




# ***Probabilistic Risk Assessment***

***North Anna Power  
Units 1 and 2  
Individual Plant E.***

## ***Volume II Appendices***

 **HALLIBURTON NUS**  
Environmental Corporation

 **VIRGINIA POWER**



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## **A.0 INTRODUCTION**

This section contains the assumptions and faults trees for the systems modeled in the North Anna PRA. In addition to the system fault trees a number of Boolean equations or basic events were also used to complete the quantification of the core damage frequency. These are detailed in the quantification section of Appendix B.

The component naming scheme and failure mode codes used in the fault trees and parametric data base are shown in Tables A.0-1 and A.0-2 respectively. Components which do not fall into any of these categories are known as "undeveloped events" and have been given a unique identity. A list of such components can be found in the parametric data base in Appendix C, as well as in the individual fault trees in this appendix.

In order to ensure a complete equivalence between the component modeled in a fault tree and the failure data derived for the component, it is necessary to define the component boundary and support systems which have to be modeled outside this boundary. The definition for the following key components are given in the following subsections.

- Diesel Generators
- Motor Driven Pumps
- Turbine-Driven Pumps
- Motor-Operated valves
- Solenoid-Controlled Air Operated Valves
- Air-Operated Valves
- Circuit Breakers

### **A.0.1 Emergency Diesel Generators (EDG)**

#### **Physical Boundaries**

The diesel generator physical boundaries include the generator body, generator actuator, lubrication system (local), fuel system (both local and the underground storage tanks and related pumps and valves), cooling components (local), startup air system, exhaust and combustion air system, individual diesel generator control system, circuit breaker for supply to safeguard buses and their associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts) with the exception of all the contacts and relays which interact with other electrical or control systems. Figure A.0-1 shows the physical boundaries defined for the Emergency Diesel Generators.

## **Support Systems**

Some of the typical support systems are:

1. DC power supply to the circuit breaker,
2. control actuation systems (closing) of the circuit breaker (automatic or manual signals),
3. DC power supply to diesel generator control,
4. diesel generator startup actuation systems (automatic or manual systems),
5. generator room cooling system,
6. fuel supply system, and
7. AC power supply to diesel generator auxiliary components.

Another support system which can potentially be postulated, the startup air system, is included within the generator boundaries since the accumulators have the capacity for three startup attempts.

### **A.0.2 Motor Driven Pumps (PAT & PSB)**

#### **Physical Boundaries**

The pump physical boundaries include the pump body, motor/actuator, lubrication system, cooling components of the pump seals, the voltage supply breaker and its associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts). Figure A.0-2 shows the physical boundaries defined for motor driven pumps.

## **Support Systems**

Some of the support systems are:

1. AC power supply to the pump breaker,
2. DC power supply to the breaker control,
3. breaker control actuation system (automatic or manual signals),
4. pump cooling system, and
5. pump room cooling system.

### **A.0.3 Turbine-Driven Pumps (TRB)**

#### **Physical Boundaries**

The turbine-driven pump physical boundaries include the pump body, turbine/actuator, lubrication system (including pump), extractions, turbine driven seal, cooling components and local turbine control system (speed). Figure A.0-2 shows the physical boundaries defined

for the turbine driven pumps. The turbine control valve and stop valve are considered within the turbine physical boundary.

### **Support Systems**

The support systems include:

1. turbine steam supply system,
2. discharge steam system,
3. DC power supply to the turbine control,
4. turbine driven pump control actuation system (automatic or manual signals), and
5. pump room cooling systems.

### **A.0.4 Motor-Operated Valves (MOV)**

#### **Physical Boundaries**

The valve physical boundaries include the valve body, motor/actuator, the voltage supply breaker and its associated local open/close circuit (open/close switches, auxiliary and switch contacts, wiring and switch energization contacts). Figure A.0-3 shows the physical limits defined for the motorized valves.

### **Support Systems**

The support systems include:

1. AC power supply to the valve motor (switch is normally closed) and
2. valve open/close actuation system (automatic or manual signals).

### **A.0.5 Solenoid-Controlled Air Operated Valves (SOV)**

#### **Physical Boundaries**

The valve physical boundaries include the valve body, three-way valve, operator (solenoid) and the local solenoid energization circuit (auxiliary contacts, wiring, solenoid energizing contacts). Figure A.0-3 shows the physical boundaries defined for the solenoid-operated valves.

### **Support Systems**

The support systems include:

1. AC or DC power supply to the solenoid,

2. valve operating air system, and
3. valve open/close actuation system (automatic or manual signals).

#### **A.0.6 Air-Operated Valves (Control) (AOV, FCV, HCV, LCV, PCV & TCV)**

##### **Physical Boundaries**

The valve physical boundaries include the valve body and current/pressure converter. Figure A.0-3 shows the physical boundaries defined for the valves.

##### **Support Systems**

Some of the support systems include:

1. AC or DC power supply to the converter,
2. valve activating air system, and
3. valve control actuation system (automatic or manual signals).

#### **A.0.7 Circuit Breakers (BKR)**

##### **Physical Boundaries**

The circuit breaker physical boundaries include the body/actuator of the breaker between the cable inlet and outlet. Figure A.0-4 shows the physical boundaries defined for the circuit breakers.

##### **Support Systems**

Some of the support systems include:

1. DC power supply to breaker control and
2. breaker control actuation system (automatic or manual signals).

#### **A.1 COMPONENT COOLING SYSTEM**

The Component Cooling System is composed of two identical subsystems. A CC subsystem is provided for each reactor unit. Only the subsystem associated with Unit 1 and the common loads will be described here. Operation of the Unit 2 subsystem is identical to that of Unit 1. The piping associated with the CC System, constructed of carbon steel, is protected by several relief valves throughout the system. These relief valves are all set to lift at

150 psig, with the exception of the relief valves for the RCP thermal barrier which relieves at 1500 psig.

#### **A.1.1 Major Components**

The following paragraphs describe the construction and operation of the major components associated with the CC system. All of the major components are located in the Auxiliary Building. Figures A.1-1 through A.1-4 illustrate the relationship of the components within the system.

##### **Component cooling surge tank**

The component cooling water surge tank provides the net positive suction head for the CC pumps. The tank is located approximately 50 feet higher than the pumps suction, ensuring that an adequate head exists at the pumps suction to prevent pump cavitation. The surge tank allows for thermal expansion and contraction in the system and serves as a source of makeup water to the system. Should a leak develop in the system, the volume of water in the surge tank allows time for the operator to locate and stop the leak prior to a loss of component cooling.

The tank is 10.6 feet high and 7.5 feet in diameter, constructed of 0.375-inch thick carbon steel. It holds approximately 3120 gallons, while normal operating volume is approximately 2150 gallons. The tank is maintained approximately 62 percent full, allowing sufficient room for expansion and contraction of the CC water. It is vented to the vent and drain system. Designed for a pressure of 40 psig and a temperature of 150°F, the surge tank normally operates at atmospheric pressure and at a temperature of near 90°F.

Makeup water to the tank is provided by the main Condensate System. The makeup water enters the tank through a 2.5-inch nozzle located approximately 7 feet from the bottom of the tank (approximately 10.5 feet above the fourth floor of the Auxiliary Building). The CC surge tank is located in a large cubicle on the north side of the fourth floor of the Auxiliary Building.

The surge tank is connected to the suction of both Unit 1 and 2 CC pumps by 4-inch headers. Manual isolation valves are provided for surge tank isolation if required.

##### **Component cooling pumps**

The component cooling pumps provide the motive force for circulating cooling water through the CC heat exchangers, individual system loads, and back to the pumps' suction. Normally,

two pumps (one per reactor unit) supply the required cooling water flow rate when both reactor units are in operation. Two standby pumps supply 100 percent backup capability. The standby pump for each reactor unit will automatically start when the running pump fails due to electrical fault or undervoltage on its associated supply bus. The pumps are operated from the Control Room.

Each CC pump has an 18-inch suction and discharge pipe equipped with expansion joints. The CC pumps take suction on a 24-inch inlet header which is supplied with component return water from the following:

1. 10-inch component cooling water bypass header,
2. 4-inch surge tank header,
3. 8-inch non-regenerative and seal water heat exchanger return header,
4. 24-inch RHR 1A equipment return header,
5. 18-inch RHR 1B equipment return header,
6. 4-inch RCP thermal barriers return header,
7. three 8-inch RCP coolers return headers, and
8. 18-inch common load return header.

Each CC pump is a horizontally mounted, single stage, centrifugal pump. The pump casing is constructed of nodular iron and is horizontally split, with the suction and discharge passages in the lower half of the casing. The impeller is a double suction, closed type and is cast from bronze to form one continuous piece. The impeller is hydraulically and statically balanced. The pump shaft is constructed of carbon steel.

Pump friction and radial and axial misalignment is minimized by the use of a radial bearing and a thrust bearing. Both bearings are oil lubricated and are equipped with sight glass oil level indicators. Oil is added to the bearings via a capped connection located on the top of the bearing housing. The thrust bearing consists of a double row of ball bearings, while the radial bearing is a single row of ball bearings. The bearings are held in place axially by a bearing lock nut. Radial placement is assured by the bearing housing.

Each pump is driven at 1170 rpm by a 4160 V, 600 HP, three-phase, squirrel cage, induction motor. The motors are equipped with space heaters to minimize condensation after the motors are deenergized. The space heaters automatically energize when the associated motor breaker opens. An ammeter on the control room benchboard indicates pump motor current. The pumps are designed to deliver 8000 gpm with a discharge head of approximately 190 feet of water. The required NPSH for these operating conditions is approximately 16 feet of water. This requirement is satisfied by mounting the CC surge tank approximately 50 feet above the pump suction. The CC pumps are centrally located on the first floor of the Auxiliary Building.

The CC pumps are provided with a recirculation flow path to the surge tank to prevent overheating of the pumps when operating at a shutoff head (discharge valve closed) and to provide a continuous vent path for the CC pumps. The normal and recirculation flow paths contain check valves to prevent backflow through an idle pump. A backpressure regulator (PCV-110), located in the CC bypass line, maintains system pressure constant when system loads are removed or placed in service.

### **Component cooling heat exchangers**

The discharge from the CC pumps is directed to the CC heat exchangers. The heat exchangers act as a heat transfer medium between the CC System and the Service Water System. They also serve as a barrier against the release of radioactive water to the environment in the event of radioactive leakage into the CC System. This barrier between the system loads and the environment allows toxic chromates to be used as a corrosion inhibitor in the CC System.

The heat input to the CC System from the individual loads is transferred to the Service Water System in the heat exchangers. Each heat exchanger is a single shell and tube unit, vertically mounted, with two passes on each side of the heat exchanger. Component cooling water enters the unit through a 30-inch opening approximately 25 feet above the bottom of the heat exchanger.

The CC outlet temperature from the heat exchanger is maintained between 70° and 100°F by throttling the service water leaving the heat exchanger. The heat exchangers are designed to transfer 53E+6 Btu/hr under normal conditions, but during plant cooldown the design transfer rate increases to 84E+6 Btu/hr. Under normal operating conditions, loss of the service water supply header will result in approximately a 3°F-per-minute increase in CC water temperature. The temperature rise allows sufficient time for corrective action to be taken prior to exceeding any temperature limits.

The main discharge header from the Unit 1 heat exchangers is a 24-inch line and supplies CC water to the following distribution headers:

1. 10-inch component cooling water bypass header,
2. 8-inch non-regenerative and seal water heat exchanger supply header,
3. two 18-inch RHR equipment supply headers,
4. three 8-inch RCP supply headers, and

5. 18-inch common load supply header.

The heat exchangers are mounted vertically on the north side of the Auxiliary Building and extend from the first floor to the fourth floor.

Dependency matrices for the CC system are shown in Table A.1-1.

#### **A.1.2 Fault Tree Analysis**

CC is a support system and has no front line functions. No event tree headings relate directly to CC. The top events for the CC system are failure to remove heat from the respective RHR heat exchanger or failure to remove heat from the respective RCP thermal barrier. The fault tree is included at the end of this section. A summary of assumptions and notes from the analysis file follows.

#### **Fault Tree Modeling Assumptions**

The following modeling assumptions are specific for the CC fault trees.

1. The CC system is assumed to be operating at the start of the accident. CC is a fairly complex system with many heat loads and several pump and heat exchanger configurations. The CC system is also common to both units. To create a realistic and manageable CC system fault tree model, the following system configuration assumptions are made:
  - a) The 1-CC-P-1A/1B pumps and the 1-CC-E-1A/1B heat exchangers are dedicated to Unit 1.
  - b) The cross-ties between Unit 1 and Unit 2 CC pump supply, pump discharge and heat exchanger discharge lines are assumed to be isolated by the valves 1-CC-40, 49, and 57, respectively.
  - c) The 1A CC pump and heat exchanger (1-CC-P-1A and 1-CC-E-1A) are assumed to be operating. The 1B CC pump and heat exchanger are assumed to be in standby.
  - d) The 1-CC-E-1B standby heat exchanger is assumed to be isolated on both the CC and SW side. Valves 1-CC-50, 1-SW-232 and 1-SW-233 are assumed closed or throttled. The training manual states that for normal operation both heat exchangers are used and system drawings show the isolation valves to be normally open. But, for this analysis, the 1-CC-E-1B heat exchanger will be modeled in a standby configuration.



The CC system can be cross-tied so that more pumps than 1-CC-P-1A/1B can supply Unit 1, or that pumps 1-CC-P-1A/1B can supply both units. Similar cross-ties are possible for the CC heat exchangers. These cross-ties are normally used for only a small fraction of time. Cross-tied operation can also be both a benefit and a detriment to system reliability. Because of the short time duration and variation in effect cross-tie operation is not modeled. Should either the CC pumps or the CC heat exchangers prove to be significant risk contributors, new models for the cross-ties can be evaluated.

2. The following CC system configuration is assumed for the CC water to RH system components.
  - a) The RH pump seal coolers 1-RH-E-2A/B are not isolated from the CC system during normal operation. The flow through the RH pump seal coolers is monitored by low flow alarms providing quick indication of loss of water through the coolers. So the normally open manual valves in these flow paths, including 1-CC-265 and 1-CC-785, will not be subject to a plugging fault. Also, 1-CC-TY-130B will not be subject to fails closed. Note these events are conservatively included in the fault tree.
  - b) The valves on the discharge side of the RHR Heat Exchangers, 1-RH-MOV-100A and 100B, are normally closed thus isolating the RHR Heat Exchangers from the CC system. For both MOVs a failed closed (MOV-FC) fault is assumed to model the failure of the valve opening from the closed position. Since there is no flow through the heat exchanger, normally open manual valves upstream of the heat exchangers are subject to a plugging fault.
3. For the RH heat exchangers 1-RH-E-1A/B and 2A/B plugging and leaking are modeled with the basic event HEX-LF (heat exchanger loss of function). For 1-RH-E-1A/B, HEX-LF basic events are modeled in the RH fault tree so these events are not included in the CC fault tree. For 1-RH-E-2A/B, the RH pump coolers, basic events HEX-LF for these components were not modeled in the RH fault tree. Thus, the CC fault tree models 1-RH-E-2A/B HEX-LF basic events.
4. The CC system surge tank 1-CC-TK-1 is assumed to be required to provide adequate NPSH for the CC pumps. A TNK-LF fault is modeled to include tank loss of inventory or isolation to CC system. Loss of the surge tank would fail all CC pumps. Tank inventory recovery from Main Condensate system was not modeled.
5. Unavailability due to maintenance was considered for the following components:

- a) 1-RH-E-1A/B, modeled in CC fault tree and omitted from RH fault tree.
  - b) 1-RH-E-2A/B, not modeled in CC fault tree as pump 1-RH-P-1A/B UM is modeled in RH fault tree. Pump UM assumed to include pump seal cooler unavailability.
  - c) 1-CC-P-1B, modeled as component is in standby.
  - d) 1-CC-E-1B, modeled as component is in standby.
  - e) 1-CC-P-1A and 1-CC-E-1A, not modeled as components are operating except for fail to run and loss of power for pump.
6. The following assumptions are only for the RCP Thermal Barrier CC2 fault tree:
- a) It is assumed that RCP seal injection is the preferred source of seal cooling, and that if RCP seal injection is lost to one RCP, it is lost to all RCPs.
  - b) Assume that CC water circulation without cooling from SW is not adequate for RCP thermal barrier cooling. The CC pumps add an unknown amount of heat to CC water, so that heat removal to SW through a CC heat exchanger is required.
  - c) Trip valve closures by a spurious CDA signal is not modeled. This fault is subsumed within the AOV-SC (AOV spurious closure) fault
7. 1-CC-TV-116A/B/C fail closed on loss of Instrument Air or control power. These valves will also close on a signal from 1-CC-FT-116A/B/C when a high flow condition exists for more than 10 seconds. The AOV-SC fault will include the fault of 1-CC-FT-116A/B/C spurious actuations.
8. 1-CC-TV-104A/B/C fail closed on loss of Instrument Air or control power. These valves also close on a CDA signal. Each of these valves contain two pilot solenoids in series. This arrangement ensures that, if one solenoid should fail open, an additional solenoid will be available to deenergize and close the trip valve. An AOV-SC fault will be modeled for each of the pilot solenoids.
9. Pump 1-CC-P-1B includes the normal standby faults of fail to start, fail to run 24 hour mission, loss of motive power, loss of control power, scheduled test and maintenance unavailability, and unscheduled maintenance unavailability. Also, a flow diversion of backflow through the A pump train is modeled. Actuation logic and start signals are not modeled.

The standby CC pump will automatically start when the running pump is tripped by a lockout relay actuation or undervoltage condition on the supply bus. Additionally, there are low flow alarms at the discharge of the heat exchangers that will quickly indicate the loss of a pump. Considering the requirements of the systems that the CCW supplies, RHR and RCP Thermal Barriers, there is greater than one hour after the loss of the CC pump to start the standby pump; thus, failure of actuation is considered negligible.

10. CC system heat removal can be defeated by undesired closure of both 1-SW-MOV-108A/B or 2-SW-MOV-208A/B on the CC heat exchanger SW flow path. The CDA actuation signal closes all four of these SW valves but this is of no concern. If a LOCA with LOOP occurred, core cooling is by RS heat exchangers and RHR and CC are not required.
11. For the RH fault tree, NUPRA Failure Mode 2 events assume a 13140 hour interval between testing, corresponding to an average of 18 months of at power operation between shutdowns requiring RHR system operation. For the standby components in the CC trains supporting the RH heat exchanger 1-RH-E-1A/B, this 13140 hour interval is used assuming CC flow through these components occurs only when the RHR system is in operation.

For CC components in standby related to 1-CC-E-1B, a 2190 hour interval is assumed for Failure Mode 2 events. This interval corresponds to 3 months, which is the frequency for PT-41.1 which tests the CC pumps and check valves. This interval is appropriate for the CC heat exchangers as the CC heat exchangers are swapped for cleaning on the SW side, at irregular intervals. For 1-CC-P-1B and related components, a 720 hour interval is assumed, corresponding to monthly rotation of the CC pumps per station procedure.

12. For AOV-SC (AOV spurious closure) faults for 1-CC-TV-101A/B, 1-CC-TV-104A/B/C, and 1-CC-TV-103A/B, the AOV-SC fault is assumed to include spurious CDA actuation faults. Hence, the CDA signal to these trip valves does not require a separate fault. This simplification reduces the number of spurious faults by combining all sources of spurious actuation for a component within a single fault. This approach is feasible since there is little hard data on spurious actuations; that data which exists has not been discriminated for source to develop individual spurious action faults.
13. Per the same logic stated in #12, spurious actuation faults for the flow instrumentation 1-CC-FT-116A/B or C for 1-CC-TV-116A/B/C are not modeled as a separate fault but included in the AOV-SC faults.

14. Common Cause Faults (CCF) are assumed for like standby components. For normal standby components, this would include:

1-CC-100A/B, RHR heat exchanger  
outlet valves, labeled 1CCMV--CC-100A:B

These motor operated valves are postulated to fail closed due to common cause failure.

## **A.2 CHEMICAL AND VOLUME CONTROL SYSTEM**

There are two major subsystems in the CVCS, the Charging and Letdown Subsystem which provides RCP seal cooling and the Makeup Subsystem which provides emergency boration. Simplified drawings of these subsystems are provided in Figures A.2-1 and A.2-2.

### **A.2.1 Flow Paths**

#### **A.2.1.1 Charging and Letdown Subsystem Flow Paths**

The CVCS letdown stream taps off of the Reactor Coolant System (RCS) loop A cold leg on the discharge side of the reactor coolant pump (RCP). The letdown flow enters the CVCS at a temperature of 547°F and a pressure of 2235 psig. The coolant discharge passes through a normally open manual isolation valve prior to entering the letdown isolation valves. The two letdown isolation valves isolate the CVCS from the RCS. The valves are designed to shut automatically on low pressurizer level to maintain RCS water inventory, in the event of a leak in the CVCS.

The regenerative heat exchanger is the first major CVCS component to receive letdown flow from the RCS. The hot letdown water flows through the shell side of the heat exchanger to give up heat to the relatively cool charging water on the tube side of the heat exchanger. The letdown stream exits the heat exchanger at a temperature of approximately 285°F.

The discharge of the regenerative heat exchanger is piped through either one, two, or all three letdown orifices and associated letdown orifice isolation valves. The letdown orifices are piped in parallel and act to control the letdown flow rate. A relief valve is located on the discharge side of the orifices to provide overpressure protection.

From the containment isolation valve, flow is directed to the non-regenerative heat exchanger which cools the 285°F tube side letdown stream to approximately 115°F by circulating cool component cooling water on the shell side of the heat exchanger. The letdown

temperature is controlled by a temperature control valve, located in the component cooling discharge line, which regulates cooling water flow in order to maintain stream temperature. The discharge of the non-regenerative heat exchanger is directed to a low pressure letdown valve which maintains a backpressure on the letdown piping downstream of the letdown orifices. The backpressure is approximately 300 psig and prevents flashing of the letdown stream.

The low pressure letdown valve discharge is normally directed to the demineralizers via a low pressure letdown divert valve, a check valve, and the letdown filter. If the temperature of the letdown stream exiting the non-regenerative heat exchanger reaches 136°F, the low pressure letdown divert valve automatically shifts and directs letdown flow directly to the VCT. This action prevents degradation of the resin in the demineralizers due to excessive temperature. The demineralizer discharge passes through a reactor coolant filter and is normally piped to the VCT by way of a level control valve. The level control valve provides level control of the VCT. When the VCT level reaches a predetermined high level setpoint, the level control valve automatically directs the letdown flow to the Boron Recovery System.

The VCT acts as a surge volume for the RCS and maintains RCS hydrogen concentration within specifications. The RCS total gas concentration is also controlled by periodically venting the VCT gas space to the gas strippers. The VCT discharge passes through two motor-operated valves and to the suction header of the charging pumps. The motor-operated valves will automatically isolate the VCT when the VCT level fall below a preset value or when safety injection is initiated. The Charging Pumps normally take their suction on the VCT but can also be aligned to draw water from the Refueling Water Storage Tanks or the discharge of the Low Head Safety Injection Pumps.

The Charging Pump discharge normally supplies charging water to the RCS to maintain pressurizer level and provides seal water injection flow to the RCPs. The Charging Pumps can also be used to:

1. inject the boron injection tank contents into the RCS;
2. fill the RCS via the loop fill header;
3. provide auxiliary spray to the Pressurizer; and
4. provide recirculation of the RCS following initiation of safety injection.

A portion of the Charging Pump discharge is recirculated through the seal water heat exchanger and VCT and then back to the suction of the Charging Pumps to prevent overheating of the centrifugal pumps. The Unit 1 and 2 Charging Pumps have the ability to be

cross connected should all Charging Pumps of either unit become unavailable such that, either unit can provide charging water to the other unit.

The Charging Pump normal discharge to the RCS passes through a charging flow control valve, two motor-operated isolation valves, the regenerative heat exchanger, and a charging line isolation valve prior to entering loop B of the RCS. The charging flow control valve operates from a signal generated by the Pressurizer Level Control System to adjust charging line flow rate. This action maintains Pressurizer level within its programmed level range.

The regenerative heat exchanger heats the cool, tube side charging water to approximately 496°F before discharging to the RCS. Heating the charging water minimizes thermal shock to the CVCS/RCS interface piping and prevents the introduction of cold water to the reactor core.

The RCPs are supplied with seal water injection flow from the CVCS charging pump discharge header. The flow enters the pumps seals by way of a motor operated isolation valve, a seal water flow control valve, and one of two seal water injection filters. The injection flow prevents the leakage of reactor coolant around the RCP shafts and provides cooling and lubrication to the pump radial bearing and seals. The seal water discharge of the RCPs passes through two motor operated isolation valves, a seal water return filter, and a seal water heat exchanger before entering the charging pump suction header.

An additional letdown path has been provided to allow for controlled leakage (seal injection flow) into the RCP seals when the normal letdown path is isolated. This path incorporates an excess letdown control valve and an excess letdown heat exchanger. Excess letdown flow is cooled in the excess letdown heat exchanger by component cooling water. The heat exchanger discharge can be directed to either the seal water return header or the primary drain transfer tank.

#### **A.2.1.2 Makeup Subsystem Flow Paths**

The Makeup Subsystem is a subsystem of the Chemical and Volume Control System and provides measured quantities of demineralized water and/or boric acid to the RCS. Also, this system provides the means for adding chemicals to the RCS. The Makeup System can be configured to deliver makeup in any one of five operational modes:

1. borate,
2. dilute,
3. alternate dilute,
4. automatic, and
5. manual.

Normal makeup consists of either concentrated boric acid from the boric acid storage tanks; demineralized water from the primary grade water tanks; or a blend of both, depending upon plant conditions. The makeup water (either borated or demineralized) is directed to the inlet or the outlet of the VCT, depending upon the Makeup Subsystem mode of operation. The only make-up path of importance to the IPE is the emergency boration flow path.

### **Emergency boration flow path**

It is possible to rapidly borate the RCS by opening the remotely operated emergency boration valve (MOV-1350). When the valve is open, the boric acid transfer pump discharge is linked directly to the charging pump suction header via a check valve. A locally operated manual emergency boration valve (1-CH-241 and 2-CH-156) is also provided. This valve, located just outside the VCT cubicles, has a Identification Tag attached for easy identification. When the local emergency boration valve is opened, concentrated boric acid solution from the boric acid transfer pump discharge is directed to the suction of the charging pumps if the boric-acid-to-blender flow control valve (1-CH-FCV-1113A) is open. FCV-1113A fails in the open position to ensure this capability exist at all times.

## **A.2.2 Major Components**

### **A.2.2.1 Charging and Letdown Subsystem Major Components**

#### **Letdown isolation valves LCV-1460A, -1460B**

These two valves are solenoid-controlled, air-operated, globe valves which are normally open but are designed to fail shut. Containment instrument air is supplied to each letdown isolation valve to open it against spring pressure. The valve is shut by allowing the air pressure to vent to atmosphere. Spring pressure then forces the valve shut.

#### **Regenerative heat exchanger**

The regenerative heat exchanger cools the hot letdown flow (shell side) to approximately 285°F and heats the cool (130°F) charging

water (tube side) to approximately 490°F. Heating of the charging water to near RCS temperature reduces thermal shock to the piping and eliminates the addition of excessive positive reactivity to the reactor core.

The regenerative heat exchanger consists of three individual tube and shell heat exchangers. It is constructed of austenitic stainless steel and cannot be disassembled. The regenerative heat exchanger is self venting and self draining and has piping connections for these purposes. The three shells are mounted horizontally on top of each other and are interconnected by stainless steel piping. Each shell consists of 84 one-half inch (outer diameter) tubes arranged in a U-tube fashion. All three shells are designed to remove  $8.34 \times 10^6$  Btu/hr, collectively. The shell side and tube side are designed to operate at 650°F and have design pressures of 2485 psig (shell side) and 2735 psig (tube side). The regenerative heat exchanger is located inside the Containment at the 242-foot elevation behind the pressurizer relief tank.

#### **Letdown orifices and letdown orifice isolation valves**

The letdown orifices control the letdown flow leaving the RCS and reduce the pressure of the letdown flow by approximately 1900 psi under normal operating conditions. There are a total of three orifices (ORLD-1, -2, -3). Orifice ORLD-1 has a design flow rate of 45 gpm, while ORLD-2 and -3 have design flow rates of 60 gpm each. Normally, only one orifice is in service at a time. As RCS pressure drops, the differential pressure across the orifice also drops, reducing the flow through the orifice.

#### **Non-regenerative heat exchanger**

The non-regenerative heat exchanger cools the letdown flow to approximately 115°F. This temperature prevents deterioration of the demineralizer resin. The heat from the letdown stream (tube side) is transferred to relatively cool component cooling water (shell side).

The shell houses 364 three-quarter inch (outer diameter) tubes arranged in a U-tube design. The shell is constructed of carbon steel and the tubes are austenitic stainless steel. The shell side has a design temperature of 250°F and a design pressure of 150 psig. The tube side has a design temperature and design pressure of 400°F and 600 psig, respectively. The heat exchanger is located in its own cubicle on the first floor of the Auxiliary Building.



## **Volume control tank**

The VCT is used to accumulate letdown water and RCP seal leakoff from the RCS; to maintain the desired hydrogen concentration in the reactor coolant; to provide positive suction head to the charging pumps; and to receive makeup water from the Makeup System via an inlet spray nozzle. The VCT is located in its own cubicle on the third floor of the Auxiliary Building. A hydrogen overpressure (hydrogen blanket) of 16 psig is normally maintained in the tank to scavenge oxygen from the letdown water. Letdown enters the VCT via a spray nozzle. Hydrogen gas is absorbed as letdown is sprayed through the gas atmosphere. The excess hydrogen combines with any free oxygen in the reactor coolant thereby minimizing the oxygen content of the coolant. A nitrogen line is provided to purge combustible hydrogen and radioactive gases from the tank and the RCS (degassing) prior to and immediately after maintenance (nitrogen purge). Contaminated gas is discharged through a separate VCT penetration that is connected to the gas stripper in the Boron Recovery System. A liquid relief valve (1-CH-RV-1257) is provided to prevent VCT overpressurization. It is set at 75 psig and relieves to the high level waste drain tanks. Additionally, a drain valve is provided for draining Unit 1 and 2 VCTs to the high level waste drain tanks.

The VCT vent isolation valve (1-CH-SOV-1258) is intermittently opened from the Control Room for degassing operations. It is a solenoid valve and is operated by a two-position (OPEN, CLOSE) control switch. Tank pressure is prevented from decreasing below 16 psig during degassing by pressure control valve 1-CH-PCV-1117, which maintains VCT N<sub>2</sub> pressure. The contaminated gas is directed to the Boron Recovery System via the Primary Vents and Drain System. Normally, the hydrogen pressure control valve (1-CH-PCV-1118) is in service and set to maintain a pressure of 16 psig in the VCT. The nitrogen pressure control valve (1-CH-PCV-1119) is normally isolated but is also set to maintain VCT pressure at 16 psig when in service. The VCT has a volume of 300 cubic feet. It is designed to withstand an internal pressure of 75 psig and a temperature of 250°F. The tank is constructed of austenitic stainless steel and normally operates at a temperature of approximately 105°F.

## **Charging pumps**

The charging pumps are the prime movers for the flow of reactor coolant to the RCS. Three charging pumps are provided and are piped in parallel. The charging pumps are located in the charging pump cubicles on the first floor of the Auxiliary Building. Each pump is a 2.5-inch, eleven-stage, horizontal centrifugal pump. A 900 HP, 1800 rpm motor rotates the pump at 4846 rpm, through a speed-increasing gearbox.

The charging pumps normally take a suction on the VCT, but depending upon plant conditions, the charging pumps can take a suction from the refueling water storage tanks or the low head safety injection pump discharge. The charging pumps normally discharge to the charging header which is connected to RCS loop B.

The charging pumps are usually controlled in the Control Room but can be operated from the auxiliary shutdown panel.

The charging pumps are designed to pass a flow of 150 gpm at a temperature of 130°F and a pressure of 2500 psig. A stationary, multi-vane diffuser is fitted around the periphery of each impeller. The cylindrical case is fitted with a removable head on the discharge end to facilitate removal of the pump internals. The pump shaft is supported at each end by a self-aligning sleeve bearing, and the axial thrust load is carried by a Kingsbury thrust bearing on the discharge end of the pump. The bearings are pressure lubricated.

As with all series-arranged multi-stage pumps, there is a net axial thrust on the shaft, acting in the direction from the discharge end to the suction end.

It is caused by the unbalance of impeller discharge pressure and suction pressure acting on opposite sides of each impeller. The charging pumps incorporate a pressure reducing bushing and sleeve, which is mounted on the outboard end of the eleventh stage impeller. Balancing piping connects the suction of the pump to the outboard end of the pressure reducing bushing and sleeve, equalizing the axial thrust across the impellers. The balancing piping has a loop in it to permit thermal expansion and contraction. The Auxiliary Feedwater pumps use a similar arrangement for axial thrust compensation.

To prevent overheating of the charging pumps when they are operated at a shutoff head, a mini-flow recirculation line is provided for each charging pump. The recirculation flow path contains a check valve, an orifice, and a motor-operated isolation valve on the discharge of each charging pump. Each orifice is designed to pass a minimum flow to prevent flashing of the water in the pump casing.

Each of the three motor-operated mini-flow recirculation valves (1-CH-MOV-1275A/B/C) is controlled from vertical board 1-1 in the Control Room by a three position (CLOSE, OPEN, NEUTRAL) control switch. The three mini-flow recirculation lines join to form a common header which discharges to the suction of the seal water heat exchanger via a common motor-operated isolation valve, MOV-1373. This MOV is controlled from the benchboard in the Control Room by a three position (CLOSE, OPEN, NEUTRAL) control switch. The discharge of the seal water heat exchanger is piped directly to the charging pump suction to complete the recirculation flow path.

The speed-increasing gearbox and pump have separate lube oil pumps and coolers. The gearbox lube oil system uses a mechanically driven oil pump to circulate oil within the gearbox for both cooling and lubrication. Service water is supplied to a cooler mounted on the gearbox casing to remove the heat generated in the gearbox. The pump lube oil system uses a shaft driven lube oil pump to circulate oil from a 30 gallon oil reservoir to the pump bearing housings, through a lube oil cooler and filter, and back to the reservoir. Service water is supplied to the pump lube oil cooler and also to two shaft mechanical seals. A motor driven auxiliary lube oil pump takes a suction on the pump oil reservoir to provide oil circulation when the charging pump is secured or when failure of the mechanical lube oil pump occurs. Fire Protection or PG Water can also be aligned to supply charging pump seal and lube oil cooler flow per 0-AP-12 (Loss of Service Water) via hose connections.

The auxiliary lube oil pumps are operated locally in the charging pump cubicles. They are normally operated in the automatic mode and they start on low charging pump lube oil pressure.

Charging pump 1B receives 4160 V power from bus 1J and charging pump 1A is supplied with 4160 V from bus 1H. Charging pump 1C can be powered from either the 1J or the 1H bus and is normally aligned to the 1H bus. The auxiliary lube oil pumps for charging pumps 1A and 1C receive 480 V power from bus 1H1-2S and charging pump 1B auxiliary lube oil pump is powered from bus 1J1-2S.

#### **Seal water injection filters**

Flow to the RCP seals is filtered by one of two seal water injection filters installed on the discharge of the RCPs. The filters are cartridge filters and are designed to pass an injection flow of 80 gpm, which exceeds the requirements of all three RCPs.

#### **Seal water return filter**

The seal water return filter removes particles as small as 25 microns from the RCP seal water return and the discharge of the excess letdown heat exchanger. It is designed to pass a flow of 325 gpm.

The seal water return filter is identical in construction to the reactor coolant and letdown filters, except that it is physically larger. It has a design pressure of 200 psig, a design temperature of 250°F, and is approximately 5.5 feet tall. The seal water return filter is located next to the seal water heat exchanger.

### **Seal water heat exchanger**

The seal water heat exchanger is used to cool the RCP's No. 1 seal water return flow leakoff, charging pump recirculation flow, and excess letdown flow (when employed). Component cooling water circulates through the heat exchanger shell side to carry the heat away from the reactor coolant on the tube side. The tube side outlet temperature is normally maintained at or near 115°F. After heat exchange, flow is directed to the charging pump suction header.

