May 7, 2001

Mr. Ted C. Feigenbaum
Executive Vice President and Chief Nuclear Officer
Seabrook Station
North Atlantic Energy Service Corporation
c/o Mr. James M. Peschel
P.O. Box 300
Seabrook, NH 03874

SUBJECT: SEABROOK GENERATING STATION, UNIT 1
NRC SPECIAL INSPECTION REPORT NO. 05000443/2001-005

Dear Mr. Feigenbaum:

On March 23, 2001, the NRC completed a Special Inspection Team at the North Atlantic Energy Service Corporation's (NAESCo's) Seabrook Generating Station to evaluate the March 5, 2001, partial loss of offsite power to the station 345 KV buses. The resulting automatic reactor trip was complicated by a failure of the turbine driven emergency feedwater pump. The results of the NRC team's inspection were discussed on March 23, 2001, with you, Mr. Kenyon, and other members of your staff. The enclosed report (Enclosure 1) presents the results of that inspection.

The NRC team examined activities related to reactor safety and compliance with the Commission's rules and regulations, and with the conditions of your operating license. The inspection consisted of selected examination of procedures and representative records, interviews with personnel, and observations of activities per the NRC team's charter (Enclosure 2).

We found that your staff's evaluations of the March 5, 2001, event was comprehensive with respect to the cause of failures. You initiated three distinct multi-discipline teams to determine the cause of the loss of the 345 KV lines, plant response to the event including operator action, and the failure of the turbine driven auxiliary feedwater pump. However, the conditions which led to or complicated the event were previously observed but not addressed appropriately through your corrective action process. For example, previous problems noted with the turbine driven emergency feedwater pump seal and rotor alignment, and arcing across the 345 KV bushing were not appropriately addressed. We noted also failure to incorporate vendor information to upgrade the seal package in the pump. These issues, coupled with the recent emergency diesel generator failure give rise to a cross-cutting concern with respect to identification and resolution of problems at the station and are identified as a "no color" finding.

This report discusses two findings that have been evaluated under the risk significance determination process (SDP) as having very low safety significance (green). The finding associated with the arcing across the 345 KV line bushing, although not a violation of an NRC requirement, was more than minor in that it affected the Initiating Event cornerstone. The second finding, associated with the failure of the turbine driven emergency feedwater pump, was a violation of regulatory requirements involving inadequate corrective actions. This violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC's Enforcement Policy. If you deny the non-cited violation, you should provide a response with the basis of your denial, within 30 days of the date of this inspection report to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Region I, the Director of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-001, and the NRC Resident Inspector at the Seabrook Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Wayne D. Lanning, Director
Division of Reactor Safety

Docket No: 05000443
License No: NPF-86

Enclosures:
1) NRC Inspection Report No. 05000443/2001-005
2) NRC Special Inspection Team Charter

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REGION I

Docket No:	05000443
License No:	NPF-86
Report No:	05000443/2001-005
Licensee:	North Atlantic Energy Service Corporation
Facility:	Seabrook Generating Station, Unit 1
Location:	Post Office Box 300 Seabrook, New Hampshire 03874
Dates:	March 12 - 23, 2001
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Approved by:	J. Linville, Chief, Electrical Engineering Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000443-01-05; on 03/12/01-03/23/01; North Atlantic Energy Service Corporation; Seabrook Station; Other Activities. Special Inspection of the March 5, 2001, partial loss of offsite power to the 345 KV buses, plant trip, and subsequent failure of the turbine driven emergency feedwater pump. Findings in effectiveness of corrective actions.

The inspection was conducted by two regional inspectors, a resident inspector, a reactor operations engineer from the Office of Nuclear Reactor Regulation (NRR), with support from a regional senior reactor analyst, a regional emergency preparedness specialist and technical staff members from the Office of NRR. This inspection identified two findings (green), one of which was also a non-cited violation. The significance of issues is indicated by their color (green, white, yellow, red) using IMC 0609 " Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

Inspector Identified Findings

Cornerstone: Initiating Events

- Green. Failure to take appropriate actions to address a 1997 event involving the 345 KV bushing arcing and preclude a similar event from occurring in March 2001. Although not associated with safety-related equipment, the failure led to a plant trip. The licensee entered this deficiency into the corrective action system as CR 01-02115. (Section 4OA3.1)

Cornerstone: Mitigating Systems

- Green. An apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," associated with the failure to evaluate significant conditions adverse to quality involving the turbine driven emergency feedwater pump was identified. The failure of the pump to function when called upon degrades the mitigating function of the emergency feedwater system. The licensee entered this issue into the corrective action system as CR 01-02120. This violation is being treated as a non-cited violation consistent with Section VI.A.1 of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 05000443/2001-005-001). (Section 4OA3.2)

Cross-Cutting Issues: Problem Identification and Resolution

- No Color. Similar problem identification and resolution issues were identified in both the initiating event and mitigating system cornerstones. The root causes associated with the partial loss of the offsite lines and the failure of the turbine driven emergency feedwater pump stemmed from inadequacies in the corrective action process and untimely incorporation of vendor technical information into plant procedures (Section 4OA3). In another event in November 2000, failure of emergency diesel generator "B" was a result of deficiencies in the corrective action process as well as failure to incorporate industry operating experience into the testing program (05000443/2000-011).

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Report Details

Summary of Plant Status

On March 5, 2001, Seabrook Unit 1 was operating at 100% Power. Severe winter weather was projected to impact the New Hampshire coast and at approximately 7:00 p.m. the winter weather reached Seabrook Station.

Background

On March 5, 2001, at 11:24 p.m., Seabrook Station experienced a generator loss of load that resulted in an automatic reactor shutdown. The loss of load occurred when the three offsite power lines (Scobie, Newington and Tewksbury) were lost to the station 345 KV bus 1. At the time of this loss, the Newington line was connected to the station's 345 KV bus 2. The line losses occurred during a severe snow storm. Earlier, at approximately 7:00 p.m., severe winter weather began to bring wet snow from the ocean. The high winds (greater than 20 mph, with gusts of up to 50 mph) blew the wet snow onto the 345 KV bushings. A band of snow accumulated across the entire length of the station termination bushings. The bushings are gas filled and provide the transition for the offsite lines into the station's onsite 345 KV buses. The snow accumulated on the "A," "B," and "C" phases of the three lines. There was arcing across the "B" phase bushings from the 345 KV lines to ground causing the lines to be disconnected from the station. The "A" and "C" phases were unaffected apparently because of their 60° angled orientation to the ground. The flashover resulted in first the loss of the Scobie line, followed by the Newington line. Personnel were sent to verify the condition of the switchyard and termination yard, and to take actions necessary for restoring the lines to service. The Newington line was restored to 345 KV bus 2, but before it could be restored to bus 1 the Tewksbury line was lost. Since the Scobie line was not closed back into 345 KV bus 1 at the time, the plant generator was isolated from the grid loads and only had the plant loads. Therefore, the plant generator experienced a loss of load. This resulted in a turbine trip and an automatic reactor shutdown per design.

The loss of the 345 KV bus 1 resulted in the loss of power to the Unit Auxiliary Transformers (UAT), through which offsite power was being supplied to both the safety-related and nonsafety-related buses. The reactor coolant pumps (RCP) tripped and the plant remained in natural circulation for approximately 30 minutes until offsite power was restored to the nonsafety-related busses and a RCP was restarted. The emergency diesel generators (EDG) automatically started and loaded on the safety-related busses. Throughout the event, offsite power remained available to 345 KV bus 2 and thus available to the plant loads through the reserve auxiliary transformers (RATs).

Following the plant trip, the turbine driven emergency feedwater (TDEFW) pump started and tripped on overspeed. The safety-related motor-driven emergency feedwater (MDEFW) pump started and remained available throughout the event. In addition, the nonsafety-related startup feed pump (SUFP), which could be powered from non-vital 4160 volt bus 4 or from vital 4160 volt bus 5 remained available throughout the event.

