10 CFR 50.59

IES UTILITIES INC.

February 28, 1994
NG-94-0677

Dr. Thomas E. Murley, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, DC 20555

Subject: Duane Arnold Energy Center
Docket No: 50-331
Op. License No: DPR-49
1993 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 Section 50.59(b), and NUREG-0737 (Item II.K.3.3), please find enclosed the subject report covering the calendar year 1993. In addition, a summary of changes to the DAEC Fire Plan implemented during 1993 is included in our report.

Please contact this office if you have any questions regarding this matter.

This letter contains no new commitments, nor does it modify any previous commitments.

Very truly yours,

John F. Franz

John F. Franz
Vice President, Nuclear

JFF/TWP/pjv

cc: T. Page
L. Liu
L. Root
R. Pulsifer (NRC-NRR)
J. Martin (Region III)
NRC Resident Office
Commitment Control No. 930079
DCRC

9403080155 931231
PDR ADOCK 05000331
R PDR

0S·100

IE47

Table of Contents

SECTION A - PLANT DESIGN CHANGES

This section contains brief descriptions of and reasons for plant design changes completed during the calendar year 1993 and summaries of the safety evaluations for those changes, pursuant to the requirements of 10 CFR Section 50.59(b). All changes were reviewed against 10 CFR 50.59 by the Duane Arnold Energy Center (DAEC) Operations Committee. None of the changes involved unreviewed safety questions.

The basis for inclusion of a modification in this report is operational release of the associated modification at the DAEC in the calendar year 1993. Portions of some of the Plant Modification Packages (PMP) and Design Change Packages (DCP) which are listed were partially closed or partially operational released in previous years.

PMP 0010 Pressure Control Valve Upgrade

Description and Basis for Change

Condensate Service Water is used to backflush the equipment radwaste filter. A pressure control valve was intended to control flow during backflushing; however, the valve did not properly regulate flow. To correct this situation, the pressure control valve was modified to provide flow control for the system rather than pressure control. This was accomplished by installing a flow controller, replacing the existing valve trim with a restricting cage and new plug to allow the valve to operate as a flow control valve, and transmitting the pneumatic flow signal to a new actuator on the valve. A gate valve was replaced to provide the required system isolation, and a globe valve was installed to provide assistance in optimizing the automatic flow controller; provide an alternate, manual method to control flow; and to provide isolation capability.

Summary of Safety Evaluation

The Condensate Service Water System is nonsafety-related. It has no effect on the accidents previously evaluated in the FSAR; it is not addressed by any of the Technical Specifications.

The modifications to this system did not increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR. The new flow controller and actuator installed on the valve increased the reliability and performance of the system. The intended operation of the system remained unchanged. The modification did not adversely affect the Radwaste System or the Condensate Service Water System.

PMP 0021 Torus/Drywell Temperature Elements

Description and Basis for Change

New higher accuracy temperature elements were installed to replace obsolete temperature elements that measure drywell and torus atmosphere. Three of the corresponding bridge completion cards were also replaced for compatibility.

The new temperature elements and bridge completion cards cover the possible temperature ranges in these areas and are an upgrade from the existing temperature elements.

Summary of Safety Evaluation

The consequences of an accident are not affected by the installations of the temperature elements and bridge completion cards. The readings of the temperature elements are used for indication only and a duplicate set exists for comparison. A failure in the temperature elements or cards would not affect any safety related equipment since the readings are used for indication only.

The possibility of the new temperature elements failing is no greater than the possibility of the old temperature elements failing. A failure in the temperature elements or cards would not affect any equipment important to safety.

PMP 0030 Circulating Water Pump Coupling Modification

Description and Basis for Change

The coupling between the 'B' Circulating Water pump and the motor was modified to compensate for the damaged threads on the pump shaft. The threads were damaged during an uncoupled run of the pump motor. The function of the threaded portion of the shaft was to support the weight of the pump shaft and to allow for vertical adjustment of the pump shaft.

The pump shaft was machined to completely remove the threads and to cut a circular keyway into the shaft. A new piece was manufactured that attaches to the shaft to support the pump's weight through a circular split ring key. The outside surface of this new piece was threaded to allow attachment to the coupling and to provide for vertical adjustment. This modification was recommended by Byron Jackson, the pump manufacturer.

Summary of Safety Evaluation

Modifications to the coupling between the 'B' Circulating Water pump and its motor were made to standards that are equivalent to the original design so the reliability was not adversely affected. For a steam line break inside of containment, having circulating water in service would provide a heat sink that might be used. However, the main condenser is not required to act as a heat sink in any of the accidents evaluated in the FSAR.

The Circulating Water System is designed to remove heat from the main condenser during normal operation. Failure of the Circulating Water System is evaluated in the turbine trip without bypass event. This modification did not adversely affect the Circulating Water pump. Since the total loss of circulating water is evaluated in the FSAR, the failure of the new coupling is bounded by the existing analysis.

PMP 0033 Hydrogen Water Chemistry (HWC) Interruption

Description and Basis for Change

GE, EPRI and Iowa Electric (IES Utilities Inc.) agreed to jointly study the effect of periodic interruption of hydrogen injection on Intergranular Stress Corrosion Cracking (IGSCC). The benefits of hydrogen protection may remain for some time after termination of hydrogen injection. The test varied the frequency and duration of hydrogen injection interruption, while observing stress corrosion cracking activity in material test specimens. The information gathered during testing provided the capability for specific materials assessment following unplanned HWC interruption. The study results may also relieve high radiation and exposure penalties from hydrogen injection, by allowing hydrogen injection reductions or interruptions during planned work in high radiation areas.

The scope of work included the replacement of the Electro-Chemical Potential (ECP) Vessel on Load Frame A and the Crack Growth Vessel on Load Frame B. A new ECP vessel was installed on Load Frame B. Crack Growth Vessel AE8944 was permanently removed from service. The tube routing was revised to achieve two equivalent Crack Arrest Verification (CAV) systems in parallel. The PMP temporarily installed two test skid assemblies. One skid injected oxygenated water to the B CAV system to simulate HWC interruption and the other skid sampled the discharge of the B CAV system to provide test data.

Summary of Safety Evaluation

The only malfunction of equipment installed by this PMP requiring consideration was the failure of test equipment resulting in a maximum oxygen injection rate. A maximum oxygen injection rate would result in an estimated increase in coolant oxygen level from 20.0 to 20.3 ppb, which would have an insignificant affect on reactor water chemistry. Temporary equipment was installed to 2 over 1 seismic criteria, in order to avoid any affect on equipment important to safety during a seismic event. The maximum oxygen injection rate of test equipment would have no effect on radiation levels.

The CAVs are a non-safety related system used to verify that hydrogen injection arrests IGSCC. They do not affect the operability of any safety related plant systems or equipment important to safety. There are no requirements for operation of the CAVs after an accident.

The equipment installed by this PMP performed a non-safety related sampling of reactor coolant. The test equipment injected oxygen into the sample. A malfunction of the oxygen injection system would result in an insignificant effect on the reactor coolant due to the small maximum oxygen injection rate, and the dilution of the sample return in the condenser. The slightly elevated oxygen content of the reactor coolant would be reduced by degassification in the condenser.

The Technical Specifications requires pH levels between 5.6 & 8.6 and conductivity levels below 1.0 micro-mho/cm. The conductivity and pH were unaffected by potential test equipment failure resulting in maximum oxygen injection.

PMP 0035 Expansion Loop

Description and Basis for Change

The high pressure turbine fourth stage extraction steam lines have a two-inch drain line which drains steam to the main condenser after a turbine trip. This drain line is a two-inch carbon steel pipe connected/welded to the twelve-inch carbon steel extraction steam line. In January 1991, a steam leak occurred at the connection/weld between the 12-inch and the 2-inch pipes. The steam leak was apparently caused by cyclic fatigue of the pipe weld as a result of thermal stress.

This plant modification installed a thermal expansion loop for the 2" pipe.

Summary of Safety Evaluation

The installation of the expansion loop increased the number of welded connections in the extraction steam line drains. This might incrementally increase the probability of a rupture, but the addition of the expansion loop decreased the stress induced by the thermal expansion of the extraction steam line. The reduction in applied stresses, coupled with the use of the same piping materials and welding specifications as the original piping, was judged to result in a net increase in reliability of this piping.

As evaluated in Section 15.6.5 of the UFSAR, a main steam line break outside of secondary containment has been previously evaluated and is considered to bound the consequences of the break in this drain line. This modification only rerouted the drain line to reduce expansion stresses and did not increase the consequences of an accident previously evaluated in the UFSAR. The modified extraction steam line drain is the same size as the previous design and is located in the same general area of the Turbine Building. Therefore, if the modified line should fail, the consequences of the resulting accident would be no different than what previously existed. The functional operation of the extraction steam line drain was not altered and the size, supports and general routing of the new piping were not changed such that new pipe whip or jet impingement targets were created.

PMP 0036 Pumphouse Chemical Tank Replacement

Description and Basis for Change

The activity replaced three carbon steel circulating water chemical addition storage tanks with four polyolefin tanks. The previous tanks were approximately 8 years old and showed signs of significant exterior corrosion.

The old tanks were removed and the new tanks installed within the existing retaining walls. The tank location is outside on the northwest side of the pumphouse. Tank fill and supply piping was replaced, as needed, to accommodate the new tank configuration. Both the tanks and exterior piping were insulated and heat traced for freeze protection. Level indicators for each tank were installed in the pumphouse near the circulating water chemical pumps. These indicators supplemented the local sight glasses mounted on each tank and required an air supply from the Instrument Air System. Concurrent with the tank replacement was a change in two of the chemicals used.

Summary of Safety Evaluation

The replacement components are located in the same area and perform the same functions as the components that were replaced. This chemical addition system does not perform any safety functions. The physical location precludes interaction with systems that are susceptible to accidents evaluated in the FSAR. No accidents that rely on the use of the circulating water system or the circulating water chemical addition system were analyzed in the Nuclear Safety Operational Analysis (NSOA) or FSAR. The volume of chemicals that the new tanks hold is less than the old tanks held and any accident involving leakage from the tanks would be less severe after installation of the new tanks. The affected systems have no seismic, separation, or environmental design requirements per the FSAR. The new components meet or exceed the design parameters of the original components. Evaluation indicates that the new tank installation will improve pump NPSH. Calculations confirm that the anchors for the new tank stands will withstand wind loadings as required by the Uniform Building Code (original construction code).

The new level indicators were installed in the portion of the pumphouse which does not contain safety-related equipment. The indicators are similar to existing units currently installed in other systems. Failure of the indicators will not affect any other plant equipment or systems. Two of the chemicals have slightly different formulations. All of the chemicals are nonflammable and nonvolatile. The DAEC Chemistry Department in conjunction with Betz concluded that none of the subject chemicals posed a threat to Control Room habitability. Additionally, inadvertent mixing of these chemicals also posed no threat to Control Room habitability.

PMP 0046 Decant Auto Vent Valve Relocation

Description and Basis for Change

This modification relocated decant auto vent solenoid valves from outside to inside the blower room of the sewage treatment plant. The sewage treatment plant is located outside the protected area, north of the plant. Its operation has no effect on the operation of any safety system in the plant. The relocation of these valves had no impact on the operation of the system. The only effect was to make the valves more freeze resistant.

Summary of Safety Evaluation

No accidents evaluated in the SAR involve the sewage treatment plant. No important-to-safety equipment is contained in the sewage treatment plant. The sewage treatment plant has no effect on equipment or systems evaluated in the SAR which could cause an accident.

PMP 0051 Lightning Protection for Well Water System

Description and Basis for Change

Flow transmitters from the well houses A through D respectively provide a measure of the well water flow to the control room. During thunderstorms, the system has frequently been damaged due to earby lightning and other induced electrical transients. Previously, modifications provided the installation of single stage Metal Oxide Varistors (MOVs) between the signal terminal of the transmitters at the well house and the manual control stations in the control room. This action reduced some of the transient effects, but was not able to provide adequate protection to the system. The purpose of this Plant Modification was to provide a better scheme of protection to the flow transmitters and the manual controllers.

This modification removed existing single stage MOVs from all of the signal terminals. A three stage solid state lightning protector was installed at each well house to protect each transmitter loop and the remote setpoint control loop at the well house. Also, a similar device was installed at the control room in panel 1C-23 near the ground bus. This device will protect the manual control stations and the associated recorders. In addition, good shield grounding is essential to achieve better protection. Therefore, all the discontinued shieldings for each loop were connected together and grounded only at one end at each well house.

Summary of Safety Evaluation

This modification only added electrical protection to the flow transmitter and control circuits for the well water system. The actual control and transmitter functions were not affected. No new failure modes were introduced. The well water system does not contribute to operability of any equipment important to safety. A failure of the well water system or a single well does not induce failure of any other equipment. Well water is not required to mitigate any accident.

DCP 1279 Warehouse Sprinkler and Fire Line Modification

Description and Basis for Change

Extension of Warehouse Sprinkler System

The old warehouse automatic sprinkler system did not cover the Warehouse Health Physics Training Room, the Q.C. Inspection Area, the Warehouse Receiving Area, a portion of the office spaces and a section of crib counter area. American Nuclear Insurers (ANI) had recommended extending the existing warehouse sprinkler system to provide coverage of those unprotected areas. Both the new and old warehouses supply full sprinkler coverage to the cross passageway area.

Installation of Underground Connection from Fire Main and Installation of Fire Hydrant

A new warehouse was installed adjacent to the existing plant warehouse. A sprinkler system was installed as a part of the warehouse construction contract. The warehouse sprinkler system was installed to a fixed underground inlet point, therefore, an underground supply line was required to be installed between the new warehouse sprinkler inlet and the 12" yard fire main. In addition, the underground supply line was extended and a fire hydrant provided at the northeast corner of the new warehouse.

Summary of Safety Evaluation

The design change was confined to the warehouse. Therefore the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report was not increased. The installation of an additional fire main isolation valve decreased the likelihood of the loss of fire water availability to either of the plant warehouses and to two fire hydrants, in the event of an impairment to the fire main.

The possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report was not created. This design change involved no unreviewed safety questions and did not reduce any margins of safety as defined in the technical specifications.

DCP 1285 Diesel Generator Monorail Hoists

Description and Basis for Change

Whenever maintenance work was required on the diesel generators, temporary rigging had to be installed to disassemble the engine. The installation of a permanent hoisting system in each diesel generator room deleted manhours involved in temporary hoisting setup and reduced time involved in disassembly and reassembly of the diesel generators.

The scope of work involved installation of a two (2) ton monorail running along the centerline of each diesel generator. In order to install these monorails, it was necessary to relocate an 8" exhaust duct and raise some of the lights in the diesel generator rooms. A monorail running in the east-west direction was also installed in each diesel generator room to aid in removing the diesel generator engine cover.

Summary of Safety Evaluation

The installation of the monorail hoisting systems in the diesel generator rooms was not a safety-related modification. Installation of the monorail cannot initiate any previously evaluated accident. The monorail framing steel was designed to withstand seismic (DBE) loading without exceeding design stresses or interacting with adjacent structures. It is not necessary that the hoist system be functional during the earthquake, but it must maintain structural integrity. Any item that was relocated was also supported in a manner that maintains the required structural integrity.

Whenever the hoisting system is used, the diesel generator associated with that hoisting system will be out of service. Whenever the diesel generator is in service, the monorail framing structure will not interact with any equipment or piping in the area due to seismic loading.

The diesel generators are redundant systems, are located in separate rooms, and are separated by a firewall. Should a load drop occur on the diesel generator while it is out of service and being repaired, the redundant diesel generator will not be affected. Since the monorail framing structure is qualified to resist seismic loading due to the self weight of the framing structure and hoists, the monorail system (unloaded) will not fall on any equipment.

DCP 1327 Install Backwashable Radwaste Filter

Description and Basis for Change

DCP 1327 added a backwashable, metal element filter to the liquid radwaste processing system upstream of the existing precoat filters. The new filter functioned as a "roughing" filter to remove enough of the particulates to prevent reaching differential pressures across the precoat filter that require disposal of the precoat resin before its ion exchange capacity can be fully utilized. The new filter could be used with either of two independent liquid radwaste processing systems or to process the contents of the Radwaste System Surge Tank. It tied into existing piping systems and utilized existing pumps. After the backwashable filter was installed, a decision was made to abandon it in place.

Summary of Safety Evaluation

This design change added another filter to the radwaste processing system in the Radwaste Building which did not contain nor interface with any equipment important to safety. The installation was intended to reduce the amount of radiation exposure and to enhance the ALARA system for radiation protection.

The design, fabrication, and materials requirements for the backwashable radwaste filter were in accordance with the codes and standards specified in the U.S. NRC Regulatory Guide 1.143 for radwaste systems. The installation of the backwashable filter was an addition to the radwaste system. The backwashable filter was an additional filter and in no way degraded the water quality in the radwaste system.