This shell and U-tube heat exchanger is mounted vertically and consists of a carbon steel shell which houses 62 type 304 stainless steel tubes. The tubes have an outer diameter of 5/8 inch. The seal water heat exchanger has a design pressure of 150 psig and a design temperature of 250°F. It is located in its own cubicle on the first floor of the Auxiliary Building.

### **Excess letdown heat exchanger**

The excess letdown heat exchanger is employed to remove controlled leakage from the RCP seals when the normal letdown path is isolated. Component cooling water is used on the shell side to cool the excess letdown stream to approximately 135°F. This shell and U-tube heat exchanger consists of a carbon steel shell which houses 22 austenitic stainless steel tubes. Each tube has an outer diameter of 5/8 inch. The excess letdown heat exchanger has a design pressure of 150 psig and a design temperature of 250°F (shell side). The tube side has a design pressure of 2485 psig and a design temperature of 650°F. It is located inside the Containment at the 231-foot elevation next to the RHR pumps.

### **A.2.2.2 Makeup Subsystem Major Components**

#### **Boric acid batching tank**

A boric acid solution is mixed in the boric acid batching tank by dissolving boric acid crystals in heated primary grade water and mechanically agitating the solution to ensure thorough mixing. Boric acid is supplied in 100-pound sacks and is stored on the third floor of the Auxiliary Building normally in the Boron Evaporator cubicle. The boric acid is mixed with primary grade water to produce 500 gallons of 7.4 percent boric acid solution per batch. Auxiliary steam is admitted to the batching tank heating coils to aid in the mixing process. Steam flow to the batching tank is controlled by 1-CH-TCV-1100. The temperature control valve throttles the steam flow as necessary to maintain batch temperature 140°F.

The boric acid batching tank is located on the third floor of the Auxiliary Building and extends down to the second floor. The 800-gallon capacity tank is filled with boric acid on the third floor and the temperature in the tank is controlled on the second floor. The design temperature of the tank is 250°F and it operates at atmospheric pressure. The tank is 7 feet 4.5 inches tall and has an outside diameter of 5 feet. The motor driven agitator is mounted on the top of the batching tank and is controlled from the third floor of the Auxiliary Building, next to the boric acid batching tank.

### **Boric acid storage tanks**

Three 7500-gallon, full-capacity boric acid storage tanks (1-CH-TK-1A/1B/1C) and four full-capacity, two-speed (75/37.5 gpm) boric acid transfer pumps are provided. Initially, the boric acid tanks are filled by making up a solution in the batching tank (which is common to both units). Each batch is transferred to the boric acid storage tanks using the transfer pumps. Since the batch tank has an 800-gallon capacity and the boric acid storage tanks are 7500 gallons each, several batches are needed initially to fill the system. Normally "A" tank is aligned to Unit 1 and "C" tank is aligned to Unit 2. "B" tank normally serves as spare and provides makeup to the in-service tanks. The contents of the batch tank is normally directed to the B Tank.

Once the plant is in operation, the principle source of concentrated boric acid for makeup will be reclaimed boric acid from the Boron Recovery System. Reactor coolant, diverted by the VCT level control valve (1-CH-LCV-1115A), is purified, reconcentrated, and returned to the boric acid storage tanks. A 12,950 ppm to 15,750 ppm solution of boron, i.e., 7.4 percent (by weight) boric acid solution, is maintained in the storage tanks.

Each boric acid storage tank is equipped with two sets of strip heaters. A total of twelve heaters per tank operate on 480 V power. The heaters are controlled to maintain tank temperature at or near 141°F to prevent crystallization of the boric acid granules.

### **Boric acid transfer pumps**

Four boric acid transfer pumps (1-CH-P-2A/2B/2C/2D) are used to supply concentrated boric acid to the blender; recirculate the contents of the boric acid storage tanks; recirculate the contents of the boron injection tank; and/or transfer boric acid from the boric acid batching tank to the boric acid storage tanks. The pumps are located on the second floor of the Auxiliary Building.

Each pump is a horizontal, single-stage, centrifugal pump. Wetted parts are constructed of 316 stainless steel for service with concentrated boric acid. They are designed to operate at 155°F to 175°F and at a maximum pressure of 375 psig. Each pump has a design flow rate of 75 gpm or 37.5 gpm, depending upon pump speed. Inboard and outboard ball bearings align and support the pump shaft. The inboard bearing is a single-row ball bearing which accepts radial loads only. The outboard bearing is a double-row bearing which is shoulder and locked onto the shaft and bearing housing so that it also acts as a thrust bearing. Bearing lubrication is provided by a constant level oiler. The shaft seal is a bellows type of mechanical seal of standard design. No external seal cooling is required.

Each boric acid transfer pump is driven by a 15 HP, 480 V motor at either 3510 rpm or 1765 rpm. The motor speed can be varied electrically. Changing the manner in which the motor stator Windings are energized effectively changes the number of stator poles.

Boric acid transfer pumps 2A and 2B are controlled from the Unit 1 Control Room benchboard while pumps 2C and 2D are controlled in the Unit 2 Control Room. Each pump is operated by a four-position (FAST, SLOW, OFF, AUTO) control switch. The boric acid transfer pumps can be controlled from the Auxiliary Shutdown Panel, located in the Emergency Switchgear Room by placing a REMOTE/LOCAL control switch in the LOCAL position. The pump is then operated by a four-position control switch identical to the one described above.

Normally, boric acid transfer pump 2A is aligned to continuously provide recirculation of the Unit 1 boron injection tank and boric acid storage tank A. Boric acid transfer pump 2D provides recirculation flow through the Unit 2 boron injection tank and boric acid storage tank C. Boric acid storage tank B is shared between Units 1 and 2 and is provided with recirculation flow by either boric acid transfer pump 2B or 2C.

The dependency matrices for the CVCS components are shown in Table A.2.1.

### **A.2.3 Fault Tree Analysis**

The charging system is a front line system which provides RCP seal injection flow and emergency boration. The functions supplied by CVCS are:

- D4 - Emergency boration for ATWS events
- SLC - RCP seal cooling

Assumptions used in the development of the fault trees models for the CVCS follow. The fault trees for these functions are shown at the end of this section.

#### **Fault Tree Modeling Assumptions, Notes, and Inputs**

1. In the event the BAT cannot be lined up to the CHP suction, boration from the RWST was modeled rather than use of the boric acid blender. Modeling of a third recovery would not be expected to reduce unavailability much further, as human error will likely dominate.
2. In the event a pressurizer relief valve sticks open, there is assumed to be an SI signal on low pressurizer pressure, thus manual actuation is not necessary.
3. For failure to borate, the mission time is one hour. Failure of the running pump to continue to run will be a very small probability. Thus, failure of the C pump to backup the A and B pumps is not modeled.
4. A flow path must be available through the minimum flow lines for each operating charging pump during ATWS to prevent pump failure from dead heading when RCS pressure rises. This assumption was not applied in the event of a stuck open relief valve, as RCS pressure will drop. SI will not be activated until the RCS pressure is below 1835 psig. At this pressure, there is no need for minimum flow lines.
5. Failure scenarios involving failure of the seal water heat exchanger or the non-regenerative heat exchanger, due to failure of CC or heat exchanger rupture, leading to common cause charging pump failure, due to pump over heating or NPSH failure were included in the seal cooling model. Failures involving pressure or inventory of the VCT are recoverable by using the RWST for a CHP suction source. Although continued reactor operation is not possible in this mode, continued seal cooling is possible. Failures involving the seal water heat exchanger are not directly isolable, as the seal return flow dumps into CHP suction downstream of the VCT isolation valves. However, seal return flow is isolable by closing MOV-1381. Seal injection flow can still be maintained by going through the excess letdown heat exchanger or relieving to the PRT. Thus seal flow can be maintained even if all let down and seal return are isolated.
6. Seal flow control valves and seal isolation valves were not modeled. The only failure mode of interest for these valves would be inadvertent closure or blockage. Failure of one valve would lead to a seal LOCA in one pump, which is accommodated by the S2 initiating event.

The tree for failure of seal injection flow is concerned with failures of the charging system that would also disable the HHSI system, thus simultaneously producing a LOCA and failing a LOCA mitigation system. The failures of interest were determined to be those associated with the charging pumps themselves.

### **A.3 MAIN STEAM SYSTEM**

Three Main Steam headers are provided for each reactor unit. The components associated with Unit 1 are described here. Significant differences between Unit 1 and Unit 2 are, however, noted where appropriate. The system is illustrated in Figures A.3-1 through A.3-3.

#### **A.3.1 Flow Paths**

Approximately  $4E+6$  lbm/hr of dry, saturated steam exits each steam generator under a pressure of 885 psig, during normal full power operation. The steam generator 32-inch outer diameter main steam discharge piping runs horizontally through Containment, penetrates the polar crane wall, and is then directed vertically downward for a distance of approximately 41 feet. A flow restricting venturi, 15 feet in length, is housed in the vertical run of piping and is designed to limit the maximum steam flow during a steam line break accident. Two static pressure taps are located on each side of the venturi and provide the necessary pressure signals to pressure transmitters 1-RC-PT-1474 and -1475. The main steam piping (header 1A) exits Containment horizontally, through penetration number 73.

The main steam piping enters the Main Steam Valve House at the 285-foot elevation. The main header contains an electro-pneumatic main steam trip valve and a motor-operated non-return valve. Steam traps are located throughout the system to facilitate the removal of moisture in the Main Steam System.

The three 32-inch main headers join in a common 40-inch distribution manifold. A 1-inch sample line is located just upstream of the manifold to allow sampling. The distribution manifold supplies steam to the following loads:

1. high pressure turbine (four 28-inch lines),
2. auxiliary steam (6-inch line), and
3. steam dumps, moisture separator reheaters, and gland steam regulator (two 18-inch lines).

As a result of the 1987 tube rupture event on Unit 1, a Nitrogen - 16 radiation detection system was installed to detect steam



generator tube leakage. Each main steam line is monitored in the Mechanical Equipment Room and a common monitor is located on the 40-inch manifold in the Turbine Building.

### **A.3.2 Major Components**

The following paragraphs describe the construction and operation of the major components associated with the Main Steam System. The major system valves are located in the Main Steam Valve House with the exception of the MSR reheat control valves and the steam dumps, which are located in the Turbine Building. Control of the major components is from the MCR. Alternate control of the atmospheric dump valve is provided at the Auxiliary Shutdown Panel.

#### **Flow restricting venturi**

A flow restricting venturi is installed in each main steam header to limit the steam flow rate and subsequent RCS cooldown during a main steam line break accident. Additionally, the flow venturi is used for steam flow measurement. The design of the flow restrictor is based on the following:

1. minimizing the cooldown rate of the RCS during a steam line break accident,
2. reducing pipe whip during a steam line break accident by limiting steam flow,
3. providing a differential pressure for the measurement of steam flow,
4. minimizing the pressure loss (head loss) across the restrictor while at the same time restricting steam flow to acceptable values,
5. withstanding the designed number of pressure and thermal cycles experienced over the life of the plant, and
6. maintaining flow restrictor integrity in the event of a double-ended shear of the main steam line immediately downstream of the restrictor.

#### **Main steam safety valves**

Five ASME (American Society of Mechanical Engineers) code safety valves (1-MS-SV-101A, -102A, -103A, -104A, -105A) are provided for each steam header to relieve excessive Main Steam System and/or steam generator pressure to the atmosphere, via piping extending through the roof of the Main Steam Valve House. The five valves

provide each header with a cumulative relieving capacity of 4,367,990 lbm/hr. The valves are designed so that, in the event a safety valve sticks in the open position, the steam flow rate does not exceed 1,020,000 lbm/hr (at a steam pressure of 1100 psia). The individual relieving capacities and setpoints are as follows:

1. 1-MS-SV-101A
  - a. capacity - 817,883 lbm/hr
  - b. setpoint - 1085 psig
2. 1-MS-SV-102A
  - a. capacity - 825,323 lbm/hr
  - b. setpoint - 1095 psig
3. 1-MS-SV-103A
  - a. capacity - 836,483 lbm/hr
  - b. setpoint - 1110 psig
4. 1-MS-SV-104A
  - a. capacity - 843,924 lbm/hr
  - b. setpoint - 1120 psig
5. 1-MS-SV-105A
  - a. capacity - 855,084 lbm/hr
  - b. setpoint - 1135 psig

Each safety valve is a spring-loaded relief valve, equipped with a mechanical gagging device and manual operating lever. The force generated by steam pressure acting on the valve disc is opposed by the spring force. The relieving steam is redirected when it impacts against the valve disc in a manner similar to impacting on turbine blading. The corresponding change in momentum aids the opening process, causing the safety valve to "pop" open. Valve chattering near the relief setpoint is prevented by valve blowdown, which prevents the valve from reseating until steam pressure has adequately decreased.

The five safety valves are identical in construction, having stainless steel operating parts, with the exception of the spring which is carbon steel. The different relieving capacities are due to the different relieving pressures and not due to different mechanical construction.

## **Main steam trip valves**

One electro-pneumatic main steam trip valve (1-MS-TV-101A/B/C) is provided in each of the three main steam headers to isolate the steam generator in the event of a steam line rupture downstream of the trip valve. The valve is essentially a check valve installed so that, when the disc is seated, flow from the steam generator through the trip valve is terminated. During normal plant operation the disc is held open above the flow path by compressed air. When a closure signal indicative of a steam line rupture is generated, the compressed air is vented to the atmosphere and the trip valve disc drops into the steam flow path and shuts due to the steam flow differential pressure, stopping steam flow through the valve.

Each trip valve has a maximum closing time of 5 seconds. The valve disc and seat are constructed of stainless steel.

The MSTVs are located in the Main Steam Valve House and are controlled from the MCR Safeguards Panels by two position (OPEN, CLOSE) push buttons. The electric solenoid valves that admit air to the air cylinders are located in the Quench Spray House. A test push button and white indicating light are also located in the basement of the Quench Spray House for testing the movement of the valve disc during normal operation. Pushing the test button allows the valve disc to travel approximately 3 degrees. A limit switch attached to the valve energizes the white test light and returns the valve disc to the full open position when disc travel testing is complete. This test provision is not used at the North Anna Power Station during normal plant operation.

Provided electrical power to the pilot solenoids is available, a main steam line trip valve shuts when any of the following conditions exist:

1. either the train A or B push button on the Safeguards Panels is depressed,
2. intermediate high-high containment pressure (17.8 psia on two of three channels),
3. either train A or B safety injection signal on high steam line flow coincident with low-low  $T_{avg}$  or low steam line pressure.
4. Control Room App. R isolation switch in EMERGENCY CLOSE, or
5. Emergency Switchgear Room Appendix R isolation switch in EMERGENCY CLOSE.

A Main Steam line trip valve opens when both train A and B OPEN push buttons are depressed, provided air pressure is available, pressure is equalized, and items 2 and 3 above do not exist. The trip valves are designed to fail shut on loss of air pressure. The valves fail "as-is" on loss of electrical power.

A Main Steam bypass trip valve (1-MS-TV-113A/B/C) is arranged in parallel with the main steam trip valves and is used to equalize the pressure across the main steam trip valves. The valves are controlled from the Safeguards Panels by CLOSE/OPEN push buttons (one for each protection train). To open a bypass trip valve, the following conditions must exist:

1. electrical power available to both pilot solenoids,
2. Instrument Air pressure available to valve actuator,
3. both train A and B OPEN push buttons depressed,
4. intermediate high-high containment pressure not present, and
5. high steam line flow coincident with low-low  $T_{avg}$  or low steam line pressure not present.

A bypass trip valve shuts whenever one of the CLOSE push-buttons is depressed or when the conditions in items 1, 2, 4, or 5 do not exist. A large black push button is located on each Safeguards Panel for resetting the train A and/or B trips (items 4 and 5 above), and the main steam trip valves.

Control of the main steam system is necessary when shutting down the primary plant to prevent an excessive rate of cooldown of the reactor coolant system and to protect against loss of steam generator inventory. In order to protect against the loss of automatic and manual control of the Main Steam Trip Valves (MSTV) due to a fire in the Control Room or Emergency Switchgear Room, an additional dedicated shutdown system for each of the three MSTVs is installed in the Quench Spray Pump House to serve as a backup. This dedicated system consists of two solenoid valves mounted in series for each of the three MSTVs. One of the solenoid valves can be operated from a control switch mounted in the Emergency Switchgear Room and powered from a 24 volt battery charger. The second of the two solenoid valves in series can be operated from a control switch mounted in the Main Control Room and powered from a similar 24 volt battery/charger. This provides two electrically independent systems to close the three MSTVs. If a postulated Quench Spray House fire were to render the MSTVs normal solenoids and the dedicated solenoids inoperable, the steam generator secondary side could still be isolated by closing the turbine stop valves, MSR inlet valves, and the main steam dump valves.

### **Main steam non-return valve (NRV)**

Downstream of each main steam trip valve is a motor-operated non-return valve (1-MS-NRV-101A/B/C). Each NRV functions to prevent reverse flow when a pressure reduction occurs in the steam generator or piping upstream of the valve. Each motor-operated NRV is driven by a 50 HP motor and acts as an angle stop-check valve.

### **Decay heat release valve**

The decay heat release valve (1-MS-HCV-104) is normally fed from all three main steam headers. The valve is normally manually isolated, using the upstream valve, due to excessive leakage past 1-MS-HCV-104. When in use, the valve allows steam to be discharged from the Main Steam System at a variable rate to assist in cooldown of the RCS. The steam is released to the atmosphere through a 8-inch opening in the top of the Main Steam Valve House.

The 4-inch air-to-open globe valve is designed to pass a maximum flow of 181,000 lbm/hr at a pressure of 1085 psig and is mounted on the top floor of the Main Steam Valve House, next to the main steam safety valves. Valve position is monitored by a flow element mounted in its discharge line and is indicated on the SPDS computer CRTs. Operation of the valve is controlled from MCR benchboard 1-1, at the steam dump control station. A manual station controller is provided for valve positioning.

The decay heat release valve is equipped with a small gray air flask, which is mounted next to the valve. The purpose of the flask is to cause the decay heat release valve to fail shut on loss of instrument air pressure. The air flask cannot be used as a backup source of air.

### **Atmospheric dump valve (PORV)**

Each main steam header is provided with one atmospheric dump valve (1-MS-PCV-101A/B/C), sized to pass approximately 10 percent (425,244 lbm/hr) of the maximum calculated steam flow from each steam generator. Valve position is monitored by a flow element mounted in its discharge line and is indicated on the SPDS computer CRTs. The pneumatically operated (air-to-open) valve is normally controlled by a manual/automatic station controller mounted on benchboard 1-2, but it can also be controlled from the Auxiliary Shutdown Panel by a manual station controller. A local handwheel is provided in the event that manual operation is required.

Each PORV is supplied with instrument air, via a seismically qualified line. The air line contains a check valve to prevent backflow in the event of a rupture in the supply line. As a backup

air supply, each valve is equipped with a seismically qualified air tank holding 16.7 ft<sup>3</sup> of air at a pressure of 110 psig.

The atmospheric dump valves are normally set to relieve at approximately 1035 psig. This setpoint is below the setpoint of the lowest set main steam safety valve, avoiding safety valve chattering. The valve is located on the top floor of the Main Steam Valve House and discharges to the atmosphere via a 10-inch line extending through the roof. The air tanks are located on the north wall of the bottom floor of the Main Steam Valve House.

### **Steam dump valves**

A total of eight steam dump valves (1-MS-TCV-1408A/B/C/D/E/F/G/H) are provided for diverting steam from the main steam headers directly to the main condensers to control heat removal from the RCS. The steam dumps, in combination with control rods, are designed to handle a 50 percent load rejection (40 percent by steam dumps and 10 percent by the control rods).

Each 8-inch electro-pneumatic globe valve passes a flow of 579,125 lbm/hr and is designed to pass no more than 1,020,000 lbm/hr with an inlet pressure of 1100 psia. The valves are controlled from benchboard 1-1 at the steam dump control station. Both the steam dumps and the feed regulating valves are equipped with manual operators which permit the valves to be overridden in the open direction only. Turning the handwheel clockwise results in opening either type of valve.

Dependency matrices for these components are shown in Table A.3-1

### **A.3.3 Fault Tree Analysis**

The main Steam System was modeled as a front line system. It provides decay heat removal, rapid cooldown, or isolation functions. The functions and general criteria for the Main Steam System were:

- SGI - Failure of SG isolation following SGTR
- Y - Core Cooling Recovery

The assumptions and notes from the analysis files, used to develop these fault trees, and the fault trees for the Main Steam System follow.

### **Fault Tree Modeling Assumptions**

1. According to procedures 1-FR-C.1 and 1-FR-C.2, the operator is to manually or locally dump steam using

- condenser steam dump valves
- atmospheric steam dump valves
- decay heat release valve
- turbine driven AFW pump
- condenser hogger

However, for this study it was assumed that dumping steam via the decay heat release valve, the TD AFW pump, and the condenser hogger will not be effective options either because of the size of the lines involved or because of timing considerations. Therefore, these options were conservatively omitted.

(Note: The decay heat release valve is sized for decay heat at 30 minutes. Steam relief through the Terry turbine is on the same order of magnitude as the decay heat release valve, but smaller).

It is assumed that steam dump via the SG PORV's would be sufficient for core cooling recovery (the 3 SG PORV capacity is approximately 1/4 the capacity of the steam dump valves). A house event XHOS-NO-ATM-DUMP, is included in the fault tree model to fail steam dump through the SG PORVs.

2. Only 2 of the 8 steam dump valves can be manually controlled to dump steam via the steam dump valves. The success criteria is assumed to be the opening of 2 of the 2 valves. These valves are 1-MS-TCV-1408A and 1-MS-TCV-1408B.
3. The 1-inch turbine bypass lines through manual valves 1-MS-169 and 1-MS-180 are assumed to be too small to handle steam dump to the condenser if the main path through the 14-inch lines become unavailable.
4. For steam dump to the condenser, the failure of the trip valves in the main steam lines is modeled. The trip valves could fail closed, or there could be a loss of instrument air closing the valves. The valves fail 'as-is' on loss of DC power. Finally, any failure (e.g., SOV failure) that could cause leakage of air from the MSTV air cylinder (thus causing the valve to fail closed) is assumed to be accounted for in the basic event for "valve fails closed."
5. The failure of the non-return valve in the main steam lines is not modeled because this valve fails as-is even on loss of power.
6. If a SG atmospheric steam dump valve is blocked prior to an event, it is possible to unblock this valve. The estimate from the system engineer is that it would take approximately 10 minutes for this task. Since there are no specific

procedures to do this, this operator recovery action is conservatively not modeled.

#### **A.4 CONTAINMENT ISOLATION SYSTEM**

The purpose of the Containment Isolation System is to limit the release of radioactive material to the atmosphere and general public in the event of an accident. For pipe penetrations through Containment, it provides, during accident conditions, at least two barriers between the atmosphere outside Containment and

1. the atmosphere inside the Containment Structure, or
2. the fluid inside the reactor coolant pressure boundary.

The system operates automatically and provides Main Control Room (MCR) position indication of the remotely operated and automatically operated valves. Failure of a single valve will not prevent isolation.

##### **A.4.1 Major Components**

The following paragraphs describe the construction and operation of the major components associated with the Containment Isolation System. Each Containment Isolation System major component is also a part of another system. The Containment Isolation System consists of containment piping penetration isolation valves from a variety of systems and that part of the Reactor Protection System which generates the automatic valve closure signal. The construction of containment piping penetrations is described in detail in the Section A.8, Containment Structure. This section describes the types of valve operators and the configuration of valves to isolate penetrations.

##### **Typical valve arrangements**

The valve arrangements presently acceptable to the Nuclear Regulatory Commission to isolate containment piping penetrations are described in Title 10 Code of Federal Regulations, Part 50, Appendix A, General Design Criteria (GDC) 55, 56, and 57.

GDC 55 describes acceptable valve arrangements for lines that are a part of the reactor coolant pressure boundary and that penetrate Containment. GDC 56 describes acceptable valve arrangements for lines that connect directly to the containment atmosphere and penetrate Containment. The acceptable isolation valve arrangements are the same for both of these types of penetrations. General Design Criteria 55 and 56 are quoted below.



"(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment, or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety."

The sketch numbers in the figure correspond to the GDC paragraph numbers quoted above. Note that a check valve may function as an automatic isolation valve inside Containment, but not outside Containment. A "locked closed" valve need not necessarily be a manually operated valve; it could be a motor-operated valve with the circuit breaker locked open after the valve has been placed in the closed position.

GDC 57 describes acceptable isolation valve arrangements for lines that penetrate Containment but are neither a part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere. The General Design Criterion requires that these lines "shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve."

All of the North Anna containment penetrations (except spares, which are welded closed) are listed in Table A.4-2 and reference the valve arrangement sketches discussed above. The plant was designed to the General Design Criteria in effect in 1966, which did not include GDC 55, 56, and 57, published in 1971. During the operating permit licensing stage, exemptions were taken from the latest GDC for some of the piping penetration designs. These other isolation valve arrangements are discussed below.

### **Other valve arrangements**

Penetrations 2, 4, 9, 10, 11, 76, 77, and 78 carry component cooling water for the Residual Heat Removal (RHR) System, the excess letdown heat exchanger and the containment air recirculation cooling coils; main feedwater; and chemical feed. These penetrations have two barriers between the outside atmosphere and the reactor coolant pressure boundary or the inside containment atmosphere: (a) the heat exchangers they serve inside Containment, and (b) the check valve outside Containment. The check valve outside containment is an exception to GDC 57.

Penetrations 7, 22, 60, 61, 62, 113, and 114 contain lines which carry Safety Injection (SI) System fluids. Each valve arrangement has a check valve inside Containment and a remotely operated, normally shut valve outside Containment, satisfying the two-barrier requirement. Some of the outside containment isolation valves open upon receipt of an SI actuation signal, and some are opened and shut by the control room operator as required after an accident. Since the outside containment isolation valve is neither locked shut nor automatically shut, this is an exception to GDC 55.

The lines passing through penetrations 35, 36 and 37 all carry reactor coolant pump (RCP) seal water supply from the Chemical and Volume Control System (CVCS). Each valve arrangement has a check valve inside Containment and a normally open manual isolation valve outside Containment. These lines remain open after an accident, carrying water to the RCP seals and contributing to SI flow. The two barriers between the reactor coolant pressure boundary and outside containment atmosphere are the check valve inside Containment and the sealed portion of the CVCS between the check valve and the discharge of the charging pumps.

The lines passing through penetrations 55, 57, 92, 93, 97, and 105 all serve the Containment Vacuum and Leakage Monitoring System. The double-barrier requirement is met by the use of two automatically closing isolation valves outside Containment. Since there is no inside containment isolation valve, this is an exception to GDC 56.

The lines passing through penetrations 63, 64, 70, and 71 carry quench spray and recirculation spray fluids to Containment. The containment isolation valves are a check valve inside Containment and a remotely operated valve outside Containment. For the quench spray discharge line, the outside containment isolation valve is normally shut and opens upon receipt of a Containment Depressurization Actuation (CDA) signal. For the recirculation spray discharge line, the outside containment isolation valve is normally open, and the second barrier is formed by the recirculation spray piping and pumps. Since the outside containment isolation valve for these penetrations is not locked shut or automatically shut, this is an exception to GDC 56.

The lines passing through penetrations 66, 67, 68, and 69 carry SI recirculation spray fluids from Containment. The lines run from sumps inside Containment, through the foundation mat, to remotely operated isolation valves located in specially constructed leaktight containers outside Containment. These containers are constructed to the same standards as Containment. For the short section of pipe between the containment boundary and the outside containment isolation valve, the two barriers are the pipe and the special valve container. Downstream of the valve, the two barriers are the valve and the sealed system formed by the pumps and piping. The outside containment isolation valve for the low head safety injection pump is normally shut. The outside containment isolation valve for the recirculation spray pump is normally open. These exceptions to GDC 56 were approved by the Advisory Committee on Reactor Safeguards.

The lines passing through penetrations 55 and 117 are used by the Reactor Vessel Level Indication Subsystem (RVLIS). Each instrument tube is closed on the inside of Containment by a bellows assembly and on the outside of Containment by an isolator. These closure devices are similar to a differential pressure transmitter mechanical housing. The effect is to seal the instrument tube on each side of the Containment, providing two-barrier protection.

#### **Valves/valve operators**

Check valves that function as containment isolation valves permit flow only in the direction from outside Containment to inside Containment and would be shut by the accident differential pressure. Containment isolation valves that are administratively controlled in the closed position may be a manual-operator, air-operator, or motor-operator. The operator must be controlled so that it does not change position due to the accident, loss of air, or loss of electrical power.

All valves which automatically shut in response to a phase A or phase B containment isolation signal are positioned by an air-operator, with the exception of RCP seal leakoff water returns which use motor-operators. All air-operators are reverse-acting, spring-loaded diaphragm types. When energized, a three-way solenoid valve admits air beneath the operator's diaphragm, raising the isolation valve's stem, compressing the spring, and opening the valve. When deenergized, the three-way solenoid valve blocks the air supply and vents the underside of the diaphragm to the local atmosphere. Energy stored in the compressed spring shuts the isolation valve. These valves operate even at containment accident pressures, because both sides of the diaphragm are at the same pressure. Air-operators fail to the closed position on loss of operating air and/or loss of electrical power. All of the solenoid valves have been tested to demonstrate their operability under LOCA

conditions or have been demonstrated to fail to the desired safety-related position.

All motor driven containment isolation valves are the Limitorque type. When the valve is signaled to open by a handswitch or a process signal, the motor drives the valve in the open direction until stopped by a limit switch. When the valve is signaled to shut by a handswitch or process signal, the motor drives the valve in the closed direction until stopped by a torque switch. The use of a torque switch in the closed direction ensures that the valve is sealed leaktight. Since adjusting the torque switch affects the leak rate of the isolation valve, the leak rate must be measured after any torque switch adjustment. Motor-operated valves fail as-is on loss of electrical power. The valve-operators contain an override lever and handwheel for emergency operation. Depressing the lever engages the handwheel and disengages the motor. The safest practice to ensure that the motor does not rotate during hand operation is to open the valve's circuit breaker. Turning the handwheel counterclockwise opens the valve and turning the handwheel clockwise shuts the valve. Since the torque switch does not stop valve travel in the closed direction during hand operation, the valve leak rate must be measured after hand operation if the valve is to remain shut.

#### **A.4.2 Power Supplies**

Most containment isolation trip valve solenoid valves are powered from the MCR 120 VAC vital bus SOV panel, train A (1-EP-CB-19A) or train B (1-EP-CB-19B), the rest of these solenoid valves are powered from 125 VDC panels 1A and 1B in the MCR. All motor-operated containment isolation valves are supplied from the onsite emergency power system.

#### **A.4.3 Fault Tree Analysis**

The CDA was modeled as a support system for Quench Spray, Recirculation Spray, and Safety Injection Actuation Signal. As such, it has no specific success criteria. The top events for CDA feed into the fault trees for SI, QS, and RS.

The Containment Isolation function was not required for the event trees. However, it was included in the fault tree task plan for the Level I work. Ultimately, a fault tree was not developed for this function. Rather, an engineering reliability analysis was performed.

The assumptions for the CDA fault tree analysis follow. The fault tree for CDA follows.

## Fault Tree Modeling Assumptions

1. Contacts were modeled as part of a relay and not modeled as separate components. For example, a device which starts when a contact is open (energized) will be modeled as a relay which fails to energize. The relay and the contact are actually one component. There is no significant advantage to separating out the contacts from the relay.
2. CDA High-High signals which transfer motor-operated valves were simplified by only including relays required to actuate the valves to the desired position. Other devices such as limit switches, hand control switches, and torque switches were not included.
3. Although common cause failure to miscalibrate the containment pressure channels I, II, III, and IV was not explicitly modeled, the primary contributor to the 0.1 common cause failure factor used for the channels (common cause failure unavailability for 1CIPIC-CC-100 =  $4.6E-4 * 0.1$ ) is generally believed to be miscalibration error. The 0.1 factor is therefore considered to adequately account for common cause miscalibration in addition to the other sources of common cause failure.
4. No fault tree development was provided for failure to restore the CDA to normal operation following system periodic tests. The CDA system has alarms and annunciators located in the control room which actuate when CDA pressure channels or logic trains are bypassed for test.
5. A single human error event was modeled representing the failure of operators to respond to common cause failure of three or four pressure instrument channels (HEP-1E0-13). However, significantly different operating circumstances and human interactions may occur depending on whether three or four instrument channels fail. Therefore, two different human error events may need to be modeled if these differences are found to be important. Additionally, if special human interactions modeling is found not to be important for common cause failures of the pressure instrument channels, then HEP-1E0-13 should be removed from the fault tree.
6. The unavailability of the numerous types of logic cards installed for CDA system operation (including output cards, universal cards, logic matrices, and power supply cards) was modeled explicitly. Their failures are lumped into the failures of the instrument channels themselves (e.g., PIC-LF). This is in accordance with Section 5.3.2.3.3 of the Task Plan for System Modeling.

7. The unavailability of the CDA pressure instrument channels (events 1CIPCI-LF-100A/B/C/D) incorporates failure of the containment pressure sensors and pressure transmitters.
8. Based on a review of CDA procedures, CDA channels which are bypassed for the purposes of testing are not automatically realigned in the event of an actual High-High containment pressure condition.
9. Components for CDA Train B were generally not shown in system drawings. Train B was drawn in the simplified schematic in a configuration similar to that of Train A.
10. There are two sets of two manual push buttons installed for manual CDA initiation. Depressing either set of push buttons will initiate CDA.
11. Based on a review of North Anna Power Station electrical drawings, the only electrical power sources required for CDA operation are 120V AC vital buses 1-I, 1-II, 1-III, and 1-IV.
12. Successful spray actuation for one train of CDS requires operation of 2 master relays. That is, master relays K519 and K505 for either CDA Train A or CDA Train B must successfully operate.
13. The operation of lock-in relays with manual reset were mentioned in the description of CDA operation in the operator training module NCR0DP-77. These lock-in relays were modeled in the CDA system fault tree and are shown as slave relays on NA-DW-1082H41.
14. The following Human Error Probabilities are defined:  

HEP-1E0-13	Manual initiation of CDA due to high-high containment pressure fails following the unavailability of auto actuation. This recovery action is used for the CDA High-High initiation or manual initiation of CDA fails following common cause failure of 3 or 4 containment pressure instrument channels.
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15. The following Common Cause Failure is defined:  

1CIPIC-CC-100	Common Cause Failure of Containment Pressure Instrument Channels 1-LM-PT-100A,B,C,D.
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#### **A.5 EMERGENCY DIESEL GENERATOR SYSTEM**

The North Anna Power Station is equipped with four 3 kW emergency diesel generators, located in individual rooms on the 270-foot

level of the Service Building, on the Unit 2 side. Each EDG is connected to an emergency 4 kV bus.

The EDGs are designed to start automatically under the following conditions:

1. safety injection signal,
2. 4 kV bus degraded voltage signal,
3. 4 kV bus undervoltage signal, or
4. improper 4 kV bus breaker lineup.

In this event, the control circuits initiate the automatic start sequence which starts the engine, increases speed up to 900 rpm, and flashes the generator field, increasing generator output voltage to 4160 V. If the associated 4 kV bus is deenergized, the EDG output breaker automatically closes onto the bus.

#### **A.5.1 Diesel Engine**

Each EDG is a Fairbanks-Morse, turbocharged, 12-cylinder, opposed piston, diesel engine. Each cylinder has two pistons that continually move in opposite directions. Scavenging air and fuel oil are introduced into the space between the pistons, and are compressed by the pistons moving toward each other. When the fuel/air mixture is sufficiently compressed, it ignites, forcing the pistons apart. The upper and lower pistons drive separate crankshafts, which are connected by a vertical drive assembly. The upper crankshaft drives the blower, which circulates scavenging air, and the camshafts, which operate the fuel injection pumps. The lower crankshaft drives the generator, the governor, the engine-driven pumps, and other associated equipment.

