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REVIEW OF THE OPERATING EXPERIENCE HISTORY OF OYSTER CREEK THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

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EXECUTIVE SUMMARY

The Systematic Evaluation Program Branch of the Nuclear Regulatory Commission (NRC) is conducting the Systematic Evaluation Program (SEP) for the purpose of determining the safety margins of the design and operation of ter of the older operating commercial nuclear power plants in the United States. These ten plants are being reevaluated in terms of present NRC licensing requirements and regulations. Thus, the SEP is intended:

1. to establish documentation that shows how these ten plants compare with current acceptance criteria and guidelines on significant safety issues and to provide a technical rationale for acceptable departures from these criteria and guidelines,
2. to provide the capability for making integrated and balanced decisions with respect to any required backfitting, and
3. to provide for the early identification and resolution of any potential safety deficiency.

The SEP evaluates specific safety topics based on an integrated review of the overall ability of a plant to respond to certain design-basis events including normal operation, transients, and postulated accidents.

As part of the SEP, the NRC contracted with the Oak Ridge National Laboratory to perform operating history reviews. These reviews are tended to augment the SEP's safety topic review and to aid in the determination of priorities for required backfitting during the integrated assessment. Each review includes collection and evaluation of availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events.

This summary presents the results from the review of the operating experience of the Oyster Creek Nuclear Power Plant, which is a General-Electric-designed boiling-water reactor, owned and operated by General Public Utilities. The plant is located at Toms River, New Jersey, adjacent to the Oyster Creek inlet of Barnegat Bay on the Atlantic Ocean. The reactor has a licensed thermal power of 1930 MW(t) and a design electric rating of 650 MW(e). Oyster Creek achieved initial criticality on May 3, 1969, and began commercial operation on December 23, 1969.

From 1970 through 1981, the reactor availability factor at Oyster Creek averaged 74.4% and the unit capacity factor averaged 61.4%, both of which were above average for commercial nuclear power plants. Startup tests reduced the values in 1969, but the availability and capacity factors remained high from 1970 through 1979. The figures for 1980 and 1981 were low because of extended refueling and maintenance outages. During these shutdowns, Oyster Creek performed the 10-year code hydrostatic test on the reactor vessel and coolant piping and made TMI modifications.

The operating history review focused on data evaluation which was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design basis events (DBEs), which are defined in the NRC's *Standard Review Plan*,[1] are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that might indicate a potential operating concern. In the reportable event segment which included environmental events and radiological release events, the review identified significant events and recurring events that might indicate a potential operating concern.

Significant events were either DBEs or events with a loss of engineered safety function.

Forced Shutdowns and Power Reductions

Of the 203 forced shutdowns and power reductions between 1969 and 1981 at Oyster Creek, 55 were DBEs of one of the following ten types:

1. turbine trip (15),
2. loss of normal feedwater (9),
3. recirculation pump trip (9),
4. loss of condenser vacuum (7),
5. inadvertent closure of main steam isolation valve (MSIV) (5),
6. pressure regulator failure resulting in decreased steam flow (3),
7. decreased feedwater temperature (2),
8. pressure regulator failure resulting in increased steam flow (2),
9. inadvertent opening of turbine valve (2), and
10. loss of external load (1).

The frequency of occurrence of each type of DBE is consistent with the experience of other plants. In all but one event, the engineered safety features worked properly and brought the unit to a safe shutdown condition.

The one event where engineered safety features failed to work properly occurred on May 2, 1979, when multiple failures resulted in a significant reduction in reactor coolant water inventory to the triple-low level. A testing error during routine surveillance caused a reactor and turbine trip. When power was lost due to the generator trip, the station loads attempted a transfer to offsite power sources. However, one startup transformer was out of service, and no power was available to two of the

three feedwater pumps. The third feedwater pump tripped on low suction pressure and left the reactor without feedwater flow. Operators closed the MSIVs to conserve reactor coolant and placed the isolation condensers in service to remove the latent heat. However, because of a procedural error, the isolation condensers failed to automatically remove the heat, and the water level decreased to the triple-low point. At that point, the operators were able to manually manipulate the isolation condensers and bring the unit to cold shutdown. This event was reported to Congress as an abnormal occurrence.[3]

Reportable Events

In the reportable event segment of the operating history review of Oyster Creek, 494 events were reviewed. The trend for the number of reportable event reports submitted by Oyster Creek is generally upward with peak years of 1974, 1980, and 1981, with 65, 75, and 72 events, respectively. The causes of reportable events have been primarily inherent equipment failures, which contributed 64% of all reported events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) caused 34% of the reported events. Other causes, such as adverse environmental conditions, were responsible for the remaining 2%. There is no apparent trend in the causes of reported events.

Of the 494 reported events, 17 are considered significant:

- o loss of containment integrity (10),
- o decreased reactor coolant inventory (3),
- o loss of containment spray capability (1),
- o reactivity anomaly during startup (1),

- o loss of onsite emergency power coincident with the loss of offsite power (1),
- o blocked suppression chamber vacuum breaker valves (1).

The major contributor to the significant event types was human error, which caused 15 of the 17 significant events. The remaining events were caused by equipment failures (valve failures) and occurred early in Oyster Creek's operating history. Since 1976, the frequency at which significant events have occurred has steadily increased. This increased rate of occurrence is directly related to the increased frequency of containment integrity violations. Disregarding the loss of containment integrity events, there is no apparent trend in the rate of occurrence of significant events.

Only one loss of containment event occurred prior to 1976. In 1972, the reactor building vent dampers failed to close because of a design error in the control logic. Between 1976 and 1981, an additional nine containment integrity losses occurred. Seven of these were due to both doors of airlocks being opened simultaneously. In the remaining two events, the piston rod in a reactor building isolation valve broke while the valve was open and a torus sample valve was left open. Human error was responsible for nine of the ten losses of containment integrity.

Recurring Events

The following six types of recurring events were noted during the two segments of operating history review:

1. MSIV failures,
2. vacuum breaker valve failures,
3. reactor vessel cracks,

4. condenser tube leaks,
5. loss of containment integrity, and
6. outdated or insufficient procedures.

All but two of these event types were identified by Oyster Creek, and corrective measures were undertaken. The two event types that continued to recur were the loss of containment integrity (discussed previously) and outdated or insufficient procedures.

Between 1969 and 1974, Oyster Creek experienced a variety of recurring mechanical problems with the MSIVs, including bent valve stems, packing leaks, and sticking pilot valves. Each problem was corrected by proper equipment modification.

A variety of problems also occurred with the torus-to-reactor-building and torus-to-drywell vacuum breaker valves. The largest contributor to these valve failures was a design error involving the use of a teflon bushing in which the valve hinge pins rotate. The teflon experienced an apparent "growing" characteristic. In 1976, the teflon bushings were replaced with nickel-plated bronze bushings. Since this replacement, the bushing failures have not recurred.

Reactor vessel cracks were noted three times throughout the history of Oyster Creek. Of the total 137 stub tubes, 123 were found cracked during the initial hydrostatic testing in 1967. These material flaws resulted from a number of fabrication and welding problems complicated by a corrosive environment during shipping and cleaning. An extensive repair program included grinding of surface defects, overlaying exposed stub tube surfaces with weld metal cladding, and a complete rework of field welds and shop welds. In 1974, an in-service inspection revealed cracking in

reactor head cladding. However, no cracks propagated into the reactor vessel base material. Later in 1974, a small leak was noted in a field weld between the in-core housing and the vessel lower head. Since repair, no further cracking has been noted.

Condenser tube leakage problems began in 1970. Through 1975, recurring power reductions were necessary to repair or plug leaking tubes. During a shutdown in the first part of 1976, condensers were retubed using welded titanium tubing. With the exception of a limited number of vibration-induced tube failures, these titanium tubes have functioned satisfactorily.

Outdated or insufficient procedures caused or at least complicated 24 of the reported events at Oyster Creek. The number of events averaged one per year between 1971 and 1977. The average increased to four per year between 1978 and 1981. Four of the events between 1978 and 1981 were significant events. The lack of proper procedural guidance for startup under peak xenon conditions directly led to control rod misoperation and high reactivity scram on December 14, 1978. Outdated procedures caused the loss of the isolation condenser system during the triple-low vessel level event on May 2, 1979, described previously. On June 13, 1979, both doors of a personnel penetration were left open because procedures failed to state the correct method for securing the doors. Insufficient procedures led to the declaration of loss of containment spray system on July 16, 1980, when both isolation doors to the containment spray pump compartments were left open.

Conclusions

For this analysis of the operating history at Oyster Creek, 203 shutdowns and power reductions were reviewed, along with 494 reportable events and other miscellaneous documentation concerning the operation of the Oyster Creek Nuclear Power Plant. The objective was to indicate those areas of plant operation that have compromised plant safety. This review identified one significant challenge to plant safety and two problems that should be of continued concern.

The most serious challenge to plant safety occurred on May 2, 1979, when the loss of feedwater and subsequent loss of the isolation condensers resulted in a reduction in reactor coolant to the triple-low level. Plant personnel reacted properly to restore safe conditions and bring the reactor to cold shutdown.

The two areas of operation that should be of continued concern are the losses of containment integrity and the outdated or inadequate procedures. Both of these event types have recurred throughout Oyster Creek's operating history, and both have occurred more frequently during the past few years.

References

1. Nuclear Regulatory Commission, "Accident Analysis for the Review of Safety Analysis Reports for Nuclear Power Plants," Chap. 15 of *Standard Review Plan*, NUREG-0800 (July 1981).
2. Nuclear Regulatory Commission, *Report to Congress on Abnormal Occurrences, April June 1979*, NUREG-0090, Vol. 2, No. 2 (November 1979), pp. 1-6.

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ABSTRACT

A review of the operating experience of the Oyster Creek nuclear power plant from initial criticality through 1981 was performed by the staff of the Nuclear Safety Information Center for the Nuclear Regulatory Commission's Systematic Evaluation Program (SEP). Under the SEP, the safety margins of the design and operation of ten of the older operating commercial nuclear power plants in the United States are being reevaluated.

The review of the operating experience for Oyster Creek included data collection and evaluation of availability and capacity factors, forced shutdowns, power reductions, reportable events (reportable occurrences, licensee event reports, etc.), and environmental considerations. As well, the review methodology and procedures as used in the review and evaluation are discussed. Data and information collected for forced shutdowns, power reductions, and reportable events are presented in Appendixes.

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1. SCOPE OF REVIEW

The assessment of the operating experience review for Oyster Creek covered the time from initial criticality through 1981. The data collection and evaluation included the following aspects of operation: availability and capacity factors, forced shutdowns and power reductions, reportable events, events of environmental importance and radioactivity releases, and evaluation of the operating experience in total. Tables at the end of Chap. 1 show the codes assigned to operational aspects of forced shutdowns, power reductions, and reportable events. These codes are used in the reporting of data collected during the review of operating experience.

1.1 Availability and Capacity Factors

Both reactor and unit availability factors were compiled for all years. Starting with 1974, the unit capacity factors using the design electrical rating (DER) in net megawatts (electric) and the maximum dependable capacity (MDC) in net megawatts (electric) were compiled as well. Data for the capacity factors were not available from earlier years.

The two availability and two capacity factors are defined as follows:

1. reactor availability =

$$\frac{\text{hours reactor critical + reactor reserve shutdown hours}}{\text{period hours}} \times 100 ,$$

2. unit availability =

$$\frac{\text{hours generator on line + unit reserve shutdown hours}}{\text{period hours}} \times 100 ,$$

3. $\text{unit capacity (DER)} = \dfrac{\text{net electrical energy generated}}{\text{period hours x DER net}} \times 100$,

4. $\text{unit capacity (MDC)} = \dfrac{\text{net electrical energy generated}}{\text{period hours x MDC net}} \times 100$.

Reserve shutdown hours are the amounts of time the reactor is not critical or the unit is shutdown for administrative or other similar reasons when operation could have been continued.

1.2 Review of Forced Shutdowns and Power Reductions

Forced shutdowns and power reductions were reviewed, and data were collected on each incident. Scheduled shutdowns for refueling and maintenance were not included in the review. However, if a utility had a refueling outage scheduled, the plant experienced a shutdown as a result of an abnormal event prior to the scheduled refueling, the utility reported that the refueling was being rescheduled to coincide with the current shutdown, and the utility reported the cause of the shutdown as refueling, then this shutdown was considered as forced. Only that portion of the outage time concerned with the abnormal event, not the refueling time, was included in the compilations.

The power reductions were included to provide information and details that may have been associated with a previous or subsequent shutdown. The power reductions are included in the proper chronological sequence with the shutdowns in the data tables for the forced shutdowns and power reductions (see Appendixes).

The following data were compiled annually for the forced shutdowns and power reductions:

1. date of occurrence,
2. duration (hours),
3. power level (percent),
4. notation of whether the shutdowns were also reportable events [e.g., a licensee event report (LER) or abnormal occurrence report (AOR)],
5. summary description of events associated with the forced shutdown or power reduction,
6. cause of shutdown (Table 1.1),
7. method of shutdown (Table 1.1),
8. system taken from NUREG-0161 (Ref. 1) that was directly involved with the shutdown or power reduction (Table 1.2),
9. component directly involved with the shutdown or power reduction (Table 1.3), and
10. categorization of the shutdown or power reduction.

Each shutdown or power reduction was placed in one of two sets of significance categories. The shutdowns and power reductions were first evaluated against criteria for DBEs as described in Chap. 15 of the *Standard Review Plan*.[3] If the shutdown or power reduction could not be categorized as a design-basis initiating event, then it was placed in one of a series of Nuclear Safety Information Center (NSIC) categories. For further discussions of the two sets of significance categories, use of the categories, and a listing of them, see Sect. 3.1.

The listings for the cause, shutdown method, system involved, and component involved along with their respective codes are those used in the NUREG-0020 series[4] ("Gray Books") on shutdowns. Note that the information

listed under the "System involved" column in the data tables in the appendixes indicates (1) a general classification of systems (fully written out) and (2) a specific system, which is coded with two letters, within the general classification.

1.3 Review of Reportable Events

The operating events as reported in LERs and LER predecessors [e.g., AORs, unusual event reports, reportable occurrences (ROs)] were reviewed. These types of reportable events were retrieved from the NSIC computer file. Approximately six years ago, operating experience information for operating nuclear power plants was input to the NSIC file for the period of time before LERs was reviewed. Any documents that contained LER-type information (such as equipment failures or abnormal events) were coded or indexed so that they could be retrieved in the same manner as an LER. Primarily, this involved various types of operating reports and general correspondence for the late 1960s and early 1970s.

The following information was recorded for each reportable event reviewed:

1. LER number or other means of identification of report type,
2. NSIC accession number (a unique identification number assigned to each document entered into the NSIC computer file),
3. date of the event,
4. date of the report or letter transmitting the event description,
5. status of the plant at the time of the occurrence (Table 1.4),
6. system involved with the reportable event (Table 1.2),

7. type of equipment involved with the reportable event (Table 1.5),
8. type of instrument involved with the reportable event (Table 1.5),
9. status of the component (equipment) at the time of the occurrence (Table 1.4),
10. abnormal condition associated with the reportable event (e.g., corrosion, vibration, leak) (Table 1.6),
11. cause of the reportable event (Table 1.4), and
12. significance of the reportable event.

As a step in the evaluation process, each reportable event was screened using the criteria further discussed in Sect. 3.2.

Note that in the tables of reportable events in Appendix A for Oyster Creek, comments and/or details on the events were included.

1.4 Events of Environmental Importance and Releases of Radioactivity

Any significant or recurring environmental problems were summarized based on the review of forced shutdowns, power reductions, reportable events (environmental LERs), and operating reports. Routine radioactivity releases were tabulated as well, and releases where limits were exceeded were reviewed and are discussed in Sect. 4.5.1.5.

1.5 Evaluation of Operating Experience

The operating history of the plants was evaluated based on a review that involved screening, categorizing, and compiling data. Judgments and

conclusions were made regarding safety problems, operations, trends (recurring problems), or potential safety concerns. Events were analyzed to determine their safety significance from the information provided through the various operating reports and the review process. The final safety analysis reports provided specific plant and equipment details when necessary.

Table 1.1. Codes and causes of forced shutdown or power reduction and methods of shutdown

	Causes
A	Equipment failure
B	Maintenance or testing
C	Refueling
D	Regulatory restriction
E	Operator training and license exams
F	Administrative
G	Operational error
H	Other
	Methods
1	Manual
2	Manual scram
3	Automatic scram
4	Continuation
5	Load reduction
9	Other

Table 1.2. Codes and systems involved with the forced shutdown, power reduction, or reportable event

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding system	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG

Table 1.2 (continued)

System	Code
Fuel storage and handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD
Turbine bypass systems and controls	HE
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD

Table 1.2 (continued)

System	Code
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB
Other	XX
Not applicable	ZZ

Table 1.3. Components involved with the forced shutdown or power reduction

Component type	Including
Accumulators	Scram accumulators Safety injection tanks Surge tanks
Air dryers	
Annunciator modules	Alarms Bells Buzzers Claxons Horns Gongs Sirens
Batteries and chargers	Chargers Dry cells Wet cells Storage cells
Blowers	Compressors Gas circulators Fans Ventilators
Circuit closers/interruptors	Circuit breakers Contactors Controllers Starters Switches (other than sensors) Switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Bus Cable Wire
Engines, internal combustion	Butane engines Diesel engines Gasoline engines Natural gas engines Propane engines
Filters	Strainers Screens
Fuel elements	
Generators	Inverters
Heaters, electric	

Table 1.3 (continued)

Component type	Including
Heat exchangers	Condensers Coolers Evaporators Regenerative heat exchangers Steam generators Fan coil units
Instrumentation and controls	
Mechanical function units	Mechanical controllers Governors Gear boxes Varidrives Couplings
Motors	Electric motors Hydraulic motors Pneumatic (air) motors Servo motors
Penetrations, primary containment air locks	
Pipes, fittings	
Pumps	
Recombiners	
Relays	
Shock suppressors and supports	
Transformers	
Turbines	Steam turbines Gas turbines Hydro turbines
Valves	Valves
Valve operators	
Vessels, pressure	Containment vessels Dry wells Pressure suppression Pressurizers Reactor vessels

Table 1.4. Codes for data collected on plant status, component status, and cause of reportable events

Code	Plant status	Component status	Cause of reportable event
A	Construction	Maintenance and repair	Administrative error
B	Operation	Operation	Design error
C	Refueling	Testing	Fabrication error
D	Shutdown		Inherent error
E			Installation error
F			Lightning
G			Maintenance error
H			Operation error
I			Weather

Table 1.5. Codes for equipment and instruments involved in reportable events

Code		Code	
	Equipment		
A	Accumulator	W	Internal combustion engine
B	Air drier	X	Motor
C	Battery and charger	Y	Nozzle
D	Bearing	Z	Pipe and pipe fitting
E	Blower and dampers	AA	Power supply
F	Breaker	BB	Pressure vessel
G	Cables and connectors	CC	Pressurizer
H	Condenser	DD	Pump
I	Control rod	EE	Recombiner
J	Control rod drive	FF	Seal
K	Cooling tower	GG	Shock absorber
L	Crane	HH	Solenoid
M	Demineralizer	II	Steam generator
N	Diesel generator	JJ	Storage container
O	Fastener	KK	Support structure
P	Filter/screen	LL	Transformer
Q	Flange	MM	Tubing
R	Fuel element	NN	Turbine
S	Fuse	OO	Valve
T	Generator	PP	Valve, check
U	Heat exchanger	QQ	Valve operator
V	Heater		
	Instrumentation		
A	Alarm	L	Power range instrument
B	Amplifier	M	Pressure sensor
C	Electronic function unit	N	Radiation monitor
D	Failed fuel detection instrument	O	Recorder
E	Flow sensor	P	Relay
F	In-core instrument	Q	Seismic instrument
G	Indicator	R	Solid state device
H	Intermediate range instrument	S	Start-up range instrument
I	Level sensor	T	Switch
J	Meteorological instrument	U	Temperature sensor
K	Position instrument		

Table 1.6. Codes used for reportable events—abnormal conditions

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Mechanical

AA Normal wear/aging/end of life: expected effect of normal usage

AB Excessive wear/clearance: component (especially a moving component) experiences excessive wear or too much clearance or gap exists because of overuse, lack of lubrication

AC Deterioration/damage: component is no longer at an acceptable level of quality (e.g., high temperature causes rubber seals to chemically break down or deteriorate, insulation breaks down)

AD Break/shear: structural component physically breaks apart (not when something "breaks down")

AE Warp/bend/deformation: shape of component is physically distorted

AF Collapse: tank or compartment has an external pressure exerted that results in deformation

AG Seize/bind/jam: component has inhibited movement caused by crud, foreign material, mechanical bonding, another component

AH Excessive mechanical loads: mechanical load exceeds design limits

AI Mechanical fatigue: failure due to repeated stress

AJ Impact: the result of the force of one object striking another

AK Improper lubrication: insufficient or incorrect lubrication

AL Missing/loose: component is missing from its proper place or is loose or has undesired free movement

AM Wrong part: incorrect component installed in a piece of equipment

AN Wrong material: incorrect material used during fabrication or installation

AO Weld-related failure: failure caused by defective weld or located in the heat-affected zone

AP Vibration other than flow induced: vibration from any cause other than fluid flow

AQ Crud buildup: buildup of foreign material such as dust, sticks, trash (not corrosion or boron precipitation)

AR Corrosion/oxidation: unanticipated attack

AS Dropped: component is dropped (includes control rod that is "dropped" into core)

AT Leak, internal, within system: leak from one part of a system to another part of the same system

AU Leak, internal, between systems: leak from one system to a different system

AV Crack: defect in a component does not result in a leak through the wall

Table 1.6 (continued)

AW	Leak, external: defect in a component results in a leak from the system that is contained in an onsite building
AX	Leak to environment: leak not resulting from a cracked or broken component
AY	Was opened/transfers open: component is/was opened by error or spuriously opens
AZ	Was closed/transferred closed: component is/was wrongly closed by error or spuriously closes
BA	Fails to open: component is in the closed state <u>and</u> fails to open on demand (e.g., the circuit breaker "fails to open" when an overcurrent occurs)
BB	Fails to close: component is in the open state <u>and</u> fails to close on demand
BC	Malposition or maladjustment: component is out of desired position (e.g., normally open valve is closed) or adjusted improperly (not for instrument drift or out of calibration)
BD	Failure to start/turn on: component fails to start on demand
BE	Stopped/failed to continue to run: component fails to continue running when it has previously started
BF	Tripped: component <u>automatically</u> trips on or off (desired or undesired) (e.g., the turbine tripped because of overspeed, the circuit breaker tripped because of overspeed, or the circuit breaker tripped because of overload)
BG	Deenergized/power removed: component on system loses its driving potential but not necessarily electrical power [e.g., (1) a fuse blows and there is no power to a sensor, and the sensor is deenergized; (2) a valve closes off the steam supply to a turbine, and the turbine has no driving power]
BH	Energized/power applied: component or system gains its driving potential but not necessarily electrical power (e.g., valve is opened allowing steam to turn a turbine)
BI	Unacceptable response time: component does not respond to a demand within a desired time frame but does not otherwise fail (e.g., a diesel generator fails to come to full speed within the time constraint)
BJ	High pressure: higher than normal or desired pressure exists in a component or system (<u>does not</u> include instrument misindications)

Table 1.6 (continued)

BK	Low pressure: lower than normal or desired pressure exists in a component or system (<u>does not</u> include instrument misindication)
BL	High temperature: component experiences a higher than normal or desired temperature
BM	Low temperature: component (or system) experiences a lower than normal or desired temperature
BN	Freezing: fluid medium (e.g., water) freezes in or on a component
BO	Excessive thermal cycling: frequent changes in temperature that could result in metal fatigue or cracking
BP	Unacceptable heatup/cooldown rate: heatup or cooldown rate exceeds limits
BQ	Thermal transient: system experiences an undesired or unstable thermal transient or thermal change
BR	Excessive number of pressure cycles: system experiences an undesired number of significant pressure changes (e.g., pressure pulses as from a positive displacement pump)
BS	High level/volume: higher than normal or desired level or volume exists (actual or potential) in a component, such as tank or sump, or area, such as auxiliary building (not for instrument misindication)
BT	Low level/volume: lower than normal or desired level or volume exists in a component (not for instrument misindication)
BU	Abnormal concentration/pH: an abnormal (either high or low) concentration of a chemical or reagent exists in a fluid system or an abnormal pH exists (does not include abnormal boron concentrations)
BV	Abnormal boron concentration: process system control rod has an abnormal boron concentration from burnup, dilution, or overaddition
BW	Overspeed: speed in excess of design limits
BX	Cladding failure: cladding of a component fails (e.g., the cladding of a fuel pellet is breached, and radioactive fuel leaks out)
BY	Burning/smoking: component is on fire or smoking
BZ	Engaged: component engages or meshes (this is not to be used when a component binds or becomes stuck or jammed)
CA	Disengaged/uncoupled: component disengages, loses required friction, or is no longer meshed (as in gears); for example, the clutch on the motor disengages from the shaft (this should not be used for dropped control rods)

Table 1.6 (continued)

Electric/instruments

EA Excessive electrical loads: electrical loads exceed design rating

EB Overvoltage/undercurrent: component failure produces an over-voltage/undercurrent condition other than open circuits

EC Undervoltage/overcurrent: component failure produces an under-voltage/overcurrent condition other than shorts

ED Short circuit/arcing/low impedance: electrical component shorts or arcs in the circuit or has a low impedance including shorts to ground

EE Open circuit/high impedance/bad electrical contact: electrical component has a structural break, or electrical contacts fail to contact and fail to pass the desired current

EF Erratic operation: component (especially electrical or instrument) behaves erratically or inconsistently (if an instrument produces a bad but constant signal, use "EG"; if an instrument produces an inconsistent signal use "EF")

EG Erroneous/no signal: electrical component or instrument produces an erroneous signal or gives no signal at all (not for out-of-calibration error)

EH Drift: a change in a setting caused by aging or change of physical characteristics (does not include personnel errors or a physical shift of a component)

EI Out of calibration: component (particularly instruments) become out of adjustment or calibration (does not include drift)

EJ Electromagnetic interference: abnormal indication or action resulting from unanticipated electromagnetic field

EK Instrument snubbing: dampening of pulsating signals to an instrument

Hydraulic

HA High flow: higher than normal or desired flow exists in a component/system (does not include instrument misindication (see code EG)

HB Low flow: lower than normal or desired flow exists in a component/system (does not include instrument misindication)

HC No flow or impulse: fluid flowing through a pipe, filter, orifice, or trench or the fluid in an impulse line (e.g., instrument sensing line) is blocked completely or decreased due to some foreign material, crud, closed (either partially or completely) valve or damper, or insufficient flow area

Table 1.6 (continued)

HD	Flow induced vibration
HE	Cavitation
HF	Erosion
HG	Vortex formation
HH	Water hammer
HI	Pressure pulse/surge
HJ	Air/steam binding
HK	Loss of pump section
HL	Boron precipitation
	Other
OA	Declared inoperable: component or system is declared inoperable as required by Technical Specifications but may be capable of partially or completely performing its desired duties when requested (a component/system that is completely failed should not use this code)
OB	Flux anomaly: flux characteristics of the reactor core are not as required or desired (e.g., flux spike due to xenon burnout)
OC	Test not performed: operator or test personnel fails to perform a required test within the required period
OD	Radioactivity contamination: component, system, or area becomes more radioactive than desired or expected
OE	Temporary modification: an installation intended for short term use (usually this is for maintenance or modification of installed equipment)
OF	Environmental anomaly
OG	Airborne release
OH	Waterborne release
OI	Operator communication
OJ	Operator incorrect action
OK	Procedure or record error

2. SOURCES OF INFORMATION

Several sources of information including periodic (annual, quarterly, and monthly) NRC publications were used in the review. Some sources contained information relative to more than one area within the scope of the review.

2.1 Availability and Capacity Factors

The availability and capacity factors were either extracted or calculated from data given in the Gray Books[3] from 1974 through 1981 (the first Gray Book was issued in May 1974). Prior to 1974, annual or semiannual reports were used to compile availability factors only.

2.2 Forced Reactor Shutdowns and Power Reductions

Review of the forced power reductions involved checking the following sources for accuracy and completeness of details.

1. *Nuclear Power Plant Operating Experience for 19XX*, for the years 1973-1979 (Refs. 4-11). The report for 1981 has not been published. However, because work on the section on outages in these reports has been performed by NSIC since 1973, the draft copy of this report for 1981 was available.
2. NUREG-0020 series[3] (Gray Books).
3. Annual or semiannual reports of the Oyster Creek plant from the time of startup through 1977. For 1977 through 1981, monthly operating reports were used because the utilities were no longer required to file annual reports. The review of power reductions involved primarily the annual, semiannual, and monthly reports.

2.3 Reportable Events

The NSIC computer file of LERs was the primary source of information in reviewing reportable events. Material on the NSIC computer file consists of the appropriate bibliographic material, title, 100-word abstract, and keywords. When additional information on the event was needed, the original LER (or equivalent) was consulted by examining (1) those full-sized copies on file at NSIC (for the years 1976–1981); (2) the microfiche file of docket material at NSIC; or (3) the appropriate operating report (semiannual, annual, or monthly).

Two computer files on RECON (a computer retrieval system containing ~40 data bases operated at ORNL) were used extensively. Printouts were obtained from the files for Oyster Creek to provide coverage on many types of "docket material", including reportable events, where the licensee may have been in correspondence with NRC [or the Atomic Energy Commission (AEC)] concerning a particular event. Licensees are often requested to submit additional information or perform further analysis. Before the LERs came into existence in the mid-1970s, it was not unusual for licensees to submit, on their own or at the request of NRC or AEC, more than one letter transmitting information on a particular event. Thus, these printouts provided additional sources of information on reportable events.

Several special publications were reviewed to provide details on events of significance. After further analyses and examination of the following publications, details, evaluations, or assessments could be found other than those provided in the appropriate NRC-requested transmission.

1. *Reports to Congress on Abnormal Occurrences*, NUREG-0090 series[11];
2. "Power Reactor Event Series" (formerly Current Event Series) published bimonthly by NRC;
3. "Operating Experiences," a section of each issue of the *Nuclear Safety* journal; and
4. the publications of NRC's Office of Inspection and Enforcement (IE), such as operating experience bulletins, IE bulletions, IE circulars, and IE information notices.

2.4 Environmental Events and Releases of Radioactivity

Events of environmental importance were obtained as a result of conducting the overall review of the plant's operating history, and the sources of information involve all types of documents listed thus far.

