To: Margie Kotzalas, OEDO
Appropriate Action

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Vice President - Hatch

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SOUTHERN COMPANY

October 28, 2011

Docket Nos.: 50-321
50-366

NL-11-2032

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Edwin I. Hatch Nuclear Plant
Appeal to the Executive Director of Operations:
Backfit and Applicability of "Compliance Backfit" Exception

Dear Mr. R. William Borchardt,

Southern Nuclear Operating Company (SNC) appeals to the Nuclear Regulatory Commission (NRC) Executive Director of Operations (EDO) the September 29, 2011, determination by the NRC staff that a backfit is necessary at Edwin I. Hatch Nuclear Plant (HNP) and also the staff's application of the "compliance backfit" exception to avoid the requirement for performance of a cost-justified backfit analysis. This letter constitutes SNC's response to the September 29, 2011 NRC letter. Notwithstanding this appeal, as a matter of policy, SNC is committed to resolving the issue technically.

Key points pertinent to this issue include:

1. In a February 23,1995 NRC Safety Evaluation Report (SER), the NRC approved the reliance on administrative controls and manual actions at HNP for maintaining adequate voltage to protect Class 1E (safety-related) electrical equipment in the event of degraded voltage conditions. It was expressly acknowledged by the NRC that this protection scheme was a deviation from the guidance on degraded voltage protection provided in a NRC letter dated June 2, 1977, but after detailed review, the NRC determined the deviation was acceptable. In addition, this protection scheme was approved as a part of a license amendment for Improved Technical Specifications (ITS) with the approved SER issued March 3, 1995. SNC has been in compliance with this approved degraded voltage protection scheme for over 16 years.

2. On May 25, 2011, the NRC staff issued a letter to SNC providing Inspection Report 05000321 and 366/2011009, regarding the Component Design Bases Inspection (CDBI) performed at HNP in July 2009. That letter concluded that the measures in effect at HNP to demonstrate compliance with the applicable provisions of 10 CFR 50.55a(h)(2) and 10

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CFR Part 50, Appendix A, General Design Criterion 17 (GDC-17) are not acceptable.

3. A risk-informed evaluation estimates that the expected frequency of the pertinent technical issue, automatic actuation of safety-related equipment due to a loss of coolant accident concurrent with a degraded grid condition below the degraded grid alarm setpoint, is on the order of 1.0 E-9 per year and is considered to be of low safety significance.

4. The NRC staff recognized that this changed position constituted a backfit. However, the staff also maintained that it does not need to perform a cost-justified substantial safety backfit analysis, as is required by 10 CFR 50.109(a)(3). Instead, the staff stated that its change in position falls within the "compliance exception" to the staff's backfit analysis obligation which is provided by 10 CFR 50.109(a)(4)(i). In a letter dated June 17, 2011, SNC disagreed with the staff's conclusion in the May 25, 2011 letter that a backfit is necessary and that the compliance exception would properly apply to such a backfit and stated the rationale for appealing this decision.

5. The NRC responded to the SNC appeal by letter dated September 29, 2011, re-affirming that the decision to use the "compliance exception" provision as allowed by 10 CFR 50.109(a)(4)(i) was appropriate. The stated NRC position was that while SNC has been in compliance with the 1995 license amendment approving the configuration of the HNP degraded voltage protection system, NRC approval of this license amendment was erroneous and has led SNC to be in violation of GDC-17 and 10 CFR 50.55a(h)(2). Because of having taken the position that former NRC approval of the license amendment was erroneous, NRC is exercising enforcement discretion for a duration to be determined after review of SNC's proposed corrective actions and schedule for compliance, to be submitted by SNC within 30 days of the NRC's September 29, 2011 letter.

6. There was no error or mistake made by the staff in approving the 1995 license amendment which established the existing HNP degraded voltage automatic protection scheme. The correspondence preceding the approval shows that the particular facts and circumstances related to degraded grid on the Southern electric system and the HNP degraded voltage protection scheme were reviewed, understood, and acknowledged by the staff. No factual errors or omissions are at issue. There were numerous letters and meetings between 1992 and 1995, with the issuance of the final SER in 1995 demonstrating that the NRC approved this change only after careful review.

7. The NRC letter of September 29, 2011 misreads IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," to conclude that the standard does not permit manual action as part of the

protection system, when in fact IEEE Std. 279-1971 contains no such prohibition.

8. The staff characterizes the existing HNP degraded voltage protection scheme as reliant solely on manual action. In fact, HNP has a fully automatic degraded voltage protection scheme. Manual action by plant operators and the operators of the Southern electrical transmission grid system is a routine controlled activity, guided by a real-time N-1 contingency analysis, to maintain the grid voltage within the normal expected range, thus minimizing challenges to the automatic degraded voltage protection scheme by a degraded grid condition. In fact, the final 1995 SER credited routine manual control action as an integral element of the automatic degraded voltage protection scheme.

9. The NRC letter of September 29, 2011 cited the 1976 Millstone and 1978 Arkansas Nuclear One (ANO) incidents to support the contention that the HNP degraded voltage protection scheme is inadequate. Evaluation of these events shows that for HNP the existing relay settings do not operate during motor starting and operating practices to keep operators informed of expected grid conditions would preclude the Millstone scenario, while the ANO incident is not relevant due to differences in switchyard design.

Enclosure 1 of this letter provides additional discussion of the SNC appeal of the staff's backfit and compliance backfit determinations, with cited supporting documents provided in Enclosure 3. The Technical Specification surveillance requirements for the relay setpoints and time delays are provided for reference in Enclosure 2.

The NRC staff's May 25 and September 29, 2011, letters, if unaddressed by the EDO, will necessitate a license amendment related to HNP trip setpoints, anticipatory alarms and related requirements. To the extent that the current staff position may require a modification to the HNP license, Southern Nuclear preserves its rights to a formal hearing under Section 189(a)(1) of the Atomic Energy Act, as amended, 42 U.S.C. § 2239(a)(1).

Southern Nuclear also requests the EDO to observe that development of the current HNP degraded voltage protection scheme was intertwined with the resolution of a prior, 1991 enforcement action. As a matter of established Enforcement Policy, the staff should not reopen that closed action absent "special circumstances" (NRC Enforcement Policy, Sec. 2.3.8). Such special circumstances do not exist here, in that the staff had extensive and detailed information at the time it made its enforcement decision. Based on this Policy, the EDO should find that the enforcement resolution closes the matter from a backfit.

As previously stated in SNC's letter of June 17, 2011, SNC is working to develop a cost-effective resolution to the underlying technical issue, which concerns the margin - under worst-case circumstances and extremely degraded conditions -

between the minimum expected voltage on the safety-related 4160 V buses at HNP and the minimum voltage required to protect the safety-related equipment on these buses. To this end, SNC is evaluating options to increase this margin and by December 31, 2011 will provide a follow-up letter outlining the proposed technical solution with an implementation schedule.

This letter contains no formal NRC commitments.

If you have any questions, please contact Mark Ajluni at (205) 992-7673.

Respectfully submitted,

D. R. Madison
Vice President – Hatch

DRM/DWD/lac

Enclosure 1: Appeal to the EDO: Backfit and Applicability of "Compliance Backfit" Exception
Enclosure 2: Loss of Power Instrumentation Surveillance Requirements
Enclosure 3: Appeal to the EDO: Reference Documents

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Edwin I. Hatch Nuclear Plant

Enclosure 1

Appeal to the EDO:
Backfit and Applicability of "Compliance Backfit" Exception

Edwin I. Hatch Nuclear Plant

Appeal to the EDO: Backfit and Applicability of "Compliance Backfit" Exception

## Introduction

Southern Nuclear Operating Company (SNC) is the licensed operator of the Edwin I. Hatch Nuclear Plant (HNP). In a letter dated May 25, 2011, the Nuclear Regulatory Commission (NRC) staff advised SNC that the degraded voltage protection scheme at HNP did not comply with 10 CFR 50.55a(h)(2) and 10 CFR Part 50, Appendix A, General Design Criterion 17 (GDC-17). The May 25 letter acknowledged that the NRC staff's position – that "administrative controls to assure adequate voltage to safety-related equipment during certain design basis events" was not an acceptable method for compliance with 10 CFR 50.55a(h)(2) and GDC 17 – was a change in a NRC staff position and therefore constituted a backfit as defined in 10 CFR 50.109. The May 25 letter maintained, however, that no cost-justified substantial safety backfit analysis, as required by 10 CFR 50.109(a)(3), is required because the change falls within the "compliance backfit" exception to the staff's backfit analysis obligation in 10 CFR 50.109(a)(4)(i).

By letter dated June 17, 2011, SNC appealed to the NRC staff the staff's determination that the backfit qualified for the 50.109(a)(4)(i) "compliance backfit" exception. In a letter dated September 29, 2011, the NRC staff responded to the SNC appeal by re-affirming that the decision to use the "compliance exception" provision as allowed by 10 CFR 50.109(a)(4)(i) was appropriate. SNC hereby appeals this determination to the NRC Executive Director of Operations (EDO), pursuant to the NRC Manual, Chapter 0514 (Management Directive 8.4).

SNC appeals the NRC staff's decision to issue a backfit under the "compliance exception" provision of 10 CFR 50.109(a)(4)(i) related to the degraded voltage protection scheme at Edwin I. Hatch Nuclear Plant (HNP). SNC requests that the EDO reverse the NRC staff's determination that: (1) the HNP degraded voltage protection scheme does not comply with the applicable regulations and (2) the acknowledged backfit constitutes a "compliance backfit" under 10 CFR 50.109(a)(4). SNC requests the EDO find that HNP is currently in compliance with 10 CFR 50.55a(h)(2) and GDC 17 and that the NRC staff's change in position regarding the requirements of those regulations does not satisfy the "compliance backfit" exception to 10 CFR 50.109(a)(4)(i).

## Background

In a February 23, 1995 NRC Safety Evaluation Report (SER), the NRC approved the reliance on administrative controls and manual actions at HNP for maintaining adequate voltage to protect Class 1E (safety-related) electrical equipment in the event of degraded voltage conditions. It was expressly acknowledged by the NRC that this protection scheme was a deviation from the guidance on degraded voltage protection provided in a NRC letter dated June 2, 1977, but after detailed review, the NRC determined the deviation was acceptable. In addition, this protection scheme was approved as a part of a license amendment for Improved Technical Specifications (ITS) with the approved SER issued March 3, 1995. SNC has been in compliance with this approved degraded voltage protection scheme for over 16 years.

The SER approving the deviation and license amendment also recognized that the HNP design configuration satisfied the requirements of GDC-17:

> "With the alternate approach, the staff concludes that both an offsite and onsite power system is available, each with the capability of providing power for the required safety components in accordance with GDC 17 of 10 CFR Part 50, Appendix A."

As a result of the Component Design Bases Inspection (CDBI) at HNP in July 2009, the NRC staff asserted that SNC was not in compliance with the degraded voltage protection requirements of 10 CFR 50.55a(h)(2) and General Design Criterion 17 (GDC-17). In its May 25, 2011 letter, the NRC staff stated that HNP was not in compliance with the degraded voltage protection requirements of GDC 17 and 10 CFR 50.55a(h)(2) and directed that HNP implement a backfit excluding reliance on manual action to maintain grid voltages. The NRC staff asserts that, although SNC has been in compliance with the 1995 license amendment approving the configuration of the HNP degraded voltage protection system, NRC approval of this 1995 license amendment was erroneous and, consequently, that SNC is in violation of GDC-17 and 10 CFR 50.55a(h)(2). Accordingly, the NRC staff asserts that the backfit qualifies for the "compliance backfit" exception codified at 10 CFR 50.109(a)(4)(i).

The NRC's regulations, for purposes relevant here, at 10 CFR 50.109(a)(1) define a backfit as:

> "...the modification of ... design of a facility...or imposition of a regulatory staff position interpreting the Commission's regulations that is either new or different from a previously applicable staff position."

The NRC staff acknowledges that its current position is a change from the NRC position reflected in the 1995 SER approving the deviation from the 1977 guidance and "constitutes backfitting." More specifically, in the Evaluation attached to the September 29, 2011 letter denying SNC's initial appeal, the NRC staff recognizes at page 3 that "a deviation from the guidance on degraded voltage protection provided in the NRC letter dated June 2, 1977 was accepted by the NRC in a SER dated February 23, 1995."

While it is clear that the NRC staff's letter of May 25, 2011 seeks to impose a backfit, SNC believes that the NRC staff's reliance on the compliance backfit provision of 10 CFR 50.109(a)(4)(i) is misplaced. SNC's appeal of the NRC's decision to issue a backfit and to apply the "compliance exception" provision of 10 CFR 50.109(a)(4)(i) is based on the following:

(1) the 1995 approval of HNP's degraded voltage protection scheme was not based on a mistake of fact or error;
(2) the approved configuration is adequate relative to risk and complies with applicable regulations;

(3) the "compliance backfit" exception is not applicable to a change in NRC staff position regarding compliance with a regulation; and

(4) imposition of the backfit as a compliance backfit would be contrary to NRC's principles of good regulation in that it would not promote a stable regulatory environment.

**Appeal**

I. The approval of the current HNP degraded voltage configuration in 1995 was not based on a mistake of fact or error.

A. The NRC staff in 1995 was cognizant of and understood the approved deviation from the 1977 guidance.

Contrary to the NRC staff's assertions underlying the current backfit, the 1995 approval of the configuration of the HNP degraded voltage protection scheme by the staff was not based on an error or mistake of fact. SNC submits that the historic correspondence between SNC and the NRC staff demonstrates that the NRC fully recognized in 1995 that its approval of the HNP system was a deviation from the 1977 NRC staff guidance.[1] In effect, the NRC staff's analysis in 1995 was similar to the cost-justified substantial safety backfit analysis that SNC contends should be performed now as a condition to the imposition of the current backfit.

The NRC staff acknowledges that correspondence between SNC and the NRC and other documentation, including two (2) SERs, demonstrates that the NRC staff formally reviewed and approved the degraded grid voltage Loss of Offsite Power (LOP) and Loss of Coolant Accident (LOCA) scenarios for HNP. Those SERs examined the sufficiency of voltage for concurrent LOP and LOCA, the likelihood of such an event, and the positive safety consequences associated with additional degraded voltage alarms, operator monitoring and potential action, and the specific setpoints for degraded voltage relays that initiate automatic separation of the plant from the system. However, the NRC staff asserts that the 1995 approval was in "error" or a "mistake." The basis for that assertion appears twofold: 1) the NRC staff in 1995 "did not explain why" the deviation from NRC's 1977 guidance was approved and, therefore, was apparently without basis (e.g. lack of information or based on inaccurate information), or 2) the 1995 conclusion to approve the license amendment including the deviation was an analytical error.

Contrary to the NRC staff's current rationale for asserting that NRC's 1995 SER was mistaken or otherwise in error, the contemporaneous documentation from the early 1990s demonstrates that the NRC staff at that time was fully aware and

[1] The 1995 staff understood that the 1977 guidance was a position, not a regulation. The 1995 staff SER expressly referred to the June 2, 1977 letter as "current NRC staff guidance" and "Staff Positions" regarding onsite emergency power systems.

cognizant of the issue at hand and of the resolution that it was approving. The documentation underlying the NRC's approval of the 1995 license amendment establishes that the deviation from the 1977 staff guidance was approved only after the particular facts and circumstances related to degraded grid on the Southern electric system and the HNP degraded voltage protection scheme were reviewed. The approval was risk-informed and appropriately considered the relative alternatives:

1. In 1982, EG&G, an NRC contractor, prepared a review of the degraded grid protection for Class 1E power systems at HNP (Enc. 3, Item 1). The contractor identified the design basis criteria, including GDC-17, IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations" and the NRC "Staff positions as detained in a letter sent to the licensee, dated June 3, 1977". The licensee provided the contractor with proposed changes to the Technical Specifications, allowable limits for setpoint and time delay, and LCOs applicable to the second level voltage monitors. Here, then, was manual action as a component of undervoltage protection, with relays set to operate and disconnect at 2912 V (70%).

2. In 1991, during an Electrical Distribution System Functional Inspection, the NRC team questioned whether the undervoltage relay setpoints were too low to ensure minimum voltage prior to disconnection from offsite power supply. Thereafter, the staff issued an inspection report on August 22, 1991, and a Notice of Violation (NOV) on October 7, 1991. The violation was contested by the licensee by letter dated November 6, 1991. The licensee maintained that the existing degraded grid protection scheme complied with the staff's positions in the June 2, 1977 letter. Enclosure 3, Items 2, 3 & 4 are the Inspection Report, the NOV and the licensee's response, respectively.

3. A meeting was held between the licensee and the staff on November 16, 1992 to address the matter; seven full-time and two part-time NRC representatives attended (Enc. 3, Item 5 is handouts from the meeting). Two licensee letters, dated November 22, 1993 and July 1, 1994 (Enc. 3, Items 6 & 7) were followed by another meeting with the staff on December 7, 1994 (January 10, 1995 meeting summary at Enc. 3, Item 8). The NRC responded with the SER on February 23, 1995 (Enc. 3, Item 9).

In summary, SNC and the NRC staff disagreed on a NOV, found common ground for a resolution that complied with GDC-17, the NRC staff evaluated that resolution and imposed additional conditions to which SNC agreed. Thus, there was no mistake or error in the NRC's approval of the license amendment that included a deviation from the June, 1977 guidance.

B. The NRC staff understood that the approved deviation included licensee commitments that added design features for enhanced safety. These enhancements guard against spurious disconnections from the preferred backup power source, when available.

The NRC's 1995 SER for the degraded grid voltage protection scheme includes the following, which demonstrates the staff's imposition of requirements for design features to the system that enhance safety. For over 16 years, HNP has implemented those features, as part of the approved design. The SER states:

> "The staff has evaluated the licensee's proposal and agrees with the approach with the following additional conditions:
>
> 1. The degraded voltage alarm relays should be included in the plant Technical Specification along with the degraded voltage relays that initiate automatic actions.
>
> 2. The offsite system operating voltage levels and their significance with respect to the Hatch approach to meeting the degraded voltage requirements should be documented in the Final Safety Analysis Report so the impact of possible future changes will receive appropriate consideration.
>
> The licensee has agreed to these added conditions.
>
> With the alternate approach, the staff concludes that both an offsite and onsite power system is available, each with the capability of providing power for the required safety components in accordance with GDC 17 of 10 CFR Part 50, Appendix A."

C. The 1995 SER expressly approved reliance on manual actions to respond to a narrow 3% band of degraded grid voltages. In addition, the SER acknowledged that certain class 1E loads at voltage levels of 600 volts and below might not receive sufficient voltage upon automatic disconnection from the grid with the HNP configuration.

A description of the manual actions approved to respond to such degraded voltage conditions is contained in the staff's March 3, 1995 SER for the Improved Technical Specifications (ITS):

> "...HNP credits manual actions in the range of 78.8% to 92% of 4.16kV. Entry into this range is annunciated. The range specified for manual action indicates that sufficient power is available to the large ECCS pump motors. However, sufficient voltage for the equipment required for loss-of-coolant accident (LOCA) conditions may not be available at lower voltages. The required channels of LOP annunciation instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an

> unnecessary automatic disconnect from the preferred offsite power source. The LOP anticipatory annunciators are designed with a time delay of 65 seconds to reduce the possibility of nuisance annunciators while permitting prompt detection of potential low voltage conditions. HNP takes credit for the annunciators in restoring acceptable voltage levels. Therefore, improved TS Table 3.3.8.1-1 is being added to the CTS [Current Technical Specification] requirements. Additionally, ACTION B, addressing the annunciator function, is being added and the other functions are renumbered and amended to provide for the annunciation. SRs [Surveillance Requirements] are also being added for the annunciator bus undervoltage and associated time delay relays."

In conclusion, the 1995 staff was informed, knowledgeable and engaged in the approval of the current HNP degraded voltage protection scheme. While the current staff may have a difference in professional opinion about that approval, *that opinion is not a sufficient basis for a backfit and for an exception to the* requirement for performing a cost-justified safety benefit evaluation.

II. <u>The current HNP degraded voltage configuration is adequate relative to risk and complies with the applicable regulations.</u>

In the Sept. 29, 2011, NRC Evaluation of Licensee Backfit Appeal, on page 4 the NRC staff maintains that the error in the NRC's 1995 SER was that the 1995 SER:

> "...was not based on the guiding principle of the NRC position that the *sole* reliance on manual controls for degraded grid voltage protection may result in the Class 1E bus voltages being too low for operation of safety-related equipment but high enough to prevent separation of the safety buses for the offsite power supply." (italics supplied)

Similar wording is found elsewhere in the Evaluation. For example, on page 6 the NRC staff states the IEEE Std. 603-1991 requires design basis documentation for justification of "permitting initiation or control subsequent to initiation *solely* by manual means" and on page 7 the NRC concludes that "...the backfit per the compliance exception..." issued to SNC "...for its reliance *solely* on manual controls for degraded grid voltage protection was appropriate".

Contrary to this characterization, HNP does not rely solely on manual controls for degraded grid voltage protection. The manual actions "credited" to prevent inadequate voltage conditions were limited to manual actions by plant operators in a specific band of degraded voltages followed by automatic actuation at a lower system voltage setpoint:

> "The NRC team determined that during a postulated design basis loss of coolant accident concurrent with the 4160 volt bus voltage in a narrow 3% band between 91% (3786 volts) and 88.34% (3675 volts) certain class 1E

> loads at voltage levels of 600 volts and below may not receive sufficient voltage." - SNC to NRC letter dated November 22, 1993 (Enc. 3, Item 6)
>
> "...the degraded grid protection system uses manual action instead of automatic disconnect in the range of the deadband. Accordingly, GPC [the licensee] has implemented an abnormal operating procedure to provide specific actions to address a degraded offsite power supply. If the 4160 volt bus voltages were to degrade below approximately 92 percent, [plant] operators will initiate a 'one hour to restore' action statement. If voltages are not restored within one hour, a plant shutdown is then initiated." - GPC to NRC letter dated July 1, 1994 (Enc. 3, Item 7)

As can be observed in the handouts from the NRC and licensee meeting of November 16, 1992 (Enc. 3, Item 5), and the attachment to the licensee's November 22, 1993 letter (Enc. 3, Item 6) the staff was aware that automatic disconnection from the grid would occur at 88.34% of 4160 volts.[2]

Neither GDC-17 or 10 CFR 50.55a(h)(2) expressly prohibit manual actions in response to degraded voltage conditions. GDC-17 is descriptive of offsite and onsite power supplies and speaks to the importance of minimizing the probability of coincident loss of power supplies – implicitly in order of safety importance – power from the unit, from the grid and from onsite backup power supplies.

> "Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

The HNP license includes requirements for anticipatory alarms, their setpoints and periodic testing (surveillance), and a limiting condition for operation (LCO). These requirements address the potential for a grid voltage drop to the minimum expected level due to a plant trip, which is the most likely grid event. The express license requirements do not require a backfit. Manual action by plant operators and the operators of the Southern electrical transmission grid system is a routine controlled activity, guided by a real-time N-1 contingency analysis, to maintain the grid voltage within the normal expected range, thus minimizing challenges to the automatic degraded voltage protection scheme by a degraded grid condition. This approach has been very successful; a review of system operating records and plant logs dating back to the March 14, 1993 degraded grid event described in the 1995 SER found no instance of the degraded grid alarm having ever annunciated at HNP.

GDC-17 states that "an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The

[2] Current tap setting is 78.8% of 4160 volts.

safety function...shall be to provide sufficient capacity and capability...as a result of anticipated operational occurrences." HNP's design and operation meets this requirement in that it has the capacity and capability for the anticipated grid conditions, including N-1 contingencies. In addition, the potential for a degraded grid at HNP (although unanticipated) is minimized by the plant and grid operational features described herein, and results in an extremely low probability of occurrence.

A risk-informed evaluation estimates that the expected frequency of the pertinent technical issue, automatic actuation of safety-related equipment due to a loss of coolant accident concurrent with a degraded grid condition below the degraded grid alarm setpoint, is on the order of 1.0 E-9 per year and is considered to be of low safety significance. SNC has determined this value through a best estimate approach with appropriate conservatism.

The September 29, 2011 NRC Evaluation of Licensee Backfit Appeal cited the 1976 Millstone and 1978 Arkansas Nuclear One (ANO) incidents to support the contention that the HNP degraded voltage protection scheme is inadequate. It should be noted (as the NRC concluded in its own documented evaluations) that neither of these two events was due to grid voltage conditions below expected values. The plant voltage issues were due instead to inadequate plant design for the anticipated grid and plant operational conditions. Evaluation of these events shows that for HNP the existing relay settings do not operate during motor starting and operating practices to keep operators informed of expected grid conditions would preclude the Millstone scenario, while the ANO incident is not relevant due to differences in switchyard design.

10 CFR 50.55a(h)(2), specifies the codes and standards applicable to nuclear power plant protection systems, and incorporates by reference IEEE Standards. For HNP, IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," is the requirement applicable to the degraded grid protection system. To support its current "compliance backfit" argument, the NRC staff relies on its interpretation of the "intent" of IEEE Std. 279-1971, rather than applying language actually found in the standard. Notwithstanding its acknowledgement on page 6 of the Evaluation that IEEE Std. 279-1971 "acknowledges the use of manual action and initiation of protection systems by manual actions," the staff adds its own gloss to the language of the standard in order to narrow its scope by stating that "manual action as discussed in Section 4.17 is intended to be 'in addition to,' as a backup, and not 'in lieu of' the automatic initiation requirement of Section 4.1."

Again, for the HNP degraded grid protective scheme, manual action by operators is taken *before* the plant conditions for automatic actuation are reached. Specifically, the November 22, 1993 GPC letter (Enc. 3, Item 6), the July 1, 1994 GPC letter to the NRC (Enc. 3, Item 7), the January 10, 1995 NRC meeting notes (Enc. 3, Item 8), and February 23, 1995 NRC SER (Enc. 3, Item 9) address in detail the plant's response to degraded grid conditions, the setpoints for automatic disconnection, and anticipatory alarms and potential manual actions at below 92%. An automatic degraded grid trip for voltages below 88.34% (currently 78.8%) of bus voltage was approved by the NRC staff for the automatic disconnect, provided that the anticipatory alarm relays and degraded voltage relays came into the Technical Specifications. (The Technical Specification surveillance requirements for the relay setpoints and time delays are provided for reference in Enc. 2.)

Manual action instead of automatic trip is applicable, then, only to a narrow band of voltages above the automatic trip level. Once the trip setpoint is reached, the actuation of the protection system goes to completion without manual intervention, in accordance with IEEE Std. 279-1971 at §4.16 on pg. 10. No regulation, order or commitment precludes anticipatory manual action for degraded grid voltages as a component of a plant's degraded grid configuration.

III. <u>The "compliance backfit exception" is not applicable to the change in NRC staff positions in this matter</u>.

> "The compliance exception is intended to address situations in which the licensee has failed to meet known and established standards of the Commission because of omission or mistake of fact." See 50 Fed. Reg. 38097, 38103 (Sept. 20, 1985).

Whether the NRC staff's invocation of the compliance backfit exception in 10 CFR 50.109(a)(4)(i) supports the backfit discussed in its May 25, 2011 letter depends on whether that exception may be used to avoid a cost-justified substantial safety backfit analysis when the NRC staff changes its position regarding what is necessary to comply with a regulatory requirement, as opposed to whether a facility or license is in compliance with a clearly stated regulatory requirement. As stated in 10 CFR 50.109(a)(4)(i), the exception applies where "a modification is necessary to bring a facility into compliance with a license or the rules or orders of the Commission, or into conformance with written commitments by the licensee." The backfit imposed by the NRC staff's May 25, 2011 letter incorrectly relies on the "compliance backfit exception" to avoid the obligation of the NRC staff to perform a cost-justified substantial safety backfit analysis.

The NRC staff's rationale for invoking the compliance backfit exception is that it disagrees with the NRC's 1995 determination that the HNP degraded grid protection system satisfies both 10 CFR 50.55a(h)(2) and GDC-17. As stated on page 3 of the Sept. 29, 2011 NRC Evaluation of Licensee Backfit Appeal:

> "...the backfitting action is necessary for compliance with GDC-17 and 10 CFR 50.55a(h)(2) and is consistent with applicable guidance and practices in effect at the time the NRC staff erroneously approved the use of manual actions for controlling voltages at HNP."

This statement is instructive. First, the NRC staff says that the backfitting action is necessary for compliance with two specific regulations. As set forth above, however, the NRC in 1995 expressly addressed the compliance of the HNP system under the same regulations and came to a different conclusion than the NRC staff does today. Because the NRC staff's position in 2011 is not based on the express language of either regulation but on the "intent" of the regulations, the difference of opinion is clearly a change in NRC staff position, not a mistake or error by the NRC in 1995.

The NRC staff's invocation of the compliance backfit exception under these circumstances would improperly enlarge the scope of the exception from "omissions or mistakes of fact" to encompass alleged "approval errors" for deviations to staff positions which were based on accurate and complete facts. Application of the compliance backfit exception in this way would be inconsistent with the clear language and intent of the backfit rule. "The compliance exception is intended to address situations in which the licensee has failed to meet known and established standards of the Commission because of omission or mistake of fact. It should be noted that new or modified interpretations of what constitutes compliance would not fall within the exception and would require a backfit analysis and application of the standard." See 50 Fed. Reg. 38097, 38103 (Sept. 20, 1985). See also NUREG 1409 § 3.1 at pg. 12 (which cites this statement from the Federal Register notice).

Second, the NRC staff says that backfitting action is "consistent with" historic guidance. NRC guidance documents are not regulations. They have not gone through the Administrative Procedures Act process and the vetting appropriate for rules. For example, Branch Technical Position (BTP) 8-6 (Rev. 3, March, 2007), "Adequacy of Station Electric Distribution Voltages," is found in NUREG 0800, Chapter 8 as part of the Standard Review Plan. The first footnote in BTP 8-6 includes: "...the Standard Review Plan is not a substitute for the NRC's regulations, and compliance with it is not required." Thus, the BTP is not a regulation. "Consistent with" is not equal to "mandated by."

Important distinctions apply to "legal requirements", "commitments" and "staff positions" in the context of backfits:

- Legal requirements are contained in explicit regulations, orders, and plant licenses (amendments, conditions, technical specifications).

- Written commitments are contained in docketed correspondence, including responses to Generic Letters.

- "Staff positions" are explicit interpretations, and are contained in documents such as Generic Letters, and to which a licensee has previously committed.

> "Positions contained in these documents are not considered applicable staff positions **to the extent that the staff has, in a previous licensing or inspection action, tacitly or explicitly excepted the licensee** from part or all of the position."

> "Imposition of a staff position to which a licensee has previously been excepted is a backfit."
>
> (NUREG-1409, Appendix D, page 13 "NRC Manual Chapter 0514, NRC Program for Plant-Specific Backfitting of Nuclear Power Plants") (Emphasis added)

Also, NUREG-1409, Section 3.3, "Plant-Specific Backfits," states at question 7 (emphasis added):

> "If the **staff previously exempted a licensee from a legal requirement or approved position**, it is not applicable to that licensee for purposes of backfit consideration."

The 1977 letter is not a regulation, order or condition in the HNP licenses. The 1977 letter's provisions with respect to degraded grid and compensatory manual actions at HNP may not be considered an applicable staff position for purposes of imposing a backfit because the licensee was previously excepted.

Nonetheless, today the staff maintains, on page 7 of the September 29, 2011 NRC Evaluation of Licensee Backfit Appeal (emphasis added), that:

> "...although GDC-17 and 10 CFR 50.55a(h)(2) do not expressly prohibit manual actions in all situations and make reference to the use of manual actions for certain situations, the NRC's *position* has been that the protection feature be automatic, which is not being met at HNP."

Accordingly, the NRC staff invocation of the compliance backfit exception to include modifications which are necessary to make a facility consistent with staff positions to which a licensee has previously been excepted is inconsistent with NRC guidance relative to application of the backfit rule.

Instructive for the EDO on this appeal is a particular question and response found in NRC staff guidance (NUREG-1409, Section 3.1, question 7). The answer addresses three cases, one involving an explicit exemption[3] from a legal requirement or approved staff position and the other two involving the staff's *"tacit"* approval associated with previous staff review of a licensee action or program or due to the passage of time. In both *"tacit"* cases, if the staff were to require additional action by the licensee, the staff's action would be a backfit, but might not be a compliance backfit (or meet other exceptions listed in the backfit

[3] Today the staff reads the guidance narrowly, as applicable to staff exemptions in accordance with 10 CFR 50.12. However, an exemption under that provision is limited to an "*exemption from the requirements of the regulations of this part*" and not applicable to exemptions from staff positions.

rule). "Explicit exemption would be done formally in writing."[4] An approved staff position, then, for which the licensee has been explicitly exempted, "is not applicable to the licensee for the purpose of backfit consideration." In other words, such a staff position cannot be relied upon by the current staff for a compliance backfit exception, as urged by the current staff.

Accordingly, the compliance exception was created to address situations when known and established standards were overlooked or requirements were not imposed due to mistakes of fact or inaccurate or incomplete information. Such is not the case in this appeal. The backfit rule requires that the staff be bound by its "previous licensing actions...that explicitly excepted the licensee from part or all of the position." The history of the approval of the 1995 deviation and license amendment also demonstrate that the current HNP degraded voltage protection scheme was intertwined with the resolution of a prior enforcement action and, as a matter of policy, the staff should not reopen that closed action. In accordance with the NRC's Enforcement Policy, Section 2.3.8, "special circumstances" must be present for the staff to "reopen" closed enforcement actions. Special circumstances do not exist here, when the staff had extensive and detailed information at the time it made its enforcement decision.

## Conclusion

In conclusion, SNC appeals to the EDO regarding the staff's determination that a backfit is warranted and to the staff's application of the 10 CFR 50.109(a)(4)(i), "compliance exception," to avoid the obligation to perform a cost-justified substantial safety benefit analysis prior to imposition of a backfit. The NRC licensed HNP for its current degraded voltage protection scheme including mandating provisions and conditions in its Technical Specifications. In addition, SNC submits there is documentation which supports that the 1995 staff did not "erroneously approve the use of manual action" to respond to degraded grid conditions. At issue here is a difference in professional opinions between the 1995 staff and the current staff. Finally, there are no new technical requirements, rules or regulations which would justify a change in the NRC staff's position. Therefore, SNC has concluded that the HNP degraded voltage protection scheme continues to meet the requirements of GDC-17 and 10 CFR 50.55a(h)(2) and no compliance backfit is warranted.

---

[4] Note the guidance does not reference "specific exemptions" (the phrase used in 10 CFR 50.12), or 50.12 (or its predecessor) or any particular precondition but "formal." "Explicit approval" could be provided in an inspection report, but "usually made in a safety evaluation reports rather than inspection reports." NUREG-1409, Section 3.3, question 1. The licensee's July 1, 1994 letter stated, "...GPC requests formal NRR staff review and approval of this deviation." (TAC No. 80948).

