# U.S. NUCLEAR REGULATORY COMMISSION

## REGION III

Report Number 50-331/91002(DRS)

Docket No 50-331 License No. DPR-49

Licensee: Iowa Electric Light and Power Company
IE Towers
P. O. Box 351
Cedar Rapids, IA 52406

Facility Name: Duane Arnold Energy Center

Inspection at: Palo, IA

Inspection Conducted: February 4 through March 8, 1991

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Inspection Summary:

Inspection on February 4 through March 8, 1991 (Report No. 331/91002(DRS))
Areas Inspected: Special electrical distribution system functional inspection in accordance with temporary instruction (TI) 2515/107 (25107).
Results: The team determined that the electrical system was functional and that the engineering and technical support was acceptable. Four open items were identified regarding testing of the SDG parallel to the grid (Paragraphs 2.1.2 and 2.1.3), lack of secondary surge arresters (Paragraph 2.1.4), sizing of the neutral ground resistor (Paragraph 2.1.8), and lack of cable tray covers for control cables (Paragraph 2.1.13). Five unresolved items were identified regarding the licensee's evaluation of the 480Vac breaker magnetic trip settings( Paragraph 1.1.16), the licensee's evaluation of DC contactor operation under low voltage conditions (Paragraph 2.2.3), the licensee's

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evaluation of TS SDG fuel storage commitments (Paragraph 2.3.1), the licensee's evaluation of seismic qualification of SDG air start accumulator relief valves (Paragraph 2.3.2), and susceptibility of SDG ducting to tornado induced depressurization (Paragraph 2.3.3). Two violations were identified regarding instruments not set in accordance with design documents and instruments left exceeding calibration tolerance (Paragraph 2.1.12), and inadequate procedures (Paragraphs 2.1.12, 2.1.15, and 2.1.17).

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## EXECUTIVE SUMMARY


From February 4 through March 8, 1991, a Region III team conducted an electrical distribution system functional inspection (EDSFI) at the Duane Arnold Energy Center to review the design and implementation of the plant electrical distribution system (EDS) and the adequacy of the engineering and technical support (E&TS) organizations. The team reviewed the electrical and mechanical support systems of the EDS, examined installed EDS equipment, reviewed EDS testing and procedures, and interviewed selected corporate and site personnel.

The team considered the design and implementation of the EDS at Duane Arnold to be acceptable. Design attributes of the EDS were retrievable and verifiable, although the team considered the condition of the plant's drawings a programmatic weakness. Engineering calculations were technically sound, although the team identified some nonconservative assumptions. The team considered the scope and implementation of the site program for surveillance testing of EDS equipment a strength. Control of modifications to the EDS was acceptable and there appeared to be an adequate interface between Engineering and Operations; however, the team considered the large number of electrical LERs related to personnel error to be indicative of a weakness in training and supervision. The team found the EDS and related support equipment properly installed in the plant and considered the material condition of the EDS and housekeeping in the plant a strength. In addition, the team considered the knowledge and expertise of the engineering staff a strength; however, staffing levels appear to be strained.

The team also had several concerns that required further action by the licensee. Examples included:

- o The acceptability of the operation of DC contactors under low voltage conditions.
- o The evaluation of the quantity of diesel fuel stored on site to meet TS requirements.
- o The evaluation of the seismic qualification of the SDG air start accumulator relief valves.

Several of the team's concerns resulted in violations of NRC requirements. For example:

- o Instruments were left exceeding their as-left calibration tolerances and the licensee failed to perform an engineering evaluation to assess the effect of leaving these instruments out of tolerance.
- o Four examples of safety related equipment with incorrectly sized fuses were found in the plant.
- o An inadequate overcurrent relay test procedure resulted in a non-conservative tap setting.

## 1.0 Introduction

During electrical inspections at various operating plants in the country, the NRC staff had identified several EDS deficiencies. The Special Inspection Branch of NRR initiated inspections of the EDS at other operating plants, after they determined that such deficiencies could compromise design safety margins. Examples of these deficiencies included unmonitored and uncontrolled load growth on safety buses and inadequate modifications, design calculations, testing, and qualification of commercial-grade equipment used in safety related applications. The NRC considered inadequate E&TS to be one cause of these deficiencies.

The objectives of this inspection were to assess the performance capability of the Duane Arnold EDS and the capability and performance of the licensee's E&TS in this area. For this inspection, the EDS included all the emergency sources of power to systems required to remain functional during and following the design basis events. EDS components reviewed included the standby diesel generators (SDGs), 125Vdc batteries, offsite circuits and switchyard, 4kV switchgear, 480Vac load centers (LCs), 480Vac Motor Control Centers (MCCs), 125Vdc MCCs, battery chargers, inverters, associated buses, breakers, relays, and other miscellaneous components.

The team reviewed the adequacy of the emergency, offsite and onsite power sources for EDS equipment, the regulation of power to essential loads, protection for postulated fault currents, and coordination of the current interrupting capability of protective devices. The team also reviewed the mechanical systems that interface with the EDS, including air start, lube oil, and cooling systems for the SDGs plus the cooling and heating systems for the EDS equipment. The team walked-down originally installed and as-modified EDS equipment for configuration and equipment ratings and reviewed qualification, testing, and calibration records. The team assessed the capability of the licensee's E&TS organization with respect to personnel qualification and staffing, timely and adequate root-cause analyses for failures and recurring problems, and engineering involvement in design and operations. The team also reviewed training for Operations and E&TS personnel relative to the EDS.

The team verified conformance with General Design Criteria (GDC) 17 and 18 and the applicable 10 CFR 50, Appendix B, criteria. The team also reviewed plant technical specifications (TSs), the updated safety analysis report (USAR), and appropriate safety evaluation reports (SERs) to verify that TS requirements and licensee commitments were met.

The areas reviewed and the concerns that were identified are described in Sections 2.0 and 3.0 of this report. Conclusions are given after each of these sections. A list of the personnel contacted and those who attended the exit meeting on March 8, 1991, is provided in Appendix A of the report.

