmil Cu	9.8	86	10.1	89	10.4	91	10.7	94	10.9	**96**	11.2	**98**
	46F3	11.36	4/0 kcmil Cu	7.4	65	7.6	67	7.8	69	8.0	71	8.2	72	8.4	74
	46F4	11.80	OH Line	9.4	80	9.7	82	10.0	85	10.3	87	10.5	89	10.8	91
Peacedale	59F1	8.83	Volt. Regulator	3.3	38	3.4	39	3.5	40	3.6	41	3.7	42	3.8	43
	59F2	9.83	OH Line	8.5	86	8.7	89	9.0	91	9.2	94	9.4	**96**	9.7	**98**
	59F3	10.67	UG Cable	7.8	73	8.1	75	8.3	78	8.5	80	8.7	82	8.9	84
	59F4	8.83	Volt Regulator	6.0	68	6.2	70	6.4	72	6.6	74	6.7	76	6.9	78
Wakefield	17F1	12.89	OH Line	9.5	74	9.8	76	10.1	78	10.4	80	10.6	82	10.9	84
	17F2	8.36	Transformer	5.9	70	6.1	72	6.2	75	6.4	77	6.6	79	6.7	80
	17F3	12.89	OH Line	11.0	85	11.3	87	11.6	90	11.9	93	12.2	**95**	12.5	**97**
Tower Hill	TH1	11.45	OH Line	9.9	86	10.1	89	10.4	91	10.7	94	11.0	**96**	11.2	**98**
	TH2	11.45	OH Line	9.3	82	9.6	84	9.9	86	10.2	89	10.4	91	10.7	93
	TH3	11.45	OH Line	6.4	56	6.6	58	6.8	59	7.0	61	7.2	63	7.3	64

Division Data Request 1-9

Request:

Provide the contingency analysis completed for the subject area. We anticipate this was completed in accordance with the Booth Reliability Assessment Item 5. In particular, we need Narragansett Electric to provide the contingency analysis associated with the substation and distribution lines in the subject area.

Response:

Contingency analysis was completed on all distribution circuits included within the electrical scope of the South County East Area Supply and Distribution Study. This analysis considers circuit worst case single contingencies when identifying possible MWH exposure in excess of the Company's Feeder Design Criteria of 20MWH's. The result of this analysis is detailed in work papers from the Area Study effort as Attachment 1 to this data request.

Similar analysis is performed for the annual assessment required in accordance with the Booth Reliability Assessment Item 5. Feeders within the study area that were identified in the most recent annual assessment (October 31, 2005) as potentially having single contingency interruptions which could exceed Feeder Design Criteria limits were:

- Wakefield substation feeder 17F1
- Lafayette substation feeder 30F2
- Bonnet substation feeder 42F1
- Old Baptist Road substation feeder 46F2

The study analysis and annual assessment results are not the same because the methods of analysis differ. The annual assessment is completed using an automated screening tool. On the other hand, assessments in a planning study are completed by the study engineer, who has more specific information related to distribution feeder switching flexibility than that modeled by the automated screening tool.

The South County East Area Supply and Distribution Study did not include detailed analysis that considered worst case substation supply single contingencies for identification of possible violations of the Company's Supply Design Criteria of 480MWH's. This is due to the fact that all study area substations supplied by transmission facilities have multiple sources. Such a supply configuration makes it extremely unlikely that single supply contingencies would produce outages that violate the Supply Design Criteria.

Prepared by or under the supervision of: Alan LaBarre, P.E.

Station	Feeder	CS	3 Year		5 Year		MWHrs	Unserved Load
			SAIDI (Min.)	SAIFI	SAIDI (Min.)	SAIFI		
Wakefield	17F1	2429	107.4	1.96	78.2	1.49	17	
	17F2	2516	79.6	1.33	68.3	1.28	10	
	17F3	620	19.0	0.33	11.4	0.20	**23**	0.4
Lafayette	30F1	1699	149.5	2.80	129.7	2.17	**26**	3.64
	30F2	2519	85.7	1.58	79.7	1.61	**21**	
Bonnet	42F1	2930	80.6	1.43	172.5	2.55	**27**	0.43
Old Baptist	46F1	1393	82.3	0.56	94.3	0.81	12	
	46F2	2695	56.6	0.70	75.1	0.84	17	
	46F3	1878	142.0	2.66	101.6	2.00	12	
	46F4	2878	63.1	0.95	74.2	0.82	12	
Peacedale	59F1	2212	144.3	1.65	121.1	1.38	8	
	59F2	1960	53.4	1.06	41.1	0.87	**21**	
	59F3	2300	105.0	1.61	133.3	1.76	**24**	
	59F4	2436	154.1	1.70	132.1	1.34	7	
Kenyon	68F1	1298	85.0	1.47	89.8	1.37	9	
	68F2	4462	117.6	1.33	96.8	1.05	12	
	68F4	2274	144.9	1.60	121.8	1.45	6	

Division Data Request 1-10

Request:

Table 7-1, in the Environmental Report Volume I shows a compounded annual growth rate of the Project Area of 0.6% from 1980-2000. Table 7-2 shows the population projections for the Project Area from 2000-2020 growing at 0.3% compounded annually. How do these numbers support peak load growth in the Project Area in the magnitudes contained in Appendices A & B?