Edwin I. Hatch Nuclear Plant

Enclosure 2

Loss of Power Instrumentation Surveillance Requirements

Edwin I. Hatch Nuclear Plant

Loss of Power Instrumentation Surveillance Requirements

| LOP Instrumentation Surveillance Requirements<br><br>Source: Hatch Units 1 & 2 Technical Specifications Table 3.3.8.1-1 | | | | |
|---|---|---|---|---|
| FUNCTION | | REQUIRED CHANNELS PER FUNCTION | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE<br><br>(% 4.16 kV) |
| 1. | 4.16 kV Emegency Bus Undervoltage (Loss of Voltage) | | | |
| | a. Bus Undervoltage | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 2800 V (67.3%) |
| | b. Time Delay | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 6.5 seconds |
| 2. | 4.16 kV Emegency Bus Undervoltage (Degraded Voltage) | | | |
| | a. Bus Undervoltage | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 3280 V (78.8%) |
| | b. Time Delay | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 21.5 seconds |
| 3. | 4.16 kV Emegency Bus Undervoltage (Annunciation) | | | |
| | a. Bus Undervoltage | 2 | SR 3.3.8.1.1<br>SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 3825 V (92%) |
| | b. Time Delay | 2 | SR 3.3.8.1.1<br>SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 65 seconds |

Edwin I. Hatch Nuclear Plant

Enclosure 3

Appeal to the EDO:
Reference Documents

Edwin I. Hatch Nuclear Plant

Appeal to the EDO: Reference Documents

1. February, 1982 EGG Report to NRC

   Subject: Degraded Grid Protection for Class 1E Power Systems

2. August 22, 1991 – NRC Inspection Report 50-321/91-202 & 50-366/91-202

3. October 7, 1991 – Notice of Violation; NRC Inspection Report 50-321/91-202 & 50-366/91-202

4. November 6, 1991 – GPC Letter to NRC

   Subject: Response to Notice of Violation

5. November 16, 1992 – GPC meeting with NRC

   Subject: HNP Degraded Grid Issues

6. November 22, 1993 – GPC letter to NRC

   Subject: Degraded Grid Protection

7. July 1, 1994 – GPC letter to NRC

   Subject: Degraded Grid Protection

8. January 10, 1995 – NRC letter to GPC

   Subject: Summary of December 7, 1994 meeting

9. February 23, 1995 – NRC letter to GPC

   Subject: SER for Degraded Grid Voltage Relay Setpoints

NRC Research and/or Technical Assistance R

EGG-EA-5754

FEBRUARY 1982

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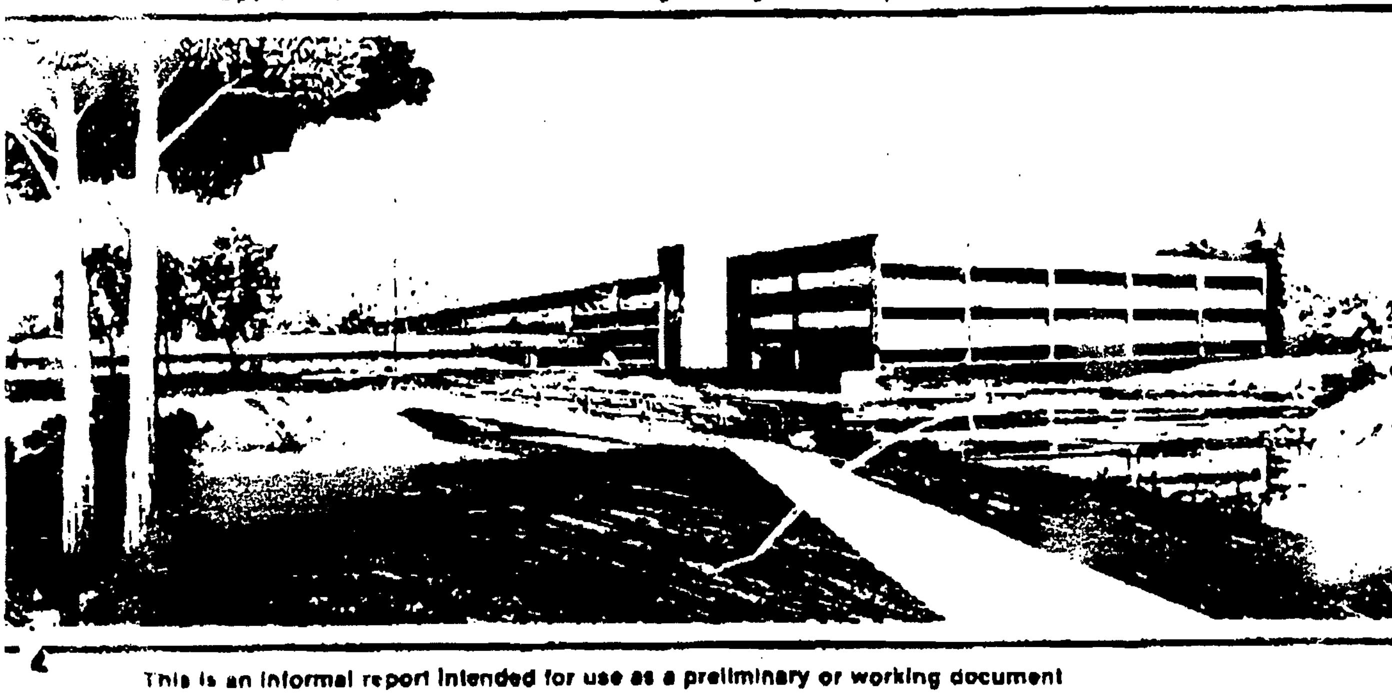
# DEGRADED GRID PROTECTION FOR CLASS 1E POWER SYSTEMS, EDWIN I. HATCH NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

A. C. Udy



U.S. Department of Energy
Idaho Operations Office • Idaho National Engineering Laboratory



This is an informal report intended for use as a preliminary or working document

Prepared for the
U. S. Nuclear Regulatory Commission
Under DOE Contract No. DE-AC07-76ID01570
FIN No. A6429

EG&G Idaho

EG&G Idaho Inc

FORM 1040 ??
(Rev 11-81)

# INTERIM REPORT

Accession No ______

Report No EGG-EA-5754

**Contract Program or Project Title:**
Selected Operating Reactor Issues Program (III)

**Subject of this Document:**
Degraded Grid Protection for Class 1E Power Systems,
Edwin I. Hatch Nuclear Power Plant, Unit Nos. 1 and 2

**Type of Document**
Informal Report

**Author(s):**
A. C. Udy

**Date of Document:**
February 1982

**Responsible NRC/DOE Individual and NRC/DOE Office or Division:**
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*This document was prepared primarily for preliminary or internal use. It has not received full review and approval. Since there may be substantive changes, this document should not be considered final.*

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Prepared for the
U.S. Nuclear Regulatory Commission
Washington, D.C.
Under DOE Contract No. DE-AC07-76ID01570
NRC FIN No. A6429

# INTERIM REPORT

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# DEGRADED GRID PROTECTION FOR CLASS 1E POWER SYSTEMS

## EDWIN I. HATCH NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

February 1982

A. C. Udy
Reliability and Statistics Branch
Engineering Analysis Division
EG&G Idaho, Inc.

TAC Nos. 10026 and 11262
Docket Nos. 50-321 and 50-366

## ABSTRACT

This EG&G Idaho, Inc. report reviews the susceptibility of the safety-related electrical equipment at the Edwin I. Hatch Nuclear Power Plant to a sustained degradation of the offsite power sources.

## FOREWORD

This report is supplied as part of the "Selected Operating Reactor Issues Programs (III)" being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Licensing, by EG&G Idaho, Inc., Reliability and Statistics Branch.

The U.S. Nuclear Regulatory Commission funded the work under authorization B&R 20 19 01 06, Fin No. A6429.

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# DEGRADED GRID PROTECTION FOR CLASS 1E POWER SYSTEMS

## EDWIN I. HATCH NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

### 1.0 INTRODUCTION

On June 2, 1977, the NRC requested the Georgia Power Company (GPC) to assess the susceptibility of the safety-related electrical equipment at the Edwin I. Hatch Nuclear Plant Unit 1 to a sustained voltage degradation of the offsite source and interaction of the offsite and onsite emergency power systems.[1] The letter contained three positions with which the current design of the plant was to be compared. After comparing the current design to the staff positions, GPC was required to either propose modifications to satisfy the positions and criteria or furnish an analysis to substantiate that the existing facility design has equivalent capabilities.

GPC replied to the NRC letter on July 22, 1977.[2] GPC supplied additional information and technical specification changes on October 9, 1980[3] and on May 21, 1981.[4] On October 2, 1981,[5] GPC submittal modified technical specification changes for Unit No. 1 and similar technical specification changes for Unit No. 2. This submittal had a typing error corrected on December 2, 1981.[6] Additional information is found in GPC letters dated September 17, 1976,[7] and January 12, 1982.[8] On January 26, 1982, GPC submitted all of the revised pages for the Unit 1 technical specifications.[9]

### 2.0 DESIGN BASE CRITERIA

The design base criteria that were applied in determining the acceptability of the system modifications to protect the safety-related equipment from a sustained degradation of the offsite grid are:

1. General Design Criterion 17 (GDC 17), "Electrical Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," of 10 CFR 50[10]

2. IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations"[11]

3. IEEE Standard 308-1974, "Class 1E Power Systems for Nuclear Power Generating Stations"[12]

4. Staff positions as detailed in a letter sent to the licensee, dated June 3, 1977[1]

   ANSI Standard C84.1-1977, "Voltage Ratings for Electrical Power Systems and Equipment (60 HZ)."[13]

### 3.0 EVALUATION

This section provides, in Subsection 3.1, a brief description of existing undervoltage protection at the Hatch Station; in Subsection 3.2, a description of the licensee's proposed scheme for the second-level undervoltage protection; and in Subsection 3.3, a discussion of how the system meets the design base criteria.

3.1 Existing Undervoltage Protection. The previous design utilized four undervoltage relays on each 4160V Class 1E emergency bus. They were arranged in a one-out-of-two-taken-twice logic scheme. The relays were set to operate at a voltage of 2912V (70%). These relays were used to sense a loss of offsite power. Should the voltage on the Class 1E buses fall to the setpoint, automatic fast transfer is initiated to the alternate offsite source by this relay logic and the diesel generators are started. If the alternate source is not available, the buses are load-stripped and the preferred and alternate source breakers are tripped and locked-out. As the diesel generators reach 90% of rated voltage and frequency, the diesel-generator bus breaker is automatically closed. The undervoltage condition is also annunciated in the main control room.

This system disables the load-shed feature once the Class 1E buses are being supplied by the diesel generators. Prior to the modification proposed in 1976, this was not disabled.[5] Non-essential loads, however, are load-shed when an accident signal exists whether the Class 1E buses are being supplied from the offsite or the onsite power sources.

3.2 Modifications. To protect the Class 1E safety-related equipment from the effects of a degraded grid condition, GPC has proposed changing the setpoints on the existing undervoltage relays. The relays used are Westinghouse type CV-7 inverse-time undervoltage relays. The two degraded voltage relays, arranged in a two-out-of-two logic, will have a nominal setpoint of 3280V (78.8% of bus voltage) with a time delay of less than or equal to 21.5 seconds. When a loss-of-voltage occurs, two other relays, also utilizing a two-out-of-two logic, will operate at a setpoint of greater than or equal to 2800V (67.3% of bus voltage) with a time delay of less than or equal to 6.5 seconds. GPC has submitted a diagram showing the relay charateristics both above and below these nominal values.[8] Upon a trip signal from both degraded voltage relays or both loss-of-voltage relays the sequence of events will be as stated in Subsection 3.1, except that the operation of any one of the four mentioned relays will initiate the start of the diesel generator associated with that bus. The voltages and time delays specified are one point on the calibration curve for that relay. The relays operate with less time delay at lower voltages, and a greater time delay at higher voltages. GPC has shown that the operating characteristics of the relays will not spuriously trip the Class 1E buses from offsite power for all expected combinations of offsite grid voltage and unit loads.

Load-shedding is blocked once the diesel generator is supplying power to its Class 1E bus, except for non-essential loads, by use of a "b" contact of the diesel-generator breaker. The load shedding is reinstated should the diesel generator breaker subsequently reopen. As stated above, this is already incorporated in the existing logic circuit.

Proposed changes to the plant's technical specifications, adding the surveillance requirements, allowable limits for the setpoint and time delay, and limiting conditions for operation for the second-level undervoltage monitors, were also furnished by the licensee. Bases for limiting conditions of operation as well as bases for surveillance requirements pertaining to these relays were also included in the technical specification changes.

3.3 Discussion. The first position of the NRC staff letter[1] required that a second level of undervoltage protection for the onsite power system be provided. The letter stipulates other criteria that the undervoltage protection must meet. Each criterion is restated below followed by a discussion regarding the licensee's compliance with that criterion.

1. "The selection of voltage and time setpoints shall be determined from an analysis of the voltage requirements of the safety-related loads at all onsite distribution system levels."

   GPC has analyzed for the voltage requirements for the safety-related loads at all onsite distribution system levels.[3] These studies have contributed to the selection of the proposed relay settings.

2. "The voltage protection shall include coincidence logic to preclude spurious trips of the offsite power sources."

   The relay logic is arranged in a two-out-of-two logic that satisfies this criterion.

3. "The time delay selected shall be based on the following conditions:

   a. The allowable time delay, including margin, shall not exceed the maximum time delay that is assumed in the FSAR accident analysis."

      The bases for limiting conditions of operation submitted by the licensee states that the proposed time delay, including margin, does not exceed the maximum time delay as analyzed in the FSAR.

      The proposed time delay will not be the cause of any thermal damage to the safety-related equipment. The equipment is rated to operate at the setpoint voltage for in excess of 30 seconds.

   b. "The time delay shall minimize the effect of short-duration disturbances from reducing the unavailability of the offsite power source(s)."

      The licensee's proposed time delay characteristics provide a time delay long enough to override any short inconsequential grid disturbances. Any voltage dips caused from the starting of large motors will not trip the offsite source.

   c. "The allowable time duration of a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components."

      A review of the licensee's voltage analysis[3] indicates that the time delay will not cause any failures of the safety-related equipment since the relay characteristics will disconnect a degraded source of AC power before the stall rating of the equipment is exceeded.

4. "The voltage monit[illegible] automatically initiate the disconnection of offsite [illegible] whenever the voltage setpoint and time-delay limit[illegible] exceeded."

A review of the licensee's proposal substantiates that this criterion is met.

5. "The voltage monitors shall be designed to satisfy the requirements of IEEE Standard 279-1971.

The licensee has stated in his submittal that all circuits associated with the undervoltage relays meet IEEE Standard 279-1971.[2,8]

6. "The technical specifications shall include limiting conditions for operations, surveillance requirements, trip setpoints with minimum and maximum limits, and allowable values for the second-level voltage protection monitors."

The licensee's latest draft proposal for technical specification changes[5,9] includes all of the required items except for instrument check. The instrument check is normally done by verifying that normal voltage is present at the input to each undervoltage relay. The Hatch station does not have voltmeters or indicators at this location, therefore the instrument check is not applicable. Analyses have been performed which assure that the range between the maximum and the minimum settings (allowable limits) will not be the cause of spurious trips of offsite power nor will they allow the voltage to be so low as to allow damage to the safety equipment.

The second NRC staff position requires that the system design automatically prevent load-shedding of the emergency buses once the onsite sources are supplying power to all sequenced loads. The load-shedding must also be reinstated if the onsite breakers are tripped.

GPC states that this feature is already incorporated in the circuit design.[2,5] A review of the logic circuitry substantiates that the load-shed is blocked by a contact of the diesel-generator breaker. All non-essential loads are, however, load-shed when the onsite source is supplying power to the Class 1E buses.

The third NRC staff position requires that certain test requirements be added to the technical specifications. These tests were to demonstrate the full-functional operability and independence of the onsite power sources and are to be performed at least once per 18 months during shutdown. The tests are to simulate loss of offsite power in conjunction with a simulated safety injection actuation signal and to simulate interruption and subsequent reconnection of onsite power sources. These tests verify the proper operation of the load-shed system, the load-shed bypass when the emergency diesel generators are supplying power to their respective buses, and that there is no adverse interaction between the onsite and offsite power sources.

The testing procedures proposed by the licensee do comply with this position. Load-shedding when offsite power is tripped is tested. Load-sequencing, once the diesel generator is supplying the safety buses, is tested. A simulated loss of the diesel generator and subsequent load-shedding and load-sequencing once the diesel generator is back on-line is tested. The time durations of the tests will verify that the time delay of the undervoltage relays is sufficient to avoid spurious trips and that the load-shed bypass circuit is functioning properly.

## 4.0 CONCLUSIONS

Based on the information provided by GPC, it has been determined that the proposed changes do comply with NRC staff position 1. All of the staff's requirements and design base criteria have been met. The setpoint and time delay will protect the Class 1E equipment from a sustained degraded voltage condition of the offsite power source.

The existing load-shed circuitry does comply with staff position 2 and will prevent adverse interaction of the offsite and onsite emergency power systems.

The proposed changes to the technical specifications do adequately test the system modifications and do comply with staff position 3. The surveillance requirements, limiting conditions for operation, minimum and maximum limits for the trip point, and allowable values satisfy staff position 1.

It is therefore concluded that the modifications and the proposed technical specification changes for Unit 1[9] and for Unit 2[5] are acceptable. These new setpoints and time delays have been implemented and it is, therefore, recommended that the changes to the technical specifications be approved and implemented at the earliest opportunity.

## 5.0 REFERENCES


1. NRC letter, V. Stello to C. F. Whitmer, GPC, dated June 2, 1977.

2. GPC letter, C. F. Whitmer, to Office of Nuclear Reactor Regulation, NRC, "Emergency Power Systems," July 22, 1977.

3. GPC letter, W. A. Widner to Office of Nuclear Reactor Regulation, NRC, "Response to Request for Additional Information--System Voltage Study," October 9, 1980.

4. GPC letter, J. T. Beckham to Office of Nuclear Reactor Regulation, NRC, "Emergency Power Systems," May 21, 1981.

5. GPC letter, W. A. Widner to Director of Nuclear Reactor Regulation, NRC, "Emergency Power Systems," October 2, 1981.

6. GPC letter, J. T. Beckham to Director of Nuclear Reactor Regulation, NRC, "Revised Technical Specifications for Degraded System Voltage," December 2, 1981.

7. GPC letter, C. F. Whitmer to Office of Nuclear Reactor Regulation, NRC, "Operation During Degraded Grid Voltage Conditions," September 17, 1976.

8. GPC letter, J. T. Beckham to Division of Licensing, NRC, "Adequacy of Station Electric Distribution System Voltages, Response to Request for Additional Information," January 12, 1982.

9. GPC letter, W. A. Widner to Director of Nuclear Reactor Regulation, "Emergency Power Systems," January 26, 1982.

10. General Design Criterion 17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."

11. IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

12. IEEE Standard 308-1974, "Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

13. ANSI C84.1-1977, "Voltage Ratings for Electric Power Systems and Equipment (60 HZ)."

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

August 22, 1991

Docket No. 50-321
50-366

Mr. W. G. Hairston, III
Senior Vice President
Georgia Power Company
40 Inverness Center Parkway
P.O. Box 1295
Birmingham, Alabama 35201

Dear Mr. Hairston:

SUBJECT: ELECTRICAL DISTRIBUTION SYSTEM FUNCTIONAL INSPECTION AT HATCH (50-321/91-202; 50-366/91-202)

We are forwarding the report of a special electrical distribution system functional inspection (EDSFI) performed June 10 through July 12, 1991, involving activities authorized by Operating License Nos. DPR-57 and NPF-5 for the Hatch Nuclear Plant, Units 1 and 2. This inspection was conducted by the Special Inspection Branch of the Office of Nuclear Reactor Regulation with the support of Region II. An exit meeting was held on July 12, 1991, during which we discussed the team's findings with members of your staff.

The areas examined during the inspection are discussed in the enclosed copy of our inspection report. The inspection team assessed the design, design implementation and technical support of the electrical distribution system (EDS). The inspection consisted of a selective review of EDS design calculations, relevant procedures, representative records, installed equipment and interviews with engineering and technical support staff.

The design and design implementation of the EDS at Hatch were generally acceptable. Several strengths were identified in the areas of retrievability of documents, monitoring of grid stability, self-assessment, and competence of the technical support staff. However, some deficiencies were identified including inadequate under voltage protection for plant operation under degraded grid voltage conditions and inadequate coordination of short circuit/fault protection devices for safety-related equipment. For example: (1) existing set points and time delay characteristics of the degraded grid undervoltage protection relays did not adequately prevent accident mitigating loads and control circuits from being operated with insufficient voltage in the unlikely event of a postulated accident concurrent with degraded grid conditions; (2) a 50.59 safety analysis had not been performed to evaluate the effect of load additions and tap changes to the startup transformer upon the undervoltage relay set points; and (3) overcurrent fault protection relay settings on several bus feeder breakers were not adequately coordinated with the fault protection on downstream breakers to protect against a potential loss of an entire safety bus before local downstream faults were isolated.

It is our understanding that you (1) have implemented interim administrative controls to protect the plant from unacceptably low undervoltage grid conditions; (2) have coordinated the overcurrent relay settings on the EDG output breakers with downstream breakers; and (3) are in the process of evaluating corrective actions for under voltage grid protection and potential miscoordination of other installed circuits.

The inspection findings indicated that certain activities were apparently not conducted in full compliance with NRC requirements. The deficiencies described in the enclosed inspection report will be reviewed by the Region II office for any enforcement action. Any subsequent actions will be taken by Region II.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

No response is required to this letter. Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

(ORIGINAL SIGNED BY STEVEN A. VARGA)

Steven A. Varga, Director
Division of Reactor Projects, I/II
Office of Nuclear Reactor Regulation

Enclosure:
Inspection Report 50-321/91-202
and 50-366/91-202

| | | | | |
|---|---|---|---|---|
| ASG | ASG for | ASG for | | |
| RSIB:DRIS | RII | RII | RSIB:DRIS | RSIB:DRIS |
| ASGautam:sf | PJFillion | LDWert | SSanders | LNTran |
| 08/20/91 | 08/21/91 | 08/21/91 | 08/21/91 | 08/22/91 |
| SC:RSIB:DRIS | C:RSIB:DRIS | D:DRIS:NRR | D:DRSP | |
| DPNorkin | EVImbro | for BKGrimes | SAVarga | |
| 08/22/91 | 08/22/91 | 08/22/91 | 08/22/91 | |

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U.S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

Division of Reactor Inspection and Safeguards

NRC Inspection Report: 50-321/91-202 and 50-366/91-202

License No.: DPR-57 and NPF-5

Docket Nos: 50-321 and 50-366

Licensee: Georgia Power Company

Facility Name: Hatch Nuclear Plant Units 1 and 2

Inspection Conducted: June 10 through July 12, 1991

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## EXECUTIVE SUMMARY

A Nuclear Regulatory Commission (NRC) team conducted an electrical distribution system functional inspection (EDSFI) at the Hatch Nuclear Plant Units 1 and 2. The inspection was conducted by the Special Inspection Branch of the Office of Nuclear Reactor Regulation (NRR), from June 10 through July 12, 1991.

The NRC inspection team reviewed the design and design implementation of the plant electrical distribution system (EDS) and the adequacy of associated engineering and technical support. To accomplish this, the team reviewed the design and installation of electrical and mechanical EDS equipment, reviewed test programs and procedures affecting the EDS, and interviewed appropriate corporate and site personnel. A number of strengths were identified as well as several deficiencies.

For the sample selected, the design and installation of the EDS at the Hatch Nuclear Plant was generally acceptable. Engineering calculations and other design documentation for attributes of the EDS were retrievable and verifiable. This was a strength compared to other plants of the same vintage. In most cases, engineering calculations had assumptions and conclusions that were technically sound. Analyses for bus transfers were generally comprehensive. Mechanical systems were well designed to support the EDS. There was an effective test program for relays and breakers; the program included testing beyond the requirements of the technical specifications. There was an aggressive program for the configuration control of fuses. Key staff support from various departments was sufficient in number and the engineers were knowledgeable. The licensee's efforts to monitor and maintain the grid voltage levels improved the overall grid system stability and increased the reliability of the offsite power to Hatch. A design-basis indexing project for drawings, calculations, and specifications was a strong initiative to further improve the control of design basis documentation. The substantive findings by the Quality Assurance (QA) group indicated an aggressive self-assessment effort. Good interaction between engineering and other technical support disciplines was evidenced by the licensee's responses to safety concerns discovered by the team during this inspection. In most cases programs and procedures were well established and controlled. Good housekeeping was observed in the plant. Installed EDS equipment was found properly labeled and appeared to be well maintained.

The team determined that under postulated degraded grid conditions the setpoints of the undervoltage relays on the 4160-volt buses were too low to prevent the voltage on the 600-volt and 208-volt buses from dropping below the minimum rated voltage necessary to power safety-related equipment relied on for accident mitigation. If the voltage on the essential 4160-volt buses dropped to between 3786 to 3675-volts the undervoltage relays would not act to transfer the buses from the offsite to the offsite power supply. Accident mitigating equipment operating at voltages below 600-volts could have failures. If the voltage on the essential 4160-volt buses dropped to between 3786 to 3675-volts during an accident under degraded grid conditions, a bus transfer would not take place from offsite to onsite power supply and insufficient voltage could cause accident mitigating equipment to fail. In addition, (1) the CV-7 undervoltage relays used for bus transfers had time delay characteristics that could cause excessive delays before the bus was transferred to an alternate source of power and (2) under degraded grid conditions, the operators did not get an anticipatory alarm before the transfer of essential buses to an alternate source of power. In response to these NRC concerns, the licensee implemented prompt administrative controls, including initiation of a 1-hour limiting condition for operation (LCO) if the grid voltage fell below 233 kVs (equivalent to 3786 volts on the 4160-volt bus). If the voltage on the 4160-volt buses cannot be restored above 3786 volts within an hour, the new administrative controls required initiation of an orderly plant shutdown. The NRC considered these controls as "interim" and was reviewing longer term corrective actions with the licensee.

Although load additions had been made to the EDS and tap changes had been made to the startup transformer, the licensee had not performed an analysis required by 10 CFR 50.59 to evaluate the effects of these changes to the undervoltage relay set points. Lack of such an analysis may have contributed to the potential of insufficient voltage for the 600-volt level and below buses.

There was incorrect coordination between the five EDG output breakers that feed essential 4160 volt buses and their corresponding downstream load breakers for Units 1 and 2, resulting in a potential loss of an entire 4160-volt essential bus during a postulated fault on associated loads. The licensee took prompt action in response to the NRC concerns by correcting the protective relay settings for the 4160-volt EDG output breakers.

Coordination calculations for pre-engineered fault protection configurations for 120-Vac and 125-Vdc control circuits were deficient. Certain combinations of relays and fuses that were approved for installation permitted feeder breakers to essential buses to trip before the downstream breaker or fuse isolated the fault. Field implementation of these approved combinations could result in incorrect coordination of the installed 120-Vac and 125-Vdc circuits. Although the licensee was of the opinion that these fuse/breaker configurations had never been used, the licensee agreed to review the plant configuration and correct any such combinations found in the field. Discrepancies also existed in the format and methodology of various coordination calculations. The team concluded that the licensee should review coordination study calculations for the EDS circuits to address, as a minimum, the discrepancies identified by the team.

Deficiencies in the undervoltage protection and the coordination of the fault current protection indicated that inadequate design reviews had been performed in those areas. The following items also require licensee actions as follows: (1) verification of the capacity of an inverter to simultaneously start and stroke three residual heat removal valves within the stroke time requirements of the technical specifications, (2) revision to plant technical specifications to accurately reflect the bus transfer function of a set of CV7 undervoltage permissive relays, (3) administrative controls to prevent an overpressure condition on the shell side of the heat exchanger for the emergency diesel generator 1B, (4) various enhancements and corrections to design drawings, calculations, and the final safety analysis report, and (5) revision of the EDG remote shutdown procedure to ensure the EDGs were operated within their ratings.

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## 1.0 INTRODUCTION

The Nuclear Regulatory Commission (NRC) initiated inspections of the electrical distribution system (EDS) at nuclear power plants because previous NRC inspections had identified similar types of deficiencies in the EDS that could affect power sources and equipment and compromise plant design safety margins. Examples of such deficiencies included unmonitored and uncontrolled load growth on safety buses and inadequate design calculations, engineering modifications, undervoltage protection and testing and qualification of EDS equipment. The NRC considered one cause of these deficiencies to be inadequate engineering and technical support.

The objectives of this inspection were to assess the adequacy of the Hatch Nuclear Plant EDS and the capability and performance of the licensee's engineering and technical support in this area. For the purpose of this inspection, the EDS included all emergency sources of power and associated equipment providing power to systems relied on to remain functional during and following design-basis events. The EDS components included two offsite circuits from the 230-kV offsite power grid switchyard, five emergency diesel generators, 125-Vdc Class 1E batteries, distribution transformers, 4160-Volt switchgear, 600-Vac load centers and motor control centers, 208/120-Vac and 250/125-Vdc distribution panels, battery chargers, inverters, breakers, relays and devices.

The team reviewed the adequacy of emergency onsite and offsite power sources for EDS equipment, protection for undervoltage conditions, the electrical load study and regulation of voltage to essential loads, protection of EDS equipment and loads from postulated fault currents, and coordination of the interrupting capability of protective devices. The team also reviewed mechanical systems supporting the EDS, including air start, lube oil, and cooling systems for the emergency diesel generator as well as cooling and heating systems for EDS equipment. The team verified nameplate data and locations of installed EDS equipment for conformance to configuration control and design documents and reviewed equipment qualification testing and calibration records. It assessed the capability and performance of the licensee's engineering and technical support functions with regard to the EDS, including organization and key staff, timely and adequate root-cause analysis for failures and recurring problems, and engineering involvement in design modifications and operations.

As part of its assessment, the NRC team verified EDS design conformance with General Design Criteria (GDC) 17 and 18 and appropriate criteria of Appendix B to 10 CFR Part 50. The team reviewed plant technical specifications, the final safety analysis report and safety evaluation report, to verify that technical requirements and licensee commitments were being met.

The team has characterized their findings within this report as deficiencies, and unresolved items, and observations. Deficiencies envelop the definitions of both deviations and violations in NRC Manual Chapter 0610. They are either 1) the failure of the licensee to comply with a requirement (violation) or 2) the failure of the licensee to satisfy a written commitment or to conform to the provisions of applicable codes, standards, guides or accepted industry practices, each of which has not been made a legally binding requirement (deviation). Unresolved items involve a concern about which more information is required to ascertain whether it is acceptable or deficient. Observations are issues considered appropriate to call to licensee management attention but which have no apparent regulatory basis.

The areas reviewed and the safety significance of identified deficiencies are described in Sections 2, 3, 4, and 5 of this report. Conclusions are provided at the end of each of these sections. Details of the findings are provided in Appendix A with a corresponding number and a reference to the section of this report in which it is discussed. A list of personnel contacted is provided in Appendix B and persons attending the exit meeting are indicated with an asterisk before their names.

## 2.0 ELECTRICAL SYSTEMS

The team reviewed a sample of specific electrical design attributes at each voltage level of the EDS. This included verifying the reliability and stability of the offsite (grid) power, plant load calculations for the regulation of voltage to electrical loads needed for the safe shutdown of the plant, undervoltage protection for essential buses, overcurrent protection calculations for short circuit and ground faults, and the sizing and coordination of protective devices.

The team reviewed a number of documents related to loads associated with the EDS. The documents reviewed addressed design calculations for ac and dc system loading, voltage regulation during normal and degraded conditions, voltage regulation during sequencing of safety-related loads onto the emergency diesel generators (EDGs), degraded voltage relay set points, Class 1E battery selection, short-circuit and ground-fault analysis, protective device coordination, and the protection of the EDS from power surges. The team also reviewed design-basis documents for the EDS, procedures and guidelines governing design calculations, design control and plant modifications, reports on EDG qualification tests, ac system voltages during degraded voltage conditions, and EDS single-line, schematic, and protective relay setting drawings.

### 2.1 Offsite Power System

The offsite power supply system at Hatch Nuclear Power Plant consisted of four 500-kV and four 230-kV transmission lines connected to the switchyard. The 500 and 230-kV lines were interconnected by three single-phase automatic transformers. Under normal operating conditions, all station non-safety loads were powered by the 230-kV/4160-V unit auxiliary transformers (UAT), and all the Class 1E loads were powered by the 230-kV/4160-V start-up auxiliary transformers (SAT) 1D and 1C for Unit 1 and SATs 2D and 2C for Unit 2. The SATs received power from the 230-kV switchyard. Two independent offsite power supplies were available for both Hatch units.

The team noted that the Hatch switchyard voltage levels were closely monitored and maintained. This effort was primarily performed at the Southern Electric System Power Coordination Center in Birmingham, Alabama. The system coordinators in this center coordinated the power transmission and interfaced with the control centers of the operating plants including Hatch. The coordinator was primarily responsible to ensure efficient operation of the system by routing the various units and matching power generations to load demands. The system coordinators in Birmingham performed contingency analyses on the overall system by postulating loss of combinations of lines, transformers, or generators. If the results of the contingency analyses indicated that the present configuration could lead to unacceptable grid voltage levels, the system coordinator would take action to preclude the potential problem.

### 2.1.1 Degraded Grid Undervoltage Protection

A generic letter titled, "Degraded Protection for Class IE Power Systems," issued by NRC on June 2, 1977 required two levels of undervoltage protection, loss of voltage and degraded voltage, to ensure that accident mitigating loads (such as pump motors, motor operated valves, control circuits, fans, and heaters) would perform their safety function. The purpose of the degraded voltage protection was to preclude the adverse effects caused by sustained low grid voltage conditions on the Class IE loads. The generic letter stated that the undervoltage scheme select undervoltage and time delay set points based on an analysis of the voltage requirements of the Class IE loads at all onsite system distribution levels. However, at Hatch the degraded grid undervoltage protection was not adequate for the safe operation of Class IE loads at the 600-Volt level and below.

Four Westinghouse type CV-7 relays having time-delay features were used to protect against potential failures of Class IE accident mitigating equipment during degraded grid voltage conditions. Two of these relays provided alarms and the other two transferred the buses to an alternate power source during a sustained degraded grid voltage condition. However, during an accident, because of the low settings of the CV-7 relays, if the 4160-V bus voltage was degraded and remained between a voltage band of 3766-V to 3675-V, automatic bus transfer to the EDGs would not take place and the Class IE loads at voltage levels of 600-V level and below would not receive sufficient voltage to perform their safety functions.

In addition, the CV-7 degraded voltage relays had a time delay feature that could cause excessive delays in the transfer of the 4160-V bus from the offsite degraded grid to the alternate power supply. The time-voltage characteristics of the relay indicated that the licensee was relying on the actuation of the relay in a range of operation that was outside the range of the performance curves supplied by the vendor. Based on these curves, the team concluded that time delay for the CV-7 undervoltage to actuate between the voltage band of 3675-V to 3280-V on the 4160-Volt bus was indeterminate.

The licensee stated that if the switchyard grid voltage was degrading, the system coordinator in Birmingham would inform the Hatch shift supervisor by telephone and take immediate action to boost the voltage through various controls including energizing capacitor banks, and adding power through routing of generating units. However, insufficient administrative controls existed for such actions and the automatic undervoltage protection was not adequate.

To mitigate the team's concerns, the licensee promptly implemented administrative controls which included initiation of a one hour limiting condition of operation (LCO) if the grid voltage fell below 101.3 percent or 233-KV (equivalent to 3766-V on the 4160-V bus). Based on these controls, if the 4160-volt bus voltage could not be restored within an hour to above 91 percent or 3766-V an orderly plant shutdown would be initiated. The NRC is reviewing these administrative controls relative to the operability of the plant and considering them "interim controls" until further discussion with the licensee regarding any long term corrective action for this condition (see Appendix A, Deficiency 91-202-01).

### 2.1.2 Load Increase and Change of Transformer Tap

Load growth had occurred to the Hatch Nuclear Plant EDS over the last ten years. The total power requirements for safety and non-safety loads after a LOCA accident in the 1991 voltage study 91212PG was higher than the load in the voltage study report submitted to the NRC in 1980 for undervoltage protection setpoints. The team also noted that during this period the SAT 1B tap position had also been changed from 100 percent to 102.5 percent. The team concluded that both of the above changes affected the voltage levels of essential buses during degraded grid conditions.

The licensee could not demonstrate that a design review in accordance with 10 CFR 50.59 had been performed to evaluate the effect of these changes on the setpoints of the undervoltage protection. Therefore the team concluded that these changes should have been evaluated to determine if any unreviewed safety question existed. The lack of such an evaluation may have contributed to the potential for inadequate voltages to safety loads (see Appendix A Deficiency 91-202-02).

## 2.2 Class 1E 4160-Vac System

The 4160-Volt Class 1E distribution system consisted of onsite EDGs, power feeds from the offsite grid source, power distribution equipment, and circuits to accident mitigating loads. Five independent EDGs provided onsite power for both units, one EDG for each of the two safety divisions of each unit and a third "swing" diesel could provide back up power for either unit. Each of the EDGs was designed to provide emergency power to its respective vital 4160-Vac bus. The 4160-Volt buses primarily supplied power for safety-related pumps and 600-Volt load centers which in turn provided power to smaller electrical loads. All safety buses were normally energized from the offsite grid, which was considered the preferred source of power.

The load capacity of the EDGs and the size of the load transformers were adequate. The load/current capabilities of the 4160-Volt safety buses, cables and breakers were adequate. The plant "Offsite Source Voltage Study-1991" showed that when the 230-kV bus was operating within its normal allowable voltage limits of 101.5 percent to 104.9 percent, all the safety loads on the ac and dc buses would operate.

All the safety-related motors, when connected to their associated loads, had sufficient voltage and torque to accelerate within their required starting time. Even the motor with the longest starting time would not cause a spurious trip on the 4160-Volt bus undervoltage protection.

### 2.2.1 Fast Transfer Permissive Relay

During undervoltage conditions the logic for the 4160-Volt buses transferred the essential buses from SAT 1I to 1C. If the voltage on 4160-Volt buses remained inadequate for more than one second the logic transfers the buses to the EDGs. Previously a set of CV-7 permissive relays sensed undervoltage on the SAT 1C and transferred power from 1C to the EDGs. These permissive relays as described in the Hatch Unit 1 Technical Specifications were required to be "instantaneous" when transferring the bus from the offsite (SAT) to onsite (EDG) source. However, the installed relay identified in the technical specification had a "time delay" feature in conflict with the technical specification requirement.

The licensee stated that these permissive relays identified in the technical specification no longer transferred the 4160-Volt bus from the offsite to onsite power because they had been modified to only sense undervoltage on the SAT 1C and control its associated breaker. The transfer to onsite power was currently performed by another set of relays on the 4160-volt buses that would not be affected by the permissive relays. The team had no safety concerns regarding the function of the relay, however, the technical specifications did not reflect the actual plant configuration (see Appendix A, Deficiency 91-202-03).

### 2.2.2 EDG Remote Shutdown Procedure

The EDG Remote Shutdown Procedure assumed diesel generator loads to be running at a power factor of 0.8 instead of 0.9. This procedure applied to EDG 1B (swing), 2A, and 2C. Since the available instrumentation only monitors current, if the procedure had been implemented, the EDGs could have been run at an output higher than the maximum diesel generator rating. To correct this error, the licensee agreed to revise the procedure to reflect lower current ratings based on a 0.9 power factor to allow the diesel generators to stay within their continuous and 7-day rating (see Appendix A, Deficiency 91-202-04).

## 2.3 Class 1E 600-Vac/208-Vac System

The cable voltage drops during the starting and running of 600-V Class 1E motors were adeqaute. The trip coils and motor overload heaters for the 600-Volt Class 1E motor operated valves (MOVs), and the length and size of the cables connecting these MOVs to the motor control centers were adequate. Preventive maintenance procedures for thermal overload relays and molded case circuit breakers, and for the selection of power and control cables indicated no deficiencies.

## 2.4 Class 1E 125-Vdc and 120-Vac Systems and 600-Vac Inverters

The voltage drop and short circuit calculations for the dc distribution system showed that (1) the associated equipment allowed adequate voltage to associated loads and had adequate protection for postulated fault currents; (2) the 125-Vdc control circuit lengths did not compromise the energization of the closing coils used in the control circuits of the 4.16-kV and 600-V circuit breakers; (3) the coordination between the installed fuses at the switchgear and the dc distribution panels did not cause a loss of a Class 1E bus and associated accident mitigating loads during postulated fault currents, and (4) fuse ratings were properly selected to sustain the starting current of the charging motor and to open the circuit in case of postulated short circuit faults.

The substation batteries were sized for 8 hours of continuous load, and the associated battery charger was sized for 12 hours recharging time. The battery and battery charger sizing calculations included design margin, temperature correction, and aging factors. The station batteries and battery chargers appeared to be capable of performing their intended functions. Data for the minimum required voltages for safety-related loads on the Class 1E dc buses showed that 210-V was adequate to operate all the safety related loads.

However, the team observed that 600-Volt inverter R44-S002, providing power to four MOVs in Division 1 and inverter R44-S003 providing power to five MOVs in Division 2 may not have adequate capacity. During an accident each inverter load included operation of the residual heat removal (RHR) injection, minimum flow, and recirculating pump suction valves. Under postulated worst case conditions each inverter could be required to supply power simultaneously to close the recirculating discharge valve, to close RHR minimum flow valve, and to stroke the RHR injection valve. The team was concerned because there was no assurance that the inverters would be able to provide enough power to stroke the valves within the time required by the Technical Specifications. The licensee agreed to perform an appropriate LPCI inverter load test during the next refueling outage to verify stroke time (see Appendix A, Unresolved Item 91-202-05).