## 2.0 Class 1E Electrical Systems

### 2.1 AC Systems

In order to assess the capability of the electrical system, the team reviewed the regulation of EDS loads, the overcurrent protection, and the coordination of protective devices for compliance with regulations, design engineering standards, and accepted engineering practices. The review included system descriptions, station USAR, equipment sizing calculations, system protection, controls and interlocks, equipment specifications, modification packages, licensee event reports (LERs), related test and operating procedures, one-line diagrams, elementary diagrams, and equipment layout drawings.

The characteristics of the power system electrical grid to which the Duane Arnold plant is connected were reviewed to assess the adequacy of important parameters, such as voltage regulation, short circuit contribution, protective relaying, surge protection and control circuits. The preferred power supply transformers were reviewed in terms of their kVA capability, their connections to the safety buses, field installation capability, protection, and voltage regulation. The SDGs were reviewed to assess the adequacy of the kW rating, the ability to start and accelerate under assigned safety loads in the required time sequence, the voltage and frequency regulation under transient and steady state conditions, compliance with single failure criteria, and the applicable separation requirements. The 4kV safety buses and their connected loads were reviewed to assess load current and short circuit current capabilities, voltage regulation, protection, adequacy of cable connections between loads and buses, compliance with single failure criteria, adequacy of the fast and slow bus transfer scheme in terms of any effects on the safety systems, and applicable separation requirements. The 480Vac safety buses and their connected loads were reviewed to assess load current and short circuit current capabilities, voltage regulation, protection, adequacy of cable connections between loads and buses, compliance with single failure criteria, and applicable separation requirements.

The team also evaluated electrical design features, parameters and the configuration management program associated with electrical systems and components. The team performed a field inspection of selected systems to verify whether field installations conformed to design basis requirements and whether modifications had been properly implemented. In addition, the team performed a detailed evaluation of portions of selected systems to confirm that they remain functional on demand.

#### 2.1.1 Retransfer of Vital Buses to the Preferred Power Source

The team's review indicated that during a loss of offsite power when the SDGs are automatically started and connected to bus Nos. 1A3 and 1A4, a ground fault on either bus or the associated ESF loads will not be properly annunciated. The annunciation will indicate a SDG fault even though the actual fault location could be one of the vital buses or an ESF load. Because the SDG is grounded through a high resistance, ground fault currents would be limited to two or three amperes. This would be sufficient to initiate the control room annunciator but would not result in ESF equipment trips. Should offsite power be restored, an operator might attempt a retransfer to the startup transformer to clear the SDG fault indication. Since the startup transformer grounding scheme allows a current of approximately 800A, the retransfer could cause a trip of the faulted load. To allow for continuous operation of ESF loads during a postulated LOCA condition which follows the loss of offsite power, a retransfer to the offsite source should be precluded since such a transfer could result in the loss of ESF loads.

A review of the drawings and the operating procedures did not reveal any provision for precluding retransfer to the offsite source in case of ground faults when the SDGs are connected to the vital buses.

The licensee stated that the operator was trained not to initiate any transfers without first ensuring that the fault had been rectified. The team accepted this response but considered the operation of the non-discriminating ground fault annunciation a weakness in the original design.

#### 2.1.2 SDG Parallel Operation with the Grid During SDG Testing

The team noted that in order to meet TS requirements for SDG testing, the SDGs are paralleled with the offsite power and operated in this test mode for the required time (one hour). The team reviewed the generator protection scheme and observed that during SDG parallel operation, the SDGs could be overloaded. In the event of a LOCA followed by a loss of offsite power (LOOP), the degraded voltage relays on the associated vital bus would not sense loss of voltage from the preferred source and trip the necessary circuit breakers. As a result, the SDG would be subjected to a sudden overload which could either damage the SDG or trip the SDG breaker. In the latter case, restoration of power to the bus would first require the local resetting of the protective relays. If the event were to occur when one of the SDGs was out for maintenance, the resulting effect would be a temporary station blackout.

The licensee responded by stating that occurrence of LOCA and a LOOP while testing the SDGs had a very low probability. The team concurred with the licensee. However, the team considered this condition to be a generic design weakness. This item is considered open pending additional NRC review (331/91002-01A(DRS)).

#### 2.1.3 Sensing Degraded Voltage on Safety Buses During SDG Testing

The team noted that in the event of a loss of offsite power when the SDGs are being tested by paralleling with the grid, the degraded voltage relays on the 4kV safety buses could fail to detect the loss of grid voltage. The SDG being tested could maintain voltage on both safety buses by supplying power to the second safety bus through the split secondary of the startup transformer. This could prevent connection of the second SDG to its associated safety bus. The team also noted that protection coordination curves for the SDG did not show the damage curve for the generator making it impossible to determine whether the generator being tested could be damaged during these conditions.

The licensee stated that the probability of a loss of offsite power during SDG surveillance testing was very low due to the limited amount of time that the

SDG would be paralleled to the grid. The team accepted the response based on the low probability of the event and hence, marginal safety significance, but considered this a generic design weakness. This item is considered open pending additional NRC review (331/91002-01B(DRS)).

### 2.1.4 Surge Protection for 4kV Motors and Load Center Transformers

The team noted that the EDS design did not incorporate surge protection on the secondary side of the switchyard transformer. Instead, the design relied upon primary side surge protection only. A surge originating in the 161 kV switchyard could be only partially discharged by the primary side surge arresters with a portion of the surge passing through the transformer to the 4kV system. If this were to occur, the LC transformers and some class 1E 4kV motors could be damaged. An accurate assessment of the likelihood of damage can only be accomplished by a study which evaluates such factors as the potential magnitude of the surge, the transient characteristics of the standby auxiliary transformer, and the ability of the LC transformers and the class 1E motors to withstand surges.