Response:

The population figures for the towns in the Project Area shown on Tables 7.1 and 7.2 were provided as part of Section 7.0, "Description of Affected Social Environment," in order to meet the EFSB Rules requiring a detailed description of all environmental characteristics of the proposed site including the physical and social environment on and off the site. These tables were prepared by Vanasse, Hangen Brustlin, Inc. as part of their general characterization of the project area, and were not used to develop the peak load growth projections contained in Appendices A & B.

The load projections for the Southwest Rhode Island Transmission Supply Study in Appendix A were based on the Company's 2001 and 2003 Power Supply Area (PSA) Forecasts of the Western Rhode Island PSA. The load projections for the South County East Area Supply and Distribution Study in Appendix B were based on the Company's 2004 Power Supply Area Forecasts. The Western Rhode Island PSA forecasts were developed using county-level population and employment projections from Moody's Economy.com, a leading economic forecasting consultant (more information about Moody's Economy.com can be found on their website, www.economy.com). The load projections for the SECT load area were provided by Northeastern Utilities (NU) and consist of NU's forecast of its Mystic and Shunock substation loads.

Prepared by or under the supervision of: Melissa Scott, P.E. and Alan LaBarre, P.E.

Division Data Request 1-11

Request:

It appears that the conclusions from the transmission analysis were based on a 2001 load forecast for the southwest Rhode Island (SWRI) load and for the southeastern Connecticut load (SECT). This is corroborated by an update in the SWRI forecast done in 2003, with no subsequent update in the SECT forecast. The 2003 SWRI forecast shows approximately 8-12% higher loads than the 2001 forecast. Please provide an explanation for the difference.

Response:

The loads studied in the October, 2003 Transmission Study were based on the 2001 and 2003 Power Supply Area (PSA) forecasts for the Western Narragansett Electric Company (NECo) PSA for substations in the Southern Rhode Island area. According to the 2003 PSA Forecast Report, the Western NECo PSA experienced extreme summer weather in 2001 and 2002 which resulted in higher than expected peak demand. One reason was a large increase in the air conditioning saturation as identified by the Company's Residential Customer Satisfaction Survey. Specific spot load additions also accounted for a large part of growth of the load. Within Narragansett, Western NECo was one of the fastest growing PSAs. The trend was expected to continue into the future. The short term forecast for the 2003 forecast included a large amount of spot loads.

Prepared by or under the supervision of: Melissa Scott, P.E. and Al Morrissey, Ph.D.

Division Data Request 1-12

Request:

The only spot load identified in the forecast is a 6 MW load addition for the campus expansion at the University of Rhode Island's West Kingston Substation. Were there others, and if so, what were they?

Response:

The URI spot load addition that was explicitly stated in the October, 2003 Transmission Study was the only spot load included in the Southern Rhode Island loads that were provided by distribution planning for the 2001 forecasted loads. The study also included an update using 2003 Western Narragansett Electric Company PSA 5% probability summer coincident peak forecasts prepared by the Planning and Financial Analysis Department, Distribution Finance New England for the Southern Rhode Island.

Spot loads that were included in the 2003 PSA forecast for the Western Narragansett Electric Company PSA at the Southern Rhode Island substations are as follows:

Customer	Year	Substation Source	Load (MW)	Probability	Spot Loads Included in the 2003 Western NECo Forecast
AMGEN	2003	Kent County	9.2	100%	9.2
AMGEN	2004	Kent County	7.3	100%	7.3
AMGEN	2005	Kent County	0.9	100%	0.9
AMGEN	2006	Kent County	4.0	100%	4.0
URI	2002	West Kingston	2	90%	1.8
Center of New England	2003	Kent County	1.0	75%	0.75
APC	2003	Kenyon	1.5	75%	1.13
Maro Displays	2003	Old Baptist	1.2	75%	0.9
Slocum Woods	2003	West Kingston	0.6	100%	0.6
Granville Commons	2003	West Kingston	1.1	100%	1.1
Richmond Sand & Gravel	2003	Kenyon	0.8	75%	0.6
American Biophysics	2003	Davisville	0.8	100%	0.8
Center of New England	2004	Kent County	2.0	75%	1.5
Granville Commons Condos	2004	West Kingston	1.2	100%	1.2

Prepared by or under the supervision of: Melissa Scott, P.E. and Alan LaBarre, P.E.

Division Data Request 1-13

Request:

On page 3 of Appendix B of the Environmental Report Volume I, the study states the following, "Spot loads include 2 MW for American Power Conversion and 1.5 MW for South County Commons." Are there other spot loads included but not specifically mentioned here and, if so, what were they?

Response:

No other spot load development was considered in the South County East Area Supply and Distribution Study.

Prepared by or under the supervision of: Alan LaBarre, P.E.

Division Data Request 1-14

Request:

How will the new and expanded substations affect feeder health ranking of circuits they relieve and newly formed circuits?

Response:

The new substation and the feeders supplied from it can be expected to significantly improve the overall health ranking of study area feeders. A feeder's health ranking is based on performance metrics including circuit load in relation to capacity, calculated MWH exposure resulting from worst case single contingencies and service reliability measures including customer interruption frequency and duration. By reducing average feeder loading in the study area, the addition of new feeders will immediately have a positive impact on performance metrics related to equipment loading. In addition, the additional operational flexibility provided by the new feeders and reduction in overall customer exposure to mainline contingencies should result in improved service reliability performance.

Prepared by or under the supervision of: Alan LaBarre, P.E.