The data for radioactivity releases were compiled primarily from *Radioactive Materials Released from Nuclear Power Plants - Annual Report 1977* (Ref. 13). This report presents year-by-year comparisons for plants in a number of different categories (such as solid, gas, liquid, noble gas, and tritium). Data for 1978 were taken from *Radioactive Materials Released from Nuclear Power Plants - Annual Report 1978* (Ref. 14). Data for 1979, 1980, and 1981 were compiled from the annual environmental reports submitted by Oyster Creek.

3. TECHNICAL APPROACH FOR EVALUATIONS OF OPERATING HISTORY

Forced shutdowns (and power reductions) and reportable events were the two areas focused on in the evaluation of the operating history of Oyster Creek. Given the large number of both forced shutdowns and reportable events, it was necessary to develop consistent review procedures that involved screening and categorizing of both occurrences. After the events were screened and categorized, the study then assessed the safety significance of the events and analyzed the categories of events for various trends and recurring problems.

The approach in evaluation of operational events (forced shutdowns and reportable occurrences) consisted primarily of a three-step process: (1) compilation of information on the events, (2) screening of the events for significance using selected criteria and guidelines, and (3) evaluation of the significance and importance of the events from a safety standpoint. The evaluations were to determine those areas where safety problems existed in terms of systems, equipment, procedures, and human error.

Shutdowns were evaluated against the DBEs found in Chap. 15 of the *Standard Review Plan*.[3] The DBEs are those postulated disturbances in process variables or postulated malfunctions or failures of equipment that the plants are designed to withstand and that licensees analyze and include in safety analysis reports (SARs). The SAR provides the opportunity for the effects of anticipated process disturbances and postulated component failures to be examined to determine their consequences and to

evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance).

The intent is to organize the transients and accidents considered by the licensee and presented in the SAR in a manner that will:

1. ensure that a sufficiently broad spectrum of initiating events has been considered,
2. categorize the initiating events by type and expected frequency of occurrence so that only the limiting cases in each group need to be quantitatively analyzed, and
3. permit the consistent application of specific acceptance criteria for each postulated initiating event.

Each postulated initiating event is to be assigned to one of the following categories:

1. increase in heat removal by the turbine plant,
2. decrease in heat removal by the turbine plant,
3. decrease in reactor coolant system flow rate,
4. anomalies in reactivity and power distribution,
5. increase in reactor coolant inventory,
6. decrease in reactor coolant inventory,
7. radioactive release from a subsystem or component, or
8. anticipated transients without scram.

Those shutdowns identified as design-basis initiating events were categorized as such. If the shutdown was not a DBE, then it was assigned a category from a list developed by NSIC to indicate the nature and type of error or failure. The NSIC categories for shutdowns not caused by DBEs were examined as part of a trends analysis.

Reportable events were screened using the criteria presented in Sect. 3.2 and were categorized according to their significance. The information collected on the reportable events was used to analyze trends for all reportable events, both significant and not significant.

3.1 Significant Shutdowns and Power Reductions

For the purposes of compiling information and evaluation, power reductions were treated in the same manner as forced shutdowns.

3.1.1 Criteria for significant shutdowns and power reductions

As indicated previously, the occurrences identified as DBEs were used as criteria to categorize and note significant shutdowns. These events are listed in Table 3.1 at the end of Sect. 3 as they are found in Chap. 15 of the *Standard Review Plan*.[3]

3.1.2 Use of criteria for determining significant shutdowns and power reductions

Generic design-basis initiating events such as "increase in heat removal by the secondary system" or "decrease in reactor coolant system flow rate," were used as primary flags for reviewing the forced shutdowns (and power reductions). Once the generic type of event was identified, the particular initiating event was determined from the details associated with the shutdown. For example, if the reactor shuts down because of an increase in heat removal because a feedwater regulator valve failed open,

the shutdown is a generic type 1 DBE. Specifically, based on the initiating event (valve failed open), it is a 1.2 DBE - "feedwater system malfunction that results in an increase in feedwater flow." Some shutdowns were readily identifiable as specific DBEs, such as tripping of a main coolant pump, a 3.1 DBE. Once categorized as a DBE, the shutdown was considered significant regardless of the resulting effect on the plant (because a DBE had been initiated).

Loss of flow from one feedwater loop was considered sufficient to qualify as a 2.7 DBE - "loss of normal feedwater flow." The closure of a main steam isolation valve in one loop was considered sufficient to qualify as a 2.4 DBE - "inadvertent closure of main steam isolation valves."

3.1.3 Non-DBE shutdown and power reduction categorization

Those shutdowns that were not DBEs were assigned NSIC categories (Table 3.2) to provide more information on the failure or error associated with the shutdown. With these categories, more specific types of errors and failures could be examined through tabular summaries to focus the reviewer's attention on problem areas (safety related or not) that were not revealed by the DBE categories.

The causes (Table 1.1) for non-DBE shutdowns taken from the Gray Books are limited and very general, while NSIC cause categories are more specific. Thus, as an example, the number of Gray Book causes noted as equipment failure should not be expected to equal those identified as equipment failures with the NSIC categories. Other NSIC categories, such as component failure, could be classified as an equipment failure if the only available designations for cause were those listed in the Gray Books.

3.2 Significant Reportable Events

3.2.1 Criteria for significant reportable events

Two groups of criteria were used in determining significant reportable events. The first set of criteria (Table 3.3) indicates those events that are definitely significant in terms of safety; they are termed significant. The second set of criteria (Table 3.4) indicates events that may be of potential concern. These events, which might require additional information or evaluation to determine their full implication, were noted as conditionally significant.

3.2.2 Use of criteria for determining significant reportable events

The reportable events were all reviewed, applying the two sets of criteria for significance rather liberally. A number of significant events and conditionally significant events were noted. The events initially identified as significant or conditionally significant were analyzed and evaluated further based on (1) engineering judgment; (2) the systems, equipment, or components involved; or (3) whether the safety of the plant was compromised. The conditionally significant events were subsequently "upgraded" to significant or "downgraded" to nonsignificant. Thus, no events in the tables in the Appendix appear as having been categorized as conditionally significant. The final evaluation for significance considered whether a DBE was initiated or whether a safety function was compromised so that the system as designed could not mitigate the progression of events. Thus, the number of events finally categorized as significant was reduced considerably by these steps in the review process.

3.2.3 Reportable events that were not significant

Those reportable events not identified as significant or conditionally significant were categorized as not significant (with an 'N' in the significance column of the coding sheets in the appendixes). These events and the events rejected during the additional review step were further reviewed by compiling a tabular summary of the systems to detect trends and recurring problems (Table 1.4 provides a listing of the systems).

Table 3.1. Initiating event descriptions for DBEs as listed in Chap. 15, *Standard Review Plan* (Revision 3)

---

1. Increase in heat removal by the secondary system
   - 1.1 Feedwater system malfunction that results in a decrease in feedwater temperature
   - 1.2 Feedwater system malfunction that results in an increase in feedwater flow
   - 1.3 Steam pressure regulator malfunction or failure that results in increasing steam flow
   - 1.4 Inadvertent opening of a steam generator relief or safety valve
   - 1.5 Spectrum of steam system piping failures inside and outside of containment in a pressurized-water reactor (PWR)
   - 1.6 Startup of idle recirculation pump[a]
   - 1.7 Inadvertent opening of bypass resulting in increase in steam flow[a]

2. Decrease in heat removal by the secondary system
   - 2.1 Steam pressure regulator malfunction or failure that results in decreasing steam flow
   - 2.2 Loss of external electric load
   - 2.3 Turbine trip (stop valve closure)
   - 2.4 Inadvertent closure of main steam isolation valves
   - 2.5 Loss of condenser vacuum
   - 2.6 Coincident loss of onsite and external (offsite) ac power to the station
   - 2.7 Loss of normal feedwater flow
   - 2.8 Feedwater piping break
   - 2.9 Feedwater system malfunctions that result in an increase in feedwater temperature[a]

3. Decrease in reactor coolant system flow rate
   - 3.1 Single and multiple reactor coolant pump trips
   - 3.2 Boiling-water reactor (BWR) recirculation loop controller malfunction that results in decreasing flow rate
   - 3.3 Reactor coolant pump shaft seizure
   - 3.4 Reactor coolant pump shaft break

4. Reactivity and power distribution anomalies
   - 4.1 Uncontrolled control rod assembly withdrawal from a subcritical or low-power start-up condition (assuming the most unfavorable reactivity conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling
   - 4.2 Uncontrolled control rod assembly withdrawal at the particular power level (assuming the most unfavorable reactivity conditions of the core and reactor coolant system) that yields the most severe results (low power to full power)
   - 4.3 Control rod maloperation (system malfunction or operator error), including maloperation of part length control rods

Table 3.1 (continued)

4.4 Start-up of an inactive reactor coolant loop or recirculating loop at an incorrect temperature.
4.5 A malfunction or failure of the flow controller in a BWR loop that results in an increased reactor coolant flow rate
4.6 Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant of a PWR
4.7 Inadvertent loading and operation of a fuel assembly in an improper position
4.8 Spectrum of rod ejection accidents in a PWR
4.9 Spectrum of rod drop accidents in a BWR

5. Increase in reactor coolant inventory

5.1 Inadvertent operation of emergency core cooling system during power operation.
5.2 Chemical and volume control system malfunction (or operator error) that increases reactor coolant inventory
5.3 A number of BWR transients, including items 1.2 and 2.1–2.6

6. Decrease in reactor coolant inventory

6.1 Inadvertent opening of a pressurizer safety or relief valve in either a PWR or a BWR
6.2 Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment
6.3 Steam generator tube failure
6.4 Spectrum of BWR steam system piping failures outside of containment
6.5 Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary, including steam line breaks inside of containment in a BWR
6.6 A number of BWR transients, including items 1.3, 2.7, and 2.8

7. Radioactive release from a subsystem or component

7.1 Radioactive gas waste system leak or failure
7.2 Radioactive liquid waste system leak or failure
7.3 Postulated radioactive releases due to liquid tank failures
7.4 Design basis fuel handling accidents in the containment and spent fuel storage buildings
7.5 Spent fuel cask drop accidents

8. Anticipated transients without scram

8.1 Inadvertent control rod withdrawal
8.2 Loss of feedwater
8.3 Loss of ac power
8.4 Loss of electrical load
8.5 Loss of condenser vacuum
8.6 Turbine trip
8.7 Closure of main steam line isolation valves

[a]These initiating events were added for BWRs to be more specific than DBE events 5.3 and 6.6.

Table 3.2. NSIC event categories for non-DBE shutdowns

- N 1.0 Equipment failure
  - N 1.1 Failure on demand under operating conditions
    - N 1.1.1 Design error
    - N 1.1.2 Fabrication error
    - N 1.1.3 Installation error
    - N 1.1.4 End of design life/inherent failure/random failure
  - N 1.2 Failure on demand under test conditions
    - N 1.2.1 Design error
    - N 1.2.2 Fabrication error
    - N 1.2.3 Installation error
    - N 1.2.4 End of design life/inherent failure/random failure
- N 2.0 Instrumentation and control anomalies
  - N 2.1 Hardware failure
  - N 2.2 Power supply problem
  - N 2.3 Setpoint drift
  - N 2.4 Spurious signal
  - N 2.5 Design inadequacy (system required to function outside design specifications
- N 3.0 Non-DBE reductions in coolant inventory (leaks)
  - N 3.1 In primary system
  - N 3.2 In secondary system and auxiliaries
- N 4.0 Fuel/cladding failure (densification, swelling, failed fuel elements as indicated by elevated coolant activity)
- N 5.0 Maintenance error
  - N 5.1 Failure to repair component/equipment/system
  - N 5.2 Calibration error
- N 6.0 Operator error
  - N 6.1 Incorrect action (based on correct understanding on the part of the operator and proper procedures, the operator turned the wrong switch or valve — incorrect action)
  - N 6.2 Action on misunderstanding (based on proper procedures and improper understanding or misinterpretation on the operator's part of what was to be done — incorrect action)
  - N 6.3 Inadvertent action (purpose and action not related, for example, bumping against a switch or instrument cabinet)
- N 7.0 Procedural/administrative error (incorrect operating or testing procedures, incorrect analysis of an event — failure to consider certain conditions in analysis)
- N 8.0 Regulatory restriction
  - N 8.1 Notice of generic event
  - N 8.2 Notice of violation
  - N 8.3 Backfit/reanalysis

Table 3.2 (continued)

N 9.0	External events
	N 9.1 Human induced (sabotage, plane crashes into transformer)
	N 9.2 Environment induced (tornado, severe weather, floods, earthquake)
N 10.0	Environmental operating constraint as set forth in Technical Specifications

Table 3.3. Reportable event criteria — significant

Category of significance	Event description
S1	Two or more failures occur in redundant systems during the same event
S2	Two or more failures due to a common cause occur during the same event
S3	Three or more failures occur during the same event
S4	Component failures occur that would have easily escaped detection by testing or examination
S5	An event proceeds in a way significantly different from what would be expected
S6	An event or operating condition occurs that is not enveloped by the plant design bases
S7	An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
S8	Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
S9	Other (explain)

Table 3.4. Reportable event criteria — conditionally significant

Category of conditional significance	Event description
C1	A single failure occurs in a nonredundant system
C2	Two apparently unrelated failures occur during the same event
C3	A problem results in an offsite radiation release or exposure to personnel
C4	A design or manufacturing deficiency is identified as the cause of a failure or potential failure
C5	A problem results in a long outage or major equipment damage
C6	An engineering safety feature actuation occurs during an event
C7	A particular occurrence is recognized as having a significant recurrence rate
C8	Other (explain)

4. OPERATING EXPERIENCE REVIEW OF OYSTER CREEK

4.1 Summary of Operational Events of Safety Importance

This study reviewed the operational history of Oyster Creek to indicate those areas of plant performance that have compromised plant safety. The review included a detailed evaluation of plant shutdowns, power reductions, and reportable events. The criteria used to indicate potential degradations in plant safety were

(1) events that initiated a design basis event (DBE), and

(2) events that compromised safety functions designed to mitigate the propagation of DBE initiating events.

Shutdowns, power reductions, and reportable events indicated the number and types of DBEs entered and the number of times each engineered safety function was compromised. The results of the shutdown and power reduction analysis identified fifty-five DBEs entered. Additionally, the reportable event analysis indicated seventeen events in which loss of safety system function or DBE occurred.

4.2 General Plant Description

Oyster Creek Nuclear Power Plant is a General Electric boiling water reactor owned and operated by General Public Utilities Nuclear Corporation. It is located at Toms River, New Jersey, adjacent to the Oyster Creek inlet of Barnegat Bay on the Atlantic Ocean. The population within 30 miles of the plant is 460,000. Trenton, New Jersey is 41 miles from Oyster Creek and Camden, New Jersey is 49 miles away. There are nine cities and a population of 3,300,000 within a 50 mile radius.

The reactor has a licensed thermal power of 1930 MWt and a design electric rating of 650 MWe. Initial criticality was achieved on May 3, 1969 with the head off the reactor vessel. The turbine generator was first synchronized to the transmission system on September 23, 1969, and commercial operation began on December 23, 1969.

4.3 Availability and Capacity Factors

Table 4.1 presents the Oyster Creek availability and capacity factors [reactor availability, unit availability, unit capacity using the maximum dependable capacity (MDC) and unit capacity using the design electric rating (DER)]. The average reactor availability was 74.4% and the average unit availability was 72.3% for the years from 1970 to 1981. The MDC and DER capacity factors for the eleven years averaged 65.7% and 61.4% respectively.

The availability and capacity factors remained high from 1970 through 1979. Startup tests reduced reactor and unit availability in 1969 while the figures for 1980 were low because of an extended refueling and maintenance outage during the first half of the year. During this shutdown, Oyster Creek performed the 10-year code hydrostatic test on the reactor vessel and coolant piping. The availability and capacity factors were low for 1981 due to extended maintenance outages dealing with 1) TMI modifications, 2) failure of tubes in two shutdown cooling heat exchangers, and 3) operability problems with the isolation condenser system.

Table 4.1. Oyster Creek availability and capacity factors

	1969[a]	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Avg.
Reactor availability	33.5	80.8	82.1	82.4	74.2	72.2	75.5	80.0	71.2	75.5	87.0	43.2	63.3	74.4
Unit availability	18.3	77.0	80.4	81.3	73.1	70.4	73.3	79.3	70.1	74.3	85.9	41.7	59.8	72.3
Unit capacity (MDC)[b]	9.3	63.6	70.4	80.0	66.0	67.6	57.9	70.9	59.8	67.1	84.0	35.9	48.4	65.7
Unit capacity (DER)[c]	8.8	60.7	67.2	76.3	63.0	64.5	55.2	67.6	57.0	64.0	80.1	34.3	46.2	61.4

[a]From initial criticality.

[b]Maximum dependable capacity (620 MWe).

[c]Design electrical rating (650 MWe).

4.4 Review of Forced Reactor Shutdowns and Forced Power Reductions

From startup in May 1969 through December 31, 1981, Oyster Creek experienced 109 forced shutdowns and ninety-four forced power reductions. Appendix A.1 presents a compilation of data describing each shutdown or power reduction. The consequence of some of these events was solely the inability to produce power. However, many of the events have safety implications. Some of the shutdowns were design basis events (DBEs). DBEs are postulated failure events which result in system transients, challenging one or more safety systems. Because they challenge safety systems and are the initiating events in postulated accident sequences, DBEs warrant special attention.

4.4.1 Forced reactor shutdowns

Table 4.2 summarizes the forced shutdowns which occurred at Oyster Creek. Sixty-four of the 109 shutdowns were caused by equipment failures, three-fourths of which were associated with the reactor coolant and connected systems. Human errors accounted for forty-two shutdowns including twenty-one operational errors and twenty-one maintenance and testing errors. The remaining shutdowns resulted from operator training exams and a lightning strike. Most of the difficulties which caused the shutdowns resulted in automatic scrams.

4.4.2 Forced power reductions

As indicated in Table 4.3, there were ninety-four forced power reductions. Most of these were due to equipment failures. As with forced shutdowns, many of the power reductions (42%) were associated with the

Table 4.2. Oyster Creek forced shutdown summary

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Total number	20	18	3	11	8	6	9	4	3	5	7	5	10	109
Cause														
A. Equipment failure	9	14	3	6	7	5	5	3		3	2	5	2	64
B. Maintenance or testing	4	3		1	1		2		1	2	1		6	21
D. Regulatory restriction													1	1
E. Operator training/exam	1													1
G. Operational error	6	1		4			2	1	2		4		1	21
H. Other						1								1
Shutdown method														
1. Manual		1	2	1	1	3	4	2		2	2	4	7	29
2. Manual scram	1	3	1				1			1				7
3. Automatic scram	19	14		10	7	3	4	2	3	2	5	1	2	72
4. Continuation					1			1					1	3
DBE shutdowns	12	11		8	5	2	5	1	3	2	5		2	56
System involved														
1. Reactivity control (RB)		1												1
2. Coolant recirculation (CB)	1	2		1				1			3		1	9
3. Main steam (CC)	4	4		4	2				1					15
4. Main steam isolation (CD)									1	1			1	3
5. Reactor core isolation cooling (CE)											1		1	2
6. Reactor coolant cleanup (CG)				1			1			1	1			4
7. Feedwater (CH)	2				2	3	1	2		2	1	2		15
8. Containment (SA)		1				2								3
9. Containment heat removal (SB)							1							1
10. Containment combustible control (SE)												1		1
11. Reactor trip (IA)	7	2		4	1							1		15
12. Engineered safety feature instruments (IB)											1			1
13. Offsite power (EA)					1	1								2
14. DC onsite power (EC)		1					1							2
15. Service water (WA)		2	2										1	5
16. Compressed air (PA)			1											1
17. Turbine-generator (HA)	5	4			1		1	1	1				1	14
18. Main condenser (HC)	1	1					3						3	8
19. Liquid rad waste (MA)				1			1			1				3
20. Gaseous rad waste (MB)												1	1	2
21. Other (XX)					1									1
22. Unknown (ZZ)													2	2

Table 4.3. Oyster Creek forced power reduction summary

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Total number	1	4	10	15	9	15	4	6		2	16	9	3	94
Cause														
A. Equipment failure	1	4	9	12	7	15	3	5		1	16	9	2	84
B. Maintenance or testing				2	1			1		1				5
F. Administrative			1		1								1	3
G. Operational error				1			1							2
System involved														
1. Reactivity control (RB)			1		2									3
2. Coolant recirculation (CB)			5	3	1			1			5			15
3. Isolation condenser (CE)			1											1
4. Main steam (CC)					2			1			3	2		8
5. Reactor core cleanup (CG)	1													1
6. Feedwater (CH)				5	2	2	1				2	2	1	15
7. Containment (SA)												1		1
8. Reactor trip (IA)											1			1
9. Engineered safety features instruments (IB)				1										1
10. Onsite DC power (EC)				2			1							3
11. Service water (WA)										1				1
12. Process sampling (PB)												1		1
13. HVAC (AA)			1											1
14. Turbine-generator (HA)		3	1	3	1						1			9
15. Main condenser (HC)		1	1	1	1	13	1	1		1	3	1	2	26
16. Turbine gland seal (HD)							1							1
17. Circulating water (HF)								1			1			2
18. Condensate cleanup (HG)												1		1
19. Liquid rad waste (MA)								1				1		2
20. Gaseous rad waste (MB)								1						1

reactor coolant system and connected systems. Another 42% of the forced power reductions involved the steam and power conversion systems. Most of the steam system power reductions were due to the continuing problems with condenser tube leakage.

4.4.3 Yearly summaries of forced shutdowns and forced power reductions

The following is a discussion of shutdowns, power reductions, and other significant events for each year 1969 through 1981.

1969

Oyster Creek went critical at 2:17 p.m. on May 3, 1969, and the turbine generator was first synchronized to the transmission system on September 23, 1969. Full power was achieved on December 7, 1969. In 1969 there were twenty forced shutdowns, nine of which were due to equipment failures, four were caused by maintenance and testing, one was due to operator training, and six were due to operational errors. The single forced power reductions resulted from equipment failure. Planned unit shutdowns occurred on numerous occasions as a result of the startup and power ascension programs.

Pressure reducing valve problems persisted in the reactor clean-up system. A design change was necessary due to abnormal vibration and subsequent leakage of the non-regenerative heat exchanger tubes.

The turbine drain system did not work and a temporary drain system was installed. The moisture separator and reheater drain tank-flash tank system required many adjustments and drain valve modifications. Additional problems associated with the drain system were in tuning up the mechanical pressure regulator (MPR) and electrical pressure regulator (EPR).

The 'D' recirculating pump failed to start on August 5, 1969, and was returned to the manufacturer for repair. Examination indicated failure of the shaft axial bearing and severe galling in the area of the auxiliary impeller and the thermal barrier. Foreign material was found in the pump seal area. The source of the material was not determined.

1970

Eighteen forced shutdowns occurred in 1970. Fourteen forced shutdowns were due to equipment failures, three were caused by maintenance and testing, and one was due to operational errors. There were four forced power reductions. All four power reductions were caused by equipment failure.

On December 2, 1970, the AEC issued Amendment No. 2 to the Oyster Creek Provisional Operating Licence increasing the maximum licensed power from 1600 to 1690 MWt. The unit operated at or near this full power for most of the year.

Three major outages limited Oyster Creek power production during 1970. Tests and minor repairs of the four main steam valves to assure conformance with the technical performance leak rates were performed during the period from January 31 to February 12. In the second major shutdown of the year, the plant was shut down to inspect the control rod drives because of large seal leakage. Inspection and repairs lasted from April 19 to May 21. The third extended shutdown (from October 16 to October 28) was a scheduled shutdown to conduct an integrated primary containment leak rate test.

Condenser tube leakage was a major operating problem during 1970. Other occurrences causing short shutdowns or power reductions included

high level in the moisture separator drain tank, primary system leakage, dirt in the steam pressure regulating valve, improper operation of the No. 2 turbine stop valve, grain in the water intake, and difficulties with the EPR.

1971

There were only three forced shutdowns during 1971 and all resulted from equipment failures. Nine of the ten forced power reductions were due to equipment failures. The cause of the tenth was administrative.

The forced shutdowns were of short duration and the power reductions were small. The unit operated at or near full power most of 1971. The longest shutdown was from September 18 to November 11 for a scheduled partial turbine-generator inspection and poison curtain removal. After this outage, uprating tests were made at power levels up to 1830 MWt which was the anticipated operating condition for fuel cycle 1-B. The difficulty encountered in 1970 with the No. 2 turbine stop valve was corrected by limiting the pilot valve off-port stroke in the closing direction.

During the five day outage from February 13 to February 18, the four main steam isolation valves were tested, maintenance was performed on the turbine control valves, the valve seats on the 'A' and 'B' electromatic relief valves were lapped to stop leakage, and the rubber seats of both reactor building to torus vacuum breaker block valves were replaced. Short power reductions were required to replace the brushes on 'A', 'B', 'C', 'D', and 'E' recirculating pump motor-generator (MG) sets. Additional shutdowns were required to repair burned exciter rings on the 'E' MG set.

1972

There were eleven forced shutdowns during 1972. Six of these were due to equipment failures, four to operator errors, and one to a maintenance and testing error. Twelve of the fifteen forced power reductions were due to equipment failures, two were due to maintenance or testing and one was due to an operating error. The unit was shutdown from May 1 to June 20 for a scheduled partial turbine generator inspection and reactor refueling. After the shutdown, the operating power level was increased from 1820 to 1890 MWt.

On April 30, the odor of hot insulation and evidence of vibrations indicated failure of the 'A' recirculating pump MG set. The outboard motor bearing was found wiped. The speeds of the remaining four pumps were increased in order to continue operation. During the shutdown on November 11, the brushes on all five recirculating pump MG sets were replaced. On December 5, load was reduced to repair the 'E' recirculating pump MG set tachometer.

Power reductions were required on November 9 and November 28 to repair leaking condenser tubes and from December 8 to the end of the year due to turbine control valve oscillations.

1973

In 1973, there were eight forced shutdowns. Seven forced shutdowns resulted from equipment failures, and one was caused by maintenance and testing. There were nine forced power reductions, eight of which were due to equipment failures and one was due to maintenance and testing.

The reactor remained shut down for the first nine days of January to perform miscellaneous maintenance work. Part of the refueling shutdown

which lasted from April 13 to June 5 was used for operator training. Another planned shutdown lasted from September 8 to October 5. This shutdown was to inspect and repair the hydraulic shock and sway arresters inside the primary containment.

Two reactor scrams occurred due to high level in the moisture separator during power level changes. One scram was caused by a trip of the 'B' feedwater pump and one was due to sluggish turbine control valve operation.

1974

There were only six forced shutdowns in 1974. Five of these resulted from equipment failures and one from an electrical storm. There were fifteen forced power reductions. All of which were caused by equipment failures.

In previous years leaking condenser tubes accounted for few power outages or power reductions. However, in 1974, 12 power reductions and one shutdown were necessary to repair leaking tubes.

Two power outages were caused by increases in the dry well leak rate. This was traced to a stem packing of the 'C' recirculating pump discharge valve and a bonnet on a bypass valve. Failure of torus vacuum relief valves, injection of cold water at lower power, electrical disturbances and instrument air line leakage caused the other forced shutdowns. The unit was shut down from April 13 to June 29 for partial refueling.

1975

There were nine forced shutdowns in 1975. Five of these were due to equipment failures, two to maintenance or testing and two to operational

errors. Three of the four forced power reductions were caused by equipment failures and the remaining one by an operational error.

Difficulties continued with condenser tube leakage throughout the year. The unit was finally shut down on November 24 due to extensive tube leakage. Repair of the leaky tubes delayed start-up until December 1. The unit again shut down on December 26 for condenser retubing and refueling.

The reactor was also shutdown from March 30 to May 24 for refueling, at which time the power level was limited to 83%.

On February 4, interaction between the rad waste systems and the feedwater system tripped all three feedwater pumps. This was due to an operational error. Air was introduced into the condensate header when water from waste sample tank 'A' was being transferred to the hotwell and simultaneously being used as a source of water for backwashing the radwaste floor drain filter.

1976

There were only four forced shutdowns in 1976. Three were due to equipment failures and one was due to an operational error. Five of the six forced power reductions resulted from equipment failures. Maintenance and testing caused the remaining power reduction.

During a shutdown started in 1975 and continuing into 1976, the main condensers were retubed using welded titanium tubing. Approximately 43,600 tubes were replaced due to corrosion and erosion. Tube leakage started again in November 1976 due to vibration induced failures.

There were 2 reactor scrams during the year. The first on May 4 was due to operational error which allowed air to leak into the condensate

system which tripped all three feedwater pumps. The second on June 30 occurred at low power during start-up and was due to improper pressure regulator set point which allowed the bypass valves to open.

1977

Only three forced shutdowns occurred in 1977. Two reactor scrams were caused by operator errors and another occurred during tests. No forced power reductions were reported.

Continuing condenser tube vibration concerns forced the plant to operate at reduced power until the annual refueling and maintenance outage from April 23 to August 4, at which time the tube problem was successfully solved. The unit operated satisfactorily for the rest of the year.

1978

There were five forced shutdowns during 1978. Three resulted from equipment failures and two from maintenance and testing errors. There were two forced power reductions, one due to equipment failure, and one due to maintenance and testing.

Reactor scrams were caused by malfunctions of the feedwater system and MSIV testing. Condenser tube leaks caused a power reduction on April 2. On May 11, an end of core life coastdown began with an average power loss of 2 MWe per day. Refueling commenced on September 15 and continued through December 5.

1979

There were seven forced shutdowns in 1979. Two of these were due to equipment failures, one resulted from a maintenance and testing error, and

four were due to operational errors. Sixteen forced power reductions, caused by equipment failures, also occurred during 1979.

On May 2, during surveillance testing on the reactor high pressure isolation condenser initiating sensors, a hydraulic disturbance caused a reactor high pressure scram. All recirculating pump valves were closed limiting circulation to the five 2 inch bypass lines. Reactor water level decreased to 12-18 inches above the top of the active fuel. Triple low water level in the core existed for 36 minutes before the transient was terminated by starting the 'A' feedwater pump. The reactor remained shut down for the rest of the month for tests which revealed that no core damage had occurred.

During the year, there were seven forced shutdowns or power reductions due to recirculating pump problems. Two of these were due to pump seal failure and five were caused by MG set failures.

1980

In 1980 there were five forced shutdowns and nine forced power reductions. All 1980 shutdowns and power reductions resulted from equipment failure.

The plant was shut down from January 4 to July 10 for refueling and maintenance. During the shutdown, the 10-year code hydraulic test on the reactor vessel and coolant piping was successfully completed. Pre-operation tests, equipment calibration and NRC mandatory scram tests were completed during the start-up.