Since both LC transformers are supplied from the same offsite source, the team was concerned that the effect of the surge could be to disable both the redundant safety trains, thereby rendering redundant portions of the EDS incapable of performing a safe plant shutdown.

The licensee agreed to investigate this matter and indicated that an analysis would be performed. Pending NRC review of this analysis, this is considered an open item (331/91002-02(DRS)).

### 2.1.5 4kV Switchgear Rating

The team was concerned that breaker interrupt ratings could be exceeded. Calculation No. E-86, "Short Circuit Study for Auxiliary Power Transformer," Revision 0, did not address the effect of maximum grid voltage on short circuit current, the short circuit current contribution from bus No. 1A4, and the contribution from the SDG when it is connected in parallel to the grid during testing.

The licensee's response to the team's concern was that the breakers were not sized to allow for the short circuit currents due to the SDG in parallel with the grid, since this was not required by the design basis document. However, the licensee stated that they were in the process of carrying out a computerized Power System Analyses (PSA) which will allow for a more accurate determination of the short circuit levels. The team found this acceptable, provided that the new calculations demonstrate that the short circuit capabilities of the circuit breakers are not exceeded.

### 2.1.6 Retransfer from Standby Transformer to Startup Transformer

The team noted that in the event of a ground fault on a safety bus or its associated ESF loads when the loads are being fed from a standby transformer, a ground fault would not be properly annunciated. The control room annunciator would indicate a transformer fault even though the actual fault location could be the safety bus or its associated ESF loads. Because the standby transformer is grounded through a high resistance, ground fault currents would be limited to two to three amperes. This would be sufficient to initiate the control room annunciator but would not result in ESF equipment trips. Should the startup transformer be restored, an operator might attempt a retransfer to the startup transformer to clear the standby transformer fault indication. Since the startup transformer grounding scheme allows a current of approximately 800A, the retransfer could cause a trip of the faulted load. To allow for continuous operation of ESF loads during a postulated LOCA condition, a retransfer to the startup transformer should be precluded since such a transfer could results in the loss of ESF loads.

The licensee agreed to add a precautionary notice to ARP No. 1C08B, A-11, and Procedure No. OI 304.2, Section 7.4, indicating that transfer of the faulted bus to the startup transformer could cause loss of the entire bus or an essential load and that this transfer should not be done in an emergency situation. The team found this response acceptable and had no further concerns.

2.1.7 Fast transfer from Startup Transformer to Standby Transformer

The team noted that during normal plant operation 4kV bus Nos. 1A3 and 1A4 are supplied from the startup transformer. In case of loss of power from the preferred source, the affected buses are fast transferred to the alternate standby transformer. However, the team noted that if the voltages are sufficiently out of phase at this stage, the motors already connected to the buses will experience high inrush current and transient torques. This could cause failure of some motors. No study had been performed to evaluate this concern.

The licensee responded by referring to an EPRI study which concluded that phase shifts of up to 80° could be expected with a six cycle transfer time for nuclear electrical distribution systems. The licensee also stated that the startup transformer to standby transformer transfer time was four to six cycles in duration (LER 84-040). The team found this response acceptable.

2.1.8 SDG Neutral Grounding Resistor Sizing

The team's review of Calculation No. BECH-EC-7C, dated July 19, 1971, produced the following concerns:

- o The calculations did not list any assumptions.
- o Supporting documents were not listed or attached.
- o Capacitance of all the cables was not considered.
- o Capacitance of the surge arresters and transformers was not considered.
- o The margin factor did not account for other capacitances in the system.

The team also noted that capacitance was not accounted for in sizing the grounding transformer or the resistor. The team was concerned about the kW rating of the resistor and its continuous rating. These ratings could be affected during a ground fault in the system when the SDG is feeding the emergency loads. The team was concerned that the grounding resistor could get damaged due to overheating. Open circuit of the neutral could cause overvoltage across the equipment, while a short circuit could cause tripping of the generator resulting in loss of one division. Overheating of the resistor could also result in a fire.

The licensee performed rough calculations and concluded that the resistor was undersized and agreed to perform more accurate calculations. Pending completion of the calculation and subsequent NRC review, this is considered an open item (331/91002-03(DRS)).

2.1.9 SDG Sizing

The team reviewed Calculation No. BECH-E931, Revision 3, dated March 10, 1987, and noted that the loading shown in Table 8.3.I "Diesel-Generator Loading Sequence and Response, LOCA Plus LOOP," did not account for the loading caused by the losses associated with LC transformers and connected cables. These losses are important and should be accounted for in the determination of the maximum SDG loading. The team was also concerned that if Table 8.3.1 was followed by the operators, that the load on the diesel generator would be 2865kW after 10 minutes, which exceeds the continuous rating of the diesel engine (2850kW).

The licensee stated that table No. 8.3.1 was based on conservative nameplate load values, and the operators had procedures in place to control SDG loading. The team reviewed the operating procedures, the original startup data, and procedure No. SPTP-122 data, which indicated that for the LOOP/LOCA event, the actual loads were less than the 2850kW continuous rating of the SDG. The team had no further concerns.

2.1.10 SDG Testing

The team noted that the SDG test procedure did not have any acceptance criteria for voltage and frequency dip of the generator during load testing. The procedure only ensured that the generator was capable of starting and accelerating under the loads connected to it. The team also noted the lack of a transient analysis to support the starting capability of the SDGs.

The licensee stated that the PSA, currently in progress, will include a SDG transient analysis. The team evaluated this response and found it acceptable, provided that the new calculations demonstrate that voltage and frequency dip during SDG loading are acceptable.

2.1.11 SDG Surveillance Test Programs

After review of 20 surveillance test procedures, the team concluded that the TS related surveillance procedures were well written and included clear acceptance criteria. The team also concluded that the instrument set points and tolerances specified in the surveillance procedures were within the values specified by DAEC TSs. The team considered the surveillance test program to be a strength at DAEC.