In this report, the "event" encompasses the time when the first of the three offsite lines (Scobie) was lost until the plant EDGs were secured.

The Special Inspection Team was dispatched to the site to inspect and assess the plant's personnel and equipment response to the event. The inspection was conducted using NRC inspection procedure 93812, Special Inspection.

4. OTHER ACTIVITIES [OA]

4OA3 Event Follow-up

.1 Loss of 345 KV Bus 1 and Automatic Reactor Shutdown

a. Inspection Scope

The team reviewed the circumstances surrounding the loss of the offsite 345 KV power lines to Seabrook Station's 345 KV buses 1 and 2 on March 5, 2001. The review included the design and configuration of the 345 KV onsite/offsite transition equipment (bushings). The team reviewed the electrical system response to the arcing across the "B" phase bushings to determine if it functioned as designed. Additionally, the team performed a walkdown of the 345 KV switchyard, the relay room, the control room, and toured the 345 KV termination yard to determine equipment alignment and material condition.

The team reviewed sections of the updated final safety analysis report (UFSAR), technical specification, engineering evaluations, and held discussions with electrical system systems engineers. The team also reviewed the licensee's activities to address a similar event that occurred in 1997.

The team reviewed the automatic reactor shutdown that resulted from the generator loss of load following the loss of offsite power to 345 KV bus 1. The team assessed the adequacy of the licensee's investigation, ongoing evaluations and corrective actions, and independently evaluated the risk significance of the event.

b. Findings

345 KV Ring Bus

Three offsite power lines - Scobie (line 363), Newington (line 369), and Tewksbury (line394) provide offsite power to the station's 345 KV termination yard bushings. The bushings provide a transition point from the overhead lines to the sulphur hexa-fluoride (SF_6) gas insulated bus sections of the 345 KV switchyard. Offsite power is supplied to the 345KV buses 1 and 2 through the bushings and a series of eight circuit breakers. The "A" and "C" phase bushings for each of the offsite power lines were angled at approximately 60° from the ground while the "B" phase bushing for each offsite power line was mounted vertically. During the March 5, 2001, storm, wet, heavy snow was driven by high winds into the bushing sheds. Most of the snow and ice fell off the "A" and "C" phase bushings due to gravity but adhered to the "B" phase bushings, eventually causing a flashover (arcing) from the line to ground. The protective differential relays operated as designed and caused the offsite power lines to be isolated from the site over approximately a 45 minute period. When all offsite power was lost to

345 KV bus 1, the main generator was disconnected from the offsite grid and was carrying only the station house loads through the UATs. The main generator then experienced a loss of load causing a reactor trip per design. The EDGs started and provided power to the vital 4160 volt buses (5 and 6). 345 KV bus 2 continued to be energized during the event, allowing the RATs to remained energized and be a viable source of offsite power. Non-vital 13.8 KV buses 1 and 2, 4160 volt buses 3 and 4, and vital 4160 volt buses 5 and 6 were normally energized from the UATs. However, because there was no fault condition when the plant trip occurred, no automatic transfer occurred from the UATs to the RATs. Power to buses 1 through 4 through the RATs had to be restored by operator action. Buses 5 and 6 were automatically powered by the EDGs. Due to continued arcing on the “B” phase bushings in the termination yard, the licensee elected to keep the vital buses powered by the EDGs during the event.

After reviewing the electrical system design basis, engineering evaluations, and having discussions with licensee personnel, the team concluded that the electrical system performed as designed during the event. No issues of significance were identified. Additionally, the team found that the licensee was prudent in not re-energizing the vital buses from offsite power while arcing continued on the “B” phase bushings.

The team reviewed a similar occurrence that happened on March 31, 1997. During the 1997 event, the Scobie and Newington Line experienced flashovers on the “B” phase bushings which resulted in actuation of the differential relaying on these lines. The Tewksbury line was lost due to an offsite fault and re-established several minutes later. The licensee’s analysis (CR 97-0633) identified that the cause of the bushing flashovers on the Scobie and Newington lines was due to the high salt content snow melting over the length of the “B” phase bushing. The licensee identified the primary root cause as not recognizing the effect that excessive snow buildup had on the bushings. The licensee also identified a secondary root cause as not meeting the required minimum clearance between the 345 KV conductor and the bushing.

The licensee’s corrective action for the 1997 event was to reroute the top 345 KV conductor further away from the “B” phase bushing to meet the minium required separation distance between the overhead power line and bushing and reduce the susceptibility to bushing flashover. The licensee also evaluated periodic cleaning of the bushings and determined that this was not appropriate based on bushing design. The licensee did place a caution in the severe weather procedure to alert the plant operators that severe winter weather could degrade the bushings, but did not provide instructions to verify the flashover did not impact a line and the actions needed to promptly restore a line to service. The licensee’s narrowly focused corrective actions on the conductor to bushing gap did not correct the issue of snow melting across the full length of the bushing and creating a flashover as evidenced by the March 2001 event. The team identified the failure to take adequate corrective actions to prevent flashover and loss of offsite power lines during severe winter weather as a finding. This finding is more than minor because it has a credible impact on safety in that if left uncorrected the “B” bushing of all three offsite power lines could fail resulting in a loss of offsite power. This finding affects the Initiating Events cornerstone. It was considered to have very low safety significance (green) using the Significance Determination Process because during the event, offsite power was available from 345 KV bus 2. The phase I SDP for initiating events was applied to this finding. Since the loss of offsite power lines affects both the likelihood of a reactor trip and the likelihood that event mitigation equipment or functions would not be available, a phase II evaluation was applicable. However, the phase II worksheets for Seabrook had not been approved, so a phase III risk evaluation for this condition was performed. The Seabrook Individual Plant Evaluation (IPE) assumes a reactor trip frequency of approximately 1 per year. A reactor trip caused by weather conditions has occurred only once (March 5, 2001) since the plant went online approximately ten years ago. Therefore, the impact of this condition on the assumed reactor trip frequency was determined to be minimal. During this event, one source of offsite power remained available to operate event mitigation equipment if the emergency power (the EDG) was not available. In addition to offsite power, Seabrook has two EDGs, either of which can power all equipment necessary to mitigate all design basis accidents or transients. Therefore, this finding was determined to be of very low risk significance because the impact on both the initiating event frequency and mitigating system availability was determined to be minimal. The licensee documented this issue in the corrective action system as CR 01-02115. No violation of NRC regulations was identified. **(FIN 05000443/2001-05-01)**

Automatic Reactor Shutdown

The generator loss of load event resulted in control rods automatically stepping in to follow the secondary side load reduction. There was an increase in the reactor coolant system (RCS) cold leg temperature which initially resulted in the ex-core reactor power detectors indicating higher reactor power. Then as the coolant temperature continued to increase the negative moderator temperature coefficient reduced reactor power. The power reduction from the control rods automatically stepping in and increased reactor coolant temperature resulted in a rapid power decrease. This power reduction exceeded the high negative flux rate trip and resulted in an automatic reactor shutdown.

This event was compared to the Updated Final Safety Analysis Report (UFSAR), Chapter 15, “Loss of Load” analysis. The inspectors concluded that the response of the Nuclear Steam Supply System (NSSS) was as expected and bounded by this analysis. The automatic reactor shutdown was an expected response to the loss of load event and, except for the issues discussed in this report, all systems performed as designed.