Based upon a review by IELP and ABB Impell personnel, it was decided not to invest any further resources into the backwashable filter system. Therefore, the backwashable filter system installed via this DCP was "abandoned in place." The controls and piping were left in place. The system was declared operational within the radwaste system. However, the backwashable filter system was not made functional for filtering.

DCP 1369 Chlorination Modifications and 1C103 Panel Removal

Description and Basis for Change

This Design Change Package consisted of two parts; removal of the abandoned 1C103 control panel, and control enhancement of the new chlorination control system. The work on the abandoned 1C103, Water Chemistry Control panel for the Circulating Water and General Service Water systems, consisted of removing the existing cabinet and abandoned control switches and indicators therein, and installing a Unistrut rack to support the electrical power distribution components contained inside the 1C103 cabinet that are still in use. The control enhancement work on the new water chemistry control system for Circulating Water and General Service Water consisted of adding a system mimic to the control panel, 1C417, and modifying the automatic control logic to increase system reliability.

The Chlorination system is a non-safety related system that affects the Circulating Water and General Service Water systems, both of which are non-safety related systems.

Summary of Safety Evaluation

Those portions of the systems that are concerned with seismic impact, mechanical failures causing water leaks, and sudden loss of condenser vacuum were not affected by this modification. The failure modes of the enhanced control logic are the same as for the old logic. The chlorination system will either not chlorinate at all, or will continuously chlorinate these water systems.

Not chlorinating will result in the slow build up of marine biological life in these water systems. Over several days time, this growth will form scale on the heat transfer surfaces of the condensers, reducing their heat transfer efficiency. To prevent this scale build up, sulfuric acid is continuously added by the acid feed system. Therefore, not chlorinating is not a safety concern.

On the other hand, continuous chlorination of these water systems only results in the waste of water treatment chemicals. The sodium hypochlorite solution added by this system was purchased with a pH of 10. The storage tank has a capacity of only 5000 gallons. If this volume of sodium hypochlorite is added to the 2.5 million gallons of water in the Circulating Water and General Service Water systems, it would tend to move system pH slightly up scale. While the chlorination of the circulating water affects pH, the acid feed system controls circulating water pH, maintaining system pH between 7.4 and 8.0. Piping/component corrosion becomes a concern when pH goes lower than 6.0. Therefore, over chlorinating is not a safety concern. Neither of these failure conditions introduced a new failure mode into any plant safety system.

DCP 1372 <u>Low Level Radwaste Processing and Storage Facility (LLRPSF) Modifications</u>

<u>Description and Basis for Change</u>

The scope of DCP 1372 was to provide and install additional equipment, relocate existing equipment, revise existing sump controls, and revise the LLRPSF electrical system design to facilitate the processing of radwaste in the LLRPSF.

<u>Summary of Safety Evaluation</u>

The LLRPSF is not a safety related facility. The equipment and systems installed in the facility relate to the cleaning of anti-contamination clothing and respirators, compaction of low level Dry Active Waste (DAW) into storage boxes and drums, and the remote operation and readout of the LLRPSF sumps in the radwaste ntrol room and are therefore not safety related. In addition, radwaste systems from the LLRPSF interface with corresponding ems in the radwaste building, and these systems are not uired for safe shutdown of the plant. The addition of the new radwaste equipment, modifications to the sump system, and relocation of existing equipment into the LLRPSF was performed in accordance with the same criteria used in the existing radwaste building.

The old la -ing and low level waste processing equipment was designed t ess similar kinds of materials as is handled by the new ar ocated equipment in the LLRPSF. The modifications to the radwaste sump controls provided controls identical to the existing radwaste building sump controls. New power cables were routed in new conduit, and new control cables were routed in new conduit and existing cable trays. The method of routing cables and the resulting conduit and tray fills was similar to those in existing buildings. The sumps handle similar types of radioactive waste as is handled by the existing sumps.

The Techn al Specifications were revised to incorporate the LLRPSF e t stack radiation monitor, which is interconnected to the exist effluent monitoring system. Exhausting of new equipment is through the LLRPSF exhaust stack. Relocation of the LLRPSF sump controls and instrumentation into the radwaste control room helps ensure overall radiological and personnel safety. In addition, the equipment added to and relocated into the LLRPSF is not safety related and does not interface with, and therefore will not adversely affect the function, operation, or operability of any safety related systems. Therefore the margin of safety as defined in the basis of the Technical Specifications was not reduced.

DCP 1411 <u>Uninterruptible Instrument AC Power</u>

<u>Description and Basis for Change</u>

The change affected the power sources for three plant AC electrical systems: The Uninterruptible AC System, the Division I Instrument AC System, and the Division II Instrument AC System. Existing power sources supplying these three systems were replaced with three independent solid state inverter power systems. The previous power sources for these systems included an Uninterruptible AC Motor Generator (MG) set and two Instrument AC transformers. Independent inverter systems replacing these power sources each consisted of a battery charger, an inverter, an AC transformer (voltage regulator), a static transfer switch, and a manual bypass switch.

The inverters are energized from the respective battery chargers and supply regulated AC power to the respective buses. If the battery charger fails or if a loss of essential bus 480 VAC supply to the charger occurs, the 125 VDC station battery will automatically provide power to the inverter. When power returns, the battery charger will resume supplying the inverter and recharge the battery. The buses receive another source of 120 VAC power directly from regulating transformers that are connected to their respective 480 VAC buses. The regulating transformers are connected to their buses by automatic solid-state static transfer switches which perform automatic transfer operations when required. Manual operation of the static switch and a separate manual transfer switch are also provided for each system.

The new inverter power systems can each be considered "uninterruptible" because they are each backed up by a station battery. Therefore, if an AC power loss event occurs, the station batteries will continue to supply DC power to the inverters and all connected branch circuit loads will remain energized for a minimum of four hours.

The installation of the inverter systems raised the ambient room temperature because of the added heat load produced by the inverters. Modifications required to keep the room temperature at normal levels were formulated under a separate modification package.

As a result of the additional load to the DC systems, the battery chargers were replaced with chargers of increased capacity which provide the required battery recharging capability. Reserve capacity exists on the essential bus sources to allow for the increase in load.

Additionally, accident monitoring instruments presently fed from the RPS power buses were transferred to the Instrument AC buses. This placed all Accident Monitoring instruments on uninterruptible power, meeting the NRC Reg. Guide 1.97 guidelines.

Summary of Safety Evaluation

The proposed modification did not alter any safety function or any essential safety equipment. Only the method of supplying power to the divisional Instrument AC buses and the Uninterruptible AC bus was changed. Failure of these power sources is not an event which will effect any previously evaluated accident described in the FSAR. A postulated simultaneous failure of both Instrument AC inverter buses would be equivalent to a loss of offsite auxiliary power (LOOP) which has been analyzed for (UFSAR 15.6.4).

The two Instrument AC systems have additional backup capability from the battery source and the alternate regulating transformer source so that reliability greater than the existing system is expected. The Uninterruptible AC system has the same number of backup sources, however, the improved solid-state technology provided by the static inverter system is expected to be more reliable than the existing commercial grade MG set.

The seismic loading created by the installation of equipment in the essential switchgear rooms was evaluated. The design process included a load study on the existing station batteries to determine each station battery load profile. The present battery capacity is adequate to support the inverter systems.

The voltage levels entering and leaving the power source equipment will remain the same. Therefore, the modification did not introduce any new voltage level parameters which had not already been analyzed.

The difference between the previous plant operation and plant operation after implementation of this modification is that the Instrument AC buses remain energized during a loss of power event. Loads controlled by these panels include indication circuits and recording devices for a number of plant systems. No malfunction of equipment or system operation will result if these systems remain energized. The modification enhanced the instrumentation capabilities by providing uninterruptible power which makes the instrumentation available through loss of plant power events.

DCP 1414 Backup Security System

Description and Basis for Change

This change installed a backup uninterruptible power supply.

Summary of Safety Evaluation

The security modification was made in accordance with the guidelines of applicable sections of 10 CFR 73, "Physical Protection of Plants and Materials," Regulatory Guide 1.17, "Protection of Nuclear Power Plants Against Industrial Sabotage," ANSI N18.17, "Industrial Security for Nuclear Power Plants" and the DAEC Security Plan.

None of the equipment involved had any seismic or environmental qualification requirements. There was no change to any DAEC Licensing Analysis or NRC compliance program as a result of this modification.

The Security System interfaces with other plant systems are through approved isolation devices which are coordinated to prevent the propagation of malfunction. There is no direct interface with any reactor control system, engineered safety system, or safety supporting system.

DCP 1415 Containment Isolation Monitoring System

Description and Basis for Change

A Containment Isolation Monitoring System (CIMS) was installed to continuously monitor the status of all Primary Containment Isolation System (PCIS) isolation components including valves, dampers and fans.

There are two CIMS Processing Units. Each is "dedicated" to monitoring one electrical logic division of the isolation valves, dampers, and fans for either the "inboard" or "outboard" devices. These processors are powered from instrument AC uninterruptible power. The power system is designed such that on loss of one instrument bus, the remaining bus is automatically switched to power both processors. To provide a "bumpless" transfer between these unsynchronized busses, each processor is equipped with a dedicated uninterruptible power supply (UPS) capable of powering the processor for several minutes. Each processor contains its own mass storage device (40 Megabyte fixed disk), data input device (floppy disk), and connections for both a monitor and keyboard.

There are four Data Acquisition Systems (DAS). Two are dedicated to each division of the isolation valves, dampers, and fans.

Various inputs are sensed by the DAS components including indicating light voltage measurements.

The PCIS mimic on panel 1C-03 was replaced to have the valve indications on the mimic in the same general "left-to-right alignment" as the layout of the associated controls on the panel benchboard.

Summary of Safety Evaluation

Following any isolation signal, an operator must verify the status of all valves, dampers, and fans which have an isolation function. Previously, this verification was performed by determining the position of valves and dampers and the status of fans via the control room status lights. Such verification was a time consuming process requiring the complete attention of at least one control room operator. The CIMS modification automated this verification and provided the operator with immediate isolation group status as well as status of any equipment whose isolation function had not been completed. The ability of the operator to determine the success or failure of independent isolation groups in a timely manner allows him to focus his attention on other pressing matters during the response to an unusual event.

Although an electrical short on the indication circuitry can lead to loss of control power for that individual control circuit via a blown fuse, this failure is no more likely for the new wiring than for the old cables. The additional cabling added to the indication circuits did not increase the likelihood of an indication short circuit. In addition, safety system design ensures that a single failure will not preclude the completion of the system's safety function.

Installation of this passive system and the relocation of PCIS mimic lights did not affect the systems monitored. Passive monitoring of the containment isolation equipment status did not affect the ability of the equipment to perform its safety function; no new failure mode was created.

The relocation of PCIS mimic valve indicating lights and the installation of this passive monitoring system did not change, degrade, or prevent any described or assumed actions in any accident discussed in the UFSAR, nor did this modification alter any assumption made in evaluating any accident in the UFSAR. Divisional signal separation was maintained up to the isolation device to assure that a failure in any input signal would not propagate into redundant circuits.

DCP 1437 River Water Supply Pump Replacement

Description and Basis for Change

This modification involved the replacement of the River Water Supply Pump Assemblies with those of another vendor. The bowl assemblies on the new pumps are stainless steel rather than bronze. The new material enhances wear resistance and helps maintain pump performance characteristics. Additionally, a vibration monitor was added to each pump at the bowl assembly.

Summary of Safety Evaluation

The new pumps are functionally equivalent to the old pumps and meet or exceed all the requirements of the original pumps as outlined in the design specification. All performance criteria exceed design specifications. The stainless steel bowl assemblies are being used for superior strength and for corrosion and erosion resistance.

This modification also added velocity monitors for vibration detection for the pump. The monitors added approximately 12 pounds to the weight of each pump assembly. This additional weight had a negligible affect on the seismic evaluation of the pumps.

The replacement of the pumps and addition of the vibration monitor introduced no new common or single mode failures. These pumps do not initiate any accident not previously analyzed and no new accident scenarios were created.

DCP 1440 Control Building HVAC System Positive Pressure Modifications

Description and Basis for Change

The purpose of this DCP was to provide positive pressure to those areas of the Control Building required to be pressurized when the Control Building HVAC System is operating in the isolation mode. The areas of the Control Building required to be pressurized with respect to the surrounding areas in the isolation mode are:

- Control Room Complex including the Computer and SAS Rooms,
- East and West Essential Switchgear Rooms,
- Mechanical HVAC Equipment Room

The Control Room Complex must remain habitable during all plant operational modes. The Essential Switchgear Rooms and the Mechanical HVAC Equipment Room must also remain pressurized as they provide return air paths to the Control Building HVAC System while in the isolation mode.

The design changes entailed rebalancing the Control Building HVAC System to redistribute the supply and return air flows from certain areas of the building to provide additional supply air flow for pressurization of other areas of the building. This design change also provided for equipment changes to reduce unnecessary exhaust and losses from the Control Building.

Some of these equipment changes included the installation of orifice plates, new flow switches capable of sensing the reduced flow in the ductwork, installing a backdraft damper which was part of the original design but was not physically installed, and the installation of new door sills.

Summary of Safety Evaluation

The effect of this design change was to reduce air flows to certain areas of the Control Building in order to supply additional air flow to other areas to establish positive pressure requirements. Evaluations were performed to determine the effects the reduced air flows would have on room temperatures.

The calculated increased temperatures for the Essential Switchgear and Battery Rooms were compared to the design temperatures for these rooms as shown in DAEC UFSAR Table 9.4-1. The temperature evaluations for these rooms showed that the maximum temperature would not be exceeded for any of the rooms as a result of this design change.

The Battery Room exhaust reduction was used to reduce the overall exhaust rates from the Control Building. The required exhaust rates for the Battery Rooms were reduced based on the battery manufacturer's information on hydrogen generated during charge and discharge of the batteries. The new reduced exhaust rates were still a safety factor of 10 over the minimum required exhaust rates for hydrogen removal from the Battery Rooms. New flow switches capable of measuring the new flow rates were installed in the Battery Room's exhaust ductwork.

The backdraft damper installed in the ductwork connecting the Cable Spreading Room HVAC unit and the Control Building Return Fan plenum was designed and installed to applicable DAEC Seismic Category I criteria and in accordance with DAEC Specification BECH-MRS-M68, Revision 3. The damper support and installation design was performed to minimize any additional loads to the existing ductwork.

Since the presence of this backdraft damper was part of the original Control Building HVAC System design, the systems operation was unchanged from the original design intent. A portion of the fire suppression system was rerouted to facilitate the damper's installation and did not affect the fire suppression system's operability.

The Control Building's HVAC System is not the direct event initiator of any of the previously evaluated accidents in Chapter 15 of the UFSAR. The system is required to maintain Control Room habitability during the isolation mode. The changes ensure that this habitability is maintained by ensuring that the required positive pressure is achievable to eliminate the infiltration of radioactive contamination from other areas. In addition to pressurizing the Control Room Complex, this change extended the pressurization boundary to include the Essential Switchgear Rooms and the Mechanical HVAC Equipment Room since they are a supply path to the Control Room Complex.

The Standby Filter Units limit the makeup air entering the Control Building HVAC System during the isolation mode. This design change package used this limited makeup to its fullest potential to maintain positive pressure in the Control Building Complex, the Essential Switchgear Rooms and Mechanical HVAC Equipment Room. The reduction of Battery Room exhaust and redistribution of air flows increased the margin of safety in maintaining this positive pressure for Control Room habitability reasons.

DCP 1446 Torus Room Lighting Enhancement

Description and Basis for Change

An Outage Motor Control Center (MCC) was provided to supply power for new torus panel boards, existing disconnect switches, and future loads. In addition, one disconnect switch was relocated to eliminate the routing of temporary power cable through a doorway.

The new Turbine Room Outage MCC is fed from the air compressor building load center. This load center is fed from an off-site power source (the switchyard).

Summary of Safety Evaluation

The Outage MCC has no safety function.

Power supplied to and branch circuits from the Outage MCC are from a non-essential bus which is independent of the essential buses.

Loss of non-essential buses is an evaluated occurrence. Therefore any electrical fault conditions associated with these circuits will not impact the essential power buses. The associated breakers were selectively coordinated such that any fault on the MCC or its associated equipment would be interrupted without affecting any existing equipment.

Permanently installed cable associated with the Outage MCC was routed in accordance with existing separation and routing criteria.

DCP 1457 Reactor Recirculation Pump Component Upgrade

Description and Basis for Change

This modification made changes to the Recirculation Pumps' components and systems to improve plant operation, performance and enhance maintenance activities.

The rotating pump element (pump shaft and impeller) was replaced in "kind" with a new improved design. The pump cover was replaced with a design that better controls the mixing of cooling water from the CRD pumps and the primary coolant in the area between the impeller and the pump hydrostatic bearing. The new cover also utilized an inner and outer gasket to aid in the prevention of pump leakage.

