50-237 Received w/Ltr Dated 7-6-70

EXHIBIT 1, CONTAING EVALUATION OF OPERATIONAL DIFFICULTIES.....

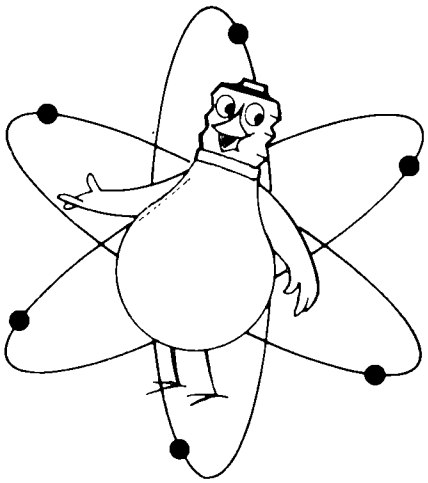
1. THE RAPID DEPRESSURIZATION INCIDENT, 6-5-7
2. MAIN STEAM LINE ISOLATION VALVES
3. EXCESSIVE HYDRAULIC FORCES IN HIGH PRESSU COOLANT INJECTION SYSTEM STEAM LINE

50-237

Received w/Ltr Dated 7-6-70

DRESDEN NUCLEAR POWER STATION
UNIT 2

Special Report
of
Incident of June 5, 1970

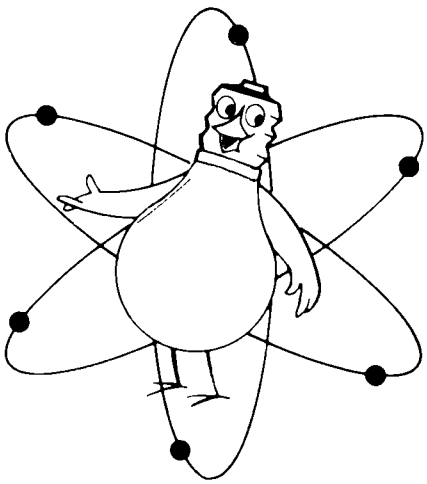


Commonwealth Edison
Company

2061

DRESDEN NUCLEAR POWER STATION
UNIT 2

Special Report
of
Incident of June 5, 1970



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I. ABSTRACT

On June 5, 1970, an incident occurred at the Dresden 2 plant which was initiated by a spurious electronic signal in the reactor pressure regulator. A reactor scram and isolation occurred in the normal fashion and the nuclear process was completely secured. In the course of events, safety valves were cocked open slightly causing the drywell to fill with steam. Normal shutdown controls were established and a controlled vent to atmosphere was conducted through the standby gas treatment system. Comprehensive monitoring conducted both on and off-site, showed that no measurable quantities of radioactivity were released to the site or to the environs.

This report contains a chronology and a complete evaluation of the incident.

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II. INTRODUCTION

On June 5, 1970, Dresden Unit 2 was operating at 75% power (1875 MWt, 623 MWe) at near equilibrium conditions, with full core recirculation flow. No testing was in progress and no maintenance operations were being performed. Off-gas activity, as measured at the main stack was 25,000 uCi/sec. The General Electric Shift Superintendent was providing the technical direction for the station operation, and the normal compliment of Commonwealth Edison personnal were operating the unit.

At 9:28 p.m., a spurious signal in the reactor pressure control occurred causing the turbine control valves to open from 75% to the load reference set of 80% and the steam bypass valves to open fully to the condenser. Within the first second, a turbine trip occurred causing reactor scram. Subsequent vessel pressure depressurization closed the main steam line isolation valves. The water level was maintained above the top of the core at all times and there was no fuel damage.

In response to the initial and expected water level drop, the operator switched to manual control of the feedwater system and began filling the reactor vessel at the maximum rate. Level monitoring difficulties led to reactor water overflowing into the main steam lines. A pressure surge resulted in the main steam lines when relief valves were cycled which momentarily opened one of the safety valves. The discharging fluid from this safety valve impinged upon the lifting levers of two other safety valves causing these safety valves to become cocked open a small amount. The water-steam mixture, discharging from the two safety valves pressurized the primary containment vessel. Damage within the drywell was basically limited to overheating of most of the flux monitoring instrumentation cables and water impingement on insulation.

The core spray pumps and LPCI pumps were automatically initiated on high drywell pressure. After an assessment of the conditions which existed, the core spray and LPCI pumps were secured and slow venting of the containment via the standby gas treatment system was initiated to reduce the containment pressure. The reactor vessel water level and the stack gas activity level were continuously monitored.

Normal cooldown of the reactor vessel continued. The drywell coolers were restarted and the containment pressure was subsequently reduced to atmospheric pressure. Entry into the containment vessel was made about 12 hours later and the open safety valves and damaged flux monitor cables were found. The transient did not result in any measurable release of radioactive products, either gaseous or liquid, to the environment. Exposures to individuals were controlled at all times by radiation protection procedures and were well within 10 CFR 20. The incident is discussed in more detail in the sections of this report.

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III. OBSERVATIONS

A. Chronology

ITEM	EVENT	TIME
1.	Operating at 75% power level in preparation for a test.	June 5, 1970
2.	Control valves opened from 75% to 80% power and the bypass valves fully opened resulting in high steam flow of about 115 percent rated flow.	21:28:40 (Time Zero)
3.	High steam flow sensors tripped but did not occur in both isolation channels simultaneously. Reactor isolation did not occur at this time.	1 second
4.	The turbine tripped.	1 second
5.	The reactor scrammed.	1 second
6.	Generator load rejection occurred.	2 seconds
7.	All four low water level sensors tripped from low reactor water level (20" on Yarway).	3 seconds
8.	After going into the "pump runout", the two operating feed pumps "B" and "C" tripped automatically.	5 seconds
9.	Reactor feed pump "C" restarted automatically.	7 seconds
10.	Water level increased from below the low level setpoint to more than 55 inches on the GE/MAC indication.	19 seconds
11.	The bypass valves were fully closed automatically.	22 seconds
12.	Main steam line low pressure trips (850 psig) occurred in both isolation channels causing an isolation signal.	33 seconds
13.	The main Steam Isolation Valves (MSIV's) reached 10% closed.	33 seconds
14.	Water level decreased from more than 55 inches to less than 15 inches on the computer trend chart.	35-40 seconds
15.	Water level rose from less than 15 to more than 55 inches on the computer trend chart, but stuck at about 17 inches on the GE/MAC recorder chart.	50-75 seconds

108.6

ITEM	EVENT	TIME
16.	Reactor pressure decayed to 775 psig and began rising.	1 minute
17.	Operator discovered stuck water level recorder pen on GE/MAC indication and manually reduced feedwater flow to about 2.7×10^6 lb/hr.	1 minute 30 sec. ±30 sec.
18.	Operators attempted to bring isolation condenser (IC) into operation and open the MSIV's. Neither attempt was successful.	2-3 minutes
19.	Reactor pressure peaked at 1054 psig and began decreasing rapidly from manual operation of one electromatic relief valve.	3 minutes 45 sec. ± 5 sec.
20.	Reactor pressure fell to 960 psig and began rising.	5 minutes 38 sec. ± 5 sec.
21.	Safety valve G on main steam line "D" opened momentarily and the discharge cocked the lifting levers of valves E and F.	5-6 minutes
22.	Pressure increased to 1050 psig and began falling rapidly from manual operation of one relief valve.	6 minutes 3 sec. ±5 sec.
23.	Drywell containment high pressure trip actuated (2 pisg).	6 minutes 3 sec.
24.	The diesel generator cooling pumps automatically started.	6 minutes 7 sec.
25.	Both recirculation pumps tripped automatically.	6 minutes 12 sec.
26.	Both emergency diesel generators started automatically.	6 minutes 13 sec.
27.	Both core spray systems automatically started but did not inject any water into the vessel.	6 minutes 24-30 sec.
28.	The high pressure coolant injection (HPCI) system received a start signal.	About 6 min. 30 sec.

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ITEM	EVENT	TIME
29.	All four low pressure coolant injection (LPCI) pumps automatically started but no water was injected into the vessel.	6 minutes 35 sec.
30.	Reactor pressure fell to about 840 psig and began rising.	8 minutes 10 sec. ± 5 sec.
31.	The bypass valves opened about 1/3 of full scale or 3 of 9 valves. (They reclosed again at 11 mins. 16 secs.)	9 minutes 15 sec.
32.	Pressure peaked at about 1097 psig and began decreasing when two relief valves were manually opened.	9 minutes 31 sec. ±5 sec.
33.	The earlier IC isolation was reset and the IC was manually initiated.	9 minutes 45 sec. ±30 sec.
34.	The first IRM erratic behavior was printed out by the process computer.	13 minutes 8 sec.
35.	The first LPRM system erratic behavior was printed out by the process computer.	13 minutes 31 sec.
36.	The MSIV's were manually opened.	14 minutes
37.	Reactor feed pump "C" was manually tripped.	20 minutes ± 1 minute
38.	Containment temperature indicators read, with highest at 205° F.	About 30 mins.
39.	Core spray and LPCI pumps were shut down.	30-40 mins.
40.	Emergency diesel generators were stopped and SBGTS was opened to the drywell.	30-40 mins.
41.	Shutdown cooling was shifted to the main condenser via a bypass valve.	45 mins.
42.	Drywell floor drain sump pump started automatically.	1 hr. 2 min.
43.	Five of seven drywell coolers were brought into service manually.	1 hr. 15 min.
44.	LPRM power suppliers were shut off.	1 hr. 30 min.

108.8

ITEM	EVENT	TIME
45.	The drywell pressure indication was back on scale and read about 2.2 psig.	2 hours
46.	A composite particulate filter sample from the drywell was measured to be 5 rad.	3 hrs. 30 min.
47.	A stack gas charcoal filter, removed at 4 hours was analyzed for iodines.	5 hrs. 20 min.
48.	A particulate filter sample (sampling time about 1 hour) was taken.	6 hours
49.	The particulate filter sample above was re-analyzed for iodines.	9 hrs. 30 min. (0700 hrs. 6/6/70)
50.	Operations and radiation protection personnel entered the drywell.	0955, 6/6/70
51.	Reactor water level was lowered below the main steam nozzles.	1030, 6/6/70
52.	Radiation protection personnel analyzed on-site air samples and on-site grass samples. No significant amounts of iodine were found.	1300-1600, 6/6
53.	A Staplex air sample from the drywell was taken.	2020, 6/6
54.	The drywell purge rate was increased.	2300, 6/6
55.	A Staplex air sample from the drywell showed the I-131 level to be down to about 25 MPC.	0600, 6/7
56.	Operations and radiation personnel entered the drywell for an inspection.	1100, 6/7

1087.9

B. Chronological Discussion

A complete description of the events is presented below in chronological order. In many cases explanatory comments have been included, but a more complete analysis and explanation of the key events is contained in later sections.

1. On June 5, 1970, the Dresden Unit 2 plant was operating at 75% power (1875 MWt, 623 MWe) at near equilibrium conditions, with full core recirculation flow. A one recirculation pump trip test was planned for approximately 12 hours later, when full equilibrium Xe would be achieved and core flux distribution data was to be obtained by traversing incore probe (TIP). No testing was in progress and no maintenance operations were underway. Offgas discharge at the stack was approximately 25,000 μc/sec. as measured by the stack gas monitor/recorder.

2. At about 9:28 P.M. the Electro-Hydraulic Control (EHC) unit of the Turbine Generator set caused the Turbine Control Valve (CV) to open from 75% to the load reference set at 80%. Simultaneously or immediately thereafter all the Bypass Valves opened fully and remained open for 22 seconds. The initiating cause of this controller malfunction has been determined at this time to be a spurious signal generated spontaneously inside one of the pressure regulators in the EHC unit.

3. The computer recorded momentary high steam flow signals at 1 second (high steam flow means greater than 116%). The true steam flow would have been a transient from 75% through 80% to about 115%, and down to 40% in the first 1+ seconds. The computer scanning and storing techniques were capable of and did show several brief signals which did not occur simultaneously. This is consistent with the noisy nature of the steam flow signals.

   The operator saw only one high steam flow annunciator, and there was no signal to close the Main Steam Line Isolation Valves (MSLIV) on high steam flow. (The signal to close the MSLIV came from low pressure and they were closed at about 33 seconds). It is concluded that the signal to close MSLIVs on high steam flow was near the trip point, but that isolation <u>did not</u> occur at this time. The high steam flow indications reset at 2±1 sec. This occurred automatically as the steam flow decreased when the stop valves closed. No operator action was involved.

108.10

4. One second after the CV and BPV opened the turbine tripped. The process computer recorded "EHC Remote Trip"; this signal normally occurs only on turbine trips caused by high reactor water level or generator lockout. There was no generator lockout.

   Turbine trip is initiated by the Yarway level monitors which are not recorded. However, based on previous testing of this type of instrumentation, it is concluded that a transient level spike sufficient to cause the trip most likely occurred.

5. The turbine trip caused a reactor scram. All nuclear instrumentation recordings, all related recorded parameters such as RPV pressure and water level, and control rod position indications verified that the reactor was fully shut down immediately and without incident.

6. At two seconds there was a generator load rejection. This event followed as an automatic consequence of stop valve and intercept valve closure. This event caused that portion of the auxiliary power that was being carried on the unit transformer to transfer to the reserve auxiliary transformer.