.2 Turbine Driven Emergency Feedwater Pump

a. Inspection Scope

The team reviewed the failure of the turbine driven emergency feedwater (TDEFW) pump that occurred when it automatically started following the plant trip. The team reviewed the licensee’s event evaluation, independently evaluated the risk significance of the failure, evaluated root causes, and assessed corrective actions to prevent recurrence. The team reviewed the TDEFW pump system health reports, surveillance procedures, condition reports and work requests. The team inspected the damaged components of the turbine driven emergency feedwater pump before the components were sent offsite by the licensee for further analysis.

b. Findings

The plant trip caused an automatic actuation of the emergency feedwater system due to Steam Generator Lo-Lo Level. Both the motor driven and turbine driven emergency feedwater pumps started. However, within approximately 57 seconds of the actuation signal, the turbine inlet steam trip/throttle valve, MS-129, tripped closed shutting down the turbine and the pump. The licensee initiated condition report CR 01-02120, "MS-V-129, Turbine Trip/Throttle Valve, Trip Resulting in Shutdown of FW-P-37A," and subsequently completed an event evaluation. The licensee concluded that the most likely cause of the turbine trip was the pump seal and/or pump impeller rubbing and releasing causing a momentary overspeed of the turbine and pump. In this failure scenario, the licensee described that the pump impeller rubbed against the casing causing binding that slowed the impeller. Inlet steam pressure then increased in response to the impeller slowing down. Subsequently, the "rub" broke free resulting in a momentary overspeed condition. This momentary overspeed actuated the overspeed trip mechanism to trip MS-V-129 which eventually shut down the turbine and pump.

The team inspected the damaged components (mechanical seal, first stage impeller and rotor, and throttle bushing) of the TDEFW pump and found indications of severe galling and discoloration from excessive heat. The damage was indicative of severe rubbing. The team reviewed records of as-found pump and turbine trip valve conditions, interviewed plant personnel and inspected the turbine and trip/throttle valve and identified no indication of abnormal component performance. Therefore, the licensee's assertion that an overspeed condition had occurred appeared appropriate.

The team reviewed results of maintenance and surveillance work activities on the TDEFW pump completed since 1997. In general, maintenance and surveillance work activities reviewed yielded satisfactory results. The results of surveillance tests (OX1436.02, TDEFW Manual Initiation; OX1436.13, TDEFW Post Cold Shutdown Operability Test; OX1436.13, TDEFW Pump Comprehensive Test; OX1436.02, TDEFW Pump Operability Test; EX1804.032, EFW Turbine Pump 18 Month Auto Actuation Surveillance) completed in early 2001 yielded acceptable results.

The team found that a similar pump failure had occurred in May 1996 during a quarterly surveillance test. During the test, an operator manually tripped the pump turbine after observing sparks at the outboard mechanical seal area. Licensee Event Report (LER) 96-003-00, "Emergency Feedwater Pump Mechanical Seal Failure," stated that the sparks appeared to be due to a mechanical interference within the mechanical seal assembly. In the LER, the licensee stated that Engineering would evaluate a mechanical seal design change which will increase the mechanical seal clearances and thus eliminate the need to use a dial indicator during seal installation. The root cause of the 1996 event was determined to be from inadequate corrective actions for a similar event in 1987 whereby operating experience was not incorporated into design changes, procedures, training, and pre-job briefings.

A contributing root cause for the 1996 failure was determined to be that the mechanical seal design clearances and tolerances were insufficient to prevent damage during operation. The licensee concluded that the as-found condition would have prevented the pump from performing its safety function. To eliminate the problem, a minor modification, MMod 96-0645, "EFW Pump Mechanical Seal Modification," was designed in accordance with the recommendation contained in Ingersoll-Dresser Pumps (IDP)

Technical Bulletin 108-96, “Rotor Preparation and Alignment.” The modification changed the throttle bushing material from carbon to graphalloy and also changed the shaft/seal alignment tolerances to minimize the potential for contact between the throttle bushing and the shaft sleeve. The bulletin was initiated by the vendor in September 1996 and received by the licensee in October 1996. The licensee completed the modification on the MDEFW pump in 1997 but failed to perform it on the TDEFW. The team was unable to determine why the modification was not completed on the TDEFW pump. The licensee was conducting an evaluation to determine the reason.

The team identified instances where the licensee did not take appropriate actions to correct the pump seal problem. In one instance, the NRC issued a notice of violation, NOV 50-443/96-04-01, for improper installation and alignment of the mechanical seals. ACR 96-588 and ACR 96-413 addressed the licensee’s actions regarding that violation. Those actions were inadequate. In another instance, on November 21, 2000, while performing mechanical support functions in preparation for 1-EFW-ET-001, “EFW Terry Turbine Overspeed Trip Test,” the licensee documented on Repetitive Task Sheet (RTS) No. 00RE00489001 that some problems with pump binding occurred during re-coupling. The team did not find any evidence that the licensee took any corrective actions.

Based on the above, the team determined that the licensee had ample information and opportunity to have implemented corrective actions that could have prevented the March 2001 pump failure from occurring. This finding is more than minor because it has a credible impact on safety in that if left uncorrected, it could result in a failure of the emergency feedwater system to perform its mitigating functions. Therefore, the licensee’s failure to take effective corrective actions to prevent recurrence of rotor binding and subsequent shut down of the TDEFW pump was determined to be a violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. This issue affected the Mitigating Systems cornerstone because EFW supplies the steam generators when main feedwater is unavailable. The phase I SDP for mitigating systems was applied to establish the risk of this finding. The last successful surveillance test was completed on February 28, 2001. The team reviewed the test results as documented in RTS 01R003054001, TDEFW Pump Operability Test, and found that the test data was within the acceptance criteria for all parameters. Since the pump was demonstrated to be operable 5 days prior to its failure, one half of the duration between the test and the failure was determined to be the fault exposure time (duration that the pump would not have been available to perform its safety function). The licensee has developed some information that supports that the TDEFW pump may have been recoverable, however, this work was ongoing at the conclusion of this inspection and was not reviewed by the team. For evaluating risk in the SDP, the team assumed that the pump function was lost. This finding did not result in the loss of secondary makeup because the motor driven emergency feedwater pump (100% capacity) remained available. The loss of a single train (TDEFW pump) was for 2 ½ days which was not in excess of the 3-day technical specifications allowed outage time. Therefore, in accordance with phase I of the SDP, this issue was found to be of very low risk significance (green). The licensee entered this issue as CR 01-02120 in the corrective action system. This violation is being treated as non-cited violation consistent with Section VI.A.1of the NRC Enforcement Policy issued May 1, 2000 (65FR25368). **(NCV 05000443/2001-05-02)**

Following repairs to the pump, the licensee completed a special post-maintenance test involving the quarterly surveillance test and the full flow test and declared the pump operable. NRC team members observed the test. Test results yielded acceptable pump performance.

.3 Plant Equipment Response

a. Inspection Scope

The team evaluated equipment failures and significant problems that occurred during the event. The following issues were reviewed: (1) Inadvertent start of the MDEFW pump during restoration of vital 4160 volt bus 6 to offsite source, (2) Startup feed pump (SUFP) non-vital 4160 volt breaker cycling, and (3) Failure of main steam isolation valve (MSIV) “C” to respond to a “slow close” signal.

The team also reviewed the operation of the reactor coolant system power operated relief valves (PORVs) during the reactor shutdown. In addition, the team evaluated the licensee’s reliance on the emergency diesel generators (EDG) to power the vital buses for an extended period of time and assessed the EDG performance.