An inter-gasket leakage line was added to provide a positive means of determining inner gasket failure. Failure of the inner gasket would result in the leakage of primary coolant to the area between the inner and outer gaskets. The subject line would route the primary coolant leakage to the adjacent drain system, where a flow device would provide monitoring and indication to the operators in the Control Room.

Summary of Safety Evaluation

The design changes are adequately addressed and within the scope of Chapter 15 "Accident Analysis" of the UFSAR. The specific modifications enhanced the ability to operate the subject pumps in a safe manner.

The original design of the inter-gasket leakage lines took into account the possibility of a LOCA, and as such, the ability to isolate them. The design change did nothing to change or modify the original design concepts, and thus the ability to maintain system integrity in the event of a LOCA was maintained. In addition, the inter-gasket leakage line improved the ability to monitor leakage and decreased the possibility of uncontrolled leakage from the pump.

The design basis for the pump component upgrade is contained in "DAEC Recirculation Pump Modifications, Safety Evaluation Report, GE Nuclear Energy, San Jose, California, December, 1989." This GE initiated Safety Evaluation addressed the actual pump component upgrade and provided the background as well as the responses to the 10 CFR 50.59 Safety Evaluation questions. The following information was contained in this GE Safety Evaluation.

The replacement rotating elements, covers and hydrostatic bearings which were installed in the recirculation pumps incorporated design improvements relative to the original components. The changes should lengthen the lifetime of the pump and improve the maintainability and inspectability of the pump.

The UFSAR considers instantaneous stoppage of the pump shaft. This is the bounding case for the safety consequences of severe shaft distortion or complete shaft severing. Use of a welded impeller and proper positioning of the balance hole in the impeller also minimized the chance of distortion of the rotating element in service. Addition of a shaft inspection hole provided the capability to perform ultrasonic examinations of the shaft to detect shaft cracking and thereby decreased the probability that the shaft would be operated with severe cracking which could result in an accident or malfunction involving severe shaft distortion or complete shaft severing.

The consequences of complete shaft severing were not made more severe by the design changes. Complete shaft severing would admit reactor coolant to the inspection hole, however the plug would withstand reactor pressure because it is designed using the code rules as a guide. If the shaft severed completely allowing reactor coolant to enter the shaft inspection hole and (as an additional failure) the plug was missing or was incapable of withstanding reactor pressure, primary reactor coolant would escape through the one inch drilled inspection hole. The type of accident allowing flow through the shaft inspection hole (small break LOCA) has been evaluated in the safety analysis report over a range of break sizes which bounds the one inch hole.

The design changes to the pump cover were made in accordance with the same ASME code provisions as the original pump cover. The added piping was designed and manufactured in accordance with ASME rules because they are part of the pressure boundary. The consequences of completely severing a one inch or 3/4 inch line had already been evaluated in the FSAR LOCA analyses.

The main improvement to the hydrostatic bearing was to change the attachment of the baffle plate to the bearing by using a one piece casting rather than by fillet welding. This improvement eliminated the potential for failure caused by cracking of the fillet welds. The inspection ports allow inspection of some pump internal parts to improve confidence that no damage or malfunction has occurred in service to the hydrostatic bearing fasteners. The design improvement improved the plant's operational availability.

In addition, the double gasket reduced the probability of gasket leaks. The drain hole elimination removed one mechanism which could contribute to cracking of the shaft and cover. The optimized drilled holes resulted in larger ligament thickness and reduced the probability of through wall cracking which would allow leakage of reactor coolant to the closed cooling water system.

The pump component upgrade was evaluated with respect to seismic concerns, missile hazards and various recirculation pump events. The DAEC recirculation pumps were originally seismically qualified by analysis. The seismic loads which form a part of the original pump specification were the same for the replacement parts. The changes to replacement hardware did not affect missile hazards, since no design features were introduced which increased the potential for forming missiles.

The modification did not affect the FSAR analyses for startup of an idle recirculation pump, recirculation pump overspeed or recirculation pump trip. The performance characteristics of the replacement components are unchanged from the original components and the changes to the rotating element did not have any significant or detectable effect on pump inertia or coast-down characteristics.

DCP 1465 Makeup Demineralizer System

Description and Basis for Change

This DCP made several changes to the Make-up Demineralizer system. These changes were:

Conductivity recorders and elements were removed and replaced. The new conductivity measuring system consists of new elements for ultra-pure water, conductivity analyzers to display the measured conductivity value, alarms, and outputs to chart recorders for permanent records.

The existing silica analyzers were replaced and new taps were added to provide additional sample points. This modification installed a temperature element to measure the temperature of the caustic solution injected into the system and to position a mixing valve to achieve the desired solution temperature.

The previous Make-up Demineralizer regeneration system did not possess indication of the acid and caustic concentrations used for regeneration. This modification installed elements and analyzers to measure and display the concentration of the caustic solution. A sample sink was installed to allow sampling from various points in the Make-up Demineralizer system and other plant systems. Various indicators, switches and recorders which did not operate properly or were obsolete were replaced.

Summary of Safety Evaluation

Per FSAR 9.2.1.2.3 'Make-up Water Treatment System', the function of the Make-up Demineralizer System is to take well water and provide a supply of treated demineralized water suitable for make-up to the plant and reactor coolant cycles and other demineralized water requirements. The make-up water treatment system is designed to:

1. Process well water by means of two parallel trains of demineralizers.

2. Maintain water purity by the correct choice of storage and piping material.

3. Provide make-up water of reactor coolant quality.

4. Provide an adequate supply of treated water for all plant operating requirements.

5. Provide an adequate supply of treated water to the condensate storage tank for refueling.

6. Provide an adequate supply of treated water for other miscellaneous requirements.

The Make-up Demineralizer System is not safety related and this modification, which replaced existing equipment and installed new equipment to monitor water quality and the regeneration process, did not change the function of the Make-up Demineralizer System. This modification used specified material to maintain water purity, and did not change the relationship that the make-up demineralizers have with other plant systems. This system is not used to mitigate the consequences of an accident.

DCP 1472 Radwaste Building Electric Heater

Description and Basis for Change

The design change replaced the existing Radwaste Building's (excluding the Control Room) hot water heating coils with an electric heating unit. The new electric heater was installed in the same location as the previous hot water heating coils. The heater is controlled from a new remote panel independent of the existing Radwaste Building HVAC System. The heater has both low air flow and overheat protection in both the manual and automatic modes (thermostat controlled).

In order for this design change to not affect the Radwaste Building auxiliary boiler hot water loop, the hot water coil supply line was changed to a bypass line with the same flow balance valve as originally installed. This ensured that the flow rate and pump sizing for the hot water loop was not affected by the removal of the hot water coils.

Summary of Safety Evaluation

The only difference between the installation of the electric heater and the hot water coils was their heat source and associated equipment. The actual Radwaste Building HVAC System operation and function were unaffected. The electric heater is capable of maintaining the same building design temperature as the hot water coils. The Radwaste Building's pressure was not significantly affected by the change because the difference in the differential pressure across the electric heater vs. the hot water coils is negligible.

In addition, the heating of the Radwaste Building is not a safety related function. A review of the UFSAR, most notably Sections 9.4.5, "Radwaste Building Ventilation System" and 15.7 "Radioactive release from a system or component," confirms that replacing the hot water coils with an electric heater will not alter any of the inputs or assumptions for previously analyzed accidents.

The only difference between the performance of the electric heater and the hot water coils is that the electric heater was sized for one supply fan running and the hot water coils were sized for two supply fans running. This means that if both supply fans are running in the Radwaste Building with the electric heater on, then the design building temperature may not be maintained if it is extremely cold outside. However, only one supply fan is required to be on when processing activities are taking place.

The purpose of heating the Radwaste Building is for personnel comfort and optimizing equipment performance in the building. The electric heater is a more reliable heat source than the hot water coils because there is no potential for coil freeze-up.

DCP 1474 Static-O-Ring Pressure Switch Replacement

Description and Basis for Change

There were 43 Static-O-Ring (SOR) pressure switches in use at the DAEC for which there was no direct replacement because SOR did not manufacture the existing model any longer.

This DCP found suitable replacement pressure switches for 40 of the existing switches. The various pressure switches were replaced to reduce maintenance requirements and to replace PVC wiring (the wiring is an integral part of the switch).

Summary of Safety Evaluation

These pressure switches are nuclear class 1E, qualified in accordance with the requirements of 10 CFR 50.49, IEEE-323-74, and IEEE-344-75 as documented in a test report that was determined to meet our EQ and seismic requirements. Those switches that are in harsh environments are radiation harsh only.

The new pressure switches are basically identical to the existing switches. They have the same mechanical and electrical characteristics except for the diaphragm material. The improved SOR switch is less susceptible to diaphragm aging and failure. Operation of the systems in which these switches are located was not altered. The switches have no new failure modes. Nothing was changed that would degrade the emergency safeguards equipment. Instrument accuracy is as good, or better, than the original switches.

DCP 1488 HPCI and RCIC Deluge Sensor Modification

Description and Basis for Change

It was determined that in the event of a small steam leak, the deluge systems in the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Rooms may initiate prior to the Steam Leak Detection (SLD) system isolating either the HPCI or RCIC system. The SLD isolation setpoints are on a sensed room high ambient temperature of 175°F and a room differential temperature of 50°F delta T. The deluge system initiated at 160°F or at a 15°F/min rate-of-rise. The SLD system setpoints were based on detecting an 8-10 gpm leak in the HPCI and RCIC Rooms. With a steam leak, an increase in room temperature would occur until the SLD isolation setpoints were reached. With the deluge system initiation setpoints at a lower temperature than the SLD isolation setpoints, system isolation based on the design leak rates, would not occur.

This modification eliminated the rate-of-rise deluge initiation and increased the temperature setpoint of the fixed temperature deluge initiation from 160°F to 212°F. Due to the elimination of the rate-of-rise detectors, additional upright sprinkler head detectors were added to each room.

Summary of Safety Evaluation

The SLD system is designed to detect small steam leaks in high temperature/high pressure systems. The fire protection system is designed for fire detection and suppression. Modification of the deluge initiation system cannot initiate a steam leak or start a fire in either the HPCI or RCIC Rooms.

The SLD system was not modified as a result of this design change. The deluge initiation system was modified to increase the number of sprinkler heads monitoring the HPCI and RCIC Rooms for fire. These sprinkler heads are also of a higher temperature rating (212°F instead of 160°F). The temperature rating and number of sprinkler heads were based on NFPA code requirements. This design change resulted in additional piping in the HPCI and RCIC deluge initiation systems. Failure of this piping or one of the additional sprinkler head[illegible] [illegible]ould result in inadvertent deluge operation. This has bee[illegible] [illegible]lyzed in the Fire Hazards Analysis (FHA) for both the HPC[illegible] [illegible]RCIC Rooms and determined to be acceptable. To minimize this possibility, the piping system and sprinkler heads were seismically mounted and hydrostatically tested after installation. Additionally, the design of the deluge initiation system provides for a small amount of leakage that would not result in deluge operation.

Replacing the 160°F and rate-of-rise deluge initiators with 212°F sprinkler heads permitted the SLD system to isolate the steam leak prior to the deluge system initiating and masking the leak. The design safety function of the SLD system as described in UFSAR Section 7.3.1.2 was not affected. Therefore, the consequences of a steam leak remain unchanged. The consequences of a fire in either the HPCI Room or the RCIC Room also remain unchanged as a result of the changes to the deluge initiation systems.

DCP 1489 Main/Standby/Startup/Auxiliary Transformer Modification

Description and Basis for Change

The previous transformer annunciator/alarm system had a history of operational problems. The overriding problem had been that multiple alarms were wired as a single input to the control room annunciator window associated with the transformers. All four main transformers each supplied 11 inputs (44 total) to one annunciator window. Each of the remaining transformers (auxiliary, startup and standby) had 12 inputs to their individual annunciator windows. For each annunciator window, alarm capabilities did not provide for reflash to make operators aware of any additional alarms after the first was acknowledged. The ability of non-critical alarms to mask critical alarms such as transformer cooling parameters was an operational and safety hazard which could result in damaged equipment and loss of generation of electricity.

These problems were resolved by providing improved control room operator acknowledgement of all power transformer alarms by removing alarm masking. This was accomplished by removing existing annunciator hardware at the transformers, installing a self-contained multi-microprocessor based LED display annunciator module at each transformer control cabinet and hardwiring transformer alarm inputs to the modules.

Additionally, the new transformer alarm modules provide a reflash capability, the ability to manually switch out each alarm input and annunciation on loss of DC power. The new module requires a temperature controlled environment for proper operation. The existing environmental conditions at each local transformer control cabinet did not provide for adequate temperature control. Therefore, provisions for temperature control were provided by adding a strip heater and two temperature control switches at each alarm module enclosure and providing alarm capability.

Summary of Safety Evaluation

Replacement of the associated transformer annunciator modules upgrades monitoring capabilities; otherwise, it is considered a like-for-like changeout. The upgraded monitoring capabilities increase operator awareness of transformer status thus decreasing the probability of an accident.

The primary operation and function of the Auxiliary AC Power System as described in UFSAR 8.3.1.1.1.5 and 8.3.1.2 was not altered. The changes improve system performance and reliability through the improved operator acknowledgement of transformer alarms and increased operator awareness of transformer status.

Control functions associated with the transfer of the startup and standby transformers as outlined in the UFSAR and Technical Specifications were not affected. The availability of the plant Auxiliary Electrical System was not affected. The improvements aid the operations staff in determining transformer status.

DCP 1491 HPCI Turbine Control System and Accessory Upgrade

Description and Basis for Change

During startup, the HPCI System previously underwent a transient that resulted in the turbine control valve first going full open and then full closed. After these events, the control system then would bring the control valve to its desired position.

This modification and its details were presented in GE SIL No. 480. A reduction in this startup transient was achieved with a modification to the HPCI turbine's hydraulic control system and a change in the procedure for calibrating the turbine's electronic control system. This was accomplished by the installation of a bypass line around the EGR hydraulic actuator to allow oil to be sent to the remote servo unit and close the turbine control valve. A check valve was installed in this bypass line to prevent oil from back feeding around the EGR when the system is operating in its steady state. An adjustment to the idle voltage to the EGR hydraulic actuator was made to support the system changes.

Additionally, various components on the HPCI turbine assembly were replaced with upgraded components to increase the reliability of the system. Some of these components included the ramp generator/signal converter module, EGM control box, EGR hydraulic actuator, overspeed test controller, and various servo and valve components. One component change increased the capability of the HPCI turbine assembly to withstand seismic loads.

Other modifications included the following:

- turbine control and stop valve position indicating lights were modified to provide intermediate position indication per standard design practices.

- turbine ramp start logic was modified to add the steam supply valve open signal to the logic. This reduced the possibility of a turbine overspeed trip under certain conditions.

- rerouting and grounding/shielding control cables to reduce electro-magnetic interference (EMI) in the control circuitry.

- rerouting D/P detector instrument piping to minimize air intrusion potential during calibration.

- replacement of the EGM control box power supply with a Class 1E qualified regulated power supply to improve reliability and performance of the EGM control box circuitry.

- upgrades to turbine auxiliary piping supports to comply with seismic qualification of the turbine assembly.

- adding a low pressure oil priming subsystem to maintain the turbine oil system piping filled during standby conditions.

- modifying the auxiliary oil pump suction piping to reduce the vacuum at the pump suction to allow the pump to operate more efficiently at pressurizing the oil piping.

Summary of Safety Evaluation

The HPCI System is provided to ensure that the reactor is adequately cooled to meet the design bases in the event of a small break LOCA that does not result in rapid depressurization of the reactor vessel.

This modification reduced the startup transient previously seen by the HPCI System and reduced the likelihood of a turbine trip during the startup transient. This modification did not affect the designed operation of the system. HPCI will continue to provide the designed flow rate within the required time limits. The modifications performed were designed and installed using design criteria that were the same or more stringent than the design criteria required for the original plant design.

Failure of the HPCI System has previously been analyzed in Chapter 15.6 of the FSAR and determined to be a nonlimiting event. This modification did not effect this analysis and did not create any new failure modes.

The various HPCI turbine components replaced by this modification are used to monitor and control the speed of the HPCI turbine or control components in the HPCI turbine's oil system. The HPCI turbine coupling end support pedestal dowel pins limit the horizontal movement of the HPCI turbine, and help maintain proper alignment of the HPCI turbine with the HPCI pump. This increases the capability of the HPCI turbine/pump with respect to seismic loads.

Failure of any of the identified HPCI turbine components will not result in an increased probability of the occurrence of an accident. The failure of the HPCI turbine is not a contributor to the initiation of a Design Basis Accident (DBA). However, the failure of the HPCI turbine limits the capability of the DAEC to respond to a DBA.