#### **A.5.2 Governor**

The governor receives mechanical and electrical signals from the EDG System. These signals are used to accomplish the purposes of the governor, which are as follows:

1. maintain nominal engine speed of 900 rpm with steady load conditions;
2. maintain engine speed greater than 95 percent (855 rpm) of nominal speed during an automatic loading sequence;
3. during recovery from transients caused by step load increases or resulting from the disconnection of the

largest single load, prevent the diesel from exceeding 1000 rpm; and

4. during any automatic loading sequence, restore engine speed to within 2 percent of nominal in less than 2 seconds.

The governor electrically monitors the generator output frequency and load, while mechanically monitoring the speed of the engine. By monitoring the speed of the engine either electrically or mechanically, the governor adjusts the engine's fuel controls to regulate the flow of fuel oil to each cylinder and thereby controls speed under all load conditions.

#### **A.5.3 Starting Air Subsystem**

The Starting Air Subsystem provides high pressure air in sufficient volume to rotate the diesel engine's crankshafts until the engine ignition cycle begins. The subsystem consists of air compressors that maintain the air receivers at high pressure. When an engine start is initiated, the engine controls signal the air start solenoids to open, which passes high pressure air to each cylinder in a sequential pattern determined by the air start distributor. The high pressure air forces the pistons apart and starts engine rotation, initiating a self-sustaining chain of events that operate the engine.

#### **A.5.4 Fuel Oil Subsystem**

The Fuel Oil Subsystem provides filtered oil at 20 psi to the engine cylinders, as well as providing controls to prevent engine overspeed. The subsystem receives fuel oil from the Fuel Oil System and stores it in the day tank. The engine-driven fuel oil pump delivers filtered fuel oil to each cylinder's injection pump. The injection pump measures the low pressure fuel oil into the correct amount for engine operation, builds up the fuel oil pressure, and delivers it to the injectors. The injectors spray the fuel oil into the cylinder to provide fuel for the combustion cycle. Excess fuel oil, not used by the injectors, is returned to the day tank. The overspeed trip device provides overspeed protection.

#### **A.5.5 Scavenging Air and Exhaust Subsystem**

The Scavenging Air and Exhaust Subsystem provides a volume of pressurized air to each cylinder for support of the combustion process, then exhausts the combustion gases to the atmosphere outside the diesel room. The subsystem consists of a blower, an unbalanced check valve, a turbocharger, and aftercoolers.



At loads less than 2200 kW, the blower provides scavenging air to each cylinder via the aftercoolers. At loads above 2200 kW, the unbalanced check valve opens and the turbo-charger blowers deliver the scavenging air to the cylinders via the aftercoolers.

The cylinder exhaust gases provide the motive force to turn the turbocharger turbines. Exhaust gases are passed from the turbo-charger to atmosphere, outside the room. Scavenging air is also used by an air ejector to draw and maintain crankcase vacuum.

An Air Cooling Subsystem removes heat from the scavenging air prior to its entrance into the cylinders, allowing denser air to be delivered to the cylinders. This is accomplished with an engine-driven pump to circulate air cooling water through the aftercoolers and the radiators.

#### **A.5.6 Lubricating Oil Subsystem**

The Lubricating Oil Subsystem cools and cleans the lube oil during engine operations, maintains lube oil temperature during shutdown conditions, provides cooling and lubrication to engine components during operations, and maintains the engine warm during shutdown. The subsystem operates in three distinct modes: shutdown, startup, and engine operations. During engines shutdown, the standby lube oil circulation pump draws oil from the engine sump and discharges through the lube oil heater. The warm oil is delivered to the lower crankline where it returns to the sump. This process ensures adequate lubrication for the next startup and keeps engine components warm. Prior to a non-emergency start, the pre-lube pump provides oil to most of the normal flow path, ensuring adequate lubrication prior to the start. In the event of an emergency start, the oil boosters provide a minimum level of lubrication. During engine operations, the engine-driven oil pump draws oil from the sump and delivers the oil to engine components via a filter, strainer, and cooler.

#### **A.5.7 Jacket Cooling Subsystem**

The Jacket Cooling Subsystem removes the heat due to combustion from the space around the engine cylinders and cylinder liners. It also removes heat from the Lubricating Oil Subsystem and the turbochargers. The subsystem flow is circulated by the engine-driven pump during engine operations. The heat is removed from the jacket cooling water in the radiators and passed to atmosphere. During shutdown conditions, the standby circulation pump and heater maintain the temperature of the jacket and air cooling water near normal engine-operating temperatures.

#### **A.5.8 Generator**

The generator converts the mechanical rotational energy of the engine to three-phase, 4160 V, 60 cycle electrical power to provide up to 3000 kW. The generator is driven from the engine lower crankshaft and rotates at 900 rpm. The generator rotor is encased by field windings. During operations, a set of collector rings and brushes apply 125 VDC to the field windings, setting up a magnetic field around the windings. As the rotor turns, the generator stator is exposed to an alternating magnetic field, which induces an alternating voltage in the stator. The output of the generator is supplied to emergency 4 kV bus 1H through breaker 15H2. The output is also used for the following:

1. potential and current transformers provide load and speed signals to the engine governor electric control box;
2. current transformers for the 87 relays (generator differential);
3. current transformers for the voltage exciter controller; and
4. the generator output ammeter.

#### **Engine, Generator, and Breaker Controls**

These ensure that the diesel generators automatically start under design conditions, reach rated speed and voltage within 10 seconds, and automatically supply power to the emergency 4 kV buses, if required. The controls also allow control of the generator voltage and frequency. The internally generated signals and other external signals are used for the following:

1. automatic starting of the diesel engine under the required conditions;
2. automatic flashing of the generator field;
3. automatic closing of the EDG output breaker under the required conditions;
4. automatic shutdown of the diesel under certain conditions;
5. establishing engine interlocks and operation of the engine auxiliaries during engine startup;
6. providing automatic generator voltage control;

7. providing local, manual control of the EDG from the diesel room (H diesels only); and
8. providing engine and generator alarms.

#### **A.5.9 Power Supplies**

The EDG auxiliaries receive 480 V power from a motor control center (MCC) that is powered from the emergency 4 kV bus, to which the EDG can be connected. EDG 1H auxiliaries receive power from MCC 1H1-1A, located in the diesel room. The MCC also provides 480 V power to the EDG battery charger.

The battery charger converts the 480 V power to approximately 130 VDC. The direct current is used to charge and "float" the EDG battery. The battery consists of 20 cells series-connected. The DC circuits provide power to the auxiliary fuel oil pump and the various control circuits. The battery/charger arrangement provides a capability to start the generator and flash the field.

The engine auxiliaries have a circuit breaker panel behind the starter box. The AC and DC powered auxiliaries have breakers inside that panel.

#### **A.5.10 Fault Tree Analysis**

The diesel generators were modeled as a support system for the 4160 V emergency buses. They were also modeled as front line systems in the loss of offsite power trees. The diesel generator fault tree is shown at the end of this section.

The dependency matrix for the modeled components is shown in Table A.5-1. The assumptions and notes used to develop these fault trees follow.

#### **Fault Tree Modeling Assumptions**

- 1) The EDG support systems such as starting air, EDG batteries, fuel oil, lubricating oil, air intake, exhaust, and engine cooling, were not explicitly modeled. These EDG subsystems are considered to be essential to the successful operation of the EDGs. Failure of a support system will cause failure of the EDG to start or run for twenty four hours. EDG start or run failures are well documented events which will provide sufficient data to determine EDG reliability. Data for the support systems may not be as readily available. Future fault tree model may consider improving the EDG model by including the support systems if the failure data has been determined to be available.

- 2) The EDG output breakers, 15H3, 15J3, 25H3, 25J3, were not included in the EDG fault trees as unique basic events. These breakers are considered to be within the component boundary of the EDGs. The failure rate of the breakers is included within the EDG start failure rates.
- 3) The dependency of the EDG output breakers have on DC power is included in the fault tree as two basic events, loss of power and common cause failure. This dependency was not modeled as an external transfer to DC power to prevent circular logic between the EDG tree and electrical power fault tree.
- 4) Common cause failures of the EDGs is modeled as suggested by the Data Team. Four different common cause failure basic events are used in the three fault trees. These four basic events are the common cause failure related to all three EDGs, or common cause failures related to the combination of any two, three or four diesels (e.g., 1H & 1J, 1H & 2H, 1H & 2J, 1J & 2H, 1J & 2J, 2H & 2J, 1H & 1J & 2H, 1H & 1J & 2J, 1H & 2H & 2J, 1J & 2H & 2J, 1H & 1J & 2H & 2J).

#### **A.6 REACTOR COOLANT SYSTEM**

The RCS consists of three piping loops connected in parallel to the reactor vessel. Each of the three loops operates to transfer heat generated in the reactor core from the core to the primary side of the steam generator. The heat is then transferred through the steam generator U-tubes to the secondary side of the steam generator. There the heat is used to boil water, making steam that is used to turn turbine generators and produce electrical power.

The reactor vessel contains the fuel rods (core), control rods, and other structural, control, and protective assemblies. Coolant enters the reactor vessel through three inlet nozzles, one from each loop, near the top vessel flange. The water flows downward between the vessel wall and the core barrel. The flow is then directed upward through the core, parallel to the axis of the fuel bundles, removing heat from the core as it passes up and out through the outlet nozzles. The vessel itself is a pressure vessel made of manganese-molybdenum steel, lined with stainless steel.

Primary coolant also continually bypasses the steam generator into manifolds where temperature sensing instruments monitor steam generator inlet temperature. Flow from the discharge of the RCPs is also circulated back to the pump suction through a manifold in order to monitor steam generator outlet temperature. The temperatures are monitored for use in control, protection, alarm, and indication functions. Details on these uses are discussed in the Instrumentation and Controls section of this module. When a loop's stop valves are shut, the RCP of the isolated loop may

continue operation by circulating flow through the loop bypass piping.

Other system flow paths involve interrelationships with other plant systems or the pressurizer. The pressurizer surge line is connected to the RCS on the hot leg of loop C between the reactor vessel and the hot leg loop stop valve. Flow can surge into or out of the pressurizer, depending on the initiating power transient. The pressurizer spray lines are connected to the cold legs of loop A and C, between the reactor vessel and the inlet loop stop valve. Flow from these lines is always into the pressurizer. A detailed discussion of pressurizer operation is contained later in this section.

Selected schematics for the RCS subsystems are shown in Figures A.6-1 through A.6-3.

#### **A.6.1 Major Components**

Dependencies for important RCS components are shown in Table A.6-1.

##### **Reactor coolant pumps**

The RCP located in each loop of the RCS is the prime mover for reactor coolant flow from the reactor core to the steam generator and back. The RCPs are vertical-shaft, single-suction, single-stage, centrifugal pumps designed to move 94,667 gpm of reactor coolant through each loop. The RCPs consist of three general sections: the hydraulic section, the seals section, and the motor section. Only the seals are important to the PRA.

The thermal barrier/heat exchanger is a welded assembly constructed of a cylindrical shell, a heat exchanger coil, and various water and instrument connections. The thermal barrier is located directly above the impeller and the turning vane-diffuser, while its shell extends into the casing on the inside of the turning vane-diffuser. The heat exchanger coil is welded to the shell. The thermal barrier prevents the transfer of heat from the reactor coolant to the internals of the seals section and the motor section. Heat from the reactor coolant is transferred to the 33 heat exchanger coils. Component Cooling System water flows through the coils, receiving the transferred heat and removing it from the RCP. If the coils develop a leak, allowing reactor coolant or high pressure injection water into the cooling water, trip valves in the component cooling piping automatically shut, based on a high component cooling flow signal.

The seals section is comprised of the floating ring seal; the No. 1 controlled-leakage, film-riding face seal; and the No. 2 and No. 3 rubbing face seals. These seals are contained within the main

flange and seal housing. Each seal consists of a non-rotating seal ring free to move axially along the pump shaft and a runner that rotates with the pump shaft. The seals are designed to control the upward flow of high pressure injection water from the CVCS, which is travelling upward from the radial bearing. Approximately 3 gpm leakage (injection water) flows past the first pump seal, the majority of which is returned to the CVCS. Leakage of 3 gph flows past the second pump seal, which is channeled to the primary drain transfer tank in the Primary Vents and Drains System. The third seal passes 100 cc/hr, all of which flows to the suction of the primary drain transfer pump.

The seal injection subsystem supplies high pressure water from the CVCS charging pumps to the RCP. Following the discharge from the charging pumps, the injection flow passes through injection filters and a manifold common to all RCPs. The filters are located on the first floor of the Auxiliary Building and are piped in parallel so that, if one filter becomes clogged, a filter may be changed without interrupting injection flow and without entering the Containment. The supply line to each pump is equipped with a throttling valve and flow indicator, allowing the adjustment of injection flow to each RCP. The throttle valve and the indicator are located in the penetration area north of the seal injection cubicles. Each supply line flow is also indicated on the MCB.

Inside Containment the injection supply line is equipped with a check valve to prevent reactor coolant back flow if injection flow is lost. The supply line is also equipped with a drain line located between the check valve and the RCP connection, which allows the seal cavity to be drained during seal maintenance.

The injection flow is delivered at 8 gpm to the thermal barrier region, where 3 gpm pass through the radial bearing and the No. 1 seal. The remaining 5 gpm pass through the thermal barrier heat exchanger and into the RCS where it constitutes a portion of the RCS makeup.

The component cooling system supplies water for the thermal barrier from a supply manifold inside the Containment. A check valve prevents backflow from the RCS to the component cooling supply lines if a pipe rupture of the thermal barrier occurs. The component cooling water discharge from the thermal barrier passes through an orificed flow meter which controls an upstream trip valve. If excessive flow is sensed, indicative of an RCS-to-component cooling leak, the trip valve automatically shuts.

### **Loop stop valves**

The loop stop valves are remotely controlled, motor-operated, double-disc gate valves. Each loop has two valves. One is positioned between the RCP and the reactor vessel; the other is

positioned between the reactor vessel and the reactor coolant pump. The valves allow the operators to isolate a loop from the reactor and the other loops but are only used in maintenance operations. The valves used in the hot and cold legs are identical except that the hot leg valve has an inner diameter of 29 inches, while the cold leg valve has an inner diameter of 27.5 inches.

### **Steam generators**

The steam generator is a vertical, pressurized-water, Class A vessel. The vessel is constructed with carbon steel and is located in the Containment Building, extending from the 259-foot level to the 323-foot level. The steam generator weighs 662,000 pounds (dry) and is 812 inches high. The vessel shell consists of a lower head and shell, a transition cone and a steam drum, with an upper head. The upper steam drum has an outside diameter of 175.75 inches and the lower shell has an outside diameter of 135 inches. The steam generator serves as the heat exchange boundary between the primary and secondary loops, and is divided into primary and secondary sides.

The primary side of the steam generator is an integral part of the RCS. The primary side is comprised of a hemispherical chamber, a tubesheet, U-tubes, and manways.

The upper boundary of the chamber is formed by the tubesheet. The tubesheet is a flat disc forging 21 inches thick and clad with Inconel on the reactor coolant side for corrosion protection and compatibility with the U-tubes. The tubesheet forms the pressure boundary between the primary and secondary plants and is designed to withstand a 1600 psid primary-to-secondary dp, or a 670 psid secondary-to-primary dp. The tubesheet has 6776 penetrations which provide access to the 3388 U-tubes and is welded to the chamber and the lower shell along its perimeter. In order to provide a large heat transfer area, the steam generator has a tube bundle which consists of 3388, vertically inverted, 0.875-inch (outer diameter), .050 inch wall thickness, U-tubes. Since these tubes also form part of the primary boundary, they are constructed of Inconel for increased tube integrity. The U-tubes are expanded at the end and welded onto the reactor coolant face of the tubesheet. The tubes are supported against lateral vibrations by an anti-vibration bar at the U-bend of the tubes. By reducing or limiting the lateral vibration, the likelihood of fatigue failure is reduced.

The secondary side of the steam generator side is comprised of a shell, a feedwater inlet nozzle, a tube bundle wrapper, a downcomer flow resistance plate assembly, moisture separators, and a wet layup nozzle. The shell consists of a lower shell, a transition cone, a steam drum, and an upper head. The shell material is made of carbon steel, with the tubesheet welded to the shell along its perimeter at the lower end. The transition cone is welded to the

upper end of the lower shell, with the steam drum and the upper head welded together above that. The shell has the following penetrations:

1. feedwater inlet,
2. bottom blowdown connections,
3. secondary side drain connection,
4. manways,
5. handholds,
6. steam nozzle,
7. instrumentation connections, and
8. wet layup nozzle.

The feedwater inlet nozzle supplies feedwater from the Main Feedwater System or the Auxiliary Feedwater System. The two bottom blowdown connections are attached on the secondary side above the tubesheet and connect to the Steam Generator Blowdown and Recovery System. This connection is used to control the water-solids concentration in the steam generator as well as for continuous sampling by the Secondary Sampling System. The drain connection is used to drain the secondary side of the steam generator during maintenance periods. It connects to the bottom blowdown lines or can be valved to the containment sump.

The wet layup nozzle connects the steam generator to the Steam Generator Wet Layup Circulation System. The wet layup system provides forced circulation inside the steam generator during cold shutdown wet layup to ensure proper mixing of water chemistry chemicals.

The feedwater enters the steam generator at the feedwater nozzle which connects to a perforated pipe known as the feed ring. The feed ring distributes the incoming feedwater into the downcomer region. The feedwater exits through the top of the inverted J-tubes, flowing downward into the downcomer. The J-tubes are not evenly distributed around the ring. There are more J-tubes that supply feedwater to the inlet chamber side of the downcomer than supply water to the outlet chamber side. This results in an increased circulation ratio, increasing the velocity across the tubesheet, enhancing the sludge removal by the blowdown system, and reducing hot side superheat.

The feedwater from the feed ring mixes with, and is preheated by, the hot drainage (recirculating water) from the separators. This secondary side water flows through the downcomer region by



traveling downward over the inside wall of the shell and over the outside wall of the tube bundle wrapper. The tube bundle wrapper is a steel cylinder that fully encloses the tube bundle, separating the downcomer from the evaporator region. The wrapper not only directs flow, but also provides additional heating of the incoming feedwater prior to its entry into the evaporator region. The preheating, in conjunction with the feedwater preheating by the recirculating water and the Main Feedwater System heaters, prevents thermal shock to the tubesheet and the U-tubes. The tube bundle wrapper is welded to the lower shell. Tube support baffles are welded to the inner surface of the wrapper. These support baffles maintain correct U-tube alignment and spacing. A transition cone is welded to the upper end of the wrapper to provide a transition between the evaporator and the steam drum (the riser section). A sufficient gap is provided between the bottom of the wrapper and the tubesheet, allowing uniform introduction of the feedwater into the evaporator region.

Located in the downcomer region is a ring-shaped perforated plate, referred to as the downcomer flow resistance plates. The ring is segmented into twenty sections, each of which are welded to the wrapper via two perpendicular gusset plates per section. A 0.19 to .25-inch gap is maintained between the radial edge of each segment and the shell. The purpose of the plate is to reduce the flow induced stresses on some of the tubes by creating better flow characteristics in the downcomer annulus.

At the bottom of the downcomer region, the secondary fluid flows inward over the secondary face of the tubesheet, then upward around the U-tubes through 3/4 inch flow holes drilled in the tube support plates. As it rises over the surface of the tubes in the tube bundle, this water is heated at the rate of  $3.167 \times 10^6$  Btu/hr by the reactor coolant flowing inside the tubes. This heat transfer process results in boiling as the secondary side water reaches the saturation temperature corresponding to the steam generator pressure. The steam-water mixture which is formed continues to rise upward in the evaporator region. As it rises, the quality of the mixture increases. At the top of the evaporator region the mixture exits to the steam drum via the riser region. As the steam rises through the deck in the riser region, it passes through steam chimneys. The chimneys project 16 inches above and below the deck and are flared at the top and bottom. The chimneys prevent water draining off the deck from mixing with the rising steam.

The moisture-laden steam enters the steam drum where it undergoes a water-steam separation process in the separators. The first stage separator, at the top of the tube bundle wrapper, consists of three swirl vane assemblies, each of which is comprised of four flat blades welded to a central hub. The blades are also welded to a swirl vane wrapper and make up the first stage in the steam separation process. As the wet steam enters the separator, the swirl vanes force the steam into a circular motion. The

centrifugal action imparted to the mixture separates the steam from the water by forcing the denser water outward to the wall of the separator. The water collects on the wall of the separator and drains over the lip of an inner barrel, returning to the downcomer region, where it mixes with and preheats the incoming feedwater. The majority of the water is removed in this process, with the steam rising to the second stage separator through deflectors.

The second stage separator consists of two-tier, four-bank vane assemblies installed parallel to the direction of steam travel. The directional changes in the surface contour of the vanes collect the water from the steam-water mixture. The water drains through eight 4-inch pipes welded into the bottom drain channel of the vane banks. Each drain pipe is approximately 137 inches long. The drain pipes run vertically down through the steam chimneys or through existing deck slots. The steam that exits the second stage separator is 99.75 percent steam with a maximum of 0.25 percent moisture.

At the top of the steam generator, the 32-inch steam outlet nozzle is the connection from the steam generator to the Main Steam System. A reducing connection is welded to the nozzle to connect the 32-inch nozzle to the 28-inch steam piping.

### **Pressurizer**

The pressurizer is a 1400 ft<sup>3</sup> vertical, cylindrical pressure vessel whose purpose is to maintain RCS pressure during steady state operation, limit the changes in pressure during transient operations, and prevent the RCS from exceeding the design plant pressure. The pressurizer consists of the pressurizer vessel, the spray line and valves, the surge line, power-operated relief valves, safety valves, and a pressurizer relief tank. The pressurizer is located in the Containment and extends from the 265-foot elevation to the 310-foot elevation.

During normal operations, the electrical load on the plant is relatively constant; however, load changes are possible. During decreases in load which cause increased reactor coolant temperature, the density of the coolant decreases. The coolant expansion causes an insurge into the pressurizer, causing pressure to increase. The spray system responds to the increase in pressure by injecting subcooled water into the upper portion of the pressurizer which is filled with steam vapor. The steam condenses on the spray, limiting the amount of pressure increase. An increase in load causes reactor coolant temperature to decrease; the coolant density increases, causing an outsurge from the pressurizer into the loops. As the water level in the pressurizer decreases, the pressure in the pressurizer decreases. As the pressure decreases, some of the water in the vessel flashes to steam, helping to limit the amount of the pressure decrease.

The primary purpose of the 1400 kW electric heaters is to heat and maintain the water in the pressurizer at saturation temperature for the corresponding RCS pressure. There are 78 individual heater elements divided into five groups one control group and four backup groups, with each individual heater seal-welded into one of the 78 heater well assemblies located on the lower head of the pressurizer. The heater element extends upward into the pressurizer where it is guided and aligned by two heater support plates. The support plates also act as baffles to direct the circulation of the water across the heaters as water surges to and from the pressurizer.

The spray line and spray nozzle connect the cold legs of loops A and C to the pressurizer. The dual connections ensure that spray flow is always available if one RCP is secured. The line is sized to pass up to 630 gpm of spray flow, which is adequate to meet the design basis of the pressurizer. The spray line inlet connections at the RCS piping extend into the piping and form a scoop. The scoop ensures that the velocity head of the RCP adds to the driving force of the spray flow. The principal driving force for spray flow is the differential pressure between the RCP discharge and the pressurizer (d/p across RX vessel). The spray valve associated with "C" Loop has greater flow due to the shorter length of piping run from "C" Loop to the PZR. The maximum spray flow rate is designed to prevent the power-operated relief valves from opening during a 10 percent step-decrease in power.

There are two spray valves (1-RC-PCV-1455A, -1455B) which receive control signals from the Pressure Control and Protection System. These valves are air operated ball valves (see Figure 38-78). They fail closed on a loss of air or power. The valves are equipped with Bailey positioners. If the feedback arm becomes disconnected the valve will stay closed if the controller demand is zero. If there is ANY open demand on the controller, the valve will go fully open because the disconnected feedback arm indicates the valve is shut regardless of actual position and the positioner will port air to the valve to open it. These valves automatically open to admit spray flow into the pressurizer in order to decrease pressure. The valves can also be controlled manually from the MCR. Arranged in parallel to the spray valves are 1/4-turn stop-to-stop spray bypass valves. These valves are manually set throttle valves which allow a minimum 1 gpm total spray flow into the pressurizer during all operations with the RCPs operating. The continual spray flow prevents the spray and surge lines from cooling off due to ambient heat losses, as well as ensuring that the boron concentration is equalized between the loops and the pressurizer. The spray lines from the loops are equipped with temperature sensors (1-RC-TE-1451, -1452) which provide temperature indication and an alarm indicative of low spray flow. There is an auxiliary spray line which connects to the spray line downstream of the spray valves. This line is not routinely used, but it provides the capability of initiating spray from the CVCS charging pumps when RCPs are not operating. The spray lines feed the spray nozzle which is located in the

pressurizer vapor space. The spray nozzle is protected by a thermal sleeve which minimizes the thermal shock of initiating relatively cold spray flow through the spray nozzle, which is in the high temperature steam environment of the steam space. The spray nozzle atomizes the spray flow, providing nucleation sites for condensing the steam.

The surge line connects the bottom of the pressurizer to the hot leg of loop C. The surge line is sized to limit the pressure drop between the RCS and the pressurizer safety valves during maximum discharge from the safety valves. This ensures that the RCS does not exceed design pressure during an overpressure transient. A retaining strainer at the inlet nozzle to the pressurizer prevents the entry of foreign material into the pressurizer water space. The surge line connects to the top of the RCS piping on Unit 1 and to the side of the RCS piping on Unit 2.

The upper head of the pressurizer has a line that leads to the power-operated relief valves (PORVs) (1-RC-PCV-1455C, -1456). The PORVs are solenoid-actuated, air-operated valves whose purpose is to provide protection for the RCS from overpressure caused by a large power mismatch. As they provide this protection, the PORVs prevent the safety valves from opening and a reactor trip due to high pressure. The PORVs also provide overpressure protection for the RCS when the plant is shut down and depressurized at low RCS temperature (NDT protection).

The valves actuate based on high pressure signals provided by the Pressure Control and Protection System. The valves are equipped with limit switches which provide an open indication in the MCR, based on valve position. Each PORV has a blocking valve (MOV-1535, -1536) located upstream of it. The motor-operated valves are normally open, but they are used to isolate a PORV which does not fully reseal after opening or is experiencing leakage. These blocking valves are controlled from the MCR. Once valve travel is initiated by placing the handswitch to the "Open" or "Close" position, the handswitch can be shifted to and maintained in opposite position, but valve travel will continue until either the "full-open" or "full-closed" position is reached. At that time the valve will reverse direction and continue stroking until the valve position matches the handswitch position. This is to prevent thermalling out the breaker with the valve in mid-position. The PORVs relieve to the pressurizer relief tank. The line from the discharge of the PORVs to the tank is monitored for temperature in order to provide indication of leakage from a PORV.

The PORVs are normally operated with 110 psig air from the containment instrument air header. When the valves reach their setpoints, the solenoid valves (SOVs) open and admit air to the operating diaphragm of the PORV. In the event that the containment instrument air system loses pressure, the PORVs have a backup

nitrogen supply. The nitrogen gas is supplied to the PORV operating lines at 2000 psig from the nitrogen reserve tanks.

#### **A.6.2 Fault Tree Analysis**

The RCS was modeled as a front line system, sometimes with functions all its own and sometimes contributing to functions with other front line systems. The functions dependent on the RCS are:

- P - Feed and bleed mode of core cooling.
- Pr - Adequate pressure relief for ATWS events. Success criteria for ATWS from high power are that 3/3 SV or 2/2 SV and 2/2 PORVs must be open.
- Q - RCS voundary intact after a transient. Success criteria are that any PORV which opened in response to a transient must reclose.
- O - Operator RCS cooldown and depressurize. Success criteria include RCS depressurization via main spray, auxiliary sprays, or PORV opening.
- O2 - Operator late RCS cooldown and depressurize the RCS to atmospheric pressure. This function was used in the Steam Generator Tube Rupture event tree.

The assumptions and notes used in fault tree development are listed below. The fault trees follow at the end of the section.

#### **Fault Tree Modeling Assumptions**

1. Since the containment air system is backed up by air bottles, failure probability of air supply to the PORVs is assumed to be negligible.
2. It is assumed that the SRVs are only demanded during ATWS events and not during transient events or SBO events.
3. During ATWS events, both PORVs and all 3 SRVs are assumed to be demanded.
4. An instrument air regulator failure will fail the PORV. This is a revealed fault and will only have an effect if it happens in the time window for the accident. Therefore this event will not be treated as a demand failure.

## **A.7 SAFETY INJECTION SYSTEM**

Schematics for this system are shown in Figures A.7-1 and A.7-9. The one line diagrams include the safety injection subsystems and the safety injection actuation logic trains.

### **A.7.1 SI System Major Components**

The Safety Injection System consists of three accumulators, one hydrostatic test pump, three high head safety injection (HHSI) pumps (also called charging pumps), one boron injection tank (BIT), and two low head safety injection (LHSI) pumps. This subsection describes the major SI System components and the flow paths used to achieve the purpose. The RWST is a major component of the QS System, but it has many safety related interfaces with the SI System. Therefore, the RWST interfaces will be discussed with the SI System major components.

#### **Accumulators**

The Safety Injection System has three accumulators: 1A, 1B, and 1C. Two of the three accumulators refill the reactor inlet plenum, downcomer, and lower core basket with borated water following a LOCA. The third accumulator is assumed in the accident analysis to be dumped out of the break. The accumulators are considered to be passive components since no electrical signal, operator action, or power is required for their operation. This subsection describes accumulator 1A. Accumulators 1B and 1C are identical except for valve numbering. The accumulators are located on the 216-foot level of Containment inside the crane wall. Figure 52-2 shows a piping diagram for accumulator 1A. Each accumulator is a pressure vessel filled with at least 7580 gallons of 2200 to 2400 parts per million (ppm) borated water and pressurized with nitrogen gas to 599 to 667 psig. The carbon steel vessel is internally clad with stainless steel and has a total volume of 1450 cubic feet. Remote accumulator pressure and level indication is provided in the Main Control Room.

Each accumulator is connected to its respective RCS cold leg through a motor-operated, accumulator isolation valve MOV-1865A and two swing-check valves. The accumulator isolation valve is used to prevent emptying the accumulator during normal plant cooldown and depressurization. All of the accumulator isolation valves are opened during RCS pressurization when the RCS pressure is between 900 and 950 psig. Above 100 psig, power is removed from the valve operators, and the power supply breakers are locked open. This action partially satisfies technical specification requirements for accumulator operability.

During RCS depressurization in support of unit shutdown, the MOVs are energized when RCS pressure is <1990 psig. This is done by unlocking the admin. locks on the power supply breakers (located on the emergency bus 480 V MCCs in the cable vault), removing the locks, and closing the respective breakers. The MOVs are left open until RCS pressure has been reduced to 950 psig. They are then closed, but the valve operators remain energized until RCS temperature is reduced to <350°F.

The accumulator check valves are normally held shut by the higher RCS pressure of 2235 psig. During a LOCA, when RCS pressure drops below the approximately 600 psig, the check valves open and the accumulator discharges into the RCS without any external requirements. A connection is provided upstream of each check valve for accumulator sampling and to permit testing the check valves for seal leakage during RCS pressurization when there is about 100 psi differential pressure across the valves.

### **Refueling water storage tank**

There is one refueling water storage tank (RWST) per unit. It is located in the yard next to the Safeguards Building. The RWST performs the following functions:

1. Provides borated water to the HHSI pumps, LHSI pumps, and quench spray pumps.
2. Provides alternate source of water to the HHSI pumps during abnormal operations.
3. Provides storage water for the refueling cavity.

The RWST is a vertical, cylindrical tank with a usable capacity of 487,000 gallons. It must contain at least 466,200 gallons of 2300 to 2400 ppm borated water during unit operation in modes 1-4. The proper boron concentration is maintained by the Chemical and Volume Control System (CVCS). The RWST is required to be maintained between 40° and 50°F during unit operation in modes 1-4. The maximum allowed temperature ensures that sufficient cooling capacity is available for the QS System to depressurize Containment in the time required in the event of a LOCA. Further information on the RWST may be found in the QS System training module (NCRODP-53). The water from the RWST is directed to the HHSI and LHSI pumps through a common supply header. Water from the supply header enters the LHSI pumps through individual, normally open, motor-operated valves 1-SI-MOV-1862A, and B. Water to the HHSI pumps passes through parallel, normally shut, motor-operated valves 1-CH-MOV-1115B and D. These valves are redundant to ensure that at least one opens on receipt of a safety injection actuation signal or a VCT low level of 5 percent. The supply header then branches

to each of the HHSI pumps through individual, normally open, motor-operated valves 1-CH-MOV-1267A, -1269A, and -1270A.

### **High head safety injection pumps**

The Safety Injection System has three high head safety injection pumps, commonly referred to as "charging pumps." They are located in the charging pump cubicles on the first floor of the Auxiliary Building. During normal operation, at least one pump is operating with the other two lined up for normal charging. When safety injection actuates, all three pumps receive an auto-start signal but only two of the pumps will remain running. The two running pumps will preferentially be powered from different emergency buses to minimize bus loading.

The HHSI pumps are horizontal, eleven-stage, centrifugal pumps. Each pump is designed to pump 150 gpm at 250°F and 2735 psig. Each HHSI pump has a self-contained oil lubrication system. The HHSI pump is driven by a 900 HP, 1800 rpm motor that rotates the pump at 4846 rpm through a speed-increasing gearbox. HHSI pumps 1A and 1C are powered from 4160 V bus 1H. HHSI pump 1B is powered from 4160 V bus 1J. HHSI pump 1C can be used as an alternate pump for either SI train and may be powered alternatively from 4160 V bus 1J. When pump 1C is powered from its alternate source, it has no automatic start features.

To prevent overheating of the HHSI pumps when they are operated at a shutoff head, a mini-flow recirculation line is provided for each pump. The recirculation flow path contains a check valve, an orifice, and an isolation valve MOV-1275A, B, or C. The three mini-flow lines join to form a common header which discharges to the seal water heat exchanger through a common recirculation line isolation valve 1-CH-MOV-1373. The recirculation flow from the seal water heat exchanger is directed back to the suction of the HHSI pumps. During a LOCA, the recirculation line isolation valve is manually shut to maximize HHSI pump flow when RCS pressure decreases below a certain point. The valve is manually reopened if RCS pressure rises above 2000 psig. When RCS pressure is above 2000 psig, the flow through the HHSI pumps is insufficient for pump cooling, and recirculation flow is necessary to prevent pump damage.

The HHSI pumps normally receive water from the VCT through a supply header that contains two series isolation valves MOV-1115C and E. The VCT supply header and the RWST supply header combine into a common HHSI pump suction header. The discharge of LHSI pump 1B can be directed to the HHSI pump supply header through normally shut, isolation valve 1-SI-MOV-1863B. Each HHSI pump is supplied in parallel from the supply header through normally open, isolation valves 1-CH-MOV-1267A, -1269A, and -1270A. LHSI pump 1A can supply each of the HHSI pump suctions through a normally shut, common



isolation valve 1-SI-MOV-1863A and individual, normally open, alternative path isolation valves 1-CH-MOV-1267B, -1269B, and -1270B.

The HHSI pumps can discharge water through individual, normally open, outlet valves 1-CH-MOV-1286A, B, and C. This discharge can pass through a common discharge header isolation valve 1-CH-MOV-1289B to the normal RCS charging header. The discharge from 1-CH-MOV-1286A, B, and C can also be directed through the BIT to the RCS cold legs or to the RCS through normally shut isolation valves 1-SI-MOV-1867C or D, hot legs through a normally shut isolation valve 1-SI-MOV-1869B. The discharge of the HHSI pumps can also be directed through individual, normally open, isolation valves 1-CH-MOV-1287A/B/C to either the RCS cold legs through normally shut, alternate path isolation valve 1-SI-MOV-1836 or the RCS hot legs through normally shut, alternative path isolation valve 1-SI-MOV-1869A.