The reactor was shut down from September 18 to September 23 as a result of increasing drywell unidentified leak rate. The leak was caused by a leaking drain line on a feedwater check valve.

The plant was shut down from November 21 to November 28 for maintenance on 'C' high pressure feedwater heater and the north feedwater line check valve.

From December 19 to the end of the year, load was steadily decreased due to high condensate demineralizer differential pressure caused by the inability of the new radwaste system to process liquid and solid waste as designed.

1981

In 1981, there were ten forced shutdowns and three forced power reductions. At the beginning of January, the capacity was limited by the condensate demineralizer differential pressure and continued to decline due to demineralizer conditions. The cause of this limitation was the inability of the new radwaste system to process liquid and solid waste as designed to support regeneration of the demineralizers. This condition continued periodically into the month of February. On February 18 and 25, the unit reduced power to plug tube leaks in the south condenser waterbox. On April 17, the unit shut down for 1004 hours for maintenance and TMI modifications with 70% of the outage charged to TMI modifications.

During June, steam trap failure in the 'A' and 'B' steam jet air ejectors systems resulted in degraded condenser vacuum. It degraded to the point of causing an automatic scram on June 26. Degraded condenser vacuum remained a problem in July and August. On August 15, the unit shut down to correct the vacuum problems and to correct an unidentified drywell leak rate. Before startup on August 27 and 28, tube failures in the 'A' and 'C' shut down cooling heat exchangers caused the unit to remain shut down until the middle of October. On December 9, the unit shut down to investigate operability problems with the isolation condenser valve.

4.4.4 Forced shutdowns and forced power reductions caused by DBE initiating events

Design basis events (DBEs) are transients which challenge the safe operation of a plant and the ability of engineered safety features to safely shut it down. Oyster Creek has experienced fifty-five forced shutdowns and forced power reductions caused by DBE initiating events. Table 4.4 gives the number of these events by DBE type for each year. This section discusses the forced shutdowns and forced power reductions in each DBE category.

4.4.4.1 DBE category 1 - increase in heat removal. The six events in category 1 were of three types:

1. 1.1 Feedwater system malfunctions that resulted in a decrease in feedwater temperature (2);
2. 1.3 Steam pressure regulator malfunction or failure that resulted in increases steam flow (2);
3. 1.7 Inadvertent opening of a turbine bypass valve that resulted in increasing steam flow (2).

All of these initiating events were followed by an automatic scram and safe reactor shutdown.

Type 1.1 initiating events occurred on August 26, 1969 and June 30, 1974. In both occurrences, cold water was injected into the reactor vessel because of a malfunctioning feedwater regulating valve. The reactor scrammed on high flux.

Steam flow transients shut down Oyster Creek twice as a result of electric pressure regulator (EPR) problems. The first event, on April 14, 1970, resulted in low reactor water level. The second EPR malfunction, on September 22, 1970, caused an MSIV closure as a result of low pressure in

Table 4.4. Oyster Creek DBE initiating event summary

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1.1 Feedwater system malfunctions resulting in decreased feedwater temperature	1					1								2
1.3 Steam pressure regulator malfunction resulting in increased steam flow		2												2
1.7 Inadvertent opening of turbine bypass valves	2													2
2.1 Steam pressure regulator malfunction resulting in decreased steam flow	2								1					3
2.2 Loss of external load					1									1
2.3 Turbine trip	3	5		1	2	1	1		1			1		15
2.4 Inadvertent closure of MSIVs	1	1							1	1			1	5
2.5 Loss of condenser vacuum	2	1		1			2						1	7
2.7 Loss of normal feedwater	1	1		1	1		1	1		1	2			9
3.1 Recirculation pump trips		1		4			1				3			9
Total	12	11	—	7	4	2	5	1	3	2	5	1	2	55

the main steam line. These EPR failures were caused by dirt fouling the EPR pilot valves. Major EPR control system modifications in mid-October of 1970 solved these control problems.

The two type 1.7 events resulted from operational errors on September 2, 1969 and December 16, 1969. On both occasions, the reactor power was low and the bypass valves were being manually operated to aid in reactor water level control. The operator opened the valves too quickly and the reactor scrammed on low level.

4.4.4.2 DBE category 2 - decrease in heat removal. The forty initiating events resulting in decrease heat removal from the reactor core were of six types:

1. 2.1 Steam pressure regulator malfunction or failure that resulted in decreasing steam flow (3);
2. 2.2 Loss of external load (1);
3. 2.3 Turbine trip (15);
4. 2.4 Inadvertent closure of main steam isolation valves (5);
5. 2.5 Loss of condenser vacuum (7);
6. 2.7 Loss of normal feedwater flow (9).

All but the loss of feedwater DBEs were terminated as designed.

Two of the three type 2.1 events occurred at low power during initial startup testing on September 9 and 18, 1969. The first event was due to electric pressure regulator (EPR) failure and the second resulted from testing of the mechanical pressure regulator (MPR). The third malfunction of steam pressure regulators occurred on November 14, 1977 when control power was lost. In all cases, the bypass valves opened and the reactor scrammed.

The single loss of external load event was on June 30, 1973. A generator load rejection scram ensued from a lightning storm.

Turbine trips (DBE 2.3), as with most nuclear plants, were the most numerous DBE initiating events. Of the fifteen turbine trips, eight resulted from high level in the moisture separator drain tank. In all of these trips, Oyster Creek was changing power level which caused an inventory imbalance and the resulting high levels. Four additional turbine trips resulted from stop valve testing. Stop valve No. 2 closed too rapidly causing two turbine trips on December 25, 1970. Repairs were completed in January 1971. A faulty stop valve test circuit induced two additional turbine trips on October 5, 1975 and October 21, 1977. Two turbine trips were related to generator problems. On December 29, 1972 an operator opened a transformer door resulting in a generator loss of field and a turbine trip. An acceleration relay tripped the turbine on September 25, 1974 when the generator attempted to respond to a power grid disturbance. The final turbine trip, on August 4, 1980, resulted from a spurious loss of condenser vacuum signal.

Four of the five MSIV closures resulting in shutdowns occurred during testing. These events were on September 19, 1969, December 3, 1977, December 13, 1978, and October 19, 1981. High ambient temperatures in a steam pipe tunnel initiated an MSIV closure on June 17, 1970 from a spurious steam line break signal.

There were seven type 2.5 (loss of condenser vacuum) events. The first of these occurred on September 24, 1969, one day after the generator was first synchronized to the transmission system, and was attributed to inner and after condenser drain system problems. A temporary drain system was immediately installed and a permanent drain connection completed in 1970. Another loss of condenser vacuum trip on December 18, 1969, was due to operator error. It resulted from not isolating the waste sample tank

'A' after the drain pump tripped. Twice condenser vacuum was lost, due to system leaks. In January 3, 1970, inleakage through the expansion joint between the 'C' condenser and exhaust section of the 'C' low pressure turbine caused a low vacuum trip. On April 24, 1972, worn seals on the steam jet air ejector pumps resulted in air inleakage and a reactor scram. A loss of power to the air ejector off gas system pressure regulator valves caused a low condenser vacuum trip on July 25, 1975. On August 27, 1975 a trip occurred as the result of an operator error. The 'A' condenser was returned to service during startup under low circulating water flow conditions. During June 1981, steam trap failure in the 'A' and 'B' steam jet air ejector systems resulted in degraded condenser vacuum to the point of finally causing an automatic scram on June 26, 1981.

The loss of normal feedwater DBEs include the most serious transients which have occurred at Oyster Creek. On May 2, 1979, one of the nine type 2.7 events resulted in a triple low water level in the reactor vessel. This event is discussed in detail in Sect. 4.5.2.6. Three losses of normal feedwater were related to controller malfunctions. On December 31, 1969, a stuck excess flow check valve gave an erroneous indication to the feedwater controllers and the reactor tripped on low level. A loss of steam flow signal yielded similar results on January 19, 1970. Malfunction of the feedwater controllers again shut the reactor down on September 4, 1978. On three occasions, systems interactions between the feedwater and radioactive waste systems caused feedwater pump trips. On April 13, 1972, a misoriented switch vented the hotwell to atmosphere causing the condensate pumps to cavitate and one feedwater pump trip. Similar interaction on February 4, 1975 and May 4, 1976 introduced air into the condensate header and tripped all three feedwater pumps simultaneously. In

the final loss of normal feedwater DBE, a single feedwater pump trip due to equipment failure shut the reactor down on June 21, 1973.

4.4.4.3 DBE category 3 - decrease in reactor coolant system flow rate. All nine events in DBE category 3 resulted from recirculation pump trips (Type 3.1). These events often had smaller consequences than other DBE initiating events resulting in power reductions rather than shutdowns. Four of the nine events illustrated a common cause mechanism affecting the recirculation pumps and feedwater pumps. On April 7, 1970, January 22, 197?, February 3, 1972, and December 12, 1975, 125V dc bus load testing errors tripped three recirculation pumps and one feed water pump. A power reduction followed each initiating event except the first which was followed by a manual shutdown. The remaining five recirculation pump trips were caused by MG set failures and affected only one pump each time.

4.4.5 Non-DBE forced shutdowns and forced power reductions

There were 148 forced shutdowns or forced power reductions which were not attributable to DBE initiating events. Table 4.5 lists the number of these events per year by NSIC category. Eighty-one of the 148 shutdowns or power reductions were due to mechanical failures, nine to instrumentation and thirty-eight to leaks. This amounts to 87% due to failures of equipment. There were eleven non-DBE events attributed to operator errors, a single externally caused event, and a single event caused by regulatory restriction.

4.4.6 Trends and safety implications of forced shutdowns and forced power reductions

The only recurring problem evidenced by the forced shutdowns and power reductions, other than those mentioned in Sect. 4.4.4, was condenser

Table 4.5. Oyster Creek non-DBE initiating event summary

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1.0 Equipment failures	2	7	12	12	11	3	1	6		3	9	12	3	81
2.0 Instrumentation and control anomalies	3	2		2							2			9
3.0 Non-DBE reductions in coolant inventory (leaks)	1	1	1	2	2	16	6	2		2	4	1	7	45
6.0 Operator error	3	1		3			1				3			11
8.0 Regulatory restriction													1	1
9.0 External events								1						1
Total	9	11	13	19	13	19	8	9		5	18	13	11	148

tube leaks. Condenser tube leakage problems began in 1970. It was necessary to plug ninety-seven condenser tubes during the last half of 1970. Seventy of these were in the north half of the 'C' condenser.

On October 25, 1970, two readily accessible condenser tube segments were removed from 'C' condenser for analysis in an effort to identify the failure mechanism. Investigations revealed that the failure was at a small, narrow, and deep pit. The appearance of the pit suggested that it was caused by jet action of water passing an obstruction in the tube (impingement attack). No corrosive deposits were found in the pit. Photomicrographs revealed no intergranular attack.

Through 1975 recurring power reductions were necessary to repair or plug leaking tubes. The attendant salt water inleakage into the condensate system caused operational difficulties which resulted in plant operation at reduced power. Occasionally, temporary repairs were made by adding a sawdust-like sealing compound.

During the shutdown in the first part of 1976, condensers were retubed using welded titanium tubing. In all, approximately 43,600 tubes were replaced, each being 43.5 ft in length. The original tube material was 0.1875 in. OD aluminum bronze, 19 bwg. The replacement tube material was 0.1875 in. OD, titanium, 22 bwg. Tube replacement was necessitated by excessive condenser tube leakage due to the effects of erosion-corrosion.

Since retubing, the titanium tubes have functioned satisfactorily in service with the exception of a limited number of vibration-induced tube failures. Condenser tube vibration developed during 1977. However, this problem was corrected during a refueling outage which began on April 23, 1977.

On February 18 and 25, 1981, the 'C' south condenser waterbox developed tube leaks. Fourteen tubes were plugged.

4.5 Reportable Events

4.5.1 Review of reportable events

This portion of the study examined 494 events concerning abnormal operations reported by Jersey Central Power and Light Company from 1969 through 1981. Appendix A.2 presents a table of these reported events. In the table, blanks indicate information that is missing, and dashes indicate "not applicable." Events from 1969 through 1972 are numbered chronologically. Beginning in 1973, events were reported as Abnormal Occurrences (AO's) and are labeled as such. Beginning in 1975, the designation was changed to Reportable Occurrences (RO's) and in 1978 to Licensee Event Reports (LER's). The table also reflects these changes.

4.5.1.1 Yearly summary of reportable events. The event reporting pattern over the life of the Oyster Creek plant is shown in Fig. 4.1. The year-by-year trend was generally toward more reported events, with peak years in 1974, 1980, and 1981. The years 1969 through 1973 averaged nineteen reported events per year, while the years 1974 through 1981 averaged forty-nine reported events per year. Recurring failures were a contributing factor to the upward trend. From 1969 through 1973, an average of three recurring failures occurred per year while for the years 1974 through 1981 that average doubled to six per year. However, even if the recurring failures are subtracted, the upward trend in the number of reported events is still apparent.

4.5.1.2 System summary of reportable events. A summary of the systems involved in all the reported events is given in Table 4.6. In this table, the number of times a reported event involved each system is shown by year. The table totals the system codes listed in the "system" category of Appendix A.2. The most frequently reported systems were:

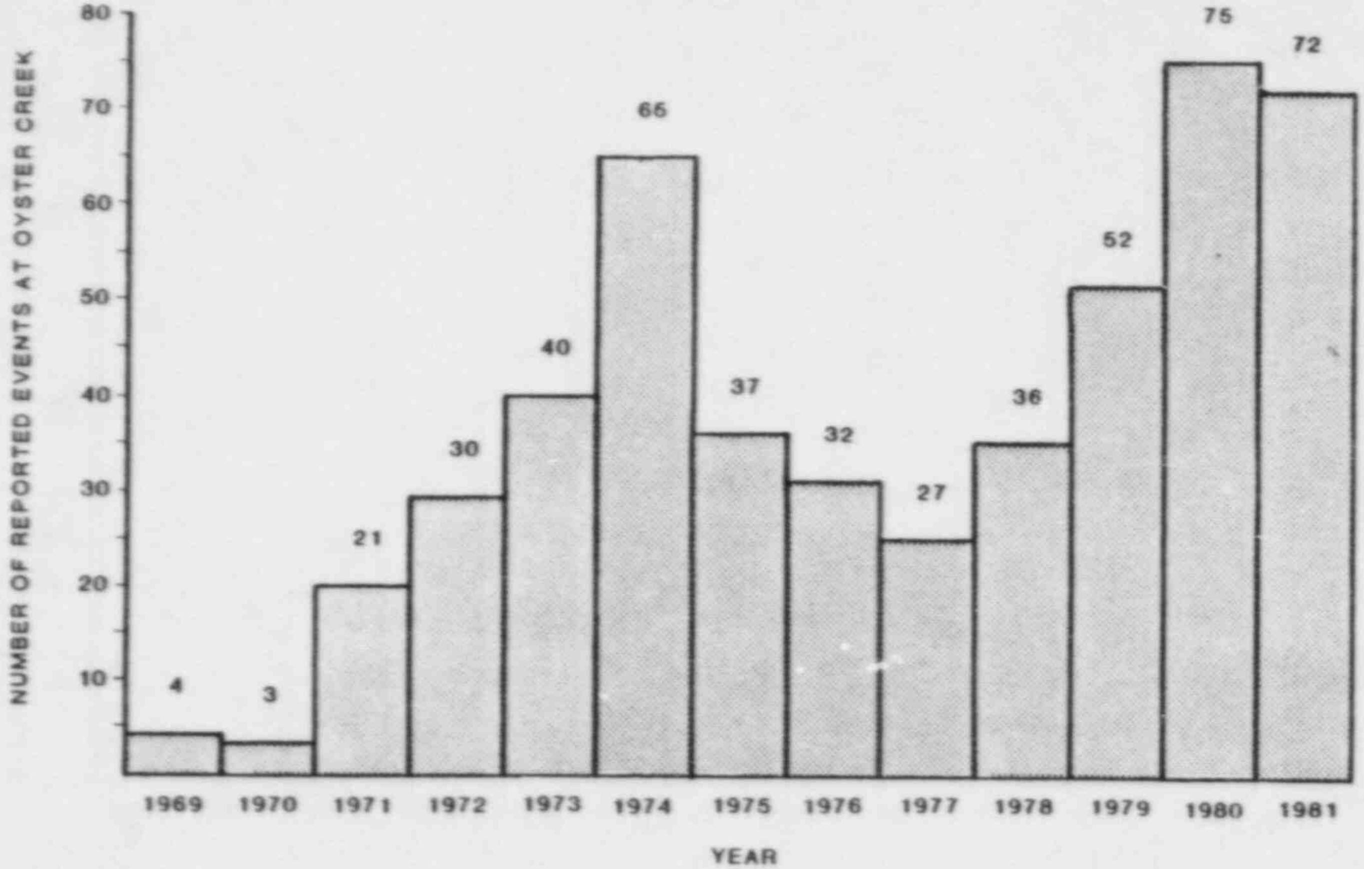

Figure 4.1 Number of Reported Events Per Year at Oyster Creek

Table 4.6. Summary of systems involved in reportable events by year

System	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Reactor general (RX)													2	2
Reactor vessel internals (RA)					1	2	2	3	1	1	2			12
Reactivity control (RB)	1	1	1	2	3		3			1	4	4	2	23
Reactor core (RC)				3		1	1	1	1	2		2	3	14
Reactor vessel (CA)						1								1
Coolant recirculation (CB)	1			2	1	1			[illegible]		6	1	1	14
Main steam (CC)			1	2	4	20	3	1	3	2	2	4	6	48
Main steam isolation (CD)	1		2	1	5	5			2	1		1		18
Isolation condenser (CE)			5	4	6	4	2	1	3	4	5	4	9	47
Residual heat removal (CF)						1							1	2
Reactor coolant cleanup (CG)					1	2							3	6
Feedwater (CH)				1	1						1			3
Other coolant subsystems (CJ)										1				1
Engineer safety features - general (SX)						1								1
Containment (SA)	1	1		2	5	13	6	7	4	4	10	4	11	68
Containment heat removal (SB)				1										1
Containment air cleanup (SC)				1										[illegible]
Containment isolation (SD)												1		[illegible]
High pressure safety injection (SF-C)													3	3
Core spray (SF-D)			1			4	4	5	4	2	6	12	5	43
Other engineered safety features (SH)				1	1				1			1		4
Containment purge (SH-A)												1	1	2
Containment spray (SH-B)			2	2	2	2	3	6	1	2	5	8		33
Standby gas treatment (SH-D)	1		2				3	1	3	5	1	6		22
Instrumentation and controls - general (IX)						1							2	3
Reactor trip (IA)				2		2	2	1	1	5		6		19
Offsite power (EA)									1	1				2
AC onsite power (EB)			1	1	2	2	1		2	2				11
DC onsite power (EC)				2			1			2		2	1	8
Emergency generator systems (EE)			2	4	4	1	1	3		5	1	3		24
Spent fuel pool cooling and cleanup (FC)					1									1
Fuel handling (FD)							1							1
Service water (WA)				1	1	1	2			1	10	10	2	28
Component cooling (WB)					1									1
Condensate storage (WF)										1		1	1	3
Compressed air (PA)			1											1
Process sampling (PB)					1						2			3
Fine protection (AB)												5	2	7
Other auxiliary (AD)			1											1
Turbine-generator (HA)	1	1								1		1		4
Main condenser (HC)							1					1		2
Condensate cleanup (HG)								1						1
Liquid rad waste (MA)			2	5	2					1	2		3	15
Gaseous rad waste (MB)				1					1	1			6	9
Process and effluent monitoring (MC)				1	1	5	4	1	2	2	2	1	1	20
Airborne radioactivity monitoring (BB)													1	1
Other systems					2	1					1	2		6
System code not applicable				1				1			1	3		6
Total	6	3	21	40	45	70	40	32	31	47	61	84		66

(1) reactor containment systems (68),

(2) main steam systems and controls (48),

(3) isolation condenser systems and controls (47),

(4) core spray systems and controls (43), and

(5) containment spray systems and controls (33).

4.5.1.2.1 Reactor containment systems. Twenty-three of the sixty-eight reactor containment systems events were failures of the torus-to-drywell vacuum breaker valves. An additional ten events involved the loss of containment integrity. Vaccum breaker valves and the loss of containment integrity are discusssed in Sects. 4.5.3.2 and 4.5.3.5, respectively. The remaining containment events ranged from oxygen analyzer failures to high torus water temperature. No single failure type accounted for a large number of events.

4.5.1.2.2 Main steam systems. Thirty of the forty-eight events involving the main steam systems were set point drifts in pressure and flow sensors. The majority (15) of set point drifts were reported in 1974. Since 1974, there have been about two reports of set point drift per year. Twelve of the steam system events were valve failures. These include the safety, relief, bypass and main steam isolation valves.

4.5.1.2.3 Isolation condenser systems. With forty-seven reported events attributed to the isolation condenser system, it ranked as the third highest contributor of reportable events. Of these events, sixteen were valve failures, seven were relay or switch failures, two were procedure errors, one was a vent line failure due to vibration, and the remaining twenty-one were set point drifts or snubber failures. Isolation condenser system averaged over four failures per year since 1971.

In three events, condensate return valves failured to open. These were important because such failures prevent an isolation condenser from performing its intended function of removing decay heat from the reactor. On December 29, 1972, the condensate return valve for isolation condenser 'B' failed to open during a significant event involving a coolant blowdown (detailed in Sect. 4.5.2.1). Four months later in April 1973, the same valve again failed to open when the valve disk jammed against the seat. No cause for either failure was discovered. On September 8, 1973, the 'A' isolation condenser condensate return valve failed to open. The cause was the starting contactor overloads being tripped.

Two events also occurred which affected both isolation condensers by a common cause problem related to the line break flow sensors. Both events occurred on September 4, 1978 and were very similar in nature. In both cases, a shutdown had occurred and the MSIV's had closed. The isolation condensers initiated and were removing decay heat from the reactor. After about half a minute, the condensers isolated. In the first event, each isolation condenser would come back online, but would only operate for ~30 seconds. In the second event, the operator immediately tripped two recirculation pumps, thereby reducing the flow and the condensers came back online (see Sect. 4.5.2.6). The cause in both cases was the tripping of the condenser line break sensors due to the effects of rated recirculation flow. The trip point was set for reduced recirculation flow conditions, and in both cases all five recirculation pumps were operating at the time of the occurrence. Full flow caused the line break sensors to give an indication of a pipe rupture, thus isolating the condensers. Therefore, a standing order was issued to trip recirculation pumps 'A' and 'E' after initiating the isolation condensers. This standing order was later rescinded after modifications were made whereby the pumps were tripped simultaneously with high pressure or low-low water level scrams.

4.5.1.2.4 Core spray system. An early water hammer problem existed in the Oyster Creek core spray system, and was corrected. Then, beginning in 1974, the core spray system contributed consistently each year to the number of reported events.

The water hammer phenomena was first observed during reactor preoperational testing during the core spray pump tests. The problem was caused by the pumps starting when the discharge piping was empty. During the early life of the plant, the water hammer was substantially reduced during testing by changing the operating procedure, limiting the bypass line test valve opening, and utilizing the condensate fill and pressure regulating system to fill the discharge piping in each of the core spray loops (A-C and B-D). It became apparent, however, that this method would not be satisfactory because leakage through the spray pump discharge check valves back into the torus raised the torus water level and created a chromated water disposal problem. Therefore, in 1971 the utility installed a jockey pump system to maintain a water inventory in both loops. Operational tests with the new system indicated that the water hammer had been eliminated. Additionally, tests on the piping to determine the effects of the water hammer before the jockey pump system was installed showed that the piping was not damaged.[15]

Beginning in 1974, the core spray system averaged five reported events per year through 1981. A potential failure due to common cause occurred September 30, 1980 when the fire protection system, inadvertently initiated during troubleshooting, sprayed both core spray system booster pump motors. Water entered the motor lead connection box and the motor leads became wet. It had been previously thought that the booster pump construction was sufficient to prevent intrusion of water. A similar event occurred two months later on November 30. On this occasion, leaks were discovered in the control rod drive pump seal water piping. As a

result, water sprayed over the core spray system pumps below, and leaked into the motor lead connection box through worn gaskets. The gaskets were replaced and the conduit opening sealed.[16,17]

During the 1978 refueling outage, scheduled inservice inspection and subsequent tests of the reactor internals identified and confirmed the existence of a crack in one of the two core spray system spargers. Action was taken at that time to strengthen the sparger at the crack location by installation of a mechanical clamp assembly. During the 1980 refueling outage, a greatly improved inspection method detected additional cracks. It was not known whether they were new cracks or previously existing cracks overlooked during the 1978 inspection. Interim repair procedure was to use additional clamp assemblies. The NRC's safety evaluation, dated May 15, 1980, concluded that although the interim repair was adequate at that time, plans for a new sparger design should be accelerated. Therefore, the utility contracted wtih General Electric for a new sparger design which was to be installed during the 1981 refueling outage.

4.5.1.2.5 Containment spray systems. No single event type dominated the forty-one containment spray systems failures. There were problems with pressure switch set point drifts, pump and valve circuit breakers transferring open, valves failing to transfer open, and pumps failing to start. Even though no one event type dominated, since 1974 containment spray systems have recurred in reportable events.

4.5.1.3 Cause summary of reportable events. Table 4.7 lists the causes of reportable events by year. The largest group of events (316) were those caused by inherent equipment failure. Human errors (170) totaled only about one-half the number of inherent equipment failures. These errors included administrative, design, fabrication, installation, maintenance, and operator errors. The remaining seven events resulted

Table 4.7. Causes of reported events by year

Cause	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Administrative error			1	2	2	4	2	2	1	2	7	2	7	32
Design error			2	4		13	3	1	2	1	4	1	[illegible]	34
Fabrication error	2			1	2	1	2		2			1		11
Inherent failure	2	2	16	15	27	39	24	22	16	24	29	54	4[illegible]	316
Installation error				3		1		2	1		3	3	[illegible]	14
Lightning					1									1
Maintenance error		1		1	4	3	2	3	3	7	6	9	5	44
Operator error			2	3	2	4	4	2	2	2	3	3	8	35
Weather					2							2	2	6
Total	4	3	21	29	40	65	37	32	27	36	52	75	71	

from adverse weather conditions. Cold temperatures caused frozen sensing lines on five occasions, lightning caused the sixth event, and strong winds caused the seventh event.

4.5.1.4 Radioactivity release summary of reportable events. Table 4.8 gives a summary by year of the total known radioactivity released from Oyster Creek. An overall increase over the past ten years is apparent in the airborne release activity, while data for liquid activity released reveals a slight decrease. A total of twenty-three events at Oyster Creek were radiological in nature, with thirteen of these involving radioactivity releases, eight involving activity levels around rad waste tanks exceeding tech spec limits, and three involving personnel exposures.

Of the thirteen events involving release of radioactivity, twelve were due to equipment failure including two occasions when outside lines containing radioactive water ruptured due to freezing. Four release events were pipe leaks, two were valve leaks, and another was a leak from fuel pool cooling to the RBCCW system then from the RBCCW heat exchanger to the discharge canal. One event was an increase in the gamma energy of the stack gas during a normal plant startup. The remaining radioactivity release occurred on February 6, 1975 due to maintenance error when backwash valves on the condenser water box were left open while inspecting the condenser for tube leaks. None of the events involved a release over tech spec limits.

Of the three instances of personnel overexposures, the first involved eleven workers who received exposures ranging from 3.01 to 3.36 rems during the 1972 refueling outage. The second occurrence was on January 1,

Table 4.8. Summary of radioactivity released from Oyster Creek

Release (curies)	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Airborne:												
Total noble gases	7.03E+03	1.12E+05	5.16E+05	8.66E+05	8.10E+05	2.79E+05	2.06E+05	1.67E+05	1.77E+05	9.98E+05	1.01E+06	
Total I-131	NA	NA	1.33E+00*	6.25E+00	6.70E+00	3.31E+00	5.46E+00	6.17E+00	7.80E+00	1.01E+01	8.74E+00	
Total halogens	2.96E-03	3.08E-01	2.03E+00	1.91E+01	3.03E+01	2.33E+01	4.13E+01	4.02E+01	4.02E+01	6.23E+01	6.65E+01	
Total particulates	7.98E-04	9.89E-03	1.10E-01	2.30E-01	4.31E-01	9.01E-01	1.78E-01	2.20E-01	1.25E+00	8.01E+00	5.84E-01	
Total tritium	NA	NA	1.09E-01*	7.54E-01	3.20E-01	4.15E-01	2.77E+00	1.11E+00	1.16E+00	3.81E+01	3.86E+01	
Liquid:												
Total mixed products	4.81E-01	1.85E+01	1.21E+01	1.00E+01	4.20E+00	6.60E-01	4.08E-01	2.21E-01	9.81E-02	1.53E-02	6.59E-03	
Total tritium	5.07E+00	2.19E+01	2.15E+01	6.16E+01	3.59E+01	1.41E+01	1.79E+01	3.86E+01	1.88E+01	1.96E+01	1.40E+00	
Total noble gases	NA	NA	NA	3.29E+00	3.00E+00	1.66E+00	6.54E-02	4.64E-02	4.57E-04	6.82E-03	2.43E-02	
Solid:												
Total	3.78E-01	2.97E+00	5.40E+00	4.47E+01	2.89E+03	1.57E+03	6.72E+02	1.29E+03	1.38E+05	1.15E+03	1.34E+03	

NA - Not available

* - 2nd half of year only

1973 when three men received excessive exposure to iodine-133 while performing maintenance on the electromatic relief valves. In the third event, on May 8, 1973, a worker who was doing maintenance work on the control rod drives received a whole body exposure of 3.02 rems.

On February 10, 1981, an unmonitored release of radioactive water occurred due to seepage through the three-foot thick outside wall around the new radwaste building (NRW). Leakage from the condensate transfer system caused an overflow into the three chemical waste collection tank vaults. When the radioactive water exceeded the ninety-five percent level, water seeped through the NRW building concrete walls. The area around the building was roped off and soil samples were taken. Direct survey results showed detectable ground contamination only within six inches of the walls. To prevent further seepage, herculite was sealed against the wall. Once the continuous overflow to the chemical waste collection tank vaults was halted, effort was concentrated on processing the water from the tank vaults to the waste surge tank. The NRW operators have recieved instructions not to exceed the ninety-five percent level in any tank, and have been made aware of what actions to take in the event a tank reaches a level greater than ninety-five percent.[18]

An unmonitored release of radioactive water occurred on April 21, 1981 due to leakage from a valve inside the condensate transfer pump building. The water seeped through the ground in the building and under the walls. By performing a water balance, a total of 10,000 gallons could not be accounted for, and therefore, was considered as leakage.

