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SECTION A - PLANT DESIGN CHANGES

This section contains brief descriptions of and reasons for plant design changes completed during the calendar year 1988 and summaries of the safety evaluations for those changes, pursuant to the requirements of 10 CFR Part 50.59(b).

The basis for inclusion of a Design Change Package (DCP) in this report is closure of the package at the Duane Arnold Energy Center (DAEC) in the calendar year 1988. It is noted that portions of some DCPs listed were partially closed in previous years.

In addition, various Minor Modifications (MMs) were completed during the calendar year 1988. MMs are not included in this report since, by definition, they do not change the facility as described in the Final Safety Analysis Report. Each MM was screened to ensure that no unreviewed safety questions were involved.

DCP 1193 Reactor Building Airlock Interlocks

Basis and Description of Change: In the past, several violations of secondary containment had occurred due to malfunctioning Reactor Building door interlocks. The Reactor Building airlock interlock mechanisms were unreliable and required significant maintenance. All Reactor Building door interlocks were replaced with magnetic door locks which were tested and proven to be more reliable than and functionally equivalent to those they replaced.

Summary of Safety Evaluation: This change replaced older high maintenance airlock interlocks with low maintenance magnetic door locks. These door locks are not safety-related. However, they are necessary to support regulatory requirements. Changing the interlocks to a better quality device ensures that regulatory requirements are met. Existing conduit was used, therefore, no new conduit was added that could impact existing safety functions or equipment. The replacement magnetic door locks function the same as the original door locks. They are a fail-safe device. The latching mechanism is mounted in the same position as the old mechanism and, therefore, will not impact existing safety functions or equipment. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1251 Control and Annunciation Wiring in Panel 1C08

Basis and Description Change: The wiring in the Generator and Auxiliary Power Panel 1C08 did not correspond to current drawings. Also, General Construction Procedure No. 2 (GCP-002) mandates that the maximum number of lugs secured by each terminal screw to be not more than two. Several terminals had four lugs attached to each terminal screw. Jumper wires had created a three lug per screw situation on 21 terminals. In addition, several wire numbers were missing or incorrectly marked. To correct this situation, the rewiring of the panel was done to be in accordance with the design

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documents and GCP-002. This modification also corrected missing or inaccurate wire numbers.

Summary of Safety Evaluation The circuits effected by this modification are the annunciators B and C in panel 1C08. These annunciators do not perform a safety-related function and the annunciator circuits are physically separated from the control/instrumentation circuits, therefore, a fault in an annunciator circuit cannot cause the spurious operation of a circuit/system it monitors. Nothing was changed electrically by this change. Jumpers and wires were moved to another location on terminal strips such that the requirements of GCP-002 could be met. The electrical circuits were not changed and only physical changes were made to electrical connections. Because of the large number of annunciators that were taken out of service to perform this modification, it was done with the plant shutdown so as to minimize the possibility of an operator error during plant operations. This modification ensures conformance to GCP-002 and does not effect any protective circuitry in such a way that the original design requirements (IEEE Standard 279-1971) are not met. Additionally, the design bases of the annunciator circuits, as stated in the FSAR, are unaffected. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1274 Relocate RE-1997

Basis and Description of Change RHRSW/ESW effluent radiation detector RE-1997 was relocated from inside the HPCI Room to an underground location approximately 90 feet downstream of its original location, outside the Turbine Building. The detector was moved because the variation in background count rate as a function of reactor power, made it necessary to recalculate the detector's trip setpoints whenever reactor power changed. Also, when HPCI was initiated, increased background radiation levels in the HPCI Room caused RM-1997 to alarm.

Summary of Safety Evaluation: The effluent radiation monitoring system and the RHRSW/ESW system downstream of the south HPCI Room wall are not safety related. The piping addition and the electrical hardware addition was constructed and tested to the same specifications and quality as the original systems. Also, the radiation monitoring system functions exactly the same (except for the background count rate being more stable - which has no safety implications) as before the modification. The basis for Technical Specification 3.14.1, Radioactive Liquid Effluent Instrumentation, states that the radioactive liquid effluent instrumentation is provided to monitor and control, as applicable, the release of radioactive materials in liquid effluents. DCP-1274 merely relocated RE-1997 further downstream. Its ability to monitor and control the release of radioactive material in liquid effluents is not lessened as there are no branch points in the piping between the old location and the new one. The alarm and trip setpoints, as specified by the Technical Specifications, remain the same. Therefore, DCP-1274 does not involve an unreviewed safety question or Technical Specification change.

DCP 1289 Refuel Bridge Modifications

Description and Basis for Change: Several components of the refuel bridge functioned improperly and were replaced. These components were the fuel grapple head air hoses, the air hose and electric cable takeup reels, the main hoist vertical position indicator, connections in the Amphenol plugs in the cable to the fuel grapple head limit switches, and the amplidyne motor-generator. The plastic fuel grapple air hoses were replaced with flexible stainless hose assemblies as direct replacement for existing units. The air hose and electric cable takeup reels were replaced with new reels designed for the intended application. The main hoist vertical position indicator was replaced with a more reliable digital readout and the amplidyne motor-generator was replaced by a static DC controller. Also, the Amphenol plugs were removed from the fuel grapple cable, and connections to the fuel grapple head limit switches and fuel grapple lights were solder connected, insulated, and water-proofed.

Summary of Safety Evaluation: The equipment added or replaced by this modification was designed to increase the refuel bridge reliability. These component replacements were evaluated and found not to introduce any new failure modes nor increase the likeihood of a bundle drop accident. For these reasons, this modification does not involve an unreviewed safety question or change to Technical Specifications.

DCP 1301 Uninterruptible Power Supply (UPS) for DAEC Telephone System

Basis and Description of Change: This change formalized Emergency Design Change Package (EDCP) 1301 and modified the uninterruptible 120VAC power circuit installed in the Control Room telephone system equipment located in the Cable Spreading Room. The modification extended a circuit to an outlet fastened adjacent to the "OSS-B" desk. In addition, the temporary outlet for the NRC Emergency Notification System equipment was removed and replaced by a permanent duplex outlet.

Summary of Safety Evaluation: Chapter 8 of the UFSAR states that the Uninterruptible AC is for "loads that are not essential to plant safety but for which power interruption should be avoided..." Uninterruptible AC power supply panel 1Y23 contains circuit breakers for this safety-related power source. The two circuits added are adequately isolated from the main bus and other safety-related circuits by individual class 1E circuit breakers. Therefore, this modification does not involve an unreviewed safety question or change to Technical Specifications.

DCP 1339 Plant Process Computer

Basis and Description of Change: This change was in response to a commitment by Iowa Electric to the NRC to update the plant process computer (PPC) hardware and software to more modern technology. A new computer was installed in the Data Acquisition Center with cable to interface with existing input/output (I/O) cabinets. Hardware and cables in the Safety Parameter Display System (SPDS) non-divisional Data Acquisition System (DAS) cabinet were installed to access signals available in the existing I/O cabinets. All accessing of signals is through the PPC I/O cabinets, SPDS DAS cabinets, and the Meteorological DAS chassis. No Division I or Division II instrumentation signals are directly accessed by the PPC.

Summary of Safety Evaluation: The PPC is described in the UFSAR as a control system not required for safety. This design change increases the reliability and accuracy of the process computer. The new data acquisition equipment enhances signal isolation from plant sensor to PPC input/output equipment beyond that which the old computer provided. Digital inputs are electrically isolated from the data acquisition system through the use of optical isolation devices on each input. Analog inputs are isolated from the data acquisition system through the use of transformer coupling circuitry on each of the inputs. This design change adds high impedance voltage sensing circuits in parallel with those of the old computer. Possible malfunctions and the consequences are the same as for the old computer. This modification does not change the function of any safety system. The PPC monitors conformance to fuel thermal limits. The replacement PPC uses the same formulas as the old PPC and performs calculations using more accurate data. For these reasons, this modification does not involve an unreviewed safety question or change to Technical Specification.

DCP 1344 Radwaste Demineralizer Replacement and Spent Resin Tank System Modifications

Radwaste Demineralizer Replacement

Basis and Description of Change: This design change replaced both the Waste Collector and Floor Drain Demineralizers with new stainless steel demineralizers. The old demineralizers had rubber linings which were deteriorating due to radiation exposure and age.

Summary of Safety Evaluation: The new demineralizer tanks involved a like-for-like modification in regards to tank geometry, function, and location with the configuration, operation, and testing of the tanks remaining as originally designed and evaluated. This modification was confined to non-safety equipment located in the reactor building demineralizer tank vaults. Installation and operation of equipment associated with this modification does not affect or require a change to plant technical specifications. Because leaks or spills from the Liquid Radwaste system will go into the Radwaste Building and/or the Reactor Building, doses at the plant boundary will not exceed the annual limits of 10CFR50, Appendix I.

Therfore, operation or malfunction of equipment installed as a result of this modification does not involve an unreviewed safety question or a change to Technical Specifications.

Spent Resin Tank System Modifications

Basis and Description Changes: The purpose of this design change was to install a remote, air-operated, 3-way plug valve and a 3 inch cross-tie to allow Radwaste operators to bypass Spent Resin Tank 1T-68 and send spent resin from reactor building floor drain and liquid radwaste demineralizers directly to Waste Sludge Tank 1T-62A. Prior to this modification, this effluent was discharged to the spent resin tank. This reroute ties the demineralizer resin water discharge to the outlet piping of the Fuel Pool Filter Demineralizers enroute to the Waste Sludge Tank.