2.1.12 SDG Instrument Calibration Program

During the review of calibration records for non-TS related SDG instruments, the team identified inconsistencies in setpoint tolerances for identical in function pressure switches and indicators on the diesel engines and their associated air compressors. Similarly, widely differing tolerances were used for level indicating switches on SDG fuel oil day tanks. The following examples were identified:

| Instrument | Q-level | Calibration tolerance | As-left value |
|---|---|---|---|
| PI-3221A | 1 | 0-600 PSIG ± 5% | SAME |
| PI-3221B | 1 | 0-600 PSIG ± 0.5% | SAME |
| PS-3224A | 1 | 225 PSIG ± 7 PSIG | 224.0 PSIG |
| PS-3224b | 1 | 225 PSIG ± 6 PSIG | 230.0 PSIG |
| PS-3232A | 4 | 175 PSIG ± 1.7% (± 5 psi) | 174.0 PSIG |
| PS-3232B | 4 | 175 PSIG (165.5 to 194.5) | 173.5 PSIG |
| PS-3247A | 4 | 0.5 INWC ± 0.1 | 0.45 INWC |
| PS-3247B | 4 | 0.5 INWC ± 1% (± 2%) | 0.46 INWC |
| PS-3248A | 4 | 0.5 INWC ± 0.1 | 0.47 INWC |
| PS-3248B | 4 | 0.5 INWC ± 1% (± 2%) | 0.47 INWC |
| LIS-3207 | 1 | NO TOLERANCE SPECIFIED | 6.0 INWC |
| LIS-3208 | 1 | 20 INFO ± 1.2 | 25.4 INFO |
| LIS-3209 | 1 | 3.5 INFO ± 0.12 | 3.5 INFO |
| LIS-3210 | 1 | 20 INFO ± 0.3 | 19.6 INFO |
| LIS-3215 | 1 | 18 INFO ± 1.2 | 20.5 INFO |
| LIS-3216 | 1 | 18 INFO ± 0.3 | 18.6 INFO |

In addition, the calibration data sheets used for the SDG instrumentation contained information write overs and corrections to data and acceptance criteria. The engineering calibration units used for day tank level instrumentation were inconsistent. Data sheets used inches of water column (INWC) and/or INFO, including the use of both units on the same data sheet. Also, the calibration data sheet for switch No.LIS 3207 did not include calibration allowable values.

The SDG fuel oil day tank level switch as-left calibration settings for switch Nos. LIS 3208, LIS 3210, LIS 3215 and LIS 3216 (all quality Level 1 instruments) were left exceeding their allowable calibration tolerances. The calibration data sheet was signed by the technician, reviewed and signed by supervision. However, no engineering evaluation or documentation of the LIS's out-of-calibration status were performed at the time of the calibration. The licensee evaluated each affected instrument and determined there was no impact on SDG operability. Failure of the licensee to assure that all test requirements were satisfied is considered an example of violation of 10 CFR 50, Appendix B, Criterion XI (331/91002-04A(DRS)).

The team also noted during the calibration data sheet review that day tank level switch setpoint discrepancies existed between ARP Nos. 1C08A/B-10 (10 INFO), 1C08B/B-3 (10 INFO), 1C93/B-5 (13 INFO), and 1C94/B-5 (13 INFO); surveillance test procedure (STP) No. 48A001-SA; and level switch setpoint drawing No. BECH-M404(24). The following examples were identified:

| Inst No. | As-found | Drawing Setting | ARP Switch Setting | ARP GALs | STP GALs |
|---|---|---|---|---|---|
| LIS-3207 | 6.86 INFO | 15" FROM BOTTOM | 10" FROM BOTTOM | 128 | 163 |
| LIS-3209 | 4.0 INFO | 15" FROM BOTTOM | 10" FROM BOTTOM | 128 | 163 |
| LIS-3215 | 18.0 INFO | 18" FROM BOTTOM | 13" FROM BOTTOM | 196 | 216 |
| LIS-3216 | 18.0 INFO | 18" FROM BOTTOM | 13" FROM BOTTOM | 196 | 216 |

SDG fuel oil day tank low-low level alarm switch Nos. LIS 3207 and LIS 3209 (quality level 1 instruments) were set at 6.86 INFO and 4.0 INFO, respectively. SDG day tank fuel oil level setting drawing No. BECH-M404(24) required that LIS 3207 and LIS 3209 be set at 15 INFO. Failure of the licensee to assure that test requirements satisfactorily incorporated the acceptance limits contained in applicable design documents is considered a further example of violation of 10 CFR 50, Appendix B, Criterion XI (331/91002-04B(DRS)).

The ARPs did not correctly reflect the BECH-M404(24) setpoints. Failure of the licensee to assure that procedures include appropriate quantitative acceptance criteria for determining that important activities have been satisfied is considered an example of a violation of 10 CFR 50, Appendix B, Criterion V (331/91002-05A(DRS)).

The team considered the non-TS calibration program to be a weakness at DAEC.

### 2.1.13 Cable Tray Loading

USAR, Section 8.3-10, and Design Specification Nos. E502, Paragraph 4.1.1.3, and E512, Paragraph 4.2.6, require that low level signal instrumentation cables be installed in separate trays with covers to provide adequate electromagnetic shielding. The team noted that low level signal cable trays in the cable spreading room were not covered. This item is considered open pending further investigation by the licensee (331/91002-06(DRS)).

### 2.1.14 Thermal Overloads Setting

The team determined that the licensee did not have a program that delineated a consistent thermal overload (TOL) motor protection sizing methodology or a TOL testing program. The team noted numerous discrepancies between the design drawings and the field settings. Although many TOLs were conservative, some examples were found that were not. For example, the motor associated with a breaker required an H16 heater (1.15A) for 125% protection; however, the drawing required an H14 (.95A) and the actual size in the field was a H14A (improved time overcurrent characteristics). In addition, the licensee was not aware at what value of rated current the TOL blocks were set. The TOL blocks were adjustable from 85% to 115%; however, the licensee had only recently become aware of this feature. Furthermore, the licensee's methodology did not account for locked rotor consideration and differences between the "H", and the "FH" type of thermal overload. The locked rotor time overcurrent characteristic was approximately 30 seconds for the "H" type but less than 20 seconds for the "FH" type.