The valve which leaked is a bypass for the condensate transfer flow control valve. However, the flow control valve was tagged out of service at the time and the bypass valve was being used to control flow. Upon

discovery of the leak, the condensate pump was shut down and the condensate storage tank was isolated. The area in front of the chlorination building was diked to trap any water collecting by the roadside. The trapped water was pumped into fifty-five gallon drums.

The leaking valve was replaced and repair work on the flow control valve was completed. Three days after the event, the radiological controls department removed the barriers and the area was cleaned. Modifications to minimize the probability of future leakage included sealing the floor in the condensate transfer building and the installation of a water detection alarm.[19]

On July 6, 1981, an unmonitored release occurred in the new radwaste ventilation exhaust system. A tear was discovered in a plastic seal used to temporarily block a newly installed section of ventilation duct. The new section had not been tied into the existing radwaste ventilation system. The total release, based upon flow calculations when the exhaust fan is operating, was less than 60 μCi.[20]

4.5.1.5 Environmental impact summary of reportable events. Twenty-four environmental events resulting from nonradiological causes occurred at Oyster Creek. Seven of these events were fish mortalities due to water temperature changes occurring because of plant discharge water stopping or starting during normal operation. Two events involved plugging of plant intake water screens and dilution pump seal water strainers by debris and crabs, while two events were caused by low intake water level due to low tide and high winds. High temperature of the condenser discharge water was the cause of one reported event. The diesel engine for the fire pump seized due to loss of cooling in another reported event.

The remaining eleven reported events involved the plant dilution pumps, designed to reduce thermal pollution by diluting the discharge

water. Dilution pump failures have been a recurring problem at Oyster Creek. Numerous pump trips have occurred, primarily due to low cooling water pressure and low seal water pressure. On one occasion, dilution pump 1-3 seized when the pump impeller sheared a number of connecting bolts and jammed against its housing. Pump 1-1 was removed from service September 10, 1980 when a bearing overheated and was damaged. At the close of 1980, an engineering evaluation was in progress to improve the dilution pump system including a proposal to replace the present cooling/seal water pumps, located on the dilution structure, with two pumps of greater capacity. The new cooling/seal water pump location was tentatively decided to be the facility's fresh water fire pond.

Another environmental event occurred on April 15, 1981 when strong winds concentrated large amounts of sea lettuce in the intake canal and clogged the intake structure. This in turn reduced the flow across the screens causing the water level in one-half of the intake structure to drop below the emergency service water pump suctions. The emergency service water system provides cooling to the containment spray heat exchangers which removes heat from containment and is the ultimate heat sink for the energy release in a LOCA. Each of the two loops of containment spray contains two emergency service water pumps, two containment spray pumps and two heat exchangers. The flow from one pump in either loop is sufficient to provide the required heat removal capability. In addition, the intake structure is divided into two halves. Since one-half of the intake structure was unaffected, one of the containment spray and emergency service water loops was available.

The second containment spray system loop was inoperable for twenty minutes. Availability returned when the circulating water pump was

stopped, thereby allowing the water level in the intake structure to rise back above the emergency service water pump suctions. In addition, new high pressure screens were scheduled to be installed during a refueling outage in November 1981.

Finally, an interest has been shown in the Oyster Creek-Barnegat Bay area concerning the existence of shipworms. Shipworms are wood boring marine organisms that do great damage to wood, such as pilings for piers, beneath the water line. These organisms began to appear around 1971, and in 1975 a large population was in evidence. The utility contracted with William F. Clapp Laboratories of Battelle Columbus Labs in June of 1974 to study the woodborer problem. Also, the Westlands Institute of Lehigh University undertook a study, hired first by three local marina owners and later funded by the NRC. In their quarterly reports, both these organizations at times concluded that the growth of certain species of shipworms was indeed encouraged by the thermal effects of the plant effluent. At other times, they reported no relationship. However, it was also reported that by using only high quality treated wood in the area, continuing to use high dilution pumping, and keeping the water clean of load wood, the shipworm infestation problem could be held to a minimum.

4.5.2 Review of significant events

The analysis of the operating history of Oyster Creek examined reported events to find those occurrences which represented significant threats to continued safe operation or to systems designed to mitigate transient conditions. Reportable events were therefore significant if they met one of these criteria:

1. an event in which the failure or failures initiated a design basis event (DBE) as listed in Table 3.1, or

2. an event in which the failure or failures compromised a function of the engineered safety features.

Several events at Oyster Creek met the above significance criteria. Table 4.9 summarizes the significance categories assigned to these events and Table 4.10 summarizes the significant events which occurred at Oyster Creek. The total in the table, twenty-five, is greater than the actual number of significant events, seventeen, because six events, 72-29, AO 73-19, LER 79-014, LER 80-032, and LER 81-018, and LE 81-061, required multiple significance categories. The events designated as significant were:

1. decrease in reactor coolant inventory,
2. reactivity anomaly due to short period during startup,
3. loss of containment integrity,
4. loss of containment spray system,
5. loss of onsite power sources coincident with loss of offsite power sources,
6. decrease in reactor coolant level to the triple-low level,
7. turbine pressure regulator trip,
8. suppression chamber vacuum breakers compromised, and
9. loss of standby liquid control system.

4.5.2.1 Decrease in reactor coolant inventory. The decrease in reactor coolant inventory is an initiating event for a design basis event (DBE) 6.3. On December 29, 1972, reactor coolant was lost to the torus through a failed relief valve. During the course of the event, three different valves failed.

The event was initiated when an operator opened the door of a cabinet housing protective fuses for the generator monitoring relays. The door

Table 4.9. Summary of significant events at Oyster Creek

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
S1 - Two or more failures in redundant systems	1				1							1		3
S2 - Two or more failures due to a common cause					1						1	1	1	4
S3 - Three or more failures				1							1			2
S7 - Greater threat to plant safety with different plant conditions or the advent of another credible occurrence				2	1			1	1		3	1	5	14
S8 - Administrative, procedural, or operational errors													1	1
S9 - Other										1				1
Total	1			3	3			1	1	1	5	3	7	

Table 4.10. Tabulation of significant reports at Oyster Creek

Report No.	Event date	Significance	Event description
69-2	9/9/69	S7	Turbine pressure regulator malfunction, recircular pump trip.
72-7	4/11/72	S7	Reactor bldg. vent dampers fail to close, violation of secondary containment.
72-29	12/29/72	S3, S7	After a scram, relief valve, MSIV, and isolation condenser condensate return valve all fail.
AO-73-19	9/8/73	S1, S2, S7	Two power failures cause pump trips; second failure due to incorrect setting on transformer; also DG failed to start.
RO-76-13	5/3/76	S7	Secondary containment willfully violated — both airlock doors open.
RO-77-1	3/10/77	S7	Both containment airlock doors open at once violating secondary containment.
LER 78-033	12/14/78	S9	Attempt to insert control rod fails due to bent switch.
LER 79-014	5/2/79	S2, S3	Reactor coolant level decreases to triple low point — no procedure for operations in this situation (Rx SD).
LER 79-020	6/13/79	S7	Both secondary containment airlock doors open.
LER 79-025	8/6/79	S7	Torus sample valve left open — violation of primary containment.
LER 79-034	10/8/79	S7	Both containment airlock doors open simultaneously.
LER 80-015	4/3/80	S7	Reactor building isolation valve broke, loss of containment integrity
LER 80-032	7/16/80	S1, S2, S7	Torus area containment spray pump room doors open. Violation of secondary containment, containment spray inoperable.
LER 81-018	4/16/81	S7, S8	Workers placed scaffold such that the two vacuum breaker valves could not open completely.
LER 81-022	5/20/81	S7	One personnel airlock door would not close and the other was left open.
LER 81-025	6/17/81	S7	Both railroad airlock doors were open at the same time.
LER 81-033	7/27/81	S7	Personnel access airlock doors were found open.

was equipped with a switch that actuated relays in the protective systems and tripped the turbine. The reactor then scrammed, and a pressure transient ensued which was terminated at 1070 psig by the opening of the electromatic relief valves. After the pressure had been reduced by 22 psi, three of the relief valves closed; however, the 'D' relief valve failed to close and continued to blow down steam to pressure suppression chamber. As a result, the primary system cooldown rate was 158°F for the first hour and 27°F and 37°F for the second and third hours, respectively. A total of 50,000 gallons of water in the form of steam was blown down during the incident.

Following the scram, the operator attempted to switch from "Run" to "Startup" mode, but the mode switch key broke off. Therefore, with the reactor in the "Run" mode, the reactor pressure fell to 850 psig, and all the MSIV's closed except one, valve NS04B. This was the second valve failure. The redundant MSIV closed and containment remained adequately sealed.

The third valve failure occurred when condensate return valve V-14-35 on isolation condenser 'B' failed to open. Isolation condenser 'B' was therefore unable to fulfill its function and the isolation condenser system lost its redundancy.

Failure of the electromatic relief valve occurred because a piece of thread material from the disk retainer of the main valve had become lodged between the pilot valve seat and disk. Since the pilot valve could not fully close, the main valve remained open. Modifications were to implement a new method of preventing rotation, by pinning the disk retainers, on all the relief valves. The MSIV which failed was found to have a sticking power-operated pilot valve, which was then replaced by a new one.

Cause of the condensate return valve failure was difficulty in breaking the valve disk free of the seat, which burned out the valve motor. The valve motor was replaced, but no cause could be discovered for the sticking.[21]

4.5.2.2 <u>Reactivity anomaly due to short period during startup.</u> On December 14, 1978, the operator was withdrawing control rods following a scram from full power the previous day. Because of high xenon concentrations, an accurate estimated critical rod position was not possible. The operator was watching the count rate as indicated by the source range monitor (SRM). Since the count rate had changed only slightly since the start of the rod withdrawal, it was thought that the reactor was still strongly subcritical. Therefore, rods were being withdrawn in the notch override mode. When the first rod in group 9 was withdrawn to notch position 10, the reactor went critical on an estimated 2.8 second period. The operator then unsuccessfully attempted to insert the rod using the "emergency rod in" switch. Finally, an automatic reactor scram occurred in the low range of the intermediate range monitor.

The procedure for approach to criticality did not provide specific guidance for startup under peak xenon conditions. Additionally, the SRM count rate was low. Therefore, the operator did not expect criticality to occur. Furthermore, the control rod did not respond to the "emergency rod in" switch because the switch failed to make contact. A mechanical switch stop was bent.[22]

4.5.2.3 <u>Loss of containment integrity.</u> Primary containment consists of a pressure absorption system including the drywell, the pressure absorption chamber or torus, a connecting vent system between the drywell and the pressure absorption chamber, isolation valves, containment cooling

systems, and other related equipment. Its purpose is to terminate the release and mitigate the consequences resulting from an accident. Secondary containment is provided by a reactor building which completely encloses the primary containment. Its objective is to minimize the release of airborne radioactive materials and provide a controlled, elevated release of building atmosphere under accident conditions. Oyster Creek experienced one loss of primary containment integrity event and nine loss of secondary containment integrity events.

On August 6, 1979, an isolation valve on the torus sample line from primary containment was found open. The valve, located on the suction side of containment spray pump 'C', was left open after the completion of torus water sampling and had been open for seven days. During this time, approximatley 10,000 gallons of torus water drained to the floor sump and pumped to the radwaste facility. The ability of primary containment to function as intended was degraded during this period.[23]

A design error discovered on April 11, 1972 caused a loss of secondary containment integrity. During a test of the reactor building ventilation system, the supply dampers for the system failed to close. The logic circuit functioned so that when a supply fan was racked out, the dampers would not close unless a jumper was installed. A circuit design change corrected the error.[24]

A degradation of secondary containment integrity occurred on April 3, 1980, when an operator discovered that the reactor building ventilation system automatic isolation valve was inoperable. The valve failed due to a broken piston rod on the closure mechanism. The piston rod was replaced. Additionally, the piston rods were inspected on all reactor building ventilation automatic isolation valves.[25]

The remaining seven instances of secondary containment integrity violation were personnel and railroad airlock doors being left open. Contractor personnel had both reactor building personnel airlock doors open simultaneously on May 3, 1976 while transfering equipment through the airlock. Responsible personnel had willfully violated plant procedures by defeating the door interlock.[26] On March 10, 1977, both personnel airlock doors were open for a simulated medical emergency drill, and again on October 8, 1979 both personnel airlock doors were discovered open due to contractor personnel disconnecting the automatic closing device on one of the doors.[27,28]

On May 20, 1981, a security guard found both personnel airlock doors open. The first door failed due to a loosened striker plate while the second door had been opened deliberately.[29] On July 27, 1981, both personnel airlock doors were again discoverd open.[30] Both reactor building railroad airlock doors were open simultaneously on June 13, 1979. The inner door had been open for several days, and the outer door swung open when normal reactor building ventilation was switched to the standby gas treatment system to effect fan repairs. Procedures failed to state the correct method for securing airlock doors. The procedure was revised.[31] Both railroad airlocck doors were again discovered to be open simultaneously on June 17, 1981. While the outer door was open, the inner door sprang open at the top because of a failed latch which had been damaged during transfer of the standby gas treatment system to normal ventilation.[32]

4.5.2.4 Loss of containment spray system. On a routine tour of the reactor building on July 16, 1980, an operator discovered that both doors to the containment spray pump compartments at the northeast and southeast

corners of the building were open. The doors were left open due to lack of administrative and procedural control. The pump room doors were closed and dogged shut by the operator immediately after their discovery.

The containment spray cooling system consists of two independent cooling loops. Each of the loops is capable of removing heat from the primary containment following a LOCA. Since both doors were open, both containment spray systems were considered inoperable because of their susceptibility to a common cause failure. The systems would have performed their designed functions as long as the structural integrity of the torus remained intact. However, if a leak path had developed which would have allowed water to enter the pump rooms, the operation of both the pumps would have been jeopardized.[11]

4.5.2.5 <u>Loss of onsite power sources coincident with loss of offsite power sources.</u> During a plant shutdown on September 8, 1973, a design error prevented the startup of both diesel generators while offsite power was unavailable to their respective safety buses. An operator was attempting to transfer station loads to the startup transformers (Fig. 4.2). When a closing signal was applied to the S1A breaker, a loss of power occurred on 4160 V ac bus 1A, tripping one of two 4160V emergency buses (emergency bus 1C), two circulating water pumps, three reactor recirculation pumps, and the operating condensate and feedwater pumps. A fast start was initiated on diesel generator (DG) 1 and power restored to bus 1C and the safety systems which it powers. The reactor scrammed due to low water level.

Following the scram, startup transformer SB powered bus 1B. Breaker S1A was then successfully closed and DG 1 secured. The operator attempted to start the 'A' condensate pump, but the inrush current tripped the S1A

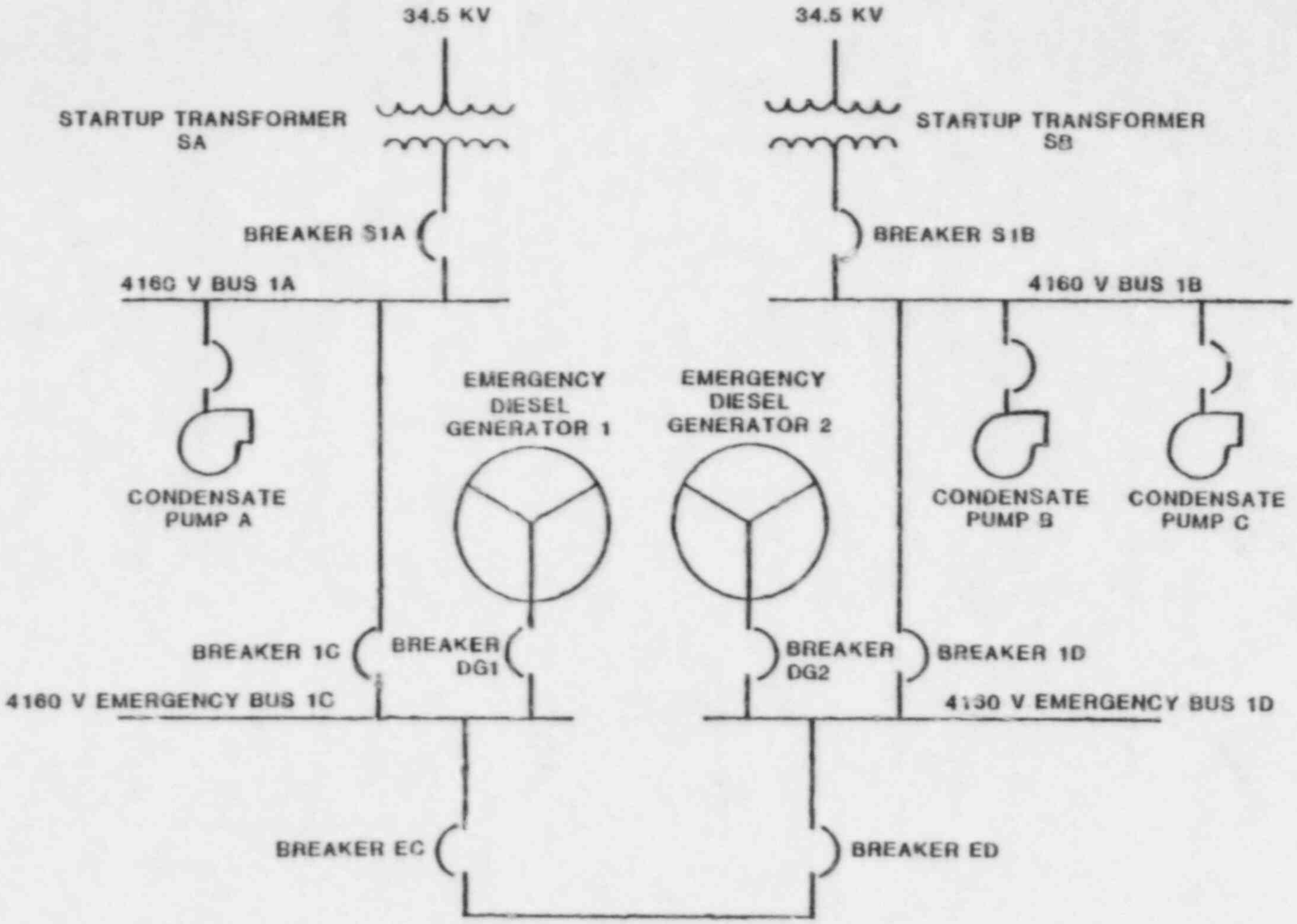

Figure 4.2 Simplified Electric Power System Diagram

breaker for a second time. At this point, the design problem with the diesel generators appeared. DG 1 failed to start because the engine lock-out relay had been actuated. Emergency bus 1C was totally without power. An attempt was made to start the 'B' and 'C' condensate pumps, tripping the S1B breaker and deenergizing emergency bus 1D. A fast start was initiated on DG 2.

The operator again restored normal power by closing breakers S1A and S1B, resetting the DG 1 lockout relay, and securing DG 2. Subsequent to the restoration of normal power, the design error appeared on DG 2. The operator attempted to start the 'B' and 'C' condensate pumps, again tripping the S1B breaker. Diesel generator 2 failed to start leaving emergency bus 1D without power. The DG 2 lockout relay had actuated, preventing the diesel generator from starting until the relay was locally reset.

The problem first experienced with the startup transformers was traced to an incorrect setting of the current transformer ratio matching taps for the 'C' phase differential relay on both units. In attempting to carry a sizeable load or start a large load, namely, the condensate pumps, a differential fault current was sensed due to the improper tap setting and the breakers (S1A and S1B) tripped. As previously stated, the problem with the diesel generators was a design error in the engine lock-out logic circuitry. After a fast start, the engine lock-out relay actuated preventing a subsequent start.

The designed redundancy for the station vital power supplies was not present and had not been present since July 30, 1973 when a test of the startup transformer phase differential relays was conducted. Under a loss of power condition, both diesel generators would have performed their intended function as was demonstrated by the fact that both units energized their respective emergency buses when initially called upon. If, however,

a problem had arisen which required a subsequent fast start immediately after the diesels had been secured from fast starts, such as occurred in this event, no ac power would have been available to any necessary safeguards equipment until the engine lockout relays had been reset. Immediate corrective action was taken to reset the tap on the startup transformers and to prepare a design change to the diesel generator logic circuits.[14]

4.5.2.6 Decrease in reactor coolant level to triple-low level. A significant reduction in water inventory to the low-low-low level occurred at Oyster Creek on May 2, 1979. The primary cause of this event was a loss of feedwater transient. Further details are given in the following paragraphs.

At the time of the occurrence, the reactor was at 98% power with the 'D' recirculation loop and the SB startup transformer out of service. A technician was performing routine surveillance testing on isolation condenser pressure switches when a spurious high reactor pressure signal occurred. The high pressure signal resulted from a testing error. This spurious signal tripped the reactor and the recirculation pumps. Steam flow and pressure, water level, and turbine generator output began to decrease. The turbine generator tripped at the low-load trip point thirteen seconds after the reactor scram.

The turbine trip initiated a transfer of power to the startup transformers. However, a loss of power occurred on 4160 V bus B because startup transformer SB was out of service. Therefore, feedwater pumps 'B' and 'C' and condensate pumps 'B' and 'C' lost power. Additionally, feedwater pump 'A' tripped due to low suction pressure. An attempt to restart feedwater pump 'A' was unsuccessful because an auxiliary oil pump failed to start. The oil pump failure was the only equipment failure of the entire event.

Steam was still flowing from the reactor to the condenser through the bypass valves, so the operator closed the MSIV's to conserve reactor coolant inventory (Fig. 4.3). An isolation condenser was then placed in service to remove decay heat from the core. The condensate return from the condensers enters the 'A' and 'E' recirculation loops. However, at that time a standing order was in effect to close the 'A' and 'E' loop discharge valves after initiating the isolation condensers. This order was intended to prevent inadvertent stopping of the condensers due to forced flow from operating recirculation pumps being sensed as if it were flow from an isolation condenser line break. This procedure was no longer appropriate since a modification had previously provided that the recirculation pumps trip simultaneously with high pressure or low-low level scrams. However, the procedure was not changed when the modification was made. Therefore, the operators had a lack of proper procedural direction in this situation. The cause of the occurrence was attributed to this procedural error.

Following the standing order, the operator closed the 'A' and 'E' recirculation loop discharge valves. He then closed the 'B' and 'C' discharge valves in preparing to attempt a restart of one or both of their associated recirculation pumps. As previously mentioned, loop 'D' was out of service. Therefore, all five loop discharge valves were closed. All five two-inch discharge valve bypass lines were open. Flow through these and flow from two control rod drive pumps which the operator had started were the only sources of flow available to the reactor. At a point 172 seconds into the event, the triple low water level in the reactor was reached.

By intermittent manual operation of the isolation condensers, the operator was able to remove heat from the system. Recirculation pump 'C'

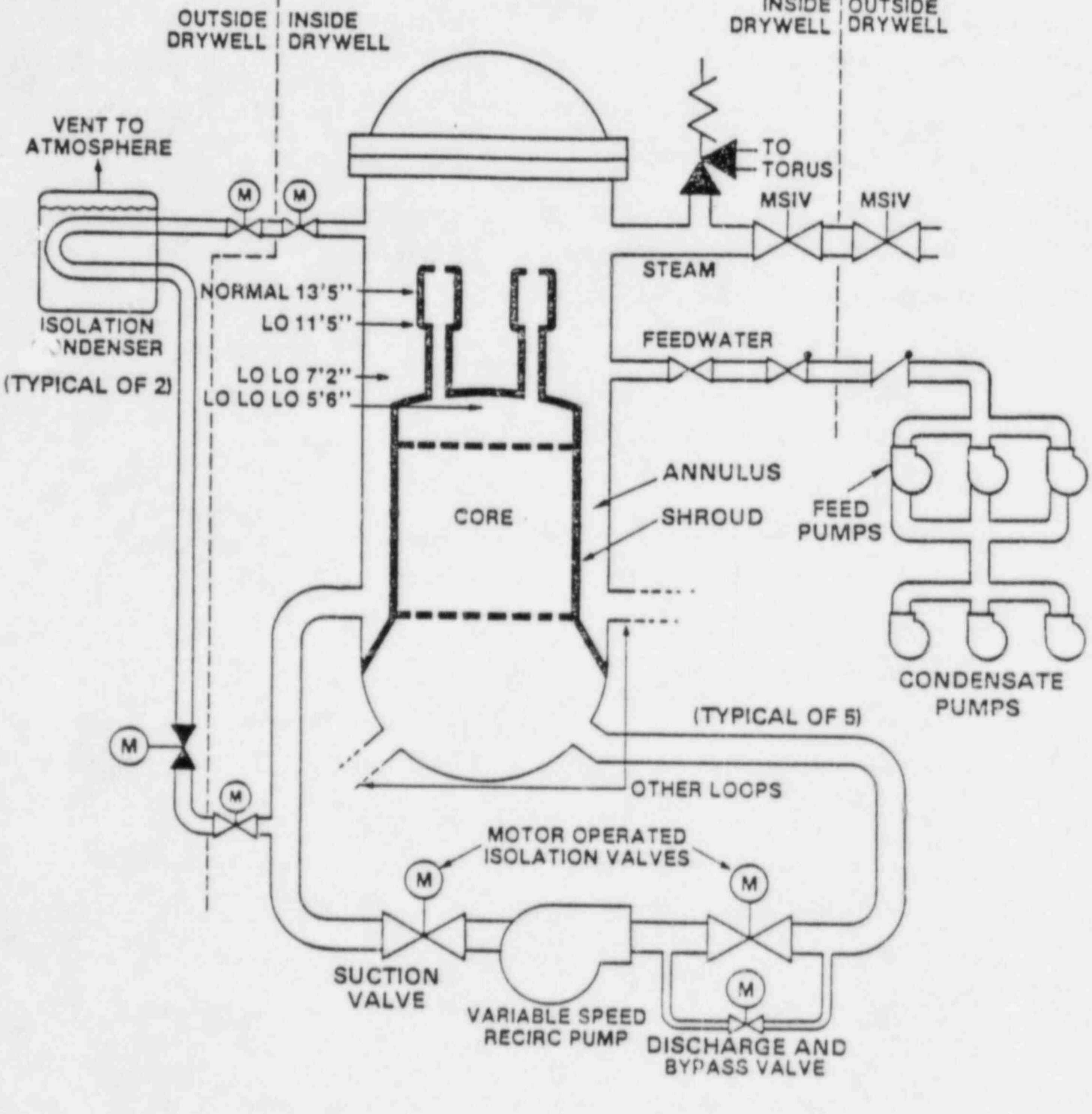

Figure 4.3 Recirculation, Steam and Isolation Condenser Schematic[37]

was started about half an hour into the transient, but it was tripped and the discharge valve reclosed when the water in the annulus was observed to drop rapidly. A feedwater pump was successfully started about five minutes later. The annulus water level began to rise, and two minutes later a recirculation pump was placed in service. The triple low water level in the core region was cleared and the reactor brought to a cold shutdown.

Later review of the occurrence established that the water level did remain above the core during the transient. The conclusion reached was that the core was not damaged. Modifications were effected to provide a readout of the core water level instrumentation in the control room, where previously, levels below the core spray sparger could not be monitored. In addition, the procedures were modified to require that the suction and discharge valves in at least two recirculation loops be open at all times.[36-37]

4.5.2.7. Turbine pressure regulator trip. This event took place during startup testing on September 9, 1969 with the reactor in the 'startup' mode at a power level of 40 MWt at 970 psig. Steam was being supplied to the steam jet air ejectors, the turbine gland seal system, and through throttling bypass valves to the condenser. The electric pressure regulator was controlling reactor pressure while the mechanical pressure regulator was set at 1020 psig as a backup. The turbine load limit was set at zero to prevent any control valve from opening.

The operator was adjusting the electric pressure regulator set point when the regulator suddenly went full scale, causing the bypass valves to open fully. The reactor pressure then began to decrease. The operator attempted to send a closing signal to the bypass valves by raising the set point of the regulator to its maximum setting. However, the regulator

signal continued to keep the valves fully open, and the reactor scrammed shortly thereafter. The operator then closed the MSIV's inside containment raising reactor pressure and lowering reactor water level.

About one minute after the scram occurred, the reactor tripped on low-low water level (about seven feet above the core). The low-low level also initiated reactor isolation, containment isolation, containment spray and core spray preliminary actuation, trip of the recirculation pumps, operation of the standby gas treatment system, emergency diesel idling, and isolation condenser operation. Due to the increase in feedwater flow, reactor water level began to increase. Two minutes after the scram the isolation condenser valves opened and added to that increase. When the water level had returned to a point 12′ 2′′ above the core, the operator tripped the core spray pumps with the reactor pressure at 600 psig.

Later analysis showed that indicated recirculation loop flows had passed through zero due to reactor depressurization. This brought the flow biased trip line down to the operating power level and tripped the reactor. The decrease in recirculation flow indication was in turn caused by steam flashing at the flow nozzles. Additionally, instrument calibration at ambient temperatures resulted in negative flow input at operating temperatures, contributing to the low flow indication.

The cause of the pressure regulator malfunction could not be determined. While checking the circuitry, the signal cleared. The amplifier and output circuitry for the regulator were replaced, and a power cutoff switch was installed in the control room to enable the operator to remove power from the regulator. By removing power from the electric regulator, the bypass valves would start to close and the mechanical pressure regulator would control reactor pressure. This action guards against similar events in the future.[18]

4.5.2.8 Suppression chamber vacuum breaker valves compromised. An equipment operator was dispatched on April 17, 1981 to open the reactor building to suppression chamber vacuum breaker valves. These valves had to be opened in order to purge the torus of nitrogen in preparation for plant shutdown. The operator discovered a scaffolding installed in front of the valves which completely prevented one of the valves from opening and allowed the other valve to open only seventy-five percent.

The vacuum breaker valves are used to equalize the pressure so that the containment external design pressure limits are not exceeded. The cause of this event was a personnel error. Contractor personnel placed the scaffolding in a position such that the valves were blocked from opening. Additionally, measures taken by cognizant personnel to prevent occurrences of this nature have been shown to be inadequate. The contractor personnel were unaware of the consequences of the placement of the scaffolding around the valve level arms.[19]

4.5.2.9 Loss of standby liquid control system. In addition to the significant events detailed above, one event occurred which is not listed as significant in the tables but is worth noting. It involves the complete loss of the standby liquid control system. The standby liquid control system is an engineered safety feature, but the event is not listed as significant because it is a backup system.