Summary of Safety Evaluation: No anticipated malfunction of the cross-tie valve or piping, such as a failure in valve operation or a valve/piping pressure boundary breach, can be expected to affect any of the design basis accident events as listed in UFSAR Chapter 15. Being part of the Solid Radwaste system and the fact that all welding was done in accordance with approved welding procedures, an anticipated malfunction of this modification can not affect reactor coolant temperature, pressure, flow rate, power distribution, coolant inventory, or lead to an anticipated transient without SCRAM. Due to its location to the Spent Resin Tank Room, no anticipated modification malfunctions will lead to a radioactive release from a subsystem or component in excess of the requirements of 10 CFR 20 or lead to loss of habitability of the Control Room. Installation and operation of equipment associated with this modification do not affect or require a change to plant technical specifications. Operation or malfunction of equipment for this modification do not effect or reduce the margin of safety. This modification does not involve an unreviewed safety question or change to Technical Specifications.

DCP 1348 DAEC PA System Modification/Upgrade

Basis and Description of Change: Following a small fire in the Cooling Tower Control Room, the entire plant paging system was left inoperable preventing emergency notification throughout the DAEC. A number of modifications to the paging system as well as some of the other intra-plant communication systems were made.

Summary of Safety Evaluation The modification enhances the effectiveness of the intra-plant communication systems. These systems are not required to mitigate or prevent any of the FSAR identified accidents nor do they interface or affect any equipment or system important to safety. The enhancements increase the efficiency and reliability of general notification in normal as well as in an accident and/or fire/evacuation situation. This modification does not involve an unreviewed safety question or change to Technical Specifications.

DCP 1349 Standby Transformer Containment Basin

Basis and Description of Change: An American Nuclear Insurer's inspection report made several recommendations concerning fire protection modifications at the DAEC. The report recommended that a catch basin be provided to contain the uncontrolled flow of oil from the Standby Transformer in the event of a transformer failure or fire. A reinforced concrete curb was installed to form a containment basin around the Standby Transformer located south of the Reactor Building adjacent to the HPCI/RCIC Building. The basin was sized to contain a volume of more than 3,395 gallons. This amount includes 1,508 gallons of transformer oil and ten (10) minutes of water from the Deluge System at a rate of 188.7 gallons/minute.

Summary of Safety Evaluation The Installation of the containment basin around the Standby Transformer consists of the construction of an 18-inch reinforced concrete curb and the replacement of the existing rock around the transformer with 1-1/4" crushed stone to a minimum depth of 6". The basin does not affect or interact with any important-to-safety systems in the plant. A seismic qualification is not required for this modification since it will not jeopardize any safety systems during or following a seismic event. The Standby Transformer is the backup offsite power source to the Startup Transformer for the essential buses 1A3 and 1A4. Installation of the reinforced concrete curb was performed on-line and did not interfere or prevent the Standby Transformer from performing its required function. Therefore, this modification does not involve an unreviewed safety question or Technical Specification change.

DCP 1374 General Electric Relay Retainer Replacement

Description and Basis for Change: Contact arm retainers on approximately 850 GE model CR120A, CR120AD, CR120C, and CR122A 300V industrial relays at the DAEC were replaced at the recommendation of GE Services Information Letter No. 229 (SIL 229). The non-fire retardant retainers (one of which was involved in a control panel fire at the DAEC) were replaced with retainers made of fire retardant material.

Summary of Safety Evaluation: The replacement retainers were a direct replacement for the original retainers and were manufactured from a nonflammable material. The method of operation of the relays is unchanged by the replacements. The material that the new retainers are made of (VALOX 310 SEO) is slightly lighter than the original retainer material. The difference in retainer weight is negligible. Therefore, the replacement retainers will not adversely impact seismic qualifications for any relay fitted with the replacement retainer. The replacement of retainers for CR120A, CR120AD, CR120C, and CR122A relays did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1383 Change Setpoint of PDIS-2119

Description and Basis for Change: The setpoint of the "A" Core Spray sparger differential pressure cell PDIS-2119 was changed from 4.46 to 2.46 PSID. This was done to make the A-loop setpoint consistent with the B-loop setpoint when non-condensible gas effects in loop-A are ignored. The core spray sparger nozzles for the "A" loop are oriented in such a way that they can collect non-condensible gases during power operation. The "B" loop nozzles are oriented in the opposite direction and do not collect these gases. The non-condensible gases introduce a bias in the PDIS reading due to the density difference. This bias had been included in the instrument setpoint calculation. At the end of the fuel cycle, during power "coastdown", the production of non-condensible gases decreases, reducing the bias in the instrument readings. If the power is reduced to a low enough value, the alarm setpoint for the "A" loop is reached, even though there is no break in the piping. Thus the instrument setpoint was adjusted to remove the bias due to the non-condensible gas effect in order to prevent these erroneous alarms.

Summary of Safety Evaluation: The existing setpoint of PDIS-2119 was reduced to account for operational variances due to the non-condensible gas effect and allowances for instrument drift, instrument calibration accuracy, and overall instrument inaccuracy. Reducing the setpoint increases the power range over which the break detection instrumentation will perform its intended function. If a break in the core spray piping were as large as the type of break the system is designed to detect and large enough to divert a significant amount of flow into the downcomer region, the accumulated non-condensible gases would escape and the instrument gauge would register a downscale (0.0 psid) reading. Because the new setpoint, including instrument tolerances, is above 0.0 psid, it is still capable of providing the required alarm if the design basis break occurs in the "A" Core Spray line between the reactor vessel wall and the core shroud. This change does not alter the physical design or intended function of the break detection system and has no effect on the function of any safety system as this instrument provides an alarm only. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1384 Retaining Curb for Normal Waste Sump T/B, El. 734'0"

Basis and Description of Change: The Normal Waste Sump was originally a radioactively clean sump capable of discharging directly to the environment and cross-connected to the Chemical Waste Sump. The Normal Waste Sump was made part of the Radwaste System after it became contaminated and was renamed the Auxiliary Turbine Building Floor Drain Sump. The cross-connect with the Chemical Waste Sump was plugged; however the possibility still existed for the Auxiliary Turbine Building Floor Drain Sump to overflow to the Chemical Waste Sump. The two sumps are located in the southeast corner of the Turbine

Building and a retaining wall isolates them from the remainder of the building. No wall separated the sumps. A retaining curb separating the two sumps was added by this modification to prevent any overflow between the sumps.

Summary of Safety Evaluation: The retaining curb prevents contaminated water in the Normal Waste Sump from overflowing into the Chemical Waste Sump and inadvertently being released to the environment. This will help to ensure that radiation levels are kept within the exposure limits defined in 10CFR50, App. I. Also, Technical Specification Section 3.14.4 describes the radioactivity concentration level at which liquid radwaste must be treated prior to discharge. Erection of the retaining wall ensures that this Technical Specification requirement is met since the wall will prevent contaminated water from being inadvertently discharged to the environment from the chemical waste sump. As described in UFSAR Section 11.2.2, several existing design features for the Normal Waste Sump/Chemical Waste Sump have been factored into the overall system to preclude any accidental release to the environment. Erection of the wall provides added assurance that no inadvertent release to the environment could occur. In addition, UFSAR Table 3.2-1 defines the turbine building as a non-seismic structure. Addition of the retaining wall around the normal waste sump does not degrade the turbine building structure since the retaining wall provides no seismic support features. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1386 Chemistry Lab HVAC

Description and Basis for Change: There were five problem areas associated with the Chemistry Lab HVAC System: 1) high humidity and uncomfortable conditions in the fume hood area; 2) low air movement at the south end of the Chemistry Lab; 3) the only conditioned air being supplied to the Post Accident Sampling Lab was the air that was drawn from the surrounding rooms; 4) flow tests performed on the supply fan for 1V-AC-66 showed a 30% decrease from design; and 5) the supply air for the hoods and Chemistry Lab was not balanced with the exhaust air. This modification replaced the existing heating coil with a heating and cooling coil. The piping network for the new coil remained the same and all instrumentation related to the new coil was changed. A return grill was installed in one corner of the Chemistry Lab and a supply register was installed in the Post-Accident Sampling Lab. Following completion of modifications, all the HVAC systems in the Chemistry Lab were balanced.

Summary of Safety Evaluation: The FSAR does not address Administration Building HVAC. Installing a new heating and cooling coil and new diffusers and grills did not affect the original design intent of the Chemistry Lab HVAC system. Providing conditioned air to the fume hoods and improving ventilation in the Chemistry Lab increased the reliability of the lab equipment. These modifications did not affect any systems important to safety. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1393 Replacement of HPCI Turbine Exhaust Pressure Switches (PS-2215A, PS-2215B, PS-2215C, and PS-2215D)

Description and Basis of Change: HPCI turbine exhaust pressure switches PS-2215A, B, C, and D provide a HPCI auto isolation signal when pressure between the two rupture discs that provide turbine exhaust line pressure protection exceeds 10 psig. PS-2215D was found to be non-repeatable and required replacement. The switch is obsolete and General Electric does not have a direct replacement. Since the four HPCI turbine exhaust pressure switches were the same age, all four switches were replaced.