7. At 3 seconds all four water level sensors tripped on low water level (20 inches on Yarway). This water level decrease was a natural consequence of scram and the resultant void collapse. The GE/MAC recorder shows a water level decrease to below zero; comparable water level changes after scram were recorded during testing and are reasonably consistent with prior analyses of such events.

8. At five seconds reactor feedwater pumps B and C tripped off from low suction pressure. This was caused by the low water level signal which demanded increased feedwater flow and forced the FW pumps into runout. The FW flow chart shows an increase from 7.1 to 9.9×10^6 #/hr and then a decrease to $\sim 3.7 \times 10^6$. This sequence of events had been observed previously during testing and had no significance in the overall sequence of events.

9. At seven seconds FW pump "C" restarted automatically because FWP "A" was out of service for maintenance. The FW flow chart shows variations in flow between about 4.6 and 6.7×10^6 #/hr for 1-2 minutes as the single pump went into and out of runout.

108.11

10. The water level rose sharply at 19 seconds to more than 55 inches. This was caused by depressurization as a result of the still-open BPV. The depressurization caused the RPV water to swell and it is probable that some two-phase mixture was carried into the steam lines (elev. 93.5 inches) at this time. After the BPV closed, the water level decreased rapidly in the time span 35-40 seconds, because of void collapse from subcooled feedwater mixing with the reactor water. In the time span 50-75 seconds, the water level again rose through the 15-55" range because of the continued feedwater flow with the resultant mass increase of RPV water.

11. At 22 seconds the Control Room recorder chart indicated that the BPV's closed. This was verified by a computer print out. It is assumed that the spurious signal which opened the valves initially had disappeared at this time.

12. The MSIV's were started closed at 33 seconds by a signal from the steam line low pressure switches which are set at 850 psig. The time for the pressure to decay to this point is consistent with the analysis for auto-blowdown events. There would not have been any flow in the steam lines at this time due to the earlier closure of the BPVs. This event was verified by a computer printout of the low pressure switch actuation.

13. A computer printout, also at 33 seconds, indicated the MSIV's were 10% closed. This is a normal function.

14. During the period of approximately 35-40 seconds the water level decreased from somewhere above +55 inches to somewhere below the +15 inches on the computer trend recorder. This level change was attributed to collapsing voids due to the continued injection of subcooled feedwater flow.

15. Vessel water level turned around and started increasing at approximately 50 seconds as indicated on both the computer trend chart and the 0-60 in. GE/MAC chart. The GE/MAC water level chart pen stuck at about the 17 inch level but the computer trend chart continued to rise off-scale. This rise is attributed to the automatically increased feed flow initiated by the low level in the above described 35-40 second period.

108.12

16. Reactor pressure, at one minute, dropped to approximately 775 psi as would be expected at this time during any trip and scram sequence. Pressure then started rising to reach saturation equilibrium. At about this time, the operator noted the low level indication on the GE/MAC recorder chart. He was not aware that water level was increasing because the pen was stuck, and, therefore, he switched feedwater from automatic to manual control and increased feed flow in an attempt to get the level back to normal. Actual level apparently rose to at least 120 inches during this time and flooded both the Isolation Condenser Steam Line and the Main Steam Lines.

17. At approximately 1 1/2 minutes, the operator determined that the GE/MAC recorder level pen was stuck; he tapped the case and the pen jumped up and off-scale at +60 inches. Manual feedwater flow control was then manually adjusted downward to the minimum position by the operator, which resulted in a flow of approximately 2.7×10^6 lb/hr. There were two 14" feed valves in service which do not provide positive shutoff. The minimum flow obtained was not considered unusual, based on past experience with these valves.

18. At approximately 2.5 - 3 minutes, the isolation condenser was manually actuated because vessel pressure was rising. It was discovered several minutes later that the isolation condenser system had isolated almost immediately after initiation, because of an erroneously established low Tech. Spec. setting on the high flow isolation signal for the condensate return line.

    Also, at this time, the operator attempted to open the MSIV's in an effort to reduce vessel pressure by dumping steam to the main condenser by way of the bypass valves. This was unsuccessful at this time because the valves had not yet been reset from the trip on low steamline pressure.

19. Since the reactor pressure had reached 1050 psig, the operator elected to manually open the E relief valve at time 3 minutes 45 seconds rather than wait further for the reset and MSIV opening time.

20. The operation of the "E" electromatic relief valve reduced the vessel pressure to 960 psig at which time the operator closed the valve. The time was then approximately 5 minutes 38 seconds after the scram. Pressure immediately turned around and started rising at a rapid rate. This rise is attributed to decay heat and injection of feedwater causing level increase to compress the steam bubble.

21. At some time between 5 and 6 minutes after the scram it is apparent that a momentary pressure pulse in the steam line caused at least one safety valve to lift. This was the cause of the observed high drywell pressure and contributed to vessel water level and pressure reduction.

    One side of the double discharge nozzle on Valve G exhausts directly at Valves E and F and it is surmised that this impingement caused the E and F lifting levers to rotate to a partially stuck-open position. These two valves subsequently remained open for the duration of vessel depressurization and cooldown.

22. Vessel pressure peaked at 1050 psig at time 6 minutes and was turned around and reduced at a rapid rate by the opening of another electromatic relief valve by the operator. It is estimated that the valve was open approximately 2 minutes.

    Pressure was reduced rapidly to 940 psig, and then at a slower rate to about 850 psig, at which time the relief valve was closed.

23. At time 6 minutes and 3 seconds, a 2 psig drywell pressure signal initiated an ECCS start, isolated reactor building ventilation, and initiated the Standby Gas Treatment System.

24. At 6 minutes 7 seconds the Standby Diesel Generator cooling water pumps started automatically as a result of the high drywell pressure signal. This was verified by a computer printout.

25. Both recirculation pumps tripped automatically at 6 minutes 12 seconds. This is verified by both the recirculation flow recorder chart and a computer printout.

26. The Standby Diesel Generators started automatically at 6 minutes 13 seconds. This was verified by a computer printout.

108.14

27. Core spray "A" started automatically at 6 minutes 24 seconds. Core spray "B" started automatically at 6 minutes 30 seconds. Injection of water into the vessel by the core spray systems did not occur because of the high reactor pressure.

28. The HPCI auxiliary oil pump, emergency oil pump and gland extractor automatically started, and the HPCI turbine went onto turning gear at around 6 1/2 minutes. However, the system did not operate and inject water because it had been valved out of service for repairs from earlier problems. Had the HPCI system been in normal readiness it would not have operated anyway because of a high reactor water level HPCI turbine trip signal.

29. All four LPCI pumps started automatically at 6 minutes 35 seconds, but did not inject water into the vessel because reactor pressure remained above the LPCI pump discharge pressure.

30. Reactor pressure decayed to about 840 psig at 8 minutes 10 $\pm$ 5 seconds because of the earlier relief valve operation. At this point, the relief valve was manually closed and pressure began rising at about 200 psi/minute. This was caused by the continued feedwater addition being greater than the safety valve losses and resultant compression of the reactor steam.

31. At 9 minutes 15 seconds, 3 of the 9 turbine bypass valves opened again. (Their normal opening mode is by sequence). The MSIV's were closed during this time and therefore there was no effect on the reactor. The cause is assumed to be the same as for the original opening, and they reclosed again at 11 min. 16 sec.

32. Pressure rose to about 1097 psig and began rapidly falling from relief valve "D" and "E" manual operation at 9 minutes 31 $\pm$ 5 seconds. The total time open was estimated by the operator to be about one minute.

    During this time a surveillance of the area radiation monitors, offgas and stack monitors was made. No radiation outside of the containment was detected. Offgas continued to decrease, reading approximately 10,000 μc/sec.

106,15

33. The earlier isolation of the isolation condenser was reset and the isolation condenser was manually initiated while relief valves "D" and "E" were still open at about 9 minutes 45 ± 30 seconds. After successfully bringing on the isolation condenser, the relief valves were closed. The isolation condenser remained in operation 5 to 15 minutes as estimated by the reactor operator. The isolation condenser temperature traces and the decreasing reactor pressure verified this. The isolation condenser was isolated by manual operator action.

34. The first of many Intermediate Range Monitor (IRM) erratic messages was printed by the computer at 13 min. 8 sec. Since reactor shutdown verification had previously been obtained, it was assumed that some sort of damage to the cable or connections was being caused by the steam in the containment.

35. The first indication of Local Power Range Monitor (LPRM) erratic behavior was printed out by the computer at 13 min. 31 sec. with the bulk of such indication starting about 23 min. 31 sec. This was also assumed to be caused by steam damage in the drywell.

36. The MSIV's were manually opened at 14 minutes to allow use of the bypass valve opening jack to bring reactor pressure down (it was about 770 psig at this point). The bypass valves were not actually opened until about 45 minutes. It is normal procedure to depressurize and cool down the reactor by controlled steam release through the BPV to the condenser.

37. Reactor feed pump "C" was manually tripped at about 20 minutes. Water level was observed over the next 10 minutes to verify that water level was being held by the approximate 60 gpm flow provided by the control rod drive pumps. The rate of decrease of the reactor pressure was approximately 14 psi/min. until 1 hr. 5 min. after the incident started; pressure was then about 200 psig. This depressurization rate was attributable to the leakage rate through the safety valves.

38. At about 30 minutes, a local temperature recorder reading an assortment of containment temperature was checked, with the highest reading 205°F.

39. During the time period 30-40 min., with reactor pressure reduced to less than 400 psig and in order to prevent injection of torus water into the core:

    a. Both core spray pumps were placed in the pull-to-lock position.

b. Three of the four LPCI pumps were placed in the pull-to-lock position.

c. The remaining LPCI pump and appropriate valving were lined up for torus spray.

d. The operator was prepared to restart any of the pumps immediately upon any indication of further difficulty (control handles are in the control room).

40. During the same time period, the emergency diesel generators were stopped and the SBGTS was valved open to the drywell under controlled, monitored conditions. Specifically:

a. A 2 inch bypass around the normal shut-off valve was opened. The flow was less than 600 cfm to each train compared to a design flow of 4000 cfm each.

b. A radiation protection man was dispatched immediately to monitor activity at the SBGTS absolute filters; he initially measured 30 mr/hr. Subsequent readings were never more than 50 mr/hr on contact with the filter housing.

c. The stack gas monitor reading remained essentially unchanged at 10,000 μc/sec.

d. Operation of the system on the 2 inch bypass continued until the next day (June 6) at 2000 hrs.

41. At time 45 minutes, shutdown cooling was shifted to the main condenser via the turbine BPV. One valve of the nine total was opened 25%. Surveillance of area monitors, main steam line monitors, and stack gas monitors continued. Stack offgas increased to approximately 25,000 μc/sec over a period of about 1/2 hr. and then reduced slowly.

42. At time one hour 2 minutes, drywell floor drain sump pump flow to radwaste started automatically at an initial flow rate of 80 gpm.

43. The drywell pressure was still more than 5 psig at about one hour 15 minutes. Five of the seven drywell cooling units were brought back into service at this time by valving out of service the drywell high pressure sensors. Reactor pressure was down to about 200 psig at this point and reactor vessel water level was above the normal water level.

108.17

44. At about one hour 30 minutes the LPRM power supplies were shut off because of indications of overheating. By then, instrument technicians had also established that SRM channel 24 and IRM channels 14 and 15 were working properly.

    Stack offgas activity had returned to 10,000 μc/sec at this time.

45. The drywell pressure indication was back on scale at two hours and reading 2.2 psig.

46. A composite particulate filter sample from the drywell was monitored at 3 hours 30 minutes. It was wet, dirty, and measured 5 rad. The filter had been in the sample stream for nearly 24 hours, but the activity was attributed to the event.

47. A stack gas charcoal filter was removed four hours after the initial transient. The total sample time was 24 hours, and included 20 hours of normal operation at 75% power before the transient. It was analyzed for iodines one hour 20 minutes after removal from the stack gas sample station. The results showed .06 μc/sec I-131 and .07 I-133, not significantly higher than the average of the previous several days results of normal operation.

48. At about 6 hours, a particulate filter air sample was taken from the drywell at a point between the "A" recirculation system header and the biological shield. The sample was begun at 0210 of 6/6/70 and stopped at 0305 (Δt=55 minutes). At 0310, it was counted for Rb-88, the particulate decay product of Kr-88, and had a concentration of 6.5×10^{-6} μc/ml.

49. The Rb-88 on the above particulate filter sample was allowed to decay and was re-analyzed at about 9 hours 30 minutes (0706 on June 6, 1970). The I-131 level in the drywell was estimated to be about 100 times the Maximum Permissible Concentration (100 MPC) as established by AEC regulations. This iodine analysis, together with the above rubidium analysis, indicated that a steam-water mixture had been leaking into the drywell.

    The Eberline Instrument Corp. of Santa Fe, New Mexico who is under contract by CECO to perform off-site monitoring and sampling, was called at 0710 of 6/6/70. Monitoring and sampling activities of the environs surrounding the Dresden station began at about 0900 the same day.