The function or method of operation of the HPCI turbine was not affected by replacement of the identified components. HPCI turbine operation with respect to startup time and power output (i.e., the HPCI System's pumping capacity) were not affected by the replacement of the components. The replacement components should improve the availability of the HPCI System during a DBA, as these components should make the HPCI turbine more reliable. The components were environmentally qualified for the postulated environment expected during a DBA when the HPCI System is required to function.

The valve position indication changes enhanced the operator's ability to monitor the turbine control valve and turbine stop valve status and did not affect the functional performance of the system or valve sequencing logic. Only valve indication logic was affected.

The ramp start logic modification improved the reliability of the turbine ramp start logic. It added the steam supply valve open signal as a permissive to ramp start. This prevents a HPCI turbine trip due to overspeed or high steam flow during startup. The time delay caused by the added relay contact in the ramp start circuit is insignificant (in milliseconds) and therefore, the modification did not affect the functional performance of the system.

This modification installed twisted shielded cables between the speed sensor and the EGM control box, and the EGM control box and the EGR hydraulic actuator. As per the vendor recommendations, the shields of the cables were grounded at the EGM control box end only, the other ends being left open or "floating." This modification implemented those recommendations by installing the appropriate cables with required shielding and grounding to eliminate spurious signal noise in the control system.

The instrument piping which was rerouted is used only during instrument calibration and is not required during HPCI System operation. Therefore, the normal HPCI System operation was not affected. The accuracy and the efficiency of the instrument calibration process improved with the change because of new instrument fittings which were installed.

The power supply replacement improved the reliability and hence performance of the EGM control box circuitry.

The performance improvement program included qualification of the HPCI turbine assembly in accordance with NUREG 0588 Category I. A typical HPCI turbine assembly was dynamically (seismic plus hydrodynamic loads) qualified by a conservative test program. In order to apply the qualification test results to the DAEC HPCI turbine assembly, its structural piping supports had to be upgraded to the as-built configuration of the tested turbine assembly. Additional piping supports were added to achieve this.

Prior to addition of the priming system, the auxiliary oil pump was used to prime and pressurize the turbine oil system piping upon initiation of HPCI. The turbine oil piping was normally void of oil, as the system would drain back to the oil sump within about 8 hours following securing of the system (verified during a special test procedure). This normal drained-down status of the turbine oil piping tended to result in acceptable but inconsistent system startup times to rated flow. These inconsistent times in turn made it difficult to identify and diagnose incipient turbine oil system problems. Operation of the priming system in the standby condition maintains the turbine oil system primed. Consequently, HPCI should be capable of consistent startup times within a 5 second band. Although a side benefit of the priming system pump is that the HPCI turbine will initiate its roll in a shorter period of time, it is still not required for the turbine oil system to be primed for the HPCI System to perform its safety function.

The HPCI auxiliary oil pump was developing a vacuum at the pump suction in excess of the vendor's recommended maximum vacuum of 15" Hg. This could cause the pump to cavitate, and have a negative effect on the priming and pressurization of the hydraulic system. Reducing the pump suction vacuum allows the auxiliary oil pump to prime the system better, and enhances the HPCI turbine performance during the startup transient. The existing 1.5 inch suction piping was increased to 2.0 inches and the existing plug type check valve was removed. Implementing these modifications reduced the friction losses in the suction piping, thus reducing the pump suction vacuum. The removal of the check valve did not affect the back flow protection to the pump because the pump discharge line is equipped with a check valve.

The only effect of these modifications was to enhance the reliability of the HPCI System which is part of the emergency core cooling system network. There was no impact on the capability of the HPCI System to perform its safety functions during the accidents identified in the DAEC NSOA because of these modifications.

The modifications did not affect the operation of any other plant systems. The reliability of the HPCI turbine control circuitry increased with the implementation of these changes. Pressure boundaries were designed to piping code B31.1, the same as the existing HPCI System. All cable employed in the modification was routed and installed in accordance with and meets the requirements of Iowa Electric SPEC-E512 for use in the Duane Arnold Energy Center. The analyses presented in the FSAR/UFSAR do not assume specific HPCI System component(s) failure. In the event that the HPCI System becomes inoperable, the ADS and LPCI Systems are available to depressurize the reactor and maintain reactor water level. None of the changes negatively impacted the ability of the HPCI System to respond per the UFSAR.

DCP 1492 Interference Removal for Reactor Recirculation Pump 'A' Maintenance and Related Activities

Description and Basis for Change

Interference existed that prohibited timely and expeditious removal and replacement of the Reactor Recirculation Pump 'A' motor or internals for maintenance or overhaul. In addition, there were two other related activities that concerned both of the Reactor Recirculation Pumps.

The changes included the following:

Modify a structural support member for the Scram Discharge Volume (SDV) instrument valve platform from a welded to a bolted connection.

Modify and re-route all of the existing instrument lines which emanate from penetration X56.

Replace the original mechanical vibration switches with a piezoelectric vibration monitoring system for the Reactor Recirculation Pump Motors to ensure a greater degree of vibration monitoring accuracy.

Modify the Reactor Recirculation Pump suction, discharge and bypass valve packing chambers from a triple stuffing box arrangement to a single packing design, which is more effective and reduces maintenance.

Summary of Safety Evaluation

Modifications of the equipment. components, structures or systems by this DCP did not have an adverse effect on any of the accidents previously analyzed in Chapter 15 of the UFSAR. The specific modifications performed by this DCP did not adversely affect the operation of any plant system or component. Rather the modifications enhanced the ability to perform plant maintenance and allow more reliable monitoring of the subject pumps for vibration.

The modifications utilized "2 over 1" criteria for seismic considerations. Modifications to the instrument lines did not negatively impact their ability to meet the intent of AEC Safety Guide 11, "Instrument Lines Penetrating Primary Reactor Containment."

The modifications performed by this DCP did not negatively change the function or method of operation of any affected system. The design changes enhanced the ability to remove the subject pump and motor for maintenance or overhaul activities in a safe and timely manner. The modifications to the subject pump discharge, suction and bypass valves' packing box decreased the possibility of uncontrolled leakage. The changes to the vibration monitoring system will result in decreased occurrences of high vibration spurious events.

DCP 1497 Diesel Generator Fuel Oil Transfer System Modification

Description and Basis for Change

The system modifications performed in this package involved changes to the Diesel Generator Fuel Oil Transfer System. The first of these changes relocated the check valves in the lines between the Emergency Diesel Generator (EDG) Fuel Oil Storage Tank and the EDG Day Tanks. Relocating these check valves upstream of the lines used to test the EDG Transfer Pumps allows the check valves to be tested in conjunction with the pumps.

The second modification involved the removal of the level indicator from each Day Tank. These indicators provided local, direct readings of oil level, but had been inconsistent when compared to Technical Specification indication switches. Repairing the indicators was possible, but would have been costly and time consuming.

Summary of Safety Evaluation

These modifications did not affect the operability of the EDG Fuel Oil Transfer System. The EDG will continue to perform the required safety functions in the event of a loss of off-site power to prevent or mitigate the consequences of an accident.

The modification that removed the local level indicators from the EDG Fuel Oil Day Tanks used appropriate materials per ANSI B31.1 and construction standards to remove the instrument and to cap the opening. The local indicators provided indication only and were located in the EDG Rooms just outside the EDG Fuel Oil Day Tank Rooms. This change did not affect the three level indicators/switches that give high, low and low-low level alarms as well as automatic EDG Fuel Oil Day Tank level control and EDG Fuel Oil Transfer Pump control.

The modification to place the check valves upstream of the line used for testing used appropriate material per ANSI B31.1 and construction standards. The new piping configuration was analyzed to ensure it met seismic constraints. This change allows the check valves to be verified operable each time the EDG Fuel Oil Transfer Pumps are tested in conjunction with Technical Specification 3/4.8 Surveillance Requirements. This change also permits the required testing per the ISI/IST Program and NRC Generic Letter 89-04.

Relocating the check valves did not alter the ability of the EDG Fuel Oil Transfer System to provide fuel oil to the EDG. The check valves' original design intent/function was unchanged by the relocation.

The proposed modifications did not change the EDG Fuel Oil Transfer Systems operating characteristics or remove any of the existing safety or control features outlined in the UFSAR. The

EDGs will operate as designed and provide power to all safety systems if off-site power is lost.

DCP 1501 Repair of the CRD Insert and Withdraw Piping

Description and Basis for Change

In May 1990, a leaking Control Rod Drive (CRD) line was discovered. This leak was located in the drywell air gap at the base of the pipe to containment shell weld in the heat affected zone. It was discovered as a result of ongoing efforts to determine the unidentified leakage which was occasionally draining from a drywell to torus vent line penetration.

After the leak was found, detailed examinations were conducted of all the CRD insert and withdraw lines that penetrate into primary containment. Only the South-West CRD piping bundle was found to be leaking; all other CRD piping bundles were in good condition. The detailed examination of the SW bundle showed signs of general corrosion on the drywell shell and crud accumulation on some CRD pipes. The dry areas in the SW bundle showed no signs of corrosion. Engineering performed an evaluation to justify the continued operability of the CRD system and the integrity of primary containment.

The modification provided guidelines for the repair of these lines and also evaluated the effect the leakage had on the primary containment shell. For the lines requiring destructive examination, a segment of the containment shell around the pipe was cut out (in order to save the defective pipe and its weld to containment). In its place, a machined fitting or sleeve was welded to two new sections of pipe and then the machined fitting was welded to the containment shell.

Instrumentation was provided such that piping loads, temperatures drywell shell vibration, and any leaking CRD pipes could be monitored and recorded in a real time domain.

Summary of Safety Evaluation

The CRD system is designed to be fail-safe. That is, if a failure of the insert or withdraw line were to occur, the associated control rod would insert or could be inserted if required. The only failure where all requirements are not met is a failure of the insert line when reactor pressure is less than the normal operating pressure. In this situation, the rod will still insert; however, scram times may not be met. When the reactor is less than approximately 400 psig, the accumulator located on each Hydraulic Control Unit is required to provide the necessary force to meet scram times.

The repair methods for these lines did not increase the probability of line failure and did not increase the magnitude of the consequences if a line failure were to occur. Prior to being declared operable, these lines were dye-penetrant examined and visually examined. In addition, 10 CFR 50 Appendix J requirements were met.

Due to the fail safe nature of the CRD system, none of the Design Basis Accidents as described in Chapter 15 of the UFSAR were more probable due to this repair effort. The Control Rod Drop Accident assumes that the reactor is at operating pressure and results from an uncoupled control rod. The probability of uncoupling was not affected by the work on the insert and withdraw lines. The probability of a Loss of Coolant Accident was also not affected by these modifications because the CRD insert and withdraw lines are not part of the Reactor Coolant Pressure Boundary. In addition, failure of the CRD insert and withdraw lines had been previously evaluated in the UFSAR and determined to be a non-limiting event. If the insert line were to fail, there is a ball check valve internal to the CRD mechanism designed to isolate this line. If the withdraw line were to break, the rod would insert and leakage would exhaust to the reactor building or drywell atmosphere. The amount of leakage would be limited to the leakage past the CRD seals (1 to 3 gpm) and worst case (without any seals) would be 10 gpm, which is well within the makeup capacity of either the normal level control or emergency systems.

The weld repairs to the primary containment were performed in accordance with all applicable Codes. This ensured that the repair weld joints met the original design criteria and bases as stated in the Technical Specifications. Minimum containment shell thickness for the areas inspected was determined. The UT examination process verified that the actual thickness met the required minimum thickness.

The stress/strain, temperature, vibration, and leak sensors only monitor the loads, temperatures, and potential leaking of the CRD piping. Vibration sensors monitor the vibration of the drywell shell. The sensors cannot cause a failure of equipment important to safety.

The modification removed the support closest to the drywell wall on each CRD insert and withdraw piping bundle inside the primary containment and revised other components (base plates, pipe straps) on the other supports for each bundle if necessary based on the stress analyses. Piping stress analyses indicated that the CRD piping stresses were within Code allowables, but some of the piping supports and penetrations failed to meet the service level A, B and C requirements of the ASME Code due to stresses induced on the drywell penetration by the gang support located closest to the drywell wall on each CRD bundle. The high stresses did, however, meet service level D requirements of the ASME Code and operation was allowed through the fuel cycle following RFO10 without modifying the supports. The CRD piping was reanalyzed as part of the modification. The modification to the piping supports restored the design stresses to within the allowables of service levels A, B, C and D as defined by the ASME Code.

DCP 1505 Upgrade/Addition of Seismic, Category I HVAC Ductwork and Supports

Description and Basis for Change

In September of 1989, a piece of structural steel which supported a portion of an HVAC plenum, pulled loose from its anchors and fell. This ductwork formed a portion of the secondary containment boundary. This incident led to LER 89-012 which committed the station to a review of all seismic, Category I HVAC ductwork. The purpose of the review was to evaluate the support of seismic, Category I ductwork and to identify inadequacies. The DCP addressed HVAC support modifications and additions as well as ductwork modifications to achieve compliance with original design or an acceptable alternative.

Summary of Safety Evaluation

In general, the activities only involved enhancing the support of seismic, Category I HVAC ductwork. The modifications were purely structural and did not change the operating characteristics or modes of any system within the plant.

The activities did involve minor changes to safety-related ductwork routing but in no way degraded or impacted the operation of these systems. All of the engineered safety features that existed within these systems remain unaffected and intact. In addition, none of the changes magnify or intensify any of the accidents previously postulated.

A majority of the changes involved non-safety related ductwork that is seismic, Category I. Modifications to structurally enhance supports or ductwork decreased the chance of support failure and the chance of damage to safety-related equipment in close proximity.

There are no direct references to HVAC supports in the Technical Specifications. However, the HVAC ductwork could affect systems that are in the Technical Specifications (Standby Gas Treatment System, Secondary Containment, etc.). As discussed previously, the modifications only enhanced the support of the ductwork. Additional support to seismic Category I ductwork made it less likely to damage safety-related equipment during a seismic event.

DCP 1507 Turbine Building Sample Sink Temperature Control/Conductivity Monitoring

Description and Basis for Change

The purpose of this change was to provide accurate continuously monitored conductivity information from condensate sample points between the hotwell and condensate demineralizer influent, common effluent and individual condensate demineralizer effluent at the Condensate Demineralizer Control Panel.

This was accomplished by replacing several conductivity analyzers, conductivity elements and associated cable. The new analyzers are micro-processor based which allows the use of more sophisticated internal algorithms to provide an accurate temperature compensated conductivity measurement, even in the non-linear portion of the temperature-conductance curve below 0.1 micromhos/cm.

The power supply to the old conductivity analyzers was connected in a "daisy chain" arrangement which prevented the de-energization of one analyzer at a time. This same "daisy chain" arrangement also affected condensate demineralizer flow, influent temperature and recorder instrumentation. The power supply to each of these instruments was modified to allow de-energization on an individual basis without affecting any of the other instruments. This was accomplished by providing parallel circuitry from the same power source as before the modifications to each instrument through respective sliding link disconnects.

Summary of Safety Evaluation

The configuration, function and systems interface of the replacement instrumentation is similar to the instrumentation that it replaced. The ability to continuously monitor condensate conductivity was retained and improved by the temperature compensating characteristics of the new instrumentation. Degradation of primary system boundaries or in-vessel components caused by undetected chloride or other impurity concentrations in the reactor water was not increased by this activity. Therefore, the probability of a loss of coolant accident, steamline break accident or control rod drop accident as described in the SAR were not increased. The probability of occurrence of a fuel handling accident is unrelated to performance of the proposed activity.

The replacement instrumentation met the specifications for the originally installed instrumentation. These modifications took place at the Turbine Building Sample Rack and Condensate Demineralizer Control Panel on the turbine operating deck. No equipment in the vicinity of the activity is considered important to safety, the replacement instrumentation did not interface with any equipment important to safety, nor could a malfunction of the new instrumentation cause a malfunction of any equipment considered important to safety.

The conductivity monitoring instrumentation that was replaced is not relied upon to mitigate the consequences of a malfunction of any equipment important to safety previously evaluated in the SAR.

Technical Specifications and bases refer to definite reactor water conductivity limitations and require continuous monitoring of condensate and reactor water conductivity. This modification enhanced the ability to continuously monitor conductivity in the condensate system by providing accurate, temperature compensated conductivity measurement.

DCP 1510 <u>Sprinkler System #4 Pipe Upgrade</u>

<u>Description and Basis for Change</u>

In 1989, the electric driven fire pump failed to pass the surveillance test acceptance criteria. Technical Specification 4.13.B.1.e required that each fire pump develop a discharge flow of at least 3100 gallons per minute with a discharge pressure of 112 psig. The corrective actions determined to be appropriate included a modification to sprinkler system #4 to replace a section of 4" pipe with a 6" pipe. This increase in pipe diameter decreased the pressure losses due to friction and therefore decreased the required discharge pressure necessary to meet the minimum flow requirements.