The event took place on September 25, 1972. On this date, a standby liquid control system pump had been removed from service to replace the packing. The other pump was therefore tested as is required by tech specs when one pump is out of operation. The second pump then failed to start when tested. Upon examination to determine the cause, a design error was discovered. An interlock had been included in the circuit of both pumps

to prevent their simultaneous operation. It was found that this interlock was activated when one pump was locked out, thus disabling both pumps. A circuit change was later made to correct this error.[40]

4.5.3 Trends and safety implications of reportable events

In reviewing the systems involved in the reportable events listed in Table 4.6 and other recurring problems in reportable events, six trends were noted. These six problem areas were:

(1) main steam isolation valves,

(2) vacuum breaker valves,

(3) reactor vessel cracks,

(4) control rod drives,

(5) loss of containment integrity, and

(6) outdated or insufficient procedures.

4.5.3.1 Main steam isolation valves (MSIV). MSIV failures were a recurring problem in the first half of the Oyster Creek plant life. Valve NS03B was the most troublesome. It failed leakage tests four times between 1969 and 1973. Valve stem problems caused three of the four events. On December 13, 1969 leakage was suspected in NS03B and later maintenance revealed the cause to be stem interference which prevented the valve operator from applying sufficient pressure to close the valve. Repairs involved increasing the clearance on the pilot stem and pilot guide area to prevent stem interference. When leakage was again discovered on November 5, 1971, the cause was traced to a bent stem which had to be straightened. Eventually, the valve stem was replaced after it was found to be the cause of leakage on May 22, 1973. The fourth event regarding leakage of NS03B was on September 9, 1973, when it was found that the valve disc was not self centering and therefore not seating fully during closure.

Valves NS04A and NS04B also failed leak tests. NS04A and NS04B were both involved in events occurring on September 27, 1973 and March 10, 1974. NS04A was again involved on January 16, 1974. All events were caused by packing leaks which required repacking. Additionally, valve NS04B had an unacceptable closing time on July 25, 1973 due to a leaking seal cartridge assembly on the hydraulic dashpot of the valve actuator.

Frequent problems with the MSIV's were also related to the pilot valves. Valve NS04B failed to close during an event on December 29, 1973 when a steam blowdown occurred (discussed in detail in Sect. 4.5.2.1). The cause was a sticking power operated pilot valve which was subsequently replaced. The pilot valve spool and sleeve assembly failed on valve NS04A on May 22, 1973. The spool was not free to slide properly. Traces of fine dust were found, so the spool and sleeve were cleaned. Finally, valve NS04A overtraveled during a 5% closure test on December 18, 1973, and NS03B failed to close on January 16, 1974. Both events resulted from pilot valves, and in both instances a fine dust or film buildup was found on the spool and sleeve assemblies of the pilot valves.

In 1974, the existing spool valves were replaced by manifold assembled poppet valves from a different manufacturer because the existing valves were susceptible to this common cause failure from particles carried by the pressurizing media. This replacement corrected the problem except for one minor adjustment. On July 14, 1974, valve NS04B was slow in closing because the speed control valves on the new pilot control system air operators were not properly throttled. Following this event, there were no more reported events on MSIV's until 1977, when an MSIV failed to close due to a blocked dc solenoid air vent and leaked because of seat cracks. Finally, leakage in three valves was found in 1978 from stem packing leaks and failure of the main poppet to seat.

4.5.3.2 Vacuum breaker valves. Reactor containment systems failures were the largest contributor to reported events (57) at Oyster Creek. Failures involving the two torus-to-reactor building vacuum breaker valves and the fourteen torus-to-drywell vacuum breaker valves accounted for 44% of those events. The torus-to-reactor building relief system assures that primary containment is not operated at a negative pressure relative to its surroundings. The torus-to-drywell vacuum breakers assure proper steam condensation during pipe break accidents by closing and prevent torus overpressure by opening when necessary. Thirteen events involved the torus-to-drywell valves, and twelve involved the torus-to-reactor building valves. Three of these were pressure switch, relay, and circuit design failures, and three were failures of the torus-to-drywell vacuum breaker alarm system. The remaining events were valve component failures.

The largest contributor to the valve failures was a design error in the torus-to-drywell valves. The error involved the use of a teflon bushing in which the valve hinge pin rotates. The teflon material experienced an apparent 'growing' characteristic over a period of time in all the valves. This led to failure of the valves to close because of excess friction between the hinge pin and the teflon bushing. A total of eight reported events from 1974 through 1977 reported this problem, and several events listed multiple valve failures in each event. On March 7, 1974, a shutdown commenced to do repair work following repeated failures. Some bushings were replaced and some were machined to manufacturers specifications at that time. This, however, did not solve the problem and discussions with the manufacturer concerning a permanent solution continued. Finally, in 1976, the teflon bushings were replaced with nickel plated bronze bushings. Modification to a number of valves

continued during each refueling outage until all were modified. Since 1977, Oyster Creek has not experienced any further bushing failures.

The vacuum breaker valves were also involved in an event considered to be significant (see Sect. 4.5.2.8). On April 16, 1981, workers placed a scaffold in front of the two vacuum breaker valves. One valve would not open at all and the other valve would open seventy-five percent. The contractor workers did not realize the significance of the breaker valves. A similar event occurred on December 19, 1979. A contractor placed a scaffolding in a position that blocked one of the breaker valves. The valve was prevented from opening more than fifty percent.

4.5.3.3 Control rod drive. Early in the life of the Oyster Creek plant, the control rod drives presented problems. During startup testing on October 2, 1969, tests showed excessive scram times on the 26 rod drives monitored. Oxide from the carbon steel equipment associated with the auxiliary system was plugging the internal filters within the drive, restricting the flow of water during a scram. All 137 drives were therefore modified by removing the internal filters and replacing the external filters with clean ones. Following this, all drives scrammed within the time limit specified. However, seal leakage was observed in later monitoring, and on April 7, 1970, three drives stopped six inches short of full insertion on a scram. The reactor was shut down to investigate, and many had broken seals and broken or worn springs. Subsequently, 136 of the 137 drives were removed, inspected, and disassembled, to replace the seals and broken parts. This maintenance assured proper drive operation.[41]

4.5.3.4 Reactor vessel cracks. During the initial hydrostatic leak tests on September 30, 1967, the reactor vessel had a slightly dripping leak from a stub tube. Further examination revealed:

(1) localized intergranular cracking and/or random outer surface defects in 123 of a total 137 stainless steel stub tubes,

(2) porosity in each of the 137 field welds joining the stub tubes to the control rod drive mechanism housings,

(3) minor slag inclusions in the welds joining the flux monitor tubes and the reactor vessel head, and

(4) approximately nineteen penetrant indications at the junction of the stub tube weld and the reactor vessel cladding indicating fabrication defects.

These material flaws resulted from a number of fabrication and welding problems complicated by a corrosive environment in shipping and cleaning solutions used at Oyster Creek. An extensive repair program included grinding of surface defects, overlaying exposed stub tube surfaces with weld metal cladding, and a complete rework of the field welds and shop welds.[42]

On May 13, 1974, inservice inspection revealed cracking in the reactor vessel head cladding. These cracks were the result of stress corrosion cracking. However, as indicated in previous studies, no cracks propagated into the reactor base material.[43] During refueling on May 28, a small leak was noted on the bottom of the reactor vessel at a two-inch flux monitor tube instrument penetration. It was determined that this leak was through the field weld between the incore housing and the vessel lower head. Repairs in 1968 had ground out surface defects in the weld. After repairs were made, no further leakage occurred.[44]

4.5.3.5 Loss of containment integrity. The first loss of containment integrity occurred in 1972 when the reactor building vent dampers failed to close. Due to a design error the logic circuit functioned so

that when a supply fan was racked out, the dampers would not close unless a jumper was installed. A circuit design change corrected this error.

From 1976 through 1981, the secondary containment integrity was lost on eight occasions and the primary containment integrity was lost once. Of the eight events concerning the loss of secondary containment integrity, seven were due to both air lock doors being open simultaneously. These air lock doors were either personnel air lock doors (five occassions) or railroad air lock doors (twice). The eighth event occurred when a reactor building isolation valve broke.

Maintenance and operator errors were the dominant cause for the occurrence of these events (seven of ten). The other events were due to an administrative error, a design error, and an inherent failure.

4.5.3.6 Procedural errors. Oyster Creek achieved initial critically on May 3, 1969 and achieved full power on December 7, 1969. The first procedural error was identified during reactor preoperational testing of the core spray pumps. A water hammer phenomena occurred when the core spray pumps were started and the discharge piping was empty. Procedural and design modifications in 1971 eliminated further occurrences. Subsequently, Oyster Creek has identified a procedural deficiency once a year up to 1979 with the exception of 1976 and 1978 when two errors were identified. From 1979 to 1981, the number of procedural deficiencies identified increased with the maximum number occurring in 1981 (six occassions). A total of twenty-four events resulted from procedural errors (Table 4.11).

Four of the procedural deficiences resulted in significant events. On December 14, 1978 a lack of procedural guidance led to a control rod misoperation and subsequent reactivity anomaly (see Sect. 4.5.2.2). The procedures did not cover reactor startups under peak xenon conditions.

Table 4.11. Summary of events resulting from procedural deficiencies at Oyster Creek

Number	NSIC accession number	Significant	Description
71-4	64232, 68974		Core spray pumps started when discharge piping was empty. Resulted in a water hammer. Design and procedural changes resulted.
72-16	72848		Radwaste tank activity exceeds limit due to overflow of waste-neutralizer tanks during regeneration of condensate demineralizer. Procedures modified to require verification that adequate tank capacity exists before starting regeneration.
73-10	81469		During a test, DG started but had to be shutdown by a sequence fault. Synchronization is not required for safety as power is lost, therefore, procedures changed for testing.
74-45	95315		MAPLHGR exceeded during MSIV closure tests and then power increase to full power. During the xenon transient that followed, the MAPLHGR was exceeded due to insufficient procedures.
75-18	103700		Handhole covers in standby gas treatment filter train were not in place. A formal procedure did not exist for the last filter testing. New procedures written.
76-22	118430		During a procedure review, it was discovered that the acceptance criteria in two procedures for the low and low-low reactor water level trip set points were less conservative than those specified in the technical specifications. Procedures were revised.
76-29	121031		Certain relief valve opening sequences could result in unacceptably high stresses on the torus.
77-16	132713		Circuit breakers for the parallelled valves in the core spray system failed to fully open due to improper circuit breaker overload settings. Procedures wer revised.
78-13	140263		Reactor low level switches actuate below limit. Discovery is due to new procedures. Cause in use of old procedures which were deficient.
78-33	142760	S9	Lack of procedural guidance led to control rod misoperation and subsequent reactivity anomaly. Procedures did n't cover startups under peak xenon conditions.
79-14	149450	S2, S3	Low-low-low water level trip due to lack of procedures for operator concerning a scrammed reactor and all recirculation pumps tripped. At the time, action was to start the recirculation and feedwater pumps to increase flow and the water level.
79-20	150103	S7	Both airlock doors open. Procedures failed to state the correct method for securing airlock doors.
79-29	152189		Rod block set point drift in source ran dures allowed no margin for instrument drift.
79-40	153766		Failure to include the methyl iodide removal efficiency testing on the master surveillance test schedule and in plant procedures. The technical specifications requires this test for standby gas treatment filter testing.
80-002E (occurred on 11/25/79)	159070		Plant procedures did not include provisions governing the dilution pump operation during startup. Only one was operating with the intake temperature below 60°F.
80-02	154934		Incomplete refueling procedures were revised after a fuel bundle was misorented 180 degrees.
80-24	158270		Control rod free travel interlock surveillance not performed on time. It was not listed on the master surveillance schedule and no procedures
80-32	160234	S1, S2, S7	Containment spray pump room doors were open due to lack of controls to lack of controls to ensure both doors were not open simultaneously.
81-19	164915		During a shutdown sequence, the intermediate range monitor calibration was not performed as required. Procedures did not specify the power level at which to calibrate.
81-32	168171		Safety and relief valve position systems were not tested within the time period required. Procedures requiring a test on May 8 were not issued until May 13.
81-39	169083		Component cooling water heat exchanger tubes fail. Inadequate operating procedures resulted in component cooling water system surge.
81-60	171595		The maximum allowable planer linear heat generation rate was exceeded. A load recovery at a time of xenon burnout combined to cause a rapid increase in MAPLHGR.
81-65	171541		The isolation condenser valve failed to operate. The method for backseating these valves created excessive stress on the valve backset.
81-71			The radwaste liquid effluent monitor read an order of magnitude low for eight months. It was declared operable during this time period. An improper surveillance procedure wa used.

The next two significant events involving procedural errors occurred in 1979. On May 2, a triple-low water level in the reactor occurred due to a lack of procedures for the operator concerning a scrammed reactor with all recirculation pumps tripped (see Sect. 4.5.2.6). The other event occurred on June 13 when both airlock doors were discovered open simultaneously (see Sect. 4.5.2.3). Procedures failed to state the correct method for securing airlock doors. After revising procedures, the airlock doors were discovered to be open simultaneously on four occasions; once in 1979 and three times in 1981. Additionally, both airlock doors had been open simultaneously on two occasions (1976 and 1977). No procedural deficiencies were identified at the time. Finally, the last significant event involving a procedural error occurred on July 16, 1980 (see Sect. 4.5.2.4). An operator discovered that both containment spray pump room doors were open simultaneously due to a lack of controls.

In addition to the reportable events caused by procedural inadequacies, many of the forced shutdowns and power reductions also resulted from procedural problems. Of particular note was a systems interaction problem between the gaseous rad waste system and the feedwater system. On three occasions, April 13, 1972, February 4, 1975, and May 4, 1976, air introduced from the rad waste system into the condensate system because of procedural inadequacies caused the feedwater pumps to trip. However, even after correcting the procedures following the 1975 event, the failure recurred in 1976.

4.6 Evaluation of Operating Experience

This analysis studied 230 shutdowns and power reductions, 494 reportable events, and other miscellaneous documentation concerning the operation of Oyster Creek nuclear generating station. The objective was to

indicate those areas of plant operation which have compromised plant safety. This review identified one significant challenge to plant safety and two problems which should be of continued concern.

The most serious challenge to plant safety occurred on May 2, 1979, when the loss of feedwater and subsequent loss of reactor core isolation cooling (RCIC) resulted in a triple-low level in the reactor vessel (see Sect. 4.5.2.6). Plant personnel reacted properly to restore safe conditions and bring the reactor to cold shutdown.

A potential problem underlying several events at Oyster Creek was outdated or insufficient procedures (see Sect. 4.5.3.9). Outdated procedures caused the loss of the isolation condenser system during the triple-low vessel level event described above. Insufficient procedures led to the declaration of loss of containment spray system on July 16, 1980, when both containment isolation doors to the containment spray pump compartments were open. On July 13, 1979, both doors of a personnel access penetration were left open, defeating containment integrity. The lack of proper procedural guidance directly led to the control rod misoperation and subsequent high reactivity scram on December 14, 1978.

The second area for potential continued failures involved the loss of containment integrity. Only one loss of containment event occurred prior to 1976. In 1972, the reactor building vent dampers failed to close because of a design error in the control logic. Between 1976 and 1981, an additional nine containment integrity losses occurred. Seven of these were due to both doors of airlocks being opened simultaneously. In the remaining two events, a reactor building isolation valve piston rod broke while the valve was open and a torus sample valve was left open. Human error was responsible for nine of the ten losses of containment integrity.

The two areas of operation that should be of continued concern are the losses of containment integrity and the outdated or inadequate procedures. Both of these event types have recurred throughout Oyster Creek's operating history, and both have tended to occur more frequently during the past few years.

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41. Letter from Ivan R., Finfrock, Jr., Manager, Nuclear Generating Stations, Jersey Central Power and Light Company to Dr. Peter A. Morris, Director, Division of Reactor Licensing, U.S. Atomic Energy Commission, May 18, 1970.

42. *Final Report on Reactor Vessel Repair Program, Amendment 35*, Jersey Central Power and Light Company, March 25, 1968.

43. Letter from Donald A. Ross, Manager, Nuclear Generating Stations, Jersey Central Power and Light Company to A. Giambusso, Deputy Director for Reactor Projects, Directorate of Licensing, U.S. Atomic Energy Commission, June 17, 1974.

44. Letter from Donald A. Ross, Manager, Nuclear Generating Stations, Jersey Central Power and Light Company to James P. O'Reilly, Director, Directorate of Regulatory Operations, Region 1, U.S. Atomic Energy Commission, June 14, 1974.

Appendix A: Oyster Creek

Part 1. Forced Shutdown and Power Reduction Tables

Table A1.1 1969 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	8/15		Low		Power reduction. RWCUS nonregenerative heat exchanger tube leaks increased radiation level and caused high surge tank level in the RBCCWS.	A	5	Reactor Coolant (CG)	Heat Exchangers	N3.2
2)	8/21		2		Pressure transients caused by a mechanical pressure regulator gave a faulty recirculation flow indication. The APRR reduced the trip set point to zero causing the shutdown.	A	3	Steam & Power (HA)	Valves	N1.1
3)	8/26		2		A faulty FCV permitted cold water to go to the reactor when the RFP was started.	A	3	Reactor Coolant (CH)	Valves	D1.1
4)	9/2		2		Manual opening of the bypass valves caused a low level trip.	G	3	Reactor Coolant (CC)	Valves	D1.?
5)	9/9		3	LTR 11/3/69	Failure of electric pressure regulator caused all turbine bypass valves to open.	A	3	Steam & Power (HA)	Instrumentation & Controls	D2.1
6)	9/18		1		While testing the mechanical pressure regulator, two bypass valves opened. When these closed the operator was unable to "range up fast enough and high flux trip was initiated by the IRM.	B	3	Steam & Power (HA)	Mechanical Function Units	D2.1
7)	9/18		3		During operator examination the reactor cooled down causing a power increase. Operator failed to "range up" soon enough.	E	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.1
8)	9/19		8		During surveillance testing of low steam pressure sensor when channel being tested was valved into service, both channels saw low pressure due to a common header, causing main steam isolation valves to close causing scram.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	D2.4

Table A1.1 (Continued)

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	9/20		8		Steam carryunder test in progess, reactor level being maintained at 56", No. 2 channel tripped on low level; when attempt was made to raise level, No. 1 channel tripped.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
10)	9/23		16		Condenser low vacuum trip occurred while opening high pressure and intermediate feedwater heater shell side drains after tripping turbine.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.0
11)	9/24		8		Loss of condenser vacuum.	G	3	Steam & Power (HA)	Heat Exchangers	D2.5
12)	9/29		8		IRM spike while changing feedwater flow control from automatic to manual.	A	3	Instrumentattion & Controls (IA)	Instrumentation & Controls	N2.4
13)	11/16		33		While performing carryover test with steam flow through bypass valves, turbine turning gear motor tripped. Operator initiated manual scram prior to low vacuum scram signal.	B	2	Steam & Power (HA)	Turbines	N1.2
14)	11/20		62		High level in reheater moisture separator drain tank caused turbine trip and subsequent high flux trip of reactor.	A	3	Reactor Coolant (CB)	Accumulators	D2.3
15)	12/1		78		High level in reheater moisture separator drain tank caused turbine trip.	A	3	Reactor Coolant (CC)	Accumulators	D2.3
16)	12/1				High level in reheater moisture separator drain tank caused turbine trip.	A	3	Reactor Coolant (CC)	Accumulators	D2.3

Table A1.1 (Continued)

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
17)	12/5		78		While attempting to raise power to 1600 MWt, steam flow limit was reached. Reactor pressure increased to 1032 psig and erroneously tripped isolation condenser on high pressure (should trip at 1060 psig). Cooler water from isolation condenser piping system caused high flux scram.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N2.3
18)	12/16		21		When valving in sensors for high flow on main steam line after calibration, erroneous signal caused trip due to high steam flow.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.0
19)	12/16		21		Low reactor level trip. Cleanup system was out of service and bypass valves were being used to aid in reactor level control. As level increased, operator opened bypass valves too fast.	G	3	Reactor Coolant (CH)	Valves	D1.7
20)	12/18		41		Condenser low vacuum trip caused by failure to isolate waste sample Tank A after drain pump tripped.	G	3	Steam & Power Conversion (HC)	Pump	D2.5
21)	12/31		83		Low water level trip resulting from malfunction of three element controllers on feedwater flow caused by stuck excess flow check valve on steam line sensor.	A	3	Instrumentation & Controls (IA)	Valves	D2.7

Table A1.2 1970 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/3	<24	74		Condenser low vacuum trip caused by inleakage through the expansion joint between C condenser and the exhaust section of the C low pressure turbine.	A	3	Steam & Power Conversion (HC)	Pipes, Fittings	D2.5
2)	1/19	<24	83		Low water level trip resulting from a loss of the steam flow signal to the feedwater control system.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	D2.7
3)	2/15	<24	70		High level in the moisture separator drain tank caused a turbine trip and a resulting reactor high neutron flux scram.	A	3	Reactor Coolant (CC)	Accumulators	D2.3
4)	2/18	<24	Low		High neutron flux in the IRM's while holding the reactor in hot standby.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
5)	4/7	<24	83		Main steam isolation valves closed due to a steam line low pressure trip signal. While making a trip test of the spare exciter breaker, a short tripping three recirculating pumps occurred lowering the D.C. control voltage. The slow closure of the valves caused the pressure to momentarily drop below 850 psig, thereby causing the low steam pressure signal.	B	3	Electric Power (EC)	Circuit Closures/ Interrupters	D3.1
6)	4/14	<24	83		Low water level trip resulting from EPR pressure oscillations.	A	3	Steam & Power Conversion (HA)	Instrumentation & Controls	D1.3

Table A1.2 (Continued)

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
7)	4/19	~700	Low		Neutron monitoring scram in the IRM-APRM overlap range while shutting down plant. Inspection and repair of CRD mechanisms.	G	3	Reactor (RB)	Instrumentation & Controls	N6.1
8)	6/17	~96	83		Main steam isolation valves closed after receiving a main steam line break signal due to high ambient tunnel temperatures.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	D2.4
9	7/3	~24	83/72		Power reduction. Check for condenser leak.	A	5	Steam & Power Conversion (HC)	Heat Exchangers	N3.2
10)	7/11	~24	83		Turbine load was reduced manually to 200 MWe and a turbine trip manually initiated. Reactor scram caused by high pressure following turbine trip. Heavy grass at Intake Structure required load reduction and turbine trip.	A	3	Auxiliary Water (WA)	Filters	N1.1
11)	7/13	<24	83/78		Power reduction. Pressure oscillations caused by dirt in an EPR pilot valve.	A	5	Steam & Power Conversion (HA)	Valves	N1.1

A1.2 (Continued)

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
12)	7/25	~ 24	83-76		Power reduction. Replace brushes on recirculation pump M-G sets.	A	1	Reactor Coolant (CB)	Pumps	N1.1
13)	8/1	<48	83		Electrical load was reduced and the turbine taken off the line due to heavy grass at Intake Structure. A rapid decrease in vacuum was noticed. The reactor was manually scrammed before the vacuum decreased to the scram set point.	A	2	Auxiliary Water (WA)	Filters	N1.1
14)	8/23	<24	83-41		Power reduction. Reduced load to 250 MWe to replace EPR amplifiers and plug 4 condenser tubes.	A	5	Steam & Power (HA)	Heat Exchangers & Instrumentation & Controls	N2.1
15)	9/16	<24	83		Electrical load reduced and turbine taken off the line due to increase in unidentified leakage into drywell sump (leaking stem packing on "E" Recirculation Pump Discharge Valve). Reactor was manually scrammed from low power.	A	2	Reactor Coolant (CB)	Pumps	N1.1
16)	9/17	<48	62	LTR 10/8/70	Power oscillations occurred at 1600 MWt. Reactor power was reduced to 1200 MWt by reducing recirculation flow. A turbine trip occurred caused by high level in moisture separator drain tank. The reactor scrammed on high flux.	A	3	Reactor Coolant (CB)	Accumulators	D2.3

A1.2 (Continued)

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DRE(B)/ NSIC(N) Event Category
17)	9/21	~24	76-76		Power reduction. Pressure oscillations due to dirt accumulation in the Moog Valve required load reduction.	A	5	Steam & Power (HA)	Valves	N1.1
18)	9/22	~24	76		EPR malfunction caused low main steam line pressure. Reactor scram on MSIV closure.	A	3	Steam & Power (HA)	Instrumentation & Controls	B1.3
19)	10/7	~24	54		Electrical load was reduced to 290 MWe to repair condenser leak. Turbine tripped on high moisture separator drain tank level. Reactor scram on high pressure.	A	3	Reactor Coolant (CC)	Accumulators	B2.3
20)	12/2	<24	88		Electrical load was reduced and turbine taken off the line due to rapid increase in drywell oxygen concentration. Manual scram of reactor from low power. (Found leaking pneumatic tool lubricator in drywell).	A	2	Engineering Safety Features (SA)	Vessels, pressure	N1.1
21)	12/25	~24	88		Rapid closure of #2 Stop Valve during valve test caused actuation of turbine trip anticipatory scram.	B	3	Steam & Power (HA)	Valves	B2.3
22)	12/25	~24	88		After complete check of all systems pertinent to Stop Valve closure and anticipatory trip, #2 Stop Valve was retested at light load with a repeat of the event described above.	B	3	Steam & Power (HA)	Valves	B2.3

Table A1.3 1971 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/8	26	88-16		Power reduction to correct the difficulty encountered during previous routine tests of No. 2 stop valve.	A	5	Steam & Power (HA)	Valves	N1.2
2)	1/25	67	88		Shut down to repair a leak in the 2B CCW cooling coil inside the DWEDT.	A	1	Auxiliary Water (WB)	Heat Exchangers	N1.1
3)	3/3	40	88		Shut down to repair a leak in the RBCCW piping on the discharge side of the DWEDT coil.	A	1	Auxiliary Water (WA)	Pipes, fittings	N1.1
4)	3/9	18	88-36		Power reduction to change from rod sequence "B" to "A" due to "B" pump malfunctioning.	F	5	Reactor (RB)	Pump	N1.1
5)	5/28	3	88-49		Power reduction to replace brushes on "A" and "C" recirculating pump M-G sets.	A	5	Reactor Coolant (CB)	Generators	N1.1
6)	6/4	1	68-45		Power reduction to replace brushes on "A" and "E" recirculating pump M-G sets.	A	5	Reactor Coolant (CB)	Generators	N1.1
7)	6/9	3	[illegible]-76		Power reduction. Over heating of the feed pump room due to ventilation duct problems.	A	5	Other Auxiliary (AA)	Pipes, fittings	N1.1
8)	7/2	1	88-77		Power reduction. Reduced power to change brushes on "B" recirculating pump M-G set and on "A" recirculating pump.	A	5	Reactor Coolant (CB)	Generators	N1.1

Table A1.3 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	8/6	8	88-73		Power reduction. Plugged 6 leaking tubes in "C" (north) condenser.	A	5	Steam & Power (HC)	Heat Exchangers	N3.1
10)	8/9	3	88-?		Power reduction. Reduced power to replace brushes on "E" recirculating pump M-G set. Found 2 burned spots on the generator exciter ring.	A	5	Reactor Coolant (CB)	Generators	N1.1
11)	8/14	10	85-?		Power reduction. Reduced power to remove burned spots from the generator exciter ring.	A	5	Reactor Coolant (CB)	Pumps	N1.1
12)	11/16	<24	66	LTR 12/17/71	Shut down due to rupture at the flexible discharge coupling on 1-2 air compressor.	A	2	Auxiliary process (PA)	Pipes, fittings	N1.1
13)	12/11	43	96-94	LTR 1/12/72	Power reduction. Reduced power due to leak in the Isolation condenser vent line.	A	5	Reactor Coolant (CE)	Pipes, fittings	N1.1

TABLE A1.4 1972 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/22		95-51	LTR 2/22/72	Power reduction. Loss of DC power to 1A 4160 V Bus during tests caused trip of three (3) recirculation pumps and one (1) reactor feed pump.	B	5	Electric Power (EC)	Mechanical function units	D3.1
2)	1/28	~96	95		Unit shutdown due to increasing unidentified leak rate in the drywell.	A	1	Reactor Coolant (CC)	Valves	N3.1
3)	2/3		95-?	LTR 2/23/72	Power reduction. Loss of DC power from "A" battery bus caused trip of three (3) recirculation pumps and one (1) reactor feed pump.	G	5	Electric Power (EC)	Mechanical function units	D3.1
4)	2/5		95-?		Power reduction. Feedwater heater 1A3 tripped, reduced load to reset.	A	5	Reactor Coolant (CH)	Heater, electric	N1.1
5)	2/6	24	95-?		Power reduction to repair "A" reactor feed pump seals	A	5	Reactor Coolant (CH)	Pumps	N1.1
6)	4/13		95		Reactor Scram on low reactor water level caused by feedwater pump trip. A misoriented switch vented hot wells to atmosphere through rad waste.	G	3	Radioactive Waste Management (MA)	Instrumentation & Controls	D2.7
7)	4/14		95		Reactor Scram in IRM range while performing operator training	G	3	Reactor Coolant (CC)	Heat Exchangers	N6.2
8)	4/24		95		Reactor Scram on low condenser vacuum caused by worn seals on SJAE drain pumps.	A	3	Reactor Coolant (CG)	Pumps	D2.5

Table A1.4 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	4/30		95-76		Power reduction. "A" recirculation pump out of service due to fire in M-G set.	A	5	Reactor Coolant (CB)	Generators	D3.1
10)	6/22		95		Reactor Scram due to trip of reactor high pressure switches while performing surveillance tests.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.3
11)	8/9	106	98		A spurious trip on sensor RN06B in Reactor Protection System No. 1 just prior to receipt of a simulated trip on sensor RN06D in Reactor Protection System No. 2 during a calibration test on the main steam line radiation sensors.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
12)	8/13	11			Power reduction due to leak in steam header drain line.	A	3	Reactor Coolant (CC)	Pipes, fittings	N3.1
13)	8/18	36	98-61		Power reduction to replace snubber on regulating valve of "C" feedwater pump.	A	5	Reactor Coolant (CH)	Shock Suppressors and Supports	N1.1
14)	8/21		98-93		Power reduction. A heater cascade valve closed causing 1 B2 heater to flood and trip.	A	5	Reactor Coolant (CH)	Valves	N1.1
15)	8/25	66	98	LTR 9/28/72	Loss of air to the control rod drive system caused control rods to scram individually. A reactor scram was initiated by reactor low water level.	A	3	Instrumentation & Controls (IA)	Relays	N1.1