2.5 Protection and Coordination

The team found various discrepancies with the adequacy of the overcurrent fault protection (short circuit and ground fault) and coordination of protective devices for the 4160-Volt system. Details are discussed below.

2.5.1 Incorrect Coordination of the EDG Circuit Breaker

The overcurrent protection relays initiating a trip signal to Unit 1 and 2 EDG output circuit breakers were not coordinated with the protective relays for the downstream circuit breakers. If the diesels were energizing essential 4160-volt buses during emergency conditions, a postulated fault on a branch feeder had the potential of tripping the EDG output circuit breaker before tripping the downstream branch feeder circuit breakers. The team also noted that the incorrect coordination of the diesel generator circuit breaker was also missed by the licensee during its review of the Appendix R fire protection study (10 CFR Part 50).

The licensee took prompt corrective action to reset the protective relays on the EDG output breakers during the inspection (see Appendix A, Deficiency 91-202-06).

2.5.2 Coordination of 120-Volt ac and 125-Volt dc Circuits

Generic fuse coordination studies specified approved configurations for various design conditions. However, the team noted several incorrect coordinations for specific ranges of fault current between protective relays on upstream breakers and downstream fuses. For example, relay characteristics on a time current curve indicated that the upstream breaker was not properly coordinated with a downstream fuse over a fault current range of 40 amperes. These "approved configurations" may have resulted in the fuses not being correctly coordinated during the upgrade and replacement program.

Over 6000 fuses had been reviewed to date under this fuse upgrade and replacement program for Units 1 and 2 affecting numerous 120-Vac and 120-Vdc circuits with breaker/fuse configurations. All pre-engineered breaker/fuse configurations should be checked to verify correct coordination. Although the licensee was of the opinion that the suspect combinations had never been used, the licensee agreed to review generic fuse coordination studies and installations for errors (see Appendix A, Deficiency 91-202-07).

### 2.5.3 Discrepancies in Coordination Calculations

Fragmented documentation of coordination calculations for the EDS equipment made it very difficult to determine if the protection on the feeder breakers to essential buses was coordinated with the protection on downstream breakers.

This was because the Hatch coordination study was fragmented. For example, calculations created to implement specific overcurrent trip device modifications had not been integrated with calculations of other related circuits. Also, Appendix R calculations only addressed Appendix R buses and loads and had not been integrated with calculations of other affected circuits. This approach of satisfying coordination for a specific modification had the potential for error.

In reviewing the Plant Hatch/Relaying Data Document, the team noted that the protective device time current curves were typical for multiple applications. Specific relays were identified on a relay data sheet that indicated relay settings and a reference to a typical time current curve. Using these typical curves could have caused coordination errors because relays using the same typical curve did not always have the same characteristics. In the cases reviewed, many of the time current curves had to be overlaid and held to a light source or be redrawn to determine coordination. An error could be easily made in identifying devices and analyzing coordination with these typical curves.

Although the licensee had a design guideline for the maximum setting of 600 volt instantaneous or short-time trip devices for coordination of these devices with upstream relays, the application of this guideline was not apparent in the calculations. In addition, the title of a short circuit study had been changed to indicate it was a coordination study, however, no changes were made to the body of the calculation to transform it to a coordination study.

Because of the above documentation difficulties the team had difficulty in verifying the adequacy of the coordination of installed circuits. The team recommended that the licensee review coordination study calculations to address as a minimum the discrepancies identified by the team (see Observation 91-202-08).

## 2.6 Conclusions

The design of the electrical systems for the electrical distribution system at Hatch Units 1 and 2 was generally acceptable. The capacity of onsite and offsite power sources was sufficient for plant loads. Staff support consisted of a sufficient number of engineers with an understanding of the relevant technical issues. Engineering calculations and other design documentation for attributes of the EDS were retrievable and verifiable. In most cases, engineering calculations had assumptions and conclusions that were appropriate.

There were some inadequacies in the design of undervoltage protection during degraded grid conditions. Under certain conditions of operation the degraded grid relay set points had the potential to cause failures of accident mitigating EDS equipment. There were various deficiencies related to the coordination of fault protective devices, as discussed in Section 2.5 of this report.

## 3.0 MECHANICAL SYSTEMS

The team translated various mechanical loads (selected pumps and MOVs) to electrical loads (kw) by examining header pressure and flow pump curves to verify the sizes of electrical loads used in the EDS load study calculations. For the sample selected the maximum pump motor loads used in the calculations were accurate.

The monthly, semi-annual and 18-month surveillance test procedures for the diesel were in accordance with the plant technical specifications. The vendor (Colt industries) recommendations for the operation of the EDG were accurately reflected in the final safety analysis report (FSAR) and plant operating procedures. The last five-start test for the EDG was completed in accordance with the requirements of the plant technical specification. The fuel oil tanks were designed to specification and the licensee's procedure for monitoring and routine testing of the diesel fuel oil was acceptable.

### 3.1 Heating, Ventilating, and Air Conditioning System

The mechanical equipment associated with the heating, ventilating, and air conditioning (HVAC) system was adequate to maintain proper ambient temperatures for the diesel generator building, battery rooms, and essential switchgear rooms. However, there were certain discrepancies in the HVAC calculations and documentation.

#### 3.1.1 High Ambient Temperatures for Battery Chargers

During summer, high ambient air temperatures expected in the location of the station battery chargers had the potential to affect the performance of the installed battery chargers. The licensee stated that the maximum temperature during the full-load operation of any battery charger would be 104°F and that the battery chargers were qualified for up to 110°F. The licensee also stated, however, that the installed battery chargers in both units would be replaced during the next outage to withstand even more stringent ambient conditions of 135°F over a 4-hour period during postulated blackout conditions.

#### 3.1.2 Discrepancies in Mechanical Design Documentation

There were several discrepancies in the FSAR and the design documentation regarding the EDG air starting compressor setpoints and operating parameters e.g., low pressure start, high pressure cutoff, operating pressure, and air receiver pressure relief valve setting. The licensee agreed to revise appropriate documents.

There were discrepancies between the licensee's calculations for the HVAC system air flow distribution. The air compressor had been replaced, resulting in an overall lower air temperature for the battery rooms. However, the calculations had not been revised to show this lower heat load. Changes had been made on the plant arrangement drawings but had not been incorporated into the P&ID and process flow drawings.

The original lead antimony batteries had been replaced with lead calcium batteries that had a lower hydrogen generation rate than the original batteries. However, the hydrogen generation rates in the calculations had not been revised to reflect the additional margins or time it would take the hydrogen to reach dangerous or explosive conditions on loss of air flow to the battery rooms.

The licensee agreed to correct the appropriate calculations and drawings (see Appendix A, Deficiency 91-202-09).

### 3.2 Plant Service Water System

The section of plant service water piping between the supply and return isolation valves of EDG 1B had the potential to trap service water in the associated heat exchanger. If the hot heat exchanger was shut down, the trapped fluid could heat up and expand and cause the internal pressure to rise on the shell side of the heat exchanger. This could lead to a potential overpressure condition. The licensee committed to revising the station operating procedure to require that the operators maintain standby service water flow for a minimum of 1/2 hour after the diesel engine was secured in order to eliminate over pressure concerns (see Appendix A, Deficiency 91-202-10; 91-202-10).

### 3.3 Conclusions

The diesel generator and its support systems were in conformance with the design specifications for the EDS. Technical staff were sufficiently knowledgeable of the mechanical systems supporting the EDS. Calculations and test reports were readily available and demonstrated a sound technical basis, which was considered a strength with regard to engineering and technical support.

Licensee action is required to address the potential of an overpressure condition on the shell side of the heat exchanger. Updating of mechanical design documents was a weakness evidenced by the discrepancies between HVAC drawings, calculations, and the FSAR. Further attention to document control and updating in this area is recommended.

## 4.0 EDS EQUIPMENT

As-built configurations of selected safety-related EDS electrical and mechanical equipment conformed to design requirements.

### 4.1 Equipment Walkdowns

The EDS equipment including supporting mechanical equipment conformed to design requirements, were properly labeled, easily identifiable, and accessible. Good housekeeping was apparent in the plant, and the equipment appeared to be well maintained. The support staff was knowledgeable, competent, and timely in answering questions.

Drawings used to facilitate the walkdowns were clear and traceable, and in most cases reflected the field configuration. Some discrepancies between design drawings and installation of certain EDS equipment were noted. For example, the dimensions of some cable tray and pipe supports were incorrectly noted on the drawings. The licensee confirmed that the equipment in the field met design requirements but that these drawings had not been updated. The licensee issued design change notices (DCNs) to correct these document errors and to implement the necessary corrective action. No further concerns were identified.

4.2 Equipment Modifications

The design evaluation review and approval process was adequate and comprehensive and included screening modification requests for required 10 CFR 50.59 safety evaluations.

The engineering design and modification control process was well proceduralized. Design changes were reviewed and approved in accordance with the technical specifications and established QA/QC controls. The licensee conducted post-modification tests, and performed test result evaluations before declaring the affected components and systems operable. Most test results reviewed were within previously established acceptance criteria. The licensee reviewed test result deviations and where applicable, performed retesting. The licensee's procedures controlling modification work and documentation records were generally complete and comprehensive.

4.3 Equipment Testing and Calibration

The licensee had a well-structured program in place for performing preventive maintenance, surveillance, and testing of EDS equipment and components. The programs addressed the testing of emergency diesel generators and associated systems, transformers, motors, batteries, circuit breakers, and protective relaying. The preventive maintenance program was based on vendor recommendations, and the surveillance testing was in accordance with the plant's technical specification requirements.

The scope of the testing and calibration program was adequate. A strong test program was in place for relays and breakers. Testing went beyond the requirements of the technical specifications. All safety-related circuit breakers, including molded-case breakers, were tested on a periodic basis.

The undervoltage relay instrument functional test and calibration procedures indicated that the "reset" voltages of Westinghouse CV-7 relays were often less than the "pick-up" voltages. The licensee acknowledged that the procedure was in error but that the Unit 1 procedure had already been corrected. During the inspection, the licensee initiated corrective action for the Unit 2 procedure. The error did not result in any adverse effects on the operability of the relays.

4.4 Conclusions

Overall the licensee had instituted a well structured periodic preventive maintenance and test program for electrical systems and components. The frequency of maintenance and surveillance and testing was adequate to verify functional performance.

## 5.0 ENGINEERING AND TECHNICAL SUPPORT

The team assessed the capability and performance of the licensee's organization to provide engineering and technical support. The team examined interfaces between the technical disciplines internal to the engineering organization and between the engineering organization and the functional groups performing design reviews, field modifications, surveillance, testing, and maintenance. The team also examined the working relationship between the onsite organizations and the offsite support organizations.

### 5.1 Organization and Key Staff

Southern Company Services (SCS) and Bechtel were the architect/engineer organizations providing primary engineering support to the Hatch EDS. Bechtel maintained an organization of about 40 engineers and administratively reported to SCS. SCS and Bechtel were responsible for maintaining the design basis of Hatch and maintained organizations of engineers dedicated to the support of plant Hatch. The engineers assigned to the Hatch project were sufficient in number and experienced.

### 5.2 Root Cause Analysis and Corrective Action

LERs, QA audits, and other documents indicated that the root cause analysis process was adequate. Review of five LERs indicated that the event review team needed to identify more detail with regard to the root cause of component failures. For example the team reviewed LER 321/91-01 and noted that the failure of the switchyard breaker 179500 was attributed to the failure of a current limiting resistor in the trip circuitry. However, the team determined that the resistor was not the primary initiator of the failure and that further root cause analysis was required.

Corrective actions in response to identified problems were considered adequate and reflected high-level management support of the licensee's self-assessment organizations. For example, both onsite and SCS audits showed that the safety analysis and engineering review (SAER) group had requested and obtained additional corrective actions beyond that initially proposed in response to a finding. No examples of inadequate responses were noted; however, in several instances the final resolution of SAER findings was not timely. For example, a 1988 finding involving breaker/relay trip testing was not resolved for over 3 years.

### 5.3 Self Assessment and Training

The licensee demonstrated a very aggressive self assessment effort. The SAER (QA) group demonstrated sound technical knowledge and identified various findings during internal audits of the EDS. The licensee had initiated several programs to address identified problems. For example, the engineering quality improvement program (EQIP) reduced a past DCR backlog. There was an aggressive program for the replacement and control of fuses. The licensee had completed a distribution panel walkdown review program that consisted of crosschecking panel layout, breaker ratings, and verification of overload relay type and settings against drawings.

The licensee had also initiated a design basis indexing (DBI) project that would cross reference all major components to the design calculations, vendor drawings, and to vendor documents. The DBI project was a strength.

The licensee was continuing to refine and enhance trending programs. For example, maintenance engineering examined trends involving repetitive corrective maintenance. Additional programs including oil analysis, vibration analysis, and thermography were also being implemented. The thermography program had successfully identified equipment problems. However, no formal trending program was in place for trending the drifting of relays.

## 5.4 Engineering Involvement in Operations

Interviews with technical staff indicated that sufficient interface existed between the licensee's onsite and corporate staff. The team observed evidence of the licensee's commitment to site support at corporate level meetings. This working relationship was also reflected by the licensee's immediate response to NRC concerns regarding the coordination of the EDG output breakers identified during this inspection.

## 5.5 Conclusions

The engineering and technical support available to the Hatch plant appeared adequate. Engineers were sufficient in number and experience. The licensee's root-cause analysis and corrective action programs appeared to be strong and continually improving. The root cause analysis of certain equipment failures needed more detail.

## 6.0 EXIT MEETING

The team conducted an exit meeting on July 12, 1991 at the Hatch Nuclear Plant to discuss the major areas reviewed during the inspection, the strengths and weaknesses observed, and findings. NRC management from NRR, and Region II and licensee representatives who attended this meeting are identified with an asterisk in Appendix B of this report. The team discussed licensee actions on major issues. The licensee did not identify any documents or processes as proprietary.

## APPENDIX A

Inspection Findings

DEFICIENCY 91-202-01

FINDING TITLE: Degraded Grid Undervoltage Relay Setpoint (Section 2.1.1 of report)

DESCRIPTION OF CONDITION:

Two levels of undervoltage protection loss of voltage and degraded voltage, are required to ensure that accident mitigating loads (such as pump motors, MOVs, control circuits, fans, and heaters) would perform their safety function. This undervoltage protection is required by Generic Letter titled "Degraded Protection for Class 1E power systems," dated June 2, 1977. The generic letter required that the undervoltage scheme select undervoltage and time delay set points on the basis of an analysis of the voltage requirements of the Class 1E loads at all onsite system distribution levels.

Two levels of undervoltage protection were used to protect the Class 1E equipment at Hatch. Westinghouse type CV-7 (short time over or under voltage) relays were used. The CV-7 relays have a time delay that is inversely proportional to the difference between the actual bus voltage and the nominal bus voltage. The first level of undervoltage relays were set to trip quickly for a loss of offsite voltage. The second level of degraded grid undervoltage relays were set to alarm and trip for a sustained degraded system voltage condition. Both levels of undervoltage protection and their trip settings were given in the technical specifications. The degraded voltage protection relays were set at "105-V Tap" and "No. 5 Time Dial" and the relays were calibrated to trip in 20 seconds at 93.7-Volts. With this setting, the relays would start to pick up at 3675-Volts (88.34% of 4160-Volts) trigger and at 3280-V (78.8% of 4160-Volts) the relays would trip in 20 seconds.

In their voltage study the licensee indicated that under the worst case operating conditions the 230 kV bus voltage could be about 98.8 percent (227 kV). The team determined that during a postulated accident if the 4160V bus voltage was between an approximate voltage band of 91 percent (3786V) to 88.34% (3675V) (equivalent to approximately 101.1 percent or 232.5-kV to 98.7 percent or 227-kVs at the 230-kV bus), the Class 1E loads at voltage levels of 600 volts and below would not receive sufficient voltage to perform their safety functions.

The CV-7 degraded voltage relays had an inverse time-voltage characteristic that could cause excessive delays in the transfer of the 4160-Volt bus from the offsite degraded grid to the alternate power supply under certain voltage conditions. The basis of this concern was the licensee's reliance on the the actuation of the relay in a range of operation that was outside the range of performance specified by the vendor. Based on these curves, the team concluded that the time delay for the CV-7 undervoltage to actuate between the voltage band of 3675 to 3280-Volts on the 4160-Volt bus was indeterminate.

The licensee stated that if the switchyard grid voltage was degrading, the system coordinator in Birmingham would inform the Hatch shift supervisor by telephone and take immediate action to boost the voltage through various controls including energizing capacitor banks and adding power through other generating units. The Hatch staff supervisor would then assess the condition and possibly reduce loads. The team concluded that although monitoring the grid increased the reliability of offsite power to Hatch, insufficient administrative controls existed for such actions, and that the automatic undervoltage protection was not adequate.

To mitigate the team's concerns the licensee promptly implemented administrative controls which included initiation of a 1 hour LCO if the grid voltage fell below 101.3 percent or 233-kVs. If the 4160-volt bus voltage could not be restored within the hour LCO to above 91 percent or 3786-Volts an orderly plant shutdown would be initiated. The NRC is reviewing these administrative controls relative to the operability of the plant and considering them "interim controls" pending further discussion with the licensee regarding any long-term corrective action for this condition.

REQUIREMENTS:

Criterion III of 10 CFR Part 50, Appendix B, states that design control measures shall provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Generic letter, "Degraded Protection for Class 1E Power Systems" (MPA B23), dated June 2, 1977 required that the selection of the second level degraded grid undervoltage and time delay set point be determined from an analysis of the voltage requirements of the Class 1E loads at all onsite system distribution levels.

REFERENCES:


1. Georgia Power Company, E.I. Hatch N. P. Surveillance Procedure No. 57SV-S32-002-1S.
2. Westinghouse Type CV Voltage Relay Installation, Operation, Maintenance Instructions.

## DEFICIENCY 91-202-02

FINDING TITLE: Load Increase and Change of SAT 1D Tap (Section 2.1.2 of report)

DESCRIPTION OF CONDITION:

Over the last ten years loads had been added to the EDS. The 1991 voltage study 91212PG showed the total power requirements for the safety and non-safety loads after a LOCA accident had increased since the voltage study report submitted to the NRC in 1980 for undervoltage protection setpoints. During this period the SAT 1D tap position had been changed from 100 percent to 102.5 percent. Both the changes affected the voltage levels of essential buses under degraded grid conditions.

The licensee could not demonstrate that a design review in accordance with 10 CFR 50.59 had been performed to evaluate the effect of these changes on the set points of the undervoltage protection. Therefore the team concluded that these changes should have been evaluated to determine if an unreviewed safety question existed. The lack of such an evaluation may have contributed to the potential for inadequate voltages to safety loads.

REQUIREMENTS:

Criterion III of 10 CFR Part 50, Appendix B, states that design control measures shall provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

10 CFR Part 50.59 states that the holder of a license may make changes in the facility as described in the safety analysis report without prior NRC approval unless the proposed change, test or experiment involves a change in the technical specifications or an unreviewed safety question.

REFERENCES:

1. GPC Voltage Study 91212PG, 1991
2. Letter from R.J. Kelly to USNRC Office of Nuclear Reactor Regulation, dated December 7, 1991 and under NRC Dockets 50-321, and 50-366.
3. GPC letter from W.A. Widner to USNRC Office of Nuclear Reactor Regulation "Response to Request for Additional Information--System Voltage Study," dated October 9, 1980 and Voltage Study Calculation, Rev. 2, (April 1980.)

## DEFICIENCY 91-202-03

**FINDING TITLE:** Fast Transfer Permissive Relay (Section 2.2.1 of report)

**DESCRIPTION OF CONDITION:**

During undervoltage conditions the logic for the 4160-Volt buses transferred the essential buses from SAT 1D to SAT 1C. If the voltage on 4160-Volt buses remained inadequate for one second the logic would transfer the buses from 1C to the EDGs. Previously a set of CV-7 permissive relays sensed undervoltage on the SAT 1C and transferred power from 1C to the EDGs. These permissive relays, as described in Table 3.2-13 of Hatch Unit 1 technical specifications (TS) were required to be "instantaneous" when transferring the bus from the offsite (SAT) to onsite (EDG) source. However, this relay had a "time delay" feature in conflict with the TS.

The team noted that in April 1981 a failure of these CV-7 permissive relays during testing had resulted in a failure of the EDGs to energize the safety buses. After an LER was submitted, discussions were held between NRR and a modification was proposed to alter the function of these two relays. In the interim, Table 3.2-13 was added to the TS (May 6, 1982, TS Amendments 88 and 27 were approved which included Table 3.2-13 and the degraded grid and undervoltage requirements). The modification (DCR 82-34) was completed in 1983. The licensee stated that these relays no longer transferred the 4160-Volt bus from the offsite (SAT) to onsite (EDG) power. These relays had been modified to only sense undervoltage on the SAT 1C and control its associated breaker. The transfer function was currently performed by another set of relays on the 4160-volt buses that would not be affected by the permissive relays. The team had no safety concerns regarding the function of the CV-7 relay, however, the TS did not reflect the actual plant configuration.

**REQUIREMENTS:**

Technical Specifications Table 3.2-13, Hatch Unit 1.

**REFERENCES:**

1. Table 3.2-13 of Hatch Unit 1 Technical Specification.
2. Relay Data Sheet 40 of U1-17, Plant Hatch.

## DEFICIENCY 91-202-04:

FINDING TITLE: EDG Remote Shutdown Procedure (Section 2.2.2 of Report)

### DESCRIPTION OF CONDITION:

The EDG Remote Shutdown Procedure, Document Number 31RS-OPS-002-2S for EDGs 1B (Swing), 2A, and 2C, incorrectly assumed diesel generator loads to be running at 0.8 power factor when in fact these loads ran at 0.9 power factor. In the procedure, on pages 2, 5, 9 and 13, a "CAUTION" to the operator stated that the diesel generators must not exceed the ratings of 490 amps continuous and 560 amps for 7-day/168 hour rating. Based on a 0.9 power factor, these current ratings allowed the diesel generators to exceed the maximum kilowatt rating. At 490 amps, the diesel generators operated at 3174kWs (continuous), which exceeded the 2850-kW maximum rating. At 560 amps, the diesel generators operated at 3,627kW (7 day/168-hour) which exceeded the 3250kWs maximum rating.

Since the available instrumentation only monitored current, if the procedure had been implemented the EDGs could have been run at an output higher than the maximum diesel generator rating. To correct this error, the licensee agreed to revise the procedure to reflect lower current ratings based on a 0.9 power factor, so as to assure the diesel generators were operated within their continuous and 7-day ratings.

### REQUIREMENT:

10 CFR Part 50, Appendix B, Criterion III, Design Control, requires measures to be established to ensure the design basis is correctly translated into specification, drawings, procedures, and instructions.

### REFERENCE:

1. Electrical Restoration Remote Shutdown Procedure, Document Number 31RS-OPS-002-2S, Revision 0, Dated January 12, 1991.

## UNRESOLVED ITEM 91-202-05

FINDING TITLE: Sizing of-250 Vdc/600-Vac Inverters (Section 2.4 of report)

DESCRIPTION OF CONDITION:

The team reviewed the capacity of the 600-volt inverter R44-S002, providing power to four MOVs in Division 1, and Inverter R44-S003, providing power to five MOVs in Division 2. During an accident each inverter load included operation of the RHR injection, minimum flow, and recirculating pump suction valves. Under postulated worst-case conditions each inverter would be required to supply power simultaneously to close the recirculating discourage valve B31-F031A and the RHR minimum flow valve E11-F007A, and to stroke the RHR injection valve E11-F015A. The team was concerned that the inverters may not have adequate capacity to provide enough power to stroke the valves within the time required by the technical specifications.

The inverters were load tested every 18 months to verify their capability to stroke the required MOVs. Procedure 34SV-R44-001-1S "LPCI Inverters Load Testing" required inverter R44-S003 to simultaneous stroke four valves and inverter R44-S002 to simultaneously stroke three valves. However, the test procedure did not measure the stroke time of the valves to ensure that the stroke time was within the requirements of the technical specifications.

The licensee agreed to perform an appropriate LPCI inverter load test during the next refueling outage to verify stroke time.

REQUIREMENTS:

Criterion III of 10 CFR Part 50, Appendix B, states that design control measures shall provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

REFERENCE:

1. LPCI Inverters Load Testing Procedure 34SV-R44-001-1S.

## DEFICIENCY 91-202-06

FINDING TITLE: Incorrect Coordination of the EDG Circuit Breakers (Section 2.5.1 of report)

DESCRIPTION OF CONDITION:

The fault current relay protection on the five EDG output circuit breakers were not coordinated with the relays on the downstream breakers. For example voltage restraint overcurrent relay IJCV51 was incorrectly coordinated with the emergency 4160-Volt bus branch feeder circuit breaker protective relay CO-5. During a loss of offsite power with the EDG supplying power to the emergency 4160-volt bus, postulated faults, such as a high-impedance fault on a branch feeder, a sluggish motor start with an extended current draw near locked rotor current, or a continuous locked rotor condition, could cause loss of the associated 4160-volt bus. The licensee analyzed this condition, determined new settings for the IJCV51 relays on the EDG output breakers, and reset these relays during the inspection.

The licensee did not recognize the EDG circuit breaker coordination error when reviewing the "Plant Hatch-Relaying Data Document" during the Appendix R fire protection study.

REQUIREMENTS:

Criterion III of 10 CFR Part 50, Appendix B, states that design control measures shall provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

REFERENCES:

1. "Plant Hatch Relaying Data Document" (also referred to as "Units 1 and 2 Appendix R Protective Device Coordination Study - Off-site Source to Largest 600V Loads"); transmitted under cover letter dated September 13, 1985.
2. Diesel Generator Dynamic Loading Calculation S52347 (Colt/Fairbanks Morse Engineering Report MSS98511148901R, dated November 14, 1989).

## DEFICIENCY 91-202-07

FINDING TITLE: Coordination of 120-Vac and 125-Vdc Circuits (Section 2.5.2 of report)

### DESCRIPTION OF CONDITION:

The team noted various deficiencies in the coordination calculations. Generic fuse coordination studies specified approved configurations for various design conditions.

Calculation Number 87 Elect (Bechtel), Revision 3, dated January 8, 1990 had several incorrect coordinations for specific ranges of fault current between upstream breakers and downstream fuses for 120 Vac and 125 Vdc control circuits. Time current curve sheet D81, Revision 1 showed that upstream breaker Gould E4 20A had been incorrectly coordinated with Bussman fuse FNM 15A for a fault current range of over 40 amperes. The calculation showed incorrect coordination on time current curve sheets D82 for a fault of approximately 400 amperes, D83 for a fault over 400 amperes, D85 for a fault over 400 amperes, and D90 for a fault of 600 amperes.

The team noted that this calculation was used in the fuse upgrade and replacement program, and concluded that these "approved breaker/fuse configurations" may have resulted in incorrect coordination. Approximately 6000 fuses including all control room fuses, had already been reviewed in this program for 120-Vac and 125-Vdc circuits in Units 1 and 2. Although the licensee was of the opinion that the suspect combinations had never had been used the licensee agreed to review the generic fuse coordination studies and installations for incorrect coordination of breaker/fuse configurations.

### REQUIREMENT:

10 CFR Part 50, Appendix B, Criterion III, Design Control, requires design control measures to be provided for verifying the adequacy of design by performing design reviews, using alternate or simplified calculational methods, or providing a suitable testing program.

### REFERENCE:

1. Calculation titled, "Breaker/Fuse, Fuse/Fuse Coordination and Cable Auto-Ignition Curves for Fuse/Cable Combination for 120Vac and 125Vdc system," Calculation Number 87 Elect (Bechtel), Revision 3, dated January 8, 1990.

## OBSERVATION 91-202-08

**FINDING TITLE:** Discrepancies in Coordination Calculations (Section 2.5.3 of report)

**DESCRIPTION OF CONDITION:**

Various discrepancies were noted in coordination calculations for the EDS equipment making it very difficult for the team to determine if the protection on the feeder breakers to essential buses was coordinated with the protection on downstream breakers. This was because the coordination study was fragmented. For example, calculations SEN-89-010 and SEN-89-008 for specific overcurrent trip device modifications had not been integrated with other calculations. Also, Appendix R calculations only addressed Appendix R buses, and loads and were not integrated with other calculations. The team concluded that this approach of satisfying coordination for a specific modification could cause inadvertent errors in coordination.

There were instances of missing design input, guidelines, references, and assumptions. For example, results from a short circuit calculation had been used without the calculation being identified and various curves and calculation sheets were not indexed, making it difficult to determine if any sheets were missing. In addition, although a design guideline of 2,400 amperes had been established as the maximum setting on 600-volt instantaneous or short time trip devices, this guideline was not addressed in calculations.

Protective device time current "typical" curves were used for multiple applications. However, specific relays using the same typical curve did not always have the same characteristics.

The title of calculation number 85084IIP had been changed to "Aux Sys Coordination Study" from "Station Aux System Short Circuit Calculation for Relaying and Fuse Coordination Study". However, no changes had been made to the body of the calculation to transform it to a coordination study.

## DEFICIENCY 91-202-09

FINDING TITLE: Discrepancies in Mechanical Design Documentation (Section 3.1.2 of report)

There were discrepancies in the plant mechanical design documentation.

Discrepancies were found between Colt Manual SX 13147, the FSAR, and associated P&ID drawings with regard to the EDG air starting compressor setpoints and operating parameters e.g., low pressure start, high pressure cutoff, operating pressure and the air receiver pressure relief valve setting.

The seismic qualification documentation of selected components and equipment in the diesel generator support systems showed some discrepancies with regard to weld lengths on expansion tank support brackets and dimensions of supports.

There were discrepancies between the licensee's calculations for the HVAC system air flow distribution. The air compressor had been replaced, resulting in an overall lower air temperature for the battery rooms. However, The calculations had not been revised to show this lower heat load.

The original lead antimony batteries had been replaced with lead calcium batteries that had a lower hydrogen generator rate (X10) than the original batteries. However, the hydrogen generation rates in the calculations had not been revised to reflect the additional margins or time it would take to reach dangerous or explosive conditions on loss of air flow to the battery rooms.

The mechanical changes for the Hatch Unit 2 modification made under DC-88-356 were shown on the plant arrangement drawings but had not been incorporated into the P&ID and process flow drawings.

REQUIREMENTS:

10 CFR Part 50, Appendix B, Criterion III, Design Control, requires measures to be established to ensure the design basis is correctly translated into specification, drawings, procedures, and instruction.

## DEFICIENCY 91-202-10

FINDING TITLE: Plant Service Water System

DESCRIPTION OF CONDITION:

The section of plant service water (PSW) piping between the supply and return isolation valves of the 1B emergency diesel generator had a potential to trap service water between the standby pump discharge check valve 2P41-F321 and the diesel generator cooling water outlet valve 2P41-F340.

If the hot heat exchanger was shut down, the cooling fluid would be isolated by valves on both sides, the trapped cooling fluid would heat up and expand, and the internal pressure would rise, thus, increasing the possibility of a over-pressure condition.

Overpressurization of that section of the piping had the potential to impair both loops because EDG 1B was shared and could supply either Unit 1 essential bus 1F or Unit 2 essential bus 2F. The licensee committed to conducting a detailed review and revision of all appropriate station operating procedures. This revision will require the operators to maintain standby service water flow for a minimum of 1/2 hour after the EDG was secured in order to eliminate overpressure concerns.

REQUIREMENTS:

10 CFR Part 50, Appendix B, Criterion III, Design Control, requires measures to be established to ensure the design basis is correctly translated into specification, drawings, procedures, and instructions.

REFERENCES:

1. ASME Code Secton III, ND-7000.
2. Station Operating Procedure 34SV-P41-001-2S

APPENDIX B

## PERSONS CONTACTED

Southern Nuclear Company (SNC)/Georgia Power Company Personnel

*Altieer, J. N. - Project Engineer, SNC
Altizer, M. - Project Engineer, SNC
*Anderson, T. - Engineering Group Manager, Electrical, SNC
Barker, G. - Superintendent, I&C
Bennett, J. D. - Manager, Training and EP
*Branum, J. - Project Engineer, SNC
Breitenbach, K. W. - Manager, Engineering
*Brinson, Jr., L. - Engineering, Supervisor
Clair, C. - Senior Engineer, SNC
Curtis, S. - Superintendent Operations Support
*Davis, J. D. - Plant Administration Manager
*Davis, R. L. - Acting SAER Site Supervisor, SNC
*Dougherty, H. M. - Site Representative
Edge, D. L. - Manager, Nuclear Section
Fraser, O. M. - SAER Site Supervisor, SNC
*Fornel, P. E. - Manager, Maintenance
*Lewis J. - Manager, Operations
*Garner, W. F. - Hatch Project Manager, SNC
Godby, R. K. - Superintendent, Maintenance
*Goode, G. A. - Assistant General Manager
Googe, M. - Manager, Outages and Planning
*Hammonds, J. - Supervisor, Regulatory Compliance
*Heidt, J. D. - Manager Engineer and Licensing, SNC
Madison, D. - Engineering Manager, SNC
McGaha, G. D. - Design Manager, Hatch
*Robertson, Jr., J. W. - Acting Manager, Engineering Support
Rogers, W. H. - Superintendent, Chemistry
Solder, B. - Supervisor, Hatch Support, SCS
*Tipps, S. - Manager, Nuclear Safety and Compliance
Vora, A. - Engineer, Maintenance
Wells, P., Superintendent

Persons Invited by the Licensee:

*Dismukes, III, D.E. - Mechanical Engineer, Supervisor, Bechtel
*Rowe, L. - Assistant Project Manager, Bechtel
*Witte, U., - Division Manager, CYGNA

Nuclear Regulatory Commission Personnel

*Fillion, P. - Reactor Inspector, RII
*Gautam, A. S. - Team Leader, NRR
*Imbro, E. V. - Chief, Special Inspection Branch, NRC/NRR
*Leung, H. - Consultant
*Lyles, P. - Consultant

*Maggio, L. - Consultant
*Merschoff, E. W. - Deputy Director, Reactor Projects, RII
*Norkin, D. P. - Section Chief, DRIS, NRR
*Sanders, S. - Reactor Engineer, NRR
~~*Skinner, P. H. - Chief, Section 3B, RII~~
*Tran, L. N. - Reactor Engineer, NRR
*Wert, L. D. - Senior Resident Inspector, Hatch

*Denotes those attending the exit interview on July 12, 1991 at the conclusion of the inspection.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

October 7, 1991

Docket Nos. 50-321, 50-366
License Nos. DPR-57, NPF-5

OCT 14 1991

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P. O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-321/91-202 AND 50-366/91-202)

This refers to the inspection conducted by A. S. Gautam of this office on June 10 - July 12, 1991. The inspection included a review of activities authorized for your Hatch facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the report.

The report documenting this inspection was sent to you by letter dated August 22, 1991.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). We are concerned about the violation because of the examples of failure to establish appropriate design control measures.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96.511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Caudle A. Julian

Caudle A. Julian, Chief
Engineering Branch
Division of Reactor Safety

Enclosure:
Notice of Violation

cc w/encl:
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ENCLOSURE 1

NOTICE OF VIOLATION

Georgia Power Company
Hatch

Docket Nos. 50-321, 50-366
License Nos. DPR-57, NPF-5

During an NRC inspection conducted on June 10 - July 12, 1991, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1991), the violation is listed below:

10 CFR Part 50, Appendix B, Criterion III, requires that design control measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the following deficiencies were identified:

Verified [illegible] -By NRC [illegible]

a. Undervoltage protection for degraded grid voltage was not adequate to ensure that accident mitigating equipment would get sufficient voltage to perform their safety function (91-202-01).

Design Review Done in Accordance w/ methodology [illegible] Ranges Revised. Dates [illegible] Program

b. A design review had not been performed to evaluate the impact of load additions and transformer tap changes on the undervoltage protection for the electrical distribution system (91-202-02).

Verified & Checked: [illegible] Fault

c. Fault current relay protection on the five emergency diesel generator output circuit breakers was incorrectly coordinated with the fault current relay protection on the downstream breakers (91-202-06).

Verified. Checked. [illegible] for coordination.

d. For 120-Vac and 125-Vdc circuits, coordination calculations included several approved breaker/fuse configurations which may have resulted in incorrect coordination between upstream breakers and downstream fuses (91-202-07).

This is a Severity Level IV violation (Supplement 1).

Pursuant to the provisions of 10 CFR 2.201, Georgia Power Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector, Hatch within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include [for each violation]: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

FOR THE NUCLEAR REGULATORY COMMISSION

Caudle A. Julian

Caudle A. Julian, Chief
Engineering Branch
Division of Reactor Safety

Dated at Atlanta, Georgia
this 7th day of October 1991

Jeff Draxum

Georgia Power Company
40 Inverness Center Parkway
Post Office Box 1295
Birmingham, Alabama 35201
Telephone 205 877-7279

J. T. Beckham, Jr.
Vice President—Nuclear
Hatch Project

Georgia Power
*the southern electric system*

HL-1885
002371

November 6, 1991

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

PLANT HATCH - UNITS 1, 2
NRC DOCKETS 50-321, 50-366
OPERATING LICENSES DPR-57, NPF-5
RESPONSE TO NOTICE OF VIOLATION

Gentlemen:

In response to your letter of October 7, 1991 and in accordance with the provisions of 10 CFR 2.201, Georgia Power Company (GPC) is providing the enclosed response to the Notice of Violation associated with NRC Inspection Report 91-202. A copy of this response is being provided to NRC Region II for review. In the enclosure, a transcription of the NRC violation precedes GPC's response.

Should you have any questions, please contact this office.

Sincerely,

J. T. Beckham, Jr.

J. T. Beckham, Jr.

JKB/cr

Enclosure: Response to Notice of Violation

cc: (See next page.)