<u>Summary of Safety Evaluation</u>

The increase in diameter for the section of pipe in sprinkler system #4 reduced pressure losses due to friction and resulted in an operating condition which required a lower discharge pressure for each pump. Based on UFSAR 9.5.1.2.3.1, the fire pump was sized to meet the largest automatic system demand plus 1000 gpm for hose streams with the shortest portion of the fire loop out of service. This modification did not impact the operation of any other fire protection system supplied by these pumps and enhanced the performance of sprinkler system #4. The fire protection system does not mitigate any accidents. This modification enhanced the reliability of the fire protection system by reducing the pressure demand from the pumps.

The only equipment important to safety located in the sprinkler system #4 area are two electrical cables which transmit low voltage control signals to the river water flow control valves. This modification improved the operating parameters of sprinkler system #4, thereby enhancing the protection of these cables from damage due to fire.

Technical Specifications 3.13 stated that the basis for sprinkler system #4 was to provide the area with 0.20 gpm/ft^2 plus 1000 gpm for hose streams. This flow requirement remained unchanged by this modification.

DCP 1511 Control Building HVAC Control System Modifications

Description and Basis for Change

The previous configuration of the Control Building HVAC system did not have a manual purge mode. The control system was also overly complex and required excessive maintenance. The system was modified to have a recirculation mode with a minimum outside air quantity of 20% and a purge mode with nearly 100% outside air. Control of this function is achieved from within the Control Room.

A vent to outside air was added to the Cable Spreading Room to lower the pressure differential between the Cable Spreading Room and the Control Room after a cardox initiation. This was determined to cause high levels of carbon dioxide in the Control Room. The Cable Spreading Room exhaust fan damper control was modified to include a time delay relay. The timer was set to hold the exhaust damper open for approximately 30 seconds longer than the carbon dioxide discharge to minimize the pressure differential to the Control Room.

Various changes were made to the Control Building ductwork and HVAC controls to better control damper positions and air flow. Some of the components in the control system that were no longer manufactured were replaced with current model equipment to improve system reliability.

Summary of Safety Evaluation

The Control Building HVAC is required to be operable to support equipment operation and Control Room habitability as defined in the FSAR. The Control Building HVAC is not an accident initiator and the enhancements implemented under this design change improved the performance and reliability of the Control Building HVAC. The changes made to the HVAC control system for the purge mode of operation are bypassed whenever the Standby Filter Unit (SFU) is initiated.

The changes made to the Cable Spreading Room ensure that the Cable Spreading Room is isolated by initiation of the SFU. Since the thyroid dose to the operators is a function of the makeup airflow rate, it is preferable to manually reduce the SFU flowrate to reduce the building pressure instead of automatically relieving pressure via the Cable Spreading Room air balance damper.

The replacement of some of the existing equipment with currently manufactured models improved individual component reliability. The addition of a manual purge mode for the building allows faster dispersion of internally generated toxic gases.

In the event of a failure of both Control Building chillers, the purge mode provides the capability to limit the building temperature rise. Therefore, these modifications to the Control Building HVAC improve the systems ability to mitigate the effects of a fire in the Control Building or the loss of both chillers. The changes made to the Control Building HVAC do not cause the system to operate outside of its design capability. This modification did not change the divisional separation nor did it affect the fail position or closure time of any air operated equipment.

While the Control Building HVAC is not specifically addressed in the Technical Specifications, its function is still required for Control Room habitability concerns and this modification did not adversely impact the systems function.

DCP 1513 RCIC (Reactor Core Isolation Cooling) Turbine Insulation

Description and Basis for Change

On July 21, 1988, the Nuclear Regulatory Commission (NRC) amended its regulations by adding a new section 50.63. 10CFR50.63 requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specific duration. The NRC then issued Regulatory Guide (RG) 1.155, "Station Blackout", which describes a means acceptable to the NRC Staff for light-water-cooled nuclear plants to meet the requirements of 10CFR50.63. As a result, it was determined that DAEC has a SBO duration of four hours.

The RCIC turbine had marginal insulation which was degraded and inadequate to prevent a heat load of 4583 BTU/hr or less to the RCIC room. It was determined that during a station blackout with the RCIC turbine running and a loss of all room cooling, the RCIC room temperature would increase above 148°F (the maximum temperature allowed by equipment operability specifications specified by General Electric).

Calculations showed that by placing three inches of insulation on the turbine, the room air temperature at the end of four hours into a SBO is reduced to 129 degrees. This value can be taken as a steady state temperature since at this time the energy in and the energy out are very nearly balanced.

The scope of this design change was to remove all existing insulation and install three inches of form-fitted, removable blanket insulation. The entire turbine was insulated, as well as any previously uninsulated steam supply or exhaust piping.

Summary of Safety Evaluation

The DAEC NSOA identifies the accidents, as defined in Chapter 15 of the UFSAR, that require the RCIC system to perform its safety function. Accidents and events that are evaluated in Chapter 15 of the UFSAR are based on the initial set of assumptions and operating conditions. Review of the DAEC UFSAR and the NSOA confirmed that this modification would not affect any of the initial assumptions or input parameters.

The insulation on the RCIC turbine was degraded and unable to prevent a 4583 BTU/hr or less heat load to the RCIC room during a station blackout. This modification enhanced the turbine insulation and thus increased the probability that equipment in the room would be operationally functional in an accident or transient situation during a station blackout. The new insulation will not cause the turbine casing to melt or corrode. Chloride leaching from the insulation will have no adverse effects on the turbine casing or components.

This modification did not change, degrade or prevent any actions described or assumed in an accident discussed in the FSAR, nor did it alter any assumptions in the FSAR for evaluating the radiological or other consequences of an accident. The pressure boundary of the system was not affected by the modification and the original design specifications and codes were satisfied. Environmental qualifications, fire protection, heavy loads and design requirements were considered.

Seismic effects were also considered. The net weight of the turbine and base is 3,900 pounds and the total weight of the insulation is approximately 40 pounds. Thus, the insulation will not effect the turbine seismically. The insulation consists of custom-designed blankets which form to the turbine casing. The fastening technique coupled with the fact that the insulation blankets are form-fitted will ensure that the blankets remain attached to the turbine during a seismic event.

DCP 1531 RPV Level Instrumentation Piping Reroute

Description and Basis for Change

During review of the effect of high Drywell temperature on the Reactor Vessel level instrumentation, it was determined that the HPCI and RCIC System automatic high level trips may not occur with the existing setpoints under specific DBA conditions. In order to assure that these trip functions will occur prior to water covering the reference leg taps, the existing variable legs were rerouted to reduce the vertical drop in the Drywell and in turn reduce the calculated error in the system. Modifications to the 'B' side were previously completed. 'A' side modifications were completed during the last refueling outage.

The change implemented the requirements of Generic Letter 84-23 for Reactor Vessel level indication.

Summary of Safety Evaluation

The method of operation and safety function of equipment important to safety were not changed. The variable legs associated with the identified instruments were rerouted to reduce the vertical drop inside the Drywell. The new pipe routing reduced the error induced in the system from Drywell temperature fluctuations during various events. The error reduction enhanced the system capabilities to reflect levels closer to the actual level. The modification did not change the input to the analysis performed for events previously evaluated in the SAR.

The modifications met all requirements of instrument accuracy, mechanical reliability, seismic interactions, fire protection, and environmental qualification. The unattached pipe length is not adequate to create the impact energy necessary to exceed the energy required to penetrate the containment. The design bases for the Reactor Vessel level instrumentation were maintained. The piping was designed to original plant standards and the existing excess flow check valve, isolation valve, and flow orifice were reused, therefore, the probability of a variable leg rupture which could not be isolated was not increased. The rerouted variable leg piping inside the Drywell reduced the amount of piping susceptible to system interaction inside the Drywell. Analysis confirmed that new failure mechanisms were not introduced. The associated trips as listed in Table 3.2-B of the Technical Specifications were maintained as specified.

DCP 1534 Standby Filter Unit Fan Assembly Modification

Description and Basis for Change

The Standby Filter Unit (SFU) supply fans had a history of vibration and maintenance problems. These fans are centrifugal, direct drive fans. Excessive vibration and severe loading on the inboard fan motor bearings resulted in reduced bearing life. No provision existed for field balancing of the existing fans without extensive disassembly of the SFU fan housing. The overall intent of DCP 1534 was to reduce the load on the fan motor bearings resulting in longer bearing life.

DCP 1534 modified the motor pedestal for each unit to independently support the fan wheel in a manner which will reduce the load on the motor bearings during operation. The DCP relocated the existing motor for each fan so the fan wheel is on a secondary shaft, which is supported by a separate set of bearings. The secondary shaft is connected to the motor shaft using a flexible coupling.

The old fan shaft had incomplete engagement with the fan wheel. The new secondary fan shaft was sized to fit entirely through the existing fan hub. A guard plate and access port were added to prevent accidental personnel contact and to allow inspection of the fan wheel following installation and facilitate in-situ balancing of the fan wheel.

Summary of Safety Evaluation

The Control Room HVAC system is designed to ensure habitability of the Control Room and operability of Control Room equipment. The requirements for the SFU's are to limit radiological doses to Control Room personnel upon Control Building isolation.

The new bearings, shaft and flexible coupling, motor pedestal and modified fan housing for the SFU fans were analyzed for seismic loads.

The DCP 1534 modification did not change the SFU system function or logic. The SFU fans continue to automatically start on Control Room isolation to maintain Control Room pressure positive.

Failure of the SFU system is not identified as an initiating event for an accident. This modification did not impact system characteristics or logic which could increase the probability of occurrence. The modification did not add or adversely impact any existing radiological release paths and did not impact the ability of existing systems required to mitigate an accident from performing their safety function.

The SFU system continues to function as before but with increased reliability. DCP 1534 enhanced the fans ability to operate by reducing stresses on the existing motor bearings.

Failure or operation of the SFU fans are not identified as initiating events for any of the equipment malfunctions previously analyzed. This DCP did not introduce any new failure modes or system interactions.

DCP 1537 Low Pressure Coolant Injection Valve Timer Override

Description and Basis for Change

For mitigation of the Design Basis Loss-of-Coolant Accident (LOCA), the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) System utilizes a Loop-Selection Logic. This logic uses a set of pressure switches on the main Reactor Recirculation System piping to determine which of the two recirculation loops contains the pipe break. Once the "broken" loop is determined, the Loop-Selection Logic aligns the LPCI subsystem valves to inject into the intact, i.e., "selected," recirculation piping loop. As part of this Loop-Selection Logic, the Outboard LPCI injection valve in the "selected" loop receives a seal-in signal that prevents that valve from being closed or throttled from the full-open position for five (5) minutes after the Reactor pressure drops below the LPCI pressure permissive of 450 psig. The intent is to prevent the Operator from diverting the LPCI flow from the Reactor until core reflood is assured. After the timer expires, the Operator can re-align the RHR system out of the LPCI mode and into other beneficial modes, such as Containment Spray or Torus Cooling. (It should be noted that, per the Design Basis documents, the 5 minutes is somewhat arbitrarily chosen and intended to generically bound the time necessary to establish core reflood.)

The purpose of this modification was to install key-locked switches in the main control panels to allow the Operator to override this 5-minute timer and to throttle closed the Outboard injection valve in the selected loop, thereby diverting some (or all) of the LPCI flow to these other modes of RHR, once the Operator has confirmed that adequate core cooling has been established. The recognition of the need for this modification came as a result of Operator training exercises on the DAEC-specific Simulator. This capability was determined to be extremely beneficial to the Operators in executing Emergency Operating Procedure (EOP) instructions during certain postulated "beyond Design Basis" events, such as Anticipated Transients Without SCRAM (ATWS). In these postulated ATWS events, the Operator is directed by the EOPs to "Stop and prevent all injection into the RPV [Reactor Pressure Vessel]..." This is done to control the Reactor power level and to prevent re-criticality once Boron has been injected into the RPV. Before this modification, the only mechanism the Operator had at his/her disposal for accomplishing this instruction, prior to the 5-minute timer expiring, was to turn-off/secure the running RHR pumps. This creates a number of difficulties for the Operator later in the event, once the need to re-establish RHR system operation, either in LPCI or some other mode, is reached. In most postulated ATWS events, the Operator cannot wait out the 5 minute timer and still prevent core or containment damage.

Summary of Safety Evaluation

The design of the timer override switches preserved the original design basis of the system. When the keylocked switches are in the normal, i.e., non-bypass, position, they are passive in the circuit and have no impact on the normal functioning of the 5-minute timer. A failure modes and effects analysis (FMEA) was performed to confirm that the modification did not degrade system reliability/availability. The design of the modification is single failure/single operator error proof. (It should be noted that the original design of the Loop-Selection Logic is not single failure proof, in that a failure of the Inboard injection valve to open upon demand will disable the LPCI function. This is an analyzed failure mode in the DAEC LOCA analysis.) If the bypass switch is taken to override inadvertently (single operator error), or fails in the closed position (single failure), thereby overriding the 5-minute lock-out, LPCI injection will still take place, as the Outboard injection valve will remain fully open (normal/standby readiness position) until the Operator takes the second action to manually close/throttle the valve. Also, the override switches are annunciated on the main control panels to alert the Operator that the switch is in the bypass position, thereby minimizing the opportunity for a mispositioning of the switch or inadvertent closure of the Outboard injection valve during the Design Basis Accident. The Operators are only instructed in their procedures to use these bypass switches during postulated ATWS scenarios, which are beyond the DAEC Design Basis. Therefore, this modification is within the constraints of the original design basis and is acceptable.

No other equipment important to safety was affected by this modification. Since the RHR System will be able to be used in other beneficial modes of operation (e.g., Containment Spray, Torus Cooling, Drywell Spray, etc.) when the LPCI function is not needed, the modification is an overall improvement. Additionally, reducing the number of pump cycles on and off may reduce the potential for water hammer in the system, thus providing a positive affect on RHR System availability and operation.

DCP 1540 HPCI/RCIC Door Modification

Description and Basis for Change

A High Energy Line Break (HELB) involving either the High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) steamlines in their associated pump rooms can cause a room pressurization and failure of the previously existing access doors. This door failure would have resulted in the propagation of an Environmental Qualification (EQ) harsh environment into the reactor building.

In order to prevent such a door failure in the event of a HPCI or RCIC HELB, new pressure resistant, fire door assemblies were installed to replace the existing door assemblies. The new door assemblies are UL labeled as 'A'-rated fire doors and are capable of resisting the pressure force resulting from the event of a HPCI or RCIC HELB.

During preparation of this modification, gaps were identified between the top of two reinforced concrete walls and the HPCI room roof slabs. The gaps were partially filled with foam material. This modification filled the remaining gap with grout.

This modification affected the walls of each room by replacing the access doors. Some masonry blockwall was modified. Additionally, some conduit and deluge piping was rerouted. These were required due to the new door frame size and anchorage. The HPCI and RCIC rooms are designed to function as compartments during a high-energy pipe rupture to contain the high temperatures, pressure, humidity and radiation doses generated during such an event. Section 3.6.1.3.3 of the UFSAR analyzes the consequences of a HPCI or RCIC steam line break on affected safety systems located in the reactor building.

Summary of Safety Evaluation

A rupture of the RCIC or HPCI steam line in the respective room would result in damage only to that system. By assuring that the HPCI and RCIC access doors remain closed during a HELB, it is concluded that the design of the high-energy piping systems outside containment is such that their failure would not result in the inability of the plant to be shut down or to be maintained in a safe shutdown condition.

The safety objective of the secondary containment system in conjunction with other engineered safeguards and nuclear safety systems is to limit the release to the environment of radioactive materials so that the offsite doses from a postulated design-basis accident (DBA) will be below the guideline values of 10 CFR 100. During a HELB in the HPCI or RCIC room, the roof plugs are calculated to lift resulting in a steam release to the environment, bypassing secondary containment. Total mass flow rate from a HPCI/RCIC line break before isolation is less than that of a main steam line break. As this is not a DBA and the core remains covered, the applicability of the Total Indicated Dose (TID) source term is not required and the use of the

Technical Specification maximum coolant activity (3.6.B) is acceptable.

The DAEC EQ requirements were not affected by this modification since the access doors were replaced to comply with the existing EQ program. There was no contribution to the overall accident probability from this modification. The compartmentalization of the HPCI and RCIC rooms prevents the Reactor Building from becoming an EQ harsh environment.

There was no increase in the radiological consequences of any previously analyzed SAR accident. The modifications did not change, degrade or prevent actions described or assumed in an accident discussed in the SAR. This modification did not alter any assumptions previously made in evaluating the radiological consequences of an accident, nor did it play a direct role in mitigating the radiological consequences of an accident described in the SAR.

As discussed previously, the lifting of the HPCI or RCIC roof plugs is a release bounded by a previously evaluated release.