Summary of Safety Evaluation: The replacement switches meet original seismic and accuracy (repeatability) requirements. The original pressure range of 2-25 psig was reduced to 1.4-18 psig, which makes the trip point more closely mid-range. The design temperature was reduced from 400°F to 160°F which still exceeds the maximum normal temperature of 121°F. Due to the 30 feet of sensing tube separating the pressure switch from the rupture disk exhaust, the exhaust medium environment will not be seen by the pressure switch. Electrical contact rating and configuration meets the original specification. These switches do not perform a direct safety function, HPCI steamline break isolations are given by other equipment (high temperature, high differential temperature, high flow and low steamline pressure). Given the one-out-of-two twice logic, an inadvertent actuation cannot cause a HPCI isolation. The replacement switches do not introduce any new failure modes. They exceed the requirements of the ambient environment extremes and will be seismically mounted. They perform the same function as the original switches. This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1395 RHRSW Air/Vent Valve Modification

Description and Basis for Change: Each of the four RHR Service Water Pumps had an air/vent valve located approximately two feet down stream of each pump. The purpose of this air/vent valve was to discharge air from the pump and system piping when the line filled and to allow air to enter when the pump stops and the line drains back to the pit. The valves were designed with a ball suspended in a cage inside the valve. As the air entered the valve, it passed around the cage and ball, and out the top. When the water entered the valve, it flowed around the cage and lifted the ball against the seat. Water pressure maintained the seal so when the pump stopped, the ball dropped into the cage and air flowed back into the pipe line. On the RHRSW System, the startup pressure and flow are so great that a slug of water shot into the valve and impacted the cage. This impact knocked the ball up onto the seal with great force. The valves repeatedly failed due to damage to the seal, ball float, and cage in the valve housing. The valves were replaced with blind flanges.

Summary of Safety Evaluation: The blind flanges were constructed per ANSI B31.7, Section III. The seismic evaluation was not adversely affected because replacement of the air/vent valves with the blind flanges reduced the weight and loading on the piping in this area. The additional air sent downstream due to the removal of the air/vent valve is small compared to the amount of air normally pumped downstream. Also, the system has high point vents and is an open loop system that exhausts to the cooling towers. Therefore, the possibility of water hammer in the system is not increased by the removal of the air/vent valve and blind flanging the vent pipe. The modification will not adversely affect the performance of the RHR Service Water System. No new accident/malfunction scenarios were created. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1397 Implementation of the SPDS on Plant Process Computer/VAX 8600

Description and Basis for Change: This design change implemented the Safety Parameter Display System (SPDS) on the Plant Process Computer (PPC). The interface to plant safety systems (data acquisition system) was not affected. The package installed a color graphics terminal to support the SPDS in the DAEC control room, installed an RS-232 connection between the KAMAN Effluent Monitoring System (EMS) and the VAX 8600, recoded existing algorithms for the meteorological data to run on the VAX 8600, and converted software for the KAMAN EMS and the MIDAS Plume Model to operate on the PPC.

Summary of Safety Evaluation:The computer cannot send a signal to a plant sensor (pressure switch, position switch, etc.) such that spurious indications or system activation are possible. The SPDS is not a safety system. It cannot initiate an accident or prevent any action to mitigate the consequences of an accident. The non-class 1E portions of the SPDS are electrically isolated from class 1E signals by using fiber-optic cables between components. Failures of the SPDS computer cannot cause erroneous indication or activation of any control room indication or plant equipment. Therefore, no transient or accident analytical result in the FSAR will be affected by either the operation or the failure of the SPDS. In the event of an SPDS failure, the existing control room instrumentation, as required by General Design Criteria 13 and 19 of Appendix A to 10CFR50, will provide the operator with the information necessary for safe reactor operation under normal, transient and accident conditions. The operation of the SPDS will not degrade operator performance because in addition to human factors considerations included in the design, the operators will be trained in procedures which describe the timely and correct safety assessment when the SPDS is and is not available. These procedures will be written to preclude the operator from taking actions based solely on SPDS display information. Operating procedures required that all operator actions affecting the safety of the plant be based on information which has been confirmed using the existing control room indicators. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1399 TSC Standby Generator

Basis and Description of Change: This installation was in response to the findings from an NRC audit/inspection of the DAEC's Emergency Response Facilities. The Technical Support Center (TSC) and Plant Process Computer (PPC) were powered from off-site sources via transmission lines. The NRC suggested that a back-up power source for the TSC and PPC be installed on-site. This modification installed a diesel engine-driven electrical generator to provide back-up power to the TSC and to the PPC. The installation consisted of an engine-generator packaged unit, a dedicated 560 gallon fuel tank inside a 1000 gallon concrete containment basin, and two automatic transfer switches. The packaged unit and fuel tank are located in the yard, on the north side of the Turbine Building, away from any equipment important-to-safety. The automatic transfer switches are located in the TSC Mechanical Room to power TSC ventilation equipment, and in the Data Acquisition Center Second Floor Mechanical Room to power the PPC and other TSC equipment.

Summary of Safety Evaluation The installation of the TSC Standby Generator and its ancillary equipment does not involve an unreviewed safety question for the following reasons: (1) The TSC Standby Generator and its fuel tank do not create an explosion/missile or fire hazard; (2) The TSC Standby Generator is physically and electrically isolated from all plant equipment; (3) The conduits and cable runs for this installation are located outside of the Reactor and Control Buildings, and can not interact with any plant power or control cables or raceways; and (4) Malfunctions of the TSC Standby Generator can not cause the PPC/SPDS to provide erroneous information the Control Room operators or Emergency Managers in the TSC. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1402 Turbine Building CO_2 Valve Access Platform

Description and Basis for Change: Access to Cardox Fire Suppression Unit valves located above the Cardox CO_2 storage tank required climbing that presented a safety hazard to personnel. A ladder and free standing platform were installed above the Cardox CO_2 storage tank to allow for safe and easy access to these valves. The ladder and platform were designed to meet applicable OSHA requirements per Title 29 of the Code of Federal Regulations and included conservative seismic criteria.

Summary of Safety Evaluation: The platform and ladder assembly is designed to surround the Cardox CO_2 storage tank and associated components which are non-seismic. Since the Cardox Fire Suppression Unit is required for protection of the cable spreading room, which contains many electrical cables associated with safety-related systems, the platform and ladder assembly is designed to seismic category 1 criteria. The installed platform and ladder above the

Cardox CO_2 storage tank do not affect the original design intent of the Cardox Fire Suppression Unit nor reduce any margin of safety. This modification does not involve an unreviewed safety question or change to Technical Specifications.

DCP 1404 Reactor Vessel Water Level Instrumentation Modifications

Description and Basis for Change: NRC Generic Letter 84-23 and Regulatory Guide 1.97 requirements for reactor vessel water level indication provide the basis for this modification. The NARROW and FUEL ZONE (2 legs total) range reactor water level instrumentation reference legs were rerouted through two new drywell penetrations to reduce instrumentation errors resulting from drywell heating effects by minimizing the vertical drop within the drywell. In addition, previously installed FUEL ZONE level indication transmitters and associated instrumentation loops were replaced with four new transmitters and Class 1E instrumentation to provide redundant, continuous indication of reactor vessel water level in the control room over the range of -153" to +218", referenced to top of active fuel. Each reference leg is associated with one division made up of two of the newly installed FUEL ZONE transmitters, with each transmitter receiving power from a different divisional power source. The previously installed control room FUEL ZONE indicator and recorder were replaced with two new indicators and two new recorders. Each division of control room FUEL ZONE reactor water level indication is made up of one new indicator and one new recorder which receive signals from their respective divisional FUEL ZONE instrumentation. Divisional reactor water level signals are also provided by the new instrumentation to the Safety Parameter Display System as well as the RHR containment spray interlock. This modification also included rerouting the sensing lines used to provide drywell atmospheric pressure input to containment water level instrumentation allowing plant operators to monitor and control primary containment water level up to the elevation of the drywell vent as required by Emergency Operating Procedures.

Summary of Safety Evaluation: The design of the modification meets all requirements for human factors considerations, instrument accuracy, mechanical reliability, seismic interactions, fire protection, environmental qualification, and electrical separation. The design bases for the reactor vessel water level and containment water level instrumentation have also been maintained. All piping and valves meet the original construction codes. Two new drywell penetrations of 8" diameter were required in the drywell shield wall for this modification. The design basis for the drywell shield wall is to remain within code allowable stresses nominal plus Operating Basis Earthquake (OBE) loading conditions and to sustain no functional failures for normal plus extreme environmental and accident conditions. With the location and design of the two new drywell shield wall penetrations considered, stresses have been determined to remain within code allowables for nominal and OBE loads, and the functional capability of the wall has been determined to remain unchanged for normal plus extreme environmental or accident loading conditions. The new penetrations were designed and installed in accordance with applicable codes and standards to maintain primary containment integrity during design bases accidents including design basis earthquake and design basis LOCA. In addition, upon completion of installation of the modification, an integrated leak rate test was performed to confirm primary containment integrity. Because the piping is designed to original plant standards and existing excess flow check valves, root isolations valves and flow orifices have been reused, the probability of an unisolable reference leg rupture has not been increased. The rerouted reference leg piping inside the drywell reduces the amount of piping susceptible to system interactions inside the drywell. The modified systems were designed and installed to prevent seismic interactions from adversely affecting piping inside the drywell, the drywell vessel, piping outside the drywell, and electrical instrumentation. New piping and cables outside the drywell are located in areas outside the area of influence for high energy line break pipe whip and jet impingement effects. The modified reactor vessel level instrumentation and associated piping located inside the drywell have been analyzed for high energy line break sources. A break in the new instrument piping or tubing in the reactor building is no different than a break in the piping or tubing which was previously possible. It has been determined that both channels of the FUEL ZONE reactor water level instrument piping cannot be affected by a single pipe break. The newly installed FUEL ZONE level instrumentation meets the design and qualification requirements of Category 1 instruments per Regulatory Guide 1.97. To address NRC Generic Letter 84-23 concerns, Iowa Electric analyzed reliability data for 19 different reactor water level instruments obtained through the DAEC Deviation Reporting System over a 5 year period. The results of the review showed that no instrument failures had occurred and acceptable performance regarding setpoint drift had been experienced. Therefore, with the exception of circuits associated with FUEL ZONE reactor water level indication, other mechanical level indication equipment was not replaced in addressing NRC Generic Letter 84-23 due to proven high instrument reliability. With the exception of the improved instrument accuracy and any spatial systems interactions that depend on equipment locations, the modified system is functionally equivalent to the system it replaced. With regard to the RHR containment spray interlock, the new design is functionally equivalent to the previous design. The two divisions are physically and electrically separated with separate control room instruments for each division to prevent a failure in one division from impacting the other division. A single failure in either the instrument piping or electrical system cannot prevent the operator from receiving FUEL ZONE range reactor vessel water level indication. The reference leg reroute increases channel accuracy and ensures that any error in instrument accuracy due to drywell heating effects is in a conservative direction. This improves reactor vessel water level indication from a human factors standpoint because any operator action in response to decreasing reactor water level is made sooner. Instrumentation affected by this modification has been recalibrated and adjusted for new channel accuracy such that they provide the same protective trip and indicating functions previously provided. Post Installation Modification Testing was performed and verified that newly installed instrumentation provides trips as required. The modifications do not adversely affect the reliability or availability of the channels, and portions requiring surveillances remain accessible so that surveillances can be performed at the presently specified frequencies. The new drywell penetrations are subject to the same leak rate testing requirements as existing instrument penetrations. The frequency of surveillance, acceptance criteria, and consequences of failure have remained unchanged. The only effect of rerouting drywell atmospheric pressure sensing lines has been to extend the range of containment water level indication. Operation of the associated pressure switches and transmitters is unchanged. The drywell atmospheric sensing line reroute has no effect on instrument calibration, reliability or availability of channels or surveillance frequency. No changes to Technical Specifications were required and it was determined that this modification involved no unreviewed safety question.