Georgia Power



cc: <u>Georgia Power Company</u>
Mr. H. L. Sumner, General Manager - Nuclear Plant
NORMS

<u>U.S. Nuclear Regulatory Commission, Washington, D.C.</u>
Mr. K. Jabbour, Licensing Project Manager - Hatch

<u>U.S. Nuclear Regulatory Commission, Region II</u>
Mr. S. D. Ebneter, Regional Administrator
Mr. L. D. Wert, Senior Resident Inspector - Hatch

002371

ENCLOSURE

PLANT HATCH - UNITS 1, 2
NRC DOCKETS 50-321, 50-366
OPERATING LICENSES DPR-57, NPF-5
RESPONSE TO NOTICE OF VIOLATION
NRC INSPECTION REPORT 50-321/91-202; 50-366/91-202

Violation 91-202

10 CFR Part 50, Appendix B, Criterion III, requires that design control measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to the above, the following deficiencies were identified:

a. Undervoltage protection for degraded grid voltage was not adequate to ensure that accident mitigating equipment would get sufficient voltage to perform their safety function (91-202-01).

b. A design review had not been performed to evaluate the impact of load additions and transformer tap changes on the undervoltage protection for the electrical distribution system (91-202-02).

c. Fault current relay protection on the five emergency diesel generator output circuit breakers was incorrectly coordinated with the fault current relay protection on the downstream breakers (91-202-06).

d. For 120-Vac and 125-Vdc circuits, coordination calculations included several approved breaker/fuse configurations which may have resulted in incorrect coordination between upstream breakers and downstream fuses (91-202-07).

This is a Severity Level IV violation (Supplement 1).

RESPONSE TO VIOLATION

Admission or Denial of the Violation

GPC agrees that items b, c, and d stated above are valid deficiencies and occurred as described in the Notice of Violation. However, we believe item a does not constitute a violation. The rationale for our conclusion is provided in the response.

We emphasize that design control measures consistent with the requirements of 10 CFR Part 50, Appendix B, Criterion III are in place to provide for verifying or checking the adequacy of design. As noted in the Inspection Report, the NRC inspection team reviewed the procedures, processes, and guidelines governing design control measures, plant modifications, and design calculations. The inspection team concluded the following:

1. The design evaluation review and approval processes are adequate and comprehensive.

2. The engineering design and modification control processes are well proceduralized.

3. Design changes were reviewed and approved in accordance with established quality assurance/quality control controls.

4. GPC's procedures controlling documentation records and modification work are generally complete and comprehensive.

Additionally, the NRC inspection team indicated that Plant Hatch provides a very aggressive self-assessment effort.

The four deficiencies listed as examples in the Notice of Violation are discussed below:

EXAMPLE a:

Example a is not considered a violation of NRC requirements.

The existing degraded grid protection scheme at Plant Hatch is in accordance with GPC's response to the NRC Generic Letter (GL) dated June 2, 1977 concerning staff positions for degraded grid protection of station electric distribution system voltages. The GL addressed compliance with General Design Criterion 17. In GPC's response, a range for nominal offsite line voltages, which were evaluated and shown to adequately supply the emergency loads, was established. Currently, the expected voltage range for the offsite supply is evaluated on an annual basis to include transmission system load and configuration changes since the previous study. As part of the periodic offsite source voltage study, calculations based on maximum and minimum plant and system load conditions are performed to assure acceptable voltages for emergency systems. Also, load additions to the essential buses are evaluated prior to installation under the Design Change Request (DCR) process.

GPC's methodology of using minimum and maximum acceptable voltage ranges for the offsite power supply was reviewed and approved by the NRC. Specifically, GPC's system voltage study submitted to the NRC on October 9, 1980 used the minimum expected voltage for the offsite grid in establishing the adequacy of plant voltage levels. At that time, a minimum expected offsite source operating voltage of 98 percent of 230 kV was identified and established to ensure adequate bus voltages. To accommodate higher expected transmission system operating voltages, tap changes were made for the Station Auxiliary Transformers in 1986 and 1987. The present minimum expected offsite source operating voltage is 101.3 percent of 230 kV. Using the present minimum expected source voltage, tap connections, and load configurations, the minimum expected 1E system voltages are, generally, slightly higher than the minimum voltages submitted in 1980. Consequently, the level of undervoltage protection determined to be sufficient in 1980 has been maintained.

The existing degraded grid undervoltage relay setpoints were approved by the NRC in the Safety Evaluation Report (SER) dated May 6, 1982. The SER affirmed compliance with staff positions for a second level of undervoltage protection. GPC has consistently maintained compliance with the regulatory requirements as established and approved. However, GPC and the NRC staff are presently negotiating to identify a mutually acceptable method of further improving the level of degraded grid protection at Plant Hatch.

EXAMPLE b:

Example b is considered a violation and occurred as described in the Notice of Violation.

Reason for the Violation

The violation was caused by the lack of a design document specifying 1E transformer tap settings. As a result, transformer tap changes were implemented using Maintenance Work Orders (MWOs) instead of the DCR process. Consequently, formal 10 CFR 50.59 safety evaluations were not performed. Plant personnel and architect/engineer personnel failed to realize the tap changes represented design changes.

The transformer tap changes were implemented consistent with GPC's methodology of establishing minimum and maximum ranges for offsite voltages. Although formal 10 CFR 50.59 safety evaluations were not performed, engineering studies and calculations were performed to evaluate the voltage impact of plant load additions and safety-related transformer tap changes. The current transformer tap settings were changed in accordance with the recommendations resulting from the 1986 degraded grid voltage study. Currently, this study is performed on an annual basis. The study is performed in accordance with the requirements of the NRC Generic Letter of August 8, 1979 entitled, "Adequacy of Station Electric Distribution System Voltages."

Corrective Steps Which Have Been Taken and the Results Achieved

In 1990 GPC identified the need to perform safety-related transformer tap changes as part of the DCR process. Consequently, on 2/21/91, drawings were issued to control changes to power transformer tap settings in accordance with the DCR process, thereby requiring the performance of formal 10 CFR 50.59 safety evaluations.

Corrective Steps Which Will Be Taken to Avoid Further Violations

Specific information for approximately 20 Class 1E low-voltage transformers has not been included in the new drawings. The necessary research and plant walkdowns will be performed to verify the remaining 1E transformer tap settings. Transformer inspections which do not require deenergization will be complete by 3/31/92. Examinations of transformers that require deenergization will be complete by the end of the next refueling outage for each unit. Drawings will be updated as necessary.

Date When Refueling Full Compliance Will Be Achieved

Full compliance for accessible transformer will be achieved by 3/31/92 when drawings will be issued. The remaining transformers will be included on the drawings by the next refueling outage. This will require the performance of 10 CFR 50.59 safety evaluations for future transformer tap changes.

EXAMPLE c:

Example c is considered a violation and occurred as described in the Notice of Violation.

Reason for the Violation

The violation was caused by personnel error. GPC protection engineering personnel did not sufficiently evaluate the coordination of the EDG overcurrent protection relays with the protective relays for the downstream circuit breakers. Additionally, GPC protection engineering personnel failed to identify the incorrect coordination during their review of the Appendix R Fire Protection Study which was performed in 1985. GPC personnel did not sufficiently evaluate the coordination scheme to ensure the required coordination was achieved.

As discussed during the inspection, the overcurrent relay protection on the five emergency diesel generator (EDG) output circuit breakers was functionally coordinated with the relay protection on the downstream breakers, with the exception of postulated faults such as a high impedance fault, a sluggish motor start with extended current draw near locked rotor current, or a continuous locked rotor condition on the associated 4160-V pump motors. These type scenarios are evaluated under single-failure analyses.

The single-failure criterion applicable to this issue is based on ANSI/ANS 52.1, "Nuclear Safety Criteria for the Design of Stationary Boiling Water Reactor Plants." Section 3.2.1 states:

> The single failure criterion requires that the plant be capable of achieving (1) emergency core reactivity control, (2) emergency core and containment heat removal and (3) containment isolation, integrity, and atmospheric cleanup given an initiating occurrence plus an independent single failure of a nuclear safety related component in any one of the systems required to support directly or indirectly these three nuclear safety functions (i.e. only one single failure need to be assumed in the plant nuclear safety related equipment for any initiating occurrence).

ANSI/ANS 52.1 is related to the specific question as follows:

For a given initiating occurrence, GPC is required to ensure no single equipment failure will prevent adequate core cooling or adversely affect containment integrity. The failure is not specifically stated; therefore, the failure of any single piece of equipment must be considered credible. For Plant Hatch, one of the limiting single failures is the total loss of an EDG. The hypothetical loss of an EDG can be from any cause. An EDG failure may be initiated by several different sources; for example, from a start signal failure or a fault on the load side of a 4-kV breaker, or other component failures.

The loss of an EDG is an analyzed event. All Appendix K requirements are satisfied, and containment integrity is not violated. The key issue for single failure is that it may occur prior to, during (simultaneously), or subsequent to the initiating (accident) event. The scenario must be analyzed for the most severe chronological occurrence of events so the plant successfully achieves mitigation of the accident.

While the loss of an EDG due to less than fully adequate breaker coordination is an undesirable event, GPC maintains that such a scenario is within the licensing basis of the plant.

Corrective Steps Which Have Been Taken and the Results Achieved

Design Change Requests 91-124 and 91-125 were implemented on 7/12/91 to revise the settings on the diesel generator output breakers to correctly coordinate the protective devices.

Corrective Steps Which Will Be Taken to Avoid Further Violations

No further corrective actions are required.

Date When Full Compliance Will Be Achieved

Full compliance was achieved on 7/12/91 when DCRs 91-124 and 91-125 were implemented.

EXAMPLE d:

Example d is considered a violation and occurred as described in the Notice of Violation.

Reason for the Violation

The violation was caused by personnel error. Electrical calculation No. 87 (Bechtel), Revision 3, dated January 8, 1990, identifies various acceptable configurations between existing upstream circuit breakers and downstream fuses for 120-Vac and 125-Vdc control circuits. Although no use of this calculation to select new fuse/breaker combinations is believed to exist, the intended us of the coordination tables was not adequately defined, and could have been misinterpreted. This calculation is not a basis for selecting fuse/breaker combinations in circuits where coordination is mandatory (i.e., Appendix R).

Corrective Steps Which Have Been Taken and the Results Achieved

Electrical calculation No. 87 has been revised to clearly state its scope and purpose. The revision ensures that further reviews, if required, will be performed when undertaking coordination studies using this calculation.

Additionally, a review was performed during the inspection and it is believed that the area of concern (overlapping of trip curves at relatively high fault levels) does not apply to any actual plant circuits.

RESPONSE TO NOTICE OF VIOLATION
NRC INSPECTION REPORT 50-321/91-202; 50-366/91-202

Corrective Steps Which Will Be Taken to Avoid Further Violations

A review of the calculation will be performed to ensure it did not result in misapplications which cause an inappropriate level of coordination. This action will be complete by 3/31/92. Appropriate A/E personnel have been counseled regarding the need for correctly translating design information.

Date When Full Compliance Will Be Achieved

Full compliance was achieved on 10/30/91 when Electrical Calculation No. 87 was revised to more clearly state its scope and purpose.

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

| | | |
|---|---|---|
| I. | INTRODUCTION | S. J. BETHAY |
| II. | BACKGROUND AND CURRENT STATUS | S. J. BETHAY |
| III. | OFFSITE POWER SYSTEM | M. B. MILLER |
| IV. | OPTIONS CONSIDERED | T. O. ANDERSON |
| V. | SUMMARY | J. D. HEIDT |
| VI. | OPEN DISCUSSION | |

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992


SUMMARY

I. GPC'S SOLUTION INTEGRATES THE REQUIREMENTS FOR ELECTRICAL DESIGN, PLANT OPERATIONS AND SYSTEM OPERATIONS.

II. THE METHODS IN PLACE PROVIDE AN ADEQUATE LEVEL OF SAFETY, AND IN SOME SCENARIOS, A HIGHER LEVEL OF SAFETY WHEN COMPARED TO AUTOMATIC CONTROLS.

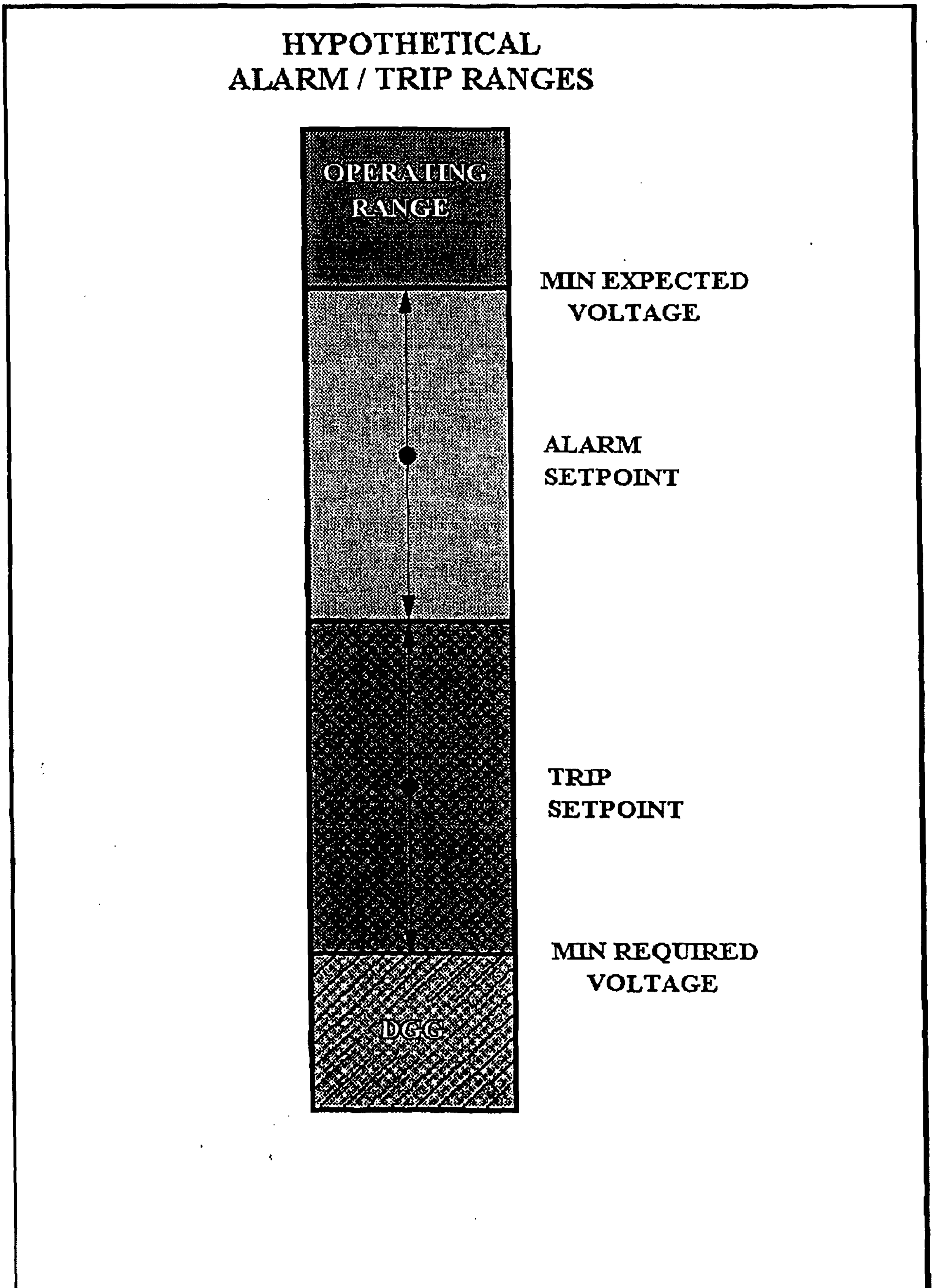
- RELIABILITY OF THE SOUTHERN ELECTRIC SYSTEM
- SOUTHERN COMPANY SYSTEM CONTROL POLICIES AND PROCEDURES
- $10^{-8}$ PROBABILITY OF DEGRADED VOLTAGE CONDITIONS (<101.3%)
- AN ORDERLY, FAST SHUTDOWN IS PREFERABLE TO AN AUTOMATIC OR SELF INDUCED REACTOR ISOLATION TRANSIENT
- ADVERSE SYSTEM IMPACT FROM AUTOMATIC DISCONNECT
- FURTHER ENHANCEMENTS ARE NOT COST BENEFICIAL

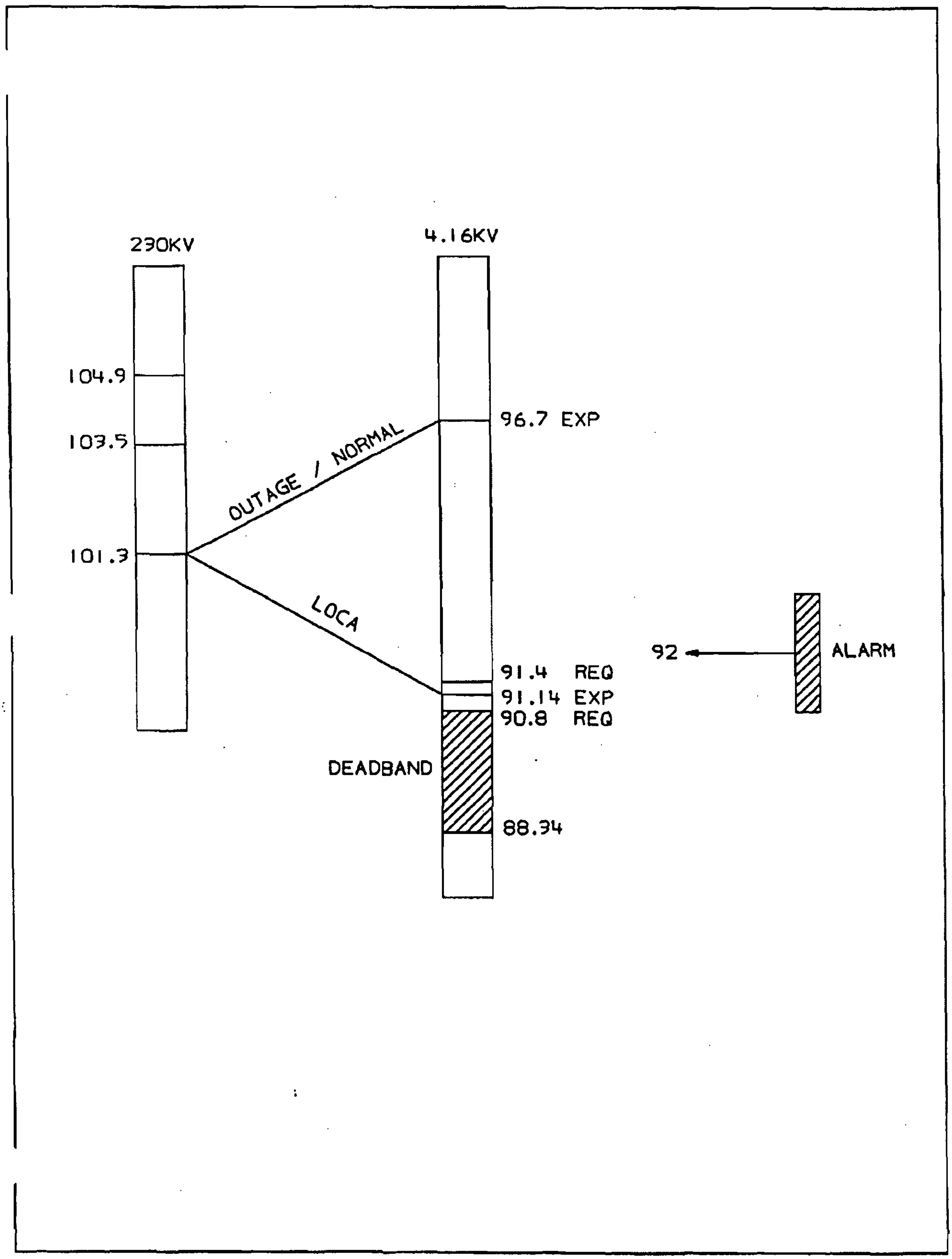
# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

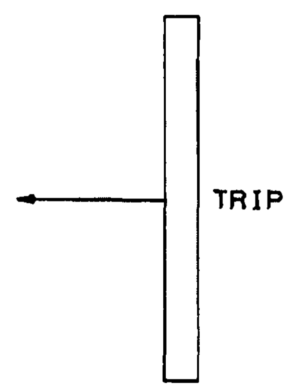
<u>ISSUE SUMMARY</u>

I. DURING SUSTAINED DEGRADED GRID CONDITIONS AT OR SLIGHTLY ABOVE THE CURRENT SETPOINT, THE UNDERVOLTAGE PROTECTION WAS NOT CONSIDERED ADEQUATE TO ENSURE SAFETY-RELATED EQUIPMENT AT 600 VOLTS AND BELOW WOULD BE SUPPLIED WITH ADEQUATE VOLTAGE.

- LOCA ACCIDENT CONDITIONS CONCURRENT WITH A DEGRADED GRID.


HYPOTHETICAL
ALARM / TRIP RANGES
OPERATING
RANGE
MIN EXPECTED
VOLTAGE
ALARM
SETPOINT
TRIP
SETPOINT
MIN REQUIRED
VOLTAGE
DGG


230KV
4.16KV
104.9
103.5
101.3
OUTAGE / NORMAL
LOCA
96.7 EXP
91.4 REQ
91.14 EXP
90.8 REQ
DEADBAND
88.34
92
ALARM


TRIP

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

## GPC OBJECTIVES

I. ENSURE THE PLANT IS ADEQUATELY PROTECTED FROM UNDERVOLTAGE CONDITIONS.

- ASSESS THE LEVEL OF SAFETY PROVIDED BY THE CURRENT SYSTEM
- IDENTIFY AVAILABLE OPTIONS
- DETERMINE IF IMPROVEMENTS ARE FEASIBLE

II. ENSURE OFFSITE POWER IS PRESERVED AS THE PREFERRED SOURCE.

III. DEVELOP AN INTEGRATED APPROACH CONSIDERING THE ELECTRICAL DESIGN REQUIREMENTS, SYSTEM OPERATION AND PLANT OPERATION.

IV. AN UNDERVOLTAGE RELAY SETPOINT WITHIN THE NORMAL SYSTEM OPERATING RANGE IS UNACCEPTABLE.

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

GPC OBJECTIVES (CONTINUED)

V. AN ORDERLY, FAST REACTOR SHUTDOWN IS PREFERABLE TO AN AUTOMATIC ISOLATION OR SELF INDUCED REACTOR ISOLATION TRANSIENT WITHOUT OFFSITE POWER.

- SYSTEM OPERATORS SHOULD BE ALLOWED TO QUICKLY MITIGATE A DEGRADED GRID TRANSIENT TO AVOID AN UNNECESSARY ISOLATION TRANSIENT AND A FURTHER CHALLENGE TO GRID STABILITY.

- SYSTEM OPERATIONS SHOULD ASSESS THE CHALLENGE TO THE GRID AND DETERMINE IF QUALITY OFFSITE POWER CAN BE MAINTAINED.

VI. ENSURE RESOLUTION DOES NOT RESULT IN AN ACTUAL DECREASE IN OVERALL SAFETY.

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

## CRITERIA

I. RISKS ASSOCIATED WITH AN AUTOMATIC SHUTDOWN MUST BE BALANCED WITH THE RISKS ASSOCIATED WITH CONTINUED OPERATION.

II. RISKS ARE ASSIGNED AS A FUNCTION OF:

- THE RELIABILITY OF THE SOUTHERN ELECTRIC SYSTEM'S GRID VS. RELIABILITY OF ONSITE POWER
- THE SOUTHERN ELECTRIC SYSTEM'S GRID MONITORING AND SINGLE FAILURE ANALYSIS CAPABILITIES VS. SETPOINT CONTROLS
- THE EXTREMELY LOW PROBABILITY OF DEGRADED VOLTAGE AT PLANT HATCH VS. THE POSSIBILITY OF SPURIOUS REACTOR ISOLATION TRANSIENTS ON THE PLANT
- THE PROBABILITY OF OFFSITE VOLTAGE FALLING BELOW 101.3% IS $4.3 \times 10^{-8}$
- THE ANTICIPATED DURATION OF A DEGRADED GRID CONDITION
- THE POTENTIAL EFFECT OF BRIEF DEGRADED VOLTAGE ON PLANT EQUIPMENT VS. THE EFFECT FROM AN ISOLATION TRANSIENT WITH 3 BUSSES AVAILABLE ON ONE UNIT AND 2 BUSSES ON THE OTHER
- THE SYSTEM IMPACT OF SEPARATING 1600MW FROM A DEGRADED GRID

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

## ACTIONS COMPLETED

I. HARDWARE AND SETPOINT CHANGES HAVE BEEN INVESTIGATED.

II. WORKED WITH SYSTEM OPERATIONS TO GAIN AN UNDERSTANDING OF:

- THE GRID MONITORING AND SINGLE FAILURE ANALYSIS CAPABILITIES
- SYSTEM OPERATING PROCEDURES THAT ENSURE ADEQUATE VOLTAGE IS MAINTAINED
- THE SYSTEM CONDITIONS WHICH WOULD HAVE TO OCCUR TO PRODUCE DEGRADED VOLTAGE AT PLANT HATCH

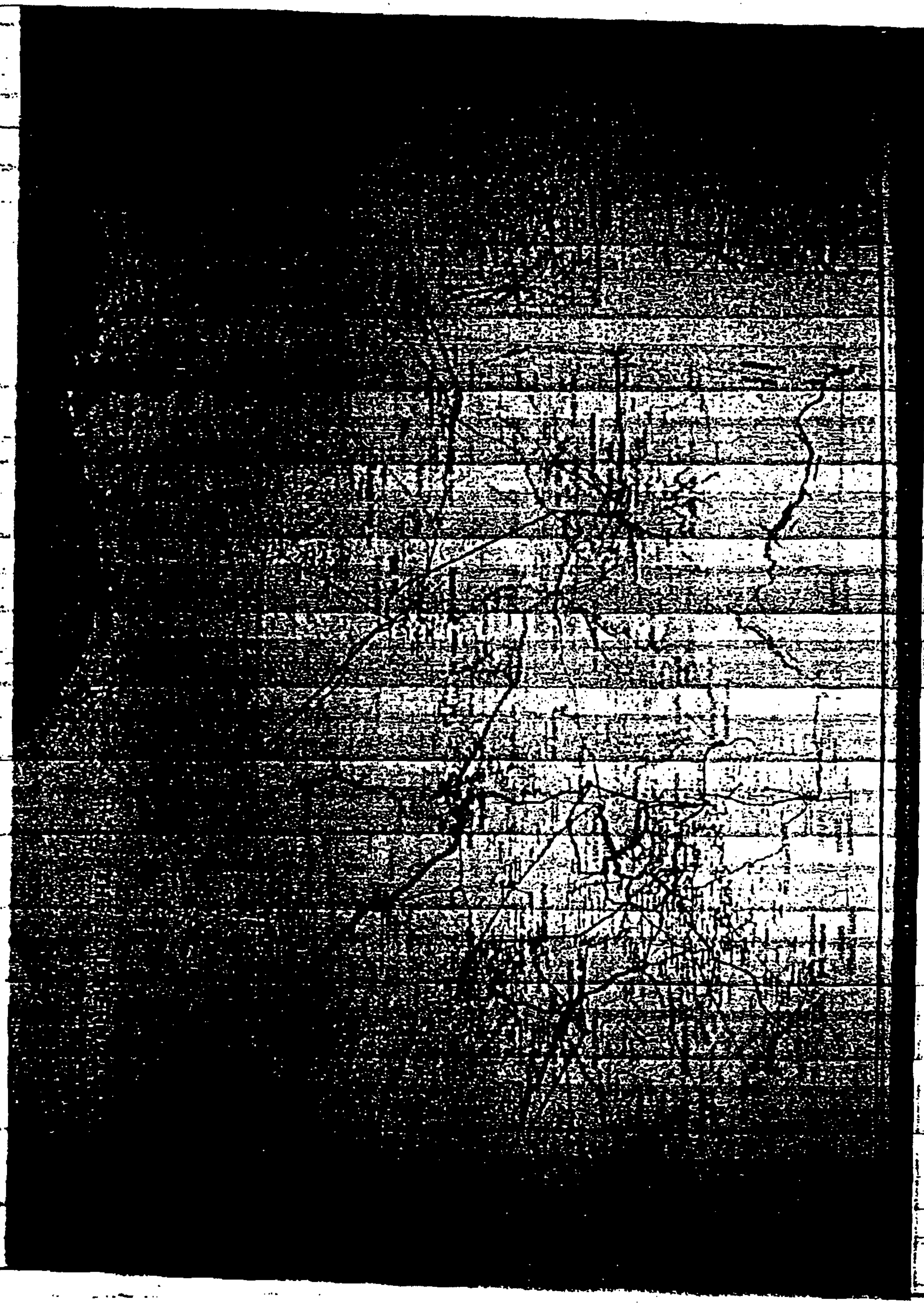
III. INSTALL ANTICIPATORY ALARMS.

IV. FORMALIZED ANTICIPATORY ACTION - BOTH ONSITE AND OFFSITE.

V. FORMALIZED COMMUNICATIONS WITH SYSTEM OPERATIONS.

VI. IMPLEMENTED AN OPERATING ORDER TO ENSURE THE REACTOR IS QUICKLY BROUGHT TO A CONDITION OF GREATER SAFETY.

- PROVIDES ACTIONS CONSISTENT WITH TECHNICAL SPECIFICATIONS ACTIONS FOR FAILURE OF ALL DIESEL GENERATORS

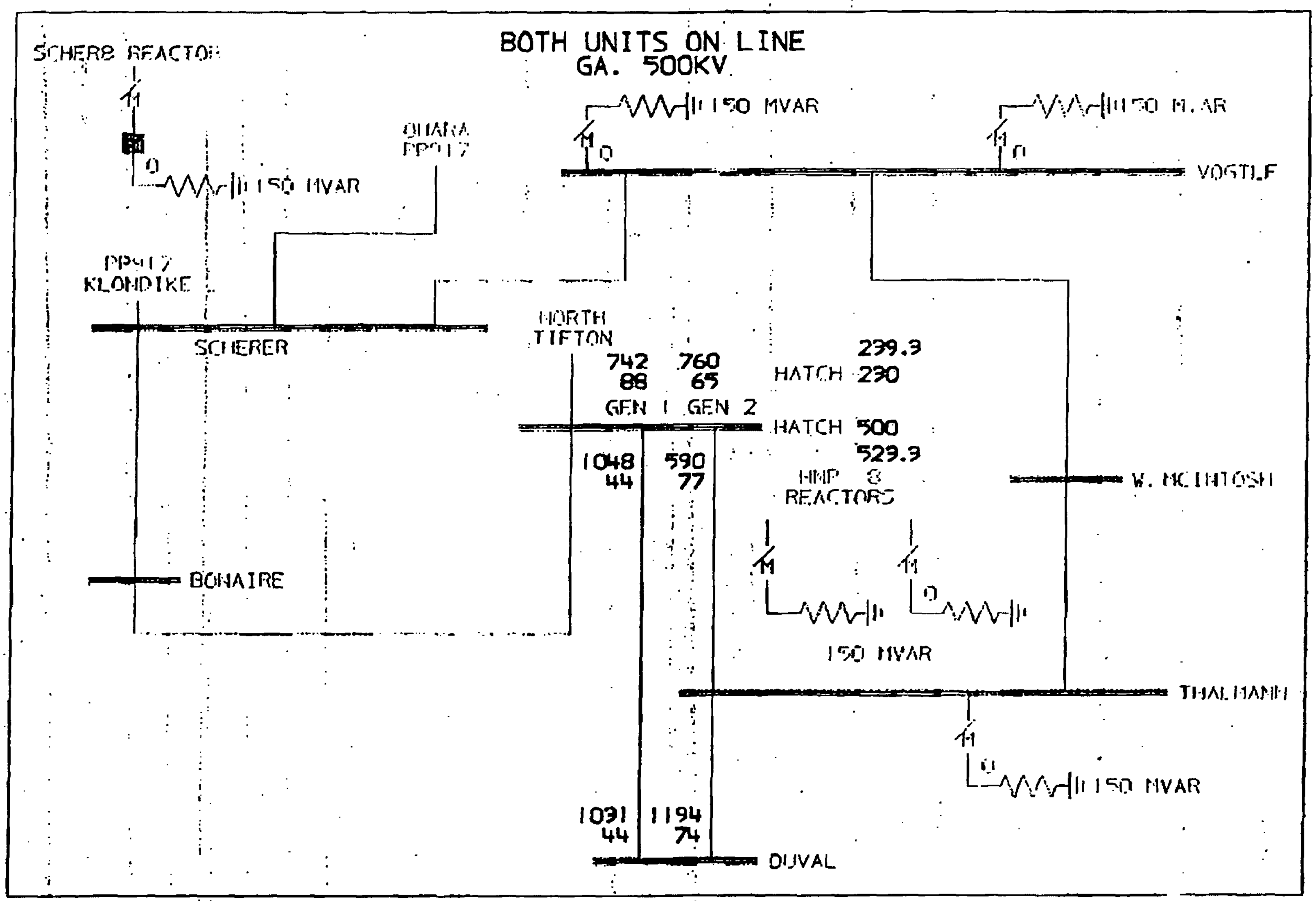


# THE SOUTHERN ELECTRIC SYSTEM ( SES )

- 5 OPERATING COMPANIES
  ALABAMA POWER
  GEORGIA POWER
  GULF POWER
  MISSISSIPPI POWER
  SAVANNAH ELECTRIC
- TOTAL GENERATION
- HATCH'S IMPACT ON SYSTEM

# SOUTHERN ELECTRIC SYSTEM (SES) SECURITY

- OPERATION CENTERS
- ON LINE COMPUTERIZED LIBRARY OF REGIONAL AND SUBSTATION SINGLE LINES
- CONTINUOUS MONITORING AND CONTINGENCY ANALYSIS

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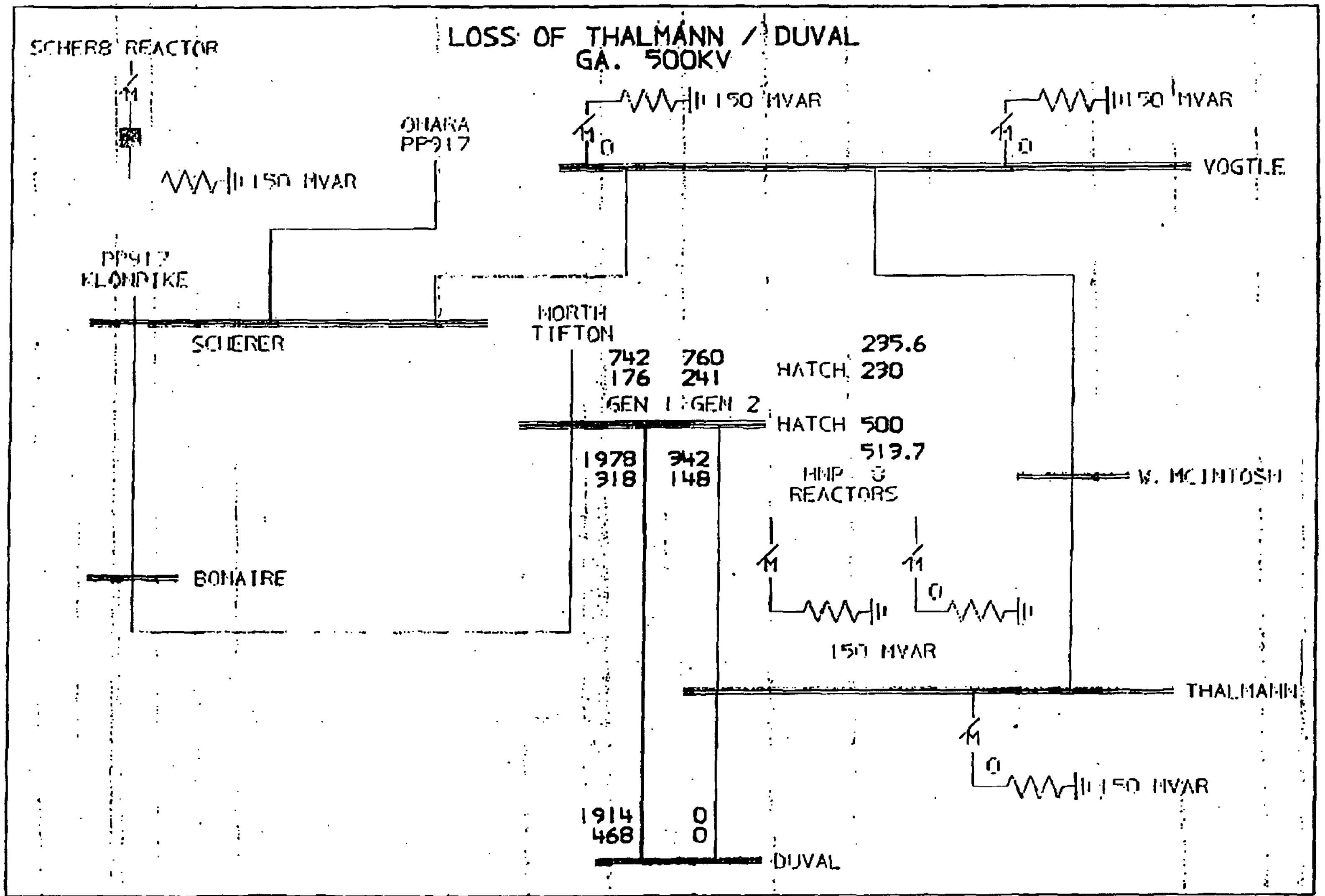