Based on the review, the team determined that little engineering emphasis had been placed on design of thermal overload devices. The concerns noted above were also noted by the licensee in 1985 during the maintenance department's walk down of the plant's TOLs and set point data. However, the licensee's design organization had not taken action to consolidate differences between the design drawings and field configuration. Further, the lack of methodology had contributed to installation of undersized thermal overloads for the battery room exhaust fan motors.

The team also noted that the existing schematic logic configuration for monitoring and indicating status of thermal overload protection on safety and non-safety related valves would not provide the operator with visual indication or audio alarm in the control room or locally when a motor operated valve (MOV) tripped on overload. As a result, a valve whose motor tripped on thermal overload actuation would not function on demand until it was determined to be tripped and was reset at the MCC. The licensee had taken action to correct this problem. Currently 20 safety related valves have had control room indicator lights installed which indicate thermal overload trips.

The licensee stated that a program based on 125% protection and TOL block setting of 115% of rated current was to be implemented in 1992; however, the team considered the above items to be indicative of a programmatic weakness relative to TOL setting and control.

### 2.1.15 Fuse Control Program/Field Inspection

The team observed that fuse Nos. 52-3401-F1 and 52-3401-F2 in the remote shutdown panel were sized at 6A instead of the 10A specified on the design drawing. Also, four fuses in control room panel No. 1C03 were not sized in accordance with Advanced Information Drawing (AID) APED-H11-067(2). Two non-safety related fuses were 5A, while the drawing specified 10A. Two other fuses in positions FF-F19 and FF-F20 in the HPCI inverter circuitry were found to be 10A instead of the 5A required by the design drawing. Concerns regarding incorrect fuses and lack of an adequate fuse control program were also noted in NRC SSFI inspection report No. 331/90003(DRS).

The licensee investigated these concerns and subsequently determined that the installed fuses would have protected the equipment; therefore, there was minimal safety impact. However, the team could not determine whether the fuses required by the drawings were correct, because the licensee did not have design calculations or sizing criteria for these installations, which could have contributed to the incorrect installation. The licensee's failure to assure that properly sized fuses were installed in accordance with the drawing is considered a further example of violation of 10 CFR 50, Appendix B, Criterion V (331/91002-05C(DRS)).

The team considered the lack of a fuse control program to be a weakness. The licensee indicated that the PSA would address this concern in 1992. Based on the team's findings in this inspection area and the findings from the NRC's SSFI, the licensee should consider more immediate action relative to fuse control.

### 2.1.16 Breaker Trip Settings

The team noted the following discrepancies between design drawings and the magnetic trip settings (current rating is in parenthesis) for the 480Vac safety related breakers associated with the following valves:

| Equipment | Drawing | Field |
|---|---|---|
| RHR Core Spray Valve | 11 (165A) | 1 (75A) |
| Reactor Building Floor Drain | 1 (75A) | 7 (120A) |
| Core Spray Discharge Valve | 4 (90A) | 9 (140A) |
| Test Isolation Valve | 1 (75A) | 7 (120A) |
| Test Valve to Torus | 4 (90A) | Hi (180A) |
| Reactor Recirculation Loop II Pump Discharge | 9 (115A) | 3 (72A) |
| RHR Loop II Injection Valve to LPCI | 6 (254A) | Low (150A) |

The licensee lacked a design basis for the magnetic trip settings listed above. The settings did not have a basis in calculations or in a documented testing program. Three of the field settings were nonconservative, that is, the motor would trip earlier than suggested by the manufacturer based on motor full load current (FLC). The first and the last two breakers associated with the above motors would trip in approximately six times FLC. The manufacturer recommends setting the instantaneous trip at 10 to 11 times motor FLC. In addition, the other four breaker set points listed above would not adequately protect the motors since the settings were approximately 14 to 18 times FLC.

The licensee was cognizant of the weakness in the setting of the breaker magnetic trip settings and planned to review this area during the PSA. Pending further review by the licensee and the NRC, this is considered an unresolved item (331/91002-07(DRS)).

2.1.17 Overcurrent Protective Relays

During a walkdown of the 4KV switchgear rooms, the team noted that the tap setting for the phase A relay of safety related Bus No. 1A3, feed breaker No. 152-301, was set differently than the other two phases; therefore, the possibility existed that the feeder breaker would trip prior to the downstream core spray breaker. The team determined that on October 21, 1987, the phase A 1A3 relay was calibrated at tap settings of 5A and 2A, in accordance with Procedure No. M-11A-TP. Because the procedure did not specify that the relay be set back to the required setting, the personnel performing the test did not readjust the tap to the proper setting of 5A. With a tap setting of 2A, the 152-301 feeder breaker time current trip setpoint curve shifted closer (in the nonconservative direction) to the load trip setpoint curves of the downstream breakers. This caused the 152-301 breaker and the core spray breaker curves ($I^2$-T) to intersect at approximately 1100-1200A, which could have caused a trip of the feeder breaker before the core spray breaker.

The failure of the licensee to provide adequate instructions for restoration of the appropriate breaker tap setting is considered a further example of violation of 10 CFR 50, Appendix B, Criterion V (331/91002-05B(DRS)).

2.1.18 Conclusions

Based on the inspection sample, the team identified no operability concerns and concluded that the design of the AC system was generally adequate. However, the team identified some weaknesses, as defined above, which require further evaluation and added attention by the licensee.