DCP 1405 <u>Shroud Head Bolt Replacement</u>

<u>Description and Basis for Change</u>: General Electric (GE) Services Information Letter No. 433 (SIL 433) identified intergranular stress corrosion cracking concerns in shroud head bolts (SHBs). In response to SIL 433, Iowa Electric Light and Power Company had GE perform an ultrasonic examination (UT) on all twenty-six SHBs during the 1987 refueling outage under DCP No. 1380. The results of the UT indicated that thirteen of the twenty-six SHBs required replacement. At that time, eleven SHBs of the new design were obtained and installed along with two new SHBs of the old design, replacing the thirteen SHBs identified as needing replacement. Of the total twenty-six SHBs, fifteen SHBs of the old design remained. DCP No. 1405 provided for the replacement of the fifteen remaining SHBs of the old design with SHBs of the new design.

<u>Summary of Safety Evaluation</u>: The function of the SHB is to fasten the shroud head and steam separator assembly to the core shroud such that the shroud head is restrained in its proper location on the core shroud. DCP No. 1380 approved the new SHB design and allows its installation as a replacement part. This modification did not alter reactor vessel internals, FSAR facility description, design of the SHB or the shroud head, nor does it alter or affect the performance of any other equipment. Replacement of the fifteen SHBs of the old design eliminated concerns regarding cracking that have been identified at BWR plants. The modification improved the reliability of the SHB by minimizing the possibility of SHB cracking. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1407 Long-Term DCRDR Enhancements for Panels 1C-08 and 1C-388

Description and Basis for Change: This DCP corrected human engineering deficiencies identified in the Detailed Control Room Design Review (DCRDR) summary report for control room panel 1C-08 and remote shutdown panel 1C-388. The Standby Diesel Generator (SBDG) frequency and voltage hand controls already installed at panels 1C-08 and 1C-388 were modified such that frequency and voltage are "lowered" by rotating the hand control to the left (counter-clockwise) and "raised" by rotating the hand control to the right (clockwise) to be consistent with human factors conventions. A timer was installed on panel 1C-08 for use with the existing SBDG prelube pushbutton to automatically prelube SBDGs for the required time period set on the timer. In addition, a 24-hour clock was installed adjacent to panel 1C-388 for use during remote shutdown panel operations.

Summary of Safety Evaluation: The failure of SBDG manual controls is not an initiator for any accident. The modifications to the frequency and voltage hand controls reduce the probability of human error when adjustments are made. The existing automatic frequency and voltage controls for either SBDG were not altered. Applicable design criteria for electrical isolation and physical separation were adhered to and Post Installation Modification Testing was performed to ensure proper installation and operation. Installation of SBDG prelube timers has no effect on the automatic start feature of either SBDG. Modifications to SBDG manual frequency and voltage controls as well as operation of the SBDG prelube timer have been incorporated into operator training and requalification. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1408 Long-Term DCRDR Enhancements for Panels 1C-05, 1C-06 and 1C-208

Description and Basis for Change: This DCP corrected human engineering deficiencies identified in the Detailed Control Room Design Review (DCRDR) summary report for reactor control panel 1C-05, feedwater and condensate panel 1C-06, and emergency shutdown panel 1C-208. At panel 1C-05: (1) the recirculation system master controller was removed since it is not used; (2) the IRM/SRM drive momentary contact pushbuttons were replaced with alternative "seal-in" pushbuttons for IRM/SRM insertion only to preclude the operator from having to maintain the pushbuttons depressed during IRM/SRM insertion; (3) the Control Rod Drive (CRD) drive water differential pressure indication range was increased from 0-350 psid to 0-500 psid to allow monitoring over the full range of CRD differential pressure due to operational characteristics of rod movements; (4) the manual scram pushbuttons were relocated to reduce the probability of inadvertent actuation while operating the reactor mode switch; (5) CRD pump control switches were rearranged in "A", "B" (left to right) order, the indicator lights for "A" and "B" Standby Liquid Control (SLC) pumps and indicating lights for the associated manual maintenance valves were relocated, three reactor pressure indicators were rearranged in "A", "B", "C" order and three reactor water level indicators were rearranged in "A", "B", "C" order to be consistent with human factors conventions. At panel 1C-06, the control switch associated with Emergency Service Water (ESW) pump 1P-99A was replaced such that the "pull-to-lock" feature was removed to ensure that 1P-99A starts whenever its respective SBDG starts. A similar modification was performed to ESW pump 1P-99B under DCP No. 1355 during the previous refueling outage. At panel 1C-208, control switches previously used to open two SRVs under emergency shutdown conditions prior to installation of the remote shutdown panel per 10CFR50 Appendix R, which disconnected these switches but not the accompanying annunciator contacts, were removed since they were no longer required.

Summary of Safety Evaluation: The removal of the recirculation system master controller eliminates the potential for minimum and maximum speed signal malfunctions for both recirculation pumps due to a single controller failure. Addition of a "seal-in" function for IRM/SRM insertion does not affect the operation of the IRM or SRM systems. Use of the "seal-in" function reduces the amount of operator attention required to insert IRM/SRMs following a reactor scram. Extending the range of the CRD drive water differential pressure indication to 0-500 psid provides better indication of rod movement anomalies. Rearranging various indications and components has no effect on their function or operation. Operator use of rearranged indications and components is improved by rearranging them to conform with human factors guidelines. Modifications to ESW pump 1P-99A improves its reliability when required to start upon receipt of a SBDG start signal by removing the capability to disable the pump from the control room. Removal of inoperable handswitches at panel 1C-208 and associated operational annunciator contacts eliminates the possibility of an operational error caused by a misleading alarm from this source. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1409 Modifications to Panels 1C-03 and 1C-38

Description and Basis for Change: This modification provided the means for relocation and/or removal of indicators and components at control room panel 1C-03 which interfered with the installation of new instrumentation installed under DCP No. 1410. Jet Pump Developed Head Indicator, PDI-4567, was relocated from panel 1C-03 to panel 1C-38, Safety Parameter Display System (SPDS) relays located inside panel 1C-03 were relocated inside panel 1C-03, and the Reactor Head Spray flow indicator, control switches and indicator lights were removed from panel 1C-03. In addition, this modification installed time delay relays in the minimum flow valve logics of all ECCS systems to correct a design condition that caused minimum flow valve control circuit contactors to burn-up. This condition allowed the closing or opening contactors in the minimum flow valve control circuit to energize prior to release of a mechanical interlock associated with valve operation. As a result, the mechanical interlock would fail to release, preventing the minimum flow valve from stroking, ultimately causing the respective contactor to burn-up.