During normal plant operation, water enters the HHSI pump from the VCT through 1-CH-MOV-1115C and E and through HHSI pump suction valve MOV-1267A, -1269A, or -1270A. The discharge of the HHSI pump passes through the pump discharge valve MOV-1286A/B/C through the RCS charging header isolation valve MOV-1289B, FCV-1122, MOV-1289A, the regenerative heat exchanger, HCV-1310, and into B-Loop cold leg downstream of the accumulator discharge line.

During the injection mode, water from the RWST enters the HHSI pumps through 1-CH-MOV-1115B and D and the pumps suction valves MOV-1267A, -1269A, and -1270A. The discharge of the pumps passes through the pump discharge valves 1-CH-MOV-1286A/B/C to the BIT.

During the recirculation mode, water from LHSI pump 1A enters the HHSI pumps through MOV-1863A and the alternate header via pump suction valves MOV-1267B, -1269B, and -1270B. LHSI pump 1B supplies water through MOV-1863B and the normal header via pump suction valves MOV-1267A, -1269A, and -1270A to the HHSI pumps. During cold leg recirculation, the HHSI pumps discharge through discharge valves 1-CH-MOV-1286A, B, and C and the BIT. Later, one of the HHSI pumps is isolated from the other HHSI pump to provide two independent paths to the RCS. Independent paths provide protection against a long-term passive failure causing a complete loss of core cooling. In the cold leg lineup, one HHSI pump discharges through the alternative discharge valve 1-CH-MOV-1287A, B, or C and MOV-1836. During hot leg recirculation, one HHSI pump discharges through its normal discharge valve and 1-SI-MOV-1869B to the RCS hot legs, while the other HHSI pump discharges through its alternative discharge valve and 1-SI-MOV-1869B to the RCS hot legs.

## **Low head safety injection pumps**

There are two low head safety injection pumps for each unit. The pumps are located in Safeguards Area outside of Containment. During normal plant operations, the LHSI pumps are in standby, lined up to pump borated water from the RWST to the RCS cold legs. On receipt of a safety injection signal, the pumps automatically start and deliver large quantities of borated water to the RCS if RCS pressure is less than discharge pressure, otherwise, they will run on recirculation to the RWST.

Each LHSI pump is a vertical, two-stage, mixed flow enclosed impeller, centrifugal pump. The pump has a capacity of 3000 gpm at a temperature of 300°F and a pressure of 175 psig with a design head of 225 feet. The pump suction is located at the bottom of the safeguards pit at the 210-foot elevation. The pump discharges along the shaft vertically to the 256-foot elevation where the mechanical seals and motor are located. The pump is driven by a 250 HP, 4160 V, induction motor that rotates the pump at 1800 rpm. LHSI pump 1A is powered from 4160 V bus 1H and pump 1B from bus 1J. The pumps are protected from overpressure by relief valves 1-SI-RV-1845A, B, and C that relieve to the Safeguards Area. Their setpoints are 220 psig.

The LHSI pump uses tandem mechanical seals to contain the water within the pump at the point where the shaft protrudes through the discharge head. In the event that the inboard seal fails, the outboard seal is capable of handling the full unit pressure. Seal water flow and cooling is provided water from the RWST. Local flow indication is provided for the combined LHSI pumps seal water supply.

The suction of the LHSI pumps is physically located at the bottom of the safeguards valve pit at elevation 210 feet. Water from the containment sump, in particular, gravity drains into the pump suction pit. The containment sump is only a few feet higher than the LHSI pump suction pits. To provide a full suction for the pumps, each pump is provided with two ejectors to remove air from each pump suction area. The air ejectors use the pump discharge as the high pressure source of water to create a suction on the pump suction space. This not only fills the pump suction bell with water, but also increases the flow of water from the sump to the pump suction pit.

A minimum flow bypass line is provided for each pump to recirculate fluid to the RWST to prevent overheating of the pump while operating at shutoff head and for test purposes. Two motor-operated, isolation valves 1-SI-MOV-1885A & C and 1-SI-MOV-1885B & D are piped in series on the recirculation line for each pump. The recirculation line is automatically isolated when the following conditions are satisfied:

1. SI recirc. mode signal is present (from SI, lock-in relay),
2. RWST level is below 24.9 percent, and
3. Either 1-SI-MOV-1863A or B respectively has opened.

During the recirculation mode, the LHSI pumps take a suction on the containment sump. If the recirculation line isolation valves did not shut radioactive gases from the sump water would be released to the atmosphere through the RWST vent. The valves do not shut until minimal cooling flow is ensured by 1-SI-MOV-1863A or B opening.

The LHSI pumps take a suction on either the RWST or on the containment sump. During normal operations and the injection mode, the LHSI pumps are lined up to receive water from the RWST through motor-operated, isolation valves 1-SI-MOV-1862A and B. During the recirculation mode, these isolation valves are shut and the motor-operated, isolation valves 1-SI-MOV-1860A and B from the containment sump are opened. On receipt of a low-low RWST level, 1-SI-MOV-1860A and B will open automatically if a SI recirc mode signal is present and the respective LHSI pump recirculation valves have shut.

The LHSI pump discharge can be directed to the RCS cold legs, the HHSI pump suction, or the RCS hot legs. During normal plant operations and the injection mode, the discharge of the pumps is lined up to the RCS cold legs through normally open, pump discharge valves 1-SI-MOV-1864A and B and a pair of normally open, isolation valves 1-SI-MOV-1890C and D that are piped in parallel. The motor operators for 1-SI-MOV-1890C and D are normally deenergized with their breakers locked open. On initiation of the recirculation mode, the discharge of the LHSI pumps continues to the RCS cold loops with some portion being directed to the suction of the HHSI pumps through normally shut, isolation valves 1-SI-MOV-1863A and B. This lineup ensures net positive suction head to the HHSI pumps, since water is no longer being provided to the HHSI pumps from the RWST. During the recirculation mode, the discharge of the LHSI pumps is periodically lined up to the RCS hot legs through normally shut, isolation valves 1-SI-MOV-1890A and B. On Unit 1, the outside recirculation pumps 1-RS-P-2A and B can discharge to the LHSI pump discharge headers in the event of failure of one or both of the LHSI pumps. Each outside recirculation pump is normally isolated from the corresponding LHSI pump by a pair of series manual isolation valves. They are operated from outside the safeguards building with a T-handle wrench inserted into the associated remote valve operator (a recessed, square-shaped hole in a round, brass device).

### **A.7.2 Fault Tree Analysis**

The Safety Injection system was modeled as a front line system, providing several safety functions.

- D1 - Failure to provide high pressure coolant injection from the RWST using 1/3 HHSI pumps.
- D2 - Failure of the Accumulators to inject water into the cold legs. The success criteria for D2 are 2/2 for large LOCA, 2/3 for intermediate LOCA, and 3/3 for core cooling recovery.
- D3 - Failure to provide low pressure coolant injection from the RWST using 1/2 LHSI pumps.
- Dh - Failure to provide coolant injection flow to the RCS hot legs using 1/2 LHSI pumps in the Containment Sump recirculation mode.
- H1 - Failure to provide low head coolant injection from the Containment Sump, using 1/2 LHSI pumps.
- H2 - Failure to provide high head coolant injection from the Containment Sump, using the piggyback recirculation mode.
- P - Failure to support feed and bleed cooling by providing 1/3 HHSI pumps injecting from the RWST.

The assumption and notes used to develop the Safety Injection system fault trees are contained in Table A.7-5. The assumptions and notes used to develop the safety injection actuation system fault tree follow.

#### **Safety Injection Fault Tree Modeling Assumptions**

1. Variations in boron concentration were not included in the failure analysis. Boron concentration is controlled by Technical Specification to a much narrower range than that required by the PRA. In fact, there are no explicit boron requirements of the accumulators in the PRA. This is because the probability of being out of tolerance enough to have any impact is generally considered (in all past PRA's) to be negligible.
2. Variations in water level and pressure were not considered included in the fault tree model. Water level and pressure are constantly monitored by Technical Specifications. These parameters are annunciated if out of specification.

3. The probability of the discharge valve (1-SI-MOV-1865A/B/C) being inadvertently closed at the time of the initiator was considered negligible in comparison to other faults. The following reasons apply:
  - a) failure to be fully open is annunciated
  - b) the valve is designed to be fully open or fully closed.
4. The loop selected for the break is not important. All valves receive redundant signals to open.
5. Stroke test interval for 1-SI-MOV-1865A/B/C valves is assumed to be 18 months.
6. Failure of the LHSI pump due to failure of seal cooling was not explicitly modeled. The seal cooling for LHSI pumps is self contained and principally passive. The water level on the seal head tank is constantly monitored and annunciated. Failure of seal cooling is considered to be included in the component boundary of the pump.
7. Failure of bearing cooling to the pump was not explicitly modeled. There is no external cooling supplied for the bearings. As long as the pumped stream is within the design temperature of the pump, the bearing temperatures are considered acceptable. Failure of the bearings for all causes is considered to be within the component boundary of the pump for pump failure, although the accident sequence delineation does not allow the pump to operate if the sump water temperature is over the pump design temperature.
8. Motor heating failures and trace heating failures were not modeled explicitly. The LHSI pumps have no external cooling. All pump failures due to loss of the internal cooling mechanisms are considered within the component boundary of the pump.
9. Misposition errors were not postulated for valves which get an open (or close signal) on an SI.
10. 1-SI-MOV-1890A and B are normally closed and have power removed.
11. Failure of one LHSI pump due to dead-heading when the 1885 valves are open, was not postulated. This assumption represents the resolution of NRC concern expressed in Information Notice 87-59. If two pumps share a common recirc line, a slightly higher discharge pressure in one pump could deadhead the other pump. At North Anna, each LHSI pump has a 2 inch minimum flow recirculation line feeding into a 3 inch common header. Due to the quarterly measuring of the

discharge head during the pump test and the 2 to 3 inch pipe size increase, the possibility of having conditions where the NRC concern was applicable was considered negligible. Dead heading of the LHSI pumps due to valve blockage in the minimum flow line or misposition of an 1885 valve were explicitly modeled. These faults are considered of much higher probability than the NRC scenario.

12. Containment sump valves 1-SI-MOV-1860A/B were considered to have a flow test frequency of 5 years, although they are never flow tested, only stroked. This assumption provides a plugging failure probability of  $2.63\text{E-}3$ , compared to a valve fail to open probability of  $1.09\text{E-}2$ .
13. 1-SI-MOV-1864A/B and 1-SI-MOV-1890C/D are flow tested every refueling. 1-SI-MOV-1862A/B are flow tested at 400 gpm every month.
14. As 1-SI-MOV-1863A/B are periodically flow tested, and they are normally closed valves, a plugging failure mode for these valves was not included. The general guideline for the fault tree analysis was that if an active failure mode is postulated for an MOV, there is no reason to include a plugging failure mode also. 1-SI-MOV-1860A/B are the exception to that guideline.
15. Restoration error for 1-QS-38 (Unit 1) and 2-QS-33 (Unit 2) was not postulated, because it is often flowed and under administrative control if it is ever closed. Its position is vicariously verified by every LHSI pump test (PT-57.1). The probability of a restoration error and a valve demand before the next pump test is considered to be small compared to the plugging fault. A plugging fault for 2-QS-33 or 1-QS-38 was postulated with a test interval of three months (PT-57.1).
16. North Anna MAAP analysis shows that the maximum sump water temperature at the time of recirculation, for all transients considered in the IPE, is well within the  $250^{\circ}\text{F}$  design temperature of the pump (which is limited by the graphite bearing assembly).
17. Common cause miscalibration of multiple 1845 relief valves is not modeled.
18. It is assumed that LHSI header pressure will not get high enough in a large LOCA to lift a relief valve.
19. In the event that 1-SI-SV-1845B opens, and the operator diagnoses the event and isolates the valve, equipment failures in the alternate injection paths are not modeled. It is assumed that one hot leg injection path or HHSR path will be available.

28. The running pump is not stopped on an SI signal; rather it continues to run.
29. A third pump can be started if another pump fails. In order to have a third pump available, pump 1C must be on H.
30. Two Charging pumps are required by Tech Spec and thus one of the three pumps can theoretically be out of service forever. Two pumps can be out of service for 24 hours. This is handled in the fault tree as follows:

The A pump is assumed to be running. The B and C pumps are both assigned a term for scheduled maintenance (TM) and unscheduled maintenance (UM). Both frequencies will come from plant specific data. All incidences when two pumps are in maintenance at the same time are lumped together, and this event is applied to both the B and C pumps. All maintenance events involving single pumps are similarly lumped and this event probability is applied to the C pump only. Unavailability due to pump tests are applied to the B and C pumps. Because two pumps can be out of service for up to 24 hours, the combination of pump B in TM and pump C in UM is an allowed cutset.

31. Isolation of charging flow (by closure of 1-CH-MOV-1289A/B) is not necessary for success of HHSI. This is not a flow diversion, as the flow goes to the RCS.
32. Service water to the lube oil coolers (1-CH-E-5A/B/C) and the gear box coolers is required when the Charging pumps are in the SI mode. Although SW has been lost at Surry, for up to 4 hours in the charging mode, with continued pump operation, there is no evidence that the pumps could operate in the SI mode without service water.
33. Because of the piping configuration of the service water supply headers, the requirement of service water to the gear box cooler will also assure supply of service water to the seal coolers, although it is not known if seal coolers are required.
34. HVAC in the charging pump cubicles is assumed not to be required for successful Charging pump operation throughout the 24 hour mission time.
35. Minimum flow lines were ignored for LOCAs and all transients with scram. For these events, RCS pressure is below 2250 psi and thus there will be flow into the RCS, thus negating the need for mini-flow line operation, if the discharge MOV (1286A/B/C) is open.

20. As the mission time for the injection phase of LHSI is one hour, system failure due to inadvertent opening of a relief valve was not modeled. At 180 gpm, the total flow in one hour would be 10,000 gallons. This is not enough diversion from the RWST to cause insufficient inventory. Nor is it enough to cause flooding of the safeguards area.
21. The cross tie between the recirculation spray system and the LHSI system is not used and was not modeled.
22. Operator action to allow injection through 1-SI-MOV-1836, in the event 1-SI-MOV-1867A/B/C/D fail was included for all initiators. The same operator error probability was used for all initiators.
23. The volume control tank must isolate in order to prevent cavitation of the charging pumps, even if both RWST valves open.
24. Cross tie to the other unit's charging will be modeled in the recovery analysis if necessary. Cross tie requires local operation of two manual valves in the auxiliary building. It is estimated that cross tie will require 20 minutes to accomplish. It is not directed by 1-FR-C.1 as is the case for Surry. The cross tie procedure, 0-AP-48 directs both reactors to be tripped in order to perform the procedure. The time and procedural direction for the set-up of cross tie is not certain at this point in the analysis.
25. One charging pump is running at all times. It was modeled as the 1A pump. The 1B pump is modeled as in standby and on the J Bus, and 1C is modeled as racked into the H bus, and in the "autoq-after-stop" condition. In this condition, it will not receive any signals, but can quickly be activated from the control room.
26. Charging pump 1A is dedicated to bus H. Charging pump 1B is dedicated to bus J. Charging pump 1C can be powered from the H or the J bus. H is the normal alignment for Charging pump 1C. There are several interlocks on breaker position to prevent crosstie of the buses through the pump 1C. If pump 1C is on the J bus, it must be running. 1C receives no auto-signals on the J bus. Only one pump can be aligned to the J bus at one time. Two pumps (1A & 1C) can be operating on H at one time (during pump test). If a loss of offsite power occurs during this time, both pumps are tripped off the bus, to prevent the diesel from loading onto a loaded bus.
27. Generally, only 2 Charging pumps will receive an autostart signal. If 1C is on the J bus, then only the 1A pump will receive an autostart. If 1C is on J, then by Administrative procedures, 1C is running.



36. If 1-CH-MOV-1286A/B/C is closed, mini-flow is assumed required to prevent pump dead head and subsequent failure.
37. Monthly testing per 1-PT-14.1, 1-PT-14.2 and 1-PT-14.3 makes the pump unavailable unless the operator takes action to open the discharge valve.
38. MOV test duration per 1-PT-212.1/2/3 or 213.1/2/3 is so short, it was not considered as an impact on system operation.
39. For recirculation from the sump, either LHSI, injecting through either 1-SI-MOV-1863A or B is sufficient to supply flow to two operating charging pumps. Either check valve 1-SI-47 must close or both MOV-1115D and 1115B must close in order to isolate the RWST. The calculation below is used to justify that sufficient hydraulic force is present to close the check valve. If the check valve operates, the head from the LHSI will keep the valve closed and thus, MOV-1115B and MOV-1115D do not have to close.

Design flow for 1 LHSI pump is 3250 gpm. Runout flow for a Charging pump is 600 gpm. Under piggyback recirc at high RCS pressure, one LHSI pump could supply up to 2050 gpm surplus flow to reseal check valve 1-SI-47 in the event MOV-1115B or MOV-1115D failed to reclose. 1-SI-47 is in an 8" line. Surplus flow of 2050 gpm would result in a back flow of 13.2 ft/sec.

40. The auxiliary oil pump on each Charging Pump was not modeled. The aux. oil pump is constantly running in the standby pumps to circulate the oil. During normal Charging Pump operation, a shaft driven pump provides lubrication. The aux oil pump is needed for initial start, before the shaft driven pump gets up to speed. It was not included for two reasons; either one is sufficient:
  - a) Start of the Charging Pump without the aux oil pump, on a one time basis is not damaging, according to the manufacturer. Repeated dry starts would degrade pump life.
  - b) Failure of the aux oil pump would be a revealed fault. The probability of an initiator simultaneous with a failed aux oil pump is very low.
41. Failure of trace heating is a revealed fault (through instrumentation) and thus not included in the fault tree.
42. The standby Charging Pump will start upon failure of the running pump on low discharge header pressure. This is a non-SI signal.

43. Resolution of NRC Information Notice 88-23 - "Potential for Gas Binding of SI Pumps" is as follows: HHSI suction piping is periodically vented. Records show a typical gas volume of .3ft<sup>3</sup> - .4ft<sup>3</sup>. This level is consistent and supports the position that the CHPs can tolerate this amount of gas flow through without any pump damage.
44. 1-CH-MOV-1115C/E will not close unless interlocks from limit switches on 1-CH-MOV-1115B/D are satisfied. The limit switches provide more redundancy and reliability than the MOVs. The interlock was therefore not included in the fault tree.
45. RWST failures and suction failures were assumed to fail all pumps by cavitation before operator action could be taken.
46. 1-QS-38 [2-QS-33 for unit 2] is a manual valve on the discharge of the RWST. Its failure represents a single point failure for the HHSI and LHSI system. Three failure modes have been postulated for this valve, plugging, closed for test or maintenance, and failure to restore after maintenance. Each of these are discussed.

a) Closed for maintenance: No PTs were discovered which require closing of the valve during power operations. Closing of the valve would be on an infrequent, as needed basis to support maintenance activities. The valve could not be closed for more than 4 hours without violating Tech Spec (as it makes both trains of SI unavailable). Therefore, the amount of time the valve could be closed is small and was neglected in the fault tree.

b) Failure to Restore after maintenance: As the valve could be closed during power operation (for whatever reason), there is a probability that it is inadvertently left closed. The valve is vicariously verified open every three months during LHSI pump test, 1-PT-57.1, which requires recirc flow from the LHSI pumps. For the misposition to cause a system failure, an SI demand would have to occur between the time of valve misposition and the next LHSI pump test (this presumes the valve is closed on a far less frequent basis than 1-PT-57.1 is performed). Assuming 1E-3 for failure to restore, 2E-2 for SI demand per year, and LHSI tests every three months, the probability of a valve misposition and a demand prior to the next pump test is:

$$(.001 * .02) / 4 = 5E-6$$

c) The plugging failure probability for a three month test period is 1.3E-4. Plugging therefore seems to be the dominant failure mode for the valve and was the only one included.

47. Pump trips due to interlocks on the breakers being activated by operator errors were not included in the fault tree. These events are revealed faults and are not present at the time of system demand. Modeling these errors during the mission time are errors of commission and are consequently not modeled.
48. Failures of the lube oil heat exchangers 1-CH-E-5A/B/C are included in the component boundary of the charging pump.
49. Failure of the Boron Injection Tank due to flow obstruction is modeled as a TNK-LF (tank-loss of function) failure.

#### **Safety Actuation Fault Tree Modeling Assumptions**

1. Contacts were modeled as part of a relay and not modeled as separate components. For example, a device which starts when a contact is open (energized) will be modeled as a relay which fails to energize. The relay and the contact are actually one component, and there is no significant advantage to separating out the contacts from the relay.
2. SI output signals to MOVs were simplified by only including relays required to actuate the valves to the desired position. Other devices such as limit switches, hand control switches, and torque switches were not included.
3. Modeling of the manual initiation of safety injection and recirculation mode transfer was not included within this fault tree. These human interactions will be included in the SI system fault tree.
4. The SI actuation system has input signals to protect against a LOCA or a Steam Line Break (SLB). All input signals were included within the model. A house event, XHOS-SLB, was included to allow the SI actuation fault tree to be used for LOCA or for SLB initiators. The input signals Related to a SLB were included under an "and" gate with XHOS-SLB. When the house event is equal to 1.0 the SLB signals are allowed to contribute to the SI actuation system unavailability. When the house event is 0.0 then only the LOCA signals contribute to SI system unavailability.
5. Based on a review of SI actuation procedures, SI actuation channels which are bypassed for the purposes of testing are not automatically realigned in the event that SI operation is required.
6. Components for SI actuation train B were generally not shown in system drawings. Train B was drawn in the simplified schematic in a configuration identical to that of Train A.

7. The  $T_{avg}$  input signal to SI actuation requires temperature signals from both hot and cold leg RCS temperature transmitters; however, only a single temperature instrument channel was modeled for each pair of hot/cold leg transmitters.
8. Relay K647 is a permissive relay that is energized when SI actuation occurs and must be energized for the initiation of recirculation mode (i.e., it is assumed that K647 must be energized in conjunction with K630).
9. Failure of the SI actuation reset permissives were not modeled as they had been in the Surry model for the steamline break portion of the SI actuation system. North Anna has several different reset permissives installed for the various inputs which cause SI actuation. Due to the numerous possible inputs which can lead to SI actuation, failure of more than one reset permissive would be necessary, and this contribution to system unavailability is assumed to be insignificant.
10. SI actuation lock-in relays (discussed in the reactor protection systems training manual) are not modeled. Failure of these relays would be revealed immediately and prompt operator action is highly probable.
11. No periodic tests specific to the logic which transfers SI to recirculation mode were identified. It is assumed that this logic is tested with one train operable and one in trip.
12. Common Cause Failure of instrument lines has been modeled where appropriate. The basic events are listed below:
 

1RCTIC-CC-TAVG	CCF of 2/3 Tavg channels
1RCPIC-CC-PRSZRP	CCF of 2/3 Pressurizer pressure channels
1MSPIC-CC-STMDPR	CCF of 2/3 Main Steam line pressure channels
1LMPIC-CC-100	CCF of 2 of 3 containment pressure instrument channels
1MSFIC-CC-MSFLOW	Steam line flow instrument channels
1MSPIC-CC-MSLP	CCF of 2 of 3 steam line pressure instrument channels
1SILIC-CC-RWST	RWST Level Instrument Channel common cause failure - 2/4 channels

13. The following House Event has been used in the SI actuation system fault tree.

XHOS-SLB	The event allows SI input channels associated with Steam Line Break Protection to be included in SI actuation system reliability. When equal to 0.0 SLB signals are not included.
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## **A.8 CONTAINMENT STRUCTURE**

There was no fault tree analysis performed nor dependency matrices developed for the Containment structure. The following descriptive information is provided for general information.

### **A.8.1 Major Components**

The order of presentation of major components is consistent with the discussion in the previous section: concrete structure, steel liner, interior structures, access penetrations, piping penetrations, and electrical penetrations.

#### **Concrete structure**

The concrete structure was constructed from the ground up, and this description follows a similar order of presentation. A circular excavation was made to elevation 203'-7" in order to found the structure on crystalline, metamorphic rock. The excavation methods minimized damage to the sidewalls, which were then reinforced with rock bolts, gunite, and covered with a welded wire fabric. The bottom of the excavation was covered with a 6-inch layer of porous concrete. Porous concrete is permeable to water and performs a drainage function as one part of the scheme to protect the Containment from ground-water corrosion. Porous concrete is formed by omission of the fine aggregate from standard structural concrete mix.

A flexible, polyvinyl chloride sheet with a minimum thickness of 40 mils surrounds the structure below grade. This waterproof membrane is another part of ground-water corrosion protection. The waterproof membrane was laid on top of the 6-inch layer of porous concrete; then another 4-inch layer of porous concrete was poured on top of the membrane. The sidewall of the excavation was covered with fill concrete from the porous concrete level up 10 feet to form a smooth surface. The waterproof membrane was brought up against this and held in place by 4-inch concrete blocks set dry. The 4-inch concrete blocks are also porous.

The containment foundation mat was formed in the 10-foot deep cylinder now existing in the bottom of the excavation. The containment foundation mat, walls, and dome are heavily reinforced with steel reinforcing bars (rebar) and other steel inserts. The largest and most frequently used rebar size is number 18, manufactured with controlled chemical composition and a minimum yield strength of 50,000 psi. The rebar in the bottom part of the mat is placed in a grid pattern. The top part of the mat contains rebar laid in concentric circles with radial spokes. The top pattern is arranged to permit the vertical wall rebar to extend into the mat. Structural concrete was poured and rodded over the mat rebar. During the pours, the temperature of the concrete was carefully controlled and the concrete was sampled frequently. Water was kept puddled on the surface while the concrete cured.

The containment cylinder wall was formed as rebar was placed in identical patterns near the inside and outside wall faces. Each pattern consisted of vertical and horizontal members. The two patterns were connected by rebar inclined at 45-degree diagonal angles in order to resist seismic stresses. Set at 45-degree inclines near the base mat are shear assemblies to resist the loads associated with the containment pressurization resulting from the DBA. The shear assemblies were constructed of 4-inch by 0.75-inch steel plate welded to vertical rebar. The cylinder wall concrete pours were made in 6-foot lifts, in approximately 18-inch layers so that one layer did not set before the following layer was poured. The mold for the inside of the cylinder wall was the containment steel liner (fully described in following paragraphs). After the cylinder wall pours were completed above grade and their outside molds removed, the work between the outside of the cylinder wall and the excavation could be finished. The waterproof membrane was brought around the exposed lip of the containment foundation mat and covered with a 4-inch layer of porous concrete. The waterproof membrane was then brought up around the outside of the cylinder wall to a level approximately 6 inches below finished grade level (270'-6") and fixed to a continuous Nob-lock termination strip embedded in the concrete. The outside of the waterproof membrane was covered with a 2-inch layer of Rodofam soft grade 300, a compressible material, to provide a "rattle-space" between the Containment Structure and the rock excavation. The space remaining between the Rodofam and the rock was filled with concrete backfill. The finished cylinder wall is 4.5 feet thick and rises 127 feet above the top of the containment foundation mat.

The containment dome is a hemisphere with an inside radius of 63 feet. Rebar was placed in a pattern of arced spokes extending in two layers from the center of the dome outward to connect with the rebar in the cylinder wall. Structural concrete was poured for the dome in the same manner as for the mat and cylinder wall. The inside form for concrete placement was the steel liner. The concrete dome is only 2.5 feet thick rather than 4.5 feet thick as in the cylinder wall.

## **Steel liner**

Erection of the steel liner began after completion of the containment foundation mat. The liner completely envelops the interior of the concrete structure to form a gastight membrane. It is constructed of two types of steel: ASTM SA-573, Grade B, quenched and tempered, is used for the first 28'-5" above the mat; and ASTM SA-516, Grade 60, fine-grained and normalized, is used for the rest of the cylinder, mat and dome lining. The liner is anchored at close intervals to the inside of the concrete structure for support and for transfer of loads. It is important to note that the liner does not perform any direct structural function; all loads are ultimately born by the concrete structure. The dimensions of liner thickness are as follows:

1. 0.25-inch thick on the containment foundation mat,
2. 0.375-inch thick on the cylinder wall,
3. 0.5-inch thick on the dome, and
4. 0.75-inch thick under the in-core instrumentation area and sump area.

All seams on the liner are double butt welded. Non-destructive testing, including 100 percent radiography, was performed on all welds. A leak test channel was welded to the back of each seam so that weld leaktightness could be verified as construction progressed. These test channels were connected in zones and capped in place so that they could be used to locate a leak if one were to occur after the plant was placed in operation.

The liner was designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, with Code Addenda through summer 1969. Consequently, no welding directly to the liner is allowed without special written procedures. There are steel insert plates on the liner with additional concrete anchors which have had brackets welded to them, primarily for the support of Quench Spray System piping and spray headers/rings.

## **Interior structures**

The steel liner on the foundation mat is covered with a concrete surface that is generally 2 feet thick, sloped for drainage toward the sump. The purpose of the concrete mat covering is to protect the mat liner from damage which might be caused by internally generated missiles or dropped equipment. This concrete protection does not exist in two areas, beneath the in-core instrumentation and the sump, and that is why the steel liner is thicker in these areas.

Rising above the concrete mat covering are a number of reinforced concrete walls, all of which perform three major functions:

1. equipment structural support;
2. biological shielding, to permit personnel entry during reactor operation; and
3. missile shielding, to protect the steel liner from puncture by internally generated missiles.

The first such wall inside the Containment Structure is the crane support wall. This wall is 2 feet thick and provides biological and missile shielding from the concrete mat covering at elevation 216' to the bend line at elevation 342'. The polar crane rests on top of this wall. The annulus space between the crane support wall and the steel liner houses cable trays, piping, and ducting. The annulus is serviced by a 5-ton monorail hoist and by several levels of grating that are accessible by ladders from the operating floor. Walls interior to the crane support wall are arranged to form equipment support cubicles for major components: three steam generator/reactor coolant pump cubicles and the pressurizer cubicle. Common walls of these cubicles enclose the reactor vessel and form part of the refueling cavity. To shield the containment dome from missiles generated by the failure of a control rod drive mechanism, a 2-foot thick removable reinforced concrete shield plug with a steel plate on the lower side covers the reactor vessel when the plant is in operation.

All interior concrete surfaces and the steel liner are covered with special epoxy coatings to prevent corrosion and to facilitate decontamination in the event of a radioactive spill. These coatings have been tested to prove their adherence during and following DBA conditions. The refueling cavity and the fuel transfer canal are lined with 0.25-inch stainless steel plate which is not coated.

### **Access penetrations**

Access penetrations include the personnel air lock, the equipment hatch, and the emergency personnel escape lock.

The personnel air lock primary point of entry and exit for the Containment Structure. It is located on the west side of the Containment Structure at elevation 291'-10" between Containment and the Auxiliary Building. The lock was fabricated in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class B, Nuclear Vessels, 1968, and bears the 'N' stamp. Additional rebar and anchors were placed in the concrete surrounding the lock for support. The lock is welded to the steel liner. Provisions are made for periodic leak-testing of the lock.



This 7-foot diameter penetration has a hinged closure head (door) inside Containment (the interior door) and one outside Containment (the exterior door). Both doors are sealed to the lock with sets of double O-rings. The space between the O-rings can be pressurized for leak-testing. The doors are electrically interlocked so that only one door may be open at a time (the electrical interlock is part of the hydraulic operating system discussed in the following paragraph). The exterior door is opened and closed manually. The interior door is opened and closed hydraulically and may be closed from inside or outside Containment. Integral to door operation is the operation of two hydraulically operated equalizing valves mounted in the interior of the lock. Prior to opening the inside (outside) door, its associated equalizing valve is opened to equalize air pressure inside the lock with air pressure inside (outside) Containment. The rate of air pressure change inside the lock is limited to 1 psi per minute.

Each door is held closed by a hydraulically operated rotating locking ring. Hydraulic power is normally supplied by a 6-GPM positive displacement pump mounted on top of a 10-gallon oil reservoir, located inside the air lock. The pump is driven by a 125 VDC 5.8 HP electric motor. The pump is started and controlled by electric push-button stations, with door position indication and interlocks, located inside and outside the lock. The hydraulic power performs three functions:

1. equalizes valve operation,
2. rotates door locking ring, and
3. operates interior door.

In the event of an electrical failure, these functions can be performed by hydraulic hand pumps. There are four hand pumps, one interior and one exterior to the lock for each door.

In the center of each door is an 18-inch diameter, manually operated emergency escape hatch. Each emergency escape hatch has a chain-driven equalizing valve. The emergency escape hatches are not interlocked to each other or to the main doors.

The largest penetration to the Containment Structure is the equipment hatch located on the south side of Containment at elevation 291'-10". This opening in the containment wall is 14 feet, 6 inches. It is covered on the inside by a single steel closure head with a removable emergency personnel escape lock and protected on the outside by a concrete missile/radiation shield. The equipment hatch is sized to permit removal of any component from the Containment Structure except the reactor vessel, reactor vessel head, or upper steam generator shells. The steel closure head is sealed to the containment steel liner and to the emergency personnel escape lock by sets of double O-rings. The space between

the O-rings can be tested for leakage by pressurization to containment design pressure (45 psig). A monorail and chain hoists are provided for movement of the equipment hatch.

The emergency personnel escape lock is a 2-foot, 6-inch interior diameter air lock mounted in the equipment hatch. It is intended for emergency egress from Containment when the personnel air lock is inoperable or inaccessible. The design of the emergency personnel escape lock is similar to the personnel air lock. The emergency personnel escape lock doors are manually operated by a handwheel and gear-driven system. The doors are mechanically interlocked to prevent both being open at the same time. The mechanical interlock can be overridden by removal of part of the gear train when containment integrity is not required. The equalizing valves on the emergency personnel escape lock are chain-driven from the door operating system. The rate of change of air pressure in the lock is controlled by the operator. The position of each door is mechanically indicated at the handwheel stations. The emergency personnel escape lock must be removed from the equipment hatch before the equipment hatch can be opened. The emergency personnel escape lock is removed by installing beneath it a cart that rides on v-tracks, disconnecting the swing-bolts that hold the lock to the equipment hatch, and rolling the lock out of Containment.

During construction of the plant, a dome ventilation opening was made in the top center of the Containment Structure. After completion of construction, this penetration was closed by welding on the inside of the steel liner and protected on the outside of Containment by a poured concrete plug.

### **Piping penetrations**

All piping penetrations are constructed of steel in accordance with the Nuclear Power Piping Code, USAS B31.7-1969. All welds are full penetration welds, subjected to 100 percent radiography. There are two basic types of piping penetrations: unsleeved and sleeved. The fuel transfer tube is discussed as a special sleeved penetration.

The unsleeved piping penetration is designed for single pipes which carry cold (less than 150°F) fluids. The pipe is welded to the containment steel liner to continue the gastight membrane, and it is welded to reinforcement plates embedded in the containment concrete for structural support.

The sleeved piping penetration is designed for multiple pipes (typically instrumentation tubing) or single pipes which carry hot (greater than 150°F) fluids. The sleeve is welded to the containment steel liner to continue the gastight membrane and is welded to reinforcement plates embedded in the containment concrete

for structural support. The pipe(s) is (are) welded to the sleeve. The sleeved penetrations for pipes carrying hot fluids are insulated and cooled to reduce the deleterious structural effects of elevated concrete temperature. There are two coolers on each of these penetrations: one is full length and located below the sleeve and pipe; and the other is part length and located outside the sleeve, close to the liner. Cooling water to both coolers is furnished from the containment side so that no extra penetrations are required for cooling. Cooling water comes from the Component Cooling System, as the primary source, and from the Service Water System as the alternate source.

The fuel transfer tube penetration design is similar to a sleeved piping penetration. The purpose of the fuel transfer tube is to facilitate the movement of reactor fuel assemblies between the refueling cavity in the Containment Structure and the spent fuel pit in the Fuel Building. Since each end of the sleeve is anchored to a different building, several bellows assemblies are used to allow for movement between the buildings and for thermal movement.

### **Electrical penetrations**

Electrical penetrations employ two basic design concepts for leaktightness: canister and compression fitting. With both designs, a sleeve is welded to the containment liner for continuation of the gastight membrane. A leak test channel is welded to the liner and sleeve. The sleeve is flanged at both ends.