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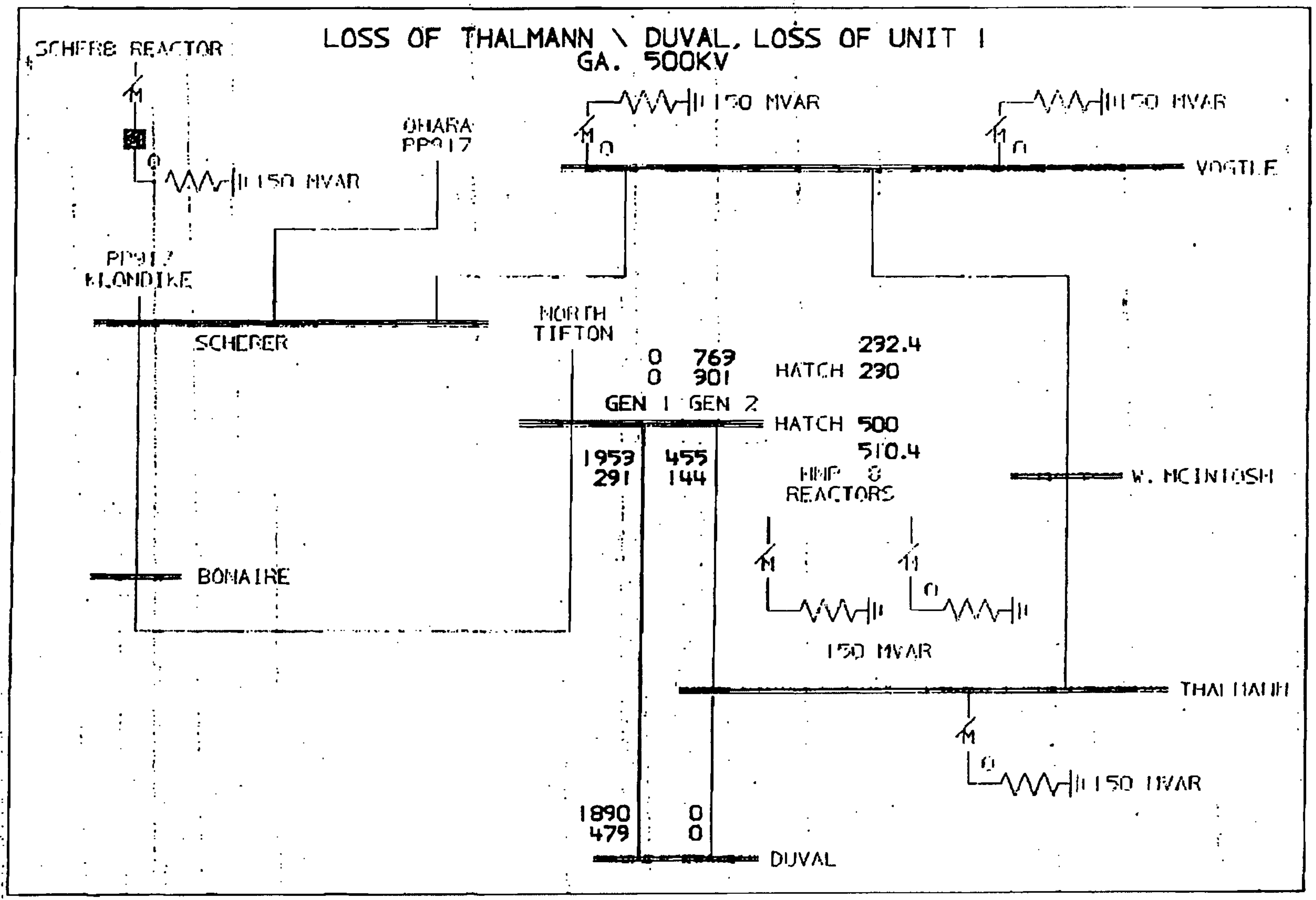


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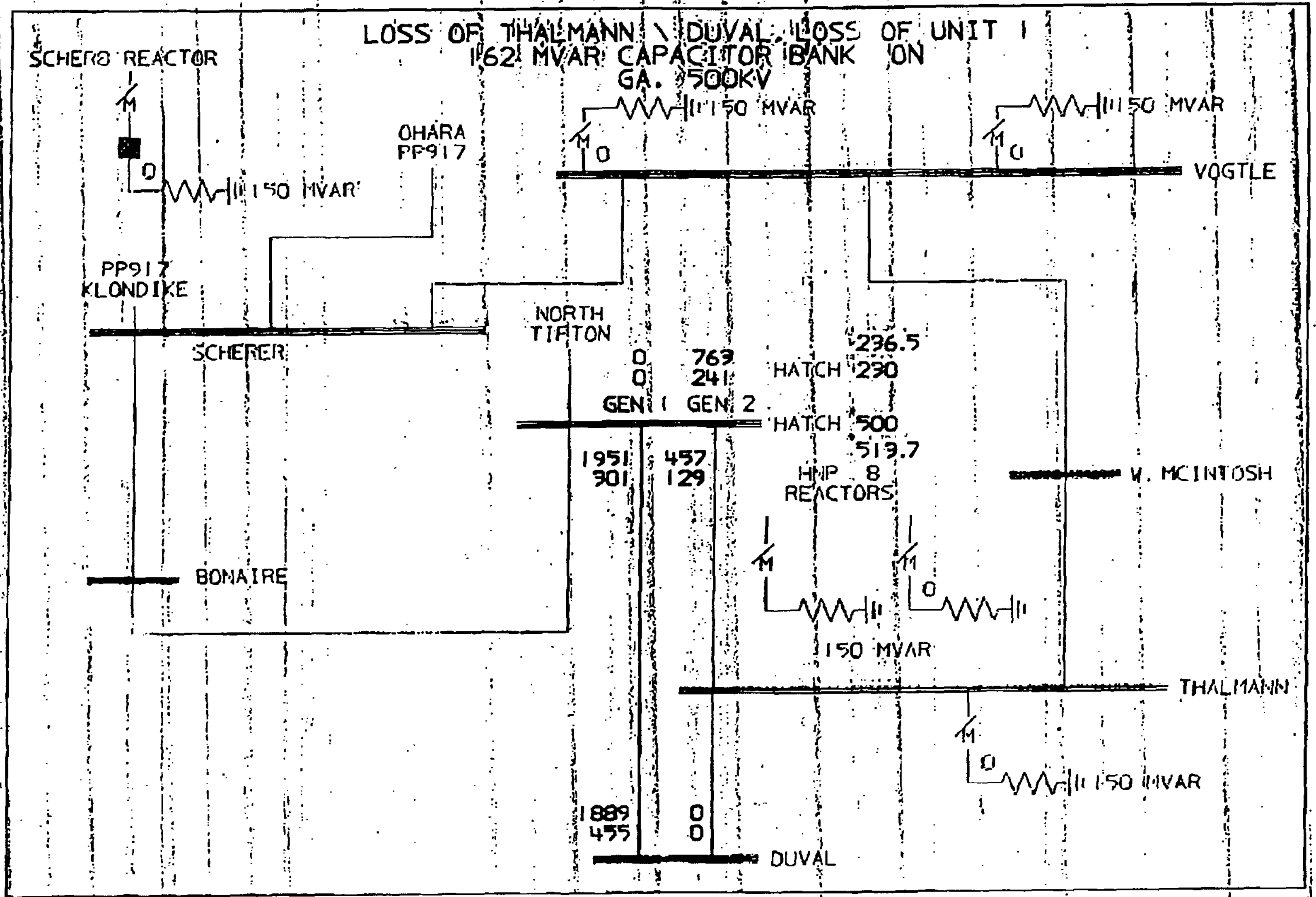


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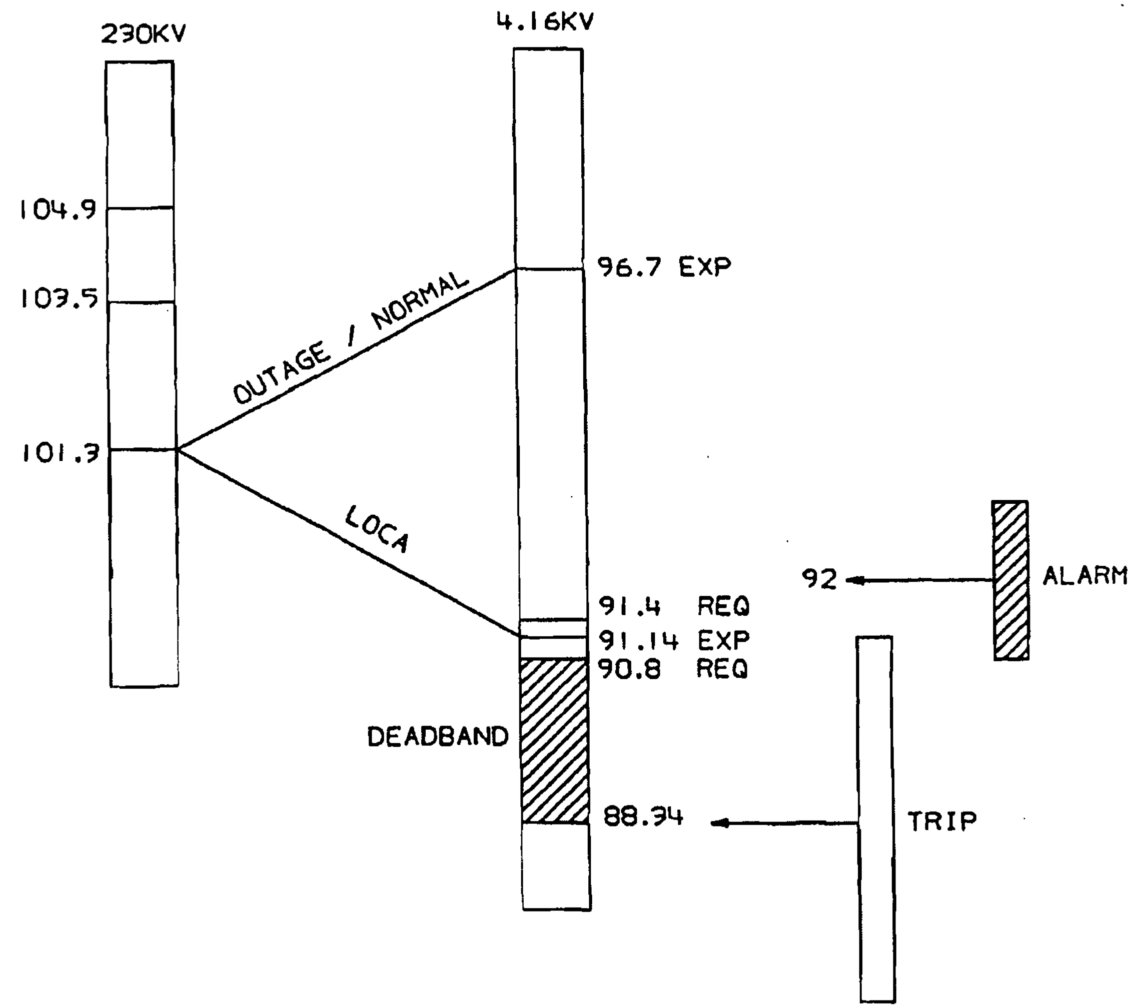
# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

## IF 230KV SYSTEM FAILS BELOW 101.3%

- RECEIVE LOW VOLTAGE ALARM
- NOTIFY CONTROL ROOM AT PLANT HATCH
- PUT CAPACITOR BANKS ON
- TURN SHUNT REACTORS OFF
- PUT COMBUSTION TURBINES (McMANUS) IN SERVICE
- BRING OUT OF SERVICE ELEMENTS BACK TO SERVICE
- REDUCE LOAD

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992

| CONCEPTUAL MODIFICATIONS | APPROXIMATE COST |
|---|---|
| I. TAP CHANGES | $ 250,000 |
| II. NEW RELAYS, CABLE AND / OR EQUIPMENT CHANGE OUT | $ 500,000 - $1 MILLION |
| III. NEW LOAD SHED / BUS TRANSFER SCHEMES | $ 1 - 2 MILLION |
| IV. RE ANALYSIS OF EXISTING LOAD AT LOWER VOLTAGE | $ 1 - 2 MILLION |
| V. NEW MAJOR EQUIPMENT | $ 10 MILLION |



230KV
4.16KV
104.9
103.5
101.3
OUTAGE / NORMAL
LOCA
96.7 EXP
91.4 REQ
91.14 EXP
90.8 REQ
DEADBAND
88.34
92
ALARM
TRIP

# GEORGIA POWER COMPANY
# PLANT E. I. HATCH
# DEGRADED GRID ISSUES
# NOVEMBER 16, 1992


## SUMMARY

I. GPC REQUESTS NRC APPROVAL OF ADMINISTRATIVE IMPLEMENTATION OF BRANCH TECHNICAL POSITION PSB-1.

II. GPC'S SOLUTION INTEGRATES THE REQUIREMENTS FOR ELECTRICAL DESIGN, PLANT OPERATIONS AND SYSTEM OPERATIONS.

III. THE METHODS IN PLACE PROVIDE AN ADEQUATE LEVEL OF SAFETY, AND IN SOME SCENARIOS, A HIGHER LEVEL OF SAFETY WHEN COMPARED TO AUTOMATIC CONTROLS.

- RELIABILITY OF THE SOUTHERN ELECTRIC SYSTEM
- SOUTHERN COMPANY SYSTEM CONTROL POLICIES AND PROCEDURES
- $10^{-8}$ PROBABILITY OF DEGRADED VOLTAGE CONDITIONS (<101.3%)
- AN ORDERLY, FAST SHUTDOWN IS PREFERABLE TO AN AUTOMATIC OR SELF INDUCED REACTOR ISOLATION TRANSIENT
- ADVERSE SYSTEM IMPACT FROM AUTOMATIC DISCONNECT

IV. FURTHER ENHANCEMENTS ARE NOT COST BENEFICIAL

Georgia Power Company
40 Inverness Center Parkway
Post Office Box 1295
Birmingham, Alabama 35201
Telephone 205 877-7279

9-3148H

File

Georgia Power
the southern electric system

J. T. Beckham, Jr.
Vice President - Nuclear
Hatch Project

November 22, 1993

Docket Nos. 50-321
50-366

HL-4440

Tac No. 80948

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant
Degraded Grid Protection

Gentlemen:

On previous occasions, Georgia Power Company (GPC) representatives and the Nuclear Regulatory Commission (NRC) staff have held meetings and telephone conference calls to discuss the performance and protection of safety-related equipment at the Edwin I. Hatch Nuclear Plant during postulated degraded grid voltage conditions. The degraded grid protection issue resulted from an electrical distribution system functional inspection which was completed on July 12, 1991.

During these meetings and conference calls, GPC discussed the objectives, criteria, and actions taken to resolve the degraded grid issue at Plant Hatch. GPC has assessed the level of safety provided by the current system and investigated options and potential modifications to upgrade the existing system. As a result, GPC has determined that the existing degraded grid protection provides adequate protection and is in accordance with the provisions of an NRC Safety Evaluation Report issued on May 6, 1982. Additionally, the degraded grid protection has been augmented by the installation of anticipatory alarms and an abnormal operating procedure. Consequently, the extensive plant modifications required to eliminate the narrow voltage deadband are unnecessary and unwarranted. Modifying the plant in this manner is unnecessary as there is no discernible increase in the protection of the health and safety of the public.

As described in the enclosure, GPC's analysis of the degraded grid protection system determined that the evaluation requires consideration of several inputs. The principal inputs involved are the electrical requirements of safety-related equipment, the reliability of the offsite power supply, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, and the extremely low probability of a sustained degraded grid concurrent with a loss of coolant accident (LOCA).

G~~orgia Power

U.S. Nuclear Regulatory Commission
November 22, 1993



Because of the offsite system monitoring, contingency analysis, and transmission system design and operation, the occurrence of a sustained degraded grid condition requiring disconnect, concurrent with a LOCA, is not considered a credible event. Additionally, the existing narrow range between the minimum expected voltage and the voltage required for LOCA loads is insufficient to allow an increase in the undervoltage relay setpoints. Consequently, an increase in the undervoltage relay setpoints would likely result in an unnecessary and unwanted disconnect from offsite power during a LOCA. The possibility of spurious disconnects would also be increased. In order to increase the available range between the minimum expected and minimum required voltage, a large investment in extensive plant modifications would be required. Also, replacing the existing CV-7 inverse time relays with discrete time relays at the existing setpoint would not resolve the deadband issue. Given the adequate level of safety provided by the existing system, GPC does not consider such expenditures to be warranted or necessary. Consequently, GPC does not consider further actions to be necessary.

The enclosure provides additional details regarding GPC's evaluation and formal documentation of the positions expressed by GPC in discussions with the NRC staff. Upon review, GPC is requesting NRC staff concurrence with these actions as representing closure for the degraded grid issue at Plant Hatch.

Sincerely,

J. T. Beckham, Jr.

JKB/cr
004440

Enclosure: Degraded Grid Voltage Protection

cc: (See next page.)

cc: *Georgia Power Company*
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NORMS

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Enclosure

Edwin I. Hatch Nuclear Plant
Degraded Grid Voltage Protection

## Background

The existing degraded grid undervoltage protection system and setpoints were established and approved in response to a Nuclear Regulatory Commission (NRC) generic letter issued on June 2, 1977. During the Summer 1991 Electrical Distribution System Functional Inspection at Plant Hatch, the NRC inspection team questioned whether, under postulated degraded grid conditions, the setpoints of the undervoltage relays on the 4160 volt safety-related buses were too low to prevent the voltage on the 600 volt and 208 volt buses from dropping below minimum required voltages prior to disconnecting from the offsite power system. In response to this issue, Georgia Power Company (GPC) implemented an Operating Order as an interim measure. As a result of subsequent discussions with the NRC staff, one permanent modification to the degraded grid undervoltage protection system, as established in 1982, has been implemented to augment the protection provided. This modification installed an anticipatory alarm to alert plant operators of marginal voltages and augments the existing transmission system voltage monitoring scheme. Additionally, the provisions of the operating order have been incorporated into a permanent plant procedure.

## Origin of the Issue

The requirements for undervoltage relay protection originated as the result of an event at Northeast Utilities' Millstone Unit 2. On July 5, 1976, several 480 volt motors failed to start following a trip of Millstone Unit 2. The failure to start was the result of blown control power fuses on the individual motor controllers. An investigation at Millstone showed that the offsite power voltage dropped approximately 5 percent from 352 Kv to 333 Kv subsequent to the trip of the Millstone unit. The voltage drop reduced the control power and voltage within the individual 480 volt controllers to a voltage which was insufficient to actuate the contactors. As a result, the control power fuses were blown when the 480 volt motors were signaled to start.

At the time, Millstone's undervoltage protection consisted of only loss of offsite power undervoltage relays to separate the plant from the grid and initiate the onsite power sources. Millstone's initial corrective action was to raise the setpoint of these relays. However, this action was later considered inappropriate when the voltage dropped below the setpoint during starting of a large circulating water pump and de-energized the emergency buses.

GPC provided an initial response on July 22, 1977, and additional information and Technical Specifications changes on October 9, 1980 and May 21, 1981. GPC submitted modified Technical Specifications changes on October 2, 1981 and December 2, 1981. Additional information is contained in GPC's submittals dated September 17, 1976; January 12, 1982; and January 26, 1982. Also, a brief description of the electrical distribution system for Plant Hatch is provided in Attachment 1.

GPC's methodology in addressing the NRC positions used the maximum plant loading conditions to determine the minimum expected voltage from the offsite power supply. At the time, the minimum expected value was 98 percent of 230 kV. Periodic, later evaluations have been performed to revise the minimum expected value as needed. GPC recalibrated one set of undervoltage relays to initiate transfers of the offsite power source to protect against a degraded grid. The Technical Specifications amendment request pertaining to degraded voltage protection was reviewed by the NRC staff and approved by letter dated May 6, 1982.

EDSFI and Degraded Voltage Protection Reevaluation

An electrical distribution system functional inspection (EDSFI) was performed at Plant Hatch from June 10 through July 12, 1991. The NRC team determined that during a postulated design basis loss of coolant accident concurrent with the 4160 volt bus voltage in a narrow 3% band between 91 percent (3786 volts) and 88.34 percent (3675 volts), certain class 1E loads at voltage levels of 600 volts and below may not receive sufficient voltage. The NRC EDSFI team did not agree with GPC's methodology which established a minimum expected value for offsite power to ensure adequate voltage and concluded that the automatic degraded grid protection was not adequate.

By letter dated October 7, 1991, the NRC issued a Level IV violation stating that the automatic undervoltage protection for degraded grid voltage was not adequate to ensure that accident mitigating equipment would receive sufficient voltage to perform their safety function. By letter dated November 6, 1991, GPC denied the violation associated with degraded grid protection. GPC concluded that a violation of NRC requirements did not exist based on the following:

1. The existing degraded grid protection scheme at Plant Hatch is in accordance with GPC's response to the NRC Generic Letter dated June 2, 1977. As part of GPC's response to the NRC staff positions concerning degraded grid protection, a range for offsite voltage was established and shown to adequately supply emergency loads.

2. Compliance with the method of using the minimum expected voltage for the offsite grid in establishing the adequacy of plant voltage levels has been maintained. In the original voltage study submitted to the NRC on October 9, 1980, a minimum offsite source operating voltage of 98 percent of 230 kV was expected. At that time, the tap setting for transformer "D" was 1.0 p.u. (i.e., for a system voltage of 98% of 230 kV the corresponding voltage on the 4160 V buses for no-load conditions was 98% of 4160 V). The current minimum expected value is 101.3 percent of 230 kV. However, the increase was not a result of load additions to the plant. Rather, the change was necessary to accommodate higher expected transmission system operating voltages. Consequently, tap changes were made for the startup transformers in 1986 and 1987. Presently, the tap setting for transformer "D" is 1.025 p.u. (i.e., for a system voltage of 101.3% of 230 kV the corresponding voltage on the 4160 V bus for no-load conditions is 98.8% of 4160 V). Using the present minimum expected source voltage, tap connections, and load configurations, the expected 1E system voltages are, generally, slightly higher than the bus voltages submitted in 1980.

3. The existing degraded grid undervoltage relay setpoints were approved in the Safety Evaluation Report dated May 6, 1982. The SER affirmed compliance with staff positions for a second level of undervoltage protection.

4. Given the elapsed time since the original submittal in 1980, GPC has reevaluated the adequacy of the degraded grid protection at Plant Hatch. GPC's objectives were to assess the level of safety provided by the current system, investigate available options, and determine if improvements are feasible. GPC has concluded that the existing protection is adequate, raising the undervoltage relay setpoints is not feasible, and replacing the CV-7 relays with discrete time relays would represent a marginal to safety improvement. This conclusion is based on the following:

   A. The event at Millstone was significant in that a plant trip and the corresponding loss of electrical generation resulted in a sustained degraded offsite power supply without operator awareness of the event. However, significant differences exist between Plant Hatch and Millstone. The Southern electric system employs state-of-the art monitoring and contingency analysis systems for the electric grid on a real time basis. System operators ensure that adequate voltage is provided and the contingency analysis feature allows system operation to predict adverse affects from postulated system failures. Based on the contingency analysis results, system operators configure the offsite power system such that a worst case postulated failure can occur without adversely affecting the minimum required voltage. If the 230 kV system were to fall below the current minimum expected value of 101.3 percent, the switchyard design and offsite system design allows system operators to quickly mitigate a dynamic voltage excursion. Such an event actually occurred in March 1993 which is discussed later. This design allows the following actions to occur if the system were to fall below 101.3 percent. These following actions should be performed by system operators within approximately 10 minutes.

- System operators receive low voltage alarm.
- System operators notify the control room at Plant Hatch.
- The 162 MVAR capacitor bank on the 230 kV switchyard is switched on (if off).
- The 150 MVAR shunt reactors on the 500 kV line are turned off (if on).
- Capacitor banks in the surrounding area are turned on (if off).
- Combustion turbines at Plant McManus are placed in service.

These actions are normally capable of improving the 230 kV voltage by approximately 2 to 4 percent. If these actions are not sufficient, system operators will take the following actions:

- Out of service elements are brought back on line.
- System load (external or internal) is reduced.

Consequently, based on the system monitoring capabilities, contingency analysis capabilities, operation of the system such that a postulated worse case failure will not impact the offsite voltage below the minimum required, and the ability for system operators to quickly restore a dynamic voltage excursion; the event at Millstone is not considered applicable to Plant Hatch.

B. Because of the offsite system monitoring capabilities and design, a sustained degraded grid does not represent the most probable event. Rather, a dynamic voltage excursion lasting less than 10 minutes is more likely. Consequently, the degraded voltage protection at Plant Hatch provides adequate assurance of plant safety for this type of event. For a dynamic voltage excursion, GPC has determined that disconnecting both units from the offsite power supply and introducing dual unit scrams and reactor isolation transients through automatic undervoltage relays would be adverse to safety. GPC initially issued an Operating Order which identified specific actions to be taken if the system operators are in jeopardy of not maintaining voltages within the required operating range. The actions consist of restoring any inoperable emergency diesel generators (EDGs), limiting maintenance or surveillance of important onsite electrical equipment, closely monitoring voltage levels on the six 4160 volt safety-related busses, and informing plant management. The Operating Order also specified actions to be performed if the 4160 volt essential busses fall below the minimum acceptable voltage. These actions include initiation of a one hour Limiting Condition of Operation (LCO) to restore safety-related bus voltages, notification of management, and an orderly plant shutdown if voltage is not restored. The actions specified in the operating order have been incorporated into abnormal operating procedure 34AB-S11-001-OS, "Operation With Degraded System Voltage." Operators receive training relative to the actions specified in the procedure through the normal operator training and operator requalification training on abnormal operating procedures.

This alternate method allows system operators to quickly restore a degraded grid to avoid an unnecessary isolation transient, further degradation of the offsite power supply to the plant, adverse impacts to neighboring utilities and other interconnected plants, when the offsite power is undergoing a temporary voltage excursion and is not in actual jeopardy.

An event as described above actually occurred at Plant Hatch on Sunday, March 14, 1993. During that weekend, record snow accumulations, along with high winds were occurring within the Southern Electric System. This was resulting in significant outages due to failures of local distribution networks. During this time, specifically on March 14, 1993 at 10:04 a.m., Florida Power Corporation's Crystal River Unit 2 tripped. The loss of generation within the Florida grid caused a dynamic voltage excursion within the Southern

Electric grid. The Hatch switchyard voltage dropped to 215 kV (93 percent) in one second and stabilized at 223 kV (97 percent) in approximately 6 seconds. At 10:05 a.m., with the Hatch switchyard voltage at 223 kV and recovering, Crystal River Unit 4 tripped. The second loss of generation resulted in a voltage drop to 218 kV (95 percent). At 10:06 a.m., the Southern Company Power Control Center contacted the Florida Power Control Center to assess the conditions causing the voltage excursion and the condition of the Florida grid. Southern Company was informed of the situation and confirmed that the Florida system was bringing up generation to stabilize the power flow from the Southern System to Florida's grid. Approximately 1.5 minutes after Crystal River Unit 4 tripped, the Hatch capacitors were manually closed and the voltage began a steady recovery. The combined voltage excursion from both the Crystal River Unit 2 and Unit 4 trips lasted approximately 6.5 minutes.

GPC's review of the event concluded that the system performed as expected given the transmission system failures caused by the snow storm and nearly simultaneous unit trips at Florida Power. The loss of generation within the Florida System caused a voltage depression throughout the south Georgia area as the power flow from the Southern System to the Florida System increased to replace the lost generation. The actual effect or drop in voltage on the 4160 volt busses at Plant Hatch is not available; however, none of the anticipatory degraded grid alarms actuated indicating that the voltage did not drop below the minimum required for normal operation for a sufficient time to exceed the relay's time delay.

As part of the review, GPC identified a discrepancy relative to communication between the system operators and the Hatch control room. Specifically, system operators did not notify the Hatch control room that the 230 kV voltage had dropped below the minimum value until after the voltage had been restored. Technically, both units should have been in a one hour to restore LCO as specified by the operating order. The notification did not occur as system operations had concluded that the system was not in jeopardy, the voltage excursion was quickly being restored, and the brief time of the excursion. Corrective actions have been taken to clarify this requirement and assure proper communications.

This event demonstrates that the existing degraded grid protection for Plant Hatch is consistent with GPC's objectives.

- The plant was adequately protected from an undervoltage condition as no alarms were actuated and no adverse effects were evident.
- The offsite power source was preserved as the preferred source. While a short term dip in voltage occurred, the integrity of the system was not in jeopardy and a disconnect was not warranted.
- The situation was not further exascerbated by the unnecessary removal from the grid of Unit 1's approximately 800 megawatts. (Unit 2 was in a fuel reconstitution outage). Accordingly, the Southern Electric System was able to provide support to the Florida Power System as needed.
- If the setpoint for the degraded grid relays had been raised, a trip of Unit 1 probably would not have occurred. However, the possibility of an unnecessary disconnect would have been increased due to possible setpoint drift. Consequently, GPC's objective of avoiding an unnecessary reactor isolation transient was met.

The actual event supported GPC's integrated approach to evaluating degraded grid protection which considered the electrical design requirements, plant operation, and system operation. In the event, the plant's electrical equipment was not adversely impacted by the voltage excursion, the plant continued to support the grid, the Southern Electric grid was able to support a neighbor utility and its public, and the plant was able to remain on offsite power. However, the application of automatic controls or prescriptive actions, in this event, could have been adverse to safety as the possibility of unnecessarily disconnecting the plant from the offsite power supply would have been increased, the possibility of unnecessary reactor isolation transients would have been increased, and the possibility of unnecessary load reductions/blackouts within the Southern Electric and Florida Power service areas would have been increased.

C. GPC has investigated options and potential modifications to improve the existing system. Based on the results, GPC has concluded that modifications in addition to the anticipatory alarms recently installed are not desirable. This conclusion is based on the following:

To meet a hypothetical alarm/trip range scheme as shown on Attachment 2, a large investment in major equipment and/or extensive plant modifications would be required. GPC has estimated the cost at approximately 10 million dollars. Given the level of safety provided by the existing system, such an expenditure is not warranted.

Because of the existing narrow range between the voltage expected with the offsite power at 101.3 percent and the minimum required for LOCA loads, it would not be advisable to raise the setpoints for the undervoltage relays on the E, F, and G 4160 volt busses. As shown in the voltage diagrams for the safety-related 4160 volt buses provided as Attachment 3, the G bus on Unit 1 represents the bus with the most narrow range between the minimum expected and the minimum required voltage. With the offsite power at 101.3 percent and loads associated with mitigating a design basis LOCA being supplied, the G bus is expected to be at 91.14 percent. However, the minimum required to ensure adequate voltage is supplied is 90.8 percent. Consequently, a band of 0.34 percent is available. Since the most accurate undervoltage relay evaluated has an accuracy of approximately 1.25 percent, the trip may occur within the expected voltage. This could result in an unnecessary and unwanted disconnect from offsite power during a LOCA which is contrary to applicable NRC staff positions for minimizing the unavailability of the offsite power source. Due to the narrow band, the anticipatory degraded grid alarm recently installed is expected to annunciate if the grid is at 101.3 percent concurrent with a LOCA. Raising the undervoltage relay setpoint would introduce a consequence which is contrary to the NRC staff positions for degraded voltage protection. As stated previously, increasing the range between the minimum expected and minimum required voltages as shown in Attachment 2 would require purchasing major equipment and/or extensive plant modifications. Given the existing level of protection and the cost for installing new startup transformers, plant modifications, or switchyard equipment, the improvement would be costly and minimal to safety improvement.

GPC has also investigated the benefits associated with replacing the existing CV-7 inverse time relays with discrete time relays without raising the setpoint. While new relays could resolve the concern relative to potentially excessive delays in the transfer of the 4160 volt bus to the onsite power supply once the setpoint is reached, new relays will not provide a resolution to the deadband issue. The setpoint for the new relays would be the same as the existing setpoint and the minimum required voltage would be unaffected. Given that the substantive issue of the deadband would not be resolved, GPC considers the installation of discrete time relays to be an unwarranted expenditure.

Conclusion

GPC's analysis of the degraded grid protection concluded that the evaluation requires consideration of several inputs. The primary inputs into GPC's evaluation involved:

- The electrical requirements of safety-related equipment.
- The reliability of the offsite power supply.
- The potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source.
- The extremely low probability of a sustained degraded grid event concurrent with a LOCA.
- The impact to the offsite power system caused by separating up to 1600 MW during a degraded grid event.

As a result of the reevaluation, GPC has concluded that the existing degraded grid protection provides an adequate level of safety. Additionally, the degraded grid protection has been augmented by the installation of anticipatory alarms and an abnormal operating procedure. GPC also concluded that raising the setpoints for the undervoltage relay to the minimum required voltage level would likely result in an unnecessary disconnect from offsite power during a LOCA with the grid at 101.3 percent of 230 kV. The modifications necessary to increase the available range between the minimum expected and minimum required, such that unwanted or unnecessary disconnects are precluded, would be costly and marginal to safety. Given the adequate level of safety provided by the existing system, GPC does not consider further expenditures to be necessary.

# ATTACHMENT 1

# EDWIN I. HATCH NUCLEAR PLANT
# ELECTRICAL DISTRIBUTION SYSTEM DESCRIPTION

Attachment 1

Edwin I. Hatch Nuclear Plant
Electrical Distribution System Description

Electrical Distribution System Description for Plant Hatch

The Georgia Power Company (GPC) grid is a network of many interconnections with other utilities and multiple locations for tying generating plants into the grid system.

The GPC system is also designed to connect generating units to the grid at optimum locations. This is evident at Plant Hatch as eight transmission lines from different locations and directions tie the units to the grid.

The switchyard at Plant Hatch consists of four 230 kV lines and four 500 kV lines. The Unit 1 main generator is connected to the 230 kV portion of the switchyard and the Unit 2 generator is connected to the 500 kV portion of the switchyard.

The following is a discussion of the electrical distribution system and is applicable to either unit. A simplified one line diagram is provided in Figure 1.

Four transformers supply power to the distribution system for each unit. Normally, transformers A and B are used when the unit is on line and supply power from the main generator to non-safety related 4160 volt busses A, B, C, and D. Transformers C and D supply power from the 230 kV switchyard to safety related busses E, F, and G and also supply non-safety related busses A, B, C, and D during startup and shutdown.

The 4160 volt busses A and B supply power to the reactor recirculation pumps and the condenser circulating water pumps which are the plant's largest loads.

The 4160 volt busses C and D supply power to various auxiliary loads such as the condensate and condensate booster pumps within the feedwater system, as well as the majority of the non-safety related loads at the plant.

The 4160 volt E, F, and G busses supply power to the unit's safety related loads such as the core spray pumps, RHR pumps, plant service water, and RHR service water pump motors, as well as safety related 600 volt and lower busses. These are the busses backed up by the diesel generators.

Attachment 1
Electrical System Description

During startup, non-safety related 4160 volt busses A and B are supplied from offsite power through transformer C. After the main generator is synchronized and the loads are stable, a synchronized transfer normally is made to transformer B. If transformer B is lost, a "fast" transfer is made back to transformer C. If startup transformer D is out of service, this transfer is blocked because the safety related busses will be transferred to transformer C. Additionally, busses A and B would be tripped if already connected.

During startup, non-safety related 4160 volt busses C and D are connected to startup transformer D. After synchronization, these busses are normally transferred to transformer A. Transformer D is sized to carry the required loads for busses E, F, G, C, and D.

During startup, shutdown, and normal operation, safety related 4160 volt busses E, F, and G are normally supplied from startup transformer D. If transformer D fails, there is an automatic transfer to startup transformer C. If both transformer D and C fail, the emergency diesel generators are connected to 4160 volt busses E, F, and G.