The team assessed the impact of the event on significant licensing basis considerations for Seabrook’s response to loss of offsite power (LOOP) events including Station Blackout (SBO).

b. Findings

Motor Driven Emergency Feedwater Pump

No findings or violations of NRC requirements were identified. During the event, when power to safety bus 6 was being restored from the EDG to the offsite source, there was an inadvertent start of the MDEFW pump. Reviews by the licensee revealed that the unexpected pump start was the result of the Emergency Power Sequencer (EPS) relays resetting. The unexpected start did not affect the EDG starting, load shedding and load sequencing, including the starting sequence of the MDEFW pump. The EPS reset during offsite power restoration to bus 6. When the EPS reset, two EPS relays (EPS-PR1 and EPS-SR6) that are in the emergency feedwater start circuitry repositioned their contacts. The EPS-SR6 relay is an ultra high speed relay and resets faster than the EPS-PR1 relay. When the EPS-SR6 relay reset before the EPS-PR1 relay, the pump start logic was completed and the pump started. This EPS reset condition would occur during recovery from an event and would not impact the post accident response of the EPS. The team reviewed the licensee’s evaluations and design information for the EPS and reviewed the results of subsequent tests of the EPS response. The team determined that the EPS relay reset timing could have caused the inadvertent pump start and that the actuation had no impact on the pump’s safety function. This issue is documented in CR 01-02164.

Startup Feed Pump

No findings or violations of NRC requirements were identified. Following the plant trip, the SUFP received a start signal when both main feed pumps (MFP) tripped. The SUFP control circuitry attempted to start the pump from de-energized bus 4, its normal power source. The control circuit sensed that no power was available from bus 4 and tripped the supply circuit breaker. Once the supply circuit breaker tripped, an eighty second timer initiated. After eighty seconds, the control circuit attempted to start the SUFP again. This cycling continued eighteen times for approximately 24 minutes. The cycling would only stop when power was restored to the SUFP supply breaker for bus 4 or the pump control switch was placed in the pull-to-lock position. The operators did not have immediate indication that the circuit breaker was cycling during the event. During recovery from the event, the operators placed the SUFP control switch to pull-to-lock per procedure ES-0.1, "Reactor Trip Response," Revision 27.

From document reviews and discussions with electrical engineers, the team confirmed that the pump's logic performed as designed. SUFP would start automatically on bus 4 based on the conditions that were present. However, due to the loss of power to bus 4, there was no power for the pump to run. The licensee performed an inspection of the SUFP supply circuit breaker and placed the issue into the corrective action system as CR-01-02156. The licensee subsequently operated the SUFP successfully. The team found no safety consequences associated with the SUFP supply breaker cycling. The SUFP could have been used if electrical power was restored to bus 4 or the licensee could have realigned the SUFP to bus 5 per procedure OS1035.02, "Startup Feed Pump Operation," Revision 8.

Main Steam Isolation Valves

No findings or violations of NRC requirements were identified. Following the automatic reactor shutdown, the "C" main steam isolation valve (MSIV), 1-MS-V-90, did not close when operators attempted to close the MSIVs from the control room "slow close" control switch. However, the valve did close when actuated through the Main Steam Line Isolation Train "A" control switch. The licensee later identified that the most probable cause of the initial failure of the valve to close was dirt on the connector to MSIV field buffer board A3-16 in local cabinet 1-MS-CP-182. The board and its connector were cleaned, reinstalled, and the MSIV tested successfully. The cabinets for the other three MSIVs were inspected and found acceptable. The team also verified that other safety related cabinets had repetitive task sheets (RTS) to clean and inspect periodically. These RTS used in conjunction with normal surveillance testing ensure operability of similar cabinets. This issue was documented in CR 01-02204. The team did not have any further concern in this area.

Emergency Diesel Generators

No findings or violations of NRC requirements were identified. When offsite power was lost to the safety buses, EDGs "A" and "B" started, properly sequenced their loads and provided electrical power to vital 4160 volt buses 5 and 6 as designed. The team reviewed the EDGs' performance data. The data provided included EDG "A" and "B" run times, voltage data, frequency data, load data, and an explanation of alarms received during their operation. The EDGs reached rated voltage and frequency in less than ten seconds as designed. EDG “A” was loaded to approximately 2,820 kilowatts and EDG “B” was loaded to approximately 1,725 kilowatts.

EDG “A” was shutdown at approximately 10:53 a.m. on March 7, 2001, following a run time of over 35 hours. EDG “B” was secured later at approximately 2:34 p.m., following a run time of over 39 hours. The licensee opted to run EDG “B” for over three additional hours because, based on a recommendation made by the manufacturer, since EDG “B” was lightly loaded during its run, the additional run time would ensure that any potential carbon buildup in the engine was eliminated.

Power Operated Relief Valve “A”

No findings or violations of NRC requirements were identified. The team reviewed the operation of the PORVs during the reactor shutdown. The generator loss of load resulted in a rapid reduction in turbine power. This resulted in a mismatch between the rate of energy being produced in the primary system and the rate of energy removal in the secondary system. Since the primary system was producing more energy than the secondary system could remove the primary system temperature and pressure increased. The “A” pressurizer PORV opened to maintain the primary system below 2385 psig. Both the “A” and “B” PORV require a pressure permissive signal (primary system pressure 2335 psig) and a high pressurizer pressure signal (2385 psig) to open. However, the “A” PORV has an anticipatory function that will allow the “A” PORV to open below the setpoint pressure of 2385 psig based on the rate of pressure increase. During the event, this anticipatory function opened the “A” PORV to limit pressure to 2250 psig. The setpoint of 2385 psig for opening the “B” PORV was not reached and the “B” PORV did not open. Therefore, the team was satisfied that PORV “A” operated as expected following the automatic reactor trip.

Grid Stability and Compliance with General Design Criterion (GDC) 17

No findings or violations of NRC requirements were identified. The team reviewed the effect of the event on grid stability and the licensee’s compliance with the requirements of 10 CFR 50, Appendix A, “General Design Criteria,” Criterion 17, “Electric Power Systems” (GDC 17) regarding restoration of a secondary access source in a timely manner (within an hour). The team reviewed documents associated with grid stability prior to and during the March 5, 2001 event. This documentation included grid voltage data, grid frequency data, a New England Power Pool Comprehensive Review of Transmission Reliability Report, and Electric System Control Center (ESCC) substation logs.

The grid voltage remained at approximately 357 KV prior to and during the event except during the arcing voltage transients that occurred at the termination yard bushings. The grid frequency remained at approximately 60 hertz prior to and during the event.

Therefore, the team did not identify any issues with the grid stability during the March 5, 2001 event. Since offsite power was available to 345 KV bus 2, the team did not identify any issues with the licensee’s compliance with GDC 17 and the licensing basis.

Station Blackout Rule Implications

No findings or violations of NRC requirements were identified. Based on the team's review of this event and discussion with the licensee, the team determined that Seabrook Station did not experience a complete loss of offsite power due to a grid-related event. The partial loss of offsite power that occurred during this event was weather-related and not grid related, therefore the Seabrook Station was within the bounds of the original SBO analysis. The SBO rule requires all licensees to assess the capability of their plants to maintain adequate core cooling and appropriate containment integrity during a station blackout and have procedures to cope with such an event. Each licensee is required to determine the specified duration (SBO coping duration) for which a plant is able to withstand an SBO. The licensee for the Seabrook Station, based on number of factors identified in RG 1.155, determined a four hour SBO coping duration for the Seabrook Station. The four hour SBO coping duration was based on several factors, such as, determining the offsite power design group, determining the emergency AC (EAC) power configuration group (number of emergency diesel generators (EDGs) available minus the number needed for decay heat removal) and selecting the EDG target reliability. In determining the offsite power design group, one of the factors used was that the Seabrook Station's susceptibility to grid-related loss of offsite power events is less than once in twenty years.