The HPCI and RCIC compartments are considered as structures and are classified as structures important to safety. This modification had no adverse impart on these structures. Additionally, the access doors must withstand a pressure of four psig and maintain a three hour fire barrier. The new doors meet these design requirements.

The modification did not affect any equipment important to safety. The replacement HPCI and RCIC access doors and the modified HPCI deluge piping (moved because of interference) meet the same design and installation codes as the previous doors and fire suppression piping.

DCP 1542 Safety Relief Valve Lifting Lug Installation

Description and Basis for Change

The removal of the Main Steam Safety Valves and Safety Relief Valves on the 775' elevation of the drywell had been a labor-intensive and dose-intensive job. This modification installed lifting lugs inside the drywell in locations convenient as rigging attachment points. The new lifting lugs are easier to utilize than the previous rigging points and improve rigging safety and efficiency.

The lifting lugs were designed, fabricated and installed per the requirements of the original primary containment code. The lifting lug material is identical to the existing drywell shell material. Calculations were performed to show that stresses are within code allowables for the lifting lug and for the attachment to drywell steel.

This modification also allowed the removal of existing non-structural steel (abandoned construction aids or supports) as identified during walkdowns. In addition, fall restraints were installed for the second floor openings.

The criteria for attachments to the primary containment are that all structural attachments to the containment structure, and the penetration reinforcements of the containment structure shall be designed so that the maximum loads (forces, moments and torques) which the corresponding structural attachments (e.g. hangers and pipes) can apply to the containment structure, will not cause failure of the containment as a functional barrier.

Summary of Safety Evaluation

This modification did not impact the primary containment system's capability to withstand the pressures and temperatures that could result from any of the postulated accidents for which it is assumed to be functional.

Failure of the lifting lugs or the primary containment are not identified as initiating events for these scenarios. The modification did not adversely impact the integrity of the primary containment or its ability to perform its safety functions.

The lugs and the attachment to the shell were designed in accordance with applicable codes in order to ensure that the primary containment remains capable of performing its function. Welding to the primary containment was performed in accordance with all applicable codes to ensure that the weld joint meets the original design criteria and bases.

Use of the lifting lugs will occur during refueling outages using plant procedures to avoid interference with other systems and presents no new risks above those of current rigging practices. The installation of the lifting lugs does not add any additional failure modes to the containment.

DCP 1543 GEMAC Water Level Instrument Reference Leg CRD Backfill

Description and Basis for Change

Non-condensible gases are generated in a BWR under normal operating conditions. These gases can collect in reference legs when steam is condensed in the condensing chamber and the gases become entrained in the condensed water. Normally this condensed water is returned directly back to the reactor vessel since the instrument tap is sloped down towards the reactor. However, if the reference leg instrument line has any sort of leakage (through fittings, plugs or valve packing) condensed water will be drawn into the reference leg resulting in the entrainment of noncondensible gases.

These noncondensible gases will remain in solution until the primary system pressure is reduced. During system depressurization, noncondensible gases evacuate the water in the reference leg and displace fluid. This displacement of fluid in the reference leg results in indicated level higher than the actual level. As a result, during the time of outgassing, the level instruments may not initiate the required automatic actions (scram, PCIS isolations, etc.) at the appropriate level and may provide the operator with incorrect level indication.

DCP 1543 installed a backfill station for each cold reference leg to provide a continual reverse flow of water through the reference legs. This extremely small amount of flow serves to prevent gas from collecting by sweeping any condensation back to the reactor vessel instrument tap.

Summary of Safety Evaluation

All automatic trip functions will remain operable and will trip when required during backfill system operation. No recalibration of the instrumentation due to density changes was required as a result of backfill injection.

A blocked instrument line (reference leg) with continued backfill system operation would pressurize to the CRD drive water header pressure, which is normally 200 to 300 psi above reactor pressure. In this situation, the level instruments will respond exactly as if the variable leg ruptured, an event previously evaluated in the FSAR. The pressure instruments will respond exactly as if an actual reactor overpressure transient were in progress, an event previously addressed in the FSAR.

This event can only result from either a flow blockage within the reference leg or by closure of the manual containment isolation valve of the reference leg. A flow blockage is extremely unlikely as the CRD system was chosen for the backfill partly because of the high purity water. In any case, a flow blockage would most likely not occur instantaneously, and the degradation in backfill system flow would be noticed by the plant operators who check flow each shift. The manual containment isolation valve inadvertently being closed is not considered credible as these are manual valves with no automatic isolation signals.

Reactor water level instruments cannot initiate any analyzed accidents, but they do serve to mitigate these events. The CRD backfill system has no adverse effects on the ability of the reactor vessel instrumentation system to perform any safety function. Components added by this change cannot compromise the reactor coolant pressure boundary. The system was designed to isolate in the event of a backfill line break in the non-safety portion of the system. Pipe class and seismic qualification are maintained to the point of isolation.

The addition of the reference leg backfill system will not increase the probability of a reference leg failure. The postulated backfill system line failures are all bounded by a reference leg line break which is already evaluated in the FSAR. The maximum injection rate has been analyzed to show that the reference leg stresses and the reactor vessel nozzle stresses are within the code allowable. Since the CRD side of the backfill system is non-safety related, two check valves in series located as close to the reference leg as possible are provided to give positive isolation in the event of a break in the CRD piping.

Due to the extremely low flow rate and isolation capability, there are no new failure modes created. A failure of this backfill system will remove this enhancement but does not create the possibility of a new malfunction of equipment important to safety.

The errors that are induced by the backfill system are calculated to be small, less than 1.5 inches on the narrow range water level instrument, with a maximum backfill flow rate. This is well within the instrument loop accuracy uncertainties.

SECTION B - PROCEDURE/MISC. CHANGES

Six (6) Special Test Procedures (SpTPs) were performed in 1993. Each was reviewed by the Operations Committee. No unreviewed safety questions were found to exist. Summaries of these special tests and their safety evaluations are found below.

During 1993, various procedures as described in the Safety Analysis Report (SAR) were revised and updated. Additionally, other various documents or items were changed or identified that required evaluation. All changes were reviewed against 10 CFR 50.59 by the Operations Committee. Summaries of these changes and their safety evaluations are also provided below. No changes were made that involved unreviewed safety questions.

TEST/PROCEDURE	TITLE/DESCRIPTION
SpTPs:	
184 185	Motor Operated Valve Testing of MO-2011, MO-2015

Description and Basis for Tests

These SpTPs accomplished performance testing of motor-operated valves in response to NRC Generic Letter 89-10.

SpTP 184 demonstrated the operability of MO-2011 and collected performance data under the following conditions:

- Opening against the differential pressure calculated to occur when lining up for shutdown cooling,
- Closing against the line pressure (no flow) postulated to occur when securing from shutdown cooling.

This activity involved manipulating various "A" side manual and motor operated valves in order to obtain the appropriate dP's which were created by using the Condensate Service Water System and then stroking the valves. The "B" side of RHR remained unaffected and fully functional.

SpTP 185 demonstrated the operability of MO-2015 and collected performance data under the following condition:

- Opening against the differential pressure calculated to occur when securing from shutdown cooling.

This activity involved manipulating various "A" side manual and motor operated valves in order to obtain the appropriate dP's which were created by using the Condensate Service Water System and then stroking the valves. The "B" side of RHR remained unaffected and fully functional.

Summary of Safety Evaluations

The RHR System does not contribute to the probability of occurrence of an accident as evaluated in the SAR. Although the RHR System contains equipment important to safety, the appropriate LCO was entered and the appropriate constraints imposed by the Technical Specifications (TS) were followed. Since the components were removed from service within LCO constraints, the valves were proven operable prior to being returned to service and the performance test did not impact any other equipment which is important to safety, the possibility of a malfunction or accident different than any previously evaluated in the SAR was not created, nor were the consequences of malfunctions or accidents previously evaluated increased.

186 Motor Operated Valve Testing of MO-2511

Description and Basis for Test

The focus of this SpTP was to stroke open the RCIC pump discharge valve, MO-2511, under dynamic conditions and obtain data in order to demonstrate valve operability per GL 89-10 guidelines.

RCIC remained fully available during performance of the SpTP; an LCO was not required. The RCIC System would have auto-aligned for injection to the vessel if an initiation signal was received during the test.

Summary of Safety Evaluation

The RCIC System does not contribute to the probability of occurrence of an accident as evaluated in the SAR. Although the RCIC System contains equipment important to safety, the RCIC System remained fully functional during the performance test and was able to fully mitigate the consequences of a malfunction of equipment important to safety. The activity had no impact on other equipment important to safety.

187 Motor Operated Valve Testing of MO-1937

Description and Basis for Test

This SpTP accomplished performance testing of MO-1937 in response to NRC Generic Letter 89-10.

SpTP 187 demonstrated the operability of MO-1937 and collected performance data under the following conditions:

- Opening against the differential pressure created by an RHR pump operating on minimum flow.
- Closing against the flow associated with an RHR pump discharging to radwaste.

The activity was accomplished by operating the RHR System in its design configuration, it was operated within normal operating parameters (flow, pressure, temperature) and it was not made inoperable; thus, the activity was accomplished via the normal operation of the RHR System.

Summary of Safety Evaluation

The RHR System does not contribute to the probability of occurrence of an accident as evaluated in the SAR. Although the RHR System contains equipment important to safety, the RHR System remained fully functional during the performance test and was able to fully mitigate the consequences of a malfunction of equipment important to safety. The performance test did not adversely affect any RHR equipment important to safety and the performance test did not impact any other equipment important to safety.

189 Motor Operated Valve Testing of MO-2238, MO-2239, MO-2400, and MO-2401

This SpTP accomplished performance testing of MO-2238, MO-2239, MO-2400 and MO-2401 in response to NRC Generic Letter 89-10.

The SpTP consisted of demonstrating the operability of HPCI Steam Supply Valves MO-2238 and MO-2239, and RCIC Steam Supply Valves MO-2400 and MO-2401. Dynamic performance data was collected under the following conditions:

- Closing the described valves individually against the achievable steam flow and differential pressure during operation of the HPCI and RCIC Systems in the Condensate Storage Tank (CST) to CST mode during power operation.

- Throttling open (unseating) the described valves for repressurization/rewarming of the steam supply piping.

The activity was accomplished within the constraints of the two 14 day LCOs for HPCI MO-2238 and MO-2239, and RCIC MO-2400 and MO-2401. The requirements of TS Tables 3.2-A and 3.2-B were satisfied for necessary defeats of auto isolation or initiation/control instrumentation.

With the appropriate defeats installed, the HPCI (RCIC) System was operated within design parameters in the CST to CST mode. The MOV under test was then stroked closed to obtain the maximum available differential pressure across the valve as it seated. Only one MOV was tested at a time.

Since the auto open logic was defeated for the steam supply valves, HPCI (RCIC) was unavailable during the periods between the closing stroke of each steam supply valve and the system recovery with the steam supply valves full open. Therefore, there were four distinct time periods of unavailability during the performance of this SpTP.

During the performance of this SpTP, at least one trip system was available to isolate the HPCI (RCIC) steam supply line and turbine exhaust line. The defeat of the auto open logic for the MOV under test eliminated the risk of steam supply piping damage from a spurious/valid initiation signal.

The impact of this testing upon other plant systems important to safety was evaluated. This Special Test affected only the HPCI (RCIC) System. Consequently, all other systems which provide a safety action remained available throughout the performance of this SpTP.

Summary of Safety Evaluation

The HPCI (RCIC) System does not contribute to the probability of occurrence of an accident as evaluated in the SAR. The components affected by the test do not contribute to the probability of an accident. Although the HPCI (RCIC) System contains equipment important to safety, the appropriate LCO was entered and the appropriate constraints imposed by the TS were followed. The components were removed from service within LCO constraints. The valves were proven operable prior to being returned to service and the performance test did not impact any other equipment important to safety.

190 Motor Operated Valve Testing of MO-2029 and MO-2031

Description and Basis for Test

This SpTP accomplished performance testing of MO-2029 and MO-2031 in response to NRC Generic Letter 89-10.

SpTP 190 demonstrated the operability of MO-2029 and MO-2031 and collected performance data under the following conditions:

- Opening against the differential pressure associated with the RHR Loop A system pumps operating near shutoff and the downstream pressure at normal standby,
- Closing against the flow associated with the RHR Loop A system pumps operating at rated flow through the MOV being tested.

The activity was accomplished by operating the RHR System in its design configuration, within normal flow, pressure and temperature limits (although RHR Loop A was depressurized during portions of the SpTP, and then filled and vented).

Summary of Safety Evaluation

The RHR System does not contribute to the probability of occurrence of an accident as evaluated in the SAR. The components affected by the test did not contribute to the probability of an accident; nor did the performance test affect any other system. The performance test did not adversely affect any RHR equipment important to safety.

The RHR System remained within the constraints of the appropriate LCO during the test (both Core Spray Subsystems remained operable). The RHR System was operated within system design parameters, the performance test did not adversely affect any "B" Loop RHR equipment important to safety and the performance test did not impact any other equipment which is important to safety.

SE 92-04 Revision to IPOI-8 to Clarify OPDRVs

Description and Basis for Change

The reason for this change to the procedure, IPOI-8, Outage and Refueling Operations, is to clarify that control rod drive line (insert and withdraw) and valve repairs are not considered as operations with the potential for draining the reactor vessel (OPDRVs).

A loss of coolant accident is defined as those accidents which result in a loss of coolant in excess of the capability of the reactor coolant makeup.

As described in UFSAR section 4.6.2.2, Rupture of (CRD) Hydraulic Lines to Drive Housing Flange, a rupture of an insert or withdrawal CRD line with the vessel depressurized (refuel or shutdown conditions) would have a negligible effect on vessel inventory. A ruptured CRD withdrawal line would leak at a maximum of 3 gpm. In the event an insert line ruptured, the head of water in the vessel would cause the ball check valve to seal off the broken line. Therefore, the maximum leakage that could occur with a failure of either an insert or withdrawal line would be approximately 3 gpm. Due to the volume of water in the vessel, a 3 gpm leak is not a safety concern with respect to core cooling or vessel inventory. Such a small leak leaves ample time to isolate the line and provide a source of makeup to the vessel.

Summary of Safety Evaluation

TS 3.5.G.3(b) provides guidance on ECCS and diesel generator operability when irradiated fuel is in the vessel and the reactor is in Cold Shutdown or Refueling to mitigate LOCAs. The probability of these accidents, however, were not increased because this procedure change did not specifically affect the operation, design or function of any equipment which could cause any of the three accidents.

This procedure change maintained these requirements but more specifically defined what actions constitute OPDRVs. The Technical Specifications ensure that certain ECCS equipment and diesels are operable during these conditions.

Any work being performed on equipment which has the potential to drain the vessel must still be performed in accordance with approved standards and work control processes.

SE 92-09 UFSAR Change 93-05: RCIC Class 1E Clarification

Description and Basis for Change

The purpose of this UFSAR change was to provide recognition that all RCIC equipment is not required for RCIC system operation and that such equipment is therefore not required to be classified as 1E.

Summary of Safety Evaluation

This change provided for general RCIC system design requirements to be more accurately reflected. The revision made the UFSAR text more consistent and did not increase accident probability or consequences since it will continue to ensure that all equipment required for RCIC system operation is appropriately qualified. All RCIC equipment will continue to be classified according to its importance to safety. This process takes the effects of equipment malfunctions into account during classification and is not affected by this change. This change did not alter any equipment configuration or the operation of the RCIC system.

SE 93-06 Recirculation Pump Discharge Bypass Valves Justification for Continued Operation/Conditional Release for Operation (JCO/CRO)

Description and Basis for JCO/CRO

The recirculation discharge bypass valves were added to the Environmental Qualification program. During the process of generating an EQ file for these valves, the vendor informed the DAEC Engineering Department that the insulation material on the motor leads was Teflon, which is not qualified for the environment in which the valves are located.

Summary of Safety Evaluation

The recirculation discharge bypass valves perform a safety function to close during the DBA LOCA to ensure a path for LPCI flow to the reactor vessel. If the discharge bypass valves do not close, then a pathway exists for LPCI flow to bypass the core region.

This safety evaluation described the effect on peak cladding temperatures of failure of the discharge bypass valves to close. It also evaluated the impact on the assumptions in the DAEC LOCA analysis.

The LOCA analysis uses a LPCI flow of 12,420 gpm (three pumps) which is approximately 10% less than the Technical Specification requirement of 14,400 gpm. This difference is larger than the expected flow through an open recirculation discharge bypass valve. The LOCA analysis provides a sensitivity study on the effects of reducing various input parameters. For a 10% reduction in LPCI flow, the peak clad temperature is increased by 25 degrees.

The recirculation discharge bypass valves combat the DBA LOCA by automatically closing. However, as shown by the amount of flow expected through an open bypass line, adequate conservatisms exist in the existing analysis to show that the peak clad temperature will not be significantly affected.