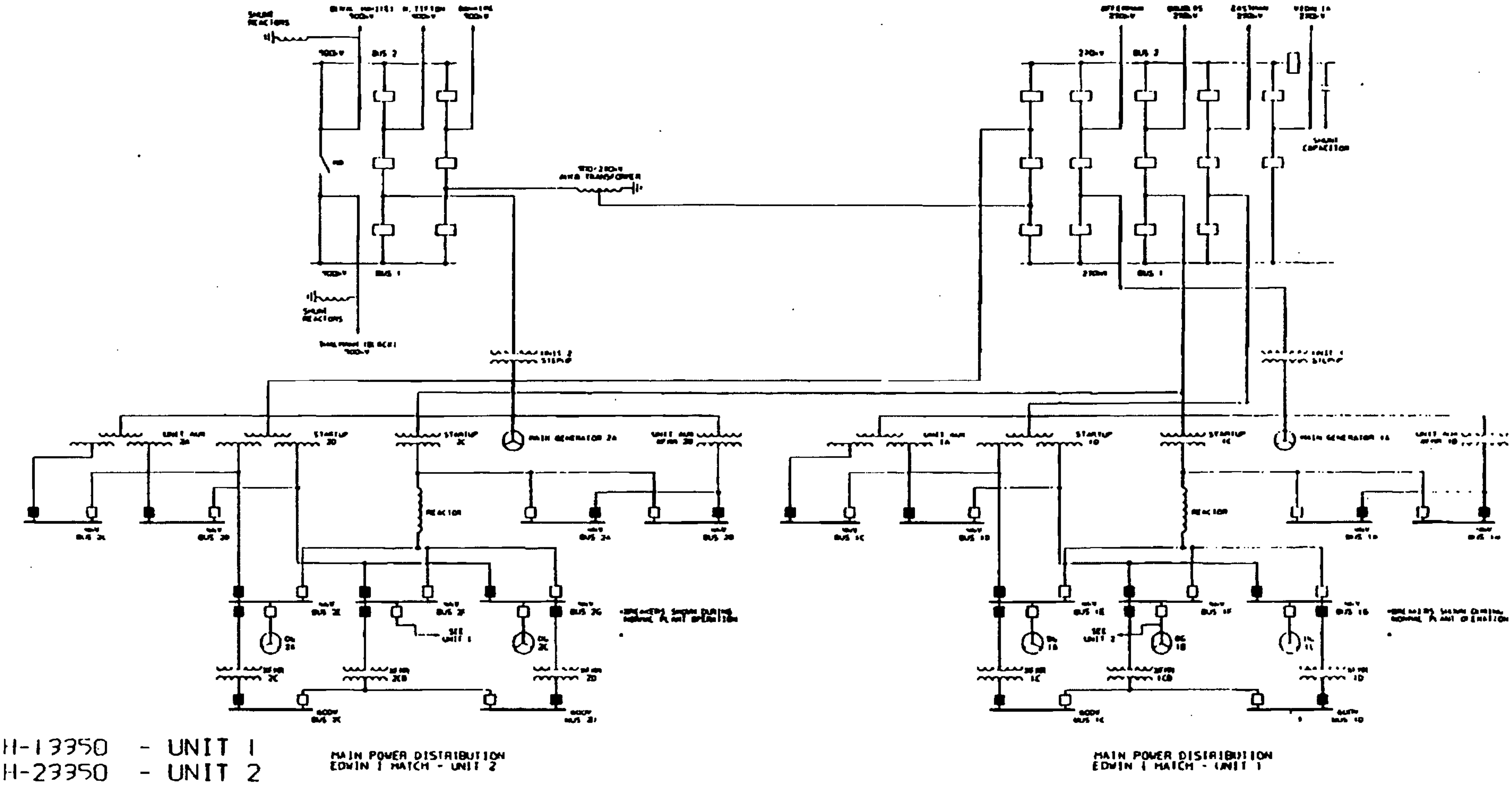
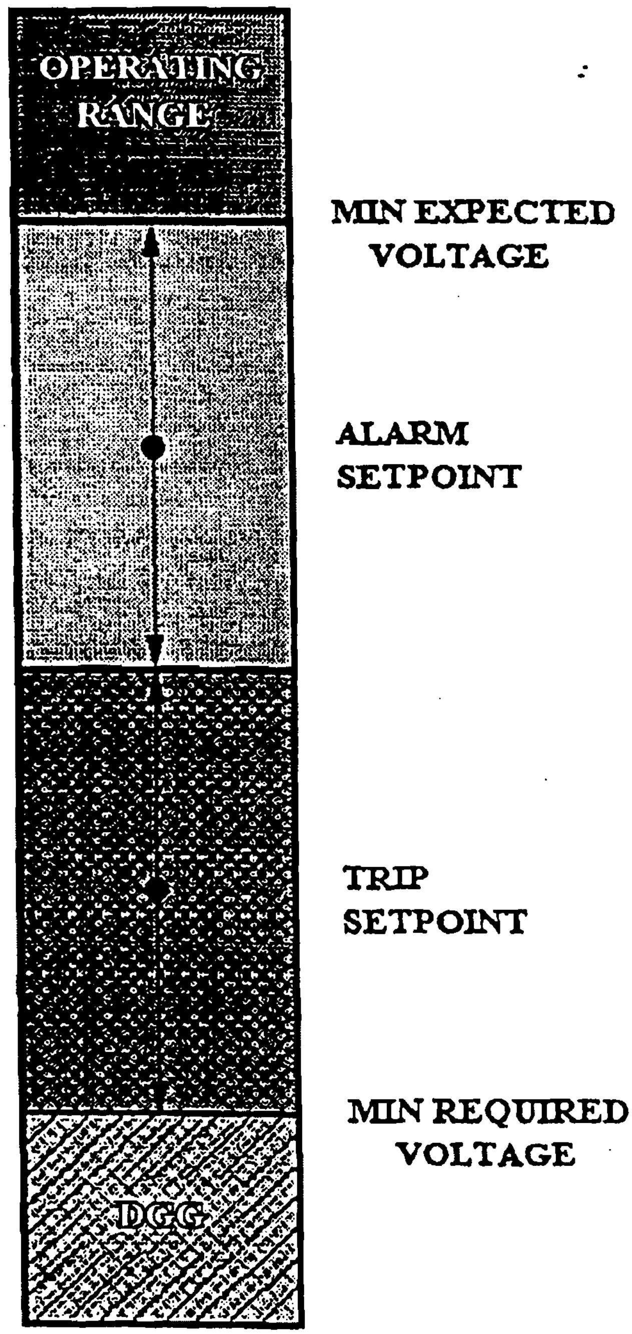



**FIGURE 1**
**MAIN POWER DISTRIBUTION SYSTEM**
**BREAKER POSITIONS - NORMAL OPERATION**

ATTACHMENT 2

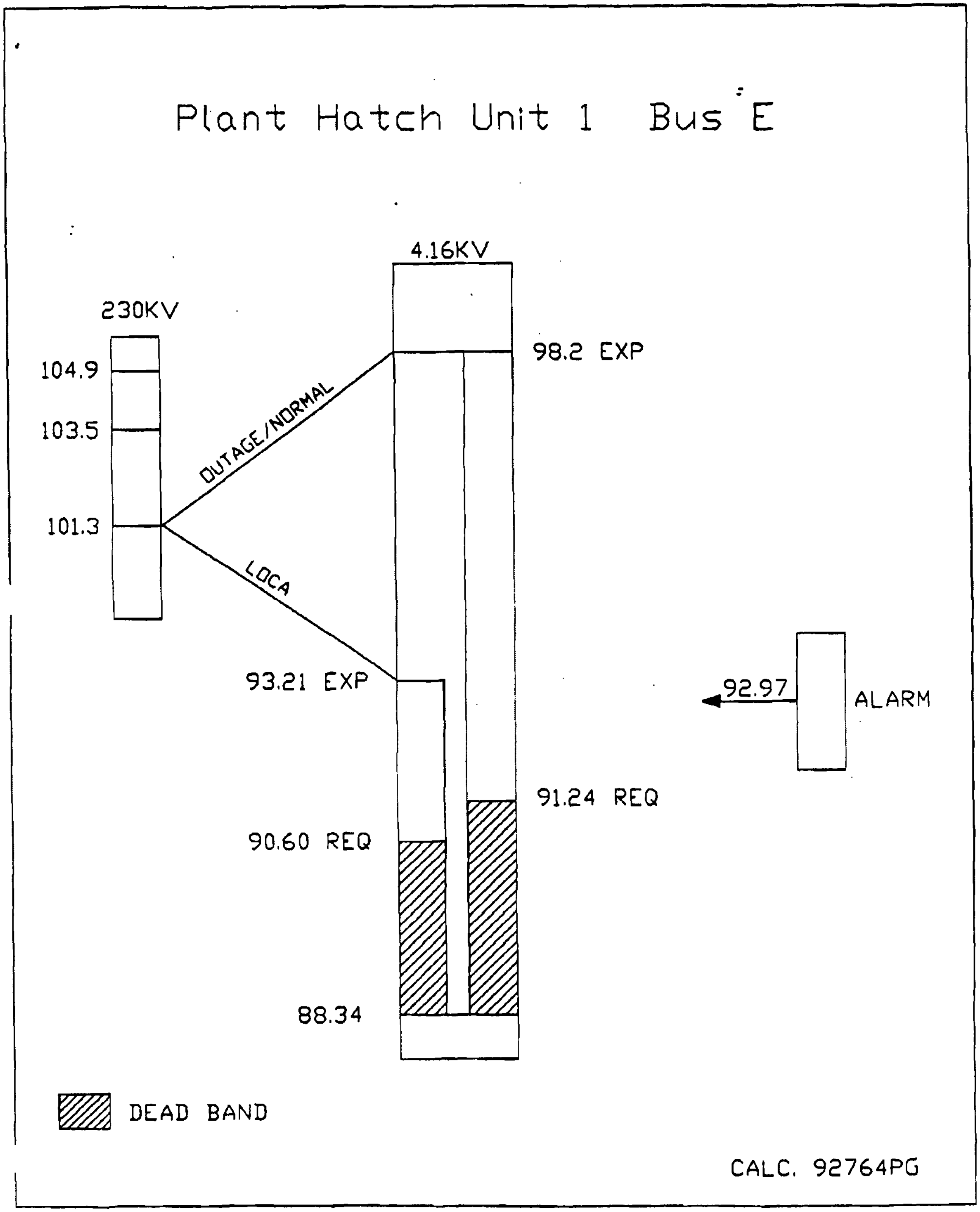
EDWIN I. HATCH NUCLEAR PLANT
HYPOTHETICAL ALARM/TRIP RANGES

## HYPOTHETICAL ALARM / TRIP RANGES

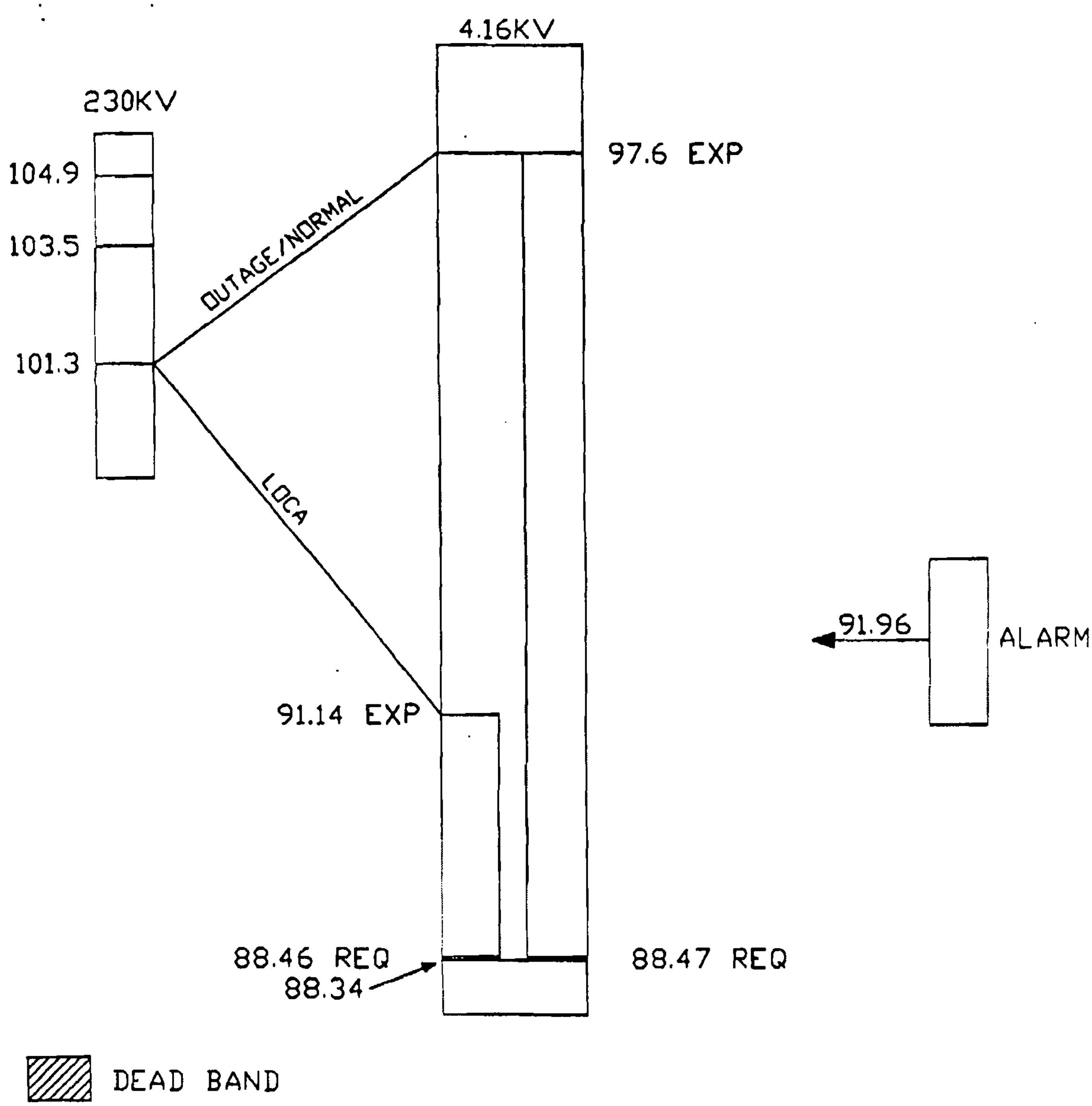


ATTACHMENT 3

EDWIN I. HATCH NUCLEAR PLANT
4160 VOLT BUS VOLTAGE DIAGRAMS


Plant Hatch Unit 1 Bus E
230KV
104.9
103.5
101.3
OUTAGE/NORMAL
LOCA
4.16KV
98.2 EXP
93.21 EXP
90.60 REQ
91.24 REQ
88.34
92.97
ALARM
DEAD BAND
CALC. 92764PG

# Plant Hatch Unit 1 Bus F

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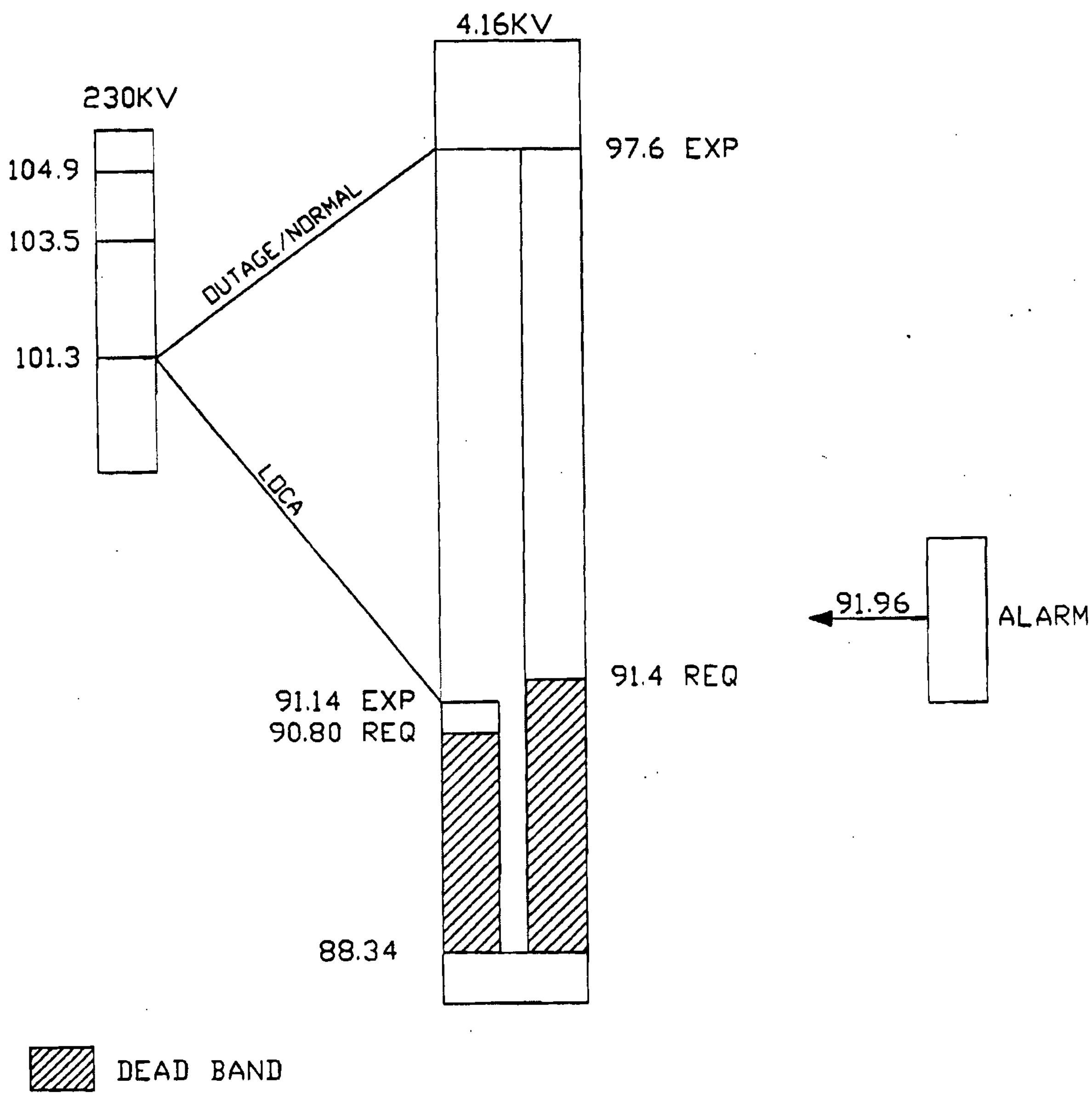
Plant Hatch Unit 1 Bus G

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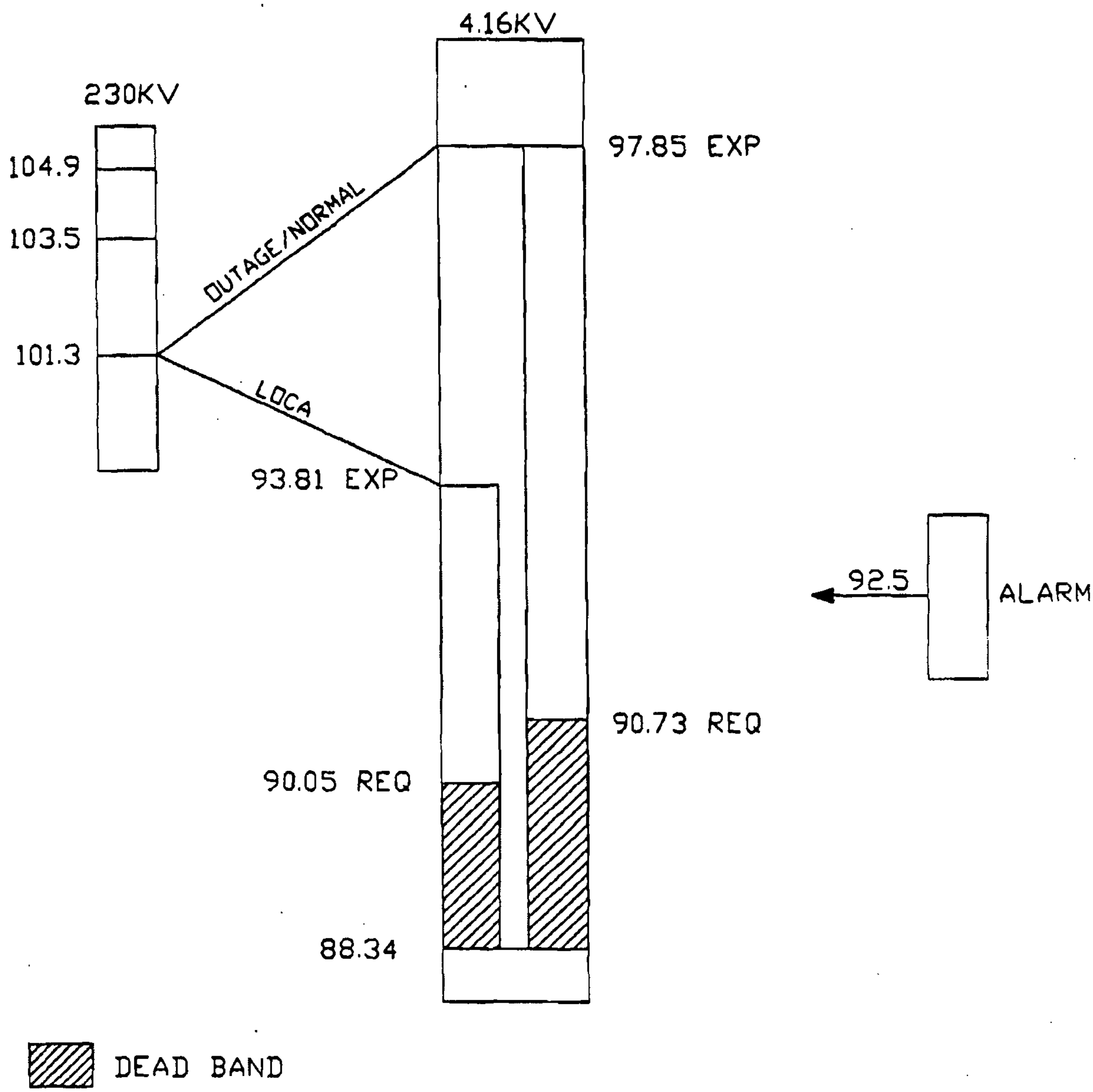
# Plant Hatch Unit 2 Bus E




CALC. 92763PG

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NORMS

Georgia Power
the southern electric system

J. T. Beckham, Jr.
Vice President - Nuclear
Hatch Project

July 1, 1994

Docket Nos. 50-321
50-366

HL-4586

TAC No. 80948

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant
Degraded Grid Protection

Gentlemen:

Following the electrical distribution system functional inspection which was completed on July 12, 1991, Georgia Power Company (GPC) representatives and the Nuclear Reactor Regulation (NRR) staff have held meetings and telephone conference calls to discuss the performance and protection of safety-related equipment at Edwin I. Hatch Nuclear Plant during postulated degraded grid voltage conditions. By letter dated November 22, 1993, GPC submitted a description of an evaluation which concluded that the existing degraded grid protection system provides an adequate level of safety and is in compliance with applicable regulations.

The degraded grid protection system was originally established in response to the Nuclear Regulatory Commission's letter dated June 2, 1977. This letter requested GPC to compare the design of the emergency power systems with the staff positions stated in the letter's enclosure to assess the susceptibility of the safety-related electrical equipment with regard to a sustained degraded voltage condition at the offsite power sources and interaction between the offsite and onsite emergency power systems. These staff positions, which were the precursors to Branch Technical Position PSB-1, are provided on page E-2 of GPC's November 22, 1993 submittal.

An electrical distribution system functional inspection (EDSFI) was performed at Plant Hatch from June 10 through July 12, 1991. The NRC team determined that during a postulated design basis loss of coolant accident concurrent with the 4160 volt bus voltage in a narrow 3% band between approximately 91 percent (3786 volts) and 88.34 percent (3675 volts), certain class 1E loads at voltage levels of 600 volts and below may not receive sufficient voltage. The NRC EDSFI team did not agree with GPC's methodology which established a minimum expected value for offsite power to ensure adequate voltage and concluded that the automatic degraded grid protection was not adequate.

GPC's analysis of expected voltages for the safety-related loads uses the minimum expected voltage from the offsite power supply rather than the setpoint for the degraded grid undervoltage relay. As a result, a "deadband" exists between the minimum required voltage on the 4160 volt safety-related busses and the setpoint of 88.34 percent of 4160 volts for initiating an automatic disconnect of the offsite power supply. Consequently, a deviation from the staff position stated in the June 2, 1977 letter exists relative to the initiation of an automatic disconnect from the offsite power source. The deviation is approximately 12 percent when comparing the minimum required voltage to the voltage and time delay stated in the Technical Specifications, which is 78.8 percent of 4160 volts at 21.5 seconds. These setpoints are specified in Table 3.2-12, and Table 3.3.8-1 of the Unit 1 and Unit 2 Technical Specifications, respectively.

GPC's analysis of the degraded grid protection system determined that the evaluation requires consideration of several inputs. As described in GPC's November 22, 1993 submittal, the inputs are the electrical requirements of safety related equipment, the high reliability of the offsite power supply, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, and the extremely low probability of a sustained degraded grid concurrent with a loss of coolant accident (LOCA). Because of the offsite system monitoring capabilities and design, a sustained degraded grid does not represent the most probable event. Rather, a dynamic voltage excursion lasting less than 10 minutes is more likely. Consequently, the degraded grid voltage protection at Plant Hatch provides adequate assurance of plant safety. As a result, the existing degraded grid protection system uses manual actions instead of an automatic disconnect in the range of the deadband. Accordingly, GPC has implemented an abnormal operating procedure to provide specific actions to address a degraded offsite power supply. If the 4160 volt bus voltages were to degrade below approximately 92 percent, operators will initiate a "one hour to restore" action statement. If voltages are not restored within one hour, a plant shutdown is then initiated.

During recent discussions, the NRR staff requested GPC to incorporate the degraded grid alarms into the Technical Specifications for both units. In response, GPC has agreed to include the alarms, along with the degraded grid undervoltage relays, in the improved Technical Specifications. Accordingly, the limiting condition of operation (LCO) will require the degraded grid alarms to be operable in modes 1, 2, and 3. The specification will include two actions. One will require monitoring the associated 4160 volt bus voltage on an hourly basis if one or more degraded grid alarms are inoperable. Each 4160 volt bus has two alarm relays. The second action will be to restore the inoperable alarm during the next refueling outage. The specification will also include a surveillance to perform an instrument calibration at least once per operating cycle.

Additionally, the NRR staff has verbally requested GPC to consider raising the degraded grid alarm setpoints from their current value of approximately 92 percent of 4160 volts to approximately 97 percent of 4160 volts. The current degraded grid alarm setpoints are specific to the individual 4160 volt busses and range from approximately 92 to 93 percent of 4160 volts. The NRR staff expressed a concern that an alarm setpoint of 92 percent would not provide sufficient notification that the voltage required for (LOCA) conditions had been degraded. GPC has evaluated this request to raise the alarm setpoints to 97 percent of 4160 volts and determined that it is not feasible nor required. The basis for this conclusion is as follows:

The NRR staff's request, basically, corresponds to applying the "hypothetical" alarm and trip ranges. That is, the range between the minimum expected operating voltage and the minimum required for LOCA conditions is sufficiently wide to accommodate an alarm and a trip prior to reaching the minimum required. As described on page E-9 of GPC's November 22, 1993 letter, the existing narrow range between the voltage expected with the offsite power at 101.3 percent of 230 Kv and the minimum required for LOCA loads would not accommodate an alarm setpoint of 97 percent due to the voltage changes associated with normal and startup/shutdown bus alignments to the startup transformers. As a result, an alarm setpoint of 97 percent would be expected to generate frequent nuisance alarms when the non-safety 4160 volt busses are powered from the startup transformers with the offsite power at 101.3 percent of 230 Kv.

The current alarm setpoints of approximately 92 to 93 percent of 4160 volts are approximately midway between the calculated minimum expected voltage with the offsite power at 101.3 percent and the calculated minimum required voltage for normal operating conditions. The current alarm setpoint values signify that adequate voltage is available for normal operations. Consequently, the annunciator response procedures direct the operators to confirm the low voltage condition, contact the GPC control center, and to enter procedure 34AB-S11-001-0S, "Operation With Degraded System Voltage" if the voltage cannot be restored. Procedure 34AB-S11-001-0S directs operators to initiate a "one hour to restore" action statement for restoring the bus voltages to acceptable levels for normal operation. An alarm at 97 percent would not necessarily signify that a degraded voltage condition existed depending on the bus alignments to the startup transformers. From a human factors perspective, the significance of the alarm would be reduced as operators would expect to receive the alarm in certain conditions. Additionally, the current "one hour to restore" action statement significance would be inappropriate for the higher alarm setpoint. Consequently, the setpoints for the degraded grid alarms consider voltage requirements for normal operation as opposed to voltage requirements for LOCA conditions as the probability of a sustained degraded grid event concurrent with a LOCA is extremely low and is not a credible event.

Since GPC's alternate methodology of using manual actions instead of an automatic disconnect differs from the staff position stated in the June 2, 1977 letter, GPC requests formal NRR staff review and approval of this deviation. As described in the November 22, 1993 submittal, GPC has evaluated the deviation from the staff position and concluded that the existing degraded grid protection system is adequate, and is in conformance with applicable regulations. GPC has determined that the deviation is acceptable based on the offsite power system monitoring, the reliability of the offsite power supply, the extremely low probability of a sustained degraded grid event concurrent with a LOCA, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, the impact to the offsite power system caused by separating up to 1600 MW during a degraded grid event, and the enhancements provided by operating orders and degraded grid alarms.

Should you have any questions in this regard, please contact this office.

Sincerely,

J. T. Beckham, Jr.

JKB/cr

cc: *Georgia Power Company*
Mr. H. L. Sumner, Nuclear Plant General Manager
NORMS

*U.S. Nuclear Regulatory Commission, Washington, D.C.*
Mr. K. Jabbour, Licensing Project Manager - Hatch

*U.S. Nuclear Regulatory Commission, Region II*
Mr. S. D. Ebneter, Regional Administrator
Mr. B. L. Holbrook, Senior Resident Inspector - Hatch

'KB

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

January 10, 1995

LICENSEE: Georgia Power Company, et al.

FACILITY: Hatch Nuclear Plant, Units 1 and 2

SUBJECT: SUMMARY OF DECEMBER 7, 1994, MEETING WITH GEORGIA POWER COMPANY ON DEGRADED GRID VOLTAGE - HATCH NUCLEAR PLANT, UNITS 1 AND 2 (TAC NO. M80948)

On December 7, 1994, the NRC staff met with Georgia Power Company (GPC or licensee) representatives and their consultant from Southern Company Services (SCS) in Birmingham, Alabama, to discuss equipment operability under degraded grid conditions at Plant Hatch, Units 1 and 2. Attachment 1 lists the attendees and Attachment 2 contains a copy of the viewgraphs used by the licensee during the presentation.

After brief introductory remarks by NRC and GPC regarding the objectives of the meeting, Mr. J. Branum, GPC, provided a summary of previous correspondence and meetings regarding the same subject. He stated that NRR staff's concerns originated from an electrical distribution system functional inspection completed in July 1991. He discussed the licensing basis associated with the existing setpoint for the degraded grid undervoltage relays and GPC's concerns when raising the setpoint.

Georgia Power's concerns are based on the low probability of a sustained degraded grid event combined with a loss-of-coolant accident, the existing narrow range between the minimum expected voltage and the minimum required voltage, the possibility of introducing unnecessary trips of the offsite power supply, and the need for major plant modifications. Mr. Branum also discussed the methods for maintaining the minimum required switchyard voltage, the basis for the setpoint of the undervoltage alarm relays, plant procedures for responding to a degraded grid event, and the incorporation of the alarm setpoint into the improved Technical Specifications.

During a followup discussion, Messrs. S. Bethay, GPC, and B. Snider, SCS, provided additional details of the alarm setpoint. The setpoint is set as high as practical to provide notification of an undervoltage condition during normal operation but also to avoid unnecessary alarms when the balance-of-plant equipment is powered from the startup transformers. Mr. Bethay also discussed the ability of the plant to respond to a postulated undervoltage condition. His statements were based on the plant's response to a station blackout condition where the pressure systems provide inventory makeup. These systems rely on DC power rather than AC power. Georgia Power concluded the meeting by stating that the existing degraded grid protection system is adequate and that further modifications are not necessary.

The NRC staff had several comments regarding the alarm and the operator actions. In addition, the staff requested that the Final Safety Analysis Report (FSAR) be amended to provide information on GPC's approach to degraded grid protection which should include a discussion of the alarms and the operating range at the 230 KV level. GPC agreed to update the FSAR.

At the conclusion of the meeting, the NRC staff stated that they will review GPC's submittal and the handouts with the view that the approach proposed by GPC constitutes a deviation from the recommendations of the Generic Letter dated June 2, 1977.

Kahtan N. Jabbour

Kahtan N. Jabbour, Senior Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-321 and 50-366

Attachments: 1. List of Attendees
2. Viewgraphs

cc w/Attachments: See next page

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Vice President - Plant Hatch
Georgia Power Company
P. O. Box 1295
Birmingham, Alabama 35201

NRC/GPC MEETING

DECEMBER 7, 1994

| NAME | ORGANIZATION |
|---|---|
| K. N. Jabbour | NRC/NRR |
| D. F. Thatcher | NRC/NRR/EELB |
| N. K. Treham | NRC/NRR/EELB |
| Gary McGaha | SCS-Hatch |
| Tom Sims | SCS-CATS |
| Jeff Branum | SNC/NEL |
| Bill Snider | SCS/Hatch |
| Roger Hayes | SNC/Farley |
| David Gambrell | SCS-Farley |
| Steve E. Bethay | SNC-Hatch Engineering |

Attachment 1

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection
December 7, 1994

## Agenda

| | |
|---|---|
| Introduction | J. D. Heidt |
| Overview of Correspondence/Meetings | J. K. Branum |
| Selected Topics | J. K. Branum |
| • Basis for existing setpoints | |
| • Concerns with raising setpoints | |
| • Plant procedures and technical specifications | |
| Discussion | All |
| Conclusion | J.D. Heidt |

Attachment 2

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

<u>Overview of Correspondence/Meetings</u>

1. EDSFI performed in May/June of 1991

   - NRC team questioned whether the undervoltage relay setpoints were too low to ensure minimum voltage prior to disconnect from offsite power supply.

2. GPC Meeting with NRC on 8/6/91

   - GPC discussed offsite system controls, extremely low probability of a sustained degraded grid and LOCA, and operating enhancements.

   - NRC Staff indicated agreement with GPC's conclusions.

3. Inspection Report 91-202, dated 8/22/91

   - Restated EDSFI Team's concern

4. Notice of Violation, dated 10/7/91

5. GPC Reply to NOV, dated 11/6/91

   - Denied violation

   - GPC determined a violation of NRC requirements did not exist

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Overview of Correspondence/Meetings (Continued)

6. GPC Meeting with NRC on 11/16/92

    - GPC provided objectives and criteria used in assessment.
    - Detailed discussion of offsite system monitoring and controls
    - Actions completed
    - Cost estimates for conceptual modifications

7. GPC letter, dated 11/22/93

    - Basis for existing setpoints
    - Basis for concerns for unnecessary disconnects

8. GPC letter, dated 7/1/94

    - Basis for alarm setpoints
    - Committed to include alarm in improved Technical Specifications
    - Formally requested NRC review and approval

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

<u>Selected Topics</u>

1. Basis for existing undervoltage relay setpoints
2. Concerns with raising setpoints
3. Basis for alarm setpoints
4. Plant procedures and Technical Specifications

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Basis For Existing Undervoltage Relay Setpoints

- Existing setpoints are in accordance with GPC's response to the NRC generic letter dated June 2, 1977
- Existing setpoints were approved in the Safety Evaluation report dated 5/6/82
- GPC used maximum plant loadings to establish the minimum expected voltage for the offsite power supply to assure the adequacy of plant voltage levels

Edwin I. Hatch Nuclear Plant

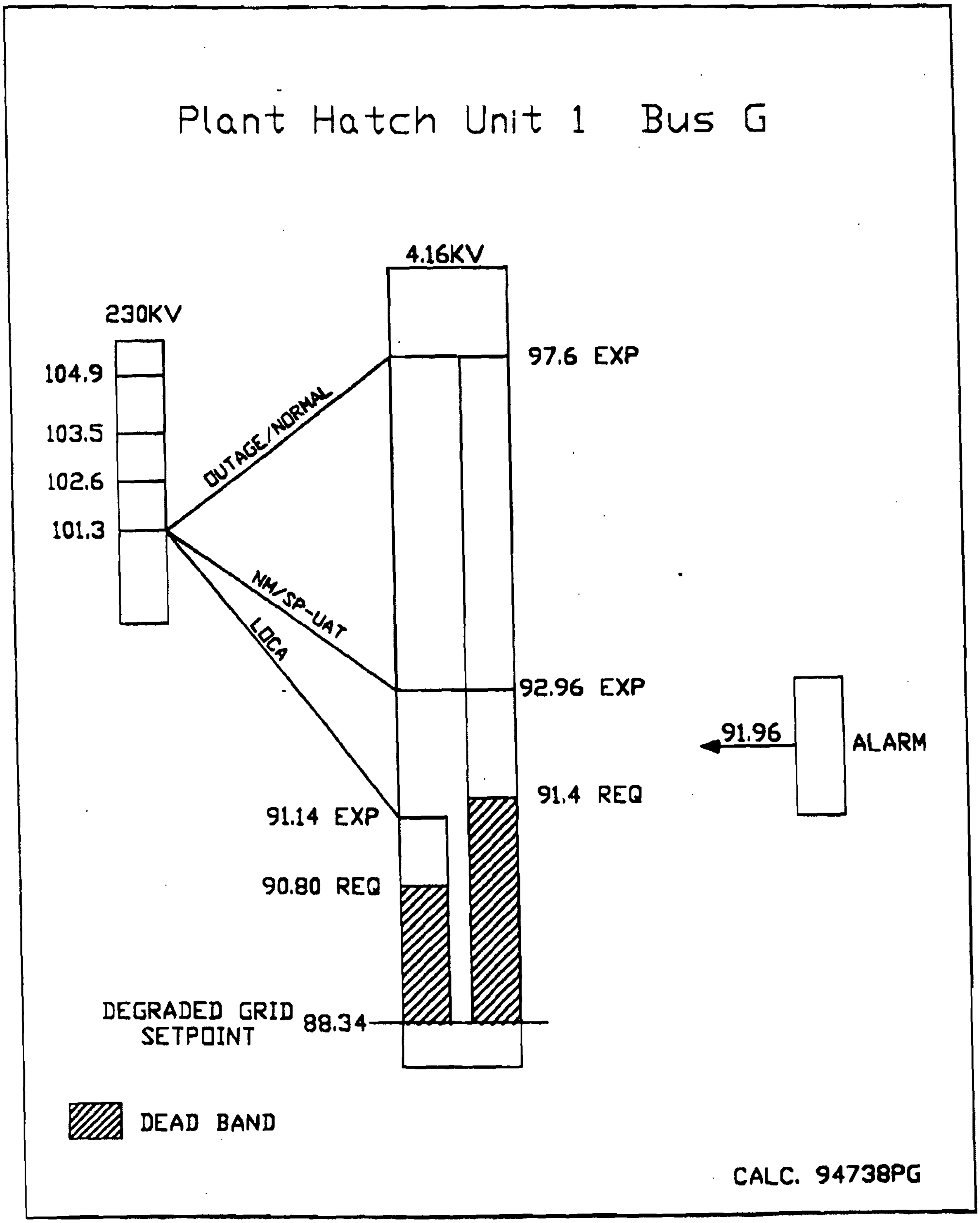
Degraded Grid Protection

- A sustained degraded grid is not a credible event for Plant Hatch

  The Southern Electric System employs state-of-the-art monitoring and contingency analysis systems for the electric grid on <u>a real time basis</u>. System operators ensure adequate voltage is provided and the contingency analysis feature allows prediction of the adverse affects from postulated system failures.

- System operators configure the offsite power supply such that a failure can occur without adversely affecting the minimum required voltage. This includes postulated trips of a Hatch unit.

- A dynamic voltage excursion is more likely


Plant Hatch Unit 1 Bus G
230KV
104.9
103.5
102.6
101.3
4.16KV
OUTAGE/NORMAL
NM/SP-UAT
LOCA
97.6 EXP
92.96 EXP
91.14 EXP
90.80 REQ
91.4 REQ
91.96
ALARM
DEGRADED GRID SETPOINT
88.34
DEAD BAND
CALC. 94738PG

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Basis For Existing Undervoltage Relay Setpoints (Continued)

- The occurrence of a sustained degraded grid is extremely unlikely
- The occurrence of a LOCA is estimated at $2.61 \times 10^{-4}$

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Concerns With Raising Undervoltage Relay Setpoints

- The existing range between the minimum expected voltage with the grid at 101.3 percent and the minimum required voltage for LOCA loads is too narrow
- Raising the setpoint could result in unnecessary and unwanted disconnects within the expected voltage range.
- Raising the setpoint could result in a trip from the offsite power supply during a LOCA when offsite power is fully adequate.
- Increasing the narrow range would require major plant modifications

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Dynamic Excursion vs Sustained Degraded Grid

The most likely degraded grid event is a dynamic voltage excursion

For a dynamic voltage excursion, disconnecting both units from offsite power and introducing dual unit scrams and reactor isolation transients through automatic undervoltage relays would be adverse to safety.