2.2 DC Systems

The team reviewed the station DC systems, 120Vac inverters and electrical containment penetrations for design compliance to applicable standards and codes. The inspection included the review of the ±24Vdc, 125Vdc and 250Vdc battery design with respect to sizing, duty cycle loading, electrolyte temperature, battery age and capacity. The associated charger designs were reviewed for total loading requirements and the bases of these calculations were checked for their adequacy. The inverters' sizing and design criteria were reviewed for their ability to meet applicable standards and power input/output requirements. Fault study calculations for the ±24Vdc, 125Vdc and 250Vdc were reviewed relative to system parameters and requirements, applicable standards, correctness, accuracy and standard engineering practices. Voltage drop studies and cable sizing calculations for the ±24Vdc, 125Vdc, 250Vdc and 120Vac were reviewed relative to system parameters and requirements, applicable standards, correctness, accuracy and standard engineering practices. A review of breaker/fuse coordination and sizing was performed to determine if protection schemes for the DC systems conformed to standards and practices used for station design. The team also reviewed the electrical penetration design against standards applicable during station design and construction.

2.2.1 Distribution Panel Coordination

The team's review of FCN No. 1411-02 DCP, Index Item 5.6, indicated that because the panel feeder breaker and the branch breaker were identical in size, the panel feeder breaker on each of the main DC systems would trip for a fault on the following branch circuits:

- o A fault on the branch circuit for charger Nos. 1D12 (400A), 1D120 (400A), or inverter No. 1D15 (400A) would also trip the panel (1D10) supply breaker (400A), thus cutting power to the entire Division 1 DC distribution system.
- o A fault on the branch circuit for charger Nos. 1D22 (400A), 1D120 (400A), or inverter No. 1D25 (400A) would also trip the panel (1D20) supply breaker (400A), thus cutting power to the entire Division 2 DC distribution system.
- o A fault on the branch circuit for charger Nos. 1D44 (400A), 1D43 (400A), or inverter No. 1D45 (400A) would also trip the panel (1D40) supply breaker (400A), thus cutting power to the 250Vdc portion of the 125Vdc distribution system.

The team determined that the lack of coordination was not safety significant since a redundant power distribution system was available; however, this concern was considered a weakness concerning breaker/fuse coordination.

2.2.2 125Vdc and 250Vdc Inverter Calibration

The team was concerned that the maintenance procedures for the 125Vdc and 250Vdc inverters did not require calibration of the high or the low input voltage shutdown functions. This could have led to a premature voltage shutdown of the inverters when the batteries neared the end of their duty cycle and their voltages went below the voltage shutdown level.

The licensee indicated that the inverter maintenance procedures were currently being revised to include these calibrations. This concern was considered an example of weak inverter maintenance.

2.2.3 DC Motor Available Current Study

The team's review of calculation No. CAL-IELP-E-88-05, Revision 0, "Limiting Power Current for DC MOVs", revealed the following weaknesses:

a. Several valves did not meet the calculation acceptance criteria. The calculation stated that additional analyses would be performed on these devices. This additional analysis was not available and valves that failed this acceptance criteria were not demonstrated to provide sufficient torque to actuate in worst case conditions.

b. The calculation stated that the "as-left" maximum allowed seating currents (torque switch settings) are controlled to conform with this analysis. The plant document used by maintenance to set torque switches is drawing BECH-E200 <13>. The team reviewed drawing BECH-E200 <13> and found many transcription errors. These errors prevented the proper adjustment of the limitorque torque switches. Torque switches set higher than worst case available torque would not deenergize the MOV control circuit on valve closure. This would lead to thermal overload actuation. This deenergizes the power circuit to the MOV. The power circuit is disabled until the overload is manually (locally) reset. The present MOV control circuit provides no indication to the operator of this condition (See Paragraph 2.1.14).

c. The calculation did not address DC MCC No. 1D42. This MCC powers RHR valve Nos. MO-1901, MO-1909, and MO-1937 and steam line drain isolation valve No. MO-4424.

d. The calculation did not include the resistance of the thermal overload devices. The resistance of these devices will further reduce the available current.

e. The calculation did not address the operability of the motor contactors located in the above DC MCCs. Failure of the motor contactors to operate will preclude energizing the MOV power circuit.

The licensee committed to revise this calculation by June 30, 1991, and address the above concerns. Pending further analysis by the licensee and subsequent NRC review, this item is unresolved (331/91002-08(DRS)).

2.2.4 <u>DC System Fault Analysis</u>

The team's review of battery sizing calculations indicated the new battery sizing calculation showed an increase in maximum available fault current at the battery terminals when compared to the original batteries. These calculations sized the new 125Vdc and 250Vdc batteries and performed a fault analysis for the associated DC distribution systems. The team noted the following weakness in the engineering analysis associated with the battery upgrade:

a. The fault analysis did not include fault current sources other than the battery. Each of the DC systems include additional sources of fault current. These sources would increase the severity of the fault analysis.

b. The limited revised fault analysis performed in battery sizing calculation Nos. CAL-IELP-E90-1, revision 0, "DAEC 125 Volt Battery 1D1 Load and Sizing," and CALC-E87-06, revision 2, "DAEC Nuclear Station 250V Battery Load and Sizing," only addressed the battery breakers. These analyses show a maximum available fault current of 11,775A. The review of CAL-BECH-EC-8F, "DC System Fault

Analysis," and Material Requisition 7884-E-29 indicated that all breakers downstream of the battery breaker and the 125Vdc and 250Vdc main distribution panels had an interrupt rating of 10,000A. The DC system fault analysis (CAL-BECH-EC-8F, "DC System Fault Analysis") was not revised to address this distribution equipment.

Preliminary calculations were submitted during the inspection that addressed the team's concerns on this issue.

2.2.5 Drawing and Installation Errors

The team found discrepancies between design schematics, wiring diagrams, and manufacturers' drawings. These included errors such as missing limit switch No. LS8 on Drawing No. BECH E121(15), Revision 5, and incorrect logic circuitry and wire designations on schematic diagrams.