Type V medium voltage penetrations for 4160 volt cables employ the canister design mounted in a 12-inch diameter sleeve. A leaktight cylinder with internal stiffeners for supporting the conductors is welded to a 12-inch flat-faced flange. Three conductors penetrate the canister flange and canister. The canister flange is bolted to the sleeve flange on the Cable Vault side and is sealed to the sleeve flange with a set of double O-rings. The canister is normally pressurized with dry nitrogen to 15 psig. A pressure gage is provided to detect leakage from the canister. A tap is provided to periodically test for leakage from the space between the O-rings. The canister is bolted to the containment side flange for structural support (not as a barrier to leakage).

All other penetrations types (type I instrumentation and control, type II low voltage power, type III nuclear instrumentation, and type IV thermocouples) use the compression fitting design. On these types of electrical penetrations, a bolted flat-faced flange is sealed to the 6-inch sleeve flange on the Cable Vault side with a double set of O-rings. A number of holes are drilled in the flange face and tapped with NPT threads. A compression fitting seals between the flange face and a feedthrough assembly. The feedthrough assembly is fabricated by drilling holes slightly

larger than the conductor diameter in cylinders of polysulfone (a radiation-resistant plastic with a high dielectric constant) of approximately 1-inch lengths. Solid copper conductors are then inserted in the drilled polysulfone cylinders, and the entire assembly is sheathed by a stainless steel tube. The completed assembly is turned in a special lathe which seals the polysulfone cylinders to each other and to the conductors. A small hole is drilled in the stainless steel tube near one end of the feedthrough assembly. That hole lines up with a similar hole in the compression fitting and a machined canal in the flange. The machined canal from each feedthrough assembly converges on one common tapped hole containing a pressure gage and fill assembly. This space is normally filled with dry nitrogen pressurized to 15 psig, and the pressure gage is periodically monitored to detect leakage from the feedthrough assemblies.

After a fire at Browns Ferry Nuclear Power Plant, in an area similar to the North Anna Cable Vault, the Nuclear Regulatory Commission (NRC) placed increased emphasis at all plants on fire prevention and protection, and on the separation of cables carrying redundant safety signals (see 10CFR50, Appendix R, for a licensing description of the rules). The insulation and jacketing covering all cables in the Cable Vault is made of tested flame-retardant material. The Cable Vault and the annulus area in Containment have fire detection and protection systems. To limit flame spreading, all electrical penetrations are mounted 2 feet apart on centers, and redundant safety channels are separated by at least one penetration. The penetrations are protected from missile damage by the cable vault structure on one side and by the polar crane support wall on the other side. On Unit 2, Design Change 81-S21B backfitted secondary overload protection on all electrical penetrations providing safety-related power. The secondary protection, in the form of additional circuit breakers, fuses, or protective relays, was necessary to ensure the mechanical integrity of the electrical penetrations in the event of a short circuit.

## **A.9 ELECTRICAL POWER DISTRIBUTION SYSTEM**

The Electrical Power Distribution System is divided into two parts, the Emergency Electrical (EE) Distribution System and the Normal Electrical Power (EP) Distribution System. The Emergency Electrical Power Distribution System provides AC and DC power to safety related components. The normal electrical power system provides AC power to non safety related components. The Normal Electrical Power System receives its electricity from off site transmission lines or from the Unit 1 or 2 main electrical power generators. The Emergency Electrical Power System receives its electricity from the Normal Electrical Power System or from emergency diesel generators.

### **A.9.1 Emergency Power System**

The Emergency Electrical Power at Unit 1 consists of two 4160 V buses, four 480 V buses, eleven 480V motor control centers, four 120 VAC vital instrumentation buses, four 125 VDC buses, two dedicated diesel generators, and their associated breakers, transformers, uninterruptible power supplies, and batteries. The EE System at Unit 2 is symmetric to Unit 1.

The following description applies to the EE System at Unit 1. Since the EE System is symmetrical to Unit 2, the description is equally applicable with the appropriate change of designator (2H for 1H, 2J for 1J). Each 4160 V bus is normally powered from the switchyard. Upon loss of offsite power the supply breakers open, the diesel generators start and their associated EDG output breakers close to load the diesels on the emergency buses. North Anna Power Station has four emergency diesel generators, one dedicated to each 4160 V emergency bus. Each diesel is a self contained, self cooled unit with its own air system and battery for control power and generator field flashing. The diesel battery is independent of the station batteries. The 4160 V buses provide power to the large pumps such as the HHSI, LHSI, and AFW pumps. The 4160 V stub buses each power one CC and Residual Heat Removal pump. The stub bus is shed on undervoltage on the main bus and must be reloaded by the operator.

The 1H 4160 V bus feeds two 480 V buses (1H and 1H1) through separate transformers. The 1H1 480 V bus is primarily used to power small pumps and an MCC. The 1H 480 V bus feeds five motor control centers (MCCs). MCC 1H1 provides power to three uninterruptible power supplies used to charge the DC batteries, and power to the 1-I and 1-II 120 VAC vital instrumentation buses. The 1J buses have a similar arrangement.

The 125 VDC bus provides control power to the switchgear for the pumps powered from the 4160 V buses. The 125 VDC buses are powered from a 480 V bus, as noted above, and in the event of loss of the AC power source, is powered from DC battery.

A simplified electrical diagram of the Emergency Electrical System, including the relevant portions of the uninterruptible power supply, is included in Figure A.9.1.

#### **A.9.1.1 Emergency Electrical Buses and MCCs**

##### **4160 V emergency buses**

The 4160 V emergency buses 1H and 1J are located along the south end of the Unit 1 Emergency Switchgear and Relay Rooms on the 254 foot elevation of the Service Building. The emergency buses are

color coded orange for bus 1H and purple for bus 1J and are separated by a cement wall.

The 4160 V emergency buses are physically divided into two panels. Each panel consists of cubicles that house various breakers and are arranged to form a passageway between the two panels. Air circuit breakers (ACB) 15H12 and 15J12 are called stub bus breakers. They connect a short bus, called the "stub bus," to the main bus bars in the emergency panels. On emergency bus 1H, the stub bus consists of the breaker cabinets for ACB 15H13, 15H14, and 15H15. The 1J stub bus consists of only two breaker cabinets, ACB 15J13 and 15J14. The purpose of the stub bus is to provide a quick reduction in the amount of load on the bus in a degraded bus voltage situation. By having the stub bus breaker open to de-energize the loads on the stub bus, each load breaker does not require degraded voltage protection. The stub bus breaker is tripped and locked out when a containment depressurization actuation signal exists.

The Unit 2 4160 V 2H and 2J buses can be interconnected by a breaker that is normally removed from its cubicle, located on the H bus. The ability to interconnect the two emergency buses provides a second source of power to an emergency bus if the normal source (and diesel) is not available. This breaker is under strict operational supervision of the station's supervisory staff to prevent inadvertent interconnection of the two emergency trains and is provided for maintenance purposes only. The Unit 1 emergency bus tie breaker has been removed because the alternate source breakers to normal buses 1B and 2B provide the second source of power to each emergency bus.

#### **480 V emergency buses**

The 4160 V emergency buses provide power to four 480 V emergency buses: 1H, 1H1, 1J, and 1J1. The 480 V emergency buses 1H and 1J are located north of their respective 4160 V bus in the Unit 1 Emergency Switchgear and Relay Rooms. The 480 V emergency buses 1H1 and 1J1 are located in the Rod Drive Room on the 280-foot level of the Auxiliary Building. Each of the 480 V buses houses its own 4160/480 V transformer and some major load breakers.

#### **Emergency motor control centers**

The MCC panels provide for the distribution of power to various 480 V loads. There are four MCCs associated with the H train and three associated with the J train. The MCCs are located in the Emergency Switchgear Room, the Cable Vault, and the Service Water Pump House. MCC 1H1-2 and 1J1-2 are divided into two panels that are physically back to back. As a result of their physical arrangement, each panel has a north and south side and the designations 1H1-2N (1J1-2N) and 1H1-2S (1J1-2S) are used.

### **Semi-vital and vital buses**

There are three 120 to 240 VAC semi-vital buses and four 120 VAC vital buses located in the Main Control Room (MCR) area. These buses are constructed like a typical lighting panel. Each load has a light switch-type circuit breaker with an ON/OFF position and trips to a middle position on an electrical fault. The four vital buses are color coded as follows:

1. vital bus 1-I red
2. vital bus 1-II white
3. vital bus 1-III blue
4. vital bus 1-IV yellow

There are four 125 VDC panels located along the north wall of the Unit 1 Emergency Switchgear and Relay Rooms. Each panel is connected to an associated station battery and provides for distribution of DC power for breaker controls. Each 125 VDC panel is color coded the same as the respective vital bus that is supplied from the DC panel. The circuit breakers are of the molded-case type suitable for 125 VDC two-wire service. Each circuit breaker has thermal and magnetic trip elements. The instantaneous magnetic elements are set to trip at ten times the current rating of the breakers. Thermal trips in the DC pump breakers are omitted.

Each 125 VDC cabinet is supplied with a noninterrupting testing system for each breaker whose rating is not over 100 amperes. Testing is achieved by replacing sources for each load by means of a 100 ampere, normally open test circuit from an adjacent cabinet. Test jacks are then used between the test circuit breaker and each branch circuit breaker to be tested. A positive and negative white light is used to indicate a ground on one of the two phases. A test circuit connection is provided between panels 1-I and 1-II, and panels 1-III and 1-IV. Each switchboard can be used as a test supply to the other, as required. Key interlocks are provided to prevent the simultaneous closing of both test breakers. Grounds on all breakers greater than 100 amperes can be found by process of elimination.

#### **A.9.1.2 125 VDC Distribution System**

### **Battery chargers**

The battery chargers provide 125 VDC to the 125 VDC buses and maintain the 125 VDC batteries at full charge. The battery

chargers are located in the Emergency Switchgear and Relay Rooms on the 254 foot level of the Service Building. The chargers are designed to produce a constant output voltage of 132 VDC over a current range of 0 to 250 amperes with a ripple voltage of less than 50 millivolts. Nominal output current is 225 amperes. Above 275 amperes (110 percent of rated current) the chargers become current limiting.

Each normal battery charger supplies power to one 125 VDC panel.

1. Normal battery charger 1-I supplies 125 VDC panel 1-I.
2. Normal battery charger 1-II supplies 125 VDC panel 1-II.
3. Normal battery charger 1-III supplies 125 VDC panel 1-III.
4. Normal battery charger 1-IV supplies 125 VDC panel 1-IV.

Two swing battery chargers supply power to one of two 125 VDC panels.

1. Swing battery charger 1C-I supplies 125 VDC panel 1-I or 1-II.
2. Swing battery charger 1C-IV supplies 125 VDC panel 1-III or 1-IV.

Key interlocked circuit breakers prevent the swing battery chargers from providing power simultaneously to both of its associated panels. The battery chargers are designed to operate in parallel if required. The battery chargers receive 480 V input power from the two safeguard trains. MCC 1H1-4 supplies input power to:

1. normal battery charger 1-I,
2. swing battery charger 1C-I, and
3. normal battery charger 1-II.

MCC 1J1-1 supplies input power to:

1. normal battery charger 1-III,
2. swing battery charger 1C-IV, and
3. normal battery charger 1-IV.

The battery chargers are designed to supply output voltage within 1 percent of the setpoint voltage over the full current output range, as long as the input voltage variation is within 10 percent and the input frequency is within 5 percent.



Each battery charger receives 480 V input power through an AC supply breaker. The AC supply breaker is controlled from the front of the battery charger panel and provides isolation of the charger power circuit from the AC source and protects the charger against damage from internal faults.

The AC breaker feeds a power transformer that isolates the AC and DC circuits, steps down the AC voltage, and supplies the AC to DC converter from its secondary windings. Conversion of AC to DC occurs in the silicon controlled rectifier (SCR) section of the charger. The SCR section consists of three phase-controlled SCRs and three diodes arranged to form a six-phase bridge rectifier. Control of the bridge rectifier is accomplished by the control amplifier. The control amplifier senses output DC voltage and compares it to a reference signal. The resulting error signal is used to control the output of the output DC voltage by varying the firing angle of the SCRs. The SCRs remain in a non-conducting condition until they have been activated by a signal from the control amplifier. If the gating signal appears later in each half cycle, the conduction interval for the bridge is reduced and, as a result, the output DC voltage is lower.

The control amplifier also contains a current limiting transformer. As the output current increases above 110 percent, the current limiting transformer takes over control of the SCRs and operates to maintain a constant output current. During a constant output current operation, the output voltage decreases as any additional DC load is applied.

Each battery charger supplies 132 VDC output power through a DC breaker during the normal float battery charge and 139.8 VDC during an equalizer battery charge. The DC breaker is controlled from the front of the battery charger panel and protects the charger against internal faults. It also allows connecting/isolating the associated 125 VDC panel and battery.

## **Batteries**

There are four 125 VDC, 60-cell, lead calcium batteries per unit. Each battery is contained in an individual, missile-protected room with its own ventilation fan. Battery Rooms 1-I and 1-III are located in the Unit 1 Cable Tray Rooms on the 294-foot elevation of the Service Building; and Battery Rooms 1-II and 1-IV are located in the Unit 1 Emergency Switchgear and Relay Rooms. Each room contains two smoke detectors and a temperature detector.

Each battery consists of 60 lead-acid battery cells. Each cell has a typical voltage of 2.17 to 2.25 volts. The 60 cells are arranged in series to produce a total battery output voltage of 125 VDC. Each cell has 12 negative plates and 11 positive plates. The positive plates are electrically arranged in parallel and hang from

a bridge. The negative plates are also electrically arranged in parallel, but they are supported from the bottom. A microporous rubber separator is placed between each positive and negative plate to prevent any physical contact between them.

Each battery cell is contained in a sealed, heat-resistant, shock-absorbent, clear plastic jar. The use of clear plastic allows quick visual checks of electrolyte level in the cells. A high electrolyte level can lead to a loss of electrolyte during an equalizer charge, and a low level can lead to plate damage. The plates in each cell are made of lead calcium alloy. Each of the battery cells is sealed to prevent entry of dirt or other foreign material and to reduce evaporation of the electrolyte. Distilled water is added as required to maintain electrolyte level. Each cell cover has a ceramic dome to allow built-up gases to escape. Sediment space is built into the cell jar to accommodate the accumulation of sediment for the lifetime of the cell. The typical specific gravity for a fully charged battery at 77°F is 1.210.

Battery capacities are rated on an ampere-hour basis (their ability to deliver a certain number of amperes for a specified number of hours before the cell voltage drops to a specified minimum value). The station batteries are rated at 225 amperes for an 8-hour period or 1800 ampere-hours. During discharge, every battery has a minimum or final cell voltage at which the battery no longer produces any useful power. The minimum or final cell voltage for the station batteries is 1.75 volts (total battery voltage of 105 VDC). Battery capacity is measured periodically under the Periodic Test (PT) program.

#### **A.9.1.3 - 120 VAC Distribution System**

##### **Static inverters**

The vital AC power system consists of four separate vital bus panels, each fed independently from an associated 125 VDC/120 VAC, single-phase static inverter. Each inverter's output is rated at a nominal voltage of 118 VAC (+3.02/-2.98 percent at 60 cycles per second  $\pm 1/2$  a cycle per second for any input between 105 and 140 VDC). Static inverter 1-I is rated at 20 kilovolt-amperes (kVA); while inverters 1-II, 1-III, and 1-IV are rated at 15 kVA. Vital bus 1-I has a greater total load requirement than the other three vital buses because it supplies power for the Control Room Annunciator System. The static inverters are located in the Emergency Switchgear and Relay Rooms.

The inverters are connected to the batteries that are continuously float charged by the battery chargers. Therefore, the effective power sources for the inverters are the 480 V emergency buses. Should effective power source to any battery charger fail, the

inverter is automatically fed from its associated station battery without disturbing the vital bus voltage or frequency. Each inverter has an input and output breaker located at the base of the inverter panel for taking the inverter in and out of service. The inverters are air-cooled by an internal fan. Malfunction of a fan can be detected by an inverter trouble alarm.

The 120 VAC inverter output is developed by alternately switching the polarity of the DC input voltage across a power transformer, thus producing an AC power wave form. Filtering of this wave form produces a sinusoidal AC output. The required switching functions are performed by four silicon controlled rectifiers, which are switched on and off by properly timed logic signals. Filtering action is accomplished by a circuit that blocks harmonic voltages and shunts harmonic currents but passes the fundamental 60-cycle-per-second sine wave.

When starting a static inverter, a pre-charge button is depressed; and, after a short period of time, a red pre-charge light energizes. Pre-charge allows the incoming DC voltage to bypass the local breaker and to charge the filtering capacitors in the output circuit. The local input breaker must never be shut until after the capacitors are fully charged. Shutting the breaker without previously charging the capacitors results in large current surges, breaker overcurrent trip, and possible circuit damage. When the inverter is first placed on the line, it starts up at 120 cycles per second and makes a high-pitched whine. Within a moment, the output is reduced to 60 cycles per second and the familiar 60-cycle hum is heard.

The Unit 2 Appendix R distribution panel can be powered from static inverter 1-I. The panel supplies power to the Unit 2 ex-core neutron flux monitors and auxiliary monitoring panel. Prior to energizing the Appendix R panel from inverter 1-I, vital bus 1-I is transferred to the transformers and the disconnect switch in the Emergency Switchgear Room is opened. The disconnect prevents cross-connecting Unit 1 and Unit 2 power sources.

### **Transfer switches**

There is one two-position, manual transfer switch for each static inverter. The transfer switches for static inverter 1-I and 1-II are located in the Unit 1 MCR Computer Room, and the switches for static inverter 1-III and 1-IV are located in the Unit 1 Logic Room. When the transfer switch is in the inverter to load position, the inverter supplies 120 VAC power to its respective 120 VAC vital bus. In the alternate source to load position, power is provided to the vital buses from the 480 V emergency buses through voltage regulating transformers. If the respective static inverter is deenergized, a mechanical pin is erected to physically block the transfer switch from being placed in the inverter to load position.

After the inverter is re-energized, the pin retracts and the operator may operate the transfer switch. An AC alternate source circuit breaker is provided on each transfer switch for local isolation.

#### **480/120 V transformers**

Voltage regulating transformers fed from 480 V emergency buses are provided to supply 118 VAC  $\pm 2$  percent power to the vital buses in the event either an inverter fails or is undergoing maintenance. Vital buses 1-I and 1-II can be powered from MCC 1H1-4 through two, parallel, 10 kVA transformers. Vital buses 1-III and 1-IV can be powered from MCC 1J1-1 through a single 15 kVA transformer. Because of the power requirements of the vital buses, only one vital bus per train may be placed on the transformers at a time. The transformers are located in the Emergency Switchgear and Relay Rooms.

#### **A.9.1.4 Emergency Electrical System Logic Model**

The Emergency Electrical System is a support system that interfaces with almost all front line safety systems and support systems. The events identified for the Emergency Electrical System represent the modeled interfaces of the Emergency Electrical System with the system requiring electrical power. These interfaces were modeled to the Motor Control Center level. The following buses and MCCs are included in the Emergency Electrical fault trees:

- 4160 V Bus 1H
- 4160 V Bus 1J
- 4160 V Stub Bus 1H
- 4160 V Stub Bus 1J
- 480 V Bus 1H
- 480 V Bus 1H1
- 480 V MCC 1H1-1
- 480 V MCC 1H1-2
- 480 V MCC 1H1-2N
- 480 V MCC 1H1-2S
- 480 V MCC 1H1-3
- 480 V Bus 1J
- 480 V Bus 1J1
- 480 V MCC 1J1-1
- 480 V MCC 1J1-2
- 480 V MCC 1J1-2N
- 480 V MCC 1J1-2S
- 480 V MCC 1J1-3
- 120 VAC Vital Instrumentation Bus 1-I
- 120 VAC Vital Instrumentation Bus 1-II
- 120 VAC Vital Instrumentation Bus 1-III
- 120 VAC Vital Instrumentation Bus 1-IV

125 VDC Bus 1-I  
125 VDC Bus 1-II  
125 VDC Bus 1-III  
125 VDC Bus 1-IV

#### **A.9.1.5 Fault Tree Analysis**

Dependency matrices for the Emergency Electrical Distribution System are shown in Table A.9-1. The Emergency Electrical Distribution System was modeled as a support system for various components, and as such does not have success criteria. For simplicity, in the event of a blackout event trees, electric power from Unit 2 was modeled as a function on the event tree rather than a support system. The success criterion was simply availability of diesel generator 1J.

The notes and assumptions used to develop the electric power fault trees follow. The fault tree for each 4160 V emergency bus is presented at the end of the section.

#### **Emergency Power Distribution Fault Tree Assumptions**

1. The normal electrical power supply for all emergency buses is from offsite power through the Reserve Station Service (RSS) transformers and transfer buses. It is assumed that if either breaker between the transfer bus or emergency bus spuriously opens or if power is lost to the transfer bus, then the normal supply power has failed and can not be recovered through this distribution path.
2. The primary method to recover the 4160 V emergency buses is by using the EDGs. Loss of the normal power supply, offsite power, to an emergency bus is automatically recovered by the degraded/undervoltage protection circuitry which opens the normal supply breakers, starts the EDG and closes the diesel output breaker. Failure to perform these actions is included in the EDG start failure rate. Manual start of the diesel if automatic start fails was included in the EDG fault trees.
3. Restoration of a 4160 V emergency bus if the normal supply path and the EDG have failed is possible by manual operator action which cross ties the emergency bus to other buses which are energized. The procedure for restoring power to the bus and the corresponding HEP basic event is HEP-0AP19. This procedure provides details of how to restore an emergency bus. It is assumed that these procedures will be revised to include the Alternate AC power supplies when the design change is completed.

### **A.9.2 Normal Electrical Power System**

The Normal Electrical Power System consists of switchyard buses, transfer buses, station service buses and intake structure buses. The switchyard buses (500 and 34.5 kV) receive power from the offsite transmission lines and the Unit 1 and 2 main electrical power generators. Three transfer buses connect the switchyard to the emergency buses and to the station service buses. Each unit has three station services 4160 V buses and supply electrical distribution to 480 V and 120 VAC buses. The station service buses receive power from the switchyard through the transfer buses or through the line connecting the main generator to the switchyard. The CW intake structure has two 4160 V buses which supply power to 480 V then to 120 VAC buses.

#### **A.9.2.1 Normal Electrical Buses and MCCs**

The electrical buses and motor control center (MCC) distribution panels are metal enclosures that contain the buses, circuit breakers, instrument transformers, meters, and relays and provide safety for operating personnel.

##### **Transfer buses**

Transfer buses D and E are located in the Unit 1 Switchgear Room in the Service Building at elevation 307 feet, 3 inches. Transfer bus F is located in the Unit 2 Switchgear Room and is physically separated from D and E by the wall that separates the Unit 1 and 2 Switchgear Rooms. Each transfer bus has breakers that connect the bus to the following:

1. an RSS transformer,
2. a bus tie to the associated normal 4160 V bus, and
3. an emergency bus (two emergency buses for transfer bus F).

#### **A.9.2.2 Normal Electric Power System Logic Model**

The key components which receive electrical power from the Normal Electrical Power System are large 4160 V pumps such as the Reactor Coolant (RC), Main Feedwater (MFW), Condensate (CN) and Circulating Water (CW) pumps. The major 4160 V and 480 V buses were included in the fault tree models. The unavailability of buses not included in the model can be approximately by selecting a bus which corresponds to the desired bus.

The Normal Electrical Power Supply was included in the NAPS PRA to show the support system dependencies it provides to the Emergency Electrical Power Supply. The EP system model also allows studying the reliability of non Technical Specification required equipment.

The following buses are included in the EP fault trees:

- 500 kV Switchyard Bus #1
- 500 kV Switchyard Bus #2
- 34.5 kV Switchyard Bus #3
- 34.5 kV Switchyard Bus #4
- 4160 V Transfer Bus 1D
- 4160 V Transfer Bus 1E
- 4160 V Transfer Bus 1F
- 4160 V Intake Bus 1G
- 4160 V Intake Bus 2G
- 4160 V Station Service Bus 1A
- 4160 V Station Service Bus 1B
- 4160 V Station Service Bus 1C
- 4160 V Station Service Bus 2A
- 4160 V Station Service Bus 2B
- 4160 V Station Service Bus 2C
- 480 V Station Service Bus 1A1
- 480 V Station Service Bus 1A2
- 480 V Station Service Bus 1A3
- 480 V Station Service Bus 1B1
- 480 V Station Service Bus 1B2
- 480 V Station Service Bus 1B3
- 480 V Station Service Bus 1C1
- 480 V Station Service Bus 1C2
- 480 V Station Service Bus 2A1
- 480 V Station Service Bus 2A2
- 480 V Station Service Bus 2B1
- 480 V Station Service Bus 2B2
- 480 V Station Service Bus 2C1
- 480 V Station Service Bus 2C2
- 480 V Intake MCC 1G1-1
- 480 V Intake Bus 1G2
- 480 V Intake Bus 1G3
- 480 V Intake MCC 2G1-1
- 480 V Intake Bus 2G2

#### **A.9.3 Degraded and Undervoltage Protection**

To alleviate potential low-voltage profile conditions of the Vital and Emergency Electrical Distribution System during an SI or CDA, there is a load-shedding scheme. When initiated, load-shedding sends tripping signals to specific pieces of equipment based on the position of a "unit startup" switch. The tripping signal trips specified running equipment and defeats the auto-start capability of nonrunning equipment.

Load-shedding ensures sufficient power supply capacity and voltage levels for emergency equipment. The equipment that is affected upon initiation of load-shedding is as follows:

1. All circulating water pump loads automatically trip and lock out during an SI signal if breaker 15G10 is closed. A push-button reset is located on safeguards panel, train B to reset the lockout circuit after the SI signal resets. A G BUS LOAD SHED alarm (window 1D-G5) actuates to inform the operator that the circulating water pumps have been tripped.
2. The 34.5 kV shunt reactor banks automatically trip and lock out during an SI signal. The master trip relay can be reset after the SI signal is reset.
3. The load tap changers for the RSSTs are given a signal to provide instantaneous voltage correction upon the occurrence of an SI signal on either unit.
4. Automatic starting of the component cooling and bearing cooling pumps is blocked for 30 seconds after initiation of the SI signal and 240 seconds after a CDA signal. The blocking circuit resets automatically.
5. Automatic starting of the steam generator feed pumps is blocked for the duration of the SI signal.
6. Automatic starting of the condensate pumps is blocked for 30 seconds after an SI signal and 240 seconds after a CDA signal. The blocking circuit must be reset manually after the required time.
7. If unit bus 2A is being supplied from the RSSTs, the high and low pressure heater drain pumps powered from that bus are tripped and locked out during the occurrence of a Unit 1 SI or CDA.
8. If unit bus 2B is being supplied from the RSSTs, the high and low pressure heater drain pumps, feedwater pumps, and condensate pumps powered from that bus are tripped and locked out during the occurrence of a Unit 1 SI or CDA.

The Vital and Emergency Electrical Distribution System receives offsite power from the three RSS transformers during normal plant operations. The RSS transformers are three-phase, step-down, 34.5 kV to 4160 V transformers and are located west of the intake structure. RSS transformers A and B provide power to emergency buses 1J and 2H through transfer buses D and E. RSS transformer C provides power to emergency buses 1J and 2H through transfer bus F. The cables from RSS transformer C are kept separate from those of



A and B to minimize the possibility of a single accident causing the loss of both emergency trains for either unit.

#### **A.9.4 Breaker Operation**

##### **4160 V breakers**

Each circuit breaker is housed in a cubicle totally enclosed by metal. Access to a breaker is via a metal door that has several retaining screws to hold it closed. All retaining screws are to be fully engaged at all times when the door is closed. The door is opened only when the breaker is to be removed from the cubicle. It is never opened when the breaker is being cycled or moved from one position to another.

The majority of 4160 V breakers are controlled remotely. A few breakers, such as the stub bus breakers and minor distribution breakers, are only controlled locally. Each breaker is provided with a local handswitch. If the breaker is remotely controlled, the local handswitch will only operate when the breaker is in the test position. Operation of the local handswitch on a remotely controlled breaker has no effect while the breaker is in normal service. For locally controlled breakers, such as the stub bus breakers, the local handswitch operates the breaker.

Each breaker is controlled by a local or remote, two-position (OPEN/CLOSE) handswitch. The breaker operates between the open and close position by means of two springs. The closing spring, which moves the breaker from the open position to the closed position, is the larger of the two. This ensures that the breaker can always be closed (if open) with or without control power available. When the handswitch is taken to either position, the breaker is unlatched and the spring forces the breaker to switch positions. As the breaker closes, the opening spring is compressed by the momentum of the breaker. A motor then compresses the closing spring. As the breaker opens, the opening spring provides the motive force for the breaker operation and is left in the non-compressed state. The use of the springs for breaker operation ensures that, on loss of DC control power, every breaker may be cycled at least once.

Inside the breaker cabinet, each 4160 V breaker can be racked to any one of the following four positions:

1. connect - breaker fully racked in; main and auxiliary contacts fully engaged;
2. test - main contacts broken, but auxiliary contacts remain engaged; breaker can be cycled, but no power is delivered to the load;

3. disconnect - all contacts are disengaged; breaker cannot be operated and may be locked in position;
4. remove from cubicle - used to remove breaker from cubicle; breaker charging springs automatically discharge as breaker is removed from this position.

To provide electrical safety during periods of maintenance, each 4160 V breaker has the following three interlocks:

1. racking screw interlock,
2. breaker lock-open interlock, and
3. breaker closed interlock.

The racking screw interlock is a mechanical device that protrudes around the racking screw. It must be rotated 45 degrees to allow the racking screw to be turned. Before the racking screw interlock can be turned to disengage from the racking screw, the breaker must be tripped and the breaker lock-open interlock must not be pulled out. Once the racking screw interlock is rotated, the breaker cannot be closed. The racking screw interlock automatically engages when the breaker is in the connect, test, and disconnect positions.

The breaker lock-open interlock is operable in only the test and disconnect positions. When pulled out, it performs the following functions:

1. Mechanically prevents the racking-screw interlock from being disengaged, thus preventing the breaker from being racked to any other position;
2. mechanically prevents the breaker closing; and
3. provides a means for placing a padlock on the breaker for additional personnel safety while work is being done.

The breaker lock-open interlock cannot be pulled out when the breaker is in the connect position, closed, or when the racking screw interlock is in the disengage position.

The breaker closed interlock mechanically prevents the racking screw interlock from being turned and the breaker lock-open interlock from being pulled out when the breaker is closed.

The 4160 V breakers are operated by 125 VDC power supplied by the battery chargers under normal conditions and supplied by the batteries under loss of power conditions. The power for the H bus breakers comes from battery 1-I (2-I) and the J bus breakers are powered from battery 1-III (2-III). The batteries for the H and J

buses are in locked rooms for security. Control power is fused by two sets of fuses inside the breaker cabinets. One is for closing power and the other is for trip power. The trip power fuses also supply the indicator lights.

#### **480 V breakers**

The breakers in the 480 V Emergency Bus 1H and 1J panels operate similarly to the 4160 V breakers described above. Each 480 V circuit breaker in Emergency Bus 1H and 1J is housed in a cubicle totally enclosed by metal.

The breakers have four positions that are identical to their 4160 V counterparts, as follows:

1. connect,
2. test,
3. disconnect, and
4. remove from cubicle.

The 480 V breakers have three interlocks that are similar to the 4160 V breakers. The interlocks are:

1. racking screw interlock,
2. breaker lock-open interlock, and
3. breaker closed interlock.

The racking screw interlock consists of a mechanical racking window, which must be lifted to crank open the breaker. It cannot be lifted when the breaker is closed, nor can the breaker be closed when the window is lifted. When the window is lifted, the breaker trip button also is engaged, causing the breaker to trip if it is closed. The racking screw interlock automatically engages itself and the window drops back whenever it is in one of the following positions: (a) connect, (b) test, or (c) disconnect. Before the racking screw interlock can be disengaged from the racking screw, the breaker must be tripped and the lock-open interlock not pulled out.

The breaker lock-open interlock is operable in the test, connect, and disconnect positions. When pulled out, it performs the following functions:

1. mechanically prevents the racking-screw interlock from being disengaged, preventing the breaker being racked to any other position;

2. mechanically prevents the breaker from closing;
3. provides a means for placing a padlock on the breaker for additional personnel safety while work is being done.

In order to pull the breaker lock-open interlock out, the trip button must be depressed. Also the breaker must not be closed and the racking screw interlock must be engaged.

The breaker closed interlock mechanically prevents the racking screw window from being opened and the breaker lock-open interlock from being pulled out when the breaker is closed.

#### **480 V MCC breakers**

The 480 volt system is the highest voltage at which contactors can be used to control power to loads. A contactor is a device which uses an electromagnet to close primary electrical contacts. Contactors are used in series with circuit breakers, but they are damaged by attempting to interrupt fault currents. The 480 V MCC breakers use contactors and are housed in a cubicle totally enclosed by metal. Access to the breaker is via a metal door that has several retaining screws to hold it closed. All retaining screws are to be engaged at all times when the door is closed. This door may be opened only for troubleshooting and/or for break removal.

Each 480 V MCC breaker has two interlocks associated with it as follows:

1. breaker closed interlock - located within the breaker control handle, the breaker door panel cannot be opened when in the ON position;
2. breaker lock-open interlock - located within the breaker handle, when the window in the control handle is opened to allow the placement of a padlock, the handle no longer moves; the door cannot be opened and the breaker cannot be closed. This interlock only works when the breaker is off.

The breakers have three positions: ON, TRIP FREE, and OFF. The breakers are provided with magnetic overcurrent protectors, which mechanically trip the breaker on overload. When the breaker is closed, power is supplied to the control circuit through the control power transformer. The contactor can then be closed manually or automatically, and remotely or locally as provided by the control circuit.

## **A.10 RESIDUAL HEAT REMOVAL SYSTEM**

The Residual Heat Removal (RHR) System is a low pressure, low temperature fluid system that is not used during power operations. The system is designed to operate at pressures less than 450 psig and at temperatures less than 350°F. The RHR System and Components are rated for a maximum of 600 psig by design. The RHR system is operated during plant cooldowns after Reactor Coolant System (RCS) pressure and temperature are within the RHR System limitations. The system is also operated after the cooldown until the subsequent plant heatup approaches the system limitations. By procedure, the RHR System is not placed in operation until the RCS is less than 418 psig and 320°F. The primary purpose of the RHR System is to remove decay heat energy, generated in the reactor core, during plant cooldown and refueling operations.

A simplified schematic of the RHR system for those services important for the PRA is shown in Figure A.10-1.

### **A.10.1 Major Components**

#### **Inlet isolation valves**

The inlet to the RHR System is connected to the RCS at a 45° angle on loop "A" hot leg. Two 14-inch, motor-operated gate valves (1-RH-MOV-1700, -1701) isolate the RHR from the RCS when RHR is secured. One of the valves (MOV-1700) is located in the loop room for loop A; the other is located outside the missile barrier on the edge of the catwalk at the RHR flat (a separate mezzanine within Containment). Each valve is a double-disk gate valve equipped with a motor operator, similar to the loop stop valves. The valves have a backseat which minimizes stem leakage with the valve in the open position. Any stem leakage is collected by the Primary Vents and Drains System and sent to the primary drain transfer tank (PDTT). The valves have a handwheel which allows manual operation in the event the motor operator fails. The valves fail in the "as-is" position. When the RHR System is shut down the feeder breakers to the motor operators are locked in the open position to prevent inadvertent closure due to a wide range pressure transmitter failure or operator error.

The valves are controlled from the vertical board in the Main Control Room (MCR) but are interlocked with pressure signals from the RCS loop wide range pressure transmitters. The pressure transmitters (1-RC-PT-1402 and -1403) provide an open permissive signal to the valve control circuit and automatically shut the valve if pressure exceeds preset values.