GPC's method of using manual actions in the deadband range allows system operators to quickly stabilize a degraded grid without introducing a plant transient when offsite power is undergoing a temporary excursion and is not in actual jeopardy.

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

| Conceptual Modifications | Approximate Cost |
|---|---|
| 1. Transformer tap changes | 250,000 |
| 2. New undervoltage relays, cable/ equipment replacement | 500,000 - 1 million |
| 3. New major equipment | 10 million |

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

## Basis For Undervoltage Alarm Setpoint

Undervoltage alarm setpoint is as high as practical

Setpoint is approximately midway between the minimum voltage for operation (BOP equipment on SAT's) and the expected voltage with the grid lowered to 101.3 percent (above 92 percent)

A higher alarm setpoint of 97 percent would be expected to generate frequent false alarms when non-safety loads are powered from the startup transformers.

The alarms are also expected to annunciate during a LOCA if the grid has lowered to 101.3 percent

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Basis For Undervoltage Alarm Setpoint

Alarm annunciation indicates that an undervoltage condition is present. However, voltage is adequate for normal operation (i.e., voltage levels, equipment performance, and availability of equipment is satisfactory).

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Actions Completed

1. Increasing the undervoltage relay setpoint and replacing the relays have been evaluated.

2. Evaluated system operations grid monitoring and failure analysis capabilities.

3. Installed anticipatory alarms.

4. Formalized anticipatory actions both onsite and offsite.

5. Implemented annunciator response and abnormal operating procedures to ensure the reactor is quickly brought to a condition of greater safety.

6. Incorporated the alarms into the improved technical specifications.

7. Installed an additional capacitator bank in the 230 Kv switchyard to provide three levels of adjustment.

Edwin I. Hatch Nuclear Plant

Degraded Grid Protection

Summary

The existing degraded grid protection system using manual actions in the deadband area followed by automatic controls provides adequate safety.

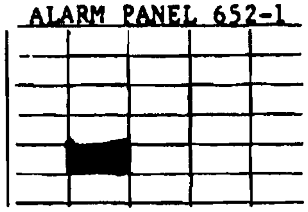
The existing system provides a higher level of safety when compared to automatic controls for more likely transient scenarios.

GPC has expended considerable resources to resolve NRR staff concerns.

Further actions are not necessary.

**1.0 IDENTIFICATION:**

ALARM PANEL 652-1



| |
|---|
| 4160V. BUS 1E<br>VOLTAGE LOW |

**DEVICE:**
1S32-K206-1/2

**SETPOINT:**
3867 volts

**2.0 CONDITION:**
A low voltage condition was sensed on 4160V BUS 1E.

**3.0 CLASSIFICATION:**
EQUIPMENT STATUS

**4.0 LOCATION:**
1H11-P652 PANEL 652-1

**5.0 OPERATOR ACTIONS:**

5.1 Confirm that voltage is less than 3867 volts on Panel 1H11-P652 on 4160V BUS 1E Voltmeter.

5.2 IF voltage is below 3867 volts; notify Georgia Control Center and request operator to raise the voltage on the system to normal.

5.3 IF voltage on the system cannot be restored, enter 34AB-S11-001-0S, Operation with Degraded System Voltage.

**6.0 CAUSES:**

6.1 System voltage is low

**7.0 REFERENCES**

7.1 H-13412, Elementary Diagrams Diesel Gen 1A

**8.0 TECH. SPEC./LCO:**

8.1 3/4.9, Electrical Power Systems

APPROVAL:
DEPT. MGR [signature] DATE 4/27/93

34AR-652-122-1S
Rev. 4

1.0 CONDITIONS

> **NOTE**
>
> Normal minmum voltage with either Unit in Modes 1, 2, or 3 is 233KV. Normal minimum voltage with both units in COLD SHUTDOWN, REFUEL or with Fuel Removed is 225KV.

1.1 The System Operating Center (Birmingham) has notified the Superintendent On Shift that the Offsite Distribution System is in jeopardy of NOT being able to maintain normal minimum voltage at the 230KV bus.

1.2 The System Operating Center has notified the Superintendent On Shift that the 230KV Bus voltage CANNOT be maintained above normal minimum voltage.

2.0 AUTOMATIC ACTIONS

None

3.0 IMMEDIATE OPERATOR ACTIONS

N/A - not applicable to this procedure.

4.0 SUBSEQUENT OPERATOR ACTIONS

4.1 Upon notification from System Operating Center that the Offsite Distribution System is one contingency (event) away from being unable to maintain normal minimum voltage on the 230KV bus, the following actions are to be taken:

4.1.1 RETURN inoperable Emergency Diesel Generators to operable status as soon as possible.

4.1.2 NO maintenance OR surveillance is to be initiated on critical components of the on-site electrical distribution system AND those in process are to be RESTORED to normal AND TERMINATED as soon as possible.

4.1.3 ASSIGN an operator to monitor the voltage indicators for the six 4160 VAC Emergency buses (1/2R22-S005,6,7) twice per hour. IF the indicated voltage is greater than 3850VAC, THEN the bus voltages are considered acceptable.

4.1.4 INFORM the entire shift operating crew AND RECORD appropriate log entries of the increased potential for a degraded voltage OR loss of offsite power event.

4.1.5 Notify the Manager of Operations, the On-site Duty Manager and the On-call Hatch Project Duty Manager.

4.2 Upon notification from System Operating Center that the 230KV bus voltage CANNOT be maintained above normal minimum voltage, OR IF the 4160VAC bus voltages CANNOT be maintained above 3850VAC, the following action will be taken:

4.2.1 INITIATE an "One Hour LCO" to RESTORE the 4160VAC Bus voltages to acceptable levels (greater than or equal to 3850VAC).

4.2.2 Notify the Manager of Operations, the On-site Duty Manager, and the On-call Hatch Project Duty Manager.

4.2.3 IF the 4160VAC Bus voltages are NOT RESTORED acceptable levels WITHIN one hour, an orderly plant SHUTDOWN will be INITIATED with the intent of reaching HOT SHUTDOWN in 6 hours and COLD SHUTDOWN WITHIN the following 30 hours. Refer to 73EP-EIP-001-0S and notify the NRC by the ENS (FPX 2000).

## 3.3 INSTRUMENTATION

### 3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each channel.
---------------------------------------------------------------------------

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One or more channels inoperable for Functions 1 and 2. | A.1 Restore channel to OPERABLE status. | 1 hour |
| B. One or more channels inoperable for Function 3. | B.1 Verify voltage on associated 4.16 kV bus is $\geq$ 3825 V. | Once per hour |
| C. Required Action and associated Completion Time not met. | C.1 Declare associated DG inoperable. | Immediately |

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

| FUNCTION | REQUIRED CHANNELS PER BUS | SURVEILLANCE REQUIREMENTS | ALLOWABLE VALUE |
|---|---|---|---|
| 1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) | | | |
| a. Bus Undervoltage | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 2800 V |
| b. Time Delay | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 6.5 seconds |
| 2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) | | | |
| a. Bus Undervoltage | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 3280 V |
| b. Time Delay | 2 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 21.5 seconds |
| 3. 4.16 kV Emergency Bus Undervoltage (Annunciation) | | | |
| a. Bus Undervoltage | 1 | SR 3.3.8.1.1<br>SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≥ 3825 V |
| b. Time Delay | 1 | SR 3.3.8.1.2<br>SR 3.3.8.1.3<br>SR 3.3.8.1.4 | ≤ 60 seconds |

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

February 23, 1995

Mr. J. T. Beckham, Jr.
Vice President - Plant Hatch
Georgia Power Company
P. O. Box 1295
Birmingham, Alabama 35201

SUBJECT: SAFETY EVALUATION FOR DEGRADED GRID VOLTAGE RELAY SETPOINTS EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2 (TAC NO. M80948)

Dear Mr. Beckham:

By letter dated July 1, 1994, you requested approval of a deviation from the current NRC staff position on degraded grid protection. This letter was a supplement to your November 22, 1993, letter which contained a description of your degraded grid protection system.

The staff has reviewed the above submittals and the information provided during our meetings on August 6, 1992, November 16, 1993, and December 7, 1994. Based on its review, the staff finds that your approach is acceptable as documented in the enclosed Safety Evaluation. This completes our action with respect to the above TAC. If you have any questions related to this matter, please contact me at (301) 415-1496.

Sincerely,

Kahtan N. Jabbour

Kahtan N. Jabbour, Senior Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-321 and 50-366

Enclosure: Safety Evaluation

cc w/encl: See next page

RECEIVED
FEB 27 1995
HATCH LICENSING & ENGNG

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

DEGRADED GRID VOLTAGE RELAY SETPOINTS

GEORGIA POWER COMPANY, ET AL.

EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-321 AND 50-366

## I. INTRODUCTION

Georgia Power Company, et al. (GPC or the licensee) is proposing to deviate from the current NRC staff guidance provided in Generic Letters (GLs) dated 1977 and 1979 with respect to sustained degraded voltage conditions of the offsite power source and the adequacy of the station electric distribution system voltages (Reference 1). The GLs provided supplemental guidance to help ensure that all plants' electrical systems meet a staff interpretation of General Design Criterion (GDC) 17 regarding degraded voltages.

The staff had concluded in 1982 that Hatch met the positions in the GLs (Reference 2). As part of the design approach, Hatch included a second level of degraded undervoltage protection with a nominal trip setpoint of 78.8% of bus voltage with a time delay of 21.5 seconds. CV-7 relays were used which have inverse time characteristics. Subsequently, an Electrical Distribution System Functional Inspection (EDSFI) determined that the voltage calculations done to support the setpoints were not adequate. Hatch was required to update the voltage calculations and the results indicated that the setpoint for the degraded grid protection should be raised to assure at least 91% voltage at the 4160 volt safety buses (Reference 3). Hatch investigated the feasibility of raising the setpoints at which automatic action would occur and concluded that the changes would involve new equipment and would be very costly. Furthermore, they believed that raising the setpoint would not significantly improve safety and could lead to unwanted plant trips. As a result, they proposed an interim approach, which relied on maintaining the 230 kV switchyard voltage between 101.3% and 104.9% and included alarm relays set at a higher voltage level (about 92%) and associated manual actions. The staff approved the interim approach but requested that the licensee continue to investigate the matter. The licensee is now proposing the interim approach as the final resolution to meet the GLs.

Specifically, the licensee is proposing to maintain the existing setpoints for their automatic degraded voltage protection scheme and to rely on anticipatory alarms set at 92% and operator actions to provide protection. They believe that this approach provides the necessary protection and that the cost of changing equipment is not justified based on their conclusion that such changes would not improve safety.

By maintaining their interim approach and not raising the setpoint for automatic action, ~~It is recognized that there is a potential range of degraded voltages for certain postulated events where automatic protection would~~ not ~~occur~~. This is considered a deviation from the GL positions, and therefore, the licensee has specifically requested that the staff approve the deviation.

In support of the deviation there have been a number of meetings and letters as listed below:

1. Meeting summary dated August 16, 1991, for the August 6, 1991, meeting.

2. Meeting summary dated December 21, 1992, for the November 16, 1992, meeting.

3. Letter from Georgia Power to NRC dated November 22, 1993.

4. Letter from Georgia Power to NRC dated July 1, 1994.

5. Meeting summary dated January 10, 1995, for the December 7, 1994, meeting.

II. EVALUATION

The licensee's approach is based on their understanding of the events which led to issuance of the GLs and potential events which might challenge the Hatch facility. The GLs were prompted by events at Millstone One and Arkansas Nuclear One which heightened concerns for potential sustained degraded grid voltages and in plant voltage problems due to potential severe loading conditions during accidents.

The specific sequence of events which would require that the voltage setpoints be raised involves the simultaneous existence of a degraded offsite power source and a loss-of-coolant accident (LOCA). A LOCA puts the heaviest demand on the safety buses and if it would occur during degraded grid voltage conditions, some safety equipment might not receive sufficient voltage to perform their function. Among other requirements, the GLs required that the occurrence of a degraded offsite voltage should be sensed, and then an automatic transfer to the emergency diesel generators (EDGs) should take place. For the sequence of events of a degraded grid voltage and a LOCA, the licensee has concluded that the likelihood of such simultaneous events is extremely low. This is based on their existing grid operation coupled with the low likelihood of a LOCA.

Plant Hatch is part of the Southern electric grid system which is a member of the Southeastern Electric Reliability Council. The Southern electric system employs state-of-the-art monitoring and contingency analysis systems for the electric grid on a real time basis. System operators of the Southern electric grid ensure that adequate voltage is provided and the contingency analysis feature allows system operation to predict adverse effects from postulated grid system failures. Based on the contingency analysis results, system operators configure the offsite power system such that a worst-case postulated failure can occur without adversely affecting the minimum required voltage.

If the 230 kV system at Hatch were to fall below the current minimum expected value of 101.3%, the switchyard design and offsite power system design allows system operators to quickly mitigate such a dynamic voltage excursion. The following actions would be performed by system operators:

- System operators receive low voltage alarm.
- System operators notify the control room at Plant Hatch.
- The 162 MVAR capacitor bank on the 230 kV line is switched on (if off).
- The 150 MVAR shunt reactors on the 500 kV line are turned off (if on).
- Capacitor banks in the surrounding area are turned on (if off).
- Combustion turbines at Plant McManus are placed in service.

These actions are normally capable of improving the 230 kV voltage by approximately 2 to 4 percent. If these actions are not sufficient, system operators would take the following actions:

- Out of service elements are brought back on line.
- System load (external or internal) is reduced.

Therefore, because of the above outlined offsite system monitoring capabilities and design, a sustained degraded grid does not represent the most probable event. Rather, a dynamic voltage excursion is more likely. For a dynamic voltage excursion, GPC believes that disconnecting both units from the offsite power supply and introducing dual unit scrams and reactor isolation transients through automatic undervoltage relays would be adverse to safety.

Even if the system operators of Southern electric grid fail to improve the 230 kV grid voltage, GPC has issued an Operating Order at Plant Hatch which identifies specific actions to be taken if the grid system operators are in jeopardy of not maintaining the Hatch voltages within the required operating range. The actions consist of restoring any inoperable EDGs, limiting maintenance or surveillance of important onsite electrical equipment, closely monitoring voltage levels on the six 4160 volt safety-related buses, and informing plant management. The Operating Order also specifies action to be performed if the 4160 volt essential buses fall below the minimum acceptable voltage. These actions include initiation of a one hour Limiting Condition of Operation (LCO) to restore safety-related bus voltages, notification of management, and an orderly plant shutdown if voltage is not restored. The actions specified in the Operating Order have been incorporated into abnormal operating procedure 34AB-S11-001-0S, "Operation With Degraded System Voltage." This procedure would also be entered on receiving the low voltage alarms on the 4160 volt buses. Operators receive training relative to the actions specified in the procedure through the normal operator training and operator requalification training on abnormal operating procedures.

Therefore, the licensee concludes that, because of the elements in place on the Southern electric grid and at Plant Hatch, it would be a very rare event for the offsite voltage at Hatch to be below 101.3% during a postulated independent LOCA (from their IPE the estimated occurrence of a LOCA is 2.61 x $10^{-4}$ for Hatch).

In response to NRC staff concerns, the licensee also investigated other potentially more likely events, and has concluded that the alarms and procedures along with the plant's inherent response capabilities provide sufficient protection.

1. Sustained degraded grid conditions (no LOCA or plant trip)

   If the voltages on the offsite system were to degrade to unacceptable levels for a sustained period of time, the plant would be notified by the Southern System load dispatcher and in addition the plant alarms would alert the operators to the condition. Procedures would be implemented to restore voltages in one hour or start an orderly shutdown. By not raising the setpoint at which automatic action would occur, some potential for unnecessary automatic unit trips could be avoided.

2. Dynamic voltage excursion (no LOCA or plant trip)

   If the voltages on the offsite system were to degrade to the unacceptable level for a short period of time (on the order of minutes), the plant would be notified by the Southern System load dispatcher. Procedures would be implemented to restore the voltages. By not raising the setpoint at which automatic action would occur, unnecessary unit trips might be avoided. As noted by the licensee, an event of this nature occurred on Sunday, March 14, 1993. The licensee's post-event analysis concluded that this event supported its integrated approach to evaluating degraded grid protection which considers electrical design requirements, plant operation, and grid system operation. Details of the event and the licensee's analysis are provided in the appendix to this evaluation.

3. Sustained degraded grid conditions or a dynamic voltage excursion with Hatch units tripping (no LOCA)

   If a plant trip occurred during a grid problem (which could reasonably be expected to occur due to problems related to the equipment exposed to the degraded voltages, or because the tripping of the Hatch units was part of the problem leading to the degraded grid voltage) operator response to correct the voltages might not be quick enough, and therefore, damage to some ac equipment could occur. In this situation, the licensee has analyzed their facility and concluded that equipment not exposed to the ac voltage problems (because it is operating on dc-backed sources or is not operating and, therefore, free from potential damage), such as reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) would be available to safely shut the plant down. This same kind of analysis was done as part of their Station Blackout analysis.

4. Sustained degraded grid conditions or dynamic voltage excursion with Hatch units tripping and then a stuck open relief valve (LOCA)

This event could be the most probable sequence involving a degraded grid and LOCA. Because the plant response would be the same (e.g., RCIC, HPCI) the same conclusions as the above event sequence would also apply.

The staff has evaluated the licensee's proposal and agrees with the approach with the following additional conditions:

1. The degraded voltage alarm relays should be included in the plant Technical Specifications along with the degraded voltage relays which initiate automatic actions.

2. The offsite system operating voltage levels and their significance with respect to the Hatch approach to meeting the degraded voltage requirements should be documented in the Final Safety Analysis Report so the impact of possible future changes will receive appropriate consideration.

The licensee has agreed to these added conditions.

~~With the alternate~~ approach, ~~the staff concludes that both an offsite~~ and ~~onsite power system is available~~, each with ~~the capability of providing power for the required safety components in accordance with GDC 17 of 10 CFR Part 50, Appendix A.~~

## III. CONCLUSION

Based on its review, the staff finds that the requested deviation from the Generic Letters is acceptable because of the added design features and the compensatory measures at Hatch as discussed in the above Safety Evaluation.

Principal Contributors: D. Thatcher
N. Trehan

Date: February 23, 1995

REFERENCES

1. a. June 2, 1977, NRC Generic Letter (Staff Positions) regarding the onsite emergency power systems.

   b. August 8, 1979, NRC Generic Letter regarding the "Adequacy of Station Electric Distribution Systems Voltages."

2. a. April 5, 1982, NRC Staff Safety Evaluation regarding the adequacy of electric distribution system voltages at Hatch Units 1 and 2.

   b. May 6, 1982, NRC Staff Safety Evaluation regarding degraded grid Technical Specifications.

3. August 22, 1991, Electrical Distribution System Functional Inspection at Hatch, NRC Inspection Report No. 91-202.

# APPENDIX

## TEMPORARY VOLTAGE EXCURSION EVENT AT PLANT HATCH

A temporary voltage excursion event occurred at Plant Hatch on Sunday, March 14, 1993. During that weekend, record snow accumulations, along with high winds were occurring within the Southern Electric System. This was resulting in significant outages due to failures of local distribution networks. During this time, specifically on March 14, 1993, at 10:04 a.m., Florida Power Corporation's Crystal River Unit 2 tripped. The loss of generation within the Florida grid caused a dynamic voltage excursion within the Southern Electric grid. The Hatch switchyard voltage dropped to 215 kV (93 percent) in one second and stabilized at 223 kV (97 percent) in approximately 6 seconds. At 10:05 a.m., with the Hatch switchyard voltage at 223 kV and recovering, Crystal River Unit 4 tripped. The second loss of generation resulted in a voltage drop to 218 kV (95 percent). At 10:06 a.m., the Southern Company Power Control Center contacted the Florida Power Control Center to assess the conditions causing the voltage excursion and the condition of the Florida grid. Southern Company was informed of the situation and confirmed that the Florida System was bringing up generation to stabilize the power flow from the Southern System to Florida's grid. Approximately 1.5 minutes after Crystal River Unit 4 tripped, the Hatch capacitors were manually closed and the voltage began a steady recovery. The combined voltage excursion from both the Crystal River Unit 2 and Unit 4 trips lasted approximately 6.5 minutes.

Georgia Power's review of the event concluded that the system performed as expected given the transmission system failures caused by the snow storm and nearly simultaneous unit trips at Florida Power. The loss of generation within the Florida System caused a voltage depression throughout the south Georgia area as the power flow from the Southern System to the Florida System increased to replace the lost generation. The actual effect or drop in voltage on the 4160 volt buses at Plant Hatch was not available, but no adverse effects were noted at the plant.

However, as part of the review, GPC identified a discrepancy relative to communication between the system operators and the Hatch control room. Specifically, system operators did not notify the Hatch control room that the 230 kV voltage had dropped below the minimum value until after the voltage had been restored. Technically, both units should have been in a one hour LCO. The notification did not occur as system operations had concluded that the system was not in jeopardy; the voltage excursion was quickly being restored. Corrective actions were taken to clarify this requirement and assure proper communications.

The licensee concluded that this event demonstrated that the degraded grid protection for Plant Hatch is consistent with GPC's objectives.

- The plant was adequately protected from an undervoltage condition as no adverse effects were evident.

- The offsite power source was preserved as the preferred source. While a short term dip in voltage occurred, the integrity of the system was not in jeopardy and a disconnect was not warranted.

- The situation was not further exacerbated by the unnecessary removal from the grid of Unit 1's approximately 800 megawatts. (Unit 2 was in a fuel reconstitution outage). Accordingly, the Southern Electric System was able to provide support to the Florida Power System as needed.

- If the setpoint for the degraded grid relays had been raised, a trip of Unit 1 probably would not have occurred for this specific event. However, the possibility of an unnecessary disconnect would have been increased due to possible setpoint drift. Consequently, GPC's objective of avoiding an unnecessary reactor isolation transient was met.

This led the licensee to conclude that the actual event supported GPC's integrated approach to evaluating degraded grid protection which considers electrical design requirements, plant operation, and grid system operation. In the event, the plant's electrical equipment was not adversely impacted by the voltage excursion, the plant continued to support the grid, the Southern Electric grid was able to support a neighbor utility and its public, and the plant was able to remain on offsite power. However, the application of automatic controls or prescriptive actions, in this event, could have been adverse to safety as the possibility of unnecessarily disconnecting the plant from the offsite power supply would have been increased, the possibility of unnecessary reactor isolation transients would have been increased, and the possibility of unnecessary load reductions/blackouts within the Southern Electric and Florida Power service areas would have been increased.

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July 1, 1994

Docket Nos. 50-321
50-366

HL-4586

TAC No. 80948

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant
Degraded Grid Protection

Gentlemen:

Following the electrical distribution system functional inspection which was completed on July 12, 1991, Georgia Power Company (GPC) representatives and the Nuclear Reactor Regulation (NRR) staff have held meetings and telephone conference calls to discuss the performance and protection of safety-related equipment at Edwin I. Hatch Nuclear Plant during postulated degraded grid voltage conditions. By letter dated November 22, 1993, GPC submitted a description of an evaluation which concluded that the existing degraded grid protection system provides an adequate level of safety and is in compliance with applicable regulations.

The degraded grid protection system was originally established in response to the Nuclear Regulatory Commission's letter dated June 2, 1977. This letter requested GPC to compare the design of the emergency power systems with the staff positions stated in the letter's enclosure to assess the susceptibility of the safety-related electrical equipment with regard to a sustained degraded voltage condition at the offsite power sources and interaction between the offsite and onsite emergency power systems. These staff positions, which were the precursors to Branch Technical Position PSB-1, are provided on page E-2 of GPC's November 22, 1993 submittal.

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An electrical distribution system functional inspection (EDSFI) was performed at Plant Hatch from June 10 through July 12, 1991. The NRC team determined that during a postulated design basis loss of coolant accident concurrent with the 4160 volt bus voltage in a narrow 3% band between approximately 91 percent (3786 volts) and 88.34 percent (3675 volts), certain class 1E loads at voltage levels of 600 volts and below may not receive sufficient voltage. The NRC EDSFI team did not agree with GPC's methodology which established a minimum expected value for offsite power to ensure adequate voltage and concluded that the automatic degraded grid protection was not adequate.

GPC's analysis of expected voltages for the safety-related loads uses the minimum expected voltage from the offsite power supply rather than the setpoint for the degraded grid undervoltage relay. As a result, a "deadband" exists between the minimum required voltage on the 4160 volt safety-related busses and the setpoint of 88.34 percent of 4160 volts for initiating an automatic disconnect of the offsite power supply. Consequently, a deviation from the staff position stated in the June 2, 1977 letter exists relative to the initiation of an automatic disconnect from the offsite power source. The deviation is approximately 12 percent when comparing the minimum required voltage to the voltage and time delay stated in the Technical Specifications, which is 78.8 percent of 4160 volts at 21.5 seconds. These setpoints are specified in Table 3.2-12, and Table 3.3.8-1 of the Unit 1 and Unit 2 Technical Specifications, respectively.

GPC's analysis of the degraded grid protection system determined that the evaluation requires consideration of several inputs. As described in GPC's November 22, 1993 submittal, the inputs are the electrical requirements of safety related equipment, the high reliability of the offsite power supply, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, and the extremely low probability of a sustained degraded grid concurrent with a loss of coolant accident (LOCA). Because of the offsite system monitoring capabilities and design, a sustained degraded grid does not represent the most probable event. Rather, a dynamic voltage excursion lasting less than 10 minutes is more likely. Consequently, the degraded grid voltage protection at Plant Hatch provides adequate assurance of plant safety. As a result, the existing degraded grid protection system uses manual actions instead of an automatic disconnect in the range of the deadband. Accordingly, GPC has implemented an abnormal operating procedure to provide specific actions to address a degraded offsite power supply. If the 4160 volt bus voltages were to degrade below approximately 92 percent, operators will initiate a "one hour to restore" action statement. If voltages are not restored within one hour, a plant shutdown is then initiated.

Georgia Power



During recent discussions, the NRR staff requested GPC to incorporate the degraded grid alarms into the Technical Specifications for both units. In response, GPC has agreed to include the alarms, along with the degraded grid undervoltage relays, in the improved Technical Specifications. Accordingly, the limiting condition of operation (LCO) will require the degraded grid alarms to be operable in modes 1, 2, and 3. The specification will include two actions. One will require monitoring the associated 4160 volt bus voltage on an hourly basis if one or more degraded grid alarms are inoperable. Each 4160 volt bus has two alarm relays. The second action will be to restore the inoperable alarm during the next refueling outage. The specification will also include a surveillance to perform an instrument calibration at least once per operating cycle.

Additionally, the NRR staff has verbally requested GPC to consider raising the degraded grid alarm setpoints from their current value of approximately 92 percent of 4160 volts to approximately 97 percent of 4160 volts. The current degraded grid alarm setpoints are specific to the individual 4160 volt busses and range from approximately 92 to 93 percent of 4160 volts. The NRR staff expressed a concern that an alarm setpoint of 92 percent would not provide sufficient notification that the voltage required for (LOCA) conditions had been degraded. GPC has evaluated this request to raise the alarm setpoints to 97 percent of 4160 volts and determined that it is not feasible nor required. The basis for this conclusion is as follows:

The NRR staff's request, basically, corresponds to applying the "hypothetical" alarm and trip ranges. That is, the range between the minimum expected operating voltage and the minimum required for LOCA conditions is sufficiently wide to accommodate an alarm and a trip prior to reaching the minimum required. As described on page E-9 of GPC's November 22, 1993 letter, the existing narrow range between the voltage expected with the offsite power at 101.3 percent of 230 Kv and the minimum required for LOCA loads would not accommodate an alarm setpoint of 97 percent due to the voltage changes associated with normal and startup/shutdown bus alignments to the startup transformers. As a result, an alarm setpoint of 97 percent would be expected to generate frequent nuisance alarms when the non-safety 4160 volt busses are powered from the startup transformers with the offsite power at 101.3 percent of 230 Kv.

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The current alarm setpoints of approximately 92 to 93 percent of 4160 volts are approximately midway between the calculated minimum expected voltage with the offsite power at 101.3 percent and the calculated minimum required voltage for normal operating conditions. The current alarm setpoint values signify that adequate voltage is available for normal operations. Consequently, the annunciator response procedures direct the operators to confirm the low voltage condition, contact the GPC control center, and to enter procedure 34AB-S11-001-0S, "Operation With Degraded System Voltage" if the voltage cannot be restored. Procedure 34AB-S11-001-0S directs operators to initiate a "one hour to restore" action statement for restoring the bus voltages to acceptable levels for normal operation. An alarm at 97 percent would not necessarily signify that a degraded voltage condition existed depending on the bus alignments to the startup transformers. From a human factors perspective, the significance of the alarm would be reduced as operators would expect to receive the alarm in certain conditions. Additionally, the current "one hour to restore" action statement significance would be inappropriate for the higher alarm setpoint. Consequently, the setpoints for the degraded grid alarms consider voltage requirements for normal operation as opposed to voltage requirements for LOCA conditions as the probability of a sustained degraded grid event concurrent with a LOCA is extremely low and is not a credible event.

Since GPC's alternate methodology of using manual actions instead of an automatic disconnect differs from the staff position stated in the June 2, 1977 letter, GPC requests formal NRR staff review and approval of this deviation. As described in the November 22, 1993 submittal, GPC has evaluated the deviation from the staff position and concluded that the existing degraded grid protection system is adequate, and is in conformance with applicable regulations. GPC has determined that the deviation is acceptable based on the offsite power system monitoring, the reliability of the offsite power supply, the extremely low probability of a sustained degraded grid event concurrent with a LOCA, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, the impact to the offsite power system caused by separating up to 1600 MW during a degraded grid event, and the enhancements provided by operating orders and degraded grid alarms.

Georgia Power



Should you have any questions in this regard, please contact this office.

Sincerely,

J. T. Beckham, Jr.

JKB/cr

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File

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November 22, 1993

Docket Nos. 50-321
50-366

HL-4440

Tac No. 80948

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant
<u>Degraded Grid Protection</u>

Gentlemen:

On previous occasions, Georgia Power Company (GPC) representatives and the Nuclear Regulatory Commission (NRC) staff have held meetings and telephone conference calls to discuss the performance and protection of safety-related equipment at the Edwin I. Hatch Nuclear Plant during postulated degraded grid voltage conditions. The degraded grid protection issue resulted from an electrical distribution system functional inspection which was completed on July 12, 1991.

During these meetings and conference calls, GPC discussed the objectives, criteria, and actions taken to resolve the degraded grid issue at Plant Hatch. GPC has assessed the level of safety provided by the current system and investigated options and potential modifications to upgrade the existing system. As a result, GPC has determined that the existing degraded grid protection provides adequate protection and is in accordance with the provisions of an NRC Safety Evaluation Report issued on May 6, 1982. Additionally, the degraded grid protection has been augmented by the installation of anticipatory alarms and an abnormal operating procedure. Consequently, the extensive plant modifications required to eliminate the narrow voltage deadband are unnecessary and unwarranted. Modifying the plant in this manner is unnecessary as there is no discernible increase in the protection of the health and safety of the public.

As described in the enclosure, GPC's analysis of the degraded grid protection system determined that the evaluation requires consideration of several inputs. The principal inputs involved are the electrical requirements of safety-related equipment, the reliability of the offsite power supply, the potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source, and the extremely low probability of a sustained degraded grid concurrent with a loss of coolant accident (LOCA).

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Because of the offsite system monitoring, contingency analysis, and transmission system design and operation, the occurrence of a sustained degraded grid condition requiring disconnect, concurrent with a LOCA, is not considered a credible event. Additionally, the existing narrow range between the minimum expected voltage and the voltage required for LOCA loads is insufficient to allow an increase in the undervoltage relay setpoints. Consequently, an increase in the undervoltage relay setpoints would likely result in an unnecessary and unwanted disconnect from offsite power during a LOCA. The possibility of spurious disconnects would also be increased. In order to increase the available range between the minimum expected and minimum required voltage, a large investment in extensive plant modifications would be required. Also, replacing the existing CV-7 inverse time relays with discrete time relays at the existing setpoint would not resolve the deadband issue. Given the adequate level of safety provided by the existing system, GPC does not consider such expenditures to be warranted or necessary. Consequently, GPC does not consider further actions to be necessary.

The enclosure provides additional details regarding GPC's evaluation and formal documentation of the positions expressed by GPC in discussions with the NRC staff. Upon review, GPC is requesting NRC staff concurrence with these actions as representing closure for the degraded grid issue at Plant Hatch.

Sincerely,

J. T. Beckham, Jr.

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004440

Enclosure: Degraded Grid Voltage Protection

cc: (See next page.)

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Enclosure

Edwin I. Hatch Nuclear Plant
Degraded Grid Voltage Protection

## Background

The existing degraded grid undervoltage protection system and setpoints were established and approved in response to a Nuclear Regulatory Commission (NRC) generic letter issued on June 2, 1977. During the Summer 1991 Electrical Distribution System Functional Inspection at Plant Hatch, the NRC inspection team questioned whether, under postulated degraded grid conditions, the setpoints of the undervoltage relays on the 4160 volt safety-related buses were too low to prevent the voltage on the 600 volt and 208 volt buses from dropping below minimum required voltages prior to disconnecting from the offsite power system. In response to this issue, Georgia Power Company (GPC) implemented an Operating Order as an interim measure. As a result of subsequent discussions with the NRC staff, one permanent modification to the degraded grid undervoltage protection system, as established in 1982, has been implemented to augment the protection provided. This modification installed an anticipatory alarm to alert plant operators of marginal voltages and augments the existing transmission system voltage monitoring scheme. Additionally, the provisions of the operating order have been incorporated into a permanent plant procedure.

## Origin of the Issue

The requirements for undervoltage relay protection originated as the result of an event at Northeast Utilities' Millstone Unit 2. On July 5, 1976, several 480 volt motors failed to start following a trip of Millstone Unit 2. The failure to start was the result of blown control power fuses on the individual motor controllers. An investigation at Millstone showed that the offsite power voltage dropped approximately 5 percent from 352 Kv to 333 Kv subsequent to the trip of the Millstone unit. The voltage drop reduced the control power and voltage within the individual 480 volt controllers to a voltage which was insufficient to actuate the contactors. As a result, the control power fuses were blown when the 480 volt motors were signaled to start.

At the time, Millstone's undervoltage protection consisted of only loss of offsite power undervoltage relays to separate the plant from the grid and initiate the onsite power sources. Millstone's initial corrective action was to raise the setpoint of these relays. However, this action was later considered inappropriate when the voltage dropped below the setpoint during starting of a large circulating water pump and de-energized the emergency buses.

Enclosure
Degraded Grid Voltage Protection

In response to the event at Millstone, by letter dated June 2, 1977, the NRC requested GPC to assess the susceptibility of safety related electrical equipment to a sustained voltage degradation of the offsite source. The letter contained positions with which the design of the plant was to be compared. These positions were the precursors to a branch technical position and are as follows:

1. "The selection of voltage and time setpoints shall be determined from an analysis of the voltage requirements of the safety related loads at all onsite distribution system levels."

2. "The voltage protection shall include coincidence logic to preclude spurious trips of the offsite power sources."

3. "The time delay selected shall be based on the following conditions:

   a. The allowable time delay, including margin, shall not exceed the maximum time delay that is assumed in the FSAR accident analysis."

   b. "The time delay shall minimize the effect of short-duration disturbances from reducing the unavailability of the offsite power source(s)."

   c. "The allowable time duration of a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components."

4. "The voltage monitors shall automatically initiate the disconnection of offsite power sources whenever the voltage setpoint and time-delay limits have been exceeded."

5. "The voltage monitors shall be designed to satisfy the requirements of IEEE Standard 279-1971.

6. "The technical specifications shall include limiting conditions for operations, surveillance requirements, trip setpoints with minimum and maximum limits, and allowable values for the second-level voltage protection monitors."

GPC provided an initial response on July 22, 1977, and additional information and Technical Specifications changes on October 9, 1980 and May 21, 1981. GPC submitted modified Technical Specifications changes on October 2, 1981 and December 2, 1981. Additional information is contained in GPC's submittals dated September 17, 1976; January 12, 1982; and January 26, 1982. Also, a brief description of the electrical distribution system for Plant Hatch is provided in Attachment 1.

GPC's methodology in addressing the NRC positions used the maximum plant loading conditions to determine the minimum expected voltage from the offsite power supply. At the time, the minimum expected value was 98 percent of 230 kV. Periodic, later evaluations have been performed to revise the minimum expected value as needed. GPC recalibrated one set of undervoltage relays to initiate transfers of the offsite power source to protect against a degraded grid. The Technical Specifications amendment request pertaining to degraded voltage protection was reviewed by the NRC staff and approved by letter dated May 6, 1982.

## EDSFI and Degraded Voltage Protection Reevaluation

An electrical distribution system functional inspection (EDSFI) was performed at Plant Hatch from June 10 through July 12, 1991. The NRC team determined that during a postulated design basis loss of coolant accident concurrent with the 4160 volt bus voltage in a narrow 3% band between 91 percent (3786 volts) and 88.34 percent (3675 volts), certain class 1E loads at voltage levels of 600 volts and below may not receive sufficient voltage. The NRC EDSFI team did not agree with GPC's methodology which established a minimum expected value for offsite power to ensure adequate voltage and concluded that the automatic degraded grid protection was not adequate.

By letter dated October 7, 1991, the NRC issued a Level IV violation stating that the automatic undervoltage protection for degraded grid voltage was not adequate to ensure that accident mitigating equipment would receive sufficient voltage to perform their safety function. By letter dated November 6, 1991, GPC denied the violation associated with degraded grid protection. GPC concluded that a violation of NRC requirements did not exist based on the following:

1. The existing degraded grid protection scheme at Plant Hatch is in accordance with GPC's response to the NRC Generic Letter dated June 2, 1977. As part of GPC's response to the NRC staff positions concerning degraded grid protection, a range for offsite voltage was established and shown to adequately supply emergency loads.