Summary of Safety Evaluation: Jet Pump Developed Head Indicator PDI-4567 is seldom used. Relocation of PDI-4567 from panel 1C-03 to panel 1C-38 does not affect operator actions performed during plant evolutions. Applicable design criteria for electrical and physical isolation and separation were adhered to and Post Installation Modification Testing was performed to ensure proper installation and operation following relocation of all components. The SPDS relays remain seismically attached to the fire wall within panel 1C-03 following relocation. The overall probability of failure of any ECCS minimum flow valve has been reduced due to the addition of the time delay relay in the valve control logic preventing energization of valve closing or opening contacts before the mechanical interlock releases. Reactor Head Spray capability was previously removed by DCP No. 1385 during the 1987 refueling outage. Associated head spray components and wiring within panel 1C-03 were abandoned in place at that time. The removal of these abandoned components has no effect on plant safety. Relocation and removal of indicators and components as well as minimum flow valve control circuit modifications are included in operator training to ensure the effects of negative transfer of training is eliminated. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1410 Long Term DCRDR Enhancements for Panels 1C-03 and 1C-09

Description and Bases for Change: This DCP corrects human engineering deficiencies identified in the Detailed Control Room Design Review (DCRDR) summary report. These modifications were completed to provide significant reduction in risk in the event that emergency operation is required and enhance the safe operation of Duane Arnold Energy Center (DAEC) by improving the operators ability to respond to transients and other abnormal operational conditions. At control room panel 1C-03: (1) An amber indicating light was installed above each Safety Relief Valve (SRV) control and below each Safety Valve (SV) control to indicate valve opening based on tailpipe pressure switch input; tailpipe pressure switch input to associated annunciators at panel 1C-03 was also included. (2) Divisional, narrow range Reactor Pressure Vessel(RPV) pressure indicators were added; two new, narrow range RPV pressure loops were installed with transmitters located on instrument racks in the Reactor Building. (3) Wide range RPV pressure indicators were relocated from panel 1C-09 to panel 1C-03. (4) Divisional, wide range torus water level and containment water level indicators were added. (5) Two divisional indicators for wide range torus pressure and wide range drywell pressure were added. (6) An average drywell air temperature indicator was added. (7) Recorders for narrow range torus water level and average torus water temperature were added. (8) An average torus water temperature indicator was added. (9) A keylock switch for the purpose of overriding interlocks associated with the High Pressure Coolant Injection (HPCI) minimum flow valve were added. (10) Keylock switches for operating Residual Heat Removal (RHR) Service Water flow control valves when RHR Service Water pumps are not operating were installed to allow use of alternate RPV injection sources when called for by Emergency Operating Procedures. (11) The two-minute timers for each channel of the

Automatic Depressurization System (ADS) were replaced with new timers and mounted above the ADS controls. (12) The high drywell pressure switch reset pushbuttons were removed; a previous DCP removed the high drywell pressure signal input from the ADS logic. (13) Two divisional, narrow range drywell pressure indicators were relocated from panel 1C-09 to panel 1C-03. (14) Replaced keylock switches for outboard containment spray valves with cane handle switches coded as throttle valves. (15) Replaced cane handle switches for inboard containment spray valves with keylock switches. (16) Keylock switches for the RHR heat exchanger inlet valves were replaced with cane handle switches switches coded as throttle valves. (17) The HPCI turbine vibration monitor and recorder were removed. (18) The square root converter for the HPCI pump discharge flow and the power supply for the HPCI turbine governor test circuit were relocated to panel 1C-18. (19) Holes in panel 1C-03 left by DCP No. 1409 and the removal of the HPCI turbine vibration monitor and vibration recorder were re-covered by weld repair.

At control room panel 1C-09: (1) Two bays of annunciator windows with associated acknowledge and test pushbuttons were added; (2) Annunciator windows that combined torus and drywell high range radiation monitor alert, high and trouble alarms were split into five annunciators and relocated from panel 1C-35 to panel 1C-09; (3) Annunciator windows that combined containment high O_2, high H_2 and analyzer trouble alarms were split into three annunciators and relocated from panel 1C-05 to panel 1C-09; (4) Wide range RPV pressure recorders were replaced with new recorders and relocated on panel 1C-09; (5) Wide range and narrow range drywell pressure recorders, wide range torus water level and drywell water level recorders, drywell H_2 and O_2 concentration recorders and containment high radiation level recorders were replaced with new recorders and relocated on panel 1C-09; and (6) The YELLOW and RED bands on the torus and drywell high range radiation monitors and associated alarm setpoints were modified to correspond with Emergency Plan Implementing Procedures levels.

At panel 1C-45, indicating lights associated with high drywell pressure input to ADS logic were removed. A previous DCP removed removed the high drywell pressure signal input from the ADS logic.

At panels 1C-15 and 1C-17: (1) Two keylock switches and associated indicating lights were installed on each to allow overriding the Group 1 isolation on RPV low-low-low water level when directed by Emergency Operating Procedures; (2) keylock switches, with associated indicating lights, were installed to override the high drywell pressure and reactor low level inputs to the inboard Group 3 isolation logic for use when directed by Emergency Operating Procedures.

Also, existing torus water level transmitters were relocated to the proper height and fitted with new bellows consistent with the new range of indication (14.5 ft). The new divisional torus pressure transmitters were installed on the torus room wall of the north-east corner room.

<u>Summary of Safety Evaluation</u>: The addition of an indicating light for each SRV and SV provides positive indication of valve position

and therefore reduces the potential for inappropriate operator action associated with these valves. The addition of pressure switches as inputs to the associated annunciator improves the effectiveness of the annunciator. The indicator lights and annunciator input require a "follower" relay to be placed in parallel with the existing relay for each valve monitored. Since the new relays are identical to the existing relays, no new failure mode of the associated equipment was created. The addition of two divisional indicators for narrow range RPV pressure and relocation of wide range RPV pressure to panel 1C-03 provides feedback for operator actions during an emergency. New transmitters seismically mounted in the reactor building to provide input to the new narrow range RPV pressure indication, were installed utilizing existing piping taps that provide leak isolation capabilities with the existing excess flow check valves. Modification, relocation and/or addition of control room indications of various reactor and containment parameters provides feedback for operator actions taken during an emergency and enhances the operators ability to respond under emergency conditions. Modification of the range of torus water level indication from 0 - 30ft. to 1.5 - 16ft. has increased the accuracy over the actual range of indication monitored. Regulatory Guide 1.97 criteria are satisfied with this range of torus water level indication. Modification of the range of drywell level indication from -20 to +80ft. to 0 to 98ft. allows monitoring from the bottom of the torus to an approximate height of 100 ft. Conversion of this range to read only positive values allows for direct conversion between torus water level and containment water level values, and eliminates confusion between the two indications. The addition of two divisional indicators for wide range torus pressure and wide range drywell pressure into the circuitry of the containment water level does not alter its operation due to the high impedance indicators being used. The sensing lines for the new torus air space pressure transmitters tap into existing lines which penetrate the torus. The new torus air pressure transmitters are seismically mounted to the reactor building wall. The signals for the added narrow range torus water level recorder, average torus water temperature recorder and indication, and average drywell air temperature indication originate from indication loops already in place and utilize qualified isolators to provide separation between each loop. Addition of keylock switches and amber indicating lights for overriding interlocks associated with the low-low-low reactor water level signal for Group 1 isolation, the low reactor water level and high drywell pressure signal for Group 3 isolation, the HPCI minimum flow valve and RHR Service Water flow control valves provides for operator actions required by Emergency Operating Procedures. The use of a keylock switch in lieu of "jumpers" and "lifted leads" is desirable in an emergency situation, and enhances operator response. The use of keylock switches prevents inadvertent operation of these valves which could lead to diversion of injection flow to the torus or radioactive release to the environment. The new ADS timers perform the same function as those previously installed and provide visual indication of time remaining before ADS automatically initiates. The new timers incorporate setpoint locks to prevent inadvertent movement of the time setpoint. These timers were not placed adjacent to similar components to prevent confusion. The removal of high drywell pressure reset switches and associated indicating lights has no effect on the operation of ADS, since high drywell pressure input to ADS was previously removed. The relocation of the square root converter for the HPCI pump discharge flow and power supply for the HPCI turbine governor test circuit from panel 1C-03 to panel 1C-18 removes non-operationally oriented components from an important panel and enhances the operator's ability to respond to an emergency condition. The replacement of inboard containment spray valve cane handle switches with keylock switches and outboard containment spray valve keylock switches with cane handle switches reduces the potential for inappropriate operation of these valves. The configuration of one valve in each containment spray line utilizing a keylock switch is maintained. The design intent and function of containment spray valve controls remains unchanged. The removal of the HPCI turbine vibration monitor and recorder from panel 1C-03 reduces the potential for inappropriate operator action by removing removing potentially misleading indication of HPCI turbine status. The addition of two new bays of annunciator windows at panel 1C-09 provides plant design flexibility in performing future modifications to the annunciator system. The new annunciators were seismically qualified and mounted. Relocation of annunciator windows from panels 1C-35 and 1C05 to panel 1C-09 provides an improvement in the location of these annunciators to reduce the possibility of inappropriate operator action during an emergency. The color-banding ranges of torus and drywell radiation monitors at panel 1C-09 corrects the non-conservative markings previously on the meters and provides concise information to the operators regarding Emergency Action Levels. The replacement and relocation of recorders on panel 1C-09 is consistent with human factors criteria and reduces the potential for inappropriate operator action during an emergency. Appropriate design criteria for electrical isolation and physical separation were adhered to and Post Installation Modification Testing was performed to ensure proper installation and operation. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1412 <u>Low Pressure Turbine "A" Rotor Replacement</u>

<u>Description and Bases for Change</u>: Previous examination of the Low Pressure "A" Turbine rotor revealed stress corrosion cracks in keyways between the shaft and shrunk-on wheels. The potential existed for the wheel material to fracture upon reaching a critical crack depth, thereby creating turbine missiles. The Low Pressure "A" Turbine rotor was replaced with a rotor of the GE monoblock design, which eliminates high stress areas of keyways where stress corrosion cracking initiates.