108.18

50. Operations and radiation protection personnel entered the drywell at 0955, June 6 for 10 minutes with Scott Air Packs and other adequate radiation protection apparatus to obtain Staplex air samples. They observed water cascading down from the upper part of the northwest portion of the drywell in the vicinity of main steamline "D", on which is mounted electromatic relief valve "D" and safety valves "E" and "F". The dose rate in the drywell was about 1 R/hr.

    Analysis of the Staplex air sample showed the I-131 level to be 82 MPC. Observations at the time of entry indicated that the leak may have been coming from one or more of the safety valves.

51. Because of the water leakage from the main steam line elevation, reactor water level was reduced to below the main steam nozzles at about 1030 on June 6. It is standard operating procedure to raise the water level above the RPV flange during the latter stages of plant cooldown so as to cool these heavy metal sections. The water level in this case had been allowed to increase above the steam lines early in the sequence of events. Once the water level was high there was no evident reason to decrease the level until the leakage was discovered.

52. During the time from about 1300 to 1600, June 6, radiation protection personnel analyzed on-site air and grass samples and found no significant amounts of iodine.

53. At about 2020, June 6, a Staplex air sample from the drywell showed a slight I-131 increase above the 82 MPC value found from the 0955, sample. It was decided that the drywell purging rate was not effective for the iodine removal and a method was sought to increase the purge rate.

54. The drywell purge rate was increased in the containment at about 2300 June 6 to allow drywell entry for damage assessment. The flow path was changed to pull air from the reactor building directly into the drywell, then through an 18 inch line (instead of the 2 inch bypass line originally used) to the SBGTS. The SBGTS absolute filters were periodically monitored and levels stayed below 30-50 mr/hr on contact.

10819

55. A Staplex air sample was taken from the drywell and analyzed at 0600, June 7 to determine whether there had been any iodine activity decrease. The sample measured about 25 MPC I-131.

56. At 1100, June 7, operations and radiation protection personnel entered the drywell for a preliminary damage inspection. It was seen that safety valves "E" and "F" on main steamline "C" were held slightly open by the position of the operating handles, which apparently had been stuck and rotated by the discharge of safety valve "G" on adjacent steamline "D".

These were the major events in chronological order from the time the incident started until the time the safety valves were found to be stuck open, thus identifying the problem. Further detailed discussion and analysis of the key points and effects of the incident are contained in the following sections.

108120

IV. OPERATIONS ASSESSMENT

A. Staffing and Responsibilities

The regularly assigned General Electric Shift Superintendent, AEC Senior Licensed, was in the control room and was providing technical direction for all station operations. Fully qualified Commonwealth Edison personnel, including both a Senior Licensed Shift Engineer and Console Control Operator were also present and receiving their operating instructions from the GE Shift Superintendent. There were no conflicting or uncertain responsibilities during the course of the incident.

B. Water Level Control

In response to an initial and expected water level drop and subsequent feedpump trip and restart, the operator switched to manual control and attempted to restore normal water level at maximum rate. This is a normal and proper response, supported by operator training and written procedures. An overriding concern to keep the core covered has prevailed in all phases of plant design and operation.

The recorder normally used for manual level control was stuck at a low indication as described in Section 1 above. This compounded the problem as the operator kept feedflow for a period; when this was discovered, he immediately adjusted the controllers to the minimum settings. However, the feedwater control valves are not completely leak tight at this point and make up was still too high. After the transient was essentially completed and stable conditions restored, the operator shutdown the feedwater system completely while watching level indications to be sure CRD cooling water make up to the RPV was adequate to maintain level.

C. SBGTS Venting

Operating procedures specify use of the SBGTS for venting purposes upon receipt of high-containment pressure alarms. By the time this was done, 30-40 min. after the incident started, the transients were over and normal shutdown procedures were being applied. Reactor pressure had dropped to about 400 psig and water level was being maintained stably with CRD pumps at a flow rate of 50-100 GPM. Stack monitors were continuously observed and no increase was noted when the SBGTS was put into service. Also, the bypass line and not the main vent line was utilized, resulting in a per-unit loading of less than 1/6 rated capacity.

Only the low range (-5 to +5 psig) drywell pressure indicator was in service when this action was taken. A 0-75 psig range indicator had been installed in late 1969, but it had not been included in the instrument check list and had not been valved into service. Subsequently, in order to aid the drywell pressure

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reduction, the drywell coolers were put back into service. Use of the containment sprays was rejected as possibly contributing to further water damage and unnecessary thermal shock to hot equipment. The exact time that the pressure came back on range is not known, but a pressure of 2.2 psig was observed about 2 hours after the incident.

Subsequent tests of the absolute filter/charcoal filter trains in service during the several days after the steam release showed iodine removal rates in excess of 99 percent, confirming satisfactory performance of the system. Further, stack iodine monitoring cartridges, removed on a daily basis following the event, also confirmed no increase occurred in iodine release rates from the plant.

D. ECCS Shutdown

Shutdown of the core spray and LPCI pumps occurred at about the same time as the drywell purge discussed above. Again, normal shutdown procedures were being effected and plant conditions were stable. All ECCS equipment had been verified as starting and operating. Placing controls on pull-to-lock position represented a step in an orderly, systematic operational response to the situation. Available Emergency Procedures deal with severe accident cases where water level could not be maintained and were therefore not applicable. Any ECCS equipment could have been restarted immediately by moving the control handles (in the control room).

E. Isolation Condenser Operation

Difficulty in putting the isolation condenser into service resulted because of the low setting on the high flow isolation trip on the condensate return line. Technical specifications required this setting to be 120% of normal flow when it should have been set at 300%. This unduly restrictive specification was not intended originally and a request for change to the Technical Specification was in the process of being made. This system was successfully initiated about 9 1/2 min. after the incident started. The condenser had been previously operated on May 14 during an isolation transient following 75% power operation, and daily surveillance testing of the valves was being conducted because of the HPCI being out of service. These tests were not done with flow in the lines, however, and the last one was done on 0000 to 0800 shift of the same day.

F. Cooldown via Bypass Valves

The MSIV's were reopened at about 14 min. and shutdown cooling was aided by bypass steam to the condenser via the bypass valves. This is normal shutdown procedure, but the previous erratic behavior of the bypass valves could have occurred again and caused further difficulty. MSIV's would have been promptly

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closed in this case and the pressure reduction continued at a slower rate with the isolation condenser, which had been put into service earlier. If reactor water level had been below the top of the core during the transient, indicating possible fuel damage, the MSIV's would have been left closed to maintain reactor isolation and conserve water inventory. As discussed above, water level was more than adequate.

G. Flux Monitor Failures

Although cable damage caused a considerable number of the SRM, IRM and LPRM flux monitors to fail, there was never any question about the reactivity status of the reactor. It was more than 13 minutes after shutdown before any of the flux monitors began to fail, and the shutdown status of the reactor was verified before the damage occurred.

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V. DRYWELL DAMAGE REPORT

ITEM	DESCRIPTION	COMMENTS
MS Line Insulation	Approximately 19 running feet of reflective insulation on assembly D extending upstream from safety valve 2-203-4H had to be replaced.	This was caused by direct or reflected discharge from the safety valves
FW Lines Insulation	Approximately 6 feet of insulation extending upward on the 12" E feedwater riser from the reducing tee on the 18" B feedwater line had to be replaced.	
Recirculation Riser G	Approximately 6 feet of insulation on recirculation riser G extending from but not including the tee on the 22" recirculation inlet manifold had to be replaced.	
MSL Safety Valves 2-203-4E,F	Lifting levers were rotated and jammed against the spring housing so they could not close fully.	
'B' Floor Drain Pump Motor	300 Kohms from external breaker connection.	These were checked again as described in Section VII.G. All other drywell motors meggered O.K.
'B' Recirc Discharge Valve Motor 202-5B	150 Kohms from external breaker connection.	
'A' Recirc Equalizing Tie Line Valve Motor 202-9A	10 Kohms from external breaker connection and a burned out brake coil.	
'A' Shutdown Cooling Valve Motor 1001-1A	2 meg ohms from external breaker connection.	
'B' Shutdown Cooling Valve Motor 1001-1B	2 meg ohms from external breaker connection.	
HPCI Valve Motor 2301-4	1.7 meg ohms from external breaker connection.	
Drywell Electric Penetrations	7 penetrations were found to be leaking from the center inboard to the drywell.	There were no outboard leaks to the reactor bldg.
SRM Cables	SRM 21 was found to have an open lead and SRM 23 was found shorted. SRM's 22 and 24 were operable.	See Sect. VI-A for more details.

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V. DRYWELL DAMAGE REPORT (continued)

ITEM	DESCRIPTION	COMMENTS
IRM CABLES	IRM's 12, 13, 17 & 18 were found to have low insulation resistances. IRM's 11, 14, 15 & 16 were operable.	See Sect. VI-A for more details.
LPRM Cables	93 LPRM cables were found to be shorted, 10 were open, and 61 operable.	
TIP	Control cables to TIP indexer were found to be shorted.	
Drywell Wall	Two one foot diameter patches with paint removed were found opposite the discharge of safety valves E&F (about 10 feet away). Surfaces in the vent piping between the drywell and torus also had paint removed, but this was only the outer layer of paint. The prime coat plus one finish coat of paint was still intact.	

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VI. ANALYSIS OF EVENTS

A. Cable Damage and Drywell Temperature Tests

Damage to the neutron monitoring cables within the drywell occurred during the incident. Tests were conducted in an attempt to determine the failure mechanism of the cables.

1. LPRM Cable Failures.

As stated in Section V, over 60% of the LPRM cables (103 out of 164) experienced failures as a result of the adverse drywell environment. The predominant failure mode was by short circuit (93 out of 103). Tests were conducted to establish the mechanism of the failure.

(a) LPRM Cable Tests Performed. New samples of the LPRM cables in the form of single pieces (3 foot samples) and as a bundle of 18 cables, were subjected to oven tests. The samples were placed in various degrees of twisting, loading (with external weights), bending, and temperature distributions which were similar to conditions experienced by D-2 cables.

(b) Test Results. Failures were caused by local buckling of the center conductor due to thermal expansion of the conductor while restrained at its ends. This mechanism may be enhanced by rough handling or a manufacturing process which kinks or predisposes the center conductor to buckling.

Other failures were caused by drift of center conductor to the point of contact with the shield. This was generally due to the combined effects of differential expansion and mechanical loading.

Some failures by buckling of center conductors occurred at temperatures as low as ~220°F and by shorts due to drifting center conductor at temperatures as low as 300°F. However, many test samples went to 500°F (for up to one hour) without exhibiting failures. Also, in many instances, tests of cables in identical configuration (bends, loading, etc.) did not produce the same results.

(c) Test Conclusions. The results of the tests are consistent with findings in the field and clearly identify the mechanism of failure. The fact that the tests were inconsistent among themselves may be due to differences in materials (e.g., the expansion coefficient of the polyethylene dielectric) or discontinuities resulting from the manufacturing and handling processes.

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2. SRM/IRM Cables.

These cables were not tested since their temperature ratings* are below those of the LPRM cables and the failure mechanism was not in question. These cables are being replaced with new high temperature cables which were tested to 500°F under conditions of small radius bends and found to survive without degradation.

3. Tests to Determine Drywell Temperature.

Several indicators of drywell temperature were found at the site and corresponding components were tested in San Jose in an attempt to independently determine the drywell temperature attained during the incident.

(a) Connector Caps. Deformed plastic caps were discovered in the penetration junction boxes. Similar plastic caps were tested and found to show appreciable deformation between 250 and 300°F.

(b) Dymo Labels. It was reported that Dymo Labels on cable bundles had lost their set and returned to the ribbon state. Tests showed that this occurred between 200 and 250°F.

(c) Cable Jackets Melted Together. It was reported that in a few cases the LPRM cable bundles had bonded together due to melting of the jackets. Tests show this occurs between 250 and 300°F, but is a function of the amount of irradiation to which the jacket had been subjected.

B. Early Transient Behavior Effects on Fuel

Using the sequence of chronological events that was established from available data, the subject incident was simulated on both the transient analysis model used for predicting effects of abnormal operational transients and also the analytical model normally used to investigate postulated loss of coolant accidents. The intent of both of these simulations was to investigate the early portion of the subject incident in detail and to determine whether such a sequence could result in possible damage to reactor fuel.

The accident analysis model was used to verify both the transient model analysis and the plant data which show that sufficient forced cooling was provided during the initial portion of the transient when fuel surface heat flux levels had not yet decayed from the pre-scram values. The transient model analysis indicates that the critical heat flux ratio would dip insignificantly during the first half second and would then increase throughout the remainder of the transient. Specifically, this

*See Section VII for further discussion of temperature ratings.

model, using the design peaking factors that would result in a MCHFR of 1.9 at full power, yielded a value for the 75% power case of 3.07 at the start of the transient and a minimum of 2.99 at 0.47 seconds. The reactor scram, which occurred at one second, together with adequate forced cooling, assured that no fuel damage from thermodynamic effects could have resulted during the initial portion of the transient.

After approximately 15 seconds of nucleate boiling cooling, all stored heat in the fuel would have been removed and the pool boiling process would then be capable of effectively removing the decay heat. During the remainder of the incident, prevention of fuel damage was assured as long as the core remained submerged. Water level was at all times considerably above the top of the core and it can thus be concluded that no fuel damage could have occurred.

The transient analysis also supports other evidence based on past testing with Yarway level instrumentation that the turbine trip resulted from indicated high water level.