## **RHR pumps**

Two 300 HP pumps provide the motive force to circulate the coolant through the RHR System. Both pumps are identical; pump 1A is described. Each pump has a suction and discharge manual isolation valve (1-RH-9, -16) which allows isolation of the pump for maintenance. The pump also has a discharge check valve which prevents backflow through a non-operating pump. The inlet piping to the pump is protected from overpressure conditions by a relief valve (1-RH-RV-1721A) which lifts at 467 psig and relieves to the PRT. The relief valve has a capacity of 900 gpm. The capacity of the relief valve is set to relieve the combined flow of all the charging pumps at the relief setpoint. The relief valves also relieve the maximum possible back-leakage through the RHR isolation valves. The suction relief valves also provide RCS overpressure protection in Modes 4 and 5, in the event that no pressurizer safety valves are operable (see Technical Specification 3.4.2).

The pump has a rated capacity of 4000 gpm at a design head of 225 feet and is located on the RHR flat. The pump has three major sections: (a) the hydraulic section, (b) the seals and (c) the motor. The single-stage hydraulic section of the pump is composed of the pump casing and the impeller. The casing and impeller translate the kinetic energy of the impeller into the water, where the volute of the pump casing transforms the velocity head of the coolant into pressure head. The pump discharges to the heat exchangers with the discharge of the pump monitored by a local pressure gage.

The seal section is composed of a mechanical seal and a seal cooler. The mechanical seal is designed for zero leakage, thus an external cooling capability is provided to the seal. A seal pumping ring attached to the pump shaft circulates coolant from the seal to the seal cooler located on the side of the pump. Component cooling water is supplied to the shell side of the cooler and provides the cooling medium for the RHR coolant. The coolant returns to the seal area where it cools and lubricates the seal. Any seal leakage is collected from the pump casing and flows into a telltale drain which leads to a local floor drain.

The pump motor is a 300 HP, 4160 V squirrel cage motor powered from an emergency bus (stub bus). The motor operates at a full load speed of 1773 rpm. The motor has a 120 W space heater and is self cooled and ventilated during operation. The motor is controlled from the vertical board in the MCR, with local operation capability on the RHR pump breaker cubicle door, and is equipped with temperature elements which monitor the temperature of the motor stator, upper motor bearings and lower motor bearings. All the components associated with the pumps are located near the pump on the RHR flat.

A miniflow recirculation line is provided to ensure that the pump does not overheat or vibrate when the system discharge line is isolated. A locked-open manual isolation valve (1-RH-48) is used to establish the design flow through the line. The design flow rate is 500 gpm; however, in pre-operational testing the estimated flow through the line with the valve full open (eight turns) was only 200 gpm, which is considered satisfactory.

Because the RHR pumps have a common recirculation line, operating both pumps simultaneously on recirculation may result in one pump operating at shutoff head. Additionally, to preclude a reduction in the pump operating lifetime, the time that an RHR pump is on recirculation should be minimized.

The common discharge line of the pumps is equipped with a temperature element (1-RH-TE-1604) which monitors the inlet temperature to the heat exchangers. The line also has a pressure transmitter (1-RH-PC-1602) which is used to annunciate a high discharge pressure alarm in the MCR. Before the coolant reaches the heat exchangers there is a 3/8-inch line which is used to sample the RHR coolant at the pump discharge.

### **Heat exchangers**

The RHR pump discharge is directed to two identical heat exchangers arranged in parallel. Each heat exchanger is designed to remove one-half the design heat load of the system (30.5E+6 Btu/hr). Each heat exchanger is a shell and tube type, two-pass heat exchanger. Reactor coolant flows through the 559 tubes, and component cooling water flows through the shell side. The heat exchanger tubes and tubesheet serve as the physical boundary between the two fluid flows, as well as the heat transfer area (4070 square feet).

Each heat exchanger is located on the RHR flat, vertically mounted, and is approximately 16.5 feet tall. The RHR side of the heat exchanger has two drain lines with isolation valves which allow the operator to drain the tube side for maintenance. The heat exchanger has an inlet (1-RH-19) and an outlet (1-RH-24) isolation valve which allow the operator to remove the heat exchanger from service.

### **Flow control valves**

The outlet flow from the heat exchangers is controlled by an air-operated butterfly valve (1-RH-HCV-1758). The valve is physically located on the RHR flat and is used to control the rate of change of RHR temperature during heatup or cooldown. The valve position is varied in response to manually controlled signals from the control located in the MCR. The valve fails in the full open position.

The total flow rate for the RHR System is controlled by flow control valve 1-RH-FCV-1605. The valve controls the heat exchanger bypass flow and is similar in construction to 1-RH-HCV-1758, except that 1-RH-FCV-1605 fails in the shut position. This valve operates in conjunction with a manual-automatic (M/A) station and the output of flow transmitter 1-RH-FT-1605. Design Change 88-01-1 relocated the manual/auto controller for FCV-1605 from the vertical section of the main control board to the benchboard section. It is now located below the station alarm control switch. The controller's new location allows the operator to remain within his normal area while operating the valve manually. The operator establishes the desired system flow rate setpoint using the M/A station; the flow transmitter measures the system flow. The setpoint and actual flow signal are processed to supply a signal to position the valve to achieve the desired flow.

### **System discharge piping**

The combined discharge flow from the heat exchangers and the bypass flow control valve join in a common line. A rate of 200 gpm is returned to the suction of the pumps as previously described and the remainder is discharged from the system. The flow is normally returned to the RCS via the RHR outlet isolation valves but can be routed to the RWST or the RP System. A connection to the Primary Sampling System is also available on the common line. The line is equipped with a temperature element which monitors system outlet temperature.

### **Outlet isolation valves**

The outlet flow from the RHR System is sent to the cold legs of RCS loops B (via 1-RH-MOV-1720A) and C (via 1-RH-MOV-1720B). Each flow path has a 10-inch motor-operated gate valve which isolates the RHR System from the respective loop. The valves have handwheels in addition to the motor operators and are located in the containment basement overhead near its respective SI accumulator discharge line. The valves are similar in construction to the inlet isolation valves. They are controlled from the vertical board in the MCR and fail in the "as-is" position. The downstream sides of the isolation valves connect into the SI accumulator discharge line before they tap into the RCS. If an RHR outlet Isolation Valve were inadvertently opened during normal plant operation the water from the SI accumulator would enter the RHR System until pressure equalized in both systems. This could render the SI accumulator inoperable or overpressurize the RHR System piping. Therefore, when the RHR System is shut down, these valves are closed and the feeder breakers to the motor-operator are opened.



### **A.10.2 Fault Tree Analysis**

The RHR system provides a single function in the entire event tree analysis, that being decay heat removal after Steam Generator tube rupture sequences with loss of Steam Generator integrity. The function is described as:

- W - The success criterion for this function is that one out of two RHR trains successfully provide flow to the RCS.

The notes and assumptions used to develop this fault tree follow. The fault tree is presented at the end of this section.

### **Fault Tree Modeling Assumptions**

The assumptions for this fault tree are contained in two parts: Generic and System Specific. The Generic Assumptions are applicable to additional systems whereas the System Specific Assumptions are intended to apply to this fault tree only.

#### **Generic Assumptions**

1. The RHR system model starts with the junctions of RH & SI piping and the RCS hot & cold leg piping. Plugging or flow blockage in the RCS outside the RHR system limits is not considered.
2. Flow diversions from the RHR system are not considered for the following:
  - RHR pump recirculation line
  - RHR system discharge to the RWST via 1-RH-36 & 1-RH-37
  - RHR flow to the Refueling Purification System via 1-RH-34
  - RHR flow to the CVCS Letdown Line via 1-RH-HCV-1142.
3. Three flow diversions are considered for the RHR system model:
  - RHR flow bypass of the RHR heat exchangers 1-RH-E-1A & B through a failed open 1-RH-FCV-1605
  - RHR flow (backflow) through an idle RHR pump with failed discharge check valve
  - RHR system flow through relief valves 1-RH-RV-1721A and 1-RH-RV-1721B to the PRT.
4. Cooling requirements for the RHR heat exchangers, 1-RH-E-1A&B, and for the RHR pump seal coolers, 1-RH-E-2A&B, are addressed in the Component Cooling fault tree.

## System Specific Fault Tree Modeling Assumptions

The following modeling assumptions are specific for the RH fault tree.

1. The RHR system is assumed to be in standby at the start of the accident. Accordingly, the following MOVs are assumed to be closed:

- 1-RH-MOV-1700
- 1-RH-MOV-1701
- 1-RH-MOV-1720A
- 1-RH-MOV-1720B

Also, interfaces to other systems are assumed to be isolated, specifically:

- RHR discharge to RWST via 1-RH-36
- RHR discharge to CVCS via 1-RH-HCV-1142
- RHR discharge to RPS via 1-RH-34

Finally, the RHR pumps are assumed to be in standby and not running.

2. Common Cause Faults (CCF) are assumed for like standby components which include:

- SI check valves 1-SI-144 & 161 CCF failed closed
- 1-RH-MOV-1720A/B failed closed
- 1-RH-P-1A/B failed to start
- RH pump discharge check valves 1-RH-7 & 15 failed closed

CCF is not assumed for the RHR pump suction MOVs, 1-RH-MOV-1700 and 1-RH-MOV-1701. Since a single fault of either MOV will fail the system, the less probable CCF does not need to be postulated.

3. Per prior assumptions, normally open manual valves in standby trains are assumed to be subject to plugging faults. All RHR manual valves in the RHR flow path are in standby and are assumed to be open, so numerous manual valve plugging faults are included.
4. The flow element orifice 1-RH-FE-1605 is assumed to be subject to a plugging fault as the orifice is normally in standby.
5. The RHR pumps 1-RH-P-1A/B are normally in standby and are modeled with the following standby pump faults: fail to start, fail to run (24 hours), loss of motive and control power, unscheduled maintenance, and loss of CC cooling to RHR pump seal cooler 1-RH-E-2A or B. The pumps are manually started.

6. The RHR pump suction MOVs, 1700 and 1701, have an open permissive interlock which can fail, prohibiting MOV opening. The interlock can be bypassed by operator restoration actions. An interlock fault has been modeled with an AND gate for hardware faults and restoration failure. Hardware faults include instrumentation channel loss of function, and power loss.
7. A flow diversion through 1-RH-FCV-1605 is assumed to fail the system. If 1-RH-FCV-1605 fails open, a 12" pipe flow bypass around the RHR heat exchangers 1-RH-E-1A&B would exist, greatly reducing the RHR flow (and heat transfer) to the heat exchangers. The flow diversion through 1-RH-FCV-1605 will be modeled as an FCV-SO (Flow Control Valve Spuriously Opens) fault. The FO, fails open, fault mode is not appropriate as FO better applies to a SOV (Solenoid Operated Valves) that does not have a control system. Also, recovery from the FO state is simple, by isolating Instrument Air to the operator and allowing the valve to fail closed without motive power. Similarly, the LF (loss of function) fault is not applicable because this failure is recoverable by isolating instrument air to the operator.
8. A flow diversion in the form of backflow through an idle RHR pump is modeled for both RHR pumps. For example, assume 1-RH-P-1A starts and runs. If 1-RH-P-1B fails to start and its discharge check valve 1-RH-7 fails open, the flow from P-1A will be diverted as backflow through the P-1B train. This model is present for both RHR pumps, although the events are mutually exclusive by definition.
9. For the RH fault tree, all NUPRA Failure Mode 2 events assume a 13140 hour interval between testing. This corresponds to an average of 18 months of at power operation between shutdowns requiring RHR system operation.
10. The breakers for the RHR pump suction MOVs 1700 and 1701 are locked in the open position to prevent inadvertent closure due to a wide range pressure transmitter or operator error. An operator action is therefore required to unlock and close the valve breakers. An HEP will not be modeled for this RHR system startup operator action, as it is felt that it would be very low. RHR system startup is well documented in procedures and is addressed in operator training. Also, during a SGTR accident, there are approximately two hours available for RHR system startup, allowing for recovery from errors, verification of human actions, etc.
11. The RHR pump suction MOVs 1700 and 1701 have a handwheel which allows manual operation in the event the motor operator fails. This recovery action was not modeled in the fault tree. If the failure of the inlet isolation valves become a significant

contributor to plant failure in the final quantification, then this recovery action will be added as part of the recovery task.

12. For the pressure channels 1-RC-PT-1402 and 1-RC-PT-1403, it will be assumed that loss of Vital Bus power prior to opening the 1-RH-MOV-1700 and 1701 valves will result as a fault to the MOVs high pressure interlock, inhibiting MOV opening. Normally, loss of power to a controller results in the controller failing in its existing state. If VB power is lost before the MOV high pressure interlock is cleared, the controllers will fail inhibiting MOV opening, which is the controller state during normal power operation (i.e., RCS pressure at 2250 psig). It will be assumed that loss of VB power to the PT-1402 or PT-1403 controllers will result in a failure to clear the RCS high pressure interlock, and will inhibit the opening of MOVs-1700 or 1701.
13. During power operation, the normal RHR system lineup is assumed to be with the RHR heat exchanger A lined up to operate and 1-RH-E-1B isolated. Per this lineup, the 1-RH-E-1B discharge manual valve 1-RH-30 (2-RH-30 for 2-RH-E-1B) is closed isolating RH flow through the 1B RHR heat exchanger. Hence, a MV--FC fault will be assumed for 1-RH-30 while a MV--PG fault is assumed for the 1B HX suction valve 1-RH-25.
14. Flow diversions from 1-RH-RV-1721A and 1-RH-RV-1721B to the Pressurizer Relief Tank are modeled, as a response to NRC IN 90-05. It is further assumed that there is no recovery; and that the relief valve reclosure on depressurization will not occur. (IN 90-05 addresses a Braidwood Unit 1 event on 12/1/89, in which a RHR suction relief valve opened prematurely and failed to reclose during plant heatup following a refueling outage.)
15. The 1-RH-HCV-1758 fault assumed is the AOV-FC fault. During power operation HCV-1758 is kept closed per 1-OP-14.1. Hence, for RHR system operation, HCV-1758 must be opened to flow RH water through the RHR HXs, 1-RH-E-1A and/or B. Note that HCV-1758 is an air operated control valve and is not a SOV. HCV-1758 position varies to maintain a constant RHR water temperature (resulting in a constant RCS water temperature). As a control valve, HCV-1758 could experience the additional fault of spurious closure. However, the SC fault is not modeled because its probability is 2 to 3 orders of magnitude smaller than the FC fault probability. It is also plausible to assume that the SC fault is subsumed within the FC fault.

## **A.11 SERVICE WATER SYSTEM**

The Service Water System is common to both reactor units and is designed for the simultaneous operation of various subsystems and components of both units. The purpose of the SW System is to provide long term cooling after a loss of coolant accident (LOCA) and to supply cooling water to the following safety-related components during normal plant operations:

1. component cooling (CC) heat exchangers;
2. recirculation spray (RS) heat exchangers;
3. control room air conditioning condensers;
4. charging pump seal coolers, gear reducers, lube oil coolers; and
5. instrument air compressors.

The SW System also serves as a backup source of water to the:

1. Auxiliary Feedwater System,
2. spent fuel pit coolers, and
3. containment air recirculation coolers.

The sources of cooling water for the SW System are the SW reservoir and Lake Anna. These two independent sources of water form the ultimate heat sink for the North Anna Power Station.

A simplified schematic of the SW System is shown in Figure A.11-1.

### **A.11.1 Flow Paths**

The SW System has two modes of operation: reservoir-to-reservoir, and lake-to-lake. It is normally operated in the reservoir-to-reservoir mode, which uses the SW reservoir as the ultimate heat sink. The SW reservoir is a large pond with a sufficient supply of treated water to provide cooling for four operating units with one of the four units suffering from a loss of coolant accident (LOCA). There are two spray headers in the reservoir that spray returning SW into the air to assist in dissipating the heat acquired while cooling the various plant components. Each spray header consists of two pairs (four total) of individual controllable spray arrays. The spray arrays can be bypassed by two spray bypass lines (one per header) leading directly to the reservoir.

There are four SW pumps, of which one pump per unit is normally in operation. The pumps draw SW from the reservoir through a set of

traveling screens that filter out debris. The SW pumps provide the motive force for the flow of the SW through the various components cooled by the SW System.

The SW System supplies cooling water through the plant with two supply headers. Two return headers collect the SW from the cooled components and return the water to the reservoir. At the reservoir, the return headers divide the returning SW among the two spray headers or spray bypass lines. Radiation monitors are used to ensure that no radioactive contamination has leaked into the returning SW.

In the lake-to-lake mode of operation, two auxiliary SW pumps draw water directly from Lake Anna through the Circulating Water (CW) System traveling screens. The lake-to-lake mode is used as a backup and during SW System maintenance. The auxiliary SW pumps discharge the SW to the same supply headers as the SW pumps used in the reservoir-to-reservoir mode. The return headers have an auxiliary return header that directs the return SW to the lake. The auxiliary return header is also monitored for radioactivity by a radiation monitor. Two of the CW screen wash pumps serve as makeup pumps for the SW System and can add lake water to the SW reservoir. The auxiliary SW pumps can also be used to provide makeup water to the SW reservoir.

#### **A.11.2 Loads**

There are two SW supply headers, 1 and 2, that provide SW to all the plant components and systems (using SW) in both units. Two supply headers are used to increase the reliability of the system. Each header is capable of providing 100 percent of the necessary SW flow. Remote supply header temperature and flow indication is provided on the safeguards panels.

The headers distribute SW to the following components:

1. four component cooling heat exchangers (two per unit);
2. eight recirculation spray heat exchangers (four per unit);
3. six control room air conditioning units (three per unit);
4. six charging pumps (three per unit):
  - seal coolers,
  - gear reducers, and
  - lube oil coolers; and
5. two instrument air compressors.

The SW System can also provide SW to the following components as a backup source of water in the event that the normal source is not available via normally locked closed isolation valves:

1. Auxiliary Feedwater System,
2. two spent fuel pit coolers, and
3. six containment air recirculation coolers (three per unit).

#### **Component cooling heat exchangers**

Normally there are two CC heat exchangers, 1-CC-E-1A and 2-CC-E-1B, in service during normal plant operations. Each SW supply header can supply SW to any of the four CC heat exchangers. SW supply header 1 normally supplies CC heat exchangers 1-CC-E-1A and 1B through two motor-operated valves (MOVs) 1-SW-MOV-108A and B. SW supply header 2 normally supplies CC heat exchangers 2-CC-E-1A and 1B through 2-SW-MOV-208A and B.

The CC MOVs are normally open and are located in the Auxiliary Building basement. They are operated from the safeguards panels and automatically shut on receipt of a CDA signal. The series arrangement of the SW supply MOVs increases the reliability that at least one valve shuts on receipt of a CDA signal to isolate CC.

From the inlet MOVs, the SW is directed through the tube side of the appropriate CC heat exchanger. In the heat exchanger the heat from the CC System is transferred to the SW in the tubes. A manual inlet and outlet isolation valve is provided for each heat exchanger. The tube side of each heat exchanger is protected from overpressure by a relief valve, which lifts at 150 psig. Each heat exchanger is provided with local inlet and outlet temperature and pressure indication.

The manual valves at the Service Water outlets of each CCHX are throttled so as to limit the minimum SW Pump discharge pressure (and hence prevent pump runout) during an opposite unit CDA with one SW Pump running on each header.

Radiation monitoring pump 9A takes a suction on the SW outlet from each of the CC heat exchangers or from SW return header 4. Radiation monitoring pump 9B takes a suction on the SW return header 3. Both pumps direct the SW sample through radiation monitor 1-RM-SW-107 to detect any CC-to-SW leakage of radioactive material. The samples are returned to either of the SW return headers. The radiation monitor provides indication and an alarm light on the radiation monitoring panel in the Main Control Room.

## **Recirculation spray heat exchangers**

Each unit has four RS heat exchangers that are isolated and drained during normal plant operations. The RS heat exchangers are used during a CDA to cool the RS water that assists the Quench Spray System to depressurize Containment. The RS heat exchangers are used to provide long term cooling after a CDA. SW supply header 1 can supply water to RS heat exchangers A and D through two supply valves, 1-SW-MOV-101A and B. Supply header 2 can supply water to RS heat exchangers B and C through 1-SW-MOV-101C and D.

The RS Heat Exchanger supply and return MOVs (1-SW-MOV-101, 103, 104 and 105 A,B,C & D) are normally shut to facilitate dry layup of RSHXs. This is required due to low fouling design margin.

The RS heat exchanger supply MOVs are normally shut and are located in the Safeguards Area. They are operated from the safeguards panels and automatically open on receipt of a CDA signal. The supply MOVs from each header are piped in parallel to increase the reliability that at least one valve opens on receipt of a CDA signal to provide RS heat exchanger cooling.

Each of the RS heat exchanger supply headers is provided with a check valve. The Auxiliary Feedwater system emergency supply headers are provided from the RS heat exchanger supply lines. The RS heat exchanger supply lines can be cross-connected through two isolation valves, 1-SW-MOV-102A and B. These cross-connect MOVs are located in the Safeguards Area and are controlled from the safeguards panels. Each heat exchanger supply header splits to supply its respective heat exchangers individually.

Each RS heat exchanger is supplied with SW through a normally shut, inlet isolation valve, 1-SW-MOV-103A/B/C/D, and a check valve. The inlet MOVs are located in the Safeguards Area and are controlled from the safeguards panels and the SW logic cabinets. The inlet MOVs receive an open signal on during a CDA. The MOV-103 limit switches are set to limit the MOV maximum open position on CDA opening. This throttling limits the minimum SW pump discharge pressure (and prevents pump runout) during a same-unit CDA with one SW pump on each header running.

From the inlet check valve, the SW is directed through the tube side of the RS heat exchanger. In the heat exchanger, during a CDA, the heat from the RS water is transferred to the SW in the tubes. The RS heat exchangers are provided with overpressure protection by a relief valve on the inlet side, which relieves at 150 psig. A high point vent on the inlet is provided to ensure the complete filling of the heat exchanger during CDA initiation. The vent line connects to the return line from the heat exchanger. The RS heat exchangers are drained during normal operations to minimize the possibility of the heat transfer surfaces becoming fouled.



As the SW leaves the RS heat exchangers, it passes through an outlet isolation valve, 1-SW-MOV-104A/B/C/D. The outlet MOVs are located in the Safeguards Area and are controlled from the safeguards panels and the SW logic cabinets. The outlet MOVs receive an open signal during a CDA. Remote SW temperature and flow indication in the individual return lines is provided on the safeguards panels.

The SW leaving the RS heat exchangers is monitored by the Radiation Monitoring System. Radiation monitoring pumps 5, 6, 7, and 8 start automatically 2 minutes after the receipt of a CDA signal if their respective handswitches are in the normal position. Each pump directs the SW sample through a radiation monitor (1-RM-SW-124, -125, -126, and -127) to detect any RS to SW leakage of radioactive material. The samples are returned to the SW outlet lines. The radiation monitor provides indication and an alarm light on the radiation monitoring panel in the Main Control Room. Design Change 90-12-3 replaced the original Radiation Monitor Pumps with new stainless steel pumps. Pump suction and discharge piping is also stainless steel. This modification will prevent corrosion products from the SW system from clogging the RMS flowpath.

The individual heat exchanger outlet lines combine to form two return headers. The two headers can be cross-connected through two isolation valves, 1-SW-MOV-106A and B. These cross-connect MOVs are located in the Safeguards Area and are controlled from the safeguards panels. The return water from RS heat exchangers A and D is directed to SW return header 4 through isolation valves 1-SW-MOV-105C and D. The water from RS heat exchangers B and C is directed to SW return header 3 through 1-SW-MOV-105A and B.

The RS heat exchanger return MOVs are normally shut and are located in the Safeguards Area. They are operated from the safeguards panels and automatically open on receipt of a CDA signal. The return MOVs from each header are piped in parallel to increase the reliability that at least one valve opens on receipt of a CDA signal to provide RS heat exchanger cooling.

#### **MCR air conditioning units**

There are three control room air conditioning units per unit. SW is provided to the air conditioner condensers, where heat is transferred to the SW from the freon as it condenses. Each supply header can be used to provide SW to the three condensers, which are piped in parallel, through manual inlet and outlet isolation valves on each supply header.

The four-inch Service Water supply and return piping for the Unit 1 Main Control Room chiller units was rerouted and replaced by Design Change Package #89-01-3. This was necessitated due to excessive corrosion, which had resulted in loss of piping

integrity, and leakage. The underground portion of the piping, located between the Unit 1 Main Steam Valve House and the Service Building, was rerouted within six-inch carbon steel sleeves, to allow for future repair or replacement without excavation. The four-inch carbon steel piping was replaced with Type 316L Stainless steel, due to its superior corrosion resistance. The portion of the piping which runs inside of the sleeves is internally supported by lugs welded onto the four-inch pipe.

New stainless steel manual isolation valves are provided at each tie-in point of each of the four four-inch lines. The valves in the Unit 1 Chiller Room are flanged to accommodate the existing piping design. The valves in the basement of the Main Steam Valve House have butt-welded ends. The new supply lines tie in to the upstream flanges on the strainers located in the Chiller Room. The return piping ties in to an existing portion of piping in the Chiller Room.

### **Charging pumps**

SW is provided to the seal coolers, gear reducers, and lube oil coolers of all six charging pumps (three per unit). All six charging pumps are identical and only charging pump 1A is described.

SW flow from either SW supply header is provided through manual isolation valves and check valves. The supply lines join together to form a common supply that provides flow to seal cooler 1, seal cooler 2, and the gear box cooler. The outlet of the gear box cooler can be isolated using a manual flow stop valve. The returns from each of the coolers join to form a single return line. The return line directs SW to either of the two return headers through solenoid-operated isolation valves. A flow switch, 1-SW-FS-102, actuates a CHARGING PUMP 1A SEAL/GEAR BOX COOLER INLET LOW FLOW alarm (window 1B-B7) when a low flow condition is sensed.

The charging pump lube oil coolers are cooled by SW from the service air and Instrument Air compressor supply and return headers. SW from either supply header passes through manual isolation valves and check valves. The supply lines join together to form a common supply that flows through the lube oil cooler. Flow through the cooler is controlled by a temperature control valve, 1-SW-TCV-102A, located on the discharge of the cooler. The temperature control valve controls the SW flow to maintain the oil outlet temperature at 125°F. The common return line directs SW flow to the SW return headers through two manually operated isolation valves.

Flow is sensed on the Charging Pumps seal coolers, gear reducers and lube oil coolers SW return lines headers prior to their entering the main SW return headers 3 & 4. This flow indication is

the combined service water flow from Unit 1 and 2 charging pumps and provides flow indication for the TSC.

### **Instrument Air Compressors**

Service Water flows through an intermediate cooling loop (part of the IA System) for both Instrument Air Compressors in the Auxiliary Building. SW flows from the SW headers to the Instrument Air Compressor supply headers through manual isolation valves and check valves. Each compressor supply header pressure indicates locally. The compressor supply headers also supply SW to the Charging Pump Lube Oil Coolers as previously discussed.

SW can flow to either compressor supply header (via a cross-connect line) through two manual isolation valves piped in series. SW flow through the heat exchangers of the compressor intermediate cooling loops is constant. Compressor and aftercooler temperature control is a function of the IA System.

The compressor return headers receive return flow from the Charging Pump Lube Oil Coolers and direct the SW back to the SW return headers through manual isolation valves.

### **Auxiliary Feedwater System**

The SW System provides an emergency source of water to the Auxiliary Feedwater pumps. The Auxiliary Feedwater System for each unit has an independent supply of SW. SW is supplied from the RS heat exchanger supply headers for each unit. The RS heat exchanger supply header is normally isolated and drained. The isolation MOVs open on receipt of a CDA signal, and the supply headers fill with SW.

The supply line from each RS heat exchanger supply header has a normally open, manual isolation valve. The supply lines combine into a single header that directs SW to the common supply header of the Auxiliary Feedwater pumps through a normally shut, manual isolation valve.

#### **A.11.3 Auxiliary Service Water System Components**

The Service Water System has an alternate flow path that uses water from Lake Anna to cool the normal SW System loads. The auxiliary SW System consists of two auxiliary SW pumps, two makeup pumps, and an auxiliary SW return header. This subsection describes each of these components and the flow paths associated with them.

### **Auxiliary SW pumps**

There are two auxiliary SW pumps (1/2-SW-P-4) located in the Auxiliary Service Water Pump House at the Intake Structure. Typically, one pump is dedicated to each unit, but either pump can supply either unit. Each pump is designed to provide 11,500 gpm at a discharge head of 127 feet, which is 50 percent of the total SW flow requirement for both units.

The auxiliary SW pumps are vertical, two-stage, turbine pumps that take a suction at the bottom of the CW screenwells at the 237-foot elevation. The CW traveling screens and trash racks filter any debris from the Lake Anna water to prevent damage to the auxiliary SW pumps. Each pump is driven by a 500 HP motor at 1180 rpm, located 28 feet above the pump suction. The pumps are powered from the 4160 V emergency buses and are controlled from the safeguards panels. Remote discharge pressure and motor amperage are provided above the handswitch.

The discharge of each auxiliary SW pump passes through a discharge check valve and a motor-operated isolation valve, 1-SW-MOV-117 (-217). The auxiliary SW pump discharge headers can be cross-connected through motor-operated cross-connect valve 1-SW-MOV-118. The MOVs are normally shut and are located in the missile-proof valve pit in the yard north of the plant. They are operated from the safeguards panels.

The auxiliary SW pump 1-SW-P-4 discharge header connects to SW supply header A through two motor-operated isolation valves, 1-SW-MOV-215B and -115A. Auxiliary SW pump 1-SW-P-4 connects to SW supply header B through 1-SW-MOV-115B and -215A. The MOVs are normally shut and are located in the basement of the Turbine Building. They are operated from the safeguards panels. Remote auxiliary SW pump flow indication is provided on the Safeguards Panels.

### **Makeup pumps**

The CW screen wash pumps (1-CW-P-2A and 2-CW-P-2B) can provide makeup water to the SW reservoir. During normal plant operations, the pumps operate to clean the CW traveling screens. When water must be added to the reservoir, the makeup pumps take 500 gpm of Lake Anna water and direct it to the auxiliary SW pump discharge headers. The additional 500 gpm of Lake Anna water enters the reservoir through the normal SW return headers.

Each makeup pump is a vertical turbine pump, with a design flow rate of 910 gpm and discharge head of 225 feet. The pumps located in the Auxiliary SW Pump House and take a suction on the CW screenwells. They are driven by 75 HP motors at 1760 rpm and are controlled from the safeguards panels.

The discharge of the makeup pumps can be directed to the SW System through individual three-way diverting valves 1-CW-TV-100 and -200. These valves operate to divert water to the SW System when the respective pump handswitches are in the service water makeup position and the respective traveling screen handswitches are in the OFF position. The makeup pump supply lines combine to form a single header that contains a manual isolation valve, a check valve, a strainer, and a flow totalizer. The flow totalizer provides flow indication and total reservoir makeup. The makeup supply line directs makeup water to either auxiliary SW pump discharge header through motor-operated valves 1-SW-MOV-119 and -219. The MOVs are normally open and are located in the missile-proof valve pit in the yard north of the plant. They are operated from the safeguards panels.

#### **Auxiliary SW return header**

The auxiliary SW return headers provide a flow path from the normal SW return headers to the Unit 2 discharge tunnel. The Unit 2 discharge tunnel directs the SW to Lake Anna. When the auxiliary SW return header is in operation, the SW must be monitored for radioactivity.

Radiation monitoring pump 10 takes a suction on each of the auxiliary SW return headers. The pump directs the SW samples through a radiation monitor 1-SW-RM-108 to detect any radioactive material. The samples are returned to the auxiliary SW return headers. The radiation monitor provides indication and an alarm light on the radiation monitoring panel in the Main Control Room.

SW from SW return header 4 passes through two motor-operated isolation valves, SW-MOV-220A and -120A. SW from SW return header 3 passes through SW-MOV-220B and -120B. The MOVs are located in the Safeguards Area and are controlled from the safeguards panels and the SW logic cabinets. Remote SW temperature and flow indication in the individual return lines is provided on the safeguards panels.

#### **A.11.4 Fault Tree Analysis**

The Service Water system was modeled as a support system. As such there are no success criteria.

The dependency matrix for this system is shown in Table A.11-1. The notes and assumptions used in the fault tree analysis follow. The fault tree is presented at the end of the section.

## Service Water Fault Tree Modeling Assumptions

1. 1A Service Water Pumps (1-SW-P-1A and 2-SW-P-1A) are assumed to be the normally running pumps for the SW system. Pumps 1-SW-P-1B and 2-SW-P-1B are assumed to be in standby. It is also assumed that the SW pumps are alternated every month. Pump 1-SW-P-1A is assumed to be aligned to service water supply header 1(A). Pump 2-SW-P-1A is assumed to be aligned to service water supply header 2(B). Similarly, the auxiliary service water pumps are assumed to be in standby with one pump aligned to each alternate service water header.
2. Per prior assumption, manual valves in running trains do not experience plugging faults.
3. Per prior assumption, manual valves in standby trains are assumed to be subject to plugging faults if they are normally open.
4. Failure Mode 2 events for the standby manual valves on the outlet of the SW standby pumps and the CW pumps assume a 720 hour interval between valve verification. It is assumed that the SW pumps are alternated every month thus allowing the valves to be checked once a month. The CW pumps are run at irregular time intervals so it is hard to set an exact time interval but a months time frame should cover at least one traveling screen wash.
5. The general guideline for the fault tree analysis is that if an active failure mode is postulated for an MOV, there is no reason to include a plugging failure mode also.
6. SW pumps will start automatically on receipt of a SI signal from either unit or a loss of reserve station power provided that all the following conditions are met:
  1. SW pump handswitch is in Auto after Start position
  2. no motor overload
  3. no undervoltage or degraded voltage

It is assumed for the fault tree that these conditions are met.

7. According to the UFSAR, the water stored in the service water reservoir can provide service water for extended periods for four units should the normal makeup pumps be inoperative. Enough water is available to guarantee 30 days of operation for four units without makeup. It was originally planned for North Anna to contain four operating units but only two were built. The reservoir was still designed to provide for four units, providing more than sufficient water for the two units

and therefore, loss of service water from the reservoir will not be modeled as a fault for this system.

8. It has been determined, based on operating history, that the traveling screens to the service water pumps could become plugged within a 24 hour period. Therefore, the traveling screens to the SW pumps need to be modeled. The CW traveling screens, used by the Auxiliary SW system, can become plugged with fish. These screens will be modeled as undeveloped events; one for each screen type. A common cause event will also be defined for the SW screenwells and the CW screenwells.
9. The service water air subsystem supplies air for the reservoir level indicator and for the traveling screen differential pressure indicators. Since it has been determined that the level of the reservoir is guaranteed adequate for 30 days, the level indicator will not be considered necessary to be modeled for the Service Water System.
10. The self-cleaning strainers (2-CW-S-3A/B) are apparently cleaned by diverting some of the screen wash flow past the surface of the strainer through 2-CW-MOV-204A/B. It is assumed that closure of these valves lead to plugging of the strainers.
11. During the periodic testing for the SW and SW Auxiliary pumps, certain valves are realigned. A restoration fault for these valves was not included in the fault tree because the procedure includes a check-off list that should verify that these valves are restored to their previous position and these valves are also visually inspected monthly to verify that their position is correct.
12. Opening the cross-tie between the two Auxiliary SW pumps was not modeled as a recovery action for the loss of a pump because as part of the success criteria it is necessary to have SW available to both units. Therefore, it was decided that each Auxiliary SW pump would be available as an alternate supply of SW for only one unit.
13. The training manual for the CW system states that; "Normally the screen wash pumps are secured. The operator monitors screen differential level on a periodic basis and, at an indicated level of 2 to 3 inches of water, manually initiates washing of the individual screen." Based on this information, the screen wash pumps and traveling screens were modeled to start running when manually started and not through the use of the automatic timer.
14. Pumps 2-SW-P-1A and 2-SW-P-4 are assumed to be dedicated to Unit 2 and no credit for their availability is taken for Unit 1.

15. Failure of the spray array bypass valves, during the cold weather period when they are in use, is not modeled. Per OP 49.1, operation with 3 SW pumps (i.e., with one operating pump failed) requires closing of the bypass valves and opening of the spray headers. Failure of the spray headers to open is a higher probability even than the spurious failure of the bypass MOV's.