<u>Summary of Safety Evaluation</u>: The replacement of the Low Pressure "A" Turbine rotor does not directly affect any safety-related equipment nor does it affect the function, operation or operability of any systems or components important to safety. The replacement of the rotor with one of the monoblock design upgraded the previous shrunk-on wheel design to an integral wheel rotor design. The monoblock's design of forging the rotor shaft and wheels as one piece eliminates high stress areas or keyways of the shrunk-on wheel design,

where turbine rotor stress corrosion cracking initiates. All turbine buckets are of like-for-like replacement and are mounted to the monoblock rotor in the same manner as they were mounted to the shrunk on wheel rotor. Therefore, the potential for turbine missiles was reduced from that previously evaluated. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1417 Miscellaneous Piping Insulation Modifications

Description and Bases for Change: This DCP continued the Drywell/Steam Tunnel HVAC Modifications begun by DCP No. 1341 in response to a Containment Cooling System Study. This modification replaced the metal reflective insulation on the Residual Heat Removal (RHR), Feedwater and Core Spray piping systems located within the drywell with NUKON blanket insulation. The new blanket insulation is more efficient than the metal reflective insulation used in the past, and reduces the drywell heat load, reducing the temperature of the drywell and eliminating local "hot spots" that could contribute to equipment failure and heat damage to safety-related cables. In addition, this modification included installation of a removable blanket insulation on miscellaneous piping components to facilitate the erosion/corrosion inspection program developed by Iowa Electric to addressing NRC Generic Letter 87-01 concerns over the thinning of pipe walls.

Summary of Safety Evaluation: The NUKON insulation system is designed to meet the maximum average heat transfer rate of 65 $Btu/hr/ft^2$ required by APED-B21-89-1, "Design Requirements for Standard BWR Plants" and is consistent with FSAR requirements for the maximum average heat transfer rate for the recirculation piping. The ease of removal and installation of NUKON insulation ensures that radiation exposures are minimized during inspection of the associated piping and components. NUKON insulation has been certified to meet Regulatory Guide 1.36 criteria for reducing the probability of intergranular stress corrosion cracking of stainless steel components by ensuring that the insulation does not contain contaminants from external sources. Seismic evaluation has shown that the NUKON insulation will remain attached to the piping during a seismic event of 3.0g in any direction and that the difference in weight between the NUKON insulation and previously installed insulation does not affect the results of seismic analysis already performed on the RHR, Feedwater and Core Spray systems. The design basis fire in the drywell is not affected by installation of NUKON insulation since NUKON insulation is non-combustible. NUKON insulation does not degrade the capability of of the ECCS pumps the meet long-term cooling requirements following a LOCA. By analysis, none of the insulation debris resulting from a LOCA will reach the RHR or Core Spray suction strainers, allowing these pumps to receive water free of debris to satisfy NPSH requirements. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1420 Main Steam Dripleg Drain Modifications

Description and Bases for Change: These modifications were performed to eliminate problems experienced with flooding of the Main Steam Isolation Valve-Leakage Control System (MSIV-LCS) low pressure manifold through feedwater check valve leak-off lines and normally-closed cross connections with main steam line drains to the closed radwaste system. Modifications included: (1) elimination of the common drain line between main steam line drains to closed radwaste and the MSIV-LCS low and high pressure manifolds; (2) elimination of the leak-off lines from feedwater check valves to closed radwaste; and (3) modifications to the main steam drain line piping arrangement to the main condenser by replacing 4 control valves with one larger control valve.

Summary of Safety Evaluation: This modification removed the common drain path between the MSIV-LCS, main steam line drains and feedwater check valve leak-off lines, thereby eliminating recurrence of MSIV-LCS low pressure manifold flooding, and preventing leakage and drainage through these paths from affecting the operation of a safety-related system. The leak-off ports from the feedwater check valves were seal welded per applicable codes and standards. Removal of feedwater check valve leak-off lines does not change the design intent of these valves. Any packing leak will leak into the steam tunnel, and any increase in temperature in the steam tunnel will be detected by the steam tunnel temperature detection system. The probabilty of a Group 1 isolation followed by a reactor scram is not increased since temperature increases due to packing leaks will be insignificant with the improved packing installed. All equipment in the steam tunnel is environmentally qualified under 10 CFR 50.49 and will operate in any environment caused by any packing leak. The main steam line drain path through drip legs was rerouted to the main condenser such that any leakage through the drip legs will not affect any safety related system. The operability of the MSIV-LCS and associated components as required by Technical Specifications is not affected by this modification. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1422 Feedwater Check Valve Soft Seat Conversion

Description and Bases for Change: The feedwater check valves at Duane Arnold Energy Center have repeatedly failed their primary containment local leak-rate tests. The nuclear industry in general has experienced problems with hard-seated check valves failing these leak rate tests. Several utilities have solved this problem by using a secondary soft seating arrangement which provides sealing at low pressures while the hard seats provide sealing at high pressures. The soft seat conversion was made by installing new discs in the check valves. The new discs have the soft seat conversion consisting of a soft seat clamped into a groove cut into the disk. Hard seating remains as it was prior to the conversion. To facilitate use of the soft seating arrangement, modifications to the valve packing, actuators and limit switch setpoints were also performed.

Summary of Safety Evaluation: The new soft seating arrangement is less likely to leak under low pressure conditions, while maintaining acceptable leakage characteristics at high pressure. Therefore, the overall ability of the valves to perform their intended safety function (to minimize containment leakage) is improved. The reactor coolant pressure boundary is not adversely affected by this modification. Installation was performed in accordance with approved DAEC design guidelines for valve integrity and cleanliness control. Modifications to the valve actuator and limit switch setpoints were made to enhance valve closure performance. Modifications to the valve packing reflects the use of improved packing design and material to decrease the drag on valve operation and enhance valve disc operation while maintaining valve integrity. Quantities of chlorines, flourines and sulfur in the soft seating material are small and since practically all of these impurities are chemically bound in compounds (i.e., not free) their presence will not adversely affect either the reactor coolant pressure boundary, via leaching into the reactor coolant or directly attack the check valve component parts. At nominal system temperature, the manufacturer recommends a service life of 5 years, equating to every third refueling outage (every 4 1/2 years). The soft seat material will be removed and inspected after the first outage to reevaluate the service life and make additional recommendations. At elevated temperatures, such as post accident conditions, the soft-seat material will experience "compression set" but will not embrittle and fall apart. However, the seats are installed in such a way as to preclude loss of parts. Under design flow conditions, the modified valves do not restrict flow and therefore will not inhibit the proper functioning of safety systems. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1423 Generator Rotor Design Improvement Changes

Description and Bases for Change: The Duane Arnold Energy Center (DAEC) generator was found to be susceptible to copper particle contamination of the fields creating field shorts and eventual field grounds and corrosion pitting and stress corrosion cracking of the retaining rings. To prevent these problems, modifications to the generator under this DCP included: (1) installing insulating material in the generator rotor fields to prevent the copper bars from rubbing; and (2) replacement of retaining rings with new retaining rings of the same physical configuration and improved material.

Summary of Safety Evaluation: The replacement of the generator retaining rings with new improved retaining rings of different material upgrades the previous installation preventing the occurrence of corrosion pitting and stress corrosion cracking. A failed generator retaining ring while the generator is in service could result in major damage to the generator and release of hydrogen could result in a hydrogen explosion and fire in the turbine building. Copper particles are produced by rubbing of copper bars in the generator. Installation of separation layers between the copper bars prevents rubbing, and thus prevents production of copper particles, which can cause generator field shorts or grounds, from this source. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1427 Test Connection Installation for MO-2006

Description and Basis for Change: By NRC letter, exemption was granted from the requirements of 10 CFR 50, Appendix J, type C testing of MO-2006 (RHR "A" suppression pool spray isolation valve). The exemption requires that an alternative test be performed such that the suppression pool cooling line between MO-2005 (RHR "A" suppression pool cooling/spray valve) and MO-2006 be pressurized at the same frequency required by type C tests to indicate the general condition of MO-2006. During the previous refueling outage, a test penetration with a welded plug on MO-2005 was used as the test connection. This required cutting the welded cap, preparing the end for connection to the test rig, and rewelding the cap when the test was completed. This modification cut the cap off of the existing test line penetration on MO-2005, and permanently installed a 3/4 inch test connection with two isolation valves.

Summary of Safety Evaluation: The addition of a 3/4 inch test connection to MO-2005 does not affect the operation of MO-2005 or any other suppression pool cooling equipment. To ensure containment integrity, the test line is closed with two ASME Section III, Class 2 gate valves and a pipe cap. The valves will only be opened for testing when the plant is shutdown with no requirement for shutdown cooling or suppression pool cooling. These are redundant valves to assure that the pressure boundary is maintained during plant operation. Procedural controls were added to ensure that the valves are not inadvertently left open. The new piping is Seismic Class I. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1430 Replacement of Breakers 1B3401 and 1B4401

Description and Basis for Change: The design of the power supply for the "A" and "B" Low Pressure Coolant Injection (LPCI) system inject valves was determined to be inadequate if a loss of one division of 125V dc power is considered in conjunction with a LOCA. 480V ac power is supplied to these valves from either one of a Division I or Division II motor control center (MCC) through respective Division I or Division II 125V dc control powered circuit breakers to a "swing bus" arrangement which supplies both the "A" and "B" LPCI inject valves. The "swing bus" provides 480V ac power from either divisional (but not both simultaneously) MCC to the valves. The 480V ac power supply to the "swing bus" was designed with a power seeking auto transfer capability to the energized division of 480V ac power upon loss of the other division af 480V ac power, thereby maintaining the "swing bus" energized for operation of LPCI inject valves. The circuit breakers are interlocked such that only one of the circuit breakers can be closed at a time to prevent cross connecting Division I and