C. Pressure Vessel Internal Response

1. Vessel Pressure Transient

The vessel pressure transient during this event has been analyzed based on the initial conditions and the sequence of events which occurred during the transient. The predicted results and the actual recorded data are plotted on Figure VI-1. The following is a discussion of the comparison between the analysis and the data extracted from the recorder charts.

In the analysis, the vessel pressure dropped from the initial value of 985 psia to 970 psia approximately 1 second after the bypass valves opened, at which time turbine stop valve closure and scram was assumed to occur. After closure of the stop valves the pressure increased to 1006 psia at 3 seconds. The bypass valves were assumed to open completely at time zero. The momentary increase in pressure in the analysis after the stop valves closed can be explained by the fact that at this time the 40% bypass capacity is not adequate to remove the decay heat from the reactor core. This pressure increase was not observed in the recorded pressure trace. The early pressure transient is sensitive to the actual precise timing of the valve position changes which could not accurately be determined from the strip chart data. However, this did not significantly affect the subsequent transient analysis.

During the 3 to 22 second-period the bypass valves were fully open and the decay heat was adequately removed, resulting in depressurization of the vessel. During this period, the analysis adequately predicted the depressurization rate as is evidenced by the data obtained from the recorded pressure trace.

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After the bypass valves were closed at 22 seconds and the reactor vessel was isolated, the vessel pressure continued to decrease. Once isolated, the water level outside the shroud dropped below the feedwater sparger level due to the collapsing voids inside the shroud. During this time, the feedwater is spraying into a steam atmosphere causing condensation to occur. This condensation, along with the continuous decrease in voids, contributed to the vessel depressurization. This effect continued until most of the voids had collapsed. After this occurred, there was a net increase in water level outside the shroud causing the feedwater sparger to become recovered. When the sparger was recovered, entrainment of steam at the liquid surface interface may have occurred because of the turbulence present. This could have persisted for a short period of time until the level was high enough above the sparger so that the turbulence at the liquid interface had subsided, and could not entrain steam. This would occur at approximately 53 seconds, at which point the vessel pressure began to rise. The difference between the analysis and the observed point at which the vessel pressure bottomed out is due to the difference in the feedwater flow rate used in the analysis and that actually obtained because the steam condensation is sensitive to feedwater flow. During the period after the control valve closed, the feedwater was observed to be oscillating between 4.7×10^6 lb/hr. and 6.7×10^6 lb/hr. In the analysis, an average value of 5.7×10^6 lb/hr. was used.

When the feedwater sparger became sufficiently covered by water, the steam quenching effect ceased and the pressure began to increase. The increase in pressure was due to the compression of the saturated steam in the steam dome by the increasing subcooled water level outside the shroud. In the analysis, the pressure reached the relief valve setting at 170 seconds, which maintained the vessel pressure at a constant value until the time (224 secs.) when the operator actually opened the relief valve. The faster compression rate obtained in the analysis can be explained as follows.

In the analytical analysis, it was assumed that the compression was adiabatic, i.e., the steam dome was assumed to be compressed without any condensation occurring. This assumption gives the fastest pressurization rate possible. Whereas, in fact, condensation actually existed between the subcooled liquid surface and the steam. This condensation of steam results in a slower compression rate.

At approximately 1 1/2 minutes, the analysis showed a decrease in the compression rate. This decrease was also observed in the actual pressure traces. This decrease was attributed to the decrease in feedwater flow that occurred at this time. At approximately 3 minutes, the pressure trace showed a significant increase in pressurization rate. This occurred because the water level outside the shroud had reached the dryers, significantly reducing the free water surface area available

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for steam condensation. At approximately 224 seconds, the operator manually opened a relief valve resulting in depressurization of the vessel.

Since water level had reached the steam lines at about 3 mins., a low quality two phase mixture was blown out when the relief valve was opened initially. This continued until the relief valve was closed. It was at this time that a safety valve momentarily opened from a pressure surge and caused two others to be propped open slightly. (See item 4 below.) However, feedwater flow was greatly in excess of that blowing out the safety valves, so repressurization occurred at about the same rate as before, when the relief valve was reclosed. A relief valve was opened two more times to control pressure before the isolation condenser was successfully put in operation to effect a continual pressure decrease. Each time there was a brief period of rapid depressurization due to steam only blowdown followed by a slower depressurization due to a two-phase mixture blowdown which was caused by the swell associated with reduced pressure.

2. Water Level Transient

Calculated level response and level data recorded during the event are compared in Figure VI-2. The recorded data points were obtained from the on-line computer recorder and the strip charts. During the incident, the indicated water level fluctuated, and as it passed through the high water level and the low water level trip points, it was recorded on the on-line computer. The recorded points shown on the figure (from point A to point H) can be explained as follows.

The level drop to point A was due to the reduction in core voids caused by the reactor scram and due to the decrease in feedwater flow when feedwater pumps tripped at 5 seconds. Continued vessel depressurization and the feedwater pump automatic restart at 7 seconds caused the level to recover and pass upward through points B and C. Based on indicated level, this occurred at about 19 sec. At 22 seconds, the bypass valve closed which caused a decrease in level (point C to D) because of the decrease in void content. Feedwater flow into the vessel raised the level (point D to E) until, at point F, the vessel pressure reached a minimum and began to increase. Increasing pressure collapsed some of the remaining voids in the core causing another decrease in level (point E to F). From point F to G, volumetric increase from feedwater injection gradually overcame the decrease from void collapse. Continuing feedwater flow resulted in further level increase as indicated by points G and H. At about 3 minutes, the analysis showed that the level reached the main steam lines. Subsequently, the level went up and down across the main steam line elevation due to the interaction of relief valve openings and continued feedwater flow.

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3. Internal Loads

An evaluation has been made of the loads imposed on the reactor vessel internal structures by the incident.

It is concluded that in no case did the maximum loads approach design values; no internals damage could thus have occurred.

The design values of the reactor vessel internals loadings are arrived at by postulating the simultaneous failure of a steam line and the occurrence of the design basis earthquake. The steam line break generates the maximum gross pressure differentials across the internals. The magnitude of these differentials is determined by a combination of the initial value of the differentials and the increase associated with the rapid vessel depressurization. For this plant, the depressurization rate produced by a steam line break would be ∿30 psi/sec. An examination of the pressure transient following the bypass valve incident indicates that the maximum depressurization rate was ∿20 psi/sec. This occurred when the D and E relief valves were opened at ∿9 1/2 minutes into the transient. The pressure rates at other times during the incident were never more than 50% of this rate. Since there was also no earthquake, it can be concluded that the loads on the vessel internals were considerably less than the design values. In addition to the maximum depressurization rate being less than that associated with the steam line break, the recirculation pumps tripped at 6 minutes. Thus, by the time the D and E relief valves were opened, the pressure differences across the internals due to forced recirculation of coolant had dropped to zero. This further minimized the consequences of the subsequent depressurization.

A visual inspection of the vessel internals has been made which confirmed that no internal damage occurred.

4. Safety Valve Behavior

During the event, a safety valve opened momentarily and caused the opening of two other safety valves which remained in a slightly open position. The two valves which remained open resulted in mixture of water-steam flow into the drywell during the event. The event was safely terminated and if these valves had not remained open, it would have been terminated without significant equipment damage in the drywell. Therefore, the circumstances of the event have been examined and post-incident analyses have been performed to determine the probable cause of safety valve lifting.

(a) Pertinent Data. The level and pressure transient used for this analysis are shown in Figures VI-2 and VI-3. Sufficient comparison could be made with available recorded data to verify these transients for times when recorded data was not available.

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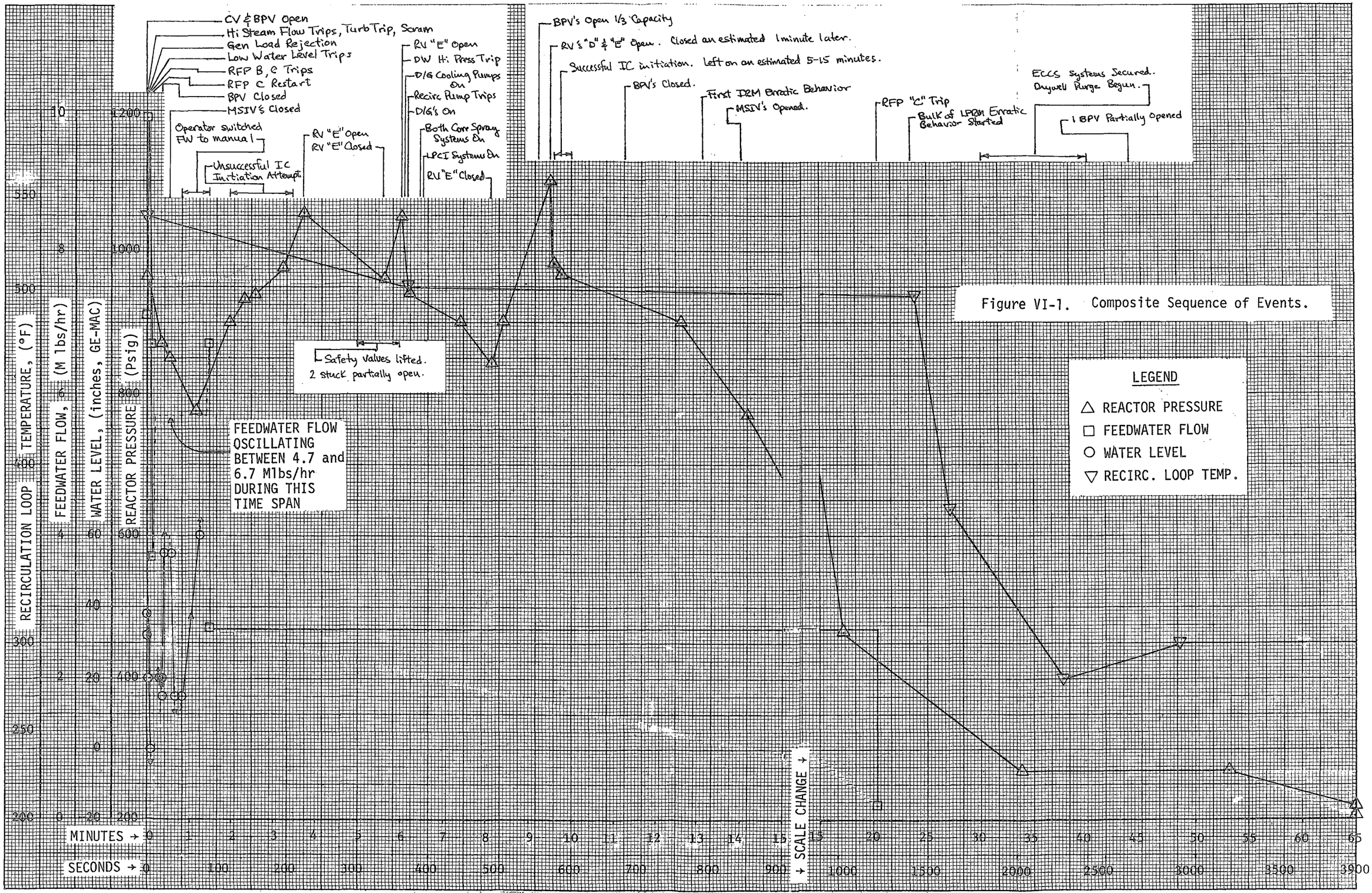

Figure VI-1. Composite Sequence of Events.