A three compartment review of 250 Vdc MCC No. IDC11 identified numerous installation errors including the absence of ring lugs, damaged insulation, and missing wire and control relay labels. A large number of discrepancies between drawings and as-built conditions were also found including incorrect wiring and jumpers in MCC No. ID41, Instrument Rack No. IC126B, SDG Panel No. IC93, ADS panel No. IC45, and Remote Shutdown Panel No. IC422B.

The licensee evaluated the drawing errors and determined that there was no effect on safety related equipment. The licensee concluded that these errors had minimal safety significance. However, the team considered this concern a weakness relative to drawing/configuration control.

2.2.6 Incorrect Breaker Installation

The team's field inspection of 125Vdc distribution panel Nos. ID21 and ID23 produced the following discrepancies:

a. DC breaker Nos. 72-2317 and 72-2117 were shown on drawing No. BECH-E027 as 70A breakers while 30A breakers were installed.

b. DC breaker 72-1320 was shown as a 30A breaker on drawing No.BECH-E027, but a 15A breaker was installed.

The licensee evaluated the effect on the safety related equipment due to the breaker sizing. They determined that the breakers in the field were correct but that the drawings had not been updated after modifications. The team considered this a further example of weak drawing/configuration control.

2.2.7 Conclusion

The team determined that the overall design and installation of the DC systems were adequate. Design attributes were retrievable and verifiable. Calculations were acceptable; however, more attention is needed in the area of breaker/fuse coordination and in the review of engineering analyses.
The team also concluded that an excessive number of errors existed on the

design drawings. However, no direct operability concerns were identified by the team. Most of the concerns noted above were due to drawing deficiencies that existed since initial operation or were the result of later modifications. The licensee informed the team that the as-built concerns noted above would be addressed through the EWR and CMAR process. The team found this acceptable: however the team considered the condition of the design drawings to be a programmatic weakness.

### 2.3 Mechanical Systems

The team reviewed the adequacy of the mechanical system design for the support of the EDS. The support mechanical systems (SMS) included the SDGs, SDG support systems, and the EDS heating/ventilation and air conditioning (HVAC) systems. The review included a system walkdown and examination of SMS licensing, engineering, vendor, purchasing, and plant operations documents including USAR and TSs; selected modifications and safety evaluations; mechanical system calculations; process and instrumentation diagrams (P&ID); pump performance curves and motor data sheets; HVAC flow diagrams (FDs); SDG manufacturer technical manuals, selected schematics, and detailed component drawings; procurement specifications for the SDG; operations manuals; and annunciator and abnormal operating procedures.

#### 2.3.1 SDG Fuel Storage Tank Capacity

The team's review indicated that SDG fuel consumption test results, storage and day tank volume calculations, and instrument setpoint calculations did not demonstrate that the required 7 day fuel capacity committments for the SDG were met.

FSAR section 9.5.4, "Diesel Fuel Oil Storage And Transfer System," states that the SDG fuel storage tank has a capacity sufficient to support 7 days operation of one SDG at full load (2850kW). Section 9.5.4 further states that each SDG day tank has a capacity sufficient to support 4 hours of SDG operation at full load.

The results of SDG fuel consumption tests carried out during plant start-up contain discrepancies in the determination of the SDG test load. The documented kW readings taken at the beginning and end of the IG-31 full-load test indicated a load of 2850kW throughout the test, whereas the documented kW-hr readings taken at the beginning and end of the test indicated an average load of 2580kW over the test period. This implies a possible error of as much as 10% in the fuel consumption rate used to check fuel tank volumes and determine level instrument setpoints.

Several important considerations were omitted in the storage and day tank volume and setpoint calculations. These included:

- o Fuel transfer pump net positive suction head requirements. Consideration of these requirements could reduce the actual available fuel quantity in the storage tank.

- o Fuel heating value and storage temperature. Differences between fuel consumption test conditions and actual operating conditions could affect fuel storage volume requirements.

The team performed a quick calculation which indicated that the capacity of the storage tank could be as much as one day short of the FSAR 7 day requirement. In view of this, the team requested the licensee to perform an operability determination for the system. The licensee subsequently declared the system operable based on the availability of alternate fuel sources (local fuel delivery, auxiliary boiler fuel storage tank), the low probability of requiring the system, the conservatism of the team's preliminary calculation, and prompt completion of the following corrective actions:

a. Evaluate the impact of the recorded kW-hr readings on the validity of the start-up fuel consumption test results, and correct the storage tank level setpoints accordingly.

b. Revise all tank volume and setpoint calculations to include consideration of transfer pump net positive suction head requirements, fuel heating value, and fuel storage temperature.

c. In the event that the revised calculations demonstrate insufficient fuel storage capacity, submit a FSAR revision with an impact study and analysis of other "backup" fuel supplies (local delivery, use of the auxiliary boiler fuel oil storage tank).

The team agreed with the licensee's operability determination, contingent on prompt completion of the corrective measures. Pending completion of the analyses and subsequent NRC review, this is considered an unresolved item (331/91002-9(DRS)).

### 2.3.2 Seismic Qualification of Relief Valves on SDG Starting Air System Air Accumulators

The licensee was unable to provide documentation to support the seismic qualification of the SDG air accumulator relief valves. This raised the possibility of a common mode failure wherein a seismic event could result in a depressurization of the primary and backup air accumulators for both SDGs. Loss of air from all accumulators could prevent the start-up of the SDGs.

10 CFR 50 Appendix A, Criterion II, requires that structures, systems and components important to safety be designed to withstand the effects of seismic events.

In view of this deficiency, the team requested the licensee to perform an operability determination for the system. The licensee subsequently declared the system operable based on a preliminary evaluation of the design of the valves by the licensee's seismic specialist. The licensee made a commitment to promptly complete the analysis of the valve design and correct any real equipment deficiencies that the analysis might reveal. The licensee's current position is that analysis of the valve design will result in their acceptance for seismic service. The team agreed with the licensee's operability determination, contingent on prompt completion of their backup analyses. Pending completion of the analysis and subsequent NRC review, this is considered an unresolved item (331/91002-10(DRS)).