Division II 480V ac sources through the "swing bus." The interlock prevents the open circuit breaker from closing on loss of divisional 480V ac power until the closed circuit breaker has opened. Loss of 125V dc control power to the closed circuit breaker coupled with loss of associated divisional 480V ac power would have caused loss of the "swing bus", leaving only one train of Core Spray available to provide low pressure water to the core in the event of a LOCA. This modification provided for replacement of the existing circuit breakers with new breakers fitted with dc undervoltage trip devices to ensure that the closed breaker trips open on loss of 125V dc control power allowing the "swing bus" to transfer to the energized division of 480V ac power. This DCP also modified the Remote Shutdown Panel to allow backfeeding of 480V ac power from a Division II ac bus through the "swing bus" to a Division I 480V ac bus to ensure the ability to initiate shutdown cooling following a fire in the Control Room. This modification was necessary since a fire in the Control Room could disable the 125V dc Division I control power to the two Division I circuit breakers required to perform the backfeed operation. The control circuits for the two Division I circuit breakers were modified to provide 125V dc Division II control power to these two Division I circuit breakers during a reactor shutdown from outside the Control Room when transfer switches are placed in the EMERGENCY position. Maintenance isolation breakers (in series with circuit breakers used for auto transfer capability) were also replaced under this DCP with breakers of a lower rating to provide coordination between these and other circuit breakers to provide protection of each divisional 480V ac source bus from the effects of a fault on the "swing bus". This ensures the availability of power to Core Spray system valves powered from the divisional 480V ac source buses upon a "swing bus" fault. In addition, the 400A circuit breakers for "A" and "B" LPCI inject valves were replaced with 70A circuit breakers to properly protect the associated motor operators and circuitry. The 400A circuit breakers were originally installed to provide overcurrent protection for 104hp motor operators. These motor operators were subsequently replaced with 26.4hp motor operators

<u>Summary of Safety Evaluation</u>: The replacement of circuit breakers under this DCP restores the function of the "swing bus" by ensuring that the normally-closed circuit breaker to the "swing bus" will open on loss of 125V dc control power thus allowing bus transfer to take place. Improved coordination between individual loads on the "swing bus" and associated circuit breakers was obtained by replacing individual load breakers with lower rated circuit breakers. Because of the existence of maintenance isolation breakers in each supply to the "swing bus", the "swing bus" auto transfer capability cannot be shown to be completely coordinated for fault currents above 1500A. Tripping of either maintenance isolation breaker could remove power from the "swing bus." In this case, since the "swing bus" auto transfer function is initiated by loss of 480V ac power at the divisional source of 480V ac power to the "swing bus" which remains energized, the auto transfer function would not be initiated leaving the "swing bus" deenergized. The loss of the "swing bus" is acceptable in the event of a "swing bus" fault provided that adequate coordination exists between breakers such that the 480V ac source buses are protected from such a fault as well as the Core Spray System

valves. The maintenance isolation breakers were replaced to provide the required coordination and protection. All modifications were designed and installed using the same or more stringent design criteria than was used in the original plant design. The design criteria took into account seismic concerns, fire protection impact, fault current carrying capability of power cables and the effect of cable additions on cable tray loading. Remote Shutdown Panel modifications enhance post-fire "swing bus" switching operations by providing Division II 125V dc control power to those Division I 125V dc control powered circuit breakers required to be operated to initiate shutdown cooling following a Control Room fire. 125V dc Division I control power could be adversely affected by a Control Room fire. All circuit breakers and cables used in the modification were procured as safety-related (Class 1E) and have been qualified for operation in their intended service environment. The modifications performed under this DCP did not change the function of any system and were required to return the plant to its originally intended design. The breaker modifications enhance system performance by ensuring the availability of a sufficient number of ECCS in the event of the loss of a single division of 125V dc power. The Remote Shutdown Panel modifications did not affect the operation of any device as long as the transfer switches are in the NORMAL position. Remote Shutdown Panels are only required for safe shutdown of the plant following Control Room evacuation. In the event of a Control Room fire, the Remote Shutdown Panel provides for isolation and control of Division II components and selected Division I components to allow safe shutdown from outside the main Control Room. Dual isolation devices that meet appropriate criteria were used to separate Division I and Division II circuits. Undervoltage trip coils used in replacement "swing bus" feeder breakers are designed to be fail-safe. Inadvertent trip of an undervoltage coil with 125V dc control power available will cause the circuit breaker to trip and transfer power to the "swing bus" from the alternate source. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1433 PDIS 2441 & 2442 Range Change (RCIC)

Description and Basis for Change: PDIS 2441 and 2442 are identical pressure differential indicating switches that monitor the RCIC turbine steam lines for high flow and are set to trip at that differential pressure which corresponds to 300% steam flow, indicative of a steam line break. In addition, each PDIS also has a negative range and trip setting used to detect instrument line failure. GE has reevaluated the design and concluded that instrument line failure detection is unnecessary. PDIS 2441 and 2442 have a history of instrument drift problems, and were replaced by this DCP with improved instruments having a smaller indicating range. The narrower range and improved instruments will reduce instrument error and operate satisfactorily within the required limits. In addition, this modification eliminated the negative differential pressure trip function by disconnecting leads to the associated terminals.

Summary of Safety Evaluation: Replacing these components and changing the range of instrument indication does not change the design function of the system. All design specifications related to seismic and environmental conditions are the same for both the old and new devices. The integrity of the radioactive barrier as well as the instrument response time remain unchanged. Other than the indicating range change, this design change was a like-for-like replacement. Deleting the instrument line break detection capability is acceptable as the instrument line is small; the maximum possible coolant loss is well within the normal vessel coolant makeup capability. The instrument lines are either inside the drywell or within the area protected by the Standby Gas Treatment System (SGTS). There are other sensors such as air particulate radiation monitors and air temperature monitors that can detect steam leaks in the areas of concern. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1434 In-Reactor Stress Corrosion Monitoring

Description and Basis for Change: The effects of hydrogen injection on the recirculation system piping are currently monitored by the Crack Arrest Verification (CAV) System, which measures electrochemical corrosion potential (ECP) and crack growth rate. The sample flow to the CAV system is obtained through the recirculation loop sample line. Due to flow variations and oxidation effects in the sample line, the measurement of ECP and crack growth may not be indicative of the actual environment in the recirculation piping. The need for in-core chemistry monitoring capability has been brought about by recent concerns over Intergranular Stress Corrosion Cracking (IGSCC) of stainless steel and nickel alloy reactor internals. In addition, the CAV system has produced increasing area radiation levels over the last operating cycle in a high traffic area, requiring installation of permanent radiation shielding. This DCP accomplished the following: (1) Installation of ECP and crack growth sensors which provide a direct correlation between the environment in the recirculation piping and the environment at the CAV sample station; (2) Installation of ECP and crack growth sensors within the reactor; (3) Installation of a data acquisition and control unit to monitor the signals from the new ECP and crack growth sensors; and (4) Installation of a block shield wall in front of the CAV sample station in the reactor building. To facilitate these changes, modified Local Power Range Monitor (LPRM) assemblies were installed in core locations 40-25 and 24-09, a monitoring assembly was installed on the "B" recirculation loop suction decontamination flange, an instrumented autoclave was installed in parallel with the existing CAV system, the H_2/O_2 monitoring panel was relocated to make room for the shield wall, and a test connection to the CAV sample station for use with temporary chemistry monitoring equipment was added.

Summary of Safety Evaluation: The reactor coolant pressure boundary is maintained in the same manner as it was prior to the modification. The instrumented autoclave was installed in parallel with the existing CAVs sample station, and since each is a part of the primary coolant pressure boundary, through the "B" recirculation system sample lines, outside of the primary containment (in the reactor building), automatic isolation is provided on a Group 1 low-low-low reactor water level signal by closure of reactor water sample flow control valves. In addition, manual isolation valves are provided outside primary containment in the vicinity of the CAVs sample station. Primary containment isolation functions remain unchanged by this modification. The instrumented autoclave was manufactured to applicable codes and standards. The modified LPRM assemblies do not affect the reactor coolant pressure boundary. Although the internals have been modified, the seal ring and flange of each LPRM has not been changed from the standard LPRM design. The LPRMs will function as normal LPRMs with the 'D' detector inoperable. Technical Specification requirements for the minimum number of LPRM inputs to the affected Average Power Range Monitors is not violated as a result of this modification. Since electrical connections between components located inside and outside of primary containment were made in junction boxes on each side of the existing containment penetration, primary containment integrity was not affected in any way by this design change. Construction of the concrete shield wall around the CAVs system and instrumented autoclave is not required to be seismically designed since it is located so that it cannot fall on any safety-related equipment. This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1439 <u>Cable Upgrade for dc Motor-Operated Valves</u>

<u>Description and Basis for Change</u>: It had been determined that valve performance to motor-operated valves (MOVs) MO-2401, MO-2511 and MO-2512 may not have been acceptable under locked rotor conditions due to excessive voltage drop in the cables connecting the MOV with the dc motor control center (MCC). This modification replaces the power cables from the MCC to each affected MOV with cables of sufficient size to minimize total cable voltage drop to 6V dc, and thereby increasing motor torque by increasing terminal voltage at the MOV.

<u>Summary of Safety Evaluation</u>: The cables replaced by this DCP supply power to MOVs in the RCIC system. The function or method of operation are not affected by these modifications. Valve operation with respect to the initiating signal and valve opening/closing time are not adversely affected. The new cables will enhance valve response under degraded voltage conditions by increasing the available voltage at the motor terminals. The replacement of cables was performed using criteria that is the same or more stringent than the original installation criteria and considers seismic impact, environmental conditions for operating equipment in the reactor building and in the HPCI/RCIC building, impact on fire protection and the effect of cable additions on existing cable trays. The cables added by this DCP are safety-related (class 1E) and have been qualified for use in their intended service environment. Except for the larger size, the replacement cables are functionally equivalent to the old cables.