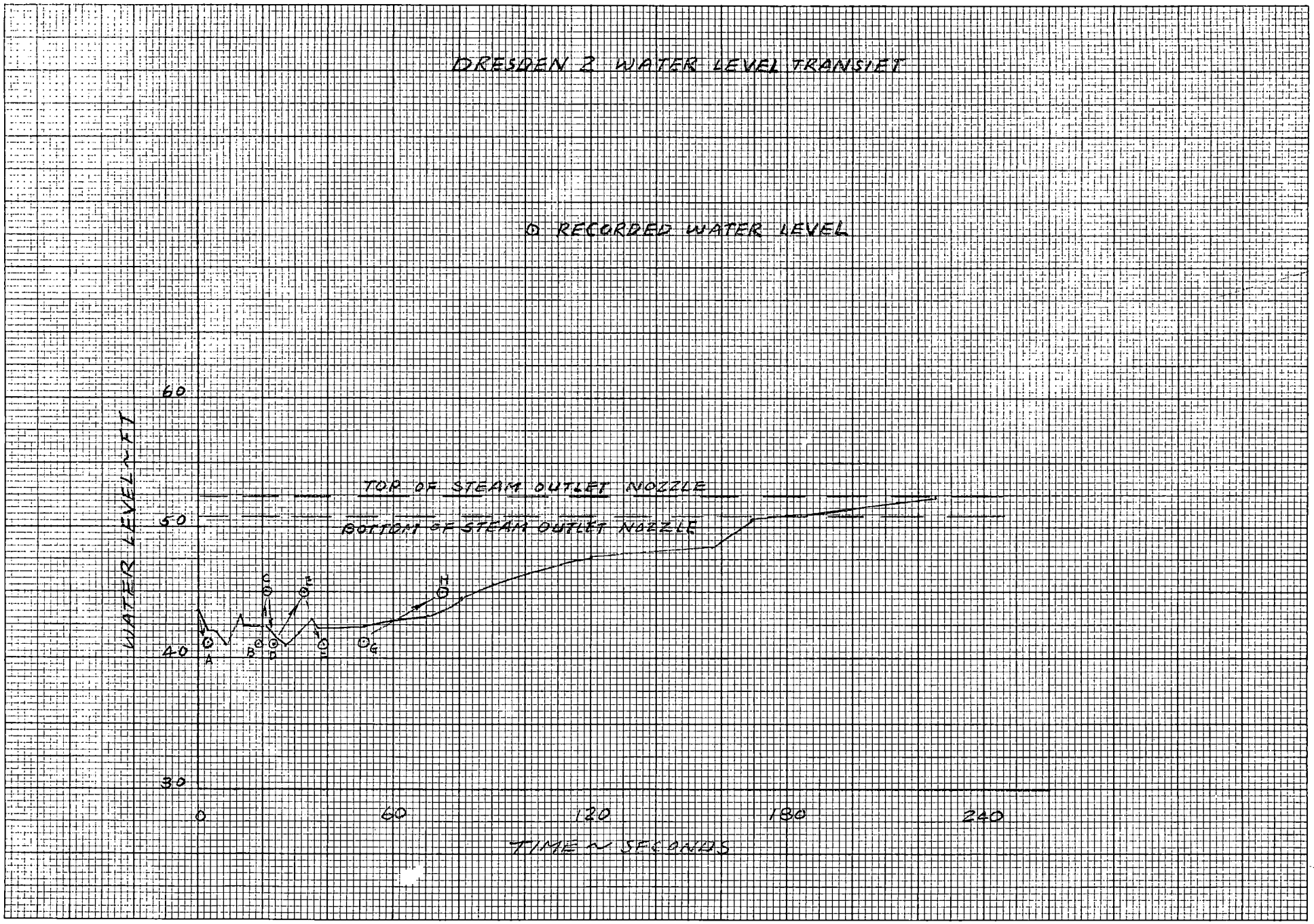
DRESDEN 2 WATER LEVEL TRANSIET
RECORDED WATER LEVEL
TOP OF STEAM OUTLET NOZZLE
BOTTOM OF STEAM OUTLET NOZZLE
WATER LEVEL ~ FT
60
50
40
30
0
60
120
180
240
TIME ~ SECONDS
A
B
C
D
E
F
G
H

Figure VI-2.

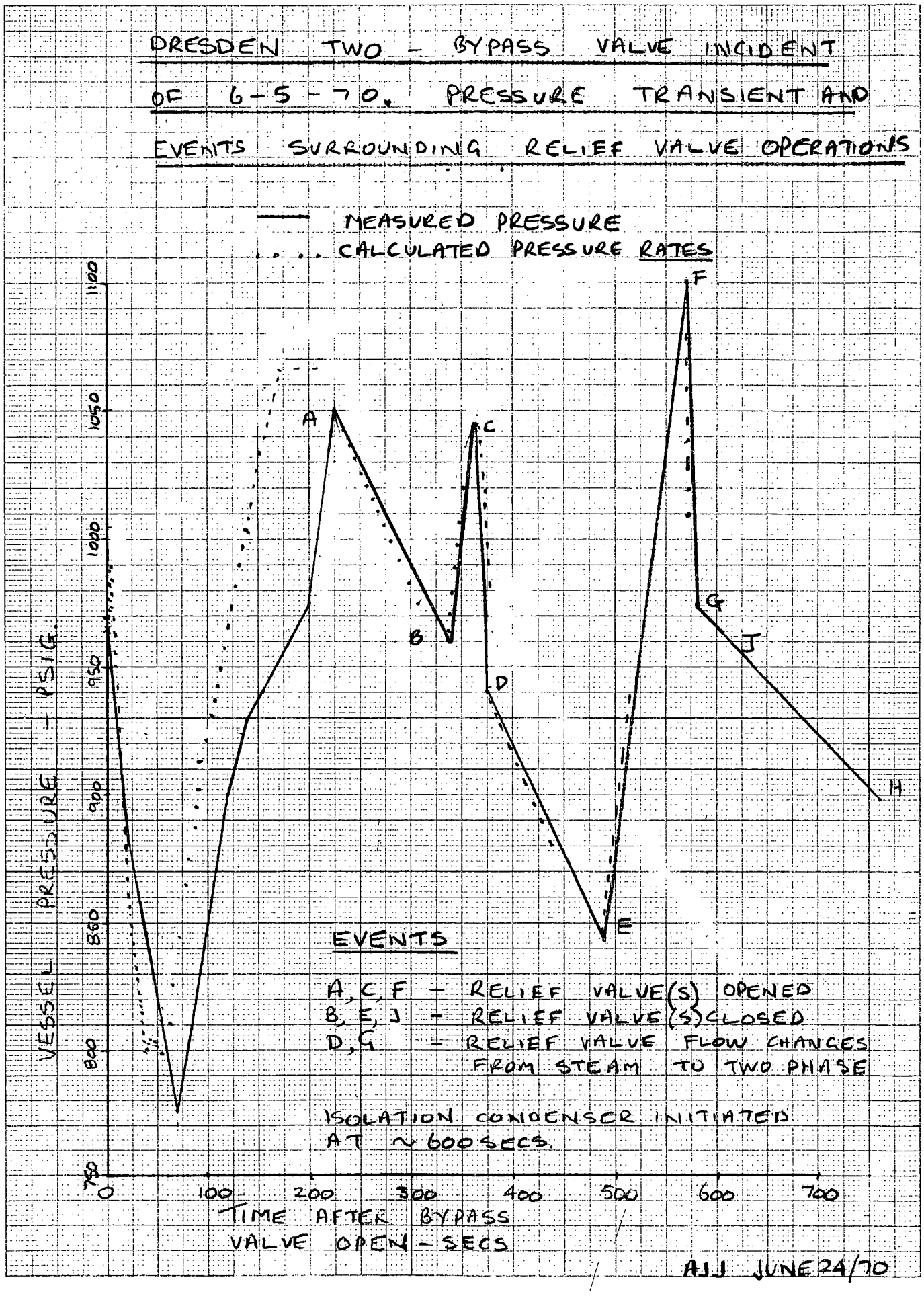
DRESDEN TWO - BYPASS VALVE INCIDENT OF 6-5-70. PRESSURE TRANSIENT AND EVENTS SURROUNDING RELIEF VALVE OPERATIONS
MEASURED PRESSURE
CALCULATED PRESSURE RATES
VESSEL PRESSURE - PSIG.
1100
1050
1000
950
900
850
800
750
A
B
C
D
E
F
G
H
J
EVENTS
A, C, F - RELIEF VALVE(S) OPENED
B, E, J - RELIEF VALVE(S) CLOSED
D, G - RELIEF VALVE FLOW CHANGES FROM STEAM TO TWO PHASE
ISOLATION CONDENSER INITIATED AT ~600 SECS.
0
100
200
300
400
500
600
700
TIME AFTER BYPASS VALVE OPEN - SECS
AJJ JUNE 24/70

Figure VI-3.

Post incident discussions with the operators provided information regarding the number of relief valves used, their identity and the order in which they were used. As discussed in the sequence of events, Section I, the operators recalled (but were not certain) that the first pressure increase (~3 1/2 mins.) was controlled by opening relief valve E on steam line B. The second pressure rise (6 mins.) was controlled again by relief valve E. The third pressure rise (~9 mins.) was controlled by opening relief valve E and relief valve D on steam line D.

Post incident examination of the rupture diaphrams of the safety valves indicated that A and B safety valves on steam line A did not lift, C and D safety valves on steam line B leaked (rupture diaphrams split), E and F safety valves on line C had lifted sufficiently to blow out the rupture diaphram, and G safety valve had lifted (no rupture diaphram) but the H safety valve did not lift on line D. The G safety valve was set at 1220 psi and the H safety valve at 1230 psi. The E and F safety valves on the C steam line were held in a slightly open position because the jack handles were wedged onto the safety valve frame. On one frame, a gouged mark was noted on the side of the frame indicating that the handle had been forced onto the frame by the discharge of the G safety valve.

(b) Analysis. Two possibilities have been considered which could cause safety valve lifting:

1. Water, which was subcooled relative to the steam in the steam dome and steam lines, entered the steam lines causing rapid condensation of trapped steam. As the steam collapsed, a pressure pulse could be generated which could lift the safety valve.

2. Water in the steam lines was suddenly decelerated when the relief valve closed causing a pressure pulse commonly referred to as a waterhammer.

A preliminary review of the situation supported the steam condensation hypothesis. The plant operators indicated that the E relief valve (B steam line) was used to control the first and second pressure rise. However, safety valves in the B line did not open enough to blow out the 10 psi diaphram. From the high drywell pressure alarm, it was known that the safety valve must have lifted prior to about six minutes, and the operators recalled (but uncertain) that only the E relief valve was used prior to that time. Since

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the relief valves on the steam line used for pressure relief did not significantly lift the safety valves on that line, but a safety valve on a line that had not been used did lift, it was concluded that sudden steam condensation was the most probable cause of safety valve lifting. This hypothesis was apparently supported by the early surmise that the safety valve lifting appeared to have been relatively general. That is, both safety valves on three of four steam lines were originally thought to have lifted momentarily. Safety valves on the A steam line did not lift.

Subsequently, investigation revealed that the two safety valves on the B steam line did not lift as originally thought; the diaphrams had only split ($\sim$1 in.), indicating that the valves had not lifted but probably had leaked. On the C steam line, the E and F safety valve jack handles had been forced onto the valve frame. The handles were in the path of the discharge from the G safety valve. Post incident analysis indicates that a force as high as about 1000 lb. could have been applied to the handle due to discharge impingement. On the D steam line, the G safety valve had lifted, but the H safety valve, which was originally thought to have lifted, had not lifted.

Thus, detailed investigation indicated that the C, D and H safety valves had not lifted; only the G safety valve lifted and the discharge from this valve lodged the lifting levers of the E and F safety valves on the frame.

This caused a slight opening of these valves, about 3/16 in. and 1/16 in. Since only one valve lifted, the mechanism is more likely to be a local phenomena, such as waterhammer, rather than a general steam collapse phenomena. The waterhammer hypothesis is supported by post incident analysis. Water level calculations indicate that the water level reached the steam lines at about three minutes. If a pressure pulse had been generated by sudden steam condensation in the steam line, it would have occurred at about this time and apparently did not. Water level calculations show that the steam lines were nearly filled with water, due to continued feedwater flow, by the time the relief valve was first opened.

Based on the pressure response data, the pressure began to increase at about 340 sec., which would be expected if this is the time when the first relief valve was closed. Assuming waterhammer occurred at this time, the calculated pressure rise is 225 psi.

Just prior to valve closure, the steam line pressure was 975 psig (960 psig vessel pressure and 15 psi elevation head) so the peak steam line pressure was 1200 psig.

The G safety valve was set at 1220 psig and is believed to have lifted at this time (340 sec.). The H safety valve, which was set at 1230 psig, did not lift significantly but leakage caused the rupture disc to split. Assuming that the E and F safety valves were forced open concurrently, the drywell pressure response can be calculated based on the flow areas of the unseated safety valves ($\sim$0.01 ft^2). Pased on this area, a drywell pressure of 2 psig would be reached in 20 seconds, or about 360 seconds into the transient. Computer printout indicates that the high drywell alarm occurred at 363 seconds.

Calculated pressure vessel internal response and containment pressure response support the waterhammer hypothesis, and the calculated steam line pressure rise is close to that which could cause safety valve lifting. While this hypothesis is consistent with the analytical evaluation, it is inconsistent with the operators recollection of the relief valve used for pressure control. Since the operators expressed uncertainty about relief valve identification, it is possible that the D relief valve was used instead of the E relief valve. The control handles are side-by-side ($\sim$ 3 in. apart) on the control panel.

(c) Conclusion. It is concluded that the probable cause of lifting the G safety valve was waterhammer in the steam line when the D relief valve was closed, and that the E and F safety valves were opened by jet impingement on the jack handles from the G safety valve discharge. Calculated peak pressure due to waterhammer is 1200 psi compared to a set point of 1220 psi in the G safety valve. The H safety valve (on the same line) was set at 1230 psi but did not lift. In addition, maximum steam line pressure did not exceed the MSIV design pressure of 1250 psi and is well within the 1565 psi pressure at which the MSIV was hydrostatically leak tested.

D. Drywell Thermal Dynamics Analysis

1. Introduction

The purpose of this section is to determine analytically the transient pressure and temperature condition based on the sequence of events during the incident.

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2. Pressure Transient

Prior to the incident, the containment pressure was maintained at 0.3 psig. The average drywell temperature and relative humidity were assumed to be 120°F and 20% respectively. The torus temperature was recorded at a continuous reading of 76°F and the relative humidity was estimated at 100%. Under these initial conditions, the containment contains 680 lb-moles of non-condensible gas divided almost evenly between the drywell and the torus.

The maximum containment pressure attainable (for small leaks) occurs when all of the non-condensible gases in the drywell are transferred to the wetwell and can be calculated accurately. The transient pressure response, however, depends on the postulated sequence of events regarding the safety valves lifting and sticking open. The following sequence of events is the basis of the calculated pressure history in the containment following the event.