During the event the plant had offsite power available to the emergency buses from 345 KV bus 2 through the RATS; however, plant personnel indicated that they were concerned with the reliability of the offsite power and allowed the emergency diesel generators to power the vital buses. The licensee selected a reliability target of 0.975 for the EDGs at the Seabrook Station to come up with a 4 hour SBO coping duration during the SBO rule compliance review process. The team reviewed the EDG reliability data and confirmed that the current reliability is greater than 97.5%. However, the team did not conduct an in-depth evaluation and analysis of the data and calculations used in determining the EDG reliability at the Seabrook Station. After review of this issue and discussion with NRR technical staff, the team did not identify any concerns with the licensee's compliance with their SBO Rule implementation. Since the event did not result in a complete loss of offsite power to the 345 KV buses, and the EDGs functioned as designed, the team did not find any challenges to the station's SBO analysis.

.4 Plant Personnel Response

a. Inspection Scope

The team reviewed the actions taken by operations personnel in response to the event. The team reviewed operator logs, computer alarm logs, CR 01-2115, “Plant Trip on 3/5/01,” and Duke Energy Company Analysis NFSB 01-0015, “Evaluation of Plant Trip on March 5, 2001”. The team focused on areas involving severe winter weather preparation, loss of off site power lines including the automatic reactor shutdown, and dealing with the loss of the turbine driven emergency feedwater pump.

The team’s review of the licensee’s preparation for severe winter weather included interviews with key operations personnel and review of applicable procedures. The procedures reviewed are listed in Attachment 1 of this report.

The team’s review of the licensee’s response to the loss of the 345 KV off site power lines and resulting loss of load condition included plant walkdowns of the relay rooms and interviews of operations personnel. The procedures reviewed are listed in Attachment 1 of this report.

The team’s review of the licensee’s activities and procedural requirements to restore off site power lines during the severe weather included the timeliness of off site power restoration and operation of the emergency diesel generators. The team reviewed the effectiveness of the corrective actions that were taken as a result of the event and Standing Operating Order 01-006, “Switchyard Severe Weather Procedure,” implemented after the March 5, 2001 event.

b. Findings

Severe Winter Weather Preparation

No findings or violations of NRC requirements were identified. As part of the preparation for the severe winter weather, the licensee limited the maintenance work being performed on equipment important to safety. For example, the licensee canceled planned service water pump work and performed Master/Satellite Procedure 2. This procedure had station personnel take precaution to ensure that routine testing and maintenance activities do not reduce the reliability of the grid. In addition, non-essential personnel were sent home and essential personnel were staged in hotels close to the site.

The team reviewed the design basis for wind loading and compared this with the procedures. Specifically the team reviewed the procedures for actions to be taken during high winds, including declarations of emergencies and other requirements on plant operations based on wind loading. The plant was designed to withstand wind speed of 110 miles per hour (mph). During the March 5, 2001, event wind gusts were measured at 50 mph, well below the design speed.

As a result of the March 5, 2001 event, the licensee implemented a standing operating order number 01-006, “Switchyard Severe Weather Guidance” as part of procedure

OS1200.03, “Severe Weather Conditions,” Revision 10. The standing order established severe weather guidance for sustained winds grater than 20 miles per hour with freezing rain, snow, or sleet. The guidance included, visually monitoring the bushings in the 345KV termination yard, placing an operator in the relay room when bushings were bridged 90%, and actions taken if a 345KV line trips.

The team reviewed the severe weather procedure and the standing operating order and found that while the actions implemented may not prevent the loss of offsite lines, they could help in the timely restoration of the offsite lines and should be viewed as short term corrective actions pending implementation of long term corrective actions.

The actions that NAESCO performed in preparation for the severe winter weather were appropriate and in accordance with the procedures reviewed. Limiting plant switchyard maintenance and other planned maintenance work prior to the storm effectively managed plant risk and minimized the potential of plant transients.

Loss of Offsite Power Lines and Automatic Reactor Shutdown

No findings or violations of NRC requirements were identified. The team reviewed the licensee’s response to the automatic reactor shutdown. This review included a review of operator implementation of E-0, “Reactor Trip or Safety Injection” and ES-0.1, “Reactor Trip Response.” In addition, the team reviewed selected recovery actions and equipment performance issues that occurred during recovery. The most significant equipment issue was the failure of the turbine driven emergency feedwater pump. Other issues reviewed included the inadvertent start of the motor driven emergency feedwater pump, the cycling of the startup feed pump breaker cycling and the failure of the MSIV “C” to respond to a “slow close” signal. The details of these issues are discussed in other sections in this report.

Finally, the inspectors reviewed this event to determine if the required reportability requirements as specified in 10 CFR 50.72, “Immediate Notification Requirements for Operating Nuclear Power Reactors,” were met. The licensee made the appropriate notification - Event Number 37810.

The inspectors concluded that the operational procedure guidance did not contain sufficient detail to quickly allow plant personnel to efficiently determine the cause of the loss of the offsite power lines and restore the lines to service. However, procedure changes alone would not prevent the loss of offsite power lines during severe winter weather conditions. NAESCO addressed this issue by developing and implementing standing orders prior to the next forecasted winter storm. During the automatic reactor shutdown the plant staff effectively implemented procedures E-0, “Reactor Trip or Safety Injection” and ES-0.1, “Reactor Trip Response.” The plant staff appropriately managed plant risk by powering critical plant equipment from the emergency diesel generators and maintaining the turbine driven emergency feedwater pump available.

.5 Emergency Preparedness

a. Inspection Scope

The team reviewed plant operating journals, computer alarm logs, licensee's sequence of events logs, and interviewed key emergency plan personnel and operations personnel to determine if the emergency plan was effectively implemented. The team reviewed the licensee's decision to declare a discretionary unusual event at 11:36 p.m. on March 5, 2001, based on emergency action level (EAL) 18a, "Hazards Experienced or Projected Which Involve Potential Degradation of Station Safety." This review included procedure ER 1.1, "Classification of Emergencies," Revision 30, and verification of timely reporting to the state of New Hampshire, Massachusetts and the Nuclear Regulatory Commission. The team also reviewed the decision to terminate the unusual event based on restoration of off site power to the station emergency buses.

b. Findings

No findings or violations of NRC requirements were identified. The licensee initiated administrative procedure NM 11800, "Hazardous Condition Response Plan," on March 5, approximately 8 hours before the storm arrived. The team reviewed the procedure and verified that selected actions in it were completed. The licensee also initiated the Emergency Response Organization (ERO) and maintained members at a local hotel to respond to storm issues. During the severe weather, although not officially required to be activated, they partially staffed the Technical Support Center (TSC) and the offsite Emergency Operating Facility (EOF).

The operators implemented operating procedure, OS1200.03, "Severe Weather Conditions," prior to the beginning of the storm. The team reviewed plant records and verified that the plant followed the required steps of the procedure.

The Unusual Event (UE) was declared, at the discretion of the licensee, due to the weather conditions and the partial loss of offsite power. The team determined that the event classification was appropriate and in accordance with plant procedures. The licensee made the proper notifications to the State of New Hampshire (NH), via the NH State Police, and to the Commonwealth of Massachusetts (MA) via the Massachusetts Emergency Management Agency. However, the NH State Police failed to notify the NH agencies and the Rockingham County Dispatch Center (RCDC), which notifies the seventeen surrounding New Hampshire (NH) communities in accordance with the NH State Emergency Plan.

The licensee became aware that the surrounding communities had not been notified by the RCDC when they were contacted by some of the local communities. The licensee then contacted the RCDC and the RCDC completed notification of the 17 communities. The NH Office of Emergency Management has reviewed this issue and is taking corrective actions to ensure that notifications occur in a timely manner. Even though the licensee is not required to notify county officials, the licensee revised the onsite emergency plan to verify that all required off-site notifications to state emergency management officials, state public health officials, and local communities have been initiated and/or completed by the 24-hour notification points in both NH and MA. This issue is documented in CR 01-02171.

The team's review revealed that, based on availability of power, all offsite sirens remained operable during the event. The sirens are not powered from the site and have backup batteries that last 7 days or two activations, whichever happens first.