Allowing the existing motor leads with Teflon insulation to remain installed and operational until the next refuel outage does not create the possibility of a different accident as the active safety related function of this valve is to close in response to a DBA LOCA.

SE 93-09 Use of GE 2000 Fuel Shipping Cask for LTA Transport

Description and Basis for Change

This safety evaluation addressed specific issues relating to the use of the GE 2000 fuel shipping cask at DAEC.

UFSAR section 9.1.4.4.5 describes the general criteria for use of a GE IF300 spent fuel shipping cask. This description is not directly applicable to the GE 2000 cask because of differences in the cask's handling system. The major differences were that the cask remained suspended in the cask pool during loading and that the cask pool gate was not in place during the cask loading. This evaluation addressed those aspects of the cask handling operation which are not bounded by the UFSAR safety evaluation for the IF300.

Cask movements were accomplished for this evolution by using the reactor building crane (which meets single failure proof design per NUREG 0554) and a single failure proof cask rigging system which uses redundant load paths to meet the requirement of NUREG 0612. Therefore, it was concluded that the probability of a load drop was sufficiently small that the planned evolution was acceptable. The safe load path for the GE 2000 was identical to that proposed for the IF300. The restriction of a one foot maximum lift height above the refuel floor described in UFSAR section 9.1.4.4.5 was also maintained.

Due to the much lower weight of the GE 2000 versus the IF300 (30,000 LBS vs 170,000 LBS), the movement of the GE 2000 is bounded by the IF300 safety evaluation with the exception of the loading evolution.

Because the reactor building crane is utilized to remove the cask pool gate and the crane was unavailable as it suspended the cask, the cask pool gate could not be moved during the time the cask was in the pool. Therefore, the cask pool gate was not installed during the cask loading evolution.

As an additional measure of precaution, because the cask pool gates were not in place, the Operations Department was notified prior to the cask movement so that in the unlikely event that Emergency Service Water (ESW) would have been required to provide emergency fuel pool cooling, it could have been initiated in a timely manner. The response time available to initiate ESW in the emergency fuel pool cooling mode was reduced from 4.4 hours to 3.8 hours with the gate removed.

Summary of Safety Evaluation

The movement of a spent fuel cask at DAEC is included in UFSAR Section 9.1.4.4.5. The evolution involving the GE 2000 cask was bounded by this evaluation with respect to a cask drop event. The same single failure proof design criteria was applied as to the IF300, and the cask was not lifted over irradiated fuel.

The effect on fuel stored in the spent fuel pool was unchanged since the normal source of safety related makeup water (i.e., ESW) was still available to provide adequate spent fuel pool cooling in the event of a cask drop.

Since no boiling was calculated to occur in the fuel pool, even given a cask drop in the cask pool while the cask pool gate was removed (provided emergency fuel pool cooling is initiated per existing procedures), the margin of safety was not reduced.

SE 93-11 Cycle 12 GE Fuel Inspection and Retrieval Procedures

Description and Basis for Change

General Electric (GE) performed fuel inspections of selected Lead Test Assemblies (LTAs) and GE-8B fuel assemblies during Cycle 12. Additionally, GE removed 38 fuel segments from an LTA for shipment to their nuclear facilities in Vallecitos, California. These inspections were performed as part of GE's commitment to monitor and evaluate fuel and material performance of fuel assemblies under actual operational conditions at selected BWRs.

The procedures for fuel inspection and fuel segment removal activities were GE's standard BWR procedures for fuel inspection and fuel segment removal. The GE procedures covered a range of detailed activities including receiving; inspection and packaging of individual fuel bundle components at the reactor site; removal/replacement of the fuel bundle upper tie plate (UTP) and individual rod handling; removal and reinstallation of a channel on an irradiated bundle; visual examination of irradiated fuel and components; eddy current and ultrasonic testing of irradiated fuel rods; fuel rod oxide thickness measurement; accountability of fuel rods; and the sampling of fuel rod corrosion deposits.

The 38 fuel segments removed from the LTA were placed in specially designed canisters. These canisters fit into a frame that was designed to be installed into a shipping cask. The NRC approval for use of the package (including the canisters, frame and shipping cask) for shipping irradiated fuel had been documented in an NRC Safety Evaluation Report (SER). The SER included a criticality evaluation that covers storage of the fuel segments in the canisters. The restriction that fuel rods would be removed/inserted from/into a fuel assembly one at a time ensures that the likelihood of an inadvertent criticality occurring during the transfer of a fuel rod to and from a fuel assembly was negligibly small.

Summary of Safety Evaluation

The unlikely event of a fuel handling accident was evaluated and documented in the FSAR. Fuel inspection activities did not increase the probability that a bundle would be dropped. Work performed under the fuel inspection and fuel segment removal procedures did not require handling a bundle over the reactor cavity or spent fuel pool.

All GE fuel types have inherent mechanical features which preclude the incorrect installation of the UTPs. In addition, administrative controls ensured that the UTP would be replaced with the prope. orientation. Procedural controls precluded the possibility of loading a fuel rod into a wrong bundle location after it had been removed.

Removal of a fuel rod from the spent fuel pool was precluded by use of a physical restraining device. The maximum fuel damage which could be postulated as a result of fuel inspection or fuel segment removal activities was bounded by the complete rupture of all 62 irradiated fuel rods. Such an event would involve multiple equipment and/or operator errors during normal fuel inspection, fuel segment removal and handling activities. The radiological consequences of such an event would be bounded by the FSAR fuel handling event which assumes a fuel bundle is dropped from a maximum height and strikes a fully loaded core causing more rods to fail than the 62 rods in a single bundle.

GE's equipment for handling individual fuel rods has been specifically designed for use in these inspection activities and has been used successfully several times at the DAEC. GE's equipment was inspected and operated by GE personnel specifically trained in its use. Therefore, the likelihood that an individual fuel rod would be dropped due to equipment malfunction was low.

The movement of irradiated fuel in either the form of whole assemblies or individual fuel rods was performed with secondary containment operational. The source term from any postulated accident was bounded by the source term evaluated in the FSAR. All inspection activities had a negligible effect on spent fuel pool water level. All postulated accidents were conservatively bounded by the FSAR or reload licensing submittal analysis.

SE 93-17 UFSAR Change 93-13: Drywell Volume Increase

Description and Basis for Change

During the review of the results from a Containment Integrated Leak Rate Test (CILRT), an error was discovered in the original calculations for the Drywell air volume, as listed in Table 6.2-1 of the UFSAR. Both the gross and net-free volume were recalculated. The results of the recalculation show that the actual Drywell gross and net-free volume are larger than originally calculated. The gross volume increased from 144,000 ft^3 to 157,700 ft^3 and the net-free volume increased from 109,400 ft^3 to 130,000 ft^3. This safety evaluation addressed this increase in the Drywell volume used in the safety analyses. **Note:** no physical change to the plant took place, only a recalculation of the Drywell volume.

Summary of Safety Evaluation

Because the volume is larger than previously assumed in the plant safety analyses, the calculated peak containment pressure after an accident will be lower than that previously calculated.

Consequently, the results of the original safety analyses are either conservative, for those areas that are pressure-dependent (e.g., Structural Integrity, CILRT (P_a), Drywell Spray Permissive, etc.) or are unaffected, for those items that are concentration-dependent (e.g., Containment H_2/O_2 concentration, CILRT (L_a), Containment Atmospheric Dilution, etc.). Therefore, the results of the previous analyses are bounding for the new larger Drywell volume.

SE 93-18 Temporary Modification 93-21: Bypass Hydrogen Water Chemistry System Trips

Description and Basis for Change

In order to support on-line corrective maintenance on the Offgas System oxygen analyzer, it was necessary to temporarily bypass both the Offgas high/low O_2 residual concentration trip and the Hydrogen Water Chemistry (HWC) System low O_2 supply pressure trip. This was done in order to keep the HWC System operating during the maintenance to correct a spiking problem with the oxygen analyzer which could have caused a spurious trip of the HWC System.

Summary of Safety Evaluation

The purpose of the HWC System is to scavenge O_2 in the reactor coolant by the injection of H_2 into the system, thereby lowering the Electro-Chemical Potential (ECP) below the threshold for crack growth in stainless steel piping due to Intergranular Stress Corrosion Cracking (IGSCC). HWC is considered to be an augmentation to the normal ASME Code requirements for ensuring the structural integrity of Code Class I piping.

The low O_2 concentration and low O_2 supply pressure trips in the HWC System are there to protect the Offgas System from potentially explosive mixtures of hydrogen due to inadequate amounts of oxygen in the offgas stream for recombination to occur. The high O_2 concentration trip is there to protect the Offgas charcoal beds from a flammability concern due to having high charcoal temperatures in an oxygen rich environment. However, these trips are system protection trips and are not safety-related functions.

It was permissible to temporarily bypass these trips during operation as there were adequate indications in the Control Room for both oxygen supply pressure and Offgas hydrogen concentration. Thus, the Operators could have isolated the HWC System in the highly improbable event of a HWC System abnormality during the limited time that the maintenance was being performed. Also, the excess flow check valve in the O_2 piping was still operable during this time, such that the piping would have still isolated in the unlikely event of a pipe leak/rupture. Thus, neither the probability nor consequences of an accident or malfunction were increased as a result of temporarily bypassing these system protection trips. Since the HWC System is only an augmentation to the ASME-required inspection program for ensuring the structural integrity of Code Class I piping, any upset in the system's operation would not have had any impact on the piping integrity.

SE 93-23 UFSAR Change 93-19: Revision of Surveillance Requirements for Smoke Detectors

Description and Basis for Change

This change revised the surveillance requirements for smoke detectors from the current frequency and type of tests being performed to the periodic testing and inspections defined in the National Fire Codes.

UFSAR Section 9.5.1 describes the DAEC's Fire Protection System, and specifically Section 9.5.1.2.2 discusses the fire detection system. The inspection and testing requirements for detectors which provide fire protection in the required safety system areas are defined in UFSAR Table 9.5-1 and the Fire Plan. Surveillance tests that were being performed for these detectors were:

1. Bi-monthly fire detector supervisory alarm circuit testing.

2. Semi-annual smoke and detector sensitivity testing (detectors are cleaned, as required, during semi-annual surveillance testing).

For the remaining detectors in the plant, the following tests and inspections were previously done.

1. Bi-monthly fire detector supervisory alarm circuit testing.

2. Semi-annual walkdown for visual observation to ensure detectors are not missing and to observe detectors which may have impeded smoke entry.

3. Annual smoke and detector sensitivity testing (detectors are cleaned, as required, during annual surveillance testing).

The surveillance requirements for all smoke detectors were revised to the following:

1. Perform bi-monthly fire detector supervisory alarm circuit testing.

2. Perform annual smoke testing.

3. Perform initial sensitivity testing when installing a new detector and routine sensitivity tests for all detectors on alternate years. (Detectors will be cleaned as required.)

4. For out buildings having detectors that are not electrically supervised, a semi-annual visual walkdown will be performed to ensure detectors are not missing.

Summary of Safety Evaluation

The above changes are consistent with the requirements of the National Fire Codes NFPA 72E 1990 Edition, and are based on the following:

1. The semi-annual walkdown, which is currently conducted to verify that detectors are not missing or that smoke entry has not been impeded, are defined in NFPA 72E Sections 8-3.2 and 8-2.4.1. However, this inspection is not required for detectors which are electrically supervised since circuits which are open because of a missing detector will alarm in the Control Room. Also, obstructions which might impede smoke entry are not a problem because it is unlikely that transient or permanent installations will interfere with smoke entry to detectors when the detectors are mounted at high ceiling elevations. In addition, the Code states that the walkdown will ensure that any protection installed during construction to prevent dust and dirt contamination of detectors has been removed. Plant procedures exist which prevent this from being a concern.

2. Reduction of smoke detector sensitivity testing from semi-annual and annual testing to alternate year testing is consistent with NFPA 72E Section 8-3.4.2. Also, changing smoke testing of detectors to an annual requirement is in accordance with Section 8-3.4.1 of the Code.

3. The increased duration period between smoke detector cleanings will have no adverse effect upon the level of protection provided by the detector. Smoke detectors become more sensitive as their screens pick up dust and lint and they will alarm early when dirty. Cleaning will be initiated when a detector goes into early alarm because of dust and lint accumulation, or if sensitivity limits from the central alarm station cannot be maintained when the detector is tested every other year.

Thus these changes to the frequency of surveillance requirements and the method of implementing the requirements do not affect the operation of other equipment in the plant, including equipment important to safety. The fire detection system will still be able to perform its function of promptly detecting a fire. No new types of failures are introduced into the fire detection system. Therefore, these changes were deemed to be acceptable.

SE 93-27 Recirculation 45% Runback Logic Rewire

Description and Basis for Change

In March 1993, a 45% recirculation pump "A" runback was initiated at the same time the 1Y11 inverter transferred from the 125 VDC battery to the regulating transformer. The runback logic was such that the runback relay would deenergize to initiate the runback. During the inverter transfer, the voltage on 1Y11 dropped low enough to drop out the runback relay, which then sealed itself out. The runback relay was replaced with a relay that was tested to drop out at a lower voltage.

In July 1993, the 1Y21 inverter swapped on undervoltage. This swap to the regulating transformer caused a momentary voltage dip on 1Y21, which caused a 45% runback on the "B" recirculation pump. This event was identical to the March event, only it occurred on the "B" side instead of the "A".

To prevent inadvertent runbacks in the event of voltage transients on the Instrument AC bus, the logic was modified to an "energize-to-trip" function. This involved wiring changes internal to Control Room panel 1C-18. No external changes were needed.

Summary of Safety Evaluation

The runback logic is powered off 1Y11 circuit 16 and 1Y21 circuit 16. Under a loss of logic power, the 45% runback would not function. The scoop tube drive is powered off 1Y11 and 1Y21 circuits 22. When the scoop tube drive loses power, a scoop tube lockup occurs.

Under a loss of 1Y11 or 1Y21, the MG set would not be capable of performing a runback even if needed, since the scoop tubes will lockup. However, on a loss of 1Y11 or 1Y21 circuit 16, the scoop tube drive would still have power but the logic would not. Under these conditions the runback will not occur if called upon. This sequence of events is considered highly unlikely, and considering the non-safety nature of the recirculation pump runbacks, this is acceptable from a design standpoint.

A failure of the relay to actuate would also prevent the runback from occurring. Though the failure of these relays to actuate is unlikely, to ensure the 45% runback relays remain functional, a preventive maintenance task has been set up to test these relays.

The recirculation runback logic and the recirculation speed control logic are non-safety related. The modification to the 45% runback logic was designed to prevent any inadvertent runbacks from occurring during voltage fluctuations on the instrument AC power supply. As a result, the possibility of an inadvertent runback was reduced.

Recirculation pump speed change events have been analyzed in Chapter 15 of the FSAR. These events are non-limiting transients which do not result in any fuel thermal margins being exceeded. The 45% recirculation pump runback is not needed to function following any accident or transient. The recirculation pump runbacks are not described in the Technical Specifications. There are no divisional criteria nor seismic criteria that apply.

SE 93-28 UFSAR Change 93-22: Torus Vent/Vent Header/Downcomer Surveillance Revision

Description and Basis for Change

UFSAR Section 6.2.1.4.2 describes the surveillance requirement for visual inspection of the Torus vent system, which includes the interior and exterior surfaces of the eight vent pipes, the vent header and the forty-eight downcomer pipes, during each refueling outage. The purpose of this inspection is to determine if there is any degradation of the coating or corrosion of the vent system metal above the Torus water line. The acceptance requirement was that any indication of degradation would be repaired prior to startup. This change to the UFSAR allows for an engineering evaluation to be performed on a case-by-case basis to determine if a repair is required or that the level of coating degradation or corrosion is acceptable for continued safe operation. These changes will allow us to avoid making unnecessary repairs to the coating or metal in those situations where the indications are very minor and would not affect the structural integrity of the Torus vent system. In addition, this change clarified the extent of the vent header system to which the inspection applies - to the accessible portions in the "water line region," i.e., the two-foot wide band centered about the normal Torus water level.

Summary of Safety Evaluation

The protective coating on the vent header system in the "water line region" is two-layered: the base layer is Carbozinc-11, 3 mils thick and the surface layer is a modified phenolic coating, 8 mils thick. The phenolic coating, which is in contact with the water in the Torus, was chosen for its very low degradation rate for normal service conditions in the Torus. The visual inspection, which inspects the accessible vent areas above the water line, verifies that there is no unacceptable degradation in the phenolic top coat. This is a general area inspection to look for degradation near the Torus water line. The changes in the UFSAR description of this inspection are editorial and merely more accurately describe the inspection as performed.