The event was initiated at 21:28 on June 5, 1970. It is concluded that "G" safety valve lifted momentarily and effected the lifting and sticking of safety valves "E" and "F". When "G" valve relieved, the jet force rotated the lifting levers on the "E" and "F" safety valves (device for manual lifting of safety valve) around and jammed them in a position such that the valves lifted slightly and remained open. The "F" valve was lifted 3/32" and the "E" valve 1/16". The valve seat diameter is 3.57 in., thus resulting in a combined leak area of .01216 ft^2. It was assumed for this analysis, that for the first 15 minutes after the safety valves lifted, the liquid level in the vessel was above the main steam line outlet and liquid blowdown into the drywell took place. At this point in time, the feedwater was shut down and liquid level in the vessel dropped below the steam lines initiating a switch from saturated liquid to saturated steam.

Figure VI-4 illustrates the results of the analysis based on the above sequence. Intermittent relief valve operation had no effect on the containment pressure. The relief valves discharged directly to the suppression pool and effected a slight temperature rise which had a negligible effect on vapor pressure and air partial pressure. The downcomers are submerged approximately 4 feet into the suppression pool such that the drywell pressure can be 1.9 psi greater than the torus pressure before venting to the torus begins. The drywell pressure was calculated to reach 2 psig about 20 seconds after the "E" and "F" safety valves wedged open. This compared almost exactly with the time when the low range drywell pressure instrument recorded 2 psig in the drywell. The pressure continued to rise until the pressure difference between the drywell and torus equaled the downcomer pipe submergence and venting to the torus

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began. The pressure in the containment gradually rose as the non-condensible gases in the torus were purged into the torus gas chamber. A mixture of steam and non-condensible gas was vented to the torus where the steam was condensed and the non-condensible gas stored in the suppression chamber air space. The result was an exponential decrease of non-condensible gases in the drywell and an increase in the torus. As the non-condensible gases were purged to the torus, the containment pressure increased to the point where essentially all of the non-condensible gases were in the torus. This was the maximum calculated pressure that the torus experienced as illustrated in Figure VI-4. The drywell pressure remained constant at a slightly higher pressure, the difference being the downcomer submergence. The peak pressure is calculated to be 20 psig in the drywell. The small increase in pool temperature experienced during the event had a negligible effect on pressure, however, it is considered.

At 30-40 minutes after the initiation of the event, venting of the drywell was initiated. At 1 hr. and 15 min., the containment fan coolers were reactivated. This combination resulted in the decrease of the containment pressure. The low range containment pressure instrument indicated that the drywell pressure was down to 2.25 psig 2 hours after the event started (23:30). The transient is shown in Figure VI-4.

3. Temperature Transient

The sequence of events affecting the temperature was the same as was postulated for the pressure response analysis. During the time that the safety valves were postulated to be blowing down liquid (21:34 to 21:49) the drywell temperature was calculated to rise steadily to approximately 250°F as illustrated in Figure VI-4. At this point, approximately 75% of the drywell non-condensibles had been washed over to the torus. Since the calculated drywell pressure did not rise above 20 psig, the steam atmosphere temperature could not rise above saturation temperature for a liquid leak.

For the first 15 minutes after the safety valves lifted, it was estimated that the liquid level in the vessel was above the main steam line outlet and liquid blowdown into the drywell through the stuck safety valves took place. At this point in time (21:49) the feedwater was shut down and the liquid level in the vessel dropped below the steam line, initiating a switch from saturated liquid to saturated steam issuing into the containment.

Saturated steam at vessel pressure will superheat when it is expanded to the much lower containment pressure. Consequently, when steam only began issuing into the drywell, the temperature in the drywell slowly rose due to the injection of superheated

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steam; the pressure continued to rise to the maximum attainable of 20 psig. The peak containment temperature response was conservatively calculated, and is shown on Figure VI-4 with a maximum of 320°F. In all probability this peak temperature was representative only of local temperatures in the immediate vicinity of the leak, and the bulk containment atmosphere was somewhat lower. Heat transfer coefficients for natural convection superheated steam are low (on the same order as air, h = 1 to 5 Btu/hr°F). Therefore, even though the peak containment atmosphere temperature was calculated to reach a maximum of 320°F, the drywell wall temperature would be considerably below this.

At 1 hour and 15 minutes after the initiation of the event (22:43) the drywell fan coolers were reactivated and the temperature slowly decreased. The heat removal capacity of the coolers under these conditions is approximated and the dotted temperature line is an estimate.

Even though the drywell temperature was not monitored during the event, there were indicators within the drywell that supported the above calculated containment atmosphere temperatures and the assertions concerning surface temperature. One such indicator was the Tempilstik markers. These are crayon like marks at various positions in the drywell that melt when the material they are on reaches a given temperature. Markers at several positions on the drywell wall indicated that the temperature of the wall did not exceed 200°F. Markers on the pressure vessel insulation above the biological shield indicated that the temperature of the insulation did not exceed 250°F.

Other indicators such as the physical condition of plastic cans and instrument cables indicated temperatures were in the neighborhood of 250°F. See Section VI-A.

4. Local Conditions at Leak

The only visible local effect of the safety valves lifting was two 1 ft. diameter patches on the drywell wall where the drywell liner paint was removed. This effect is attributed to the jet of water-steam mixture issuing from the safety valves. The patches of removed paint were the points of impingement of the jets on the drywell wall and the paint appeared to be erroded away rather than charred or melted.

During the time interval of postulated liquid blowdown from the safety valve, the maximum temperature of the jet after expansion was calculated to be 260°F or less depending on the containment pressure. It was during this period that paint was most likely erroded off the drywell wall by the high velocity steam-water mixture. The maximum wall temperature at the localized impingement spots would, therefore, have been close to this temperature, but no higher.

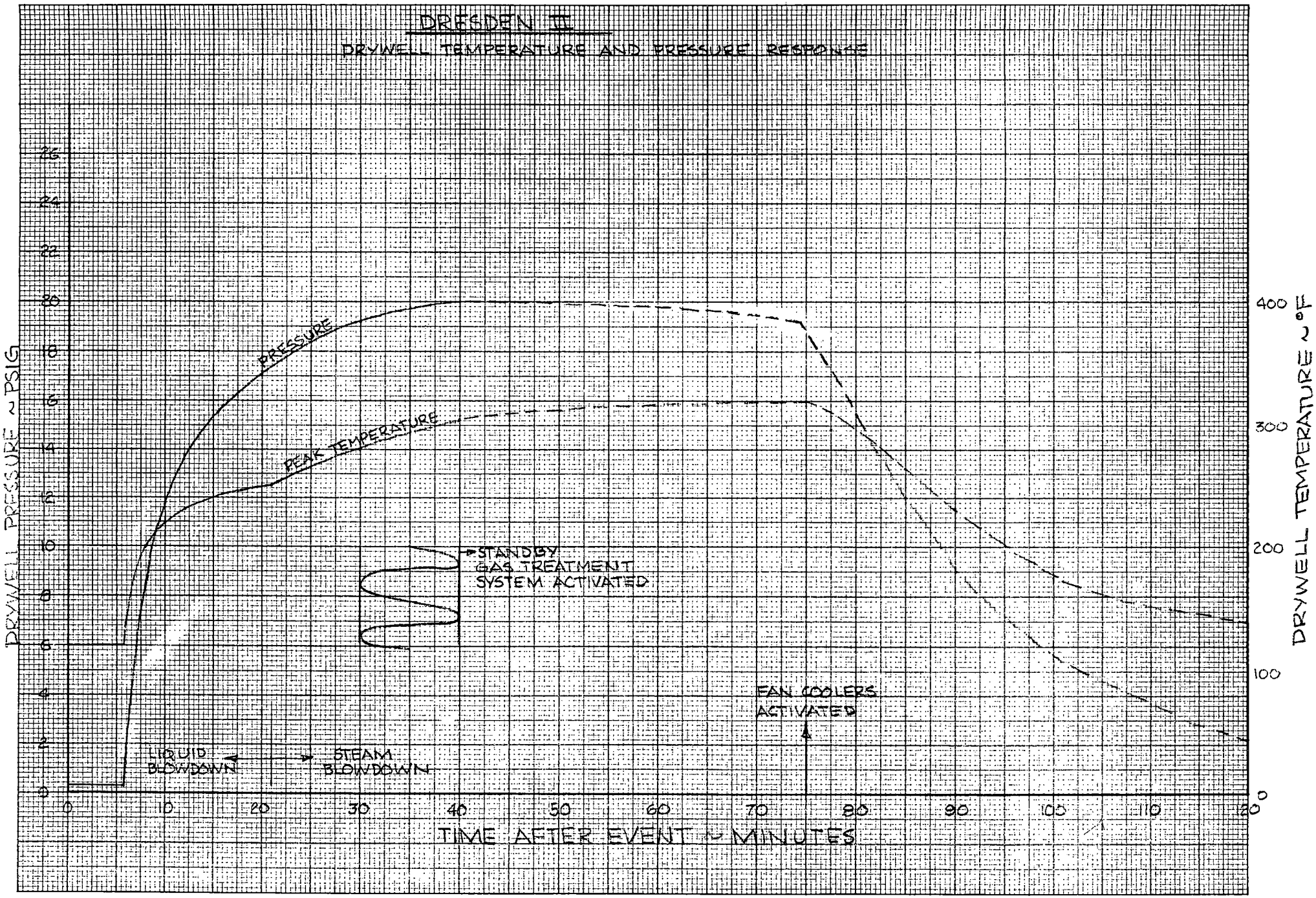

Figure VI-4.

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During the time interval of postulated steam blowdown from the safety valves, the maximum temperature of the jet after expansion was calculated to be 320°F depending on the vessel pressure. However, at this point in time, the G safety valve opened and had a flow rate of only about 6 lb/sec. This flow was split in half by the rams head so that 3 lb/sec. of steam was coming out of each side.

5. Drywell Integrity

The primary containment vessel was subjected to a pressure-temperature transient which was conservatively calculated to peak at 20 psig and 320°F. This transient was well within the design pressure condition of the drywell (62 psig) and is within the usable temperature range of the vessel material (-20 to 650°F).

The drywell expansion allowance for calculating the safety factor against buckling due to this temperature related condition as defined in the FSAR, Section 5.2.3.6, is shown in Table I.

Table I corresponds to the design margin safety factor against buckling of the drywell shell for the maximum sustained temperature of 320°F compared to Table 5.2.6 "Drywell Thermal Expansion" for the nominal design condition of 281°F.

The safety factors against buckling for this higher temperature are well within the design criteria for the vessel.

TABLE I

Location	Resultant Thermal Growth @ 320°F (inches)	Resultant Loading @ 0 psig (psi)	Allowable Loading (psi)	Safety Factor
A	0	0	1.55	---
B	0.68	0.8	1.57	2.0
C	0.94	0.95	3.05	3.2
D	1.17	1.2	3.84	3.2
E	0.39	0.7	2.77	4.0

The loading resulting from temperature at 0 psig is greater than at pressure because the pressure counteracts the effects of loading by temperature. If the effects of the 20 psig were included in this analysis, the resulting loading would be less than that determined originally for 281°F and 0 psig.

E. Electro-Hydraulic Control Unit Performance

A spurious signal was generated inside the Electro-Hydraulic Control unit of the Turbine Generator Control System which caused both control and bypass valves to open resulting in reactor depressurization. Investigation as to the cause of

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this spurious signal was initiated immediately. These investigations have resulted in a conclusion that the most probable cause was a faulty component in one of the two pressure controllers of the EHC system.

Continuous monitoring of the pressure controllers in the Electro-Hydraulic Control System was begun immediately after the shutdown using special test equipment and recorders.

By 6/12/70 many of the possibilities had been eliminated. Checks of variations and spikes on all grounds, all power input lines, all of the redundant DC and AC power supplies and basic oscillators, and input circuits had been made. No significant effects were found. Starting during the evening of 6/12/70, spurious behavior was observed which was sufficient to cause valve opening demands similar to subject event. By systematically tracing back the spurious signals during the following week (when they occurred) the difficulty was traced to a lead-lag network in the "A" pressure regulator. The prime suspect was one of the two potentiometers used to adjust the pressure regulator to the required dynamic characteristics. Recordings have been made which now substantiate that the intermittent erroneous signals coming from the suspect potentiometer are enough to cause the bypass valves to open as occurred on 6/5/70.

VII. CORRECTIVE ACTION

A. Drywell Neutron Flux Monitor Cables

1. SRM/IRM

The original Dresden 2 cables were selected for signal transmission qualities and represented the best temperature rating available at that time. More recently, a special cable has been designed which will meet the shielding and transmission qualities plus offering a temperature specification of 350°F (for 10 hours). These cables have been tested to 500°F under conditions of small radius bends without appreciable degradation.

The new higher temperature cables have been installed at Dresden 2. Special care in pulling these cables and use of new isolated conduits (2 IRM's and 1 SRM per conduit) should insure the incident survival qualities of these signal paths. Since these channels provide monitoring capabilities from start-up through at least 15% power, adequate neutron monitoring of a post-incident condition should be available. Separation criteria have been maintained.

2. LPRM's

The LPRM cables are being replaced with the same type of cable but using extra care to reduce handling abuse, twisting, and crowding in ducts. (The SRM and IRM cables were removed.) These cables are vendor specified at 275°F (continuously) and, as mentioned in Section VI.A, have been tested to 500°F without appreciable degradation.