This modification did not involve an unreviewed safety question or Technical Specification change.

DCP 1442 Safety Parameter Display System Signal Loops

Description and Basis for Change: Plant process computer points for Average Power Range Monitors (APRM) and recirculation system flow were connected in parallel to associated chart recorders which affected their input to the process computer. When the associated chart recorder was turned on or off, the computer point "saw" a change in input signal. To remove the effect of chart recorder operation on computer point signal voltage, the computer point was moved off of the same voltage divider network as the chart recorder to a parallel voltage divider network on the same output buffer amplifier. This arrangement allows the chart recorder and computer point to "see" the same signal voltage, but eliminates the effect of chart recorder operation on the computer point. In addition, the plant process computer point for RWCU inlet temperature had a switch in the signal loop which was removed.

Summary of Safety Evaluation: This design change changed the locations where plant signals are accessed. The methods of wiring the signals are the same as those previously used and analyzed for the plant computer and SPDS. APRM signals were wired into the same circuit that was used for the original SPDS. Signals for reactor recirculation flow and RWCU inlet temperature are accessed the same as previously used for the old plant process computer. For all Class 1E signals, isolation is provided by the divisional SPDS data acquisition cabinets per the original SPDS design. No new types of equipment were added by this modification. This modification did not adversely affect the function of any safety system. This modification did not involve an unreviewed safety question or Technical Specification change.

SECTION B - PROCEDURE CHANGES

During 1988, various procedures as described in the safety analysis report were revised and updated. All changes were reviewed against 10 CFR Part 50.59 by the DAEC Operations Committee. No changes in procedures were made that involved unreviewed safety questions or changes in Technical Specifications.

All Special Test Procedures (SpTPs) performed in 1988 were also reviewed by the DAEC Operations Committee. No unreviewed safety questions were found to exist. Summaries of these special tests and their safety evaluations are found below.

<u>TEST</u> <u>TITLE/DESCRIPTION</u>

SpTP No. 149 <u>Plant Process Computer Extended Parallel Run</u>

This test was performed to compare input signal readings on the new VAX 8600-based plant process computer with the old 4020-based plant process computer to ensure that the new system was correctly receiving and accurately converting incoming signals. Readings were compared at several different power levels. Performance of this test completed the Post Installation Modification testing for DCP No. 1339.

This test was performed during the period December 19, 1987 through January 11, 1988.

<u>Summary of Safety Evaluation</u>: This test was passive in that no changes, adjustments, or modifications were made to plant equipment or operation. The plant process computer is not important to safety and this test did not affect any plant safety systems. Performance of this test did not affect plant operation and did not affect control room computer readings. An accident or malfunction of safety significance could not have resulted due to performance of this test. Performance of this test did not constitute an unreviewed safety question or change to Technical Specifications.

SpTP No. 152 <u>RHR and Core Spray Minimum Flow Test Data</u>

The purpose of this test was to collect test data for minimum flow operation of the RHR and Core Spray pumps. This data was required to address NRC Bulletin 88-04, "Potential Safety-Related Pump Loss." The RHR and Core Spray pumps were run one pump at a time to collect flow data to construct actual pump curves and to determine minimum flow line flowrates. During portions of the test, automatic opening of the minimum flow valves was disabled by deenergization at the breaker, one at a time.

This test was performed on June 23, 1988.

<u>Summary of Safety Evaluation</u>: In large part this test consisted of running the RHR and Core Spray pumps on the test bypass lines to gather pump flowrate data. During periods of minimum flow

valve deenergization, a dedicated operator was stationed at the valve breaker. The procedure directed the operator to close the respective breaker in the event of automatic system initiation. Only one minimum flow valve was deenergized at a time. When the minimum flow valve is disabled, only one loop of RHR or Core Spray is affected, which had been previously analyzed. Performance of this test did not constitute an unreviewed safety question or change to Technical Specifications.

SpTP No. 153 <u>Reactor Water Cleanup System Area Differential Temperatures with P&ID M152 Airflow Paths</u>

The purpose of this test was to collect operating data on the differential temperatures between the air entering and exiting the reactor water cleanup area with a temporary device restricting exit airflow through the reactor water cleanup heat exchanger area. The data was used to ensure that the steam leak detection system logic setpoints for the reactor water cleanup area meet the requirements of Technical Specifications and are consistent with design documentation (P&ID M152). This test also aided in resolving NRC unresolved item 331/86002-02 identified in inspection report 86-02 relating to restricting air flow to the reactor water cleanup heat exchanger area.

This test was performed during the period July 22, 1988 through July 24, 1988.

<u>Summary of Safety Evaluation</u>:

This test did not alter normal operation of the plant with the exception of bypassing two differential temperature switches that provide outboard isolation signals to the reactor water cleanup system. Even though these switches were bypassed, Technical Specifications were still met since redundant differential temperature switches in both the inboard and outboard reactor water cleanup isolation logic remained operable. During the test, the steam leak detection systems associated with both the "A" and "B" reactor water cleanup systems were taken out of service at separate times to allow placement of jumpers without causing system isolation. At no time during this test were both steam leak detection systems simultaneously out of service. Performance of this test did not involve an unreviewed safety question or Technical Specification change.

SpTP No. 154 <u>HPCI System Motor Operated Valves MO-2312 and MO-2311 Opening Testing at Abnormal Differential Pressure</u>

The purpose of this test was to demonstrate the ability of valves MO-2312 and MO-2311 to open at an abnormal operating differential pressure of 1339 psid. Performance of this test on each valve required that the valve be shut, the piping on the opposite side of the valve be vented to atmosphere, and the piping between the valves be pressurized to 1339 psig. Following pressurization, motor-operated valve (MOV) diagnostic signature traces were taken on each valve as they were opened against the differential pressure. Differential pressure testing was required by NRC IE Bulletin 85-03 Supplement 1.

This test was performed on December 10, 1988.

<u>Summary of Safety Evaluation</u>: This test was performed during a refueling outage with the reactor plant in cold shutdown. The reactor vessel, HPCI pump and condensate storage tanks were isolated from the test pressure throughout the test. The test was performed under plant conditions that did not require HPCI to be operable. The test demonstrated the ability of these MOVs to operate on demand against differential pressure conditions that may be encountered during or after a LOCA. Overpressurization of piping was not a concern since the test pressure of 1339 psig was below the system maximum service pressure of 1590 psig, the test rig had a relief valve set between 1369 and 1409 psig and an individual was continuously monitoring the test rig with access to a manual drain valve and test pressure gage. This test did not constitute an unreviewed safety question or change to Technical Specifications.

SpTP No. 155 <u>Motor Operated Valve MO-2516 Opening Operability Testing at Abnormal Differential Pressure</u>

The purpose of this test in the RCIC system was to demonstrate operability of valve MO-2516 at an abnormal operating differential pressure of 122 psid. Performance of this test required that MO-2516 be shut, piping on the upstream side of the valve be vented to the torus, and piping on the downstream side of the valve be pressurized to 122 psig. When test pressure was reached, a motor-operated valve diagnostic signature trace was taken on the valve as it was opened against the differential pressure. Differential pressure testing was required by NRC IE Bulletin 85-03 Supplement 1.

This test was performed during the period December 17, 1988 through December 19, 1988.

<u>Summary of Safety Evaluation</u>: This test was performed during a refueling outage with the reactor in cold shutdown. The test pressure was isolated from the reactor throughout the test. The test was performed while the RCIC system was shutdown for maintenance and with normal backup systems available. This test verified the ability of RCIC valve MO-2516 to operate against differential pressures that may be encountered following a LOCA. Overpressurization of piping during this test was not a problem because the test pressure of 122 psig is below the initial system hydrostatic test pressure of 188 psig, the test rig had a relief valve set to relieve between 130 and 138 psig, and the test rig was manned throughout the test with access to a manual drain

valve and test pressure gage. This test did not involve an unreviewed safety question or change to Technical Specifications.

SECTION C - EXPERIMENTS

This section has been prepared in accordance with the requirements of 10 CFR Part 50.59(b). No experiments were conducted during calendar year 1988.

SECTION D - SAFETY AND RELIEF VALVE FAILURES AND CHALLENGES

This section contains information concerning relief valve and safety valve failures and challenges for calendar year 1988 in accordance with the requirements of Technical Specification 6.11.1.e. Note that any instance in which a main steam relief or safety valve was manually cycled open, for surveillance testing or other reasons, is included for your information. There were no safety valve failures or challenges during 1988. There were no relief valve failures or challenges during 1988.

Date	Event Description
December 25, 1988	Relief valves PSV-4400, -4401, -4402, -4405, -4406 and -4407 were opened and closed during the satisfactory completion of a normal surveillance test.

Iowa Electric Light and Power Company

February 28, 1989

NG-89-0506

Dr. Thomas E. Murley, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: Duane Arnold Energy Center
Docket No: 50-331
Op. License No: DPR-49
1988 Annual Report of Facility Changes, Tests, Experiments, and Safety and Relief Valve Failures and Challenges

File: A-118e

Dear Dr. Murley:

In accordance with the requirements of Appendix A to Operating License DPR-49, 10 CFR Part 50.59 (b), and NUREG-0737 (Item II.K.3.3), please find enclosed the subject report covering the calendar year 1988.

Very truly yours,

Daniel L. Mineck
Manager, Nuclear Division

DLM/BHJ/pjv+

cc: B. Johnson
L. Liu
L. Root
R. McGaughy
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