## **A.12 QUENCH SPRAY SYSTEM**

During normal plant power operations, Containment is maintained subatmospheric at 9 to 11 psia by the Containment Vacuum System. During a loss of coolant accident (LOCA) or a steam line break (SLB) inside Containment, high energy fluid and vapor is released into the containment atmosphere causing an increase in containment pressure. The Containment Depressurization System (CDS) operates to maintain peak containment pressure less than 45 psig, maintaining the structural integrity of Containment.

The QS System, in conjunction with the RS System, sprays a fine mist (atomized) of water into the containment atmosphere. The refueling water storage tank (RWST) supplies the QS System with the cool water. Atomizing the water increases the water surface area available for heat transfer, thereby greatly increasing the rate of heat transfer from the containment atmosphere to the mist. The fine water droplets also provide nucleation sites to condense any steam. The RS System uses water collected in the containment sump as its source of water.

The three purposes of the QS System are (a) depressurizing the Containment during a LOCA or SLB, (b) removing iodine from the containment atmosphere during a LOCA, and (c) pH control of the water in the containment sump. These two purposes achieve an integrated purpose. Removing the iodine and depressurizing Containment minimizes the total gaseous leakage from Containment, thus reducing public exposure levels.

A simplified schematic of the QS system is shown in Figure A.12-1.

### **A.12.1 Flow Paths and Components**

The QS System is composed of a refueling water storage tank (RWST), two QS pumps, two 360° spray rings, a chemical addition tank (CAT), an RWST cooling subsystem, and a CAT recirculation subsystem. During normal plant power operations, the QS System is in standby, lined up for automatic initiation as follows:

1. RWST is maintained greater than 97.3 percent full of 40° to 50°F borated water.



2. QS pumps are in standby with their suction valves open.
3. CAT is isolated to prevent premature mixing of the NaOH with the water in the RWST.
4. RWST cooling subsystem is normally operating as required to maintain temperature.

#### **QS flow path**

The RWST stores borated water at a low temperature for use in the QS and Safety Injection (SI) Systems during a LOCA or SLB. As containment pressure increases during a LOCA or SLB, a containment depressurization actuation (CDA) signal is generated to initiate CDS. On receipt of a CDA signal, the QS pumps automatically start and the discharge valves open. The water from the RWST passes through two normally open isolation valves to the suction of the QS pumps. The pumps provide the motive force for flow from the RWST to the spray rings. From the discharge of each pump, the water passes through a discharge strainer that removes any debris that could clog the spray nozzles. The normally isolated recirculation line from the discharges of the pumps allows periodic testing of the QS pumps. Each discharge header leads to a separate 360° spray ring through a normally closed isolation valve. Each spray ring atomizes the water and distributes it around the Containment. Inside Containment some of the QS flow is directed to the suction of the inside RS pumps. This flow provides a source of lower temperature water to the pumps to increase their net positive suction head (NPSH).

#### **Chemical Addition Tank (CAT) flow**

The NaOH gravity drains from the CAT to the RWST through two normally shut isolation valves. Five minutes after the CDA signal initiates the spray systems or the QS pumps are manually started, the CAT isolation valves open automatically. The 5 minutes ensure that the operator has had sufficient time to verify that the CDA signal is valid. Inside the RWST is a weir that surrounds the suction connections to the QS pumps and the inlet connection from the CAT. The weir ensures proper mixing of the NaOH with the RWST water that is flowing into the QS pump suctions, with no significant amounts of NaOH being directed to the RWST SI System connection. A normally isolated CAT recirculation pump provides for proper mixing and sampling during normal plant operation. The recirculation pump draws NaOH from the normal tank outlet and discharges the NaOH back into the top of the CAT. A local sample sink is provided on the suction of the pump.

### **A.12.2 Fault Tree Analysis**

The Quench Spray system was found to be non-essential in the PRA analysis except for the large LOCA. The Recirculation Sprays provide Containment heat removal. The QSS is included in the event trees as appropriate to provide adequate sump inventory. The QSS is principally required to reduce the Containment pressure to sub-atmospheric in one hour after an accident, and to provide subcooling for RS pump suction. The first function is not required by the IPE criteria and the second was shown by MAAP analysis to not be necessary except for the large LOCA. The dependency matrix for Quench Spray is shown in Table A.12-1. The function used in the North Anna event trees is:

QS - Failure to provide flow to 1/2 Quench Spray headers from 1/2 QS pumps.

The notes and assumptions used to develop this fault tree follows. The fault tree is listed at the end of this section.

#### **Quench Spray System Fault Tree Modeling Assumptions**

- 1) The Quench Spray (QS) system includes the RWST and the CAT. The RWST is equipped with a RWST cooling subsystem which is used to maintain the temperature of the water in the tank. Since RWST temperature is a Tech Spec controlled parameter this subsystem can be assumed operable at the time of the initiating event. Therefore it will not be modeled in the PRA. The RWST temperature and volume are assumed to be within the values allowed by the Tech Specs.
- 2) Using the same logic as Assumption 1, the heat tracing associated with the RWST is not modeled.
- 3) Using the same logic as Assumption 1 the boron concentration in the RWST is not modeled. Therefore, there is no interface with the Chemical and Volume Control System.
- 4) The CAT and associated piping form a subsystem to supply water containing NaOH to the containment. For the level I/II analyses being performed to support the IPE the CAT is not required. The NaOH serves to remove iodine and neutralize the borated water from the RWST. Neither of these functions are part of the success criteria or the acceptance criteria for the North Anna IPE. The water volume from the CAT is negligible in comparison to the RWST. Therefore, none of the chemical addition subsystem components are included in the Quench Spray model.
- 5) Passive failure of piping in the QSS is assumed to have a negligible probability in comparison to failure probability

for active components. Therefore, it will not be included in the models.

- 6) Manual valves 1-QS-5 & 21 are realigned for periodic flow testing of the QS pumps. These valves therefore could be subject to restoration errors. The diameter of the recirculation line is large enough to cause a flow diversion under the fault tree modeling guidelines of the IPE. The valves are marked off on the periodic test sheet and a verification of the closed position is also signed off on the sheet. 1-PT-63.4 also verifies their position monthly. However, the valves are manual valves with no position indication in the control room. Assurance of valve position relies entirely on administration procedures. Therefore, a restoration error for these valves will be included in the fault tree.
- 7) The Quench Spray pump suction MOV's have only one failure mode, plugged during standby. The valves are normally open and controlled by TS 3.6.2.1. Periodic tests on the valves do not disable them but just require verification of the valve alignment. Periodic tests on the spray pumps do not change their alignment. Finally, the valve position is indicated in the main control room. Therefore, it is reasonable to assume that the valve is open and that the failure of motive power or control power is essentially insignificant.
- 8) The RWST tank has a 12 inch vent on the top of the tank. The environment exists for possible plugging of the RWST vent. Therefore, the plugging of the vent is a concern and will be modeled as a plugging fault in the fault tree.
- 9) Periodic Test 1-PT-63.3 outlines the procedures for ensuring that the spray nozzles are unobstructed. The test requires that spool pieces are removed and that blind flanges are installed on each quench spray header. Also, the supply lines to the Inside Recirc Spray Pump suction are isolated by 'pancake' installation. Per drawing 11715-FM-091A, the only spool pieces that can be removed and flanged are on the lines from the spray headers to the containment sump. Therefore, any of the flanges that are installed for this periodic test do not affect the availability of the Quench Spray System. Problems could arise if the flanges to the Inside Recirculation Spray Pump suction lines were left in after the test, but this would affect the Recirc Spray System and not Quench Spray.
- 10) Periodic Tests 1-PT-63.1A, 63.1A.1, 63.1B, and 63.1B.1 require flow testing of the QS pumps every three months. This test will also determine if any of the normally open valves in the QS system are plugged. Therefore, 2160 hours was used for the

time interval for the plugging fault of the normally open valves.

11) Common Cause Assumption

Common cause failure of the check valves in the spray lines has been included in the model. A failure of the weighted check valves is included which would fail both trains. It is also assumed that the check valves in each line fail due to common cause which fails one train. The Quench Spray pumps are assumed to have a potential for the common cause failure of both pumps. Finally, the MOV's in the discharge of the pumps are assumed to be subject to common cause failure.

12) Human Interaction Assumptions

An operator action is needed to manually start the QS pumps if they fail to start following a CDA signal. He is directed by the EOPs to do so. There are two basic events that represent the manual starting of the quench spray pumps in accordance with the EOPs. The EOPs also direct the operator to open MOVs 1-QS-MOV-101A&B if they fail to open following a CDA signal.

13) There are no special basic events in the Quench Spray fault tree.

### A.13 FEEDWATER SYSTEM

The purpose of the main Feedwater System is to supply and maintain water inventory in the steam generators for the production of steam and to provide a secondary heat sink for the Reactor Coolant System (RCS).

The purpose of the Auxiliary Feedwater System is to:

1. Maintain Hot Standby (mode 3) conditions for 8 hrs. while dumping steam to the atmosphere during a total loss of offsite power (based on ECST capacity).
2. Facilitate cooldown of the RCS to 350°F from normal operating conditions during a total loss of offsite power.

Simplified schematics are shown in Figures A.13-1 through A.13-3.

#### A.13.1 Flow Paths

The major flow paths include a normal (main) feedwater flow path and an auxiliary feedwater flow path. Some of the components and instrumentation in these flow paths contain condensate (CN)

designations. These components and instruments are discussed here because of their relevance to the Feedwater System.

### **Normal Feedwater**

The Main Condensate System is the source of feedwater for the steam generators. The relatively cool condensate discharge from the 5th point heater drain coolers is heated in a series of six feedwater heaters, pressurized by the main feedwater pumps, and distributed to the three steam generators. The flow rate of the feedwater and the corresponding level in the steam generators are determined by the positioning of a feedwater regulating valve or feedwater regulating bypass valve. These valves receive positioning control signals from the Steam Generator Water Level Control Subsystem.

The six feedwater heaters form two trains of feedwater heating (A and B). Each train is similar and is monitored locally by condensate system temperature indicators. The feedwater heaters are shell- and tube-type heat exchangers, which act to increase the temperature of the feedwater prior to its entering the steam generators. The manner in which the temperature rise occurs results in an increase in overall plant efficiency. Extraction steam from the main turbine is directed through the shell side of the heaters, giving up heat to the feedwater passing through the heat exchanger tubes. By directing extraction steam and secondary drains to the Feedwater System rather than the main condenser, heat is added to the Feedwater System instead of being rejected to the Circulating Water System.

Three main feedwater pumps are provided for raising the pressure of the feedwater to a pressure greater than steam generator pressure. At full power operation, two feedwater pumps are running and the third pump is in standby status. Recirculation lines and associated recirculation control valves are provided to direct feedwater flow back to the main condenser when little or no feedwater is required by the steam generators. A warmup line with a flow restricting orifice is provided for each pump to allow a small backflow through an idle pump.

The discharge of the main feedwater pumps is directed to three feedwater headers, each supplying a steam generator with feedwater flow. Each header contains a motor-operated valve (MOV) that acts as a header isolation valve, a main feedwater regulating valve, and a feedwater regulating bypass valve. The feedwater regulating bypass valve is smaller in diameter than the main feedwater regulating valve and is used to control feedwater flow to the steam generators at low power levels. As power is increased, the bypass valves are shut and the main feedwater regulating valves are opened to supply a greater feedwater flow rate. Both regulating valves are positioned by control signals developed in the Steam Generator Water Level Control Subsystem, or manually by the control room

operator. Each feedwater header also contains a check valve that acts as a containment isolation valve, preventing blowdown of a steam generator in the event of a feedwater piping rupture upstream of the valve. A loop seal in each header prevents draining the steam generator feed ring when the associated feedwater header is drained.

### **Auxiliary Feedwater**

The Auxiliary Feedwater portion of the Feedwater System is used to automatically supply a reserve source of feedwater to the steam generators. The normal source of Auxiliary Feedwater is the emergency condensate storage tank. Alternate sources of water originate in the Fire Protection System (firemain) and the Service Water System.

As required by Technical Specifications, each Auxiliary Feedwater pump is provided with a separate suction header and an independent discharge path to its respective steam generator. A normally isolated full flow recirculation path to the emergency condensate storage tank is provided for each pump. A full flow recirculation line is also provided for each AFW pump for testing purposes (normally isolated). These full flow recirculation lines direct pump discharge back to the emergency condensate storage tank and allows for verifying the pumps head-capacity curve on a routine basis. The minimum recirculation flow line provides a path for the pump when flow to the steam generator is low. The oil lubrication system associated with each pump is cooled by a small amount of leakoff from the pump.

Three Auxiliary Feedwater pumps are provided; two are motor-driven and the third is turbine-driven. This ensures that at least one pump is available during a complete loss of power. The discharge header of the turbine-driven pump has an orifice which limits the maximum flow from the pump in the event of a piping rupture downstream of the orifice. This flow-limiting action for the motor driven pumps is accomplished by pressure control valves located on the pump discharge.

One pump is normally dedicated to a particular steam generator, but any pump can feed any steam generator if required. A hand control valve (HCV) and a MOV header are provided on the Auxiliary Feedwater pumps discharge for each steam generator. These headers permit greater Auxiliary Feedwater diversity and reliability. Prior to joining the main feedwater headers, a check valve in the Auxiliary Feedwater line prevents backflow from the steam generators in the event of an Auxiliary Feedwater piping rupture.

### **A.13.2 Major Components**

This subsection provides a brief description of the major Feedwater System components. The major components are controlled from the Main Control Room (MCR), with alternate controls provided at the Auxiliary Shutdown Panel for some components. The major components are the feedwater heaters, main feedwater pumps, emergency condensate storage tank, and Auxiliary Feedwater pumps.

#### **Feedwater heaters**

Six sets of shell and U-tube feedwater heaters are used to increase the efficiency of the power plant. Each set is comprised of two heat exchangers (train A and train B). Extraction steam and/or high temperature water are directed through the shell side of the heat exchangers, while relatively cool feedwater is pumped through the tubes. Condensed extraction steam is discharged from the feedwater heaters to the Secondary Drains System, while the heated feedwater is piped to the next feedwater heater and eventually to the steam generators. The 3rd, 4th, 5th, and 6th A train heaters receive extraction steam from low pressure (LP) turbine number 1, while the 3rd, 4th, 5th, and 6th B train heaters are provided with extraction steam from LP turbine number 2. Extraction steam to the 1st and 2nd point feedwater heaters is supplied by the high pressure (HP) turbine first point extraction (3rd stage) and turbine exhaust respectively. The feedwater is heated from approximately 110°F at the inlet of the 6th point heaters to 442°F at the inlet to the steam generators.

#### **Main feedwater pumps**

Three main feedwater pumps (1-FW-P-1A/B/C) provide the necessary driving force to pump water from the Main Condensate System to the steam generators. Normally, two feedwater pumps are running and one pump is maintained in a standby status. Control of the feedwater pumps is from the MCR. The main feedwater pumps are mounted next to each other on the east end of the turbine building basement.

Each main feedwater pump is a horizontally mounted, single-stage, double-suction, vertically split centrifugal pump. Each pump is rated 16,250 gpm and is driven by two 4500 HP motors mounted in tandem. Radial movement of the pump shaft is restricted by two journal bearings mounted on opposite sides of the pump. A 6-inch thrust bearing minimizes pump axial motion.

## **Emergency condensate storage tank**

The emergency condensate storage tank (1-CN-TK-1) stores and supplies water to the suction of the Auxiliary Feedwater pumps for use as a backup source of feedwater. The tank is capable of holding approximately 126,000 gallons of water and of supplying water to the steam generators for up to 8 hours for the removal of residual heat during Hot Standby (Mode 3). The Technical Specification capacity of 110,000 gallons is based on maintaining Hot standby while dumping steam to the atmosphere during a loss of offsite power.

The tank is 28 feet in diameter and 33 feet tall. The steel enclosure is insulated from the outside atmosphere by 2 inches of rotofoam insulation, surrounded by a 24-inch layer of concrete that provides missile/tornado protection. Two manholes are provided for visual internal inspection of the tank. A 20-inch manhole is located on the top of the tank and an 18-inch manhole is located on the side. Penetrations into the tank include the following:

1. nitrogen purge line,
2. three suction lines to the Auxiliary Feedwater pumps,
3. atmospheric vent,
4. fill line from the 300,000 gallon condensate storage tank,
5. level transmitters, and
6. recirculation line from the Auxiliary Feedwater pumps.

The emergency condensate storage tank can be purged continuously with nitrogen to minimize air introduction into the secondary system; however, this gas supply is normally isolated. Operating pressure in the tank is atmospheric by virtue of a 6-inch vent connection in the top. The steam-driven Auxiliary Feedwater pump (Terry turbine) takes suction on the tank via an 8-inch connection, while the motor driven Auxiliary Feedwater pumps are supplied by 6-inch connections. All three connections are located approximately 18 inches above the tank bottom. A 2-inch recirculation line from the discharge of the Auxiliary Feedwater pumps enters the tank at the 18-inch level. This line is equipped with a Cuno filter (1-FW-FL-1), which can be manually valved-in to provide cleanup of the tank contents. The tank is filled through a 6-inch connection. The driving force for tank fill is the difference in static head developed between the 300,000 gallon condensate storage tank (1-CN-TK-2) and the ECST. Level transmitter (1-CN-LT-100A) provides tank level indication in the MCR. 1-CN-LT-100B provides level indication in the Control Room and ASDP. The emergency condensate



storage tank is attached to the Auxiliary Feedwater Pump House, in the south yard.

### **Auxiliary Feedwater pumps**

There are three Auxiliary Feedwater pumps (1-FW-P-2, -3A, and -3B). Pump P-2 is turbine-driven, while pumps P-3A and -3B are motor driven. The turbine-driven Auxiliary Feedwater pump is also referred to as the Terry turbine. The pump end of the three Auxiliary Feedwater pumps is similar, with only minor differences. Normally one Auxiliary Feedwater pump is dedicated to a steam generator to ensure that a heat sink is available for the RCS. The Auxiliary Feedwater pumps take suction on either the emergency condensate storage tank (normal), the firemain, or the Service Water System. The pumps are located in the Auxiliary Feedwater Pump House, next to the emergency condensate storage tank.

Each Auxiliary Feedwater pump is a horizontally mounted, six-stage, horizontally split centrifugal pump. The pump inlet and outlet connections are contained in the lower half of the horizontally split casing. The single-suction impellers are keyed to the pump shaft and individually mounted by means of split rings and spacing sleeves.

Individual oil lubrication systems are provided for each Auxiliary Feedwater pump. A shaft-driven pump provides the motive force for oil circulation to the pump bearings. Additional oil system components include a lube oil reservoir, an oil filter, and a cooler. The oil cooler transfers heat from the lube oil to a small portion of the Auxiliary Feedwater flow coming from the first stage of the pump (leakoff). The warmed Auxiliary Feedwater flow is then directed back to the emergency condensate storage tank, via the pump recirculation line. Oil level in the reservoir is indicated locally on the top of the reservoir. A Terry Turbine low lube oil reservoir level condition will initiate annunciator alarm Turbine Driven Auxiliary Feedwater Pump Trouble/Lo Trouble in the MCR. Prior to routine periodic testing of any Auxiliary Feedwater pump, the operator may be required to pre-lubricate the pump's bearings manually if the pump has not been run within the last 24 hours.

Each motor driven Auxiliary Feedwater pump is powered by a 450 HP, 4160 V motor. The motors are energized from the H and J emergency buses. Control power for the motor breakers is provided by the battery buses. The turbine-driven Auxiliary Feedwater pump receives steam from the Main Steam System, via trip valves 1-MS-TV-111A and B.

The motor driven pumps are rated at 370 gpm each, of which 20 gpm is pump normal recirculation flow. The turbine-driven Auxiliary Feedwater pump is rated for a total flow of 735 gpm (35 gpm is normal recirculation flow). An orifice downstream of 1-FW-MOV-100D

restricts total flow from the turbine-driven pump to approximately 450 gpm, when a pressure of 1005 psig exists in the steam generators. The orifice is designed to restrict the maximum flow from the pump in the event of a piping rupture downstream of the orifice.

The Terry turbine is a single-inlet, single-stage, solid rotor unit, rated at 710 HP and 4200 rpm. The steam exhaust from the turbine is directed to atmosphere and is monitored for radiation. The inlet piping contains a trip/throttle valve and a governor valve. Under normal conditions, the trip valve is fully open and the governor valve is opened to a setting corresponding to the normal speed of the turbine (4100 rpm). In order to achieve normal discharge pressure and flow, steam generator must have adequate pressure. The opening of 1-MS-TV-111A or B admits steam directly to the turbine rotor, causing the turbine to accelerate to normal speed. Position of 1-MS-TV-111A and B, as well as steam flow indication, is monitored by 1-MS-FE-107. These indications are obtainable on CRTs in the MCR and TSC. The speed of the turbine is then controlled locally at the governor. The trip valve permits manual control of turbine speed and also trips shut at a speed of 4860 rpm as sensed by the overspeed trip device on the turbine shaft. Once tripped, the trip valve must be manually reset, locally at the turbine.

### **A.13.3 Fault Tree Analysis**

The dependency matrices for Main and Auxiliary Feedwater are shown in Tables A.13-1 and A.13-2. Auxiliary and Main Feedwater were modeled as front line systems. Functional descriptions are summarized below.

- L - Failure to provide AFW to operable Steam Generators. For initiators with scram, 1/3 pumps were required. For ATWS, 2/3 pumps were required. For transients with scram, feed to 1/3 generators was required, except where 1 generator was unavailable because of the initiator.
- M - Provision of Feedwater from 1/2 MFW pumps to 1/3 generators was required for transients where AFW was failed and MFW could be recovered.

The notes and assumptions used to develop these fault trees and the fault tree follow.

### **Auxiliary Feedwater Fault Tree Modeling Assumptions**

1. No credit is taken for any normally-closed bypass valves.

2. Since AOVs 1-MS-TV-111A and -111B fail open on loss of DC power or Instrument air, no dependencies for these AOVs are modeled.
3. The lube oil system is assumed to be part of the pumps.
4. Flow diversion through the recirculation lines is considered as a failure mode due to the size of the recirc lines. These recirculation lines are full flow lines and are sized the same as the pump discharge lines.
5. After test & maintenance on the AFW pumps, these pumps are tested on recirculation. At the conclusion of some tests (1-PT-71.1Q, -71.2Q, and -71.3Q), full flow to the steam generators is measured. Therefore no restoration error is needed for these tests. However, in other tests (1-PT-71.1, -71.2, and -71.3) the discharge valves downstream (i.e., 1-FW-HCV-100C, 1-FW-MOV-100B and 1-FW-MOV-100D) are not flow tested, and therefore a restoration error for these valves is included. In addition, failure to restore the manual valves in the full flow recirculation line to a closed position is also modeled. The position of these valves are not indicated or alarmed in the control room.
6. MOVs -100B and -100D and HCV-100C are normally open but are not actuated by the operation of the AFW motor driven pumps if they happen to be closed. To be conservative, a plugging failure is modeled for these valves.
7. To calculate the unavailability due to plugging in manual and motor-operated valves, a test interval of once a quarter is used. This is based on the full flow tests to the steam generators (PTs 71.1Q, 71.2Q, and 71.3Q) once every three months. Actuation of the AFW system for purposes other than the above mentioned tests is conservatively ignored in the calculation of test interval.
8. If there is insufficient water inventory to the AFW pumps, steps 7 and 18 of North Anna procedure 1-FR-H.1 directs the operator to establish feed flow from alternate sources, namely the fire main and the service water system. This AFW make-up procedure is also spelled out in 1-AP-22.7 which states that the fire main is the preferred makeup source. These backup sources are modeled.
9. Except for ATWS cases, actuation of the AFW pumps is not modeled, i.e., actuation is assumed to be present. The reason for this assumption is that for all initiating events, there will be at least two signals to automatically start the AFW pumps, plus there will be approximately 30 minutes for the operator to manually actuate the pumps. In the case of ATWS, the time for operator action is much less. Therefore, in

these cases, auto actuation is modeled but no credit is taken for manual actuation. In addition, auto start on a AMSAC signal is also modeled for ATWS scenarios. The AFW auto start signal will be modeled as a "black box." The failure probability used will be obtained from the fault tree model developed for AFW auto start in the Surry PRA.

10. Common cause failure is modeled for each set of components that see unique environments, or operating demands. So the discharge check valves (1-FW-68, -100, -132) are unique. The two PCV's (1-FW-PCV-159A/B) in the pump discharge headers are different from the discharge check valves, but the same as the CKV's in the pump discharge headers. And since there are fewer valves in the discharge headers than in the pump headers, the more restrictive case (i.e., common cause failure of 1-FW-PCV-159A/B) is chosen. (Note: The NRC has pointed out in NRC Information Notice No. 88-87 that there are instances at Surry where AFW pump wear have resulted in foreign objects in the AFW piping, thus restricting flow to the SGs. In this analysis, this possible flow restriction will be included into the calculation of CCF probability of the discharge check valves.)
11. Backleakage of steam through the discharge check valves causing a common mode failure of all three AFW pumps by steam binding is included in the fault tree model. Although this event has caused some concern in the industry (and has occurred at Surry), it has not occurred at North Anna and procedures are in place to detect the possible occurrence of such an event.
12. Failure of the trip and throttle valve, and the governor valve upstream of the TDP is not modeled. These valves are normally open, and are within the component boundary for the TDP.
13. Back-flow through a failed AFW pump from running pumps is not modeled because at least two other failures are required to permit this back-flow. A manual valve on the discharge of the running pump has to fail open and the check valve on the discharge of the failed pump also has to fail open. For back-flow through the full flow recirculation lines, at least three other failures have to occur.
14. The HCV's on the AFW pump discharge headers to the steam generators (1-FW-HCV-100A/B/C) operate on a air-to-close, fails-open mechanism. Therefore, the dependency on instrument air to open these valves is not modeled.

## **Main Feedwater**

1. For non-loss of feedwater transients, i.e., if the feedwater system is already in operation, normally open valves are assumed not to fail closed. These include the isolation valves 1-FW-MOV-154A, -154B, and 154C; the isolation MOVs 150A, 150B and 150C and the manual valves 1-FW-MV-46, 1-FW-MV-78, and 1-FW-MV-110.
2. For cases where MFW is already in operation, no credit will be taken for FW regulating bypass valve operation.
3. It is assumed that the FW heaters will not contribute to system failure. Therefore, these heaters are not included in the fault tree model. Loss of feedwater as a result of heater malfunction is considered as an initiating event.
4. Makeup water from the CST to the hotwells is through valves 1-FW-LCV-109-1 and 1-FW-LCV-109-2. 1-FW-LCV-109-2 is the normal makeup valve and opens first on decreasing level in the hotwell, permitting makeup water to enter the hotwell through a 4 inch line. If the capacity of this valve is insufficient to provide adequate makeup, 1-FW-LCV-109-1 opens to supply additional water through a 10-inch line. It is assumed that flow through both valves is needed for makeup to the hotwell.
5. The loss of inventory in the condenser hotwells can be through a pipe break between the condenser and the CST. In this case makeup from the CST is also lost. This failure mode is not modeled because the probability of this pipe break is negligible when compared to the probability of the other failure modes.
6. No spurious signals was considered which could cause the FRVs to fail closed. This is considered as an initiating event.
7. When attempting to re-establish FW flow (in loss of FW transients), the condensate pumps are assumed to be already running for those initiating events where loss of condensate pumps was not the cause of loss of feedwater.
8. It is assumed that the manual valves on the Reg-valve bypass lines (i.e., 1-FW-48, 49, 80, 81, 112, 113) are flow tested (or utilized) once every quarter.
9. It is assumed that the condensate pumps by themselves will not provide enough flow to the SGs for system success.
10. Plugging of check valves during mission time is negligible. This includes valves 1-CN-9, -21, -33 and 1-FW-1, -10, -19, -47, -79 and -111.

11. The lube oil system for the MFW pumps is modeled as a "black box" with a failure rate assumed to be  $3.31\text{E-}5$ . This assumes that the failure of the pump to run (PAT-FR) is the dominant failure mode.
12. Valves 1-FW-FCV-150A, 1-FW-FCV-150B and 1-FW-FCV-150C control FW recirculation flow to the main condenser. These valves are designed to open at low FW flow rates. The failure of FCV-150A/B/C to open is not modeled because these valves are designed to fail in the open position and all three valves have to fail closed for recirculation flow failure. (Note: Only one of these recirculation valves are in service at a time. The other two valves are manually isolated.) Since the position of these valves are indicated in the control room, operator action to open the valves (if necessary) during a routine at pump startup is assumed.
13. Flow diversion through a failed or standby FW pump is not modeled because two other failures have to occur. The MOV and check valve on the discharge of the failed pump will both have to fail open for flow diversion.

Flow diversion through a failed condensate pump is modeled. The discharge valve is a manual valve. It is throttled only when a condensate pump is manually started or secured. In the fault tree, it will be assumed that this manual valve is left open. Therefore, backflow would be through a single failed-open check valve.
14. Pumps 1-FW-P-1C and 1-CN-P-1C are assumed to be the standby pumps. Unavailability due to test and maintenance will be modeled for these pumps.
15. In accordance to the guidelines of the dependent failure task (Task DF), common cause failure for running pumps is not modeled. This includes both the condensate and the main feedwater pumps.

#### A.14 RECIRCULATION SPRAY SYSTEM

The RS System, in conjunction with the QS System, sprays a fine mist (atomized) of water into the containment atmosphere. Atomizing the water increases the water surface area available for heat transfer, greatly increasing the rate of heat transfer from the containment atmosphere to the mist. The fine water droplets also provide nucleation sites to condense steam. The RS System uses water collected in the containment sump from the LOCA and QS System as its source of water.

The purposes of the RS System are to:

1. cool and depressurize the containment structure to subatmospheric pressure;
2. maintain the containment at subatmospheric pressure following a LOCA/SLB; and
3. provide the Emergency Core Cooling System (ECCS) with water for effective core cooling on a long-term basis after a LOCA.

System schematics are shown in Figures A.14-1 and A.14-2.

#### **A.14.1 Major Components**

The RS System consists of two inside RS pumps, two outside RS pumps, four recirculation coolers, four spray rings, one casing cooling tank, two casing cooling pumps, two casing cooling recirculation pumps, and two casing cooling refrigeration units. The primary purpose of the RS System is to return the containment atmosphere to subatmospheric conditions within one hour of a LOCA or SLB and to remove heat from the water in the containment sump in the long term. This subsection describes the major RS System components and the flow paths used to achieve that purpose.

Water from the LOCA/SLB and QS System collects on the containment floor and gravity drains into containment sumps. A containment sump is a depressed area in the floor to hold water and to provide suction points for the four recirculation spray pumps and the two LHSI pumps (in the recirculation mode). The containment sumps are completely enclosed by a screen assembly divided into two separate half sections. The screen assembly consists of outer vertical and inclined 1 x 1/8-inch gratings and three inner stages of mesh screens. The grating acts as a trash screen to prevent large debris from reaching the coarse, fine, and cylindrical mesh screens. Downstream of the grating, there are three stages of mesh screening. The first stage is a coarse mesh with 0.615-inch (0.558-inch for Unit 2) square openings. The second and third stages are fine meshes with 0.12-inch square openings that approximate the size of the smallest nozzle orifice in the RS rings.

The screen assembly is divided into two separate halves by a fine mesh screen divider, so that failure of either half will not adversely affect the other half. Each half of the assembly has a screen surface area of approximately 84 square feet. Each pipe suction point for the outside RS pumps is enclosed with a cylindrical mesh screen extending from the bottom of the containment sump to the top of the screen assembly support with an area of approximately 33 square feet. The inside RS pumps suctions

are located in approximately 7½ foot deep, lined wells which extend into the containment mat. Water enters the suction wells via cylindrical mesh screens which extend from the top of the suction wells to the bottom of the pump motor support structure.

### **Inside RS pumps**

There are two inside RS pumps for each unit. The pumps are located at the 217-foot level in Containment. During normal operation, the RS pumps are in standby, lined up to deliver water from the containment sumps to their respective recirculation cooler and spray ring. On receipt of a CDA signal, the pumps automatically start after a 195-second time delay. The QS System supplies 150 gpm of water from the RWST via the QS pumps to the suction of each inside RS pump. This cooler water increases the NPSH available to the pumps.

Each inside RS pump is a vertical, two-stage, turbine pump which has a capacity of 3300 gpm at a design head of 269 feet. Each pump has 50 percent of the spray capacity necessary to return the containment atmosphere to subatmospheric conditions following a CDA. The pump motors are located in the containment basement, approximately 9 feet above the floor. Each pump is driven by a totally enclosed, air-cooled, 300 HP, induction motor at 1780 rpm. RS pump 1A is powered from 480 V Bus 1H1; RS pump 1B is powered from 480 V Bus 1J1. The pumps are controlled from respective Safeguards Panels in the Main Control Room (MCR). Remote pump discharge pressure and motor current are indicated above the respective handswitch. Each pump has local discharge pressure indication.

The suctions of the inside RS pumps are in approximately 7½ foot deep wells. The 4-inch lines from the QS headers contain orifices that limit cooling water flow to 150 gpm. At the sump, each line branches and forms a ring header. The ring header distributes the cooling water to four symmetrically arranged outlets that extend to the inlet of the pump. The outlets are designed such that the velocity of the injected water is only slightly higher than the flow velocities of the water entering the pump. When the QS System is secured and the headers fill with air, the design of the outlets prevents air from being drawn into the suction of the pumps.

### **Outside RS pumps**

There are two outside RS pumps for each unit, located at the 256-foot level in the Safeguards Area. During normal operation, the RS pumps are in standby, lined up to deliver water from the containment sump to their respective recirculation cooler and spray ring. On receipt of a CDA signal, the pumps automatically start after a 210-second time delay.



Each outside RS pump is a vertical, two-stage, turbine pump with a capacity of 3700 gpm at a design head of 286.7 feet. Each pump has 50 percent of the spray capacity necessary to return the containment atmosphere to subatmospheric conditions following a CDA. Each pump is driven by a 400 HP, induction motor at 1780 rpm. RS pump 2A is powered from 4160 V Bus 1H; RS pump 2B is powered from 4160 V Bus 1J. The pumps are controlled from respective Safeguards Panels. Remote pump discharge pressure and motor current are indicated above the respective handswitch. Each pump has local suction and discharge pressure indication.

The outside recirculation spray pumps are equipped with tandem mechanical seals to provide redundancy against shaft leakage. A separate closed loop seal water system filled with primary grade water is provided for seal lubrication. The seal water system is designed such that the seal water is maintained at a pressure slightly higher than the pressure of the pumped fluid inboard to the inboard seal. This design helps to prevent leakage of radioactively contaminated fluid into the seal water system.

The seal water system lubricates the outboard seal during normal operation. Since these pumps are vertical pumps that are not vented prior to an emergency start, the seal water also is necessary to keep the inboard seals lubricated during this initial startup to prevent reduced seal life. This design also helps to keep debris from the pumped fluid away from the inboard seal faces during operation thereby extending the life of the seals.

The demineralized water in the seal water closed loop system is cooled by a finned air cooled coil. The demineralized water is circulated by a pumping ring which is integral to the mechanical seal assembly. A seal head tank serves as a boundary between the seal water subsystem and the pumped fluid. The seal head tank has a diaphragm attached to a weighted "float" to prevent the two fluids from mixing. The weighted "float" maintains the seal water at approximately 1 psi pressure greater than the pressure of the pumped fluid at the inboard seal. The seal head tank is refilled manually from the Primary Grade Water System when a low level condition exists.

The suction lines between the containment sump and outside RS pumps are cross-connected to ensure a supply of water to each pump if one side of the containment sump suction screens becomes clogged. The suction lines contain normally open, motor-operated isolation valves 1-RS-MOV-155A and B. The valves are controlled from their respective Safeguards Panels. In the event of a CDA, the normally open valves receive an open signal to ensure their open status. The Casing Cooling Subsystem provides approximately 800 gallons per minute of cool water to the suction line of each outside RS pump. This water increases the NPSH available to the pump.