B. Drywell TIP Indexer Control Cables

The TIP Indexer control cables experienced some melting of insulation and were replaced with a higher temperature rated multiconductor cable. The new cable is rated for 300°F.

C. Penetrations

Damaged electrical containment penetration seals are being repotted in place with an adhesive previously used successfully at Oyster Creek. The major leakage path identified after preliminary investigation is due to thermocouple sleeve failures. This wire is being resleeved and integrally potted into the seal.

D. Thermal Insulation

All thermal insulation which was damaged during the incident has been completely replaced.

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E. Main Steam Line Safety Valves

The three safety valves (E, F & G), which were positively identified as having lifted, will be inspected and tested in accordance with the manufacturer's recommended criteria and ASME and Illinois Boiler Code requirements. In addition, all of the damaged rupture discs will be replaced and the discharge of all safety valves will be oriented for optimum direction so as to preclude direct impingement on adjacent valves and minimize damage to other components within the drywell. Action is being taken to obtain approval of the Illinois Boiler Board for removal of the lifting levers. These levers are not required by Section III of the ASME Code.

F. Electro-Hydraulic Control System

As a result of the investigation described in Section IV, the following corrections are being made to the EHC control system:

1. The malfunctioning device which is causing the spurious signals is a wire-wound 10-turn potentiometer and is located at a considerable distance from the pressure amplifier card. The wires to these pots also go through a set of terminals. In order to avoid noise and the resultant spurious signals, a ceramic pot will be used, the terminals will be eliminated and the pot will be located near the pressure amplifier card.

2. Cables from the EHC adjustment panel will be routed such that all signal cables are separated from the power cables. This precaution will preclude the possibility of inductive noise on the signal wires.

3. From the automatic load following circuits, there is a connection to the recirculation flow control system, which closes the circuit to the EHC load frequency control circuit and has the possibility of introducing erroneous voltages to the EHC control panel. This will be rearranged to eliminate this possibility.

Following the completion of the above modifications, the pressure control units will continue to be monitored to verify that stable operation has been achieved.

G. Electric Motors

The motors on all valves were dryed out, inspected, and meggered to verify that the resistance is within the manufactured specified tolerances. It was established that none of the valve motors required replacement.

One of the seven drywell cooling blower motors did not meet the specified tolerance due to water steam damage and it has been replaced.

All electrical motors in the containment will be tested prior to startup of the unit to ensure proper operation.

H. Drywell Shell

The internal protective coating, which was damaged as a result of impingement from the discharge of the safety valves, has been refinished. The area in the vent piping between the drywell and torus which had one coat of paint removed will not be repainted because a prime coat plus a finish coat still remains.

I. Vessel Water Level

1. Vessel Instrumentation - Both the GEMAC and Yarway Level Sensing Systems will be thoroughly checked out for calibration and adjustments will be made as required to obtain accuracy and response within the vendor certified limits.

2. Feedwater Control - The feedwater control system will be thoroughly checked out and re-calibrated as required to obtain satisfactory control over the full range of operating conditions. Specific action will be taken to minimize (a) control valve leakage, (b) insensitivity of flow control, and (c) low suction trip caused by pump runout conditions.

3. Transient analyses support the conclusion that vessel level could have reached the high level turbine trip set point. Additionally, on a depressurization occurrence of the type experienced, some overshoot of the Yarway instrument would be expected. Therefore, it is considered that the Yarway instrumentation responded correctly during the incident.

4. In addition, both normal and emergency operating procedures are being reviewed and will be revised as appropriate to place more emphasis on high water level situations.

J. ECCS Sequence

A thorough field review of the core spray and LPCI system logic will be made to determine the reasons for improper sequence and starting times. Corrections will be made as appropriate and the system will be tested to verify conformance to design. The design has been reviewed and the electrical installation drawings are correct.

K. Isolation Condenser Isolation Trip Point Change

A proposed change to Dresden 2 technical specifications is in progress. This change will recommend raising the set points for isolation trips on the isolation condenser to agree with the design intent and operating conditions. This proposal would change the condensate return isolation trip point on the Isolation Condenser to 300% of normal flow.

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L. Instrumentation Availability

Specific attention will be given to the valving in and proper operation of the wide-range drywell pressure indicator and the drywell temperature recorder. Although the availability of these instruments would not have prevented the incident, they nevertheless would have been valuable as a data source for post-incident analysis.

M. Post-Incident Recovery

1. Venting

Following the incident, the containment was vented through the standby gas treatment system to reduce containment pressure. This was done without significant increase in the radiation levels to the plant environs as was verified by environs sampling. In addition, releases were well within the limits of 10 CFR 20. It is recognized, however, that the existing procedures do not provide sufficiently definitive actions and action points. Therefore, a revised procedure is being prepared for approval which will address these deficiences. The procedure will emphasize the following:

(a) The containment will not be vented until drywell pressure is less than 2 psig.

(b) Prior to venting, the drywell will be sampled to assess the contents and potential release.

(c) During venting, samples will be taken from the intake and discharge of the standby gas treatment system to verify filter efficiency and release.

(d) The release will be monitored by the stack gas monitor and dilution air will be available to the chimney.

(e) Stack limits listed in the technical specification will be adhered to during the operation.

We strongly feel that venting of the containment following an incident or accident to reduce radiation levels so entry can be made is vital to assessing damage and correcting an abnormal situation. We also feel that venting in a controlled manner and meeting the requirements of 10 CFR 20 ensure there is no undue risk to the health and safety of the public.

2. Containment Cooling & Depressurization

It is recommended that containment cooling and depressurization be accomplished by use of the containment cooling mode of the LPCI system. The preferred mode will be by spraying water into the torus. Containment spray will not be used unless absolutely necessary.

3. Drywell Coolers

During the incident, the drywell coolers were brought back into service before the drywell pressure was down to 2 psig. It is recommended in the future that during post-incident recovery drywell coolers not be brought back into service until the drywell pressure is below 2 psig.

4. Environs Monitoring

The environs monitoring program undertaken following the incident was adequate and no further recommendations are made in this area.

VIII. SAFETY EVALUATION

Some aspects of the incident are significant from a safety point of view. This section is an evaluation of those aspects.

A. Venting

As a means of reducing the high containment pressure, containment venting through the standby gas treatment system (SGTS) was employed approximately 30 minutes following the first indication of high drywell pressure. A discussion of this venting operation follows.

1. Justification

During plant startups the containment pressure normally rises above atmospheric pressure. During these times the containment pressure was reduced by venting through the SGTS and the filtered containment atmosphere was discharged via the main stack. Containment purging is accomplished in a similar manner. Procedures existed for venting of the containment and these procedures were judged to be an acceptable means of reducing the containment pressure. Radiation monitors in the vicinity of the drywell were checked and no abnormally high indications were observed. Also, because the reactor core had never been uncovered and because the reactor core flow was maintained at a high level throughout the transient, there was believed to be no fuel damage. Therefore, containment venting was initiated by opening the 2 inch by-pass valve to the operating SGTS which discharges the filtered gases up the main stack.

2. Precautionary Steps Taken

Observations were made initially of the main stack monitors, the area radiation monitors and the ventilation plenum monitors to insure that radioactive gases were not being released to the environs. No positive indication of radioactive gas release was observed. Each of the monitors were observed periodically thereafter.

A radiation protection man was immediately dispatched to monitor activity at the SGTS absolute filters where a reading of 30 mr/hr on contact was observed. Subsequent readings were made, but never did the activity level exceed 50 mr/hr on contact (on filter casing).

Approximately 40 minutes after the venting operation was started, the drywell coolers were brought back into service. This aided the pressure reduction rate within the containment.

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3. Results

Radiological Consequences - All available information at the site indicated that no abnormal release of radioactive material had occurred during, or following the incident. As a precautionary measure, environs samples were collected and analyzed the following day.

The area radiation monitors at the on site environs stations were observed to be reading normal, and ionization chamber readings from both on site and off site environs stations were normal.

Numerous samples of vegetation, both upwind and downwind, were collected and analyzed for I^{131} at the station and then sent to Eberline for confirmatory analyses. Again no increase in activity above background was found.

In conjunction with the above, the routine weekly environs samples were collected and forwarded to Eberline. Results showed no significant variation from previous weekly samples.

In summary, there was no significant release of radioactive gases during the venting operation. No radiological consequences are evident over and above those which would have occurred had venting not been employed.

B. ECCS Shutdown

The core spray pumps, the four LPCI pumps, the standby gas treatment system and the emergency diesel generators started as the containment pressure increased to the 2 psig initiation point. The two core spray pumps, three of the LPCI pumps and the diesel generators were secured approximately 30 minutes following their automatic startup. This was an acceptable procedure in view of the following:

1. Justification

The water level in the reactor vessel at all times during the transient was well above the top of the core and the water level at the time the pumps and diesels were secured was verified to be sufficiently high to insure the maintenance of adequate core cooling.

The feedwater pump was secured and the water level was observed to remain constant with only the makeup present from the control rod drive pump. This verified that the primary system rate of coolant loss was small and controllable.

Finally, injection of the torus water into the reactor vessel was not desirable because of a requirement to keep the water purity in the reactor vessel as high as possible. (The reactor pressure was approaching the pressure which would

allow injection of the torus water via the core spray and LPCI into the vessel.)

2. Precautionary Steps Taken

Each of the operators in the control room was made aware that the core spray and LPCI pumps had been secured. It was recognized that all of these core spray or LPCI pumps were readily available if normal makeup water was not available.

3. Results

Neither the core spray, LPCI nor diesel generators were required since normal makeup water was available to the vessel. Placing of these pumps in the pull-to-lock position did not subject the plant to a less safe mode nor would their operation in this incident have aided or otherwise assisted in the successful shutdown and securing of the Dresden 2 Unit.

C. Opening of Main Steam Line Isolation Valves (MSLIV)

The MSLIV's were manually opened at 14 minutes after the incident began. This was done to reduce the reactor pressure (it was about 770 psig at this point) by use of the turbine condenser through the by-pass valves. The by-pass valves were not actually opened, however, until about 30 minutes later.

1. Justification

Standard operating procedures call for restoration of normal pressure control via bypass valves to the condenser by resetting and opening the MSLIV's. This is considered a precautionary measure to protect against the unlikely loss of the isolation condenser.

2. Results

The normal operating mode, calling for cooldown of the reactor via the bypass valves to the condenser is justified for normal shutdowns. However, in the event that an accident signal (high drywell pressure or low-low reactor water level) is present, it is a questionable action. There was not any abnormal consequences as a result of this action. Any discharge of radioactive gases would have been through the steam-jet-air-ejectors via the condenser, then through the 30 minute holdup volume and finally to the main stack where the gases were monitored before release.

D. Reactor Vessel Water Level

During the first few seconds after the incident occurred, water level decreased due to collapse of voids. The feedwater control system, sensing low water level, went in automatic control to

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the runout control valve position. The feedwater pumps tripped from a low suction pressure signal. As designed, one feedwater pump automatically restarted and went into runout valve position. At this time the feedwater control was placed on manual control and the manual control was opened to the runout flow condition because the recorder normally used for controlling vessel level indicated no increase in vessel water level.

After approximately two minutes it was noticed that other instruments, such as the Yarway level gauges, showed full scale indication. The water level recorder was tapped and it then also indicated full scale. The feedwater controller was therefore immediately run back to mimimum. In spite of this, a substantial flow to the vessel was maintained because of leakage through the regulating valves. The isolation valves were not closed nor were the feedwater pumps tripped at this time because of the need to maintain a readily available source of feed flow to the vessel.

It is now clear that the overflowing of water into the main steam lines caused lifting of safety valves and resulting in damage in the drywell during what should have been a normal shutdown following an anticipated transient. It is also apparent now after the event that insufficient emphasis has been placed in operator training and operating procedures on the problems associated with excessively high reactor water level. This situation has been caused by an overriding concern for keeping the vessel level high to ensure that the core is covered, which prevails in all phases of plant design and operator esponse.

E. ECCS Pump Sequencing

The design of the ECCS pump starting provides for the starting of all six (2 core spray, 4 LPCI) pumps simultaneous when off-site power is available. When off-site power is not available and emergency power is being used, sequencing of the pumps is specified to protect against overload of the diesel generators. However, during the incident a high drywell pressure signal initiated the ECCS pumps, during a time when off-site power was available, and the ECCS pumps sequenced on rather than starting simultaneously. First core spray A was started, 5 seconds later core spray B was started and 5 seconds later all four LPCI pumps started simultaneously.

The sequencing circuitry is being checked and thorough tests will be performed to verify that the operation of the ECCS pumps will be in accordance with the Final Safety Analysis Report. This will be verified for both the off-site power available case and the loss of off-site power case.

F. EHC Pressure Control

The Dresden Unit 2 plant was operating at 75% power with full recirculation flow when the turbine control valves opened from 75% to the load reference set of 80% and the steam bypass valves to the condenser opened fully. Following the shutdown the pressure

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controllers in the Electro-hydraulic Control System were monitored to determine what caused the turbine control valves and bypass valves to open. Spurious signals were monitored which were of a sufficient magnitude and in a direction to cause this event. These spurious signals were traced to the lead-lag network of the "A" pressure controller. Two potentiometers which are used to adjust the pressure regulator to the required dynamic characteristics, have been emitting intermittent erroneous signals which can cause the bypass valves to open.