Table A1.4 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
16)	9/25		98-?	LTR 10/6/72	Power reduction. Surveillance test indicated that 1-2 standby liquid control system pump would not start. 1-1 was being repacked.	A	5	Instrumentation & Controls (IB)	Instrumentation & Controls	N2.1
17)	11/9		98-97		Power reduction to plug a leaking tube in "B" condenser.	A	5	Steam & Power (HC)	Heat exchangers	N1.1
18)	11/11				Increase of reactor pressure to the high pressure trip point when a main steam isolation valve was closed for a test.	B	3	Reactor Coolant (CC)	Valves	N6.0
19)	11/28	4	98-93		Power reduction to plug 2 tubes in "A" condenser.	A	5	Reactor Coolant (CB)	Heat exchangers	N1.1
20)	12/3		98		Loss of "B" reactor recirculating pump from an MG set failure caused a turbine trip due to high level in moisture separator 1-1.	A	3	Reactor Coolant (CB)	Generator	D3.1
21)	12/5		98-92		Power reduction to perform maintenance on "E" recirculating pump M-G set tachometer.	B	5	Reactor Coolant (CB)	Generator	N1.1
22)	12/8		98-96		Power reduction due to turbine control valve oscillation	A	5	Steam & Power (HA)	Valves	N1.1

Table A1.4 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
23)	12/10		96-94		Power reduction due to turbine control valve oscillation.	A	5	Steam & Power (HA)	Valves	N1.1
24)	12/12		94-93		Power reduction due to turbine control valve oscillation.	A	5	Steam & Power (HA)	Valves	N1.1
25)	12/24	28	93-67		Power reduction to repair feed-water heater.	A	5	Reactor Coolant (CH)	Pipes, fittings	N1.1
26)	12/29		98	LTR 1/17/73	Operator opened door on trans-former which simulated loss of main generator field.	G	3	Instrumenta-tion & Controls (IA)	Instrumenta-tion & Controls	D2.3

Table A1.5 1973 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	12/29/72	240			Loss of generator field closed main stop valves.	G	4	Instrumentation & Controls (IA)	Instrumentation & Controls	
2)	1/14	<24	90-89		Power reduction. Turbine control valve oscillations.	A	5	Steam & Power (HA)	Valves	N1.1
3)	2/17	11	98		High level in the moisture separator caused a turbine trip.	B	3	Reactor	Accumulators	D2.3
4)	3/9	<24	98-92		Power reduction. Replace brushes on "B" and "D" recirculating pumps M-G sets.	A	5	Reactor Coolant (CB)	Generators	N1.1
5)	3/13-4/13	~700	97-92		Power reduction. High peaking factor caused by inoperable control rod 18-15.	A	5	Reactor (RB)	Control rod drive mechanisms	N1.1
6)	4/13	~1300	93		High level in moisture separator caused a turbine trip.	A	3	Reactor Coolant (CC)	Accumulators	D2.3
7)	6/21	19	71		Scram due to turbine trip following rapid recirculating flow load reduction caused by trip of feedwater pump "B".	A	3	Reactor Coolant (CH)	Pumps	D2.7
8)	6/22	<24	71-42		Reactor high pressure caused by sluggish turbine control valve operation.	A	3	Steam & Power (HA)	Valves	N1.1

Table A1.5 (Continued)

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	6/30	21	97		Turbine-generator trip due to relay operation on both 230 KV lines due to an electric storm.	A	3	Electric Power (EA)	Circuit closers/ interrupters	D2.2
10)	7/21	96	98		The plant was shut down to determine the cause of excessive unidentified leakage inside the primary containment. Subsequently, work was done on a leaking feed-water check valve.	A	1	Reactor Coolant (CH)	Valves	N3.1
11)	[illegible]	<24	98-80		Power reduction. Reactor power was decreased to make repairs on a reactor feedwater pump.	A	5	Reactor Coolant (CH)	Pumps	N1.1
12)	8/[illegible]4	<24	98-92		Power reduction. Reactor power was reduced to comply with limits on the average planar linear heat generation rate produced in the core.	A	5	Reactor (RB)	Fuel Elements	N1.1
13)	8/[illegible]0				Power reduction. Reactor power was reduced to repair leaking tubes in one of the main condensers.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
14)	9/[illegible]	686	94	AO 73-21	During a deliberate plant shutdown to inspect and repair the hydraulic shock and sway arrestors inside the primary containment, the reactor scrammed at approximately 250 MWt due to reactor low water level.	A	3	Other (XX)	Shock suppressors and supports	N1.1
15)	1[illegible]/17	~24	89-58		Power reduction. Reactor power was decreased in order to perform a main steam line isolation valve full closure test.	B	5	Reactor Coolant (CC)	Valves	N1.2

Table A1.5 (Continued)

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
16)	11/25	~24	92-90		Power reduction. The reactor was operated at a reduced power because the second stage reheaters were not in service due to a steam leak.	A	5	Reactor Coolant (CH)	Heat exchangers	N1.1
17)	11/25	27			The reactor scrammed due to a neutron monitoring system trip which was initiated by an inadvertent loss of the continuous power supply.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N1.1
18)	12/18	<24	94-78	AO 73-32	Power reduction. Reactor power was decreased to replace a main steam line isolation valve pilot test valve.	A	5	Reactor Coolant (CC)	Valves	N1.1

Table A1.6 1974 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	3/7	105	95	AO 74-16	The plant was shutdown in a controlled manner due to a failure of the torus to drywell vacuum relief valves during an operability surveillance.	A	1	Engineered safety features (SA)	Valve	N1.2
2)	3/24	<24	95-67		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
3)	6/30	5	Low		During a plant startup the reactor scrammed due to the neutron flux exceeding the scram set point. Cold water was injected due to failure of feedwater control valve.	A	3	Reactor Coolant (CH)	Valve	D1.1
4)	7/5	<24	71-69		Power reduction to remove "C" Feedwater Pump from service to perform maintenance on the leaking "C" Feedwater Pump Check Valve.	A	5	Reactor Coolant (CH)	Valve	N3.1
5)	7/13	42	69		The plant was shutdown in a controlled manner due to a problem of maintaining drywell N_2 content. A leaking section of instrument air piping to a testable check valve on the core spray system was replaced.	A	1	Engineered safety features (SA)	Pipes	N1.1
6)	8/3	<24	100-63		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1

Table A1.6 (Continued)

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
7)	8/15	~24	100-77		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
8)	8/29	<24	100-72		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
9)	9/2	<24	100-66		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
10)	9/8	~24	101-68		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
11)	9/15	~24	100-68		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
12)	9/21	≤24	99-71		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
13)	9/22	≤24	71-68		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
14)	9/25	21	100		The reactor scram resulted from an acceleration relay turbine trip when the generator reacted to an electrical system disturbance.	H	3	Electric power (EA)	Generators	D2.3

Table A1.6 (Continued)

No.	Date (19 74)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
15)	10/8	145	101		The plant was shutdown in a controlled manner due to an increase in the drywell unidentified leak rate.	A	3	Reactor Coolant (CH)	Valve	N3.1
16)	11/9	<24	99-64		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
17)	11/11	67	92		The plant was shutdown in a controlled manner due to an increase in the drywell unidentified leak rate and to repair leaking condenser tubes.	A	1	Reactor Coolant (CH)	Valve	N3.1
18)	11/22	<24	100-91		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
19)	12/1	~48	97-87		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
20)	12/4	~24	100-90		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
21)	12/14	~24	103-60		Power reduction. 1 A 3 high pressure heater relief valve.	A	5	Reactor Coolant (CH)	Valve	N1.1

Table A1.7 1975 Forced Outages and Power Reductions for Oyster Creek

No.	Date (19 75)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/20	<24	99-87		Power reduction to make repairs on leaking condenser tubes.	A	5	Steam & Power (HD)	Heat exchangers	N3.1
2)	2/4	133	97		An automatic reactor scram occurred due to low reactor water level. The water level decreased when all three (3) reactor feedwater pumps tripped simultaneously on low suction pressure. The drop in suction pressure to the feedwater pumps was caused by air being introduced into the condensate header which occurred when water from waste sample tank "A" was being transferred to the hotwell and simultaneously being used as the source of water for backwashing the radwaste floor drain filter.	G	3	Radioactive Waste Management (MA)	Pump	D2.7
3)	2/21	~24	97-61		Power reduction to accommodate feedwater heater repair.	A	5	Reactor Coolant (CH)	Valve	N1.1
4)	6/4	~24	84-64		Power reduction to accommodate condenser repairs.	A	5	Steam Power (HC)	Heat exchangers	N3.1
5)	6/13	49	82		The plant was shutdown in order that the source of high unidentified leakage could be located.	A	1	Reactor Coolant (CH)	Valve	N3.1
6)	7/25	15	82		Loss of power to the air ejector off gas system pressure regulator valves caused low condenser vacuum.	A	3	Electric power (EC)	Circuit closures	D2.5

Table A1.7 (Continued)

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
7)	8/27	105	10		Low condenser vacuum occurred when condenser "A" was returned to service under low circulating water flow conditions.	G	3	Steam & Power (HC)	Heat exchangers	D2.5
8)	9/24	155	85		High reactor water conductivity Occurred when a demineralizer was returned to service.	B	2	Reactor Coolant (CG)	Demineralizer	N6.0
9)	10/5	30	32		Test circuit malfunctioned which Closed 3 stop valves instead of 1.	B	3	Steam & Power (HA)	Instrumentation & Controls	D2.3
10)	11/24	161	80		Extensive condenser tube leaks.	A	1	Steam & Power (HC)	Heat exchangers	N3.1
11)	12/12	~24	84-66	AO 75-33	Power reduction. Temporary loss of power to the "A" 125V DC bus during load testing tripped three recirc pumps and one FW pump.	G	5	Electric Power (EC)	Circuit closers/ interrupters	D3.1
12)	12/19	32	90		Leak in isolation condenser valve.	A	1	Engineered safety features (SB)	Valve	N3.1
13)	12/26	120	80		Main condenser retubing and refueling outage.	A	1	Steam & Power (HC)	Heat exchangers	N3.1

During the period from July 1 to December 31, in addition to the above, there were 23 power reductions to repair leaking condenser tubes to maintain the condensate demineralizer differential pressure below the operating limit.

Table A1.8 1976 Forced Power Outages and Reductions for Oyster Creek

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event *	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	12/26/75	~1700	80		Main condenser retubing and refueling outage.	A	4	Steam & Power (HC)	Heat exchangers	
2)	4/1	~410	86-73		Power reduction. Failure of the waste concentrator prevented condensate demineralizer regeneration.	A	5	Radioactive waste management (MA)	Heat exchangers	N1.1
3)	5/4	19	92		Loss of feedwater pumps due to air leak onto condensate system.	G	3	Reactor Coolant (CH)	Pumps	D2.7
4)	6/3	~24	92-55		Power reduction. Grass accumulation on the traveling debris screens.	A	5	Steam & Power (HF)	Filters	N1.1
5)	7/2	~24	93-84		Power reduction. A MSIV failed to close on daily test.	A	5	Reactor Coolant (CC)	Valve	N1.2
6)	7/26	108	93		Leak in feedwater check valve.	A	1	Reactor Coolant (CH)	Valve	N3.1
7)	7/30		Low		Low reactor water level. Improper pressure regulator set point.	A	3	Steam & Power (HA)	Valves	N1.1
8)	7/30		Low		Startup terminated because of packing leaks on V-1-106 and "A" recirculating pump dishcarge valve.	A	1	Reactor Coolant (CB)	Valves	N3.1

Table A1.8 (Continued)

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	10/29	15	97-86		Power reduction. Maintenance on recirculating pumps M-G sets.	B	5	Reactor Coolant (CB)	Generators	N1.1
10)	11/15-12/30	1108	96-82		Power reduction. Condenser tube leakage.	A	5	Steam & Power (HC)	Heat exchangers	N1.1
11)	12/22	12	88-63		Power reduction. The line to the operable stack gas monitor froze.	A	5	Radioactive waste management (MB)	Pipe	N9.2

Table A1.9 1977 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	10/21	77			Reactor scram caused by the malfunction of a stop valve test solenoid during a surveillance test on the turbine stop valves. Test valves were replaced and general plant maintenance accomplished during the outage.	B	3	Steam & Power (HA)	Valve operators	D2.3
2)	11/14	27			Neutron flux scram due to loss of power to PRV's.	G	3	Reactor Coolant (CC)	Valves	D2.1
3)	12/03	23	100		Inadvertent closure of a main steam isolation valve.	G	3	Reactor Coolant (CD)	Valves	D2.4

Table A1.10 1978 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	4/2		98		Power reduction. Condenser tube leaks.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
2)	6/14	55	~85		Leaking feedwater check valve hinge pin.	A	1	Reactor Coolant (CH)	Valves	N3.1
3)	8/14	~24	~70-30		Power reduction to clean both turbine building closed cooling water heat exchangers.	B	5	Auxiliary Water (WA)	Heat exchangers	N1.1
4)	8/24	38	~70		Repaired drywell sump pump.	A	1	Radioactive waste management (MA)	Pumps	N1.1
5)	9/4	28	69		Malfunction of feedwater control system.	A	3	Reactor Coolant (CH)	Instrumentation & Controls	D2.7
6)	12/7	~48	Low		Resin fines caused high conductivity in reactor water.	B	2	Reactor Coolant (CX)	Dimeralizer	N1.1
7)	12/13	124	100		MSIV closed during a surveillance test.	B	3	Reactor Coolant (CD)	Valves	D2.4

Table A1.11 1979 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/5	~24	100-91		Power reduction. Cycled "E" electromatic relief valve to eliminate leakage into torus.	A	5	Reactor Coolant (CC)	Valve	N3.1
2)	1/12	~24	100-91		Power reduction to try to locate a suspected tube leak.	A	5	Steam & Power (HC)	Heat exchangers	N3.1
3)	1/15	86	100		Cleanup system pipe high vibration when returning it to service.	G	3	Reactor Coolant (CG)	Pipes	N6.0
4)	2/6	17	100		"C" feedwater pump tripped when breaker cubicle door was closed, shaking the "C" differential relay; scram occurred from a low water level after the pump trip.	G	3	Reactor Coolant (CH)	Relays	D2.7
5)	2/9	~24	100-35		Power reduction. Condenser vacuum rapidly decreased.	A	5	Steam & Power (HC)	Heat exchangers	N1.1
6)	2/13	<24	100-65		Power reduction. Replace leaking scram pilot solenoid valve.	A	5	Instrumentation & Controls (IA)	Valve	N2.1
7)	3/22	~24	100-83		Power reduction. "D" recirculating pump seal failure.	A	5	Reactor Coolant (CB)	Pumps	N3.1

Table A1.11 (Continued)

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	3/22		100-?	LER 79-5	Power reduction. "C" recirculating pump tripped due to faulty voltage regulator on M-G set.	A	5	Reactor Coolant (CB)	Generators	D3.1
9)	3/23		100-?	LER 79-5	Power reduction. "C" recirculating pump tripped due to faulty voltage regulator on M-G set.	A	5	Reactor Coolant (CB)	Generators	D3.1
10)	3/		100-?	LER 79-5	Power reduction. "C" recirculating pump tripped due to faulty voltage regulator on M-G set.	A	5	Reactor Coolant (CB)	Generators	D3.1
11)	3/26	316	100		Repair "D" recirculation pump seal.	A	1	Reactor Coolant (CB)	Pumps	N1.1
12)	4/17		100	LER 79-8	"C" recirculating pump M-G set failure.	A	1	Reactor Coolant (CB)	Generators	N1.1
13)	5/2	728	98	LER 79-14 LTR 5/29/79	A reactor high pressure scram during testing caused all the recirculation pump discharge valves to close resulting in a triple low water level above the core for 36 min during tests of isolation condenser pressure switches.	B	3	Engineered safety features (SD)	Instrumentation & Controls	D2.7
14)	June		?-?		Power reductions. Repeated low vacuum on "C" condenser.	A	5	Steam & Power (HC)	Heat exchangers	N1.1
15)	June		?-?		Power reductions due to cooling water intake problems.	A	5	Steam & Power (HF)	Filters	N1.1

Table A1.11 (Continued)

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
16)	June		?-?		Power reductions due to failure of a generator voltage regulator.	A	5	Steam & Power (HA)	Generators	N1.1
17)	7/15	~24	100-45		Power reduction to repair 1 A3 feed-water heater and clean debris from water intake.	A	5	Reactor Coolant (CH)	Heat exchangers	N1.1
18)	7/19		90-40		Power reduction. Repair "A" recir-culating pump M-G set.	A	5	Reactor Coolant (CB)	Generators	N1.1
19)	9/11	<72	100-26	LER 79-23	Power reduction to repair 2 leaking feedwater check valves.	A	5	Reactor Coolant (CH)	Valves	N3.1
20)	9/14	<72	100-?		Power reduction to replace auxiliary flash tank pump motor.	A	5	Reactor Coolant (CC)	Motors	N1.1
21)	9/17	32			A worker struck a cable tray attached to a reactor protection system instru-ment rack.	G	3	Instrumenta-tion & Controls (IB)	Relay	N6.3
22)	11/6		100-88	LER 79-42	Power reduction. "A" electromatic relief valve opened. It was manually closed and power lowered during repairs.	A	5	Reactor Coolant (CC)	Instrumenta-	N2.1
23)	11/23	57	100		Inadvertent opening of an isolation condenser return valve during backseating.	G	3	Reactor Coolant (CE)	Valves	N6.1

Table A1.12 1980 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1980)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	7/31	100	80		Leak in control nitrogen system inside the drywell.	A	1	Engineered safety features (SE)	Pipes, fittings	N1.1
2)	8/4		Low		Erroneous loss of condenser vacuum signal tripped turbine. Reactor tripped on high flux in range 9 of the IRMs.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	D2.3
3)	8/6		80	LER 80-33	Power reduction due to high O_2 concentration in the torus.	A	5	Engineered safety features (SA)	Vessel	N1.1
4)	8/6		80-15		Power reduction due to high drain tank levels.	A	5	Reactor Coolant (CH)	Vessel	N1.1
5)	8/12		80-?		Power reduction due to flash tank problems.	A	5	Reactor Coolant (CH)	Vessel	N1.1
6)	8/15	0.3	90	LER 80-36	Loss of stack gas sample pump.	A	1	Radioactive waste management (MB)	Pump	N1.1
7)	9/18	120	90		Leaking drain line on feedwater check valve.	A	1	Reactor Coolant (CH)	Valve	N1.1
8)	10/26	~24	100-32		Power reduction due to RBCCW fouling.	A	5	Auxiliary Water (PB)	Heat exchangers	N1.1
9)	11/4		96		Power reduction for an ABRO on a condensate demineralizer.	A	5	Steam & Power (HC)	Demineralizer	N1.1

Table A1.12 (Continued)

No.	Date (1980)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10)	11/7	75	90-?		Power reduction for maintenance on "C" feedwater valves and turbine stop valve.	A	5	Reactor Coolant (CH)	Valves	N1.1
11)	11/21	190	98		Leaking feedwater heater tubes and valves.	A	1	Reactor Coolant (CH)	Heat exchangers and Valves	N3.1
12)	12/2		99-?		Power reduction. Vibrations caused by the Hotwell Sucker/Dumper Station.	A	5	Steam & Power (HC)	Pump	N1.1
13)	12/12	13	99-38		Power reduction "C" feedwater heater relief valve.	A	5	Reactor Coolant (CH)	Valve	N1.1
14)	12/19	~500	?-?		Power reductions. Rad waste system cannot process concentrated waste as designed. This caused high condensate demineralizer differential pressure.	A	5	Radioactive waste management (MA)	Demineralizers	N1.1

Table A1.13 1981 Forced Outages and Power Reductions for Oyster Creek

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/18				Power reduction. "C" south condenser water box developed tube leaks which potentially could cause a chloride intrusion. 14 tubes were plugged.	A	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.1
2)	2/25				Power reduction. "C" south condenser water box developed tube leaks. Reduced load to perform helium test. Terminated helium test due to procedural problems and exposure.	A	5	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.1
3)	3/12	103			Shutdown to repair steam leaks in the condenser bay to facilitate maintenance on "A" north water box which was causing high conductivity in "A" hotwell.	B	1	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.1
4)	3/28	92	90		Shutdown to correct increasing leak rate in primary containment caused mainly by the "C" recirculating pump seal and a leak in 1-5 drywell cooler.	B	1	Reactor Coolant (CB)	Pumps	N3.1
5)	4/6				Power reduction. "B" feedwater string was taken out of service to avoid impingement and further damage from tube leaks.	F	5	Reactor Coolant (CH)	Instrumentation & Controls	N3.1
6)	4/17	309			Shutdown for TMI modifications and maintenance.	B	1	Unknown (ZZ)	Unknown	N1.1.4
7)	4/17	695	0		Shutdown for TMI modifications and maintenance.	D	4	Unknown (ZZ)	Unknown	N8.0

Table A1.13 (continued)

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	6/26	116	70		Low condenser vacuum due to problems with steam traps for steam jet air ejectors.	A	3	Steam & Power (HC)	Heat Exchangers (Condensers)	D2.5
9)	8/15	1540	60	LER: 81-038	Shutdown to correct an increasing drywell unidentified leak rate and condenser vacuum problems.	B	1	Steam & Power (HC) Auxiliary Water (WA)	Heat Exchangers (Condensers) Heat Exchangers	N3.1
10)	10/19	22			Inadvertent closing of a MSIV during daily testing.	G	3	Reactor Coolant (CD)	Valves	D2.4
11)	10/21	13			Conduit carrying control cable for V-7-31 and the AOG building dropped off the side of the reactor building.	A	1	Radioactive Waste Management (MB)	Electrical Conductors	N1.1.4
12)	10/30	78			Shutdown to correct steam leaks from second stage reheater manway.	B	1	Steam & Power (HA)	Heat Exchangers	N3.1
13)	12/9	531	100		Shutdown to investigate isolation condenser valve operability concerns and correct operability problems.	B	1	Reactor Coolant (CE)	Valves	N1.1.4

Appendix A: Oyster Creek

Part 2. Reportable Event Coding Sheets

Table A2.1 Coding Sheet for Reportable Events for Oyster Creek - 1969

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
69-1	58492	Feb-Mar 1969	9/14/70	A	SA,SH-D	KK	-	C	AK	G	N	Standby gas treatment system pre-op testing-(several reactor building leaks)
69-2	38757	9/9	11/3	B	HA.CB	NN,OO	M	B	BK,AY	D	S7	Turbine pressure regulator malfunction, recirc. pump trip (Reactor Shutdown)
69-3	38758	10/2	10/14	B	RB	J,P,FF	-	B	AQ,BI,EJ, AD	C	N	Control rod drive filters plugged causing excessive scram times
69-4	40504	12/13	12/24	B	CD	OO	N	B	AT	D	N	Suspected leak in MSIV

Table A2.2 Coding Sheet for Reportable Events for Oyster Creek - 1970

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
70-1	47285 58513	4/7	4/21	B	RB	J,FF	-	C	AT	D	N	Seal leakage in control rod drives (Reactor shut-down 4/19 for investigation)
70-2	56979	9/17	10/8	B	HA	OO,F	M	B	AQ	G	N	Load oscillations due to turbine-generator (power reduction)
70-3	56980	10/20	11/2	D	SA	OO	-	C	AW	D	N	Torus oxygen sample valve leak

Table A2.3 Coding Sheet for Reportable Events for Oyster Creek - 1971

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
71-1	63220	3/19	5/17	B	CE	-	P	C	EE	D	N	Relay failure (blocked by insulation)
71-2	64245	4/22	6/15	B	AD	-	-	B	AA,AD	D	N	Package boiler flue collapsed
71-3	63310	5/7	6/14	B	SH-B	-	M	C	AL,EE	D	N	Containment spray pressure sensor fails
71-4	64232 68974		6/25	B	SF-D	Z	-	C	HH	B	N	Inspection and modifications after core spray water hammer
71-5	64602	6/3	7/21	B	SH-B	OO,X,F, QQ	-	C	BF	D	N	Containment spray valve breaker malfunction
71-6	64602	6/11	7/21	B	CE	QQ	P	C	BH	D	N	Isolation condenser valve relay failure
71-7	66468	7/6	9/9	B	SH-D	OO,HH, QQ	-	B	AG	D	N	Minimum flow valve solenoid failure
71-8	66467	8/2	9/9	B	SH-D	OO	M	B	AW	D	N	Standby gas treatment valve leak
71-9	66465	8/12, 13,22	9/9	B	MA	N,LJ	-	B	OD	D	N	Rad waste tank activity exceeds .7 curies
71-10	66466	8/17	9/9	B	RB	J,JJ	I	C	AG	D	N	Scram dump volume level switch binding
71-11	67443	9/3	9/30	B	CE	H	M,P	C	BL	D	N	Steam break sensor and relay failure in isolation condenser

Table A2.3 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component States	Abnormal Condition	Cause	Significance Category	Comment
71-12	67522	9/9	12/13	B	EE	F,N	B	A	OI	H	N	Operator closed DC breaker switch with engine stopped
71-13	70036 73799	Oct.	5/1/72	B	CC	OO	-	A	AV	D	N	Cracks found in safety valve seat bushings
71-14	67545	11/2,5	12/13	B	CD	OO	-	C	AE	D	N	MSIV leakage-bent stem
71-15	68484	11/14		B	HA	M,JJ	-	B	OD	D	N	Rad waste tank activity exceeds .7 curies
71-16	68668	[illegible]	[illegible]/14	B	CB	OO	-	C	BB,AC	H	N	MSIV fails to close
71-17	68485	[illegible]	[illegible]/17	B	PA	G	T	B	AD	D	N	Flexible connection failed, causing loss of station air (Reactor Shutdown)
71-18	68486	11/17	12/14	B	CE	QQ,X,FF	-	B	AT,BY	D	N	Isolation condenser valve motor windings burned (leaking oil)
71-19	69200	12/11	1/12/72	B	CE	Z	-	B	HD	B	N	Isolation condenser vent line fails due to excessive vibration (Power Reduction)
71-20	55896	12/22	3/10/72	B	EB	G	-	A	OA,OJ	A	M	One emergency bus de-energized (T.S. Violation)
71-21	68647	12/28	1/5/72	B	EE	N,DD	I,Y	B	AQ	D	N	Switch failure on DG fuel pump

Table A2.4 Coding Sheet for Reportable Events for Oyster Creek - 1972

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
72-1	34082	1/14	2/22	B	SH-B, EE	N	-	C,A	OA,OJ	H	N	DG #2 inoperable while testing containment spray system #1 (T.S. Violation)
72-2	39040	1/22	2/22	B	EC,CB	DD	A	B	BF,OJ	H	N	Momentary loss of DC trips recirc. pump, causes load drop (Power Reduction)
72-3	39041	2/3	2/23	B	EC,CB, CH	DD,G	-	B	OJ,BF	H	N	Operator switching error causes loss of DC, recirc. and feedwater pumps trip
72-4	55893	3/1	3/10	B	RB	J,JJ	I	C	OJ,AG	G	N	Failure of scram dump volume level switch
72-5	70014	3/15-3/20	4/4	B	MA	JJ,M	-	B	OD	D	N	Rad waste outside tank activity high (limit change requested)
72-6	101742		4/8	C	EB,EE	F,G	-	B	ED	D	N	Bus cable failure due to ground
72-7	70027	4/11	4/20	B	SC	E	C	C	BB	B	S7	Reactor bldg. vent dampers fail to close (design error) violation of secondary containment integrity
72-8	71754	4/14	5/30	B	MB,MC	-	N	B	OD	-	N	Increased gamma energy of stack gas
72-9	71752	5/6	5/24	C	RC	R	-	A	BC,OJ	E	N	Fuel assembly loading error (10/31/71 refueling)
72-10	71755	May	6/2	C	SA	-	-	A	AD	E	N	Torus baffle bolts broken

Table A2.4 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
72-11	73347 85166	May	8/11	C	CC	OO	-	A	AV	D	N	7 of 16 safety valves have cracked seat bushings
72-12	79374	May	1/11/73	C	RC	R	-	A	AR	D	N	Zirconium oxide deposits found on fuel rods
72-13	72415	6/15	6/26	C	IA	-	P	B	BL	D	N	Relay overheated
72-14	72417	6/15, 16	6/26	B	WA	Z,OO	-	B	AA,AT	D	N	Expansion joint failure, valve leak
72-15	72419	6/26	6/30	B	EE	N	U,T	B	EC	D	N	Defective DC temperature switch
72-16	72848	6/28	7/11	B	MA	JJ,M	-	B	OD	A	N	Excessive activity in outside rad waste tank
72-17	71576		8/10	C	RC	-	-	B	OD	A	N	Personnel exposures during refueling
72-18	73243	8/1	8/11	B	SH-B	DD,F	-	B	EE,AQ	D	N	Breaker improperly racked in
72-19	73346	8/4	8/11	B	CE	H	M	B	AL	C	N	Torque tube preload lost in pressure instrument
72-20	73805	8/9	8/22	B	CE	OO,F	M	B	OJ,AL, AG	D	N	(1) Snubber not replaced in line; (2) valve seated too tightly
72-21	74039	8/18	8/28	B	MA	JJ,OO	-	B	OD,BB	D	N	Valve failure leads to excessive rad waste activity

Table A2.4 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
72-22	75980		9/28	B	MA	JJ	-	B	AS,AE,AW	D	N	Rad waste drum fell and ruptured, rad waste tank activity limit exceeded
72-23	75548	8/25	9/28	B	RB,IA	J,OO	P	B	EE,AT	D	N	Loose relay wire (Reactor Shutdown)
72-24	80490	8/29, 12/30	3/29/73	B	SB,SH	E,DD	P	A	-	B	N	Logic circuit changes—Reactor Bldg. ventilation and standby liquid control systems
72-25	75601	9/25	10/6	B	SH	DD	C	A	OK	B	N	Design/Procedure error—standby liquid control system inoperable (Power reduction)
72-26	76459	11/11	11/22	D	CE	OO,H,Z, QQ	M,T	B	AY	E	N	Isolation condenser limit switch opens too soon
72-27	76741	11/28	12/7	B	EE	N,X	-	C	CA	B	N	DG start motor pinions too light
72-28	77449	12/6	12/19	B	MA	Z,JJ	-	B	AR,HF, AD	D	N	Waste sample tank line break
72-29	78413 77916	12/29	1/17/73	B	CD,CC, CE,SA	OO	-	B	BA,BB	D	S3,S7	After a scram, relief valve, MSIV, and isolation condenser condensate return valve all fail
72-30	78301 79605	12/29-1/10	1/30/73	B	ZZ	-	-	-	OF	D	N	Fish mortalities due to temperature change