### 2.3.3 Tornado Induced Depressurization

The licensee was unable to provide documentation demonstrating that tornado-induced pressure differentials had been considered in the design of ducting associated with the SDG system. The team was particularly concerned with the ducting for SDG combustion air, exhaust, and room ventilation. Should this ducting be crushed due to the pressure differential, then the following could occur:

- o Cooling to the SDG rooms could be impaired.
- o The supply of combustion air to the SDGs could be impaired.
- o The release of combustion gases could be impaired.

The primary consequence of these events could be the failure of both the SDGs.

DAEC FSAR section 3.1.2.1.2, "Criterion Conformance - Criterion 2 - Design Bases For Protection Against Natural Phenomena," requires structures, systems and components to be designed to withstand the effect of tornadoes. Section 3.3.2.1, "Tornado Loading - Applicable Design Parameters," specifies a 300 mph tornado with an associated pressure differential of 3 psi occurring in 3 sec.

10 CFR 50, Appendix A, Criterion II, requires that structures, systems, and components important to safety be designed to withstand the effects of tornadoes.

The licensee committed to evaluate the effects of a tornado-induced depressurization on the integrity of the ducting and the operation of the SDG systems. Pending completion of this analysis and subsequent NRC review, this is considered an unresolved item (331/91002-11(DRS)).

### 2.3.4 Conclusions

The acceptable design and operation of the mechanical systems supporting the EDS at DAEC were not fully demonstrated during the course of the inspection. The team concurred with the licensee's prompt operability determination associated with SDG fuel capacity, SDG starting air supply, and the effect of tornados on the SDGs; however, the final determination of acceptablity of these issues remains unresolved.

## 3.0 Engineering and Technical Support

During the inspection, the team evaluated Iowa Electric's E&TS capability. The team reviewed the licensee's temporary modification program, permanent modification program, portions of the station's discrepancy management program, 10 CFR 50.59 evaluation program, and QA/QC program. In addition, the team reviewed the electrical training programs for crafts and engineers and the root cause analysis for licensee event reports (LERs) .

## 3.1 Modification Program

The team's review of electrical modification packages (DCPs) indicated that DCPs were receiving inadequate reviews, checks, and walkdowns prior to approval for installation. This resulted in the initiation of large numbers of field changes in DCPs and two corrective maintenance action requests to replace failed components. The following examples were identified:

- DCP No. 1317 required two field change requests (FCRs), two field change notices (FCNs), six field variances (FVs), and one design change notice (DCN).
- DCP No. 1462 required two FCRs and ten FVs.
- DCP No. 1454 required 11 FVs.
- DCP No. 1411 required 22 field FVs.

## 3.2 Personnel Errors

The team noted that of the 22 LERs submitted in 1990, 10 were in the electrical area. Of that 10, 7 had personnel error related entries in the root cause evaluation. These errors included failure to follow procedures, misinterpretation of drawings, lack of protection of adjacent systems while installing modifications, and inadvertent disabling of systems during maintenance and modifications.

## 3.3 Conclusions

The team found that, in general, the licensee provided adequate E&TS to the operational staff. Quality control personnel were well qualified and had substantial experience in their fields of expertise. Rotational assignments of senior reactor operators (SROs) to QA/QC to perform operational audits and surveillances was considered a strength. Inadequate up-front reviews and walkdowns of electrical modifications which resulted in excessive field changes was considered a weakness. The high rate of electrical personnel errors, which caused the majority of the LERs in the electrical area, was considered a weakness.

## 4.0 Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the team, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during this inspection are discussed in Paragraph Nos. (2.1.2 and 2.1.3), 2.1.4, 2.1.8, and 2.1.13.

## 5.0 Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during this inspection are included in Paragraph Nos. 1.1.16, 2.2.3, 2.3.1, 2.3.2, and 2.3.3

## 6.0 Exit interview

The team conducted an exit meeting on March 8, 1991, at Duane Arnold to discuss the major areas reviewed during the inspection, the weaknesses observed, and the inspection findings. NRC personnel and licensee representatives who attended this meeting are documented in Appendix A of this report. The team also acknowledged commitments made during the inspection. The licensee did not identify any documents or processes as proprietary.

# APPENDIX A

Iowa Electric Light and Power Company (IE)

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*T. Erger, System Engineer
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*M. Harris, Engineering Support, CYGNA
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*G. Hawkins, System Engineer
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J. Loehrlein, Design Engineer
*D. Mineck, Manager, Nuclear Division
*W. Miller, EDSFI Team Manager, Design Engineer
*J. Mohr, Operations Maintenance Coordinator
O. Olson, Group Leader, I&C D/C Engineer
L. Ormsby, Project Engineer Secretary (Admin Supervisor)
*M. Paulson, Systems Engineer
*B. Peden, Assistant EDSFI Team Manager
*M. Petersen, System Engineer
*K. Peveler, Manager, Corporate Quality Assurance
R. Potts, Procedure Supervisor
J. Prost, Technical Support Engineer
*K. Putnam, Supervisor, Technical Support
*K. Ridley, Electrical Maintenance Procedure Writer
*R. Roby, Analysis Engineer
*R. Salmon, Manager, Nuclear Licensing
N. Sikka, Supervisor, DC Engineering
M. Smith, Quality Control Engineer
*S. Swails, Manager, Nuclear Training
S. Tait, System Engineer DC
J. Thorsteinson, Technical Services Superintendent
*B. Turnbull, Engineer
G. VanMiddlesworth, Assistant Plant Superintendent-OPS & Maintenance
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*D. Wilson, Plant Superintendent

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*R. Hague, Section Chief, Division of Reactor Projects
J. McCormick-Barger, Project Manager, Division of Reactor Projects
*C. Miller, Resident Inspector
*M. Parker, Senior Resident Inspector
*S. Sands, NRR/Project Manager, NRR

*Denotes those attending the exit meeting on March 8, 1991.