2. Compliance with the method of using the minimum expected voltage for the offsite grid in establishing the adequacy of plant voltage levels has been maintained. In the original voltage study submitted to the NRC on October 9, 1980, a minimum offsite source operating voltage of 98 percent of 230 kV was expected. At that time, the tap setting for transformer "D" was 1.0 p.u. (i.e., for a system voltage of 98% of 230 kV the corresponding voltage on the 4160 V buses for no-load conditions was 98% of 4160 V). The current minimum expected value is 101.3 percent of 230 kV. However, the increase was not a result of load additions to the plant. Rather, the change was necessary to accommodate higher expected transmission system operating voltages. Consequently, tap changes were made for the startup transformers in 1986 and 1987. Presently, the tap setting for transformer "D" is 1.025 p.u. (i.e., for a system voltage of 101.3% of 230 kV the corresponding voltage on the 4160 V bus for no-load conditions is 98.8% of 4160 V). Using the present minimum expected source voltage, tap connections, and load configurations, the expected 1E system voltages are, generally, slightly higher than the bus voltages submitted in 1980.

3. The existing degraded grid undervoltage relay setpoints were approved in the Safety Evaluation Report dated May 6, 1982. The SER affirmed compliance with staff positions for a second level of undervoltage protection.

4. Given the elapsed time since the original submittal in 1980, GPC has reevaluated the adequacy of the degraded grid protection at Plant Hatch. GPC's objectives were to assess the level of safety provided by the current system, investigate available options, and determine if improvements are feasible. GPC has concluded that the existing protection is adequate, raising the undervoltage relay setpoints is not feasible, and replacing the CV-7 relays with discrete time relays would represent a marginal to safety improvement. This conclusion is based on the following:

   A. The event at Millstone was significant in that a plant trip and the corresponding loss of electrical generation resulted in a sustained degraded offsite power supply without operator awareness of the event. However, significant differences exist between Plant Hatch and Millstone. The Southern electric system employs state-of-the art monitoring and contingency analysis systems for the electric grid on a real time basis. System operators ensure that adequate voltage is provided and the contingency analysis feature allows system operation to predict adverse affects from postulated system failures. Based on the contingency analysis results, system operators configure the offsite power system such that a worst case postulated failure can occur without adversely affecting the minimum required voltage. If the 230 kV system were to fall below the current minimum expected value of 101.3 percent, the switchyard design and offsite system design allows system operators to quickly mitigate a dynamic voltage excursion. Such an event actually occurred in March 1993 which is discussed later. This design allows the following actions to occur if the system were to fall below 101.3 percent. These following actions should be performed by system operators within approximately 10 minutes.

- System operators receive low voltage alarm.
- System operators notify the control room at Plant Hatch.
- The 162 MVAR capacitor bank on the 230 kV switchyard is switched on (if off).
- The 150 MVAR shunt reactors on the 500 kV line are turned off (if on).
- Capacitor banks in the surrounding area are turned on (if off).
- Combustion turbines at Plant McManus are placed in service.

These actions are normally capable of improving the 230 kV voltage by approximately 2 to 4 percent. If these actions are not sufficient, system operators will take the following actions:

- Out of service elements are brought back on line.
- System load (external or internal) is reduced.

Consequently, based on the system monitoring capabilities, contingency analysis capabilities, operation of the system such that a postulated worse case failure will not impact the offsite voltage below the minimum required, and the ability for system operators to quickly restore a dynamic voltage excursion; the event at Millstone is not considered applicable to Plant Hatch.

B. Because of the offsite system monitoring capabilities and design, a sustained degraded grid does not represent the most probable event. Rather, a dynamic voltage excursion lasting less than 10 minutes is more likely. Consequently, the degraded voltage protection at Plant Hatch provides adequate assurance of plant safety for this type of event. For a dynamic voltage excursion, GPC has determined that disconnecting both units from the offsite power supply and introducing dual unit scrams and reactor isolation transients through automatic undervoltage relays would be adverse to safety. GPC initially issued an Operating Order which identified specific actions to be taken if the system operators are in jeopardy of not maintaining voltages within the required operating range. The actions consist of restoring any inoperable emergency diesel generators (EDGs), limiting maintenance or surveillance of important onsite electrical equipment, closely monitoring voltage levels on the six 4160 volt safety-related busses, and informing plant management. The Operating Order also specified actions to be performed if the 4160 volt essential busses fall below the minimum acceptable voltage. These actions include initiation of a one hour Limiting Condition of Operation (LCO) to restore safety-related bus voltages, notification of management, and an orderly plant shutdown if voltage is not restored. The actions specified in the operating order have been incorporated into abnormal operating procedure 34AB-S11-001-OS, "Operation With Degraded System Voltage." Operators receive training relative to the actions specified in the procedure through the normal operator training and operator requalification training on abnormal operating procedures.

This alternate method allows system operators to quickly restore a degraded grid to avoid an unnecessary isolation transient, further degradation of the offsite power supply to the plant, adverse impacts to neighboring utilities and other interconnected plants, when the offsite power is undergoing a temporary voltage excursion and is not in actual jeopardy.

An event as described above actually occurred at Plant Hatch on Sunday, March 14, 1993. During that weekend, record snow accumulations, along with high winds were occurring within the Southern Electric System. This was resulting in significant outages due to failures of local distribution networks. During this time, specifically on March 14, 1993 at 10:04 a.m., Florida Power Corporation's Crystal River Unit 2 tripped. The loss of generation within the Florida grid caused a dynamic voltage excursion within the Southern

Electric grid. The Hatch switchyard voltage dropped to 215 kV (93 percent) in one second and stabilized at 223 kV (97 percent) in approximately 6 seconds. At 10:05 a.m., with the Hatch switchyard voltage at 223 kV and recovering, Crystal River Unit 4 tripped. The second loss of generation resulted in a voltage drop to 218 kV (95 percent). At 10:06 a.m., the Southern Company Power Control Center contacted the Florida Power Control Center to assess the conditions causing the voltage excursion and the condition of the Florida grid. Southern Company was informed of the situation and confirmed that the Florida system was bringing up generation to stabilize the power flow from the Southern System to Florida's grid. Approximately 1.5 minutes after Crystal River Unit 4 tripped, the Hatch capacitors were manually closed and the voltage began a steady recovery. The combined voltage excursion from both the Crystal River Unit 2 and Unit 4 trips lasted approximately 6.5 minutes.

GPC's review of the event concluded that the system performed as expected given the transmission system failures caused by the snow storm and nearly simultaneous unit trips at Florida Power. The loss of generation within the Florida System caused a voltage depression throughout the south Georgia area as the power flow from the Southern System to the Florida System increased to replace the lost generation. The actual effect or drop in voltage on the 4160 volt busses at Plant Hatch is not available; however, none of the anticipatory degraded grid alarms actuated indicating that the voltage did not drop below the minimum required for normal operation for a sufficient time to exceed the relay's time delay.

As part of the review, GPC identified a discrepancy relative to communication between the system operators and the Hatch control room. Specifically, system operators did not notify the Hatch control room that the 230 kV voltage had dropped below the minimum value until after the voltage had been restored. Technically, both units should have been in a one hour to restore LCO as specified by the operating order. The notification did not occur as system operations had concluded that the system was not in jeopardy, the voltage excursion was quickly being restored, and the brief time of the excursion. Corrective actions have been taken to clarify this requirement and assure proper communications.

This event demonstrates that the existing degraded grid protection for Plant Hatch is consistent with GPC's objectives.

- The plant was adequately protected from an undervoltage condition as no alarms were actuated and no adverse effects were evident.

- The offsite power source was preserved as the preferred source. While a short term dip in voltage occurred, the integrity of the system was not in jeopardy and a disconnect was not warranted.

- The situation was not further exascerbated by the unnecessary removal from the grid of Unit 1's approximately 800 megawatts. (Unit 2 was in a fuel reconstitution outage). Accordingly, the Southern Electric System was able to provide support to the Florida Power System as needed.

- If the setpoint for the degraded grid relays had been raised, a trip of Unit 1 probably would not have occurred. However, the possibility of an unnecessary disconnect would have been increased due to possible setpoint drift. Consequently, GPC's objective of avoiding an unnecessary reactor isolation transient was met.

The actual event supported GPC's integrated approach to evaluating degraded grid protection which considered the electrical design requirements, plant operation, and system operation. In the event, the plant's electrical equipment was not adversely impacted by the voltage excursion, the plant continued to support the grid, the Southern Electric grid was able to support a neighbor utility and its public, and the plant was able to remain on offsite power. However, the application of automatic controls or prescriptive actions, in this event, could have been adverse to safety as the possibility of unnecessarily disconnecting the plant from the offsite power supply would have been increased, the possibility of unnecessary reactor isolation transients would have been increased, and the possibility of unnecessary load reductions/blackouts within the Southern Electric and Florida Power service areas would have been increased.

C. GPC has investigated options and potential modifications to improve the existing system. Based on the results, GPC has concluded that modifications in addition to the anticipatory alarms recently installed are not desirable. This conclusion is based on the following:

To meet a hypothetical alarm/trip range scheme as shown on Attachment 2, a large investment in major equipment and/or extensive plant modifications would be required. GPC has estimated the cost at approximately 10 million dollars. Given the level of safety provided by the existing system, such an expenditure is not warranted.

Because of the existing narrow range between the voltage expected with the offsite power at 101.3 percent and the minimum required for LOCA loads, it would not be advisable to raise the setpoints for the undervoltage relays on the E, F, and G 4160 volt busses. As shown in the voltage diagrams for the safety-related 4160 volt buses provided as Attachment 3, the G bus on Unit 1 represents the bus with the most narrow range between the minimum expected and the minimum required voltage. With the offsite power at 101.3 percent and loads associated with mitigating a design basis LOCA being supplied, the G bus is expected to be at 91.14 percent. However, the minimum required to ensure adequate voltage is supplied is 90.8 percent. Consequently, a band of 0.34 percent is available. Since the most accurate undervoltage relay evaluated has an accuracy of approximately 1.25 percent, the trip may occur within the expected voltage. This could result in an unnecessary and unwanted disconnect from offsite power during a LOCA which is contrary to applicable NRC staff positions for minimizing the unavailability of the offsite power source. Due to the narrow band, the anticipatory degraded grid alarm recently installed is expected to annunciate if the grid is at 101.3 percent concurrent with a LOCA. Raising the undervoltage relay setpoint would introduce a consequence which is contrary to the NRC staff positions for degraded voltage protection. As stated previously, increasing the range between the minimum expected and minimum required voltages as shown in Attachment 2 would require purchasing major equipment and/or extensive plant modifications. Given the existing level of protection and the cost for installing new startup transformers, plant modifications, or switchyard equipment, the improvement would be costly and minimal to safety improvement.

GPC has also investigated the benefits associated with replacing the existing CV-7 inverse time relays with discrete time relays without raising the setpoint. While new relays could resolve the concern relative to potentially excessive delays in the transfer of the 4160 volt bus to the onsite power supply once the setpoint is reached, new relays will not provide a resolution to the deadband issue. The setpoint for the new relays would be the same as the existing setpoint and the minimum required voltage would be unaffected. Given that the substantive issue of the deadband would not be resolved, GPC considers the installation of discrete time relays to be an unwarranted expenditure.

## Conclusion

GPC's analysis of the degraded grid protection concluded that the evaluation requires consideration of several inputs. The primary inputs into GPC's evaluation involved:

- The electrical requirements of safety-related equipment.
- The reliability of the offsite power supply.
- The potential adverse effects to the plant caused by an unnecessary disconnect from the offsite power source.
- The extremely low probability of a sustained degraded grid event concurrent with a LOCA.
- The impact to the offsite power system caused by separating up to 1600 MW during a degraded grid event.

As a result of the reevaluation, GPC has concluded that the existing degraded grid protection provides an adequate level of safety. Additionally, the degraded grid protection has been augmented by the installation of anticipatory alarms and an abnormal operating procedure. GPC also concluded that raising the setpoints for the undervoltage relay to the minimum required voltage level would likely result in an unnecessary disconnect from offsite power during a LOCA with the grid at 101.3 percent of 230 kV. The modifications necessary to increase the available range between the minimum expected and minimum required, such that unwanted or unnecessary disconnects are precluded, would be costly and marginal to safety. Given the adequate level of safety provided by the existing system, GPC does not consider further expenditures to be necessary.

## ATTACHMENT 1

## EDWIN I. HATCH NUCLEAR PLANT
## ELECTRICAL DISTRIBUTION SYSTEM DESCRIPTION

Attachment 1

Edwin I. Hatch Nuclear Plant
Electrical Distribution System Description

Electrical Distribution System Description for Plant Hatch

The Georgia Power Company (GPC) grid is a network of many interconnections with other utilities and multiple locations for tying generating plants into the grid system.

The GPC system is also designed to connect generating units to the grid at optimum locations. This is evident at Plant Hatch as eight transmission lines from different locations and directions tie the units to the grid.

The switchyard at Plant Hatch consists of four 230 kV lines and four 500 kV lines. The Unit 1 main generator is connected to the 230 kV portion of the switchyard and the Unit 2 generator is connected to the 500 kV portion of the switchyard.

The following is a discussion of the electrical distribution system and is applicable to either unit. A simplified one line diagram is provided in Figure 1.

Four transformers supply power to the distribution system for each unit. Normally, transformers A and B are used when the unit is on line and supply power from the main generator to non-safety related 4160 volt busses A, B, C, and D. Transformers C and D supply power from the 230 kV switchyard to safety related busses E, F, and G and also supply non-safety related busses A, B, C, and D during startup and shutdown.

The 4160 volt busses A and B supply power to the reactor recirculation pumps and the condenser circulating water pumps which are the plant's largest loads.

The 4160 volt busses C and D supply power to various auxiliary loads such as the condensate and condensate booster pumps within the feedwater system, as well as the majority of the non-safety related loads at the plant.

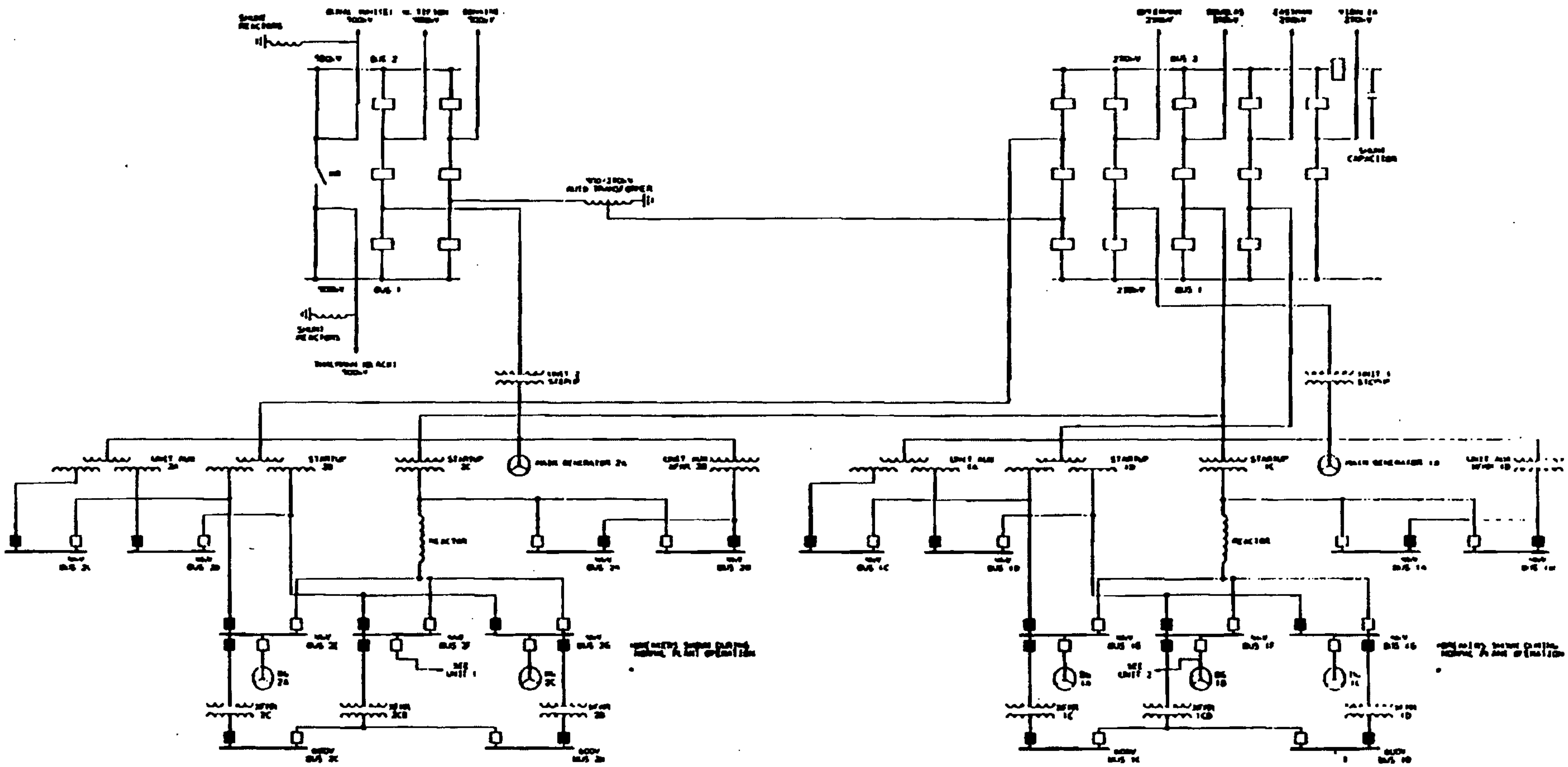
The 4160 volt E, F, and G busses supply power to the unit's safety related loads such as the core spray pumps, RHR pumps, plant service water, and RHR service water pump motors, as well as safety related 600 volt and lower busses. These are the busses backed up by the diesel generators.

Attachment 1
Electrical System Description

During startup, non-safety related 4160 volt busses A and B are supplied from offsite power through transformer C. After the main generator is synchronized and the loads are stable, a synchronized transfer normally is made to transformer B. If transformer B is lost, a "fast" transfer is made back to transformer C. If startup transformer D is out of service, this transfer is blocked because the safety related busses will be transferred to transformer C. Additionally, busses A and B would be tripped if already connected.

During startup, non-safety related 4160 volt busses C and D are connected to startup transformer D. After synchronization, these busses are normally transferred to transformer A. Transformer D is sized to carry the required loads for busses E, F, G, C, and D.

During startup, shutdown, and normal operation, safety related 4160 volt busses E, F, and G are normally supplied from startup transformer D. If transformer D fails, there is an automatic transfer to startup transformer C. If both transformer D and C fail, the emergency diesel generators are connected to 4160 volt busses E, F, and G.



H-13350 - UNIT 1
H-23350 - UNIT 2

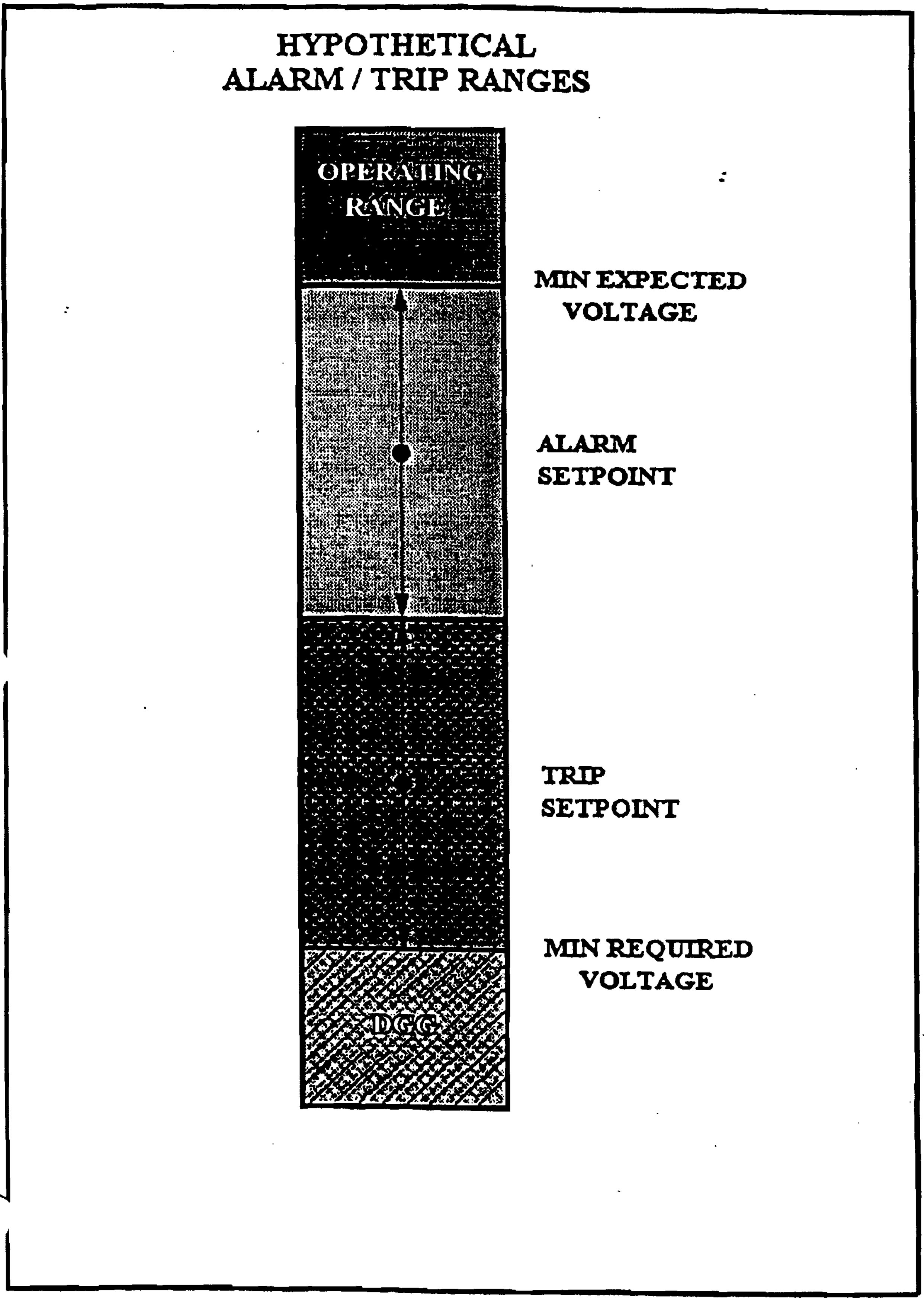
MAIN POWER DISTRIBUTION
EDWIN I HATCH - UNIT 2

MAIN POWER DISTRIBUTION
EDWIN I HATCH - UNIT 1

**FIGURE 1**
**MAIN POWER DISTRIBUTION SYSTEM**
**BREAKER POSITIONS - NORMAL OPERATION**

## ATTACHMENT 2

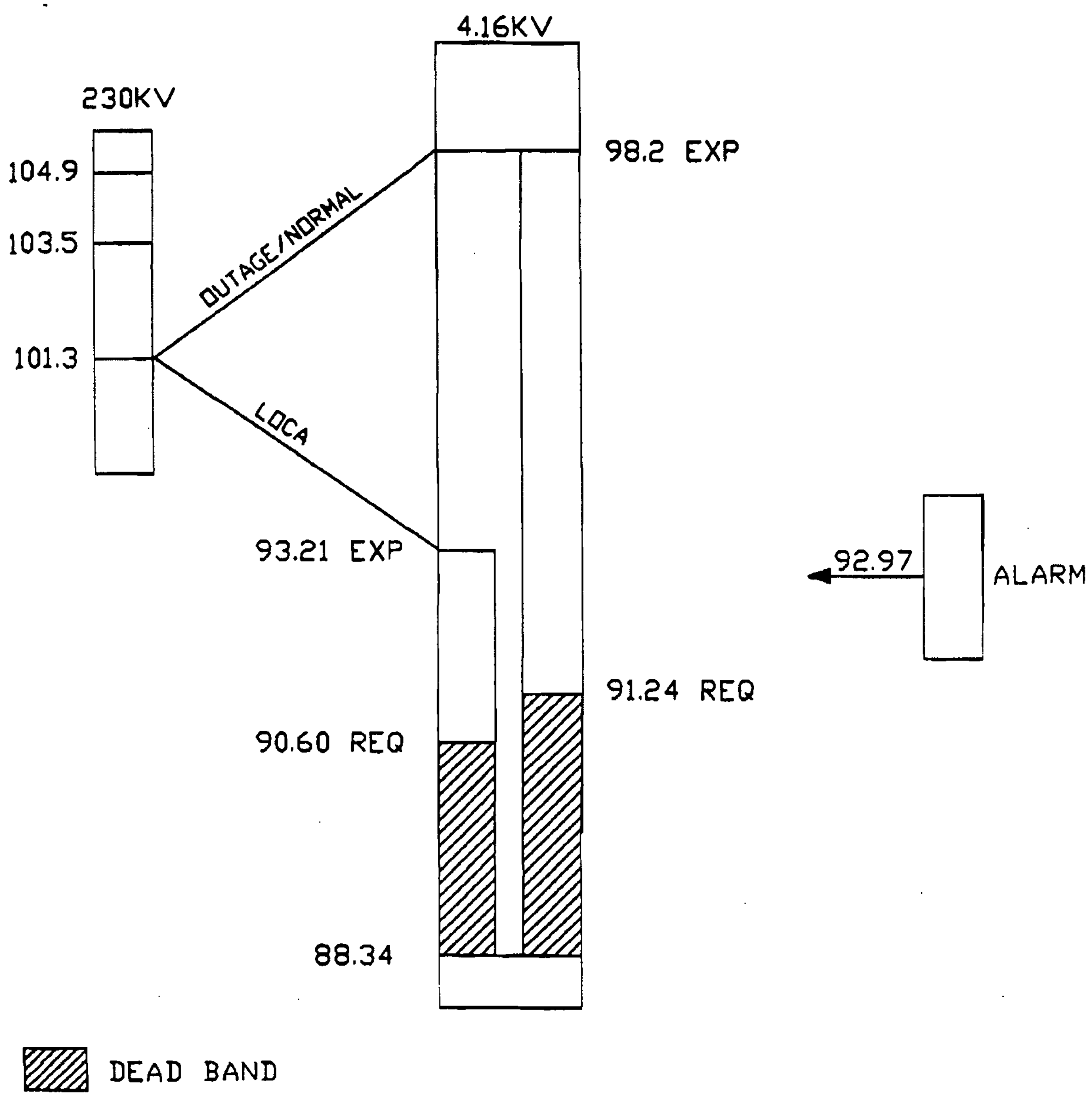
## EDWIN I. HATCH NUCLEAR PLANT
## HYPOTHETICAL ALARM/TRIP RANGES


HYPOTHETICAL
ALARM / TRIP RANGES
OPERATING RANGE
MIN EXPECTED VOLTAGE
ALARM SETPOINT
TRIP SETPOINT
MIN REQUIRED VOLTAGE
DGG

ATTACHMENT 3

EDWIN I. HATCH NUCLEAR PLANT
4160 VOLT BUS VOLTAGE DIAGRAMS

# Plant Hatch Unit 1 Bus E

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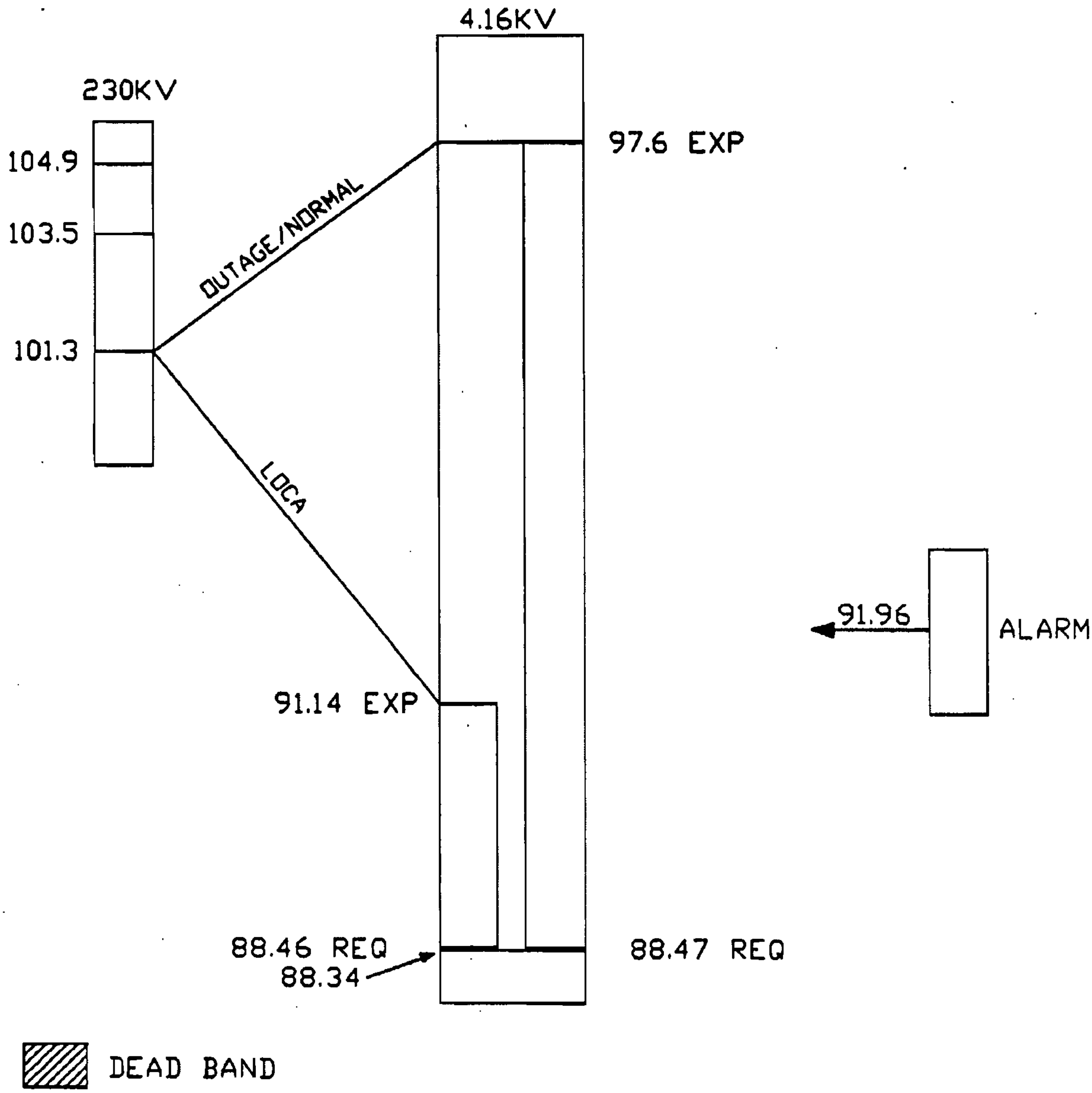
# Plant Hatch Unit 1 Bus F

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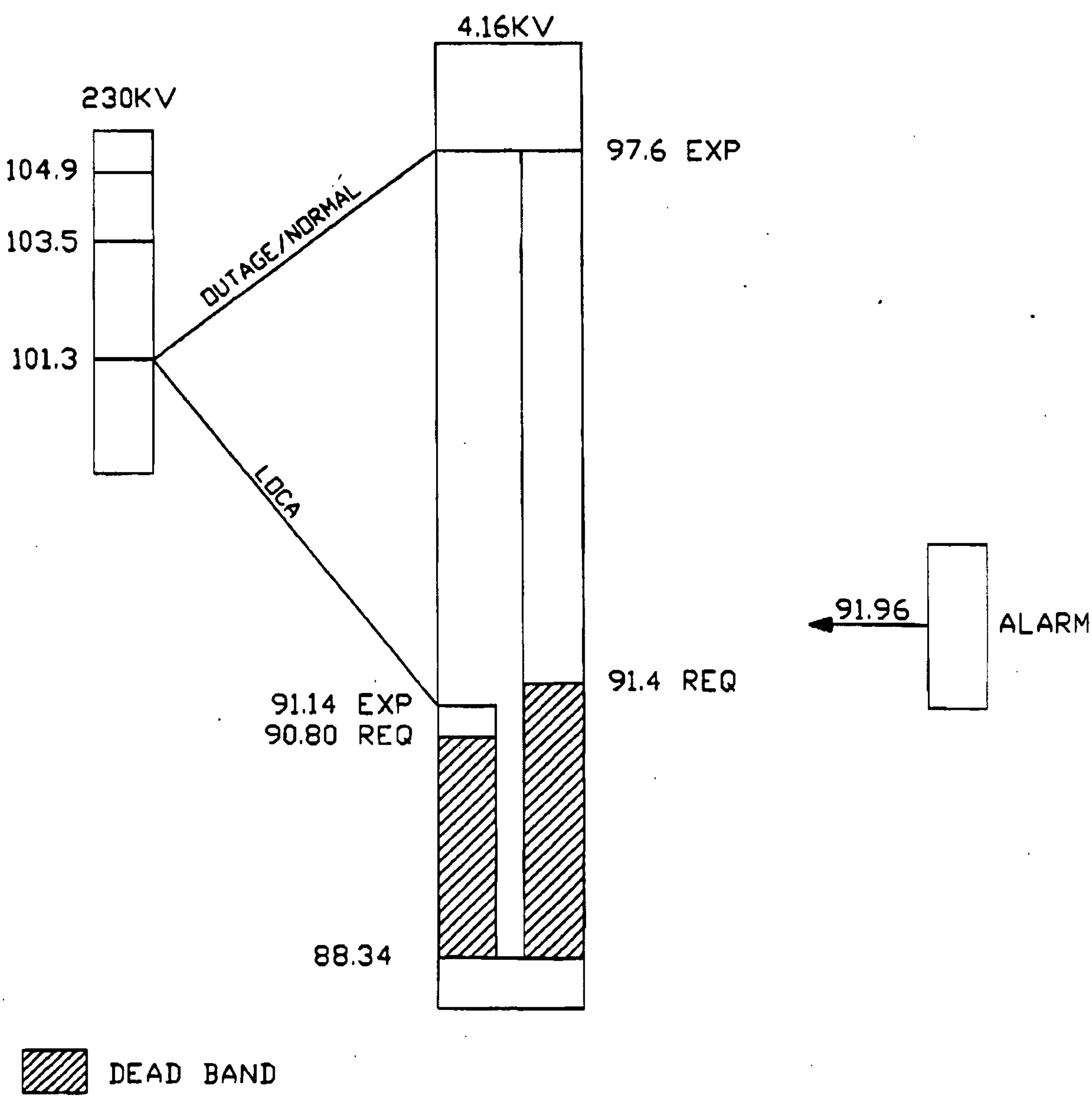
# Plant Hatch Unit 1 Bus G

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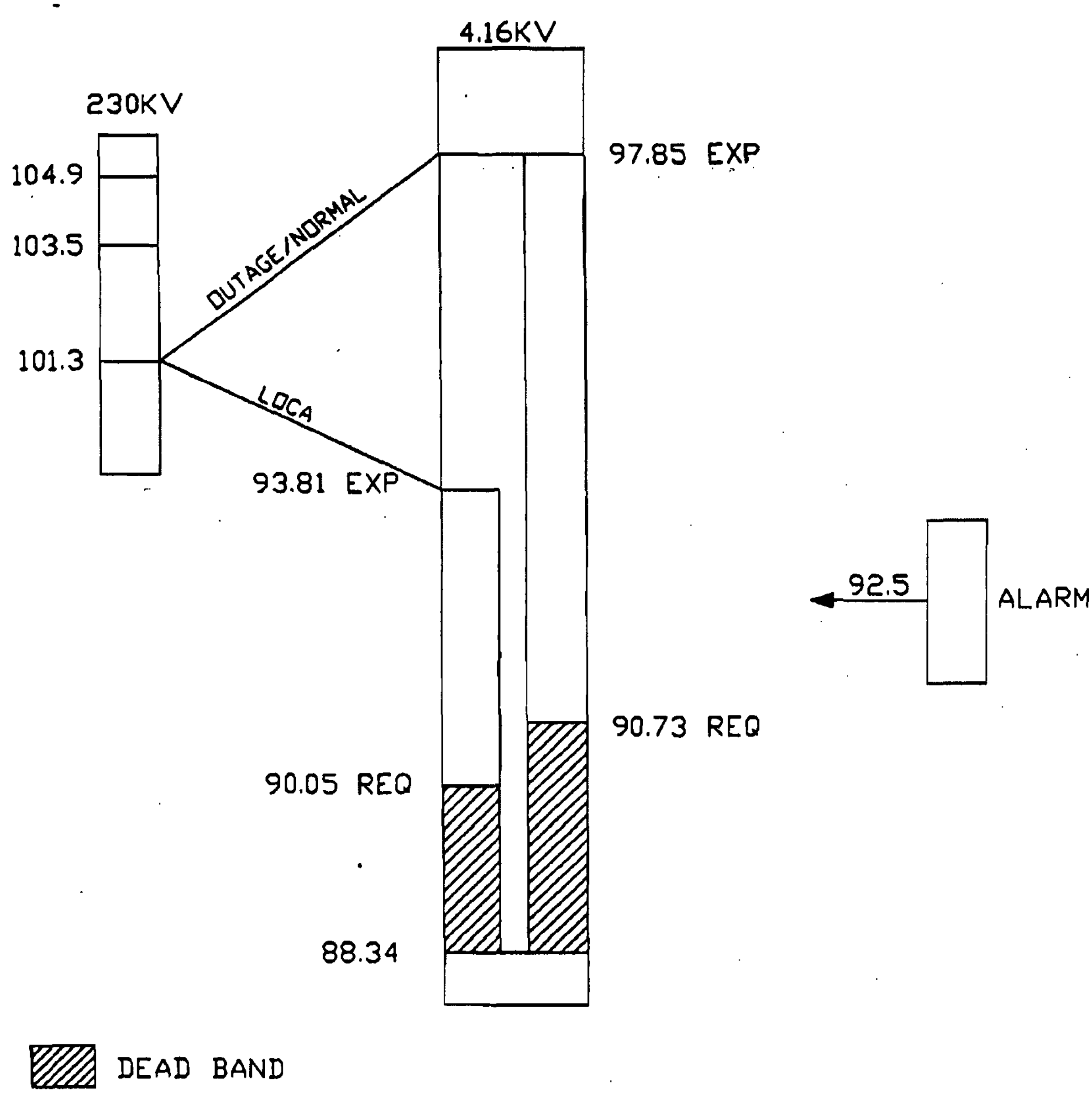
# Plant Hatch Unit 2 Bus E

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