Table A2.5 Coding Sheet for Reportable Events for Oyster Creek - 1973

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
	79062 82192	1/1	2/8	D	CC	OO	-	A	OD	A	N	Maintenance workers receive exposure
	79063		2/8	B	RB	I,J	T	B	BB,BG	D	N	Control rod drive selector switch failure
	78657	2/12	2/27	B	MC	MM	N	B	BN	I	N	Stack gas sample line froze
	79603	3/10	3/23	B	CB	DD,Z	U	B	BQ,OB	H	N	Temperature difference exceeded when starting recirc. pumps
	74380	April	4/24	D	CE	OO,QQ,F	-	C	AG,EC	D	N	Valve jammed closed, tripped breaker
	74381 81484	4/13	4/24	D	CC	OO	-	C	AE,AO	C	N	Relief valve failure—marginal soldering
	80730	5/4	5/15	C	SA	OO	-	C	AW	D	N	Torus-reactor bldg. vacuum breaker failure
		5/8	6/5	C	RB	J	-	A	OD	H	H	Personnel exposure
	81271	5/18	5/30	C	SH	S,DD	-	C	EE	G	N	Improper fuse size used
	81480	5/22	6/5	C	CD	OO	-	C	AT	D	N	MSIV leak
	81481	5/27	6/5	B	SA	FF	-	A	AW	D	N	Drywell manhole cover gasket leaks
AO 73-10	81469	6/11	6/22	B	EE	N	-	C	BE	A	N	Procedures prevented DG from synchronizing with bus
AO 73-11	81494	6/9	6/28	B	PB	-	N	B	EG,OK	D	N	Coolant radioactivity analyzer failure

Table A2.5 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO 73-12	81495	6/18	6/28	B	SH-B	DD	P,T	C	AC,EE	D	N	Containment spray #2 valve relay failure
AO 73-13	81500	6/22	7/5	B	EE	N,S	-	B	EA,BG	F	N	Lightning blows three DG fuses
AO 73-1[illegible]	82791	7/1- 7/23	7/31	B	CH	OO,FF	-	B	AW	D	N	Feedwater check valve leak
	83101	7/21	8/6	B	SA	GG,FF	-	A	AC,AK, AW	D	J	Snubber seal leaks due to high temp.-evidence of wrong material in design
AO 73-1[illegible]	82969	7/25	8/3	D	CD	OO,FF	-	C	AC,BI, HI,AK	D	N	MSIV closed too fast-oil leak
AO 73-17	82967 83099	8/8	8/8	B	EE	N	-	B,C	CA	D	N	DG start motor fails to engage
	82498	8/9	8/31	B	WA	-	-	-	BF,BT, OF	D	N	Plant dilution pump trip causes fish mortalities
	83609	8/17	8/31	B	MA	JJ	N	B	OD	D	N	Outside rad waste tank activity limit exceeded
AO 73-19	83833	9/8	9/18	D	EB,EE	LL,N, DD	P	B	BG,BD	G	S1,S2, S7	2 power failures cause pump trips; second failure due to incorrect setting on transformer; also, DG failed to start
AO 73-20	87087 83835	9/8	9/10	D	CE	H,OO,F	-	B	BF	D	N	Overloads for condensate return valve tripped
AO 73-21	87088	9/8	9/10	D	XX	GG,FF	-	A	AC,AK, AW	D	N	Seal leaks in shock absorbers (Plant Shutdown for repair)

Table A2.5 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO 73-22	84201 84349 86992	9/9	9/21	D	CD	OO	M	C	AT	D	N	MSIV leak
AO 73-23	87019 84550	9/22	9/25	B	SA	OO	T	C	AQ	D	N	Torus-reactor bldg. vacuum breaker pressure switch failure
AO 73-24	84759	9/27	10/12	D	CD	OO	-	C	AT	D	N	MSIV leak-stem repacked
AO 73-25	87020 84676	9/29	10/1	B	CE	d	P,T	C	BA,BI	D	N	Isolation condenser switch relay failure
AO 73-26	84883	10/6	10/16	D	RA	-	N,L	B	OJ	G	N	APRM resetting not logged
AO 73-27	87089	10/17	10/18	B	SH-B	U,Z	-	B	AW	D	N	Containment spray HX pipe nipple leak
	85376	10/29	11/8	B	WB,FC	MM,U	-	B	AU	D	N	Leak from fuel pool cooling to RBCCW, then from HX to canal
	85587	11/2	11/13	B	XX	GG	-	C	AC,AW	D	N	Shock arrestor fluid leaks
	87017	11/21	12/20	B	SA	QQ	P	B	BY	D	N	Torus-reactor bldg. vacuum breaker relay smoking
	88103	11/25	1/2/74	B	CE	GG	E,C	B	AB	D	N	Isolation condenser line snubber fails
AO 73-30	87018	12/6	12/24	B	CC	-	M,T	C	EH	D	N	Main steam line pressure switches set point drift
AO 73-31	86991	12/13	12/24	B	EB,RB, CE,CG	DD,H	R	B	ED,BF	G	N	"E" power panel grounded

Table A2.5 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO 73-32	93689	12/18	1/7/74	B	CD	OO	-	C	AG,BC	D	N	MSIV overtravel due to test spool valve sticking (power reduction for repair)
	88098	12/20	1/3/74	B	MA	JJ,Z	-	B	BN,OH	I	N	Crack in outside drain tank line due t. freezing (chromated water spill)
	88085	12/21	1/4/74	B	CE	H	E	C	EH	D	N	Isolation condenser high flow sensor set point drift
AO 73-34	88086	12/27	1/9/74	B	CC	-	N	C	EE	C	N	Main steam line radiation monitors - cold soldered connection

Table A2.6 Coding Sheet for Reportable Events for Oyster Creek - 1974

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-1	88087	1/4	1/15	B	CC	-	M,T	C	EH	D	N	Main steam line pressure sensing switch-set point drift
AO-74-2	88088	1/8	1/17	B	CC	-	E,T	C	EH	D	N	Main steam line high flow sensing switch-set point drift
AO-74-3	88095	1/13	1/23	B	CE,SF-D	GG	-	A	AC,AK	B	N	Core spray and isolation condenser snubber failure
AO-74-4	88094	1/16	1/25	C	CD	OO,QQ	-	C	AG,BB	B	N	MSIV pilot valve fails
AO-74-5	88093	1/16	1/25	C	CD	OO	-	C	AT	D	N	MSIV shaft packing leaks
AO-74-6	88092	1/22	1/23	B	SC	-	G	B	OJ	H	N	Available nitrogen used-operator error
AO-74-7	88080	1/23	1/28	B	RA,IA	-	M,T	C	EH	B	N	Reactor pressure sensors set point drift
AO-74-8	88081	1/17	1/29	C	RA,IA	-	M,T	C	EH	B	N	Reactor pressure sensors set point drift
AO-74-9	88453	1/31	2/6	B	CC	-	M,T	C	EH	B	N	Main steam line low pressure switch set point drift
AO-74-10	88532	2/8	2/14	B	CC	-	M,T	C	EH	B	N	Main steam line low pressure switch set point drift

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-11	88788	2/15	2/25	B	SA	OO	-	C	BB,AG	D	N	Torus-drywell vacuum breaker failure to close (4 of 14)
AO-74-12	89246	2/15	2/25	B	CC	-	M,T	C	EH	D	N	Main steam line low pressure switch set point drift
AO-74-13	89247	2/18	2/27	B	CG	F,DD,OO	-	B	BF,BB	G	N	Breaker, valve, recirc. pump trip in cleanup system
AO-74-14	89189	2/22	3/1	B	SA	OO	-	C	BB,AG	D	N	Torus-drywell vacuum breakers fail to close (2 of 14)
AO-74-15	89197	2/28	3/7	B	SA	OO	-	C	BB,AG	D	N	Torus-drywell vacuum breakers fail to close (1 of 14)
AO-74-16	89349	3/7	3/15	D	SA	OO	-	C	BB,AG	D	N	Torus-drywell vacuum breakers fail to close (4 of 14) (Plant shutdown for repair)
AO-74-17	89318	3/7	3/15	D	EB	F	T	B	BB,EE	D	N	Breaker fails in transferring power from auxiliary to startup transformer
AO-74-18	89350	3/8	3/18	D	SA	GG	-	B	AC,AW	B	N	Drywell snubber leak

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-19	89351	3/9	3/18	D	SA,CB,CF	F	O	B	BL,EF,OJ	H	N	Temp. recorder inaccurate - operator failed to notice rise in temp. Failure to maintain primary containment integrity
AO-74-20	89352	3/10	3/18	D	CD	OO	-	C	AT	D	N	MSIV leakage
AO-74-21	89384	3/13	3/22	B	CC	OO	M	B	BC	G	N	Bypass valve left open
AO-74-22	89383	3/15	3/22	B	CC	-	M,T	C	EH	B	N	Main steam line pressure switch set point drift
AO-74-23	89382	3/15	3/25	B	CE	-	M,T	C	EH	B	N	Pressure switch set point drift
AO-74-24	90579	4/9	4/19	B	MC	P	N	B	OC,OJ	H	N	Stack gas particulate not counted
AO-74-25	90415	4/9	4/19	B	SA	OO,PP	-	B	AT	D	N	Torus - reactor bldg. vacuum breaker leaking
AO-74-26	90580	4/12	4/22	B	SH-B,WA	DD	P,U	D	BD,BF	D	N	Emergency service water pump tripped due to thermal overload relay
AO-74-27	90581	4/17	4/26	C	SA	GG	-	A	AC,AK,AW	D	N	3 snubbers have no oil
AO-74-28	90646 94167	4/19	4/26	C	SF-D	DD,OO	T	C	BA	D	N	Core spray suction valve fails to open

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-29	90625	4/23	5/1	C	CC	OO	M,T	C	EH	D	N	Electromatic relief valve set point drift
	91665	4/24	4/25	C	SA	OO	-	A	AV	D	N	Torus-drywell vacuum breaker valve cracks during inspection
	94242	5/13	6/14	C	CA	BB	-	C	AI,AV	C	N	Cracks in vessel head cladding
AO-74-30	91660	5/14	5/23	C	CC	NN	M,T	C	EH	G	N	Turbine steam pressure switch set point drift
AO-74-31	91664	5/19	5/29	C	SA	GG	-	A,C	AC,AK,AW	B	N	Leaking snubbers
AO-74-32	91659	5/21	5/31	C	SF-D	DD	P,T,M	C	AZ,BH	D	N	Core spray pump relay pressure switch failure
AO-74-33	91670	5/21	5/31	C	SX	-	C	C	BI,OK	H	N	Auto - depressurization timers drift
	92609	5/25	6/6	C	SF-D	DD	M,T	C	OK,BF	A	N	Core spray pressure switches tripped
AO-74-34	91594	5/28	5/30	C	IX	MM,BB	F	B	AW	D	N	Leak in reactor vessel instrument penetration line
	94168	6/10	7/10	C	CD	OO,QQ	-	C	BA	B	N	Valves in main steam line not controlled by isolation system
AO-74-35	94394	7/5	7/15	B	CC	-	M,T	C	EH	D	N	Main steam line pressure switches set point drift

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-36	94391	7/10	7/18	B	RA,IA	-	M,T	C	EH	D	N	Reactor pressure switches set point drift
AO-74-37	94595 94770	7/12	7/12	B	CC	-	M,T	C	EH	D	N	Main steam line pressure switches set point drift
AO-74-38	94525	7/14	7/23	B	CD	OO,QQ	-	C	BI,AM	B	N	MSIV closing time excessive (Pilot valve sensitivity too low)
AO-74-39	94596	7/14	7/23	B	CC	OO	M,T	C	EH,OK	A	N	Electromatic relief valve pressure switch set point drift
AO-74-40	94524	7/15	7/16	B	SA	GC	-	A,C	AW,AD,AK	D	N	Snubber - loss of oil (seal cut)
AO-74-41	94740 94592	7/19	7/19	B	CC	-	M,T	C	EH	D	N	Main steam line pressure switches set point drift
AO-74-42	94741	7/25	8/2	B	CC	-	M,T	C	EH,OK	D	N	Main steam line pressure switches set point drift
AO-74-43	94906	8/2	8/12	B	CC	-	M,T	C	EH,OK	D	N	Main steam line pressure switches set point drift

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-44	95101	8/9	8/19	B	CC	-	M,T	C	EH,OK	D	N	Main steam line pressure switches set point drift
AO-74-45	95315	8/24	8/30	B	RC	R	F	B	OB,OK	A	N	Xenon transient
AO-74-46	95143	8/26	9/3	B	SA	OO	-	C	AC	D	N	Torus-drywell vacuum breakers sticking
AO-74-47	95409	9/12	9/23	B	XX	GG	-	A,C	AG,AK,AW	D	N	Pipe snubbers inoperable (loss of oil)
AO-74-48	95596	9/25	10/4	B	CE	H	E	B	BF	A	N	Isolation condenser flow trip switch set too low
AO-74-49	96067	9/27	10/4	B	CC	-	M,T	C	EH,OK,HI	D	N	Main steam line pressure switches set point drift
AO-74-50	96271	10/4	10/11	B	CG	OO,QQ	-	B	AE,BB	D	N	Isolation condenser valve fails to close
AO-74-51		10/7	10/11	B	CC	-	M,T	C	EH,OK	D	N	Main steam line pressure switches set point drift
AO-74-52	96525	10/12	10/21	D	CC	-	M,T	C	EH,OK	D	N	Main steam line pressure switches set point drift
AO-74-53	96425	10/15	10/24	D	MC	DD,OO,Z	-	B	AL	E	N	Loose fitting on stack gas sample pump

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-54	97514	10/18	10/21	D	MC	DD,F	U,T	B	BF	D	N	Stack gas sample pump trip
AO-74-55	96440	10/18	10/28	B	SH-B	DD	–	C	BD	D	N	Containment spray pump fails to start
AO-74-56	97059	10/25	11/4	B	CC	–	M,T	C	EH,OK	D	N	Main steam line low pressure switches set point drift
AO-74-57	97720 97508	11/8	11/18	B	MC	DD,F	–	B	BG	D	N	Stack gas sample pump breaker open
AO-74-58	97719 97507	11/8	11/11	B	SA	OO,QQ	–	C	AG,AR,BB	D	N	Binding of reactor bldg. ventilation valves
AO-74-59	97509	11/12	11/22	D	EE	N	U,T	B	BL,BA	D	N	Temperature switch for DG cooling water fails
AO-74-60		11/22	11/25	B	CE	–	M,T	C	EH	D	N	Isolation condenser pressure switch set point drift
AO-74-61	98580	12/18	12/26	B	MC,EB	DD,G	–	B	BF	B	N	Transmission line fault trips stack gas sample pump (circuit design error)

Table A2.7 Coding Sheet for Reportable Events for Oyster Creek - 1975

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-1	99198	1/8	1/17	B	SA	OO	-	C	BA	D	N	Torus - reactor bldg. vacuum breaker fails to unseat
AO-75-2	99709	2/6	2/13	D	HC	OO,H	-	A	BC,OH	G	N	Condenser valves left open (Radioactive liquid release)
AO-75-3	100042	2/11	2/19	B	SH-B	DD	-	C	BD	D	N	Containment spray pump fails to start
AO-75-4	100573	3/3	3/13	B	RB	I,R	P	B	BC	D	N	Relay failure causes accidental rod insertion
AO-75-5	100572	3/6	3/13	B	SH-B	DD,F	-	C	BD,AG	D	N	Containment spray pump breaker binds
AO-75-6	100918	3/10	3/19	B	MC	DD,F	U	B	BF	B	N	Design error - one thermal overload for two pumps in stack gas sample system
AO-75-7	101144	3/19	3/27	B	SH-D	V,MM	-	C	AQ	D	N	Dehumidifying heater control air line plugged
AO-75-8	101410	3/25	4/3	B	RC,RB	R	N	B	OJ	H	N	Excess core heat generation
AO-75-9		3/29	4/8	C	EB	G	-	B	ED,BG	D	N	Bus 1C grounded
AO-75-10	101698	4/4	4/14	C	SA	OO	-	C	AT	D	N	Torus - reactor bldg. vacuum breaker valve leakage

Table A2.7 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-11	102282	4/10	4/18	C	CC	OO,Z	-	C	AT	D	N	Main steam line valve leak
AO-75-12	102564	4/26	5/6	C	RA,IA	-	M,T	C	EH	D	N	Reactor pressure switches set point drift
AO-75-13		5/7	5/14	C	CE	-	M,P	C	EH	D	N	Isolation condenser reactor pressure sensor set point drift
AO-75-14	103205	5/29	6/6	B	WA	DD,OO	-	C	BK,AQ	D	N	Emergency service water pump insufficinet pressure
AO-75-15	103204		6/6	B	RA	-	L	C	OB	H	N	Improper APRM settings
AO-75-16	103631	6/14	6/24	C	CC	OO,QQ	M,T	C	EH	D	N	Electromatic relief valve set point drift
AO-75-17	103701	6/19	6/27	B	SF-D	OO,F	-	C	BF,EE,AD	D	N	Core spray valve trip breaker stab broken
AO-75-18	103700	6/23	7/1	B	SH-D	P,Z	-	B	AL,OK	A	N	Standby gas treatment system handhole covers out of place
AO-75-19	104221	7/8	7/17	B	IA	-	M,T	C	EH	D	N	Reactor pressure switches set point drift
AO-75-20	104685	7/17	7/25	B	SF-D	-	M,T	C	EH	D	N	Core spray pressure switch set point drift

Table A2.7 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-21	104994	8/1	8/11	B	CE	OO,QQ	T	C	BB,BF,EI	A	N	Isolation condenser valve torque switch set low
AO-75-22	105165	8/10	8/19	B	MC	DD	U	A	BF,BQ	D	N	Stack gas pump trip
AO-75-23	105550	8/17	8/28	B	MC	F	-	B	AQ,OJ	H	N	Stack gas flow through wrong filter train
AO-75-24	106349	8/29	9/8	D	CC	OO	M,T	C	EH	D	N	Main steam pressure switches set point drift
AO-75-25	106347	8/29	9/8	D	MC	DD	U	B	AD	D	N	Stack gas pump lubricator malfunction
	106346		9/10	B	SA	OO	M	C	BB	B	N	Torus - reactor bldg. vacuum breaker - circuit design error
AO-75-26	106531	9/23	10/3	B	SH-B,WA	DD	P,T	C	BD,AA	D	N	Emergency service water pump relay failure
AO-75-27	107226	10/8	10/17	B	SF-D	-	M,T	C	EH	D	N	Core spray pressure switches set point drift
AO-75-28	107684	10/15	10/24	B	SH-D	S,HH	-	B	AA,BF	D	N	Standby gas treatment system fan solenoid fails
	109252		11/6	B	FD	JJ	-	B	OD	G	N	Excess radioactivity - fuel cask

Table A2.7 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-29	107767	10/27	11/6	B	SA	OO	T	C	AG,EG	D	N	Vacuum breaker alarm switch failure
AO-75-30	108283	11/6	11/14	B	SF-D	OO	M,T	C	BF,EH	D	N	Core spray pressure switches set point drift
AO-75-31	108516	11/24	12/3	B	SA	OO	P	C	EE	C	N	Vacuum breaker alarm relay contacts defective
AO-75-32	108803	12/3	12/11	B	EE	N	P	C	BA	C	N	DC relay fails to open due to varnish on contacts
AO-75-33	109195	12/12	12/23	B	EC	OO,C	-	C	BG	H	N	125V DC de-energized; various pump trips (power reduction)
	110332	12/20	1/23/76	D	RB	-	-	B	AL	D	N	Rod worth minimizer console driver board loose
RO-75-34	109456	12/23	1/2/76	B	SA	OO	-	C	AG,BB	B	N	Vacuum breaker binding

Table A2.8 Coding Sheet for Reportable Events for Oyster Creek - 1976

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-1	109654	1/2	1/12	C	SF-D	-	M,T	C	EH	D	N	Core spray pressure switch set point drift
RO-76-2	[illegible]	1/6	1/14	C	SA	OO	-	C	AW	D	N	Torus - reactor bldg. vacuum breaker leak (new replacement valve)
RO-76-3	110330	1/6	1/16	C	SA	OO	-	C	BK,AX	G	N	Reactor bldg. vacuum test fails
RO-76-4	110942	1/23	2/2	C	EE	N,MM	-	C	BK,BF,AW	D	N	Cooling water leak trips DG
RO-76-5	111912	3/3	3/16	C	EE	N	P	C	EE,AP	D	N	DG relay contacts chattering
RO-76-7	112728	3/27	4/9	B	RC	I	N	B	OB,OJ	H	N	Flux peak exceed due to improper core monitoring
RO-76-8	113202	3/26	4/12	B	SF-D	-	M,T	C	EH	D	N	Core spray pressure switch set point drift
RO-76-9	112652	4/1	4/13	B	SH-B	-	M,T	C	EH	D	N	Containment spray pressure switch set point drift
RO-76-10	113278	4/1	4/26	B	SH-B	OO,F	-	C	BC	D	N	Containment spray valve - breaker contacts misaligned
RO-76-11	113547	4/6	5/4	B	SA	-	M,T	C	EH	D	N	Drywell pressure sensor set point drift

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-12	113978	4/14	5/13	B	SH-D	MM	T	A	EI,BC	E	N	Standby gas treatment low flow sensor lines reversed
RO-76-14	114208	4/23	5/24	B	SF-D	DD,FF	-	B	AW	D	N	Core spray pump seal leak
RO-76-15	114207	4/25	5/24	B	SF-D	MM	M,T	C	BO,AW	D	N	Core spray pressure line leak
RO-76-13	117155	5/3	5/4	B	SA	-	-	B	OJ	G	S7	Secondary containment will fully violated - both airlock doors open
	115464		6/28	B	ZZ	-	-	-	OJ	H	N	Unauthorized person gains access to protected area
RO-76-16	115735	6/8	7/6	B	EE	N,X	-	C	CA	D	N	DG start motor fails to engage
RO-76-17	116533	7/1	7/14	B	SA	-	C	B	EF,EI	G	N	Torus oxygen analyzer erratic
RO-76-18	115784	7/1	7/23	B	CE	-	M,T	C	EH	D	N	Condenser pressure switch set point drift
RO-76-20	117179	7/27	8/17	C	CC	DD	T	C	EH	D	N	Electromatic relief valve switch set point drift
RO-76-19		8/5	8/6	B	RA	-	L	C	AL	D	N	APRM pin receptacle loose

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-21	117664	8/20	9/2	B	SH-B	OO,QQ	T	C	EE,AQ	D	N	Containment spray valve switch contacts dirty
RO-76-22	118430	9/10	10/8	B	IA	–	I	B	OK	A	N	Reactor low water level trip points set too low
RO-76-23	119009	9/17	10/15	B	SH-B	DD	P	C	EH	D	N	Containment spray timer set point drift
RO-76-24	119163	9/28	10/21	B	SA	OO	–	B	AG,BB	D	N	Torus – drywell vacuum breaker fails to close
RO-76-25	120306	11/11	12/10	B	SH-B	OO,QQ,F	–	C	BA,BF,AG	D	N	Containment spray valve fails to open
RO-76-26	119164	10/12	10/26	B	HG	M,OO	–	B	BB,OH	B	N	Radioactive water release through failed open condensate valve
RO-76-27	120472	11/11	12/10	B	SH-B	DD,D,F	–	C	AG	D	N	Containment spray pump breaker binding
RO-76-28-3L	120673	12/1	12/23	B	SF-D	OO,QQ,F	–	C	ED,BF,BA	E	N	Pinched wire short to core spray valve breaker
RO-76-28-1T		12/20	12/21	B	RA	–	L	C	AL	D	N	APRM pin receptacle loose
RO-76-29	121031	12/20	1/3/77	B	SA	OO	–	C	OK	A	N	Relief valve opening sequence changed to prevent high torus pressure

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-30	121027	12/20	1/3/77	B	RA	–	F,N	C	AL	D	N	Two APRM channels inoperable
RO-76-31	121058	12/22	1/3/77	B	MC	P,Z,V	–	B	BN	D	N	Ice plug - stack gas sample line

Table A2.9 Coding Sheet for Reportable Events for Oyster Creek - 1977

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 77-1	129305	3/10	3/23	B	SA	-	-	B	OJ	H	S7	Both containment air lock doors open at once—Violation of secondary containment integrity
RO 77-2	129306	3/14	3/24	B	MC	DD,OO	-	B	AA,BF	D	N	Lube valve for stack gas sample pump failed
RO 77-3	129307	3/17	3/30	B	MC	DD	-	B	AC	C	N	Stack gas sample pump fab. error causes failure
RO 77-4	123040	3/18	3/30	B	EB	G	-	B	ED,BG	D	N	Bus 1C grounded
RO 77-5	129308	3/23	4/22	B	SF-D	OO,QQ,F	-	C	BB,BF	D	N	Core spray valve breaker trip
RO 77-6	133028	4/5	4/26	B	CE	-	M,T	C	EH	D	N	Isolation condenser pressure switch set point drift
RO 77-7	124869	4/7	5/2	B	SA	FF	-	C	AX,BK AA	D	N	Reactor bldg. manway leak
	125176	April	5/16	-	SH-B	OO,DD,Z	-	B	OK	B	H	Containment spray design error
RO 77-8	124870	4/21	5/12	B	SA	FF	-	C	AC,AX, BK	D	N	Secondary containment railroad airlock seal tank
RO 77-9	129309	4/23	5/5	D	CD	OO,FF	-	B	AE,BB	D	N	MSIV failure to close
RO 77-10	125036	4/23	5/20	C	CD	OO	-	C	AA,AT	D	N	MSIV leakage
RO 77-11	125229	5/4	5/25	C	CC	-	E	A,C	ED	G	N	Main steam high flow sensors damaged in maintenance

Table A2.9 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 77-12	133027 125551	5/27	6/24	C	EB, SH-D	G	-	B	EE,BY,BG, OA	E	N	Cable insulation fire-substation de-energized and standby gas treatment system 2 inoperable for repair.
RO 77-13	130911	6/10	11/10	C	RC	R	-	A,C	AE	D	N	High degree of bowing found in fuel channel
RO 77-14	133026	7/21	8/19	C	CE	-	E	A	EH	D	N	Isolation condenser flow sensor-SPD
RO 77-15	133025	7/22	8/19	C	RA	-	H,F	C	AL,EG	G	N	IRM channels inoperable due to damage in maintenance
RO 77-16	132713	7/27	8/26	C	SF-D	OO,F	-	C	BA,SF	A	N	Core spray isolation valve breaker set inaccurately
RO 77-17	133024	7/28	8/26	C	SF-D, SH-D, EA	DD,F	P	B	BF,BG	D	N	Bus breaker trip-power lost to core spray pumps on this bus and to SGTS I
RO 77-18	133022	7/29	8/29	C	CC	OO	M,T	C	EH	D	N	Relief valve SPD
RO 77-19	132714	8/2	9/1	B	CC	OO	-	C	AG,BA	C	N	Relief valve fails to open-possible maintenance damage
RO 77-20	132715	8/29	9/23	B	SA	OO	-	B	AG,BB	B	N	Torus-drywell vacuum breaker fails to close
RO 77-21	132716	8/27	10/27	B	MB	OC	-	B	BB	D	N	Off gas SGTS activation valve fails to close

Table A2.9 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 72-[illegible]	133020	9/1	9/15	B	IA,CB	-	E	B	EG	D	N	Flow converters for APRM in recirc. loops fail
RO 72-?3	143421	9/8	9/28	B	SF-D	OO,F	-	C	BF,BB	C	N	Core spray valve breaker defective
RO 72-?5	143423	10/11	11/10	B	SH-D	OO,HH	E	C	BC,AC	D	N	SGTS flow sensor failures
RO 72-?6	143425	10/22	11/21	D	SH	-	-	-	OC	H	N	Test not performed on SLC system-(misunderstanding of procedure)
RO 72-?7	143427	11/14	11/29	D	CE	-	M,F	B	EH,EF	E	N	Isolation condensers isolate 3 times due to relay failure and set point error

Table A2.10 Coding Sheet for Reportable Events for Oyster Creek - 1978

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 78-1	134345	1/3	1/26	B	EE	-	U,T	B	AA	D	N	DG temp. sensor fails
RO 78-2	135765	1/19	2/17	B	CE	OO,QQ	-	C	AG,BF	G	N	Isolation condenser valve seated too tight by maintenance
RO 78-3	135469	2/14	3/15	B	EA	G,LL	A	B	ED,BF	D	N	Cable short circuit trips transformer
RO 78-4	138233	4/6	5/5	B	SH-D, MC	G,AA,S	N,G	B	ED,EI	G	N	Radiation monitor power supply fails due to ground. Also monitors not calibrated by maintenance (SGTS activated).
RO-78-5	138776	4/27	5/26	B	SH-D	P	-	B	HB,AQ	D	N	Increased T.S. testing clogs standby gas treatment filter
RO 78-6	138777	4/28	5/26	B	MA	Z,JJ	-	B	AX,BN,	D	N	Rad waste pipe freezes and breaks radioactive liquid release
RO 78-7	139386	5/10	6/6	B	MC	JJ	N	B	EG,BH	D	N	Lack of heating allows condensation in radiation monitor-erroneous signal
RO 78-8	139664	5/24	6/22	B	EE,EC	N,C	-	C	OC	H	N	T.S. violation on DG and battery testing.
RO-78-9	142768	6/7	6/29	B	IA	BB	M	G	EB	D	E	Reactor high pressure sensor set point drift
RO 78-10	139663	6/7	6/23	B	EB	F	-	B	EK,BC	G	N	Breaker mistakenly opened
RO-78-11	139878	6/22	7/20	B	EE	N	C	C	EB	D	N	DG load sequence timer set point drift

Table A2.20 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 78-12	140052	7/4	7/31	B	SH-B	-	N	C	EH	D	N	Standby gas treatment system radiation monitor set point drift
RO 78-13	140263	7/15	8/11	B	IA	BR	I	C	DK	A	N	New testing procedure reveals reactor low water level sensor below T.S. limit
RO 78-14	140804	8/24	9/21	B	EB,HA	T,G	-	B	BF,BG	D	N	Breakers open improperly on turbine trip, causing loss of power exceeding T.S.
RO 78-15	140356	9/4	9/14	D	CE,CC	N,DD	M	B	BF	D	N	Isolation condensers isolate in shutdown-tripped by line break sensors
RO 78-16	140765	9/14	9/28	B	SF-B	GG	-	B	DC	A	N	Core spray snubbers in high radiation area not inspected (T.S. change requested)
RO 78-17	141587	9/14	10/12	B	CE	F,OO, QQ	T	C	AL,BF, BA	D	N	Loose torque switch set screw trips valve breaker
RO 78-18	140706	9/16	9/29	C	CD	OO	-	C	AQ,AT, AO	D	N	MSIV leak
RO 78-19	141146	9/15	10/16	B	SA	OO	-	C	AK,BC	D	N	Torus-Reactor Bldg. vacuum breaker inoperable
RO 78-20	141526	9/13	10/5	C	IA,HC	I	H	B	EG,BG	G	N	Maintenance workers disconnect IRM 17