.6 Event Causal Factors, Root Causes and Corrective Actions

a. Inspection Scope

The team reviewed the licensee's analysis and corrective actions that were taken for the partial loss of the 345 KV off site power lines, the plant trip and the failure of the turbine driven emergency feedwater pump. The review included condition reports, CR 01-02115, "Plant Trip on March 5, 2001," and "Loss of Power to Station Buses," and CR 01-02120, "MSV-129 Trip Resulting in Shutdown of FW-P-37A."

The team also assessed the adequacy of the licensee's corrective actions and extent of condition review for selected event related equipment failures.

b. Findings

Regarding the partial loss of offsite power, the licensee determined that each of the 345 KV offsite power lines was lost due to bushing flashover on the "B" phase bushing. These flashovers occurred as the insulation capability of the bushing was decreased due to the melting of the snow, which apparently had a high salt content, across the bushing surface. The "B" phase bushing is orientated perpendicular to the ground, the "A" and "C" phases are orientated at approximately a 60° angle from the ground. Therefore, as the snow melted a continuous current path developed across the length of the "B" phase bushing. This resulted in a flashover from the corona shield at the top of the bushing to the corona ring at the bottom of the "B" phase bushing. There were no flashovers of sufficient magnitude to actuate the differential relaying on the "A" or "C" phases. The orientation of the "A" and "C" bushings helped to prevent a continuous current path from developing across the entire length of the bushing surface.

The licensee was still evaluating the appropriate corrective actions to take.

Regarding the TDEFW pump failure, the licensee determined that the seal/impeller rotor rubbing caused the turbine overspeed. The team also determined that this was the most likely cause. The team further determined that this failure occurred because, the licensee failed to take adequate corrective actions to address a similar failure that occurred in 1996. In addition, in late 1996, a vendor technical bulletin had prescribed measures to implement to ensure that the pump would be less susceptible to this phenomena.

The enhanced seal package was installed in the TDEFW pump prior to restart. The MDEFW pump had been upgraded in 1997.

.7 Risk Significance of Event

a. Inspection Scope

The team evaluated the risk significance of the event, partial loss of offsite power and turbine driven emergency feedwater pump failure, based on Conditional Core Damage Probability (CCDP). The licensee was not required to complete a risk assessment based on CCDP and did not complete one.

b. Findings

Since offsite power remained available, this event was modeled as a transient with a loss of the turbine driven emergency feedwater pump. Due to the loss of power to the non-safety-related buses, the Main Feedwater (MFW) system was assumed to be unavailable (conservative assumption since the secondary system could have been powered via the RATs). The TDEFW pump was assumed to be not recoverable. In addition, the risk contribution associated with the potential for failure of emergency power and the recovery of offsite power was considered.

The CCDP using the NRC's revision 3 GEM/SPAR analysis was approximately 1.1E-5. The primary sequence of concern was the loss of the motor-driven emergency feedwater pump with a loss of the startup feed pump (SUFP) and a failure to initiate feed and bleed (operator action). This one sequence contributed approximately 90% of the CCDP. Following the plant trip, if the emergency diesel generators (EDGs) had failed, operator action would have been necessary to restore offsite power to the safety-related buses. The Region I senior reactor analyst (SRA) estimated that the failure of both EDGs and the operators failure to restore offsite power to the safety-related buses would contribute approximately 1E-5 to the CCDP for this event. Therefore the total CCDP estimate for this event would be approximately 2.1E-5 (1.1E-5 + 1E-5).

Had offsite power been completely lost and if recovery was significantly hampered by the weather, this event would have had a significantly higher CCDP.

4OA4 Cross-Cutting Issues

.1 Conclusions

In developing the probable causes of the March 5, 2001, event, the NRC team noted an apparent trend related to untimely measures to address known conditions affecting the operability of essential event mitigation equipment. Timely and effective corrective actions were not taken to address a 1996 turbine driven emergency feedwater pump mechanical seal failure, and vendor information was not incorporated in a timely manner to ensure that the pump would continue to operate properly (Section 4OA3.2). Also, effective corrective actions were not taken to address a 1997 345 KV line bushing arcing that occurred when snow accumulated on the bushing (Section 4OA3.1). Regarding another event that occurred in November 2000, another NRC Special Inspection Team (NRC inspection report 05000443/2000-011) found that the failure of the "B" emergency diesel generator was a result of deficiencies in the corrective action process as well as failure to incorporate industry operating experience into the testing program.

These issues have a related cause in that they represent known degraded conditions and industry operating experience information that were addressed incompletely or in an untimely manner. The individual findings each have had a direct impact on safety, increasing the frequency of initiating events and affecting the reliability, operability and functionality of a train of mitigating equipment. This performance trend is considered a substantive cross-cutting issue not captured in individual issues that reflects problem identification and resolution issues, and is a finding characterized as “no color.” **(FIN 05000443/2001-05-03)**

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On March 23, 2001, the NRC team presented the inspection results to Messrs T. Feigenbaum, B. Kenyon and other members of the North Atlantic Energy Service Corporation. One document reviewed during the inspection was considered proprietary. The document is noted in the list of documents reviewed. No information from that document was included in this report.

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

NAESCO (Licensee)

P. Brangiel, System Engineer, Diesel
T. Couture, System Engineer, Diesel
K. Doyle, I&C Training
T. Feigenbaum, Executive Vice President and Chief Nuclear Officer
P. Freeman, Event Team Manager
G. Gram, Director, Support Services
J. Grillo, Assistant Station Director
L. Hanson, Electrical Engineer
R. Jamison, Design Engineering
B. Kenyon, President, Northeast Utilities (NU)
G. Kotkowski, Electrical Engineer
N. Laversque, Supervisor, Vibration analysis
K. Letourneau, Senior Engineer
M. Makowicz, Event Team Leader
R. Marble, Electrical Engineer
E. Metcalf, Plant Engineering NSSS Supervisor
J. Peschel, Manager, Regulatory Programs
B. Plummer, Operations Manager
L. Rau, Reliability & Safety Engineering Supervisor
P. Richardsen, NSARC Chairman
D. Sherwin, Maintenance Manager
M. Sketchly, Unit Supervisor (former)
J. Sobotka, Regulatory Compliance Supervisor
G. St. Pierre, Station Director
D. Tall, Emergency Preparedness Manager
J. Vargas, Engineering Director

NRC Personnel

J. Linville, Acting Deputy Director, DRS
J. Brand, Resident Inspector, Seabrook
R. Arrighi, Acting Resident Inspector, Seabrook

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

FIN	05000443/2001-05-01	Arcing of the 345 KV line bushings during severe weather condition resulted in a plant trip. (Section 4OA3.1)
NCV	05000443/2001-05-02	Inadequate corrective actions to address turbine driven emergency feedwater pump seal failure. (Section 4OA3.2)
FIN	05000443/2001-05-03	Cross-cutting problem identification and resolution issues. (Section 4OA4).