To prevent future spurious signals which can cause the reactor pressure regulator to open, a ceramic potentiometer will be used in place of the wire-wound potentiometer. A design change will also move the potentiometer nearer to the pressure amplifier card, thus eliminating some terminals to further avoid noise generation.

Other modifications are being made as an extra precaution against spurious signal generation although these other areas did not show evidence of any noise or signal generation.

G. Isolation Condenser

The isolation condenser was placed in operation approximately 3 minutes after the incident occurred in an attempt to lower the reactor vessel pressure and begin cooldown. It was discovered several minutes later that the isolation condenser had failed to go into service; it had isolated apparently on a high flow signal in the condensate return line. The isolation trip was reset and isolation condenser operation was again manually initiated and operated satisfactorily.

It was known prior to this incident that the condensate return isolation signal was set too low by an error in the Technical Specifications. The trip setting should have been 63" water (300% of normal flow) but the actual trip setting was 27" water (120% of normal flow). It appears that the initial surge of condensate return water as the isolation condenser was placed into operation was sufficient enough to cause isolation of the system.

A revision to the Technical Specifications was in process at the time of the incident and pending acceptance of this revision by the AEC, the isolation trip setting will be established at its design value of 63" water.

H. Drywell Temperature Design

The analysis of the containment (drywell) response during the incident showed the containment atmosphere to be a maximum of 320°F which is greater than the design temperature as listed in the FSAR. The design temperature, however, is the metal temperature of the containment, not the atmosphere temperature within the containment. It can be shown that the shell (metal) temperatures

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will be less than the atmosphere temperature, but it was decided to reanalyze the containment to establish a new design temperature for the containment of 320°F. The reanalysis made in Section IV.D.5 shows a new design temperature for the containment of 320°F. It can be seen from Table I (Section IV.D.5) that a safety factor of 2 or greater is present at the 320°F design temperature.

The containment was thoroughly inspected following the incident and no indication of buckling of the containment was observed thereby verifying that the containment is designed satisfactorily for the temperature present during the incident.

I. HPCI Function

The HPCI system was removed from service prior to the incident so there was no operation of the HPCI during the incident. However, the possible use of the HPCI during the incident was reviewed to determine what the contribution it could have made had it been operable. The reason for the HPCI being out of service was presented in a letter to Dr. P. A. Morris from Harlan K. Hoyt, dated June 2, 1970.

Upon receipt of the high drywell pressure during the incident, the HPCI auxiliary oil pump, emergency oil pump and gland extractor automatically started and the HPCI turbine went onto turning gear. This gave evidence to the fact that the HPCI did receive the signal to begin operation. However, the turbine did not start because it was valved out of service. Had the turbine been available for service at the time the initiation signal was received, the turbine would not have started due to high water level in the reactor vessel. The high water level signal prevents the steam supply valve from opening. Therefore, the HPCI would not have made a contribution to the incident even if it had been available for service.

J. Pressure Monitoring of Drywell

Pressure monitoring of the drywell during the incident consisted of a pressure indicator with scale reading from -5 psig to +5 psig. A 0-75 psig pressure indicator had been installed but had not yet been placed in operation. Had the higher range pressure indicator been operable during the incident more precise pressure monitoring could have been obtained. Prior to startup, the 0-75 psig pressure indicator will be calibrated and made operable.

K. Temperature Monitoring of Drywell

The temperature in the drywell is monitored at various locations and the temperatures are recorded on a multi-point recorder. This recorder, however, had run out of paper so no recording of drywell temperature was accomplished.

However, as stated in Section VI other means were available to approximate the drywell temperature. These other means consisted of Templesticks, flux monitoring cable deterioration and plastic caps.

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IX. CONCLUSIONS AND RECOMMENDATIONS

A. The initiating event for this incident was a spurious signal in the turbine control system EHC unit. The design modifications identified in Section VII.F will be made to protect against further spurious signal generation.

B. Suitable level instrumentation was available and was operating adequately during the incident; however, the level recorder being observed by the operator was stuck at low level indication. Thus:

1. The vessel level instrumentation changes and corrections as stated in Section VII .I will be implemented.

2. Critical water level regions will be marked on the level recorders to assist the operator in recognizing his approaching off-standard conditions.

C. Throughout the incident, plant operating and management personnel reacted and performed in accordance with procedures to achieve an orderly shutdown.

D. The procedures that were followed led to a safe and orderly shutdown during this incident. However, the procedures are being reviewed and revised to assure their appropriateness for such incidents. Revision to the procedures as described in Sections VII.I.4 and VII.M.1 will be made.

E. The safety valve which operated functioned properly; however, the existence of lifting levers on the safety valves caused unnecessary operation of two additional safety valves. These lifting levers are not required by Section III of the ASME Code and approval is being obtained from the Illinois Boiler Board to remove the lifting levers.

F. Upon receipt of the initiation signal, all ECCS equipment started and were ready to perform their function. The diesel generators also started and were prepared to accept load should there have been a loss of off-site power.

G. Neutron monitors provided information to the reactor protection system which verified reactor shutdown. Following safety valve lifting and subsequent to the release of steam to the drywell, the neutron monitor cabling was damaged. All the neutron monitor cabling will be replaced. The SRM and IRM cabling will be replaced with upgraded cabling to assure shutdown monitoring for higher temperature conditions.

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H. Motors and other equipment in the drywell were subjected to a steam atmosphere. All motors and equipment including the drywell itself have been checked (meggered in the case of motors, inspection of hangers and insulation in the case of piping, pressure tests and reseal in the case of electrical penetrations, jet force evaluation of drywell, etc.) to assure suitability for future operation. Decontamination of equipment and surface areas will be carried out as necessary.

I. No measurable release to the environment of radioactivity above normal operation occurred as a result of the incident and all radiation exposures to on-site personnel were well within the limits of 10 CFR 20.

J. Dresden radiation protection procedures were followed throughout the incident. All containment entries and other recovery actions were made in accordance with Dresden Radiation Protection Standards.

K. Those items resulting from the incident which require corrective action prior to plant startup have been corrected or will be prior to startup. Programs have been initiated to investigate and then correct those items which have been identified as requiring corrective action subsequent to plant startup. An operational or functional check will be made on all equipment that has been repaired or replaced. A system hydrostatic test at 1000 psig will be conducted.

L. It is concluded that the Dresden Unit 2 incident has caused no off-site effects of concern. Damage to the plant has been minor and will be repaired such that the plant can be returned to its startup test program without undue risk to the public health and safety.

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Received w/Ltr Dated 7-6-70

Regulatory File Cy.

DRESDEN 2

HPCI LINE DAMAGE REPORT

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HPCI LINE DAMAGE REPORT

The HPCI steam line was found to be damaged. Investigations showed that the damage was caused by excessive hydraulic forces created by a large water slug which was propelled through the line. A construction strainer was to be removed from the line; and hence, two valves were closed to isolate the strainers from the vessel. The downstream valve is normally closed and a drain pot arrangement is provided in order to keep steam in the line up to the HPCI turbine. The other valve, located outside the drywell penetration is normally open. While both valves were closed, a reactor scram occurred. During the recovery of the plant from the scram, a high water level situation occurred which allowed some water to be trapped at the upstream valve. Additional water accumulated behind the valve due to condensation after the plant was again brought to power. Upon completion of the strainer removal, the HPCI system was restored to the normal operating valve alignment. At this time, the upstream valve was opened with the reactor at pressure and the water slug was driven to the closed downstream valve. Subsequent visual inspection of the valve alignment and leak checks verification revealed the resulting damage.

Damage that was found consisted of broken or bent piping weight support hangers and seismic support snubbers, a dented section of piping, and damaged pipe insulation. The HPCI system was immediately removed from service and corrective measures initiated. These measures and results are:

1. The dented pipe section, approximately 10 feetin length and including a 90° elbow, was removed and replaced.

2. The downstream isolation valve, including the case, the disk and stem were inspected visually. External surfaces of the valve were magnetic particle inspected. In addition, the valve was cycled a number of times to assure proper operation. No damage was found.

3. The turbine stop valve connection to the piping was PT inspected and also operated to assure it was not damaged. External surfaces of the valve were magnetic particle inspected.

4. The flange connecting the stop valve to the turbine casing was inspected for any signs of damage. No evidence of a problem was found. Removal of the flange bolts shows no effects of any nature on the flange, the bolts or the seal.

5. The HPCI turbine valve chest was visually inspected and magnetic particle inspected for evidence of any damage. None was found.

6. The HPCI turbine mounting was inspected to determine if any movement had occurred. No evidence of any such movement was found.

7. The anchor connection to the pipe located near the drywell was inspected as was the piping support system within the drywell. No evidence of any damage was found.

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8. All hangers and sway braces located within the affected zone were replaced.

9. All pipe to elbow welds within the affected zone of piping were radiographed. No defects were found.

10. Dye Penetrant tests of all pipe to elbow welds and the heat affected zones were made. No indications were found.

11. Shear wave UT tests were made of the base metal of the affected pipe and elbows. These tests were conducted in both the longitudinal and circumferential directions. No defects were found.

12. The piping was hydrostatic tested satisfactorily in accordance with B31.1.0 1967 Piping Code.

It is concluded that thorough examinations of the piping systems have been made and have shown that the excessive hydraulic forces experienced were not sufficient to degrade the quality of the system nor to decrease confidence of the system reliability. The carbon steel used in the system is very ductile and few restrictions exist during fabrication on the amount of bending, forming, straightening or cold working of the material. Shop cold working in amounts experienced during this incident are acceptable. Bending and cold working of carbon steel materials in the field is also commonly performed. Such conditions are more severe than experienced in the incident as this was a shock loading of extremely short duration whereas purposeful cold work results in a sustained loading condition. Had the impact loads actually degraded the pipe, the nondestructive tests performed would have revealed the condition. Where damage was actually experienced, the pipe was replaced.

In addition, an interlock system is being installed between the valves outside and inside the drywell. Anytime the outside valve is closed, the inside valve will close automatically. This addition will prevent a reoccurrence of the problem because the inside valve is located in a horizontal section of piping at the elevation of the vessel nozzle.

In summary, the damaged section of the line has been replaced, the damaged suspension system has been replaced, the remaining portion of the system has been thoroughly inspected and tested, and a method of prevention has been initiated. It is consequently concluded that the HPCI system has satisfactorily been repaired and is again ready for operation.

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CONTROL VALVE

For

Main Steam Line Isolation Valves

OPERABILITY PROBLEM

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CONTROL VALVE FOR MAIN STEAM LINE ISOLATION VALVE

OPERABILITY PROBLEM

During the Dresden 2 startup test program, it was found on several occasions that the main steam isolation valves did not respond properly to the control signals. In most cases, this improper response occurred after the valves were test exercised, closed, and then failed on signal to open. An investigation of the problem revealed that the spool piece component of the pneumatic control valves was occasionally sticking. This piece is positioned by a solenoid operator and moves to direct or block air flow to the main valve operator cylinder through a series of ports in a sleeve. The cause of the sticking problem was threefold: Contaminated air supply; excessive heating of the control valves; and when coincident with either or both of the above, the problem was aggrevated by the close fit of the moving parts of the pneumatic control valve.

Subsequent to the manufacture of the Dresden 2 valves, the design was changed to provide a substantially greater minimum tolerance between the spool piece and sleeve in order to minimize possible clearance problems. The valves at Dresden 2 and 3 have all been checked and matched spool-sleeve components provided which have equal or greater tolerances than the new design minimum specification.

Inspection of the valves also revealed that a carboneous material had adhered to the surfaces of the failed components. This material had entered the valves from the air supply and plated out on the valve sliding surfaces. The contaminates are considered to be the primary cause of sticking, although the amount of such material was quite low and without the other factors would have been less significant. The air supply is from the plant instrument air supply. After noting the contaminates, the system was completely blown-out and then allowed to blow through a test filter to determine if any further contaminates exist. This test showed the system was now clean, and it is therefore postulated that the contaminates entered the system during the construction phase and are no longer present.

An overheating condition of the control valves was also found to be contributory to the problem. The valves were specified to operate continually in a 150°F environment and have been tested at 310°F for short duration operation capability. The actual temperatures in the steam tunnel at the location of the pilot valves was originally as high as 200°F. This temperature was attained primarily from radiant heat emitted by the valve bonnets and the main steam line pipe whip anchors which were not insulated. Subsequent to the problem, these items have been insulated and the tunnel air coolant system is being redirected to maintain the valves within the design temperature of 150°F. Thermocouples were installed on the valves and the temperatures were measured after the insulation was added to determine the heat condition. Results of this test show that after continual hot operations, the temperatures are stabilized near or below 150°F. An interim cooling coil installation was made on

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a preliminary basis to help alleviate the heat problem. However, this temporary solution is not in use and the temperatures noted above were obtained without use of these coils. The temperature coils will be removed prior to startup.

It is concluded that the causes of the problem with the valve operation have been identified and that proper corrective actions have been taken. These causes have been reduced to acceptable levels or eliminated and proper operation is now expected. The valves will be tested during startup of the unit in the hot condition to verify proper operation and installation.

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