Table A2.10 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO 78-21	145385	10/16	10/18	C	SP-D	Z	–	B	AV	D	N	Possible Crack in core spray sparger
RO 78-22	141390	10/17	10/15	C	SB-D	FF,OO,P QQ	–	C	BA,AL	D	N	Standby gas treatment system valve solenoid seal loose, prevents valve closure
RO 78-2	141720	10/18	11/15	C	IA,RC	I,G	B	B	EG,EC AC	C	N	Maintenance workers damage cable to IRM 12
RO 78-24	141198	10/18	11/16	C	MB	OO,FY,	–	A	AG,AC	D	N	Off gas system detonations damage filter, valve seal
RO 78-25	142304	10/31	12/1	C	WF	JJ	–	B	AM,AR	D	N	Leak in condensate storage tank
RO 78-26	142281 145383 145398	11/21	12/5	C	SA	–	M,T	C	AD,BJ	B	N	Component not designed for pressure
RO 78-27	142807	11/25	12/21	C	IA	–	M,T	C	EK	D	N	Reactor high pressure switches set point drift
LER78-28	142323	11/29	12/13	C	CC,RA, CJ	OO,S	P	C	AE,BR	D	N	Primary containment isolation valves fail to close
RO 78-29	142326	11/29	12/14	C	CE,SA	OO	M,T	C	AW	D	N	Leakage past vent valves
RO 78-30	142705	11/25	12/22	C	SH-B	F,DD	–	C	AG,XD	D	N	Containment spray pump trip due to excess breaker friction
RO 78-31	142776	11/30	12/28	C	EE,WA	N,DD	P	C	AG	D	N	DG trips, service water pump fails to trip-breaker binding

Table A2.10 (continued)

Report	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER78-32	145201	12/6	1/3/79	C	SH-B	GO,F	-	C	BA	G	N	Containment spray valve breaker not racked in
LER78-33	142760	10/14	1/28/79	D	RB	I	T	B	AE	D	S9	Attempt to insert control rod fails due to bent switch
LER78-34	145244	12/13	1/9/79	B	ZE,EC	B,C	-	C	GC	G	N	DG test, battery test not done
LER78-35	145247	12/22	1/5/79	B	SA	-	U	A	BL	B	N	Higher than desired torus water temperature
LER78-36	115245	12/12	1/10/79	E	SH-D	GO,QQ	-	C	AQ	D	N	Standby gas treatment valve operator corrosion

Table A2.11 Coding Sheet for Reportable Events for Oyster Creek - 1979

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER79-001	149448	1/18	2/15	D	CE	OO,QQ	T	C	BA,EE	D	N	Dirty swtich contacts on isolation condenser valve operator
LER79-002	147275	2/6	2/27	B	CE	-	M,T	B	EH	D	N	Isolation condenser pressure switch set point drift
LER79-003	148538	2/26	3/26	B	SA,WA	U	-	B	BQ,BK	D	N	Drywell pressure drop due to service water temp. drop
LER79-004	148537	3/1	3/26	B	SH-B, WA	U	-	B	AW	E	N	Containment spray HX leak
LER79-005	148607	3/22, 23	4/4	B	CB	DD,T	C	B	BF	D	N	Recirc. pump trip-bad voltage regulator circuit (Reactor Shutdown)
LER79-006	149233	4/2	5/1	D	RB	I	-	B	OK	A	N	Rod worth minimizer not used in test
LER79-007	149455	4/8	5/8	B	SA	OO	A	C	AL	D	N	Vacuum breaker valve alarm jam nut loose
LER79-008	149235	4/17	5/8	B	CB	DD,T	P	B	AL,BF,EC	D	N	Recirc. pump trip-motor generator brush loosened and burned (Reactor Shutdown)
LER79-009	149454	4/16	5/16	B	SA	OO,HH	-	C	AQ	D	N	Vacuum breaker solenoid fails
LER79-010	149453	4/17	5/17	B	HA	Z	-	B	OH	D	N	Leak in DEDT line-small local release to soil

Table A2.11 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER79-011	149452	4/19	5/17	B	SF-D	DD,F,S	-	C	BD,EE	D	N	Core spray pump trip due to blown breaker fuse
LER79-012	149451	4/19	5/17	B	SA	-	I	B	EI	D	N	Torus oxygen level high (analyzer out of calibration)
LER79-013	149234	4/27	5/10	B	CB	DD	-	B	-	B	N	Four recirc. pump operation not included in LOCA analysis
LER79-014	149450	5/2	5/16	B	CB,CH, CE	DD	-	B	OK,BF, BG,BD	A	S2,S3	Reactor coolant level decreases to triple low point-no procedure for operators in this situation (Reactor Shutdown)
LER79-015	149449	5/2	5/16	D	CB	DD	-	B	OJ,BM	B	N	Recirc. pump started with loop coolant temp. low
LER79-016	149610	5/6	6/5	D	CE	-	M	C	EH	B	N	Isolation condenser pressure switch set point drift
LER79-017	149963	5/17	6/15	D	SF-D	OO,F	-	C	BB,BF, EE	D	N	Core spray valve operator breaker failure
LER79-018	149964	5/17	6/15	D	SF-D	GG	-	A,C	AA	D	N	Core spray snubber failure
LER79-019	150104	5/26	6/21	D	CE	-	M,T	C	EH	D	N	Isolation condenser pressure switch set point drift

Table A2.II (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER79-020	150103	6/13	6/27	B	SA	–	–	B	OK	A	S7	Both secondary containment airlock doors open (containment integrity breached)
LER79-021	150683	6/20	7/20	B	SA	–	M,T	C	EH	D	N	Containment pressure switch set point drift
LER79-022	150688	6/27	7/27	B	SH-B, WA	U,Z	–	B	AR,AW	D	N	Containment spray HX leak
LER79-023	150696	7/19	8/2	B	CB	DD,T	–	A	ED	D	N	Recirc. pump motor generator brush repair (Reactor Shutdown)
LER79-003E	151255	7/19	8/14	B	WA	DD	–	B	BF,HC, OJ	H	N	Reserve dilution pump not started in time
LER79-001E	154818	7/26	8/7	B	PB	K	A,O,U	B	EI	B	N	Temperature sensing processor out of calibration
LER79-004E	151256	8/1	8/20	B	WA	DD	U,T	B	BF,EI, OJ	D	N	Dilution pump #2 trips–operator fails to start #3
LER79-005E	151768	8/3	9/10	B	ZZ	–	–	–	OF	D	N	Fish mortalities due to temp. change or low dissolved oxygen
LER79-025	152984	8/6	11/13	B	PB,SA, SH-B	OO,Z	–	B	AW	G	S7	Torus sample valve left open–violation of primary containment integrity
LER79-026	151461	8/7	9/6	B	MA	Z	–	B	OH	D	N	Laundry tank line leak
LER79-027	151405	8/7	8/21	B	SF-D	GG	–	B	AC,BC	E	N	Core spray snubbers installed improperly

Table A2.11 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER79-028	151406	8/7	9/6	B	SF-D	OO,F	H	C	BB,BF	H	N	Core spray valve Stuck open due to breaker trip
LER79-002E		6/6-8/8	8/8	B	XX	-	U	B	OF,OK	A	N	Thermal monitor not redundant
LER79-029	152189	8/22	9/21	B	RA,RB	I	S	B	EH	A	N	SRM trips due to set point drift
LER79-030	151636	8/12	9/12	B	RB	J,DD,Z	-	B	AW	G	N	Control rod drive pump vent line leak
LER79-031	151940	8/29	9/28	B	RB	J,DD,Z	-	B	AW	G	N	Control rod drive pump vent line leak
LER79-006E	153416	9/5	9/19	B	WA	DD,FF,P	-	B	HC,BF,BK	D	N	Dilution pump seal water pressure low due to clogged filter
LER79-032	152651	9/14	10/10	B	SH-B,WA	U,Z	-	B	AR,AW	D	N	Containment spray HX leak
LER79-033	152553	9/17	10/10	D	CC	OO	M,T	C	AA	D	N	Electromatic relief valve pressure switch defective
LER79-034	152978	10/8	10/22	B	SA	-	-	B	OK	G	S7	Both containment airlock doors open simultaneously (violation of secondary containment integrity)
LER79-035	152976	9/26	10/25	B	MC	-	N	B	EH	D	N	Main steam line radiation monitor set point drift
LER79-007E	153415	10/9	10/18	B	WA	DD,P	M,T	B	BF,BK,HC,AC	D	N	Dilution pump trip-low lube pressure, blocked filter

Table A2.11 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER79-036	152985	10/11	11/6	B	SH-B	-	-	B	-	G	N	Containment spray #1 inoperable (door open)
LER79-037	153770	11/3	11/30	B	SF-D	S,DD	-	C	BD,EE	D	N	Core spray pump failure to start (loose fuse)
LER79-038	153769	11/15	11/30	B	EE	N,F	T	C	BB,EI	D	N	DG breaker switch out of adjustment
LER79-039	153768	11/5	12/3	B	RA	-	L,N	B	EH	D	N	APRM set point drift
LER79-040	153766	11/2	11/30	B	SH-D	P	-	B	OC,OK	A	N	Standby gas treatment system filters not tested properly
LER79-041	153767	11/2	12/3	B	MC	-	-	B	OC	B	N	Rad waste building effluent monitor inadequate
LER79-042	153774	11/6	12/6	B	CC	OO	M,T	B	AY,AM	E	N	Relief valve spuriously opens-wrong pressure switch used (Reactor shutdown)
LER80-002E	159070	11/25	8/1/80	-	WA	DD	-	B	OK	A	N	One dilution pump used during startup
LER79-044	153939	12/19	1/18/80	B	SA	OO	-	B	AG	G	N	Scaffold blocks vacuum breaker
LER79-008E	153497	12/28	1/7/80	B	WA	DD,FF	-	B	BF,BK	D	N	Dilution pump trip leaving only 1 in operation
LER79-043	153938	12/28	1/24/80	B	SA	OO	-	C	AG,BA	D	N	Vacuum breaker fails to open (binding)

Table A2.12 Coding Sheet for Reportable Events for Oyster Creek - 1980

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-001E	154622	1/5	1/15	D	ZZ	-	-	-	OF	D	N	Fish mortalities due to low temperature
LER80-001	154450	1/5	1/21	B	CC	OO	-	C	BA	C	N	Electromatic relief valve retainer ring backed off
LER80-002	154934	1/16	2/14	C	RC	R	-	A,C	BC	H	N	Fuel bundle found rotated
LER80-003	154449	1/16	1/30	C	SF-D	Z	-	A,C	AV	D	N	Crack in core spray sparger
LER80-004	155556	1/25	2/25	C	WF	Z	-	B	AR,OH	D	N	Condensate transfer pipe leak-radioactive release to soil
LER80-005	155557	2/5	2/29	C	SH-D	-	N	C	OJ,EH	G	N	Set point drift and incorrect setting on radiation monitors
LER80-006	155560	1/31	2/29	C	CB	-	E	C	EH	D	N	Recirculation flow sensors set point drift
LER80-007	155456	2/13	3/7	C	SH-D	E	-	C	CA	D	N	Standby gas treatment system fan belt slipping
LER80-008	155601	2/15	2/29	C	CE	GG,Z	-	A,C	AM	E	N	Welded lugs not on snubbers
LER80-009	155993	2/19	3/19	C	SH-B, WA	U	-	A,C	AV,AR	B	N	Tube corrosion and leakage in containment spray HX's
LER80-010	155474	2/20	3/7	C	SH	GG	-	A,C	AL,AM	E	N	Liquid poison system pipe snubbers omitted and of incorrect design
LER80-011	155994	2/19	3/17	C	SH-D	MM	E	C	BF,AV, EG	G	N	Standby gas treatment system trip-flow sensor stepped on and cracked

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-012	155443	2/28	3/27	C	EE,EC	C	-	B	OC	G	N	DG battery test not performed
LER80-013	155996	3/9	3/24	C	AB	OO	-	A	AV,OA	D	N	Fire protection system removed from service-valve crack
LER80-014	155999	3/2	3/24	C	EE	S	-	C	BF,AL	D	N	DG trip-loose fuse holder
LER80-015	157006	4/3	5/7	C	SA	OO,QQ	-	B	AD	D	N	Broken reactor bldg. isolation valve-secondary containment integrity degraded
LER80-016	157162	5/12	5/23	C	HA	-	M,T	C	BC	D	N	Generator load rejection pressure switch failure
LER80-017	158695	5/16	5/30	C	RB	I,J	T	B	AG,OJ	H	N	Control rod position switch stuck; position interlock bypassed by operator
LRE80-018	157699	5/7	6/5	C	IA	-	M	C	EH	D	N	Reactor pressure sensor set point drift
LER80-019	160257	5/17	6/17	C	SF-D	OO	-	C	EH	D	N	Core spray relief valve set point drift
LER80-020	158250	6/5	6/18	C	AB	-	-	B	OJ	E	N	Fire barrier penetrations inadequate; safety watches not conducted
LER80-021	CANCELLED											
LER80-022	160256	6/3	7/1	C	CE	-	T	C	EI	D	N	Isolation condenser actuation switches out of calibration

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-023	160261	5/23	7/23	C	CC	OO	M	C	EH	D	N	Electromatic relief valve pressure sensors set point drift
LER80-024	158270	5/20	6/27	C	RB	I	-	-	OC	A	N	Control rod test not performed
LER80-025	160263	6/18	7/1	C	AB	OO	-	C	AL,AT	D	N	Fire protection valves-one failure, one leak
LER80-026	160295	7/9	8/8	C	XX	GG	-	C	AQ	D	N	Snubber failure
LER80-027	158779	7/16	7/31	B	SA	OO	-	B	OE	G	N	Plastic bag for leak test left on vacuum breaker
LER80-028	159326	7/30	8/28	B	IA	-	M	C	EH	D	N	Reactor high pressure scram sensors set point drift
LER80-029	160236 164443	7/11	8/13	B	SA, SF-D	DD	M	B	EH	D	N	Drywell pressure sensor set point drift starts core spray pumps (Shutdown for calibration)
LER80-030		7/16	8/11	B	CC	OO,QQ	-	B	BA	D	N	Electromatic relief valve failure to open
LER80-031	160235	7/16	8/11	B	XX	GG	-	C	AC	D	N	Snubber failure-leakage
LER80-003E	159137	7/21	7/30	B	WA	DD,P,X	A	B	BF,BL, BE	D	N	Two dilution pump motors fail (windings),other trips due to clogged filter and high lube oil temp.
LER80-004E	159520	7/27	8/7	B	WA	DD	-	B	BF,BL, BK	D	N	Dilution pump trips from high lube temperature and low cooling water pressure

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-032	160234	7/16	8/14	B	SA	-	-	B	BC	A	S1,S2, S7	Torus area-containment spray pump room doors open. Violation of secondary containment integrity-containment spray inoperable.
LER80-033	159327	8/6	8/14	B	SH-A	-	-	B	EI	D	N	Torus oxygen concentration too high-reduced flow in purge system (Power Reduction)
LER80-034	159328	7/29	9/2	B	SH-D	E	P	C	BF,BL	D	N	Standby gas treatment system fan trip-high temperature, bad relay
LER80-005E		8/8-8/12	8/26	B	WA	DD	-	B	BC,BK, BL	D	N	Dilution pump trips due to high temp. (low lube oil pressure)
LER80-006E		8/11	8/26	B	HC,WA	H	-	B	BL	D	N	Condenser discharge high temperature
LER80-035	160326	8/14	9/10	B	SH-B	-	M,T	C	EH	D	N	Containment spray pressure switches set point drift
LER80-036	160207	8/15	9/15	B	MC	DD	-	B	AL,BF	D	N	Stack gas sample pump trip due to loose fan (Reactor Shutdown)
LER80-037	160354	8/19	9/18	B	SH-D	-	M	C	BC	G	N	Welding lead causes standby gas treatment system sensor failure

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-038	159672	8/26	9/25	B	IA	-	I	C	EH	D	N	Reactor water level sensors set point drift
LER80-039	159675	8/29	9/25	B	CD	-	M,T	C	EH	D	N	MSIV pressure sensor set point drift
LER80-007E	160300	9/1	9/19	B	WA	DD	-	B	AG,AD	D	N	Dilution pump impeller shear causes seizure
LER80-040	160433	9/4	10/1	B	SF-D	GG,FF	-	C	AT,AC	D	N	Core spray snubber fails
LER80-041	160432	9/5	10/1	B	SF-D	DD,Z	-	A	AW	G	N	Leak in core spray pump line
LER80-008E	160357	9/10	9/25	B	WA	DD,D	-	B	BL	D	N	Dilution pump failure—overheated bearing
LER80-0042	160817	9/11	10/7	B	SH-B	-	M,T	C	EH	D	N	Containment spray pressure switches set point drift
LER80-043	160418	9/25	10/14	B	IA	-	I	C	EH	D	N	Reactor water level sensors set point drift
LER80-044	160902	9/30	10/29	B	SF-D, AB	DD,X	-	A	-	G	N	Fire protection system inadvertently actuates, wetting core spray pump motor leads
LER80-045	160863	10/2	10/27	B	SF-D	DD,X	-	A	AW	D	N	Leak in core spray pump pipe nipple
LER80-046	160520	10/17	11/11	B	SH-D	P	-	C	AM,BJ	G	N	Wrong filter installed in standby gas treatment system
LER80-009E		10/26	11/3	B	WA	H,P	-	B	RC,OF	D	N	Intake screens plugged with debris and crabs

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-047	161644	11/1	11/25	B	SF-D	-	M,T	C	EH	D	N	Core spray pressure sensors set point drift
LER80-048	161664	10/29	11/18	B	SH-B	GG	-	C	AC	D	N	Containment spray snubber failure
LER80-049	161667	11/5	11/19	B	CE,SD	OO	-	A	AT,BB	D	N	Isolation valves leak, fail to close
LER80-050	161763	11/6	12/2	B	SH-B	-	M,T	C	EH	D	N	Containment spray pressure switches set point drift
LER80-051	161877	11/8	12/4	B	RC	-	-	C	OC	H	N	Core tests not done as per T.S.
LER80-010E	161676	11/11	11/21	B	WA	DD,P	-	B	BF,BK, HC	I	N	Debris in bay clogs seal water strainer of dilution pump
LER80-011E	161678	11/18	11/25	B	ZZ	-	-	-	OF	D	N	Fish mortalities-low temp.
LER80-052	161873	11/18	12/8	B	IA	-	I,T	C	EH	D	N	Reactor water level sensors set point drift
LER80-015E	162433	11/21	12/17	B	AB	DD,X, FF	-	B	AA,BL, AT,AG	D	N	Loss of cooling water causes fire pump diesel to overheat and seize
LER80-012E	161677	11/22	12/2	D	ZZ	-	-	-	OF	D	N	Fish mortalities-low temp.
LER80-053	162046	11/30	12/23	B	RB	J,DD, Z,FF	-	A	AP,AT	D	N	Control rod drive pump vibration causes pipe leaks

Table A2.12 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER80-054	162045	11/30	12/23	B	SF-D	DD,X	-	A	A,U,AC	D	N	Water leak into core spray pump motor
LER80-055	162044	12/3	11/22	B	SF-D	-	M,T	C	EH	D	N	Core spray pressure switches set point drift
LER80-013E	162062	12/4	12/17	B	WA	DD,P	-	B	HC,BT BF	I	N	Low tide and wind causes low intake water level (Reactor Shutdown)
LER80-056	163385	12/4	12/23	B	CC	-	E,T	C	EH	D	N	Main steam line flow sensors set point drift
LER80-057	162041	12/5	12/23	B	SH-B	-	M,T	C	EH	D	N	Containment spray pressure switches set point drift
LER80-058		12/11	1/9/81	B	SF-D, SH-B	GG	-	C	AC	D	N	Core spray and containment spray snubber failure
LER80-059	163366	12/15	1/15/81	B	EE,EC	C	-	C	OC	G	N	Main station battery and DG battery tests not done
LER80-060		12/11	1/9/81	B	CE	-	M,T	C	EH	D	N	Isolation condenser pressure switches set point drift
LER80-061	163364	12/17	1/16/81	B	SF-D, SH-B	GG,FF	-	C	AC,AQ, AT	D	N	Containment spray and core spray snubber failures
LER80-062	163359	12/18	1/16/81	B	RB	J,DD, X	-	B	AC	D	N	Control rod drive pump motor fails (one of those mentioned in 80-053)
LER80-063	163362	12/17	1/16/81	B	IA	-	I,T	C	EH	D	N	Reactor water level sensor set point drift

Table A2.13 Coding Sheet for Reportable Events for Oyster Creek - 1981

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-001	163602	1/2	1/30	B	SH-B	–	M	C	EH	D	N	Set point drift in a containment pressure sensor.
LER81-002	164438	1/2	1/30	B	MB	DD	–	B	AA	D	N	Stack gas sample pump reached end of life.
LER81-003	164233	1/12	2/9	B	AB	OO	–	C	BN	I	N	Fire hydrant valve leaked and the water froze in the hydrant.
LER81-004	164442	1/16	1/30	D	EC	N	–		OK	B	N	The diesel generator may be under-rated for a LOCA given a LOOP.
LER81-005	164454	1/6	2/5	B	WA	P	–	C	AQ	D	N	A service water pump had a clogged strainer.
LER81-006	164229	1/15	2/9	B	RX	–	T	C	EH	D	N	Low reactor water level trip switch drifted.
LER81-007	164350	2/2	3/26	B	SH-B	FF	–	B	OK	H	N	Containment spray compartment door not closed as required.
LER81-008	164564	2/10	3/12	B	MA	BB		B	AX,BS	B	C3	Radioactive water seeped through the new radwaste building.
LER81-009	164710	2/13	3/16	B	SH-B	FF		B	AW	D	N	Containment spray snubber leaked due to a deteriorated seal.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-010	165180	2/2	4/2	B	BB	-	N	B	OK	A	N	Radiation monitor set point was not set correctly.
LER81-011	165344	3/9	4/8	B	CE	-	M	C	EH	D	N	Isolation condenser pipe break sensor drifted.
LER81-012	165394	3/13	4/10	D	SF	-	M	C	EH	D	N	Set point drift in pressure relief valve pressure sensors.
LER81-013	165948	3/19	4/20	B	SF-D	-	M,T	B	EH	D	N	Set point drift in core spray high drywell pressure switch.
LER81-014	165392	4/1	4/15	B	SH-A	BB	-	B	BS	D	N	Containment oxygen concentration too high due to a low rate of inertion.
LER81-015	165880	3/24	4/21	B	CC	-	E	C	EH	D	N	Set point drift in main steam line high flow sensors.
LER81-001E	165398	4/15	4/27	B	MA	DD	T	B	BD	D	N	Reserve dilution pump did not start within time requirement.
LER81-016	166426	4/21	5/21	D	WF	OO	-	B	AX	D	C3	Condensate transfer valve leaked 10,000 gallons.
LER81-017	166241	4/15	5/14	B	SH-B	DD	-	B	AQ	I	N	Containment spray loop inoperable.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-018	166120	4/16	4/30	B	SA	OO	–	B	OK	G	S7,S8	Workers placed scaffold such that the two vacuum breaker valves could not open completely.
LER81-019	165915	3/28	4/27	B	IX	–	–		OK	A	N	Failed to calibrate IRM in reactor protection system during shutdown.
LER81-020	166398	5/1	6/1	D	CE	–	I	C	EI	D	N	Isolation condenser level instrument reading high.
LER81-021	166841	6/3	7/1	B	SF-C	–	M	C	EH	D	N	Set point drift in reactor high pressure sensors.
LER81-022	166463	5/20	6/3	D	SA	FF	–	B	BC	H	S7	One personnel air lock would not close and the other was left open.
LER81-023	166724	6/3	7/6	B	SA	BB	–	B	BS	D	N	Water in instrument line gave bad reading of oxygen in the drywell.
LER81-024	167723	6/8	7/8	B	WA	DD	–	C	OA	D	N	Two service water pumps found inoperable and testing of pumps was late.
LER81-025	166723	6/17	7/1	B	SA	FF	–	B	BC	H	S7	Both railroad air lock doors were open at the same time.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-026	167843	6/27	7/27	D	CE	-	M,T	B	EH	D	N	Set point drift in isolation condenser pressure switch.
LER81-027	168039	7/9	8/10	B	SA	-	T	B	BC	G	N	Limit switch on containment isolation valve misaligned.
LER81-028	167844	7/6	8/3	B	SA	FF	-	B	AX	G	C3	Radioactivity release through a tear in a duct seal.
LER81-029	168536	6/8	8/14	B	RB	X,D	-	B	AA	D	N	A CRD motor had its bearings wear out.
LER81-030	167850	7/14	7/27	B	SA,MB	OO	E	B	BB,BD	D	C2	RB exhaust valve failed to close and standby gas treatment system failed to start.
LER81-031	168538	5/8	8/14	D	SF	OO	-	C	BA	D	N	One of the ADS relief valves failed to open during test.
LER81-032	168171	7/13	8/12	B	CC	OO	-	B	OC,OK	A	N	Safety and relief valve position system not tested in required time limit.
LER81-033	168131	7/27	8/6	B	SA	FF	-	B	BC	G	S7	Personnel access airlock doors were found open.
LER81-034	168542	7/22	8/21	B	RB	-	-	B	OB	H	N	Fuel peaking occurred due to operator error.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-035	168524	7/21	8/21	B	AB	-	-	B	OK	H	N	Nonfunction fire barrier discovered.
LER81-036	169225	9/5	10/5	C	RX	-	-	B	BT	D	N	Reactor water level channel lost its reference head.
LER81-002E	167768	7/29	8/21	B	MA	DD	-	C	BF	B	N	Two dilution pumps tripped.
LER81-037	168620	7/31	8/31	B	SH-B	FF	-	B	OK	H	N	Containment spray pump compartment door found open.
LER81-038	169232	8/27	9/28	C	CG	U	-	B	AU	D	N	Two shutdown cooling heat exchangers experienced tube leaks.
LER81-039	169083	8/19	9/18	C	CG	U	-	C	HD,AU	A	N	Component cooling water heat exchanger had several tubes fail.
LER81-040	168608	8/15	9/1	C	CC	-	M,T	C	EH	D	N	Set point drift in emergency relief valve pressure switches.
LER81-041	171084	8/24	9/8	C	MB	DD	-	B	AA	D	N	A stack gas pump failed due to wear.
LER81-042	169114	8/20	9/11	C	MB	PP	-	B	BF	D	N	Stack gas pump tripped and alarm did not annunciate.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-043	168932	8/29	9/14	C	MB	OO	-	B	AZ	D	N	Stack gas sample flow control valve closed.
LER81-044	168931	8/25	9/23	C	SA	D	-	C	AA	D	N	Exhaust fan had worn out bearings.
LER81-045	169655	9/24	10/23	C	CE	OO	-	C	BA	D	N	Isolation condenser isolation valve failed to open.
LER81-046	169653	9/20	10/21	C	CF	GG	-	C	AK	D	N	Dirty oil and faulty seals caused 3 RHR snubbers to fail.
LER81-048	171046	10/12	11/11	C	CG	OO	-	C	BB	D	N	Cleanup system isolation valve failed to close.
LER81-049	171033	10/12	11/11	C	SH-B	_	M,T	C	EH	D	N	Set point drift in containment spray pressure switch.
LER81-050	171384	10/15	11/17	C	SF-D	-	M,T	C	EF	D	N	Core spray pressure switch closed alarm failed to clear.
LER81-051	171085	10/17	11/18	C	CC	-	M,T	C	EH	D	N	Set point drift in emergency pressure relief valve pressure switch.
LER81-052	171032	10/21	11/13	B	SA	OO	_	C	BA	D	N	Containment isolation valve failed to open.
LER81-053	170138	10/21	11/24	B	MB	OO	-	B	BA	E	N	Off-gas bypass valve failed to open.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-054	171104	10/28	11/30	B	CB	–	M	C	EH	D	N	Set point drift in main steam low pressure sensor.
LER81-055	171105	10/31	11/30	D	IX	G	–	B	EE	D	N	Two acoustic monitoring system channels had broken cables.
LER81-056	171826	11/13	12/14	B	CE	–	M,T	C	EH	D	N	Set point drift in isolation condenser pipe break sensors.
LER81-057	171106	10/31	11/30	D	CC	–	M,T	C	EH	D	N	Set point drift in emergency pressure relief valve pressure switch.
LER81-058	171803	11/11	12/11	B	SH-B	–	M,T	C	EH	D	N	Set point drift in containment spray pressure switches.
LER81-059	171800	11/16	12/17	B	RC	–	–	–	OK	H	N	Linear heat generation limit not checked.
LER81-060	171595	11/21	12/21	B	RC	–	–	–	BQ,OB	A	N	Linear heat generation limits exceeded.
LER81-061		12/22	2/5/82	C	SH-B SF-D,CE	GG	–	B	OA	D	N	Nine snubbers failed in the core spray, containment spray, shutdown cooling and isolation condenser systems.
LER81-062	171574	11/25	12/23	B	SA	–	M	C	EH	D	N	Set point drift in drywell pressure sensor.

Table A2.13 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER81-063	171577	11/19	12/21	B	CE	OO	-	C	BB	G	N	Isolation condenser valve failed to close.
LER81-065	171541	12/9	12/23	B	CE	OO	-	B	BB	A	C8	Isolation condenser valve failed to close.
LER81-066	172285	12/1	12/31	B	CC		E	C	EH	D	N	Set point drift in main steam high flow sensors.
LER81-067		12/20	1/20/82	C	RB	OO,HH	-	C	BI	D	N	Scram solenoid valve failed.
LER81-068		12/18	1/18/82	C	RC	-	G,T	C	EH	D	N	Reactor triple low water level indicator switch set point drift.
LER81-069	172026	12/30	1/26/82	D	SF-D	-	M,T	C	EH	D	N	Set point drift of core spray high drywell pressure switches.
LER81-070	172027	12/31	1/28/82	D	CE	-	M,T	C	EH	D	N	Set point drift in isolation condenser pipe break sensor.
LER81-071		12/31	3/5/82	B	MC	-	N	B	OK,OA	A	C3	Radwaste liquid radiation monitor read a factor of ten low for 8 months.
LER81-072	172028	12/29	1/28/82	C	SF-D	OO	-	C	BC	H	C8	Core spray valve failed partially open.