LIST OF ACRONYMS USED

ACR	Adverse Condition Report
CCDP	Conditional Core Damage Probability
CFR	Code of Federal Regulations
CR	Condition Report
D/P or DP	Differential Pressure
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EFW	Emergency Feedwater
EOF	Emergency Operating Facility
ERO	Emergency Response Organization
ESCC	Electric System Control Center
EPS	Emergency Power Sequencer
GDC	General Design Criteria
IDP	Ingersoll-Dresser Pumps
KV	Kilovolt (1,000 Volts)
LER	Licensee Event Report
LOOP	Loss of Offsite Power
MDEFW	Motor Driven Emergency Feedwater
mph	Miles per Hour
MSIV	Main Steam Isolation Valve
NAESCO	North Atlantic Energy Service Corporation
NCV	Non cited violation
NH	New Hampshire
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OD	Operability Determination
RAT	Reserve Auxiliary Transformer
RCDC	Rockingham County Dispatch Center
RTS	Repetitive Task Sheet
SBO	Station Blackout
S/G	Steam Generator
SDP	Significance Determination Process
SF_6	Sulphur Hexa-fluoride
SIT	Special Inspection Team
SUFP	Startup Feed Pump
TBEFW	Turbine Driven Emergency Feedwater
TS	Technical Specifications
UAT	Unit Auxiliary Transformer
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report

PARTIAL LIST OF DOCUMENTS REVIEWED

Condition Reports

CR 01-02115, Reactor Trip 3/5/01 at 2324 Due to Loss of Offsite Power Due to Snow Storm
CR 01-02120, MS-V-129 Tripped Closed
CR 01-02124, The Rod Control Demand Counters Counted Erratically
CR 01-02156, Supply Breaker to the SUFP (FW-P-113), Cycled Closed
CR 01-02164, Unexpected Start of the Electric EFW Pump
CR 01-02171, NH Emergency Planning Zone Notification of Unusual Event Declaration
CR 01-02173, SI V 48 and SI V 132 Accumulations of Boric Acid Crystals
CR 01-02204, MS-V-90 Failed to Close From the MCB Normal Close Control Switch
CR 01-02263, Unavailability of MPCS Transient and Recording Analysis from Plant Trip
CR 01-02336, “A” PORV Opened as Expected on 3/5/01 Transient
CR 01-02412, 345KV Bushing Cleaning with Unapproved Solvent
CR 01-02701, Follow up notification documentation
CR 97-07867 01 through 10, ACR 97-0633 - 345KV Lines and Breakers

Drawings

1-MS-D20582, P&ID, Main Steam System Emergency Feedwater Pump Supply Detail, Rev. 12
1-FW-D20688, P&ID, Emergency Feedwater System Details, Revision 16
1-FW-D20686, P&ID, Feedwater System Details, Revision 10
1-NHY-310002, Unit Electrical Distribution One Line Diagram, Rev. 32
1-NHY-310844, Sh. A47a through f, Startup Feed Water Pump 1-P-113
1-NHY-310844, Sh. CN1a and b, Startup Feed Pump 1-P-113 Prelube Pump 1-P-161
1-NHY-310844, Sheets A80a through A80h, EFW Pump 1-P37B Electrical Drawings

Engineering Evaluations/Calculations

92-01, Evaluation of 345, 13.8, and 4.16KV Circuit Breaker Interlocks and Tripping Schemes and Out of Step Relay 78/B3 Tripping Scheme
9763-3-ED-00-02-F, “Voltage Regulation,” Revision 6

Event Evaluations - P. Freeman, Team Manager

Loss of Power to Station Buses, M. Makowicz, Team Leader
Plant Trip on March 5, 2001, P. Falman, Team Leader
MS-V-129 Trip Resulting in Shutdown of FW-P-37A, R. Campo, Team Leader

Modifications

94-0525, Minor Modification EFW Pump (Motor Driven) Rotor Replacement
94-0042, Minor Modification EFW Pump (Steam Driven) Rotor Replacement
96-0645, Minor Modification EFW Pump Mechanical Seal Modification
97-604, Termination Yard HV Entrance Bushing Connection

Procedures

E-0, Reactor Trip or Safety Injection, Revision 27
ES-0.1, Reactor Trip Response, Revision 23
ECA-0.0, Loss of All AC Power, Revision 23
ODI.12, Switching Orders, Revision 16
OS1000.08, Post Trip Review, control number K500, for the March 5, 2001 Trip
OS1200.03, Severe Weather Conditions, Revision 10
OS1246.02, Loss of Vital Unit Substation or MCC, Revision 01
ER1.1, Classification of Emergencies, Revision 30
ER 2.0D, Event Notification Sheet, Revision 21
NAWM , Work Management Manual, Revision 9
NM 11800, Hazardous Condition Response Plan, Revision 7
WM 10.1, On-Line Maintenance, Revision 2
OS1035.02, Startup Feed Pump Operation, Revision 8
OS1046.04, 345KV Operations, Revision 5
OS1200.03, Severe Weather Conditions, Revision 10
OX1436.13, TDEFW Pump Post Cold Shutdown or Post Maintenance Surveillance and Comprehensive Pump Test, Revision 07
OX1436.02, TDEFW Quarterly and 18 Month Surveillance Test and Monthly Valve Alignment, Revision 08
EX1804.032, EFW Turbine Pump 18 Month Auto Actuation Surveillance, Revision 03
ES1807.016, Thermography Program, Revision 02
ES1807.021, Level I Vibration Trending and Analysis, Revision 00
Turbine Driven Emergency Feedwater Pump Post Cold Shutdown Or Post Maintenance Surveillance And Comprehensive Pump Test, Revision 07
OX1436.02, Turbine Driven Emergency Feedwater Pump Quarterly and 18 Month Surveillance Test And Monthly Valve Alignment, Revision 08
EX1804.032, Emergency Feedwater Turbine Pump 18 Month Auto Actuation Surveillance, Revision 03
PEG-57, Predictive Maintenance Monitored Equipment List (PMEL), Revision 00
ES1807.022, Level II Analysis, Revision 00
B8470 345 KV 394 Voltage Low, Revision 0
B8471, 345 KV Line 363 Voltage Low, Revision 0
B8472, 345 KV 369 Voltage Low, Revision 0
Standing Operating Order 01-006, Switchyard Severe Weather Guidance, 3/12/01

Work Orders

01W000560, " EFW Pump has developed an internal rub" dated March 7, 2001
01W000556, Clean and Deice the 345KV Bushings, 3/01
01W000573, Clean and Deice the 345KV Bushings, 3/01
01W000574, Clean and Deice the 345KV Bushings, 3/01
01W000686, Determine Cause of DGA Alarm During Run, 3/01
95W000504, 1-FW-P-37A Pump rotor replaced with a stainless steel element, 12/95
95W001024, 1-FW-P-37A Pump outboard bearing excessive heat, 5/96

Other Documents

USNRC Event Report 37810, Seabrook, Emergency Declared, RPS Actuation

* Nuclear Products Operation, Flowserve Pump Division March 22, 2001 Letter to North Atlantic Energy (sic) Services Corporation.
- Nuclear Safety Engineering Report, File NS2000-01; Evaluation of SOER 99-1, Loss of Grid, 4/12/00
- Station Information Report Number 91-018, 345KV Circuit Breakers 11 and 163 Opened Causing a Loss of Offsite Power and Subsequent Turbine Trip/Reactor Trip, 7/22/91
- New England Power Pool Comprehensive Review of Transmission Reliability 1998-2003, ISO-New England, 3/2/99
- Analysis of Debris Particles Removed from 345KV Switch Yard Bushing Sheds Purchase Order No. 0200915, Release 107 MRR Project No. J4189, March 8, 2001
- NFSB 01-0015, Evaluation of Plant Trip on March 5, 2001, dated March 20, 2001
- Vendor Technical Bulletin No. 108-96, dated September 20, 1996 from Ingersoll-Dresser Pumps for “Rotor Preparation and Alignment”
- LER No. 96-003-00, “Emergency Feedwater Pump Mechanical Seal Failure”
- RTS, No. 00RE00302001, “Emergency Feedwater Turbine Pump 18 Month Auto Actuation Surveillance”, 3/7/01.
- RTS No. 00RE00489001, “Perform Mechanical Support Functions for 1-EFW-ET-001, EFW Terry Turbine Overspeed Trip Test”, dated March 2, 2001
- RTS No. 95R03602C001, “Turbine Driven Emergency Feedwater Manual Initiation Surveillance”, dated June 10, 1996
- RTS No. 96R003054002, “Turbine Driven Emergency Feedwater Pump Operability Test”, dated June 11, 1996
- RTS No. 01R003054001, “Turbine Driven Emergency Feedwater Pump Operability Test”, dated February 28, 2001

* Denotes Proprietary Document

Chronology of Events

Monday March 5, 2001

10:00 Plant preparing for severe weather in accordance with procedure OS1200.03, Severe Weather Condition.