The original FSAR stress analysis for the Torus assumed the maximum wall thickness, with no allowance for corrosion. Hence, the pre-existing wording in the UFSAR that stated that any corrosion would be repaired before resuming power operation. However, the re-analysis of the primary containment structures conducted as part of the MARK-I program in the late 70's/early 80's, indicates that there is some margin that could be used to account for minor, localized corrosion. This change to the UFSAR will allow for an engineering evaluation to be performed to determine whether any degradation in the coating found during the inspection needs be repaired prior to startup or can be trended and repaired at a later date, using the margin available in the MARK-I structural analysis.

SE 93-29 UFSAR Change 93-23: Revision of Environmental Qualification (EQ) Program

Description and Basis for Change

QUAL-SC100, Environmental Service Conditions Analysis, and QUAL-SC101, Environmental and Seismic Service Conditions were issued as Revision 5. These revisions incorporated the latest analyses and positions of the DAEC EQ program with regard to High Energy Line Break (HELB), Loss of Coolant Accident (LOCA) and definitions of harsh versus mild environments. The description of Environmental Design of Electrical Equipment at the DAEC, which was contained in UFSAR Section 3.11, required revision for consistency with the latest positions of the EQ program. In addition, the description of the operability testing referenced as being conducted on the heating and ventilation equipment required revision to avoid any inconsistency with UFSAR Section 9.4.

This UFSAR change did not degrade the basis for the EQ program as described in the EQ Design Bases Document (DBD).

Summary of Safety Evaluation

The original list of HELB events analyzed for the DAEC included the RHR corner rooms due to the presence of steam piping for the steam condensing mode of RHR operation. Because this connection to the steam supply system was removed, HELBs are no longer postulated in these rooms. The Reactor Water Cleanup (RWCU) heat exchanger room, Traversing In-core Probe (TIP) room and TIP room mezzanine were added to the list since HELBs are postulated to occur in these areas. The EQ program has analyzed reactor building equipment for the environmental effects of these HELBs. Therefore, the ability of the plant to mitigate a HELB is not degraded by this change.

The 340°F temperature was used in the original EQ response to qualify drywell equipment. Because the DAEC was already operating, this equipment was qualified to the DOR guidelines. Subsequent analyses performed for the DAEC power uprate program provided new values for drywell conditions post-LOCA. New and replacement equipment is qualified to the current requirements of 10 CFR 50.49 using the temperature from the current analysis of record. The 340°F value only applies to the existing equipment which was qualified under the DOR guidelines. This revision was editorial in nature and did not change the fact that all drywell equipment is qualified as required per one of the NRC accepted methods. Therefore, there was no degradation in the ability of drywell equipment to perform its safety function post-LOCA.

Increasing the overall drywell gamma radiation value results in a more conservative value for radiation doses to some equipment. The qualification and testing methods used to demonstrate that equipment can meet this value are unchanged. Therefore, the assurance that drywell equipment will be able to perform its function post-LOCA was not reduced.

The discussion of beta radiation indicates that jacket insulation can stop beta particles eliminating the need to consider beta radiation in every situation. This does not mean that beta radiation is never considered. Cables in drywell junction boxes which contain openings and where the jacket insulation has been removed were analyzed for the effect of beta radiation. The revised UFSAR wording was intended to make this distinction clear. In both cases all cables are qualified for the appropriate radiation dose. Therefore, there is no reduction in the ability of drywell equipment to perform its safety function.

The deletion of the specific operability testing indicated as being conducted on the heating and ventilation equipment and referencing the HVAC test and inspection requirements outlined in Section 9.4 did not in anyway degrade the operating capabilities of this system. This position was based on the consistency between these test and operability requirements and those in the Technical Specifications.

This revision did not alter any assumptions of the NSOA with regard to events, protective action sequences or equipment required to mitigate these events. Rather, it clarified the manner in which Iowa Electric (IES Utilities Inc.) assures that this equipment will be able to perform its function given the environmental conditions created by these events.

No changes were made to system operating modes, process parameters, design criteria or logic. Because equipment has already been analyzed/qualified for these events and conditions, this change did not introduce any new failure modes or increase the probability of existing failure modes. The EQ program assures that equipment will be able to perform its safety function given the environmental conditions created by the accidents. The changes did not impact any existing radiological release paths nor impact the ability of existing systems to perform their safety function.

SE 93-31 Core Operating Limits Report for Cycle 13

Description and Basis for Change

In accordance with DAEC Technical Specifications, a Core Operating Limits Report (COLR) was prepared to support the addition of new fuel to the core and the relocation, i.e., shuffling, of the existing fuel that would remain in the core for the next operating cycle. The COLR contains the thermal limits (MCPR, MAPLHGR and LHGR) for the fuel, which are derived from the results of the analysis of the limiting operating transients and accident analyses in the UFSAR. The cycle-specific analysis of these limiting transients and accidents was performed using NRC-approved methods, as described in GE's Standard Application for Reactor Fuel (GESTAR: NEDE-24011-P-A) and the results were presented in the Cycle 13 Supplemental Reload Licensing Submittal (SRLS) for the DAEC.

The new fuel designs used for Cycle 13 were of the same fuel type (GE-10) as those loaded in previous reloads at the DAEC (i.e., Cycles 11 and 12). These fuel designs are licensed by the NRC via GE's topical report, NEDE-31152P, GE Fuel Bundle Designs.

Summary of Safety Evaluation

The GE-10 fuel design met all requirements for fuel designs and was essentially a like-for-like replacement of the fuel previously loaded in the DAEC core. Compliance with the thermal limits for this core design ensure that the fuel design requirements are satisfied during reactor operation in all applicable Operating States in the NSOA. These thermal limits were derived using NRC-accepted methods, which demonstrate, in the SRLS, that the consequences of the limiting events in UFSAR Chapter 15 are within the acceptance criteria for such events. The fuel, proper, is an event initiator only for the Fuel Loading Error (either mislocated or rotated bundle). No changes to the fuel loading and verification procedures were made as part of this change, and the GE-10 fuel type had the same verification attributes (e.g., ID on handle, dog-eared boss, etc.) as the existing fuel designs.

Given that the GE-10 fuel types loaded in this reload met all acceptance criteria for fuel designs and were manufactured/constructed under an NRC-approved Quality Assurance program, the probability of a failure of the fuel cladding (the equipment important to safety), when operated in accordance with the thermal limits provided in the COLR was not increased from that previously evaluated. Also, the ASME Vessel Overpressure analysis in the SRLS demonstrated that the peak RPV pressure was well within the design allowable.

SE 93-32 Temporary Water Storage in the LLRPSF

Description and Basis for Change

This safety evaluation documented the acceptability of using the spent resin storage vault in the Low Level Radwaste Processing and Storage Facility (LLRPSF) to house temporary water storage tanks. These tanks were needed to segregate some water which had been contaminated with Ethylene Glycol from the normal liquid radwaste streams, until special equipment could be brought in to remove the Ethylene Glycol. The normal liquid radwaste processing equipment cannot remove organic chemicals, such as Ethylene Glycol, if they are inadvertently introduced into the radwaste system. (This Ethylene Glycol entered the radwaste system as a result of a broken hydraulic hose on a piece of temporary equipment being used in the Drywell during a Refuel Outage.) An estimated 80,000 gallons of water needed to be stored.

Summary of Safety Evaluation

The resin vault was originally designed for the storage of spent resin in High Integrity Containers (HICs). While the resin vault was designed for dry containers, it was also designed to contain the water which would result from an initiation of the fire suppression system located in the resin vault. Additionally, since it was anticipated that this water would become contaminated in the process of putting out a fire in the vault, the resin vault floor drains are routed to a controlled sump which pumps to the floor drain sludge tank.

UFSAR Section 11.4.2.5 states that shielding has been provided in the LLRPSF to limit radiation exposure to personnel to within the guideline values of 10 CFR Part 20. Additionally, this evaluation states that the operating procedures and containment and storage facilities are designed to limit the concentrations that could result from any accidental or inadvertent release of radioactive materials to within the guideline values of 10 CFR Part 20.

UFSAR Section 11.2.1.3 states that the liquid radwaste system is designed so that any quantities of liquid radwaste inadvertently released result in radiation levels within the exposure limits of 10 CFR Part 20. The basis for this evaluation is an analysis which assumes that the entire volume of the liquid radwaste system is discharged to the environment. This analysis is the basis for the Technical Specification limit (Ref. TS 3.14.A) for the maximum radioactive inventory of 50 Curies to be contained in the liquid radwaste system. This analysis included the proposed 70,000 gallon surge tank (not yet installed) in the surge tank room located adjacent to the HIC vault in the LLRPSF storage area. The surge tank room floor drains to the same sump as the resin vault.

The water to be stored in the temporary tanks contains very low radioactivity (less than 0.4 Curies). Since the resin vault was designed to house spent resin HICs having far greater radiation levels than will be emitted from the temporary water storage tanks, and the curie content of the tanks is such a small fraction of the Technical Specification limit, the proposed use of the resin vault is not considered to be beyond the design basis of the liquid radwaste system.

The resin vault was designed with a fire suppression system specifically to address the fire loading in the vault related to polyethylene HICs. The temporary water storage tanks are constructed of the same material as the HICs and will represent a smaller total combustible loading; therefore, the existing fire hazards analysis is considered to bound the housing of the temporary water storage tanks in the resin vault.

Should a leak occur in one of the tanks, the water would be directed to the resin vault floor drains. The floor drains have motor operated isolation valves which will be tagged closed under normal operation. The radwaste operators would have the option of allowing the water to remain in the resin vault, or draining it to the LLRPSF storage area sump. From this sump the water would be pumped to the floor drain sludge tank. The resin vault has the capacity to hold approximately 150,000 gallons of water which is in excess of the 84,000 gallon capacity of the temporary tanks.

In conclusion, the resin vault is ideally suited to house temporary polyethylene water storage tanks. Both from a radiological and a fire protection standpoint, the resin vault has engineered features which address all potential concerns. The only deviation from the original intended use of the vault is that water rather than dry waste will be housed in the vault. This change will have no impact on the facility's ability to protect the health and safety of the public or plant personnel.

SE 93-33 Weld Repair of CV 4421, "D" Outboard MSIV

Description and Basis for Change

The as-found local leakage rate test (LLRT) performed on the "D" Main Steam Isolation Valve (MSIV) in Refueling Outage (RFO) 12 identified unacceptable leakage. This resulted in the valve being disassembled, inspected and machined. The valve machining exposed indications of unacceptable lengths. These indications were ultimately repaired via a non-Code repair. Since this repair did not conform to the ASME Code, a Relief Request (RR-002, Revision 1) was submitted and subsequently approved by the NRC.

Summary of Safety Evaluation

The repair created an acceptable condition within the MSIV. The repair activity itself was performed during a plant shutdown with no impact on safety. Engineering evaluated the effects of the repair on the valve and concluded that there was no concern with regard to wall thickness (pressure boundary), crack growth potential, or operational performance.

Description and Basis for CRO

The HPCI System injection valve was to be modified to assure the required stem thrust under accident conditions, assuming degraded bus voltage. However, delays in delivery of parts precluded completion of the planned modifications.

The gears were installed in the valve operator, but the new stem/stem nut assembly did not arrive in time for installation before planned startup from the refuel outage. The interim configuration increased the valve stroke time such that it did not meet the original design specification for stroke time of 20 seconds in the open and closed direction. With the new gears and original stem/stem-nut, the valve was projected to close in approximately 26 seconds. This safety evaluation was written to support operation with the interim configuration until the valve stroke time could be returned to within the design specification requirement or a DCP could be prepared to revise the design documentation to match the new valve stroke time.

In the current LOCA analysis for the DAEC, the performance of the HPCI System is demonstrated to be acceptable with a startup time from initiation signal to achieving rated flow and pressure of 45 seconds.

Summary of Safety Evaluation

The relaxation of the stroke time for this valve did not change the probability of occurrence of any previously-analyzed event, as the only event for which the HPCI System is the event initiator, proper, is the Inadvertent HPCI Injection.

The LOCA events place the greatest demand upon the HPCI System to support the core cooling function. The LOCA was reanalyzed with the relaxed HPCI start time, which bounds the relaxed stroke time for this valve. The results were obtained using NRC-accepted methods, which demonstrated that the consequences of a LOCA are within the acceptance criteria of 10 CFR Part 50.46 limits and are bounded by the existing Licensing Basis Peak Cladding Temperature of 1570°F.

In the Inadvertent HPCI Injection Event, the HPCI System is assumed to inject full flow instantaneously into the Feedwater System. Therefore, the stroke time of the injection valve has no effect on the analyzed result of this event.

This valve only needs to close to isolate the HPCI System from the Feedwater System as the HPCI turbine coasts down and injection is terminated as a result of a Feedwater line break inside containment. The closure time is not important to fulfilling its isolation function, as the inboard Feedwater check valve will close as soon as the differential pressure is higher on the Reactor/Drywell side than on the HPCI side. Therefore, the slower stroke time in the closing direction did not adversely impact the isolation function of this valve.

The failure of the injection valve to open upon demand has the same impact on HPCI performance (a total loss of HPCI flow) as the failure of other components in the HPCI System. The LOCA analysis demonstrates that the failure of the HPCI System to perform upon demand does not have unacceptable results.

The consequences of the failure of this valve to close upon demand was not increased from that previously evaluated.

The revised LOCA analysis demonstrates that the margin of safety, which is defined by the PCT limit of 2200°F of 10 CFR Part 50.46, is not challenged. The existing Licensing Basis PCT of 1570°F is still bounding, even with the increased stroke time for this valve.

SE 93-37 UFSAR Change 93-26: Rewrite UFSAR Section 9.1.4.4.5 to Reflect Commitments on Heavy Loads

Description and Basis for Change

This UFSAR section was rewritten to make it consistent with current NRC commitments regarding the handling of Heavy Loads and more specifically spent fuel casks. The UFSAR was revised to show that the basis for handling spent fuel casks, which employ single-failure-proof rigging as defined by ANSI N14.6, did not rely on the acceptability of a load drop, but on the probability of the event being sufficiently small so as to not be considered credible. The upending and removal of casks from their transporter where single-failure-proof rigging is not practical was also addressed in the rewrite.

Per the acceptance criteria in NUREG-0612, which was committed to by Iowa Electric (IES Utilities Inc.), either a drop of the load must be found to be acceptable or the lifting/handling system, including the crane and associated rigging, must meet the criteria for single-failure-proof design as detailed in NUREG-0554 and ANSI N14.6 respectively. As a result of these commitments, the reactor building crane was upgraded to single-failure-proof status in 1985 and now meets the requirements of NUREG-0554. As a requirement for use at DAEC, spent fuel casks must be supplied with rigging which meets the single-failure-proof design criteria of ANSI N14.6. The only exception to this requirement is that for most spent fuel casks which were designed prior to these design requirements being implemented, it is impractical for single-failure-proof rigging to be employed during the removal and reinstallation of the cask from and to the cask transporter. For this specific evolution, the acceptability of a load drop from the standpoint of potential impact on nuclear safety related equipment was performed. A safe load path was included within which a cask could be dropped while being removed from or reinstalled on a transporter and not have any detrimental effect on nuclear safety related equipment. This safe load path does not allow the cask to be lifted directly over any safety related equipment, including the Torus, and limits movement to areas of the Reactor Building elevation 757'-6" floor which are directly supported by the corner room wall below. By following the requirements included in the rewritten UFSAR Section 9.1.4.4.5, all NRC commitments and requirements are fulfilled.

Summary of Safety Evaluation

This change is consistent with previously approved evaluations which are currently included in the UFSAR. This change did not affect plant equipment. It addressed inconsistencies which previously existed as a result of a series of modifications and changes in regulatory positions which resulted from the issuance of NUREG-0612 and other related documents. This change removed confusing information which was no longer pertinent to the basis for acceptability of the Reactor Building Crane for the purpose of handling spent fuel casks.

Since single-failure-proof rigging shall be used or the impact of a potential load drop was evaluated as having no impact on safety related equipment, the consequences of an accident were not increased.

SECTION C - EXPERIMENTS

This section has been prepared in accordance with the requirements of 10 CFR Section 50.59(b).

No experiments were conducted during calendar year 1993.

SECTION D - SAFETY AND RELIEF VALVE FAILURES AND CHALLENGES

This section has been prepared in accordance with the requirements of Technical Specification 6.11.1.e., "A report documenting safety/relief valve challenges shall be submitted within 60 days of January 1 each year."

No safety valve or safety relief valve failures or challenges occurred during calendar year 1993.

SECTION E - FIRE PLAN CHANGES

The information contained in this section identifies, briefly describes and provides assurance that changes made to the DAEC Fire Plan during the calendar year 1993 did not alter our commitment to the NRC guidelines contained in "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance."

Revision No.	Description of Change
27/28	Various minor changes were made to the Fire Plan. Miscellaneous improvements to Area Fire Plans were made, such as improved plant area descriptions, adding details for outbuilding areas and drawing enhancements. Additionally, verification steps were added to some Area Fire Plans for post-fire conditions.