19:00 Under severe weather conditions.

22:38 **Loss of 345 KV Scobie Line** (Line 363): Breakers 1-SY-BKR-163 (345 KV Bus 1) and 1-SY-BKR-632 (345 KV Bus 2) open.

22:48 **Loss of 345 KV Newington Line** (Line 369): Breakers 1-SY-BKR-169 (345 KV Bus 1) and 1-SY-BKR-692 (345 KV Bus 2) open.

23:15 **Operators commence power reduction at 10% per hour.**

23:21 **Newington line restored to 345 KV Bus 2** via Breaker 1-SY-BKR-692.

23:24 **Loss of 345 KV Tewksbury Line** (Line 394): Breakers 1-SY-BKR-294 (345 KV Bus 1) and 1-SY-BKR-941 (345 KV Bus 2) open.

Isolation of 345 KV Bus 1 from offsite power causes a **Generator "Loss of Load"** Event

23:24 **Reactor Trip** - "Negative High Flux Rate"

23:24 Operators open Main Generator Output Breaker.

23:24 **Emergency Feedwater (EFW) Automatic Actuation - Lo Lo S/G Level.**

Turbine Driven Emergency Feed Water (TDEFW) Pump "A" starts.

Motor Driven Emergency Feed Water (MDEFW) Pump "B" starts.

23:24 MDEFW Pump trips (load shed).

23:24 Emergency Diesel Generator (EDG) "B" automatic actuation (rated voltage in 8.17 seconds; rated frequency in 8.47 seconds).

23:24 EDG "A" automatic actuation (rated voltage in 8.99 seconds; rated frequency in 8.89 seconds).

23:25 Startup Feedwater Pump's (SUFP) Bus 4 breaker starts cycling on dead bus.

23:25 **TDEFW Pump Trips** (Overspeed) within approximately 57 seconds of actuation.

23:36 **Operators declare Unusual Event** (UE) in accordance with EAL 18A (anticipating loss of offsite power to 4.16 KV Safety Buses E-5 and E-6 for more than 15 minutes).

23:43 Operators initiate "Slow Close" of Main Steam Isolation Valves (MSIV) from Main Control Board. MSIVs A, B and D close. MSIV C does not close.

23:44 Plant notifies states of New Hampshire and Massachusetts of Unusual Event.

23:47 Operators actuate Main Steam Isolation signal. MSIV C closes.

23:52 13.8 KV Bus 1 re-energized from Reserve Auxiliary Transformer (RAT).

23:53 13.8 KV Bus 2 re-energized from Reserve Auxiliary Transformer (RAT).

23:54 4.16 KV Bus 3 re-energized from Reserve Auxiliary Transformer (RAT).

23:55 SUFP Bus 4 Breaker found cycling. Pump switch placed in "Pull To Lock."

23:55 4.16 KV Bus 4 re-energized from Reserve Auxiliary Transformer (RAT).

Tuesday March 6, 2001

00:07 One of four Reactor Coolant Pumps Started.

00:24 NRC Notified of Unusual Event.

00:27 Newington Line re-established to 345 KV Bus 1.

00:37 Scobie Line re-established to 345 KV Bus 1 and Bus 2.

01:36 Startup Feedwater Pump placed in service.

01:32 Tewksbury Line re-established to 345 KV Buses.

02:00 **All three off site lines restored.** Operators leave 4.16 KV Emergency Buses 5 and 6 on the EDGs - continued arcing across the 345 KV bushings.

02:12 Motor Driven Emergency Feed Water secured.

08:04 Tewksbury Line removed from service to clean the bushing.

09:27 Plant re-transmitted Unusual Event to New Hampshire State Police.

10:54 Tewksbury Line re-established to 345 KV Bus 1.

Wednesday March 7, 2001

10:31 4.16 KV Emergency Bus 5 energized from the Unit Auxiliary Transformer (UAT).

10:40 **Unusual Event Terminated.**

10:46 EDG “A” Output Breaker to 4.16 KV Emergency Bus 5 opened.

10:53 Emergency Diesel Generator “A” Secured

10:59 4.16 KV Emergency Bus 6 energized from the UAT in parallel with EDG “B.”

MDEFW Pump inadvertently starts (Emergency Protection System Relay Reset - make before break).

14:27 EDG “B” Output Breaker to 4.16 KV Emergency Bus 6 opened.

14:34 Emergency Diesel Generator “B” Secured.

Enclosure 2

March 12, 2001

MEMORANDUM TO: James C. Linville, Team Manager
Special Inspection

Jimi T. Yerokun, Leader
Special Inspection

FROM: Wayne D. Lanning, Director ***/RA/***
Division of Reactor Safety

SUBJECT: SPECIAL INSPECTION CHARTER - SEABROOK NUCLEAR POWER STATION

A special inspection has been established to inspect and assess the plant's response to a loss of offsite power that occurred at Seabrook Nuclear Power Station on March 5, 2001. The special inspection team will include:

Manager:	James C. Linville, Deputy Director, DRS
Leader:	Jimi T. Yerokun, Senior Reactor Inspector, DRS
Members:	Alan J. Blamey, Resident Inspector, DRP
	Keith A. Young, Reactor Inspector, DRS
	James M. Trapp, Senior Reactor Analyst, DRS (In-office support)
	Michael J. Maley, Reactor Inspector, DRS (Trainee)

This special inspection is in response to a loss of offsite power that was complicated with some safety related equipment failure and resulted in the declaration of an Unusual Event by the Seabrook Nuclear Power Station on March 5, 2001. The basis for the special inspection is to assess the licensee's root cause evaluation and corrective actions, independently evaluate the risk significance of the loss of offsite power and related equipment failures, and determine possible generic implications.

The special inspection was initiated in accordance with NRC Management Directive 8.3 (draft), NRC Incident Investigation Program. The inspection will be performed in accordance with the guidance of Inspection Procedure 93812, Special Inspection. The report will be issued within 45 days following the exit for the inspection. If you have questions regarding the objectives of the attached charter, please contact James Linville at (610) 337-5129.

Attachment: Special Inspection Charter

Special Inspection Charter
Seabrook Nuclear Power Station
Loss of Offsite Power and Related Equipment Failures

The objectives of the inspection are to determine the facts surrounding the loss of offsite power and related equipment failures that occurred at Seabrook Nuclear Power Station on March 5, 2001. Specifically, the team should:

1. Assess the adequacy of the licensee's investigation and root cause evaluation of the loss of offsite power and reliance on its emergency diesel generators (EDG) to power its vital buses for an extended period of time.

2. Assess the adequacy of the licensee's corrective actions and extent of condition review for selected loss of offsite power related equipment failures, including as a minimum, an assessment of EDG performance, the failure of the turbine driven emergency feedwater pump to adequately start and run in response to an automatic start signal and the failure of the "C" main steam isolation valve to close in response to a manually initiated signal.

3. Independently evaluate the risk significance of the loss of offsite power and confirm the adequacy of the licensee's risk evaluation through consultation with regional and headquarters Senior Reactor Analysts.

4. Assess the adequacy of the licensee's event classification and notification relative to the LOOP event.

5. Determine possible generic implications associated with the loss of offsite power event and associated equipment failures and significant licensing basis considerations for Seabrook's response to LOOP events including station blackout.

6. Document the inspection findings and conclusions in an inspection report within 45 days of the exit meeting for the inspection.