The discharge line from each pump contains a recirculation line, a cross connection to the LHSI pumps (Unit 1 only), a motor operated isolation valve, and a containment isolation check valve. The normally isolated recirculation line contains a flow element and is used for periodic testing of the outside RS pumps. The connection to the LHSI pump discharge on Unit 1 only provides additional redundancy should a low head safety injection pump fail. The normally open, motor-operated isolation valves 1-RS-MOV-156A and B are controlled from their respective Safeguards Panels. In the event of a CDA, the valves receive an open signal to ensure their open status. The containment isolation check valves are weight-loaded to ensure that any air in the outside RS piping does not enter the subatmospheric Containmentment.

### **Recirculation coolers**

The discharge of each RS pump passes through individual recirculation coolers located in the basement of the Containmentment. Each recirculation cooler is a single-pass, shell and tube heat exchanger with a heat removal capacity of 56,835,000 Btu/hr. The RS water passes through the shell side of the heat exchanger and transfers its heat to the service water on the tube side. The shell side of the heat exchanger has a design pressure of 225 psig and a design temperature of 280°F.

During normal plant operation, the recirculation coolers are maintained empty. The clean, dry, and ready condition of the coolers prevents tube fouling and the associated loss of heat transfer capability. Upon receipt of a CDA signal, the service water recirculation cooler header isolation valves open and admit 4,500 gpm of service water to each cooler. The RS water in the cooler is at a higher pressure than the service water. Therefore, the dilution of the borated water in the containment sump caused by a leak from the Service Water to the Recirculation Spray System is not possible. The leakage of sump water into the service water is detected by means of radiation monitors in the SW System outlets of each cooler.

### **RS spray rings**

There is one 180° spray ring for each RS Subsystem. Each spray ring is a semicircular 8-inch pipe that contains 150 nozzles to atomize the RS water. The inside and outside RS Subsystem spray rings are arranged to form a complete 360° circular ring at elevations 376 feet, 10 inches and 377 feet, 10 inches respectively. The ESF train A and B subsystems are arranged so that the two RS Subsystems in a single train provide 360° spray. The spray coverage of the quench sprays and the four recirculation sprays is 86 percent of the entire containment atmosphere and 87 percent of the atmosphere above the operating floor. The RS spray

rings have a combination of spray nozzle types that are oriented to obtain a wide distribution of varying size spray droplets. This provides maximum quench spray coverage. The RS water droplets average 1094 microns in diameter.

#### **A.14.2 Fault Tree Analysis**

Recirculation Spray was modeled as a front line system providing the Containment heat removal function. Success criteria was 1 of 4 RS pumps with SW to the respective heat exchanger.

The notes and assumptions used in the fault tree development follow. The fault tree is listed at the end of the section.

#### **Recirculation Spray Fault Tree Modeling Assumptions**

- 1) Passive failure of the piping in the RS System is assumed to have a negligible probability in comparison to the failure probability for active components. Therefore, pipe segments will not be included in the fault tree model as basic events.
- 2) Orifices in pipe segments are not included in the fault tree model by the same reasoning as Assumption 1.
- 3) The RS system includes the Casing Cooling Tank. The Casing Cooling Tank is equipped with a cooling subsystem which is used to maintain the temperature of the water in the tank. Since the temperature of the tank is a Tech Spec controlled parameter this subsystem can be assumed operable at the time of the initiating event. Therefore it will not be modeled in the PRA. The Casing Cooling Tank's temperature and volume are assumed to be within the values allowed by the Tech Specs.
- 4) Using the same logic as Assumption 1, the heat tracing associated with the Casing Cooling Tank is not modeled.
- 5) Periodic Tests 1-PT-64.1A, 64.2A, 64.1B, and 64.2B require testing of the RS pumps every three months. This test will also determine if any of the normally open valves in the RS system are plugged. Therefore, 2160 hours was used for the time interval for the plugging fault of the normally open valves.
- 6) Failure to restore the discharge valves from the casing cooling pumps (i.e., 1-RS-MOV-101A, B) is not included in the model because the valves receive a CDA open signal.
- 7) IRS pump suction containment sumps receives flow from the QS system. The A QS train provides flow directly to the A IRS

pump suction containment sump. The B QS train provides flow to the suction containment sump of the B IRS pump.

- 8) Common cause errors are postulated to occur on most active components. The typical active components are accounted for including the IRS pumps, the ORS pumps, the ORS pumps inlet and outlet isolation valves and the containment sump. The sump is not an active component but it must be considered since its failure would eliminate all heat removal capability for the containment.

The CC errors for the service water supply to the RS heat exchangers include the active components in the two trains. These components are the train isolation valves, the heat exchanger inlet isolation valves and the heat exchanger outlet isolation valves.

- 9) The human interaction errors are primarily restoration or type A errors or type C errors. The type A errors are failure to restore a train of equipment to operable status. Type C errors are failure to start equipment manually following failure of automatic initiation.
- 10) Special basic events have been included in the model. Each of the events is listed below with a discussion of its importance.

1CESTR-CC-SUMPPG	This basic event represents the failure of the outermost screens around the sump to collect and prevent debris from entering or blocking the suction of the four RS pumps.
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1RSTNK-PG-CCTNK	This basic event represents the plugging of both the vent on top of the Casing Cooling Tank and the overflow line to the safeguards sump. This is a special event because the plugging rate in the PRM file is not appropriate for a dry vent.
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- 11) Three house events have been defined for the RS System:

XHOS-QS-REQ-NPSH	This house event is used to turn on and turn off quench spray water supply to the IRS pump suction.
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XNOS-CASCOOLREQD	Similarly, this house event is used for casing cooling water supply to the ORS pumps.
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XHOS-SW	Service water required for RS heat exchangers.
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## **A.15 EMERGENCY SWITCHGEAR ROOM COOLING SYSTEM**

### **A.15.1 Components**

The Main Control Room and Emergency Switchgear Room Cooling System consists of two sets of three chillers, one set for each reactor unit. Each set supplies chilled water to air conditioners (also referred to as air handling units, or AHU). The first set, consisting of Unit 1 Main Control Room and Emergency Switchgear Room (ESGR) chillers 1-HV-E-4A, -4B, and -4C, supplies the air conditioners in the Unit 1 MCR and ESGR. The second set of Unit 2 MCR and ESGR chillers, consisting of chillers 2-HV-E-4A, -4B, and -4C, supplies the air conditioners in the Unit 2 MCR and ESGR.

The chiller units are typical gas/liquid refrigerant units that are piped in parallel for each set. The 4A, B, C chillers are rated at about 80 tons with 85°F cooling water. Each chiller has an associated condenser (or condensate) water pump and a chilled water pump. A typical chiller unit is discussed in the General System Operation section of this module.

The condenser water pump takes suction on the condensing water supply line, pumps it through the chiller condenser, and returns it to the condensing water system. The condensing water for the 4A,B,C sets of chillers is taken from the supply headers of the Service Water System. The condensing water is basically an open system, as the heated water is returned to the Service Water discharge header and is normally directed to the Service Water Reservoir for cooling.

The chilled water pump for each chiller pumps the water through the chiller, where it is chilled, and then to the cooling coils of the air handling units. In the cooling coils, the water absorbs the heat from the air drawn across the coils. This warmed water returns to the suction side of the chilled water pump to repeat the process. The chilled water flow path is basically a closed-loop system, with makeup water added as needed from the Domestic Water System and expansion tanks provided as surge tanks for the closed loops.

One line schematics are presented in Figures A.15-1 through A.15-4. The Unit 1 ESGR Chilled Water and Service Water subsystems are presented in the first two figures. The next two figures present the same information for Unit 2.

### **MCR and ESGR Air Conditioning System**

Two independent, 100 percent capacity air cooling systems are provided per reactor unit, for a total of four. Each cooling

system consists of an air handling unit and a chiller unit. For the Unit 1 Emergency Switchgear Room, these are:

1. air handler 1-HV-AC-6 with associated chiller 1-HV-E-4A, and
2. air handler 1-HV-AC-7 with associated chiller 1-HV-E-4C.

For the Unit 2 Relay Room, these are:

1. air handler 2-HV-AC-6 with associated chiller 2-HV-E-4C, and
2. air handler 2-HV-AC-7 with associated chiller 2-HV-E-4A.

A third chiller 1-HV-E-4B (2-HV-E-4B) for Unit 1 (Unit 2) is provided as a spare and serves as a backup/replacement for either chiller 1-HV-E-4A (2-HV-E-4A) or 4C.

These ESGR air handling units take in air from the ESGR rooms, filter it, cool it, and return it to the associated room.

#### **A.15.2 Fault Tree Analysis**

The dependency matrices for the ESGR cooling system are shown in Table A.15-1. The ESGR cooling was modeled on the event trees as a front line function. Loss of ESGR cooling of one reactor unit for an extended period of time leads to loss of all emergency AC power for that reactor unit and thus, it was an all encompassing critical failure. The HV1 fault tree success criteria for Unit 1 ESGR cooling were 1 of 3 chillers and 1 of 2 AHUs during all accident conditions.

The HV2 fault tree success criteria for Unit 2 ESGR cooling assumes that Unit 1 ESGR cooling is preserved through procedure 0-AP-55, which directs operators to open the doors between the Unit 1 ESGR and Unit 2 ESGR, and to place portable fans to direct cool Unit 2 ESGR air into the Unit 1 ESGR. The success criteria for Unit 2 ESGR equipment is 1 of 3 chillers and 1 of 2 AHUs, which will permit some heatup of both rooms, but will keep both rooms below 120°F.

The notes and assumptions used to develop the fault tree follow. The fault tree is listed at the end of the section.

#### **ESGR Cooling Fault Tree Modeling Assumptions**

The following modeling assumptions are specific for the Unit 1 HV1 fault tree.

1. For the HV1 fault tree only, at the start of the accident, it is assumed that chiller train A is operating, and that both chiller trains B and C can be used as backup (chiller C is labeled standby and chiller B is labeled spare for clarity, but these labels only affect the order of backup chiller startup). Also, AHU 1-HV-AC-6 is assumed to be operating at the start of the accident, with AHU 1-HV-AC-7 used as backup. SW supply is assumed from the "normal" SW supply header (36"-WS-2-151-03, Supply Header B) through the 1-HV-S-1A strainer with SW discharge to the "normal" SW discharge header (36"-WS-4-151-03, Discharge Header B).
2. For the HV1 fault tree only, on the standby C Chiller train, it is assumed that the following valves are initially closed:

- 1-CD-182
- 1-HV-MOV-111C
- 1-HV-MOV-113C
- 1-HV-PCV-1235C-1
- 1-HV-PCV-1235C-2
- 1-SW-386
- 1-SW-402

For the HV1 fault tree only, on the spare B Chiller train, it is assumed that the following valves are initially closed:

- 1-CD-205
- 1-CD-209
- 1-CD-216
- 1-HV-MOV-111B
- 1-HV-MOV-113B
- 1-HV-PCV-1235B-1
- 1-HV-PCV-1235B-2
- 1-SW-420
- 1-SW-436

For the HV1 fault tree only, the following manual valves are assumed to be closed to isolate the B & C chiller suction and discharge piping from the operating A chiller:

- 1-CD-174
- 1-CD-175
- 1-SW-362
- 1-SW-385

3. Manual valves in running trains do not experience plugging faults. This includes the A chiller train on both the SW and chilled water sides.
4. Manual valves in standby trains are assumed to be subject to plugging faults if they are normally open. This applies primarily to the B and C chiller trains on both the SW and

chiller water sides. Plugging faults are subsumed within the fails closed fault for normally closed manual valves and MOVs.

5. The standby chiller train faults for the C chiller include the normal faults modeled for a standby pump train. These include fail to start (pumps & chiller), fail to run for 24 hour mission (pumps & chiller), loss of motive power, loss of control power, and unscheduled maintenance. As motive and control power sources are the same for all components, these sources are modeled as electrical faults within the chiller train.

The spare chiller train faults for the B chiller are similarly modeled and include the normal faults modeled for a standby pump train. These include fail to start (pumps & chiller), fail to run for 24 hour mission (pumps & chiller), loss of motive power, loss of control power, and unscheduled maintenance. As motive and control power sources are the same for all components, these sources are modeled as electrical faults within the chiller train.

6. The AHUs are assumed to be passive except for the fan motors. A loss of function fault is used to address fans, tube leaks, tube plugging, air flow blockage and other faults. Note that the motor operated dampers are physically separate from the AHUs, and the MODs are modeled as a separate active component in both fault trees.

The AHU chilled water flow path includes a TCV which is modulated to control ESGR ambient temperature by limiting chiller water flow through the AHU coils. For a standby AHU, the TCV bypasses the AHU coil (e.g., water flows through a bypass line -- see the Dependency Matrix). No TCV faults were noted within the North Anna operating history, and the TCV-LF type 3 probability of  $1.81\text{E-}2$  is felt to be unreasonably high. Accordingly, the type 4 TCV-SC (spurious closure) fault is used to model TCV faults for a running AHU. For the standby AHU, a TCV-FC fault is also modeled due to the initial state of the TCV.

7. The AHU fan motors are modeled with a fail to start (backup 1-HV-AC-7 and 2-HV-AC-6 only) and fail to run 24 hours faults. The fan motors have a motive power source, but no control power.

For the HV1 fault tree only, the AHU chilled air flow path includes a MOD (Motor Operated Damper) that opens when the AHU fan is energized. For the standby AHU 1-HV-AC-7 the MOD is initially closed, blocking the AHU chilled air flow path (and preventing air flow diversion from the operating AHU 1-HV-AC-6). The type 4 MOD-SC (spurious closure) fault is used to model MOD undesired closure faults for a running AHU. For the



standby AHU, a MOD-FC fault is modeled due to the initial state of the MOD. Also, during backup AHU 1-HV-AC-7 startup upon operating AHU 1-HV-AC-6 run fault, the 1-HV-MOD-137 for the failed operating AHU must close to avoid an air flow diversion path (e.g., backflow from 1-HV-AC-7 through the failed 1-HV-AC-6, exiting through the failed 1-HV-AC-6 filters into the ESGR). Although this air flow diversion would still dump chilled air into the ESGR, the chilled air is not distributed so as to remove heat from the switchgear. Hence a MOD-FO fault for 1-HV-MOD-137 is modeled for this air flow diversion, failing the standby 1-HV-AC-7 upon startup. This fault would be easily recovered by the operators, but fault discovery could be prolonged because there is little instrumentation/annunciation.

8. The 1-HV-MOV-111A/B/C and 113A/B/C (2-HV-MOV-211A/B/C and 213A/B/C) valves are modeled as described in the station drawings. It is assumed that the running 111A & 113A (211A & 213A) valves can spuriously close, and that the standby 111B/C & 113B/C (211B/C & 213B/C) valves are closed and can fail to open (MOV-SC is subsumed within the MOV-FC fault).
9. For the HV1 fault tree only, Unit 1 HV SW supply is assumed from the "normal" SW supply header (36"-WS-2-151-03, Supply Header B) through the 1-HV-S-1A strainer with SW discharge to the "normal" SW discharge header (36"-WS-4-151-03, Discharge Header A). The "alternate" SW supply and discharge headers and the 1-HV-S-1B strainer are assumed to be isolated from the operating chiller train A flow path by manual valve 1-SW-362 & 1-SW-385. An external transfer is provided to the SW1 fault tree to model SW supply faults (pumps, headers, etc.) and SW discharge faults (e.g., MOV faults for lake-to-lake mode).
10. No plugging history was noted in the North Anna operating data for the 1-HV-S-1A & 1B (2-HV-S-1A & 1B) strainers. Generally strainers in clean water (i.e., not lake water) systems are not modeled; however, since there is some possibility of debris or foreign material in the SW system, an exception is made. For the HV1 (and HV2) fault tree, strainer plugging is modeled based upon an assumed strainer/SW supply header lineup configuration. The 1-HV-S-1A (2-HV-S-1A) strainer is assumed to be operating at the start of the accident, and is modeled with a type 4 STR-PL fault. The 1-HV-S-1B (2-HV-S-1B) strainer is assumed to be in standby, and is modeled with a type 2 STR-PG fault. A one month (720 hour) interval between tests is assumed based upon monthly chiller rotation.
11. The 1-HV-RV-1200 & 1201 (2-HV-RV-2200 & 2201) relief valve flow diversions are modeled as SV--SO (safety relief valve spuriously opens) faults over a 24 hour mission. Recovery is possible through Domestic Water system makeup; but, as this

system is not powered by an Emergency Bus, this recovery is not modeled.

12. The 1-HV-RV-1202A, 1202B & 1202C (2-HV-RV-2202A, 2202B & 2202C) relief valve flow diversions are modeled as SV--SO (safety relief valve spuriously opens) faults over a 24 hour mission. Recovery is possible through Domestic Water system makeup, but as this system is not powered by an Emergency Bus, this recovery is not modeled.
13. The 1-HV-RV-1205A, 1205B & 1205C (2-HV-RV-2205A, 22-5B & 2205C) relief valve flow diversions are modeled as SV--SO (safety relief valve spuriously opens) faults over a 24 hour mission. Since the concern with these valves spuriously opening is flooding, it is assumed that the affected chiller train must be isolated to avoid loss of all three chillers (leading to a station blackout). Flooding without isolation is addressed within the Internal Flooding analysis, so that the fault in HV1 is limited to the sole affected chiller that is assumed to be isolated to prevent Unit 1 Air Conditioning Room flooding.
14. HV makeup is provided by the Domestic Water system. A review of station drawings indicates that HV for both Unit 1 and Unit 2 is isolated from the Domestic Water system by at least two check valves so that a flow diversion from HV to the Domestic Water system is not probable and does not require modeling within the HV1 or HV2 fault trees.
15. The spurious closure of 1-HV-PCV-1235A-2, 1235B-2, or 1235C-2 (2-HV-PCV-2235A-2, 2235B-2, or 2235C-2) will fail the applicable chiller train, so a PCV-SC fault is modeled for all three chiller trains. Since 1-HV-PCV-1235B-2 & 1235C-2 (2-HV-PCV-2235B-2 & 2235C-2) are open initially in the spare chiller B train and the standby chiller C train, PCV-FC faults are not modeled.
16. The spurious closure of 1-HV-PCV-1235A-1, 1235B-1, or 1235C-1 (2-HV-PCV-2235A-1, 2235B-1, or 2235C-1) will fail the applicable chiller train, so a PCV-SC fault is modeled for all three chiller trains. Since 1-HV-PCV-1235B-1 & 1235C-1 (2-HV-PCV-2235B-1 & 2235C-1) are closed initially in the spare chiller B train and the standby chiller C train, PCV-FC faults are modeled.
17. Although TM & UM take place on the SW side of the chiller trains, the TM & UM faults are modeled on the chilled water side. A fault on either the chilled water or SW side fails the train, so placement of the fault is not important.

19. For mode 2 faults on standby components, an interval of 720 hours is used as chillers are rotated each month per North Anna procedure 0-MISC-2.
20. Common Cause Faults (CCF) for the Unit 1 HV1 fault tree are assumed for like active components in standby. For normal standby components, this would include

- 1-CD-182 and 1-CD-209 (check valves)
- 1-HV-E-4B and 1-HV-E-4C
- 1-HV-MOV-111B and 1-HV-MOV-111C
- 1-HV-MOV-113B and 1-HV-MOV-113C
- 1-HV-P-20B and 1-HV-P-20C
- 1-HV-P-22B and 1-HV-P-22C
- 1-HV-PCV-1235B-1 and 1-HV-PCV-1235C-1
- 1-SW-386 and 1-SW-420 (check valves)
- 1-SW-402 and 1-SW-436 (check valves)

All of these are standby components, and all are obvious active components and are included within the HV1 fault tree.

The following modeling assumptions are exceptions to the Unit 1 HV1 fault tree assumption list, that apply only to the Unit 2 HV2 fault tree.

21. For the HV2 fault tree only, at the start of the Unit 1 accident, it is assumed that the Unit 2 chiller train A is operating, and that both Unit 2 chiller trains B and C can be used as backup (chiller C is labeled standby and chiller B is labeled spare for clarity, but these labels only affect the order of backup chiller startup). Also, the Unit 2 AHU 2-HV-AC-7 is assumed to be operating at the start of the accident, with AHU 2-HV-AC-6 used as backup. SW supply is assumed from the "normal" SW supply header (36"-WS-1-151-03, Supply Header A) through the 2-HV-S-1A strainer with SW discharge to the "normal" SW discharge header (36"-WS-4-151-03, Discharge Header A).
22. For the HV2 fault tree only, on the standby 2-HV-E-4C Chiller train, it is assumed that the following valves are initially closed:

- 2-CD-187
- 2-HV-MOV-211C
- 2-HV-MOV-213C
- 2-HV-PCV-2235C-1
- 2-HV-PCV-2235C-2
- 2-SW-306
- 2-SW-322

For the HV2 fault tree only, on the spare 2-HV-E-4B Chiller train, it is assumed that the following valves are initially closed:

- 2-CD-207
- 2-CD-209
- 2-CD-218
- 2-HV-MOV-211B
- 2-HV-MOV-213B
- 2-HV-PCV-2235B-1
- 2-HV-PCV-2235B-2
- 2-SW-337
- 2-SW-353

For the HV2 fault tree only, the following manual valves are assumed to be closed to isolate the 2-HV-E-4B & 4C chiller suction and discharge piping from the operating 2-HV-E-4A chiller:

- 2-CD-176
- 2-CD-198
- 2-SW-302
- 2-SW-305

23. For the HV2 fault tree only, the Unit 2 AHU chilled air flow paths include a MOD (Motor Operated Damper) that opens when the AHU fan is energized. For the standby AHU 2-HV-AC-6 the MOD is initially closed, blocking the AHU chilled air flow path (and preventing air flow diversion from the operating AHU 2-HV-AC-7). The type 4 MOD-SC (spurious closure) fault is used to model MOD faults for a running AHU. For the standby AHU, a MOD-FC fault is modeled due to the initial state of the MOD. The Unit 2 HV2 model includes the MOD-FO air flow diversion fault similar to that for the Unit 1 HV1 fault tree, as a 1 of 2 AHU success criteria is assumed in both models. If the operating AHU 2-HV-AC-7 fails during the mission, there is no T8 recovery success if the AC-7 MOD fails open. See assumption 7 for HV1 for a similar approach.
24. For the HV2 fault tree only, Unit 2 HV SW supply is assumed from the "normal" SW supply header (36"-WS-2-151-03, Supply Header A) through the 1-HV-S-1A strainer with SW discharge to the "normal" SW discharge header (36"-WS-4-151-03, Discharge Header A). The "alternate" SW supply and discharge headers and the 2-HV-S-1B strainer are assumed to be isolated from the operating chiller train A flow path by manual valves 2-SW-302 & 305. An external transfer is provided to the SW1 fault tree to model SW supply faults (pumps, headers, etc.) and a second external transfer is provided to the SW1 fault tree to model SW discharge faults (e.g., MOV faults for lake-to-lake mode).

25. Common Cause Faults (CCF) for the Unit 2 HV2 fault tree are assumed for like active components in standby. For normal standby components, this would include

- 2-CD-187 and 2-CD-211 (check valves)
- 2-HV-E-4B and 2-HV-E-4C
- 2-HV-MOV-211B and 2-HV-MOV-211C
- 2-HV-MOV-213B and 2-HV-MOV-213C
- 2-HV-P-20B and 2-HV-P-20C
- 2-HV-P-22B and 2-HV-P-22C
- 2-HV-PCV-2235B-1 and 2-HV-PCV-2235C-1
- 2-SW-306 and 2-SW-337 (check valves)
- 2-SW-322 and 2-SW-353 (check valves)

All of these are standby components, and all are obvious active components and are included within the HV2 fault tree.

#### **A.16 COMPRESSED AIR SYSTEM**

This system consists of three individual subsystems associated with each reactor unit. The system can be considered common to Units 1 and 2, however, by virtue of the extensive cross-connections between the two reactor units. Its primary purpose is to provide a source of clean, filtered, dry, pressurized air for the operation of pneumatically operated valves and other components throughout the reactor plant. An additional purpose of the Compressed Air System is to provide service air facilities for the operation of air-operated tools.

The reliability of the system is improved by cross-connecting the Units 1 and 2 Service Air Subsystems and the Units 1 and 2 Instrument Air Subsystems. The two Containment Instrument Air Subsystems operate independently of each other. Each Containment Instrument Air Subsystem is backed-up by the Units 1 and 2 Instrument Air Subsystems, further enhancing system reliability. The Instrument Air Subsystems are backed-up by the Units 1 and 2 Service Air Subsystems. References in this text to the Service or Instrument Air Subsystems include both the Units 1 and 2 subsystems.

##### **A.16.1 Components**

##### **Service Air Subsystem**

The Service Air Subsystem air supply consists of two compressors located outside the Unit 2 Turbine Building north rolling door (truck bay). Each Service Air Compressor is associated with one unit in terms of power supply and control. However, both compressors discharge into a common header.

Service Air storage capability consists of three receiver tanks. One large receiver is located in the Unit 2 Turbine Building Basement just below the truck bay, and two smaller receivers are located on the second floor of the Auxiliary Building South of the Charging Pump Cubes. The Auxiliary Building Service Air Receivers normally supply the plant Service Air System header, and also supply backup air to the two Instrument Air Receivers.

### **Instrument Air Subsystem**

The Instrument Air Subsystem air supply consists of two compressors located on the second floor of the Auxiliary Building South of the Charging Pump Cubes. Each Instrument Air Compressor is associated with one unit in terms of power supply and control, and discharges to individual Instrument Air Receivers.

Instrument Air storage capability consists of two receiver tanks-both located on the Auxiliary Building second floor south of the Charging Pump Cubes, right next to the two Service Air Receivers. The outlet of the Instrument Air receivers flows to the Instrument Air Drying Towers in the Auxiliary Building.

The Instrument Air Drying Tower assemblies consist of a Prefilter, Desiccant Towers and Postfilter. There are three Drying Tower assemblies. One at the outlet of each of the two Instrument Air Receivers in the Aux Bldg, and one in the Unit 2 Turbine Building basement. The tower in the Turbine Bldg dries air which can be supplied from the Turbine Bldg Service Air Receiver to the Turbine Building Instrument Air header (normally not in service). The function of the filters and drying towers is to clean and remove moisture from Instrument Air so that it meets or exceeds purity requirements for control air systems. The outlets of the drying towers flows to the plant Instrument Air headers.

### **Containment Instrument Air Subsystem**

The two Containment Instrument Air Subsystems are each provided with two 100 percent capacity air compressors located inside Containment. Containment air loads are normally supplied with air from the Instrument Air Subsystem.

Small, seismically qualified instrument air receivers have been provided for critical valves in the Main Steam and Auxiliary Feedwater Systems that receive air from the Instrument Air Subsystem. These valves may be required to operate in an accident situation; therefore, an additional reserve air source is provided. A check valve associated with each of these receivers prevents the receiver from depressurizing if Instrument Air Subsystem pressure is lost.

## **Construction Air Subsystem**

The Construction Air Subsystem consists of three motor driven, oil lubricated, rotary air compressors located South of the plant outside the Protected Area fence. One is located by Security Post #4, and two are located at the Northeast corner of the Service Water Reservoir. Two Construction Air Receivers (one just North of the air compressors by the SW Reservoir and one by the Liquid Waste Treatment Facility in Units #3 and #4 area) makeup the Construction Air Subsystem storage capability.

### **A.16.2 Flow Paths**

#### **Service Air Subsystem**

The two Service Air Compressors (1-SA-C-1 and 2-SA-C-1) are located outside, just North of the Unit 2 Turbine Building North wall and just East of the Unit 2 Station Service Transformers. They are protected from sun, rain and snow by a sheet metal shed roof. The compressors take suction from outside air and discharge to a common 4 inch header. The entire run of Service Air piping from the SA Compressors to the Auxiliary Building is of stainless steel. Each compressor has a discharge isolation valve (1-SA-301, 2-SA-1026) and a muffler (1/2-SA-SIL-1) for maintenance isolation and flow testing. A Temporary Compressor Tie-In via 1-SA-302 can be used for additional compressed air capacity when one or both of the Service Air Compressors are out of service.

The common discharge line from the Service Air Compressors has connections for a future aftercooler just before going through the Unit 2 Turbine Building North wall. The Air then flows to the Service Air Receiver (2-SA-TK-2) in the Unit 2 Turbine Building basement via 2-SA-1030 (check valve) and 1031. Moisture is removed from this line by a trap (2-SA-TD-1).

The Service Air Receiver (2-SA-TK-2) serves as a storage volume for compressed Service Air and a distribution point for Service Air supply to:

1. Service Air Receivers in the Auxiliary Building (1/2-SA-TK-1).
2. Unit 2 (and Unit 1 via crosstie valves) Turbine Building Instrument Air header through 2-IA-2016 and Instrument Air Dryer (2-IA-D-7). This flowpath will be normally isolated.
3. Unit 2 (and Unit 1 via crosstie valves) Turbine Building Service Air header through 2-SA-1039. This flowpath will be normally isolated.

Service Air Receiver (2-SA-TK-2) can be bypassed, and air sent directly to the Auxiliary Building Service Air Receivers and/or the Turbine Bldg SA header by opening 2-SA-1032. Moisture is removed from this tank by trap (2-SA-ADV-1).

The 4 inch stainless steel SA line to the Auxiliary Building leaves the Service Air Receiver (2-SA-TK-2) via 2-SA-1038, runs south to the south wall of Unit 2 Turbine Building basement, turns east and over to Unit 1 Turbine Building basement where it enters the TB/AB Pipe Tunnel. From the Auxiliary Building end of the Pipe Tunnel, the line runs to a distribution manifold on the second floor Aux Bldg just south of the Charging Pump cubicles. Between 2-SA-TK-2 and this manifold moisture is removed from the SA line by three traps (2-SA-TD-2, 3 and 4)--the Pipe Tunnel is the low point in the SA header.

From the distribution manifold in the Aux Bldg Service Air is normally sent to Service Air Receivers (1/2-SA-TK-1) via 1-SA-310 and 2-SA-1061 respectively. If need be, Service Air can also be sent directly to 1/2-IA-TK-1 via 2-IA-29, 30 and 31 at the manifold and 1-IA-1673 and 2-IA-8 at the respective IA Receivers. The direct SA to IA Receiver feed can also be split by closing 2-IA-30. The direct feed from SA to IA Receivers is normally isolated.

The Service Air Receivers (1/2-SA-TK-1) are located on the second floor of the Auxiliary Bldg just south of the Charging Pump cubicles. They serve as additional SA storage capacity and as a point of Service Air distribution to the plant SA header and backup supply to the Instrument Air Receivers for both Units 1 and 2 (1/2-IA-TK-1). Moisture is removed from each Aux Bldg SA Receiver by an Automatic Drain Valve. The entire SA header throughout the plant is normally fed from the Aux Bldg SA Receivers (Turbine Bldg fed by line from Aux Bldg to Turb Bldg through Pipe Tunnel).

Each SA Receiver serves as a backup supply to both IA Receivers via four (4) pressure control valves (PCVs). 1-SA-TK-1 backs-up 1-IA-TK-1 and 2-IA-TK-1 via 1-SA-PCV-101 and 1-SA-PCV-105 respectively. 2-SA-TK-1 backs-up 1-IA-TK-1 and 2-IA-TK-1 via 2-SA-PCV-205 and 2-SA-PCV-201 respectively. Additionally, there is a normally-shut manual valve (1-IA-1671 and 2-IA-10) which can be used to feed to the IA outlet of each IA Receiver from just downstream of each unit's respective SA to IA backup PCV. These PCVs are installed and designed to open on decreasing IA Receiver pressure. Pressure controllers located adjacent to these PCVs were originally set to open at 90 psig decreasing IA Receiver pressure, but are currently set at 120 psig. Since IA pressure is nominally about 100 psig, the result is that these PCVs are currently always full open such that Service Air is the primary source of Instrument Air pressure, and the Instrument Air Compressors load as necessary on decreasing IA pressure for additional IA supply. In the future, when modifications to the Compressed Air System are complete, the



pressure controllers for the backup PCVs will be reset to open at 90 psig.

### **Service Air Subsystem**

Service air is provided to Containment for the operation of the fuel transfer conveyor and air hose connections. Locked-shut manual isolation valves isolate service air from Containment. Whenever the isolation valves are opened, an individual is assigned to stand near the valves to provide containment isolation, if required.

### **Instrument Air Subsystem**

The Instrument Air Compressors (1/2-IA-C-1) are located on the second floor of the Auxiliary Bldg just South of the Charging Pump cubicles. They take suction from the air in the South side of the Auxiliary Bldg fourth floor through two Filter Silencers (1-FA-FL-3A and 3B). The IA Compressors discharge to their respective IA Receivers through individual check valves and manual isolation valves. The check valves (1-IA-1658 and 2-IA-7) have a 1/8 inch bleed hole drilled through their disks so that the pressure switches (located in the IA Compressor enclosures) controlling compressor loading and unloading can sense IA Receiver pressure. The discharges of the two IA Compressors can be crosstied via normally-shut manual valve 1-IA-2074.

The Instrument Air Receivers are located on the Auxiliary Bldg second floor next to the Service Air Receivers and are equipped with automatic moisture-removing drain valves. Instrument Air flows from each unit's IA Receiver to individual IA Desiccant Tower Dryers (1/2-IA-D-1) where remaining moisture is removed before flowing to the Instrument Air distribution header. The IA Dryers can be bypassed by opening manual bypass valves (1-IA-1676 and 2-IA-23). Instrument Air flows from the outlet of the Desiccant Towers to the IA header which distributes IA to the entire plant.

The Instrument Air header to the Unit 1 and Unit 2 Containments enters the containment structures through Containment Isolation Trip Valves, and interfaces with the Containment Instrument Air Subsystem. Normally, the Containment Instrument Air Subsystem is secured and the plant Instrument Air Subsystem supplies IA to all IA loads in the Containment.

The Instrument Air Subsystem supplies dry air primarily to air-operated control valves, such as the turbine control valves, secondary drains normal and high level divert valves, and feedwater and Auxiliary Feedwater control valves, to mention a few. In addition to the seismic air flask mentioned previously, some of the Instrument Air Subsystem control valves are provided with smaller

air flasks to provide a source of air for failing the valve to a safe position when normal air pressure is lost. An example of this type of flask is mounted next to the discharge valves of the high pressure (HP) heater drain pumps and provides a backup air source to the HP heater drain pump discharge valves to fail the valves open.

### **Containment Instrument Air Subsystem**

Each reactor unit is supplied with two air compressors (1/2-IA-C-2A/B), two air receivers (1/2-IA-TK-2A/B), an aftercooler, and two air dryers (1/2-IA-D-2A/B), all of which are located inside the Reactor Containment. The following discussion describes the flow path associated with compressor 2-IA-C-2A. The flow paths associated with 2-IA-C-2B are similar.

Compressor 2-IA-C-2A takes suction of the Containment atmosphere via an air filter. The compressor discharge is directed to containment instrument air receiver 2-IA-TK-2A, via a check valve. The normal pressure in the containment instrument air receivers is 95 psig. The discharge of the receiver is cross-connected to receiver 2-IA-TK-2B.

The desiccant-type dryer located on the discharge side of the aftercooler removes moisture from the containment instrument air, while a filter on either side of the dryer removes particles from the air. A check valve downstream of the dryer prevents backflow to the compressors.

### **A.16.3 Fault Tree Analysis**

A detailed fault tree was not developed for the instrument air system. Reliability analysis of the IA determined that it could be modeled as a basic event, input to the appropriate loads.

## **A.17 REACTOR PROTECTION SYSTEM**

### **A.17.1 Description**

An elaborate reactor protection system has been designed in order to guarantee the integrity of the reactor systems and to avoid undue risk to the health and safety of the public. The system is capable of supplying reactor trip signals and of initiating engineered safety features to provide protection during all normal operating and casualty conditions. There are two complete and independent sets of logic circuits in the reactor protection system, each set constituting a logic train.

The nuclear and process instrument system continuously monitor the operation of the reactor plant. When an unsafe condition is sensed by either logic train, a trip signal is sent to the protection cabinets. If a reactor trip is required, the protection cabinets send a signal to the reactor trip breakers to remove power from the control rod drive mechanisms, allowing the rods to drop into the reactor core. If the condition warrants safeguards actuation, the protection cabinets actuate the appropriate safeguard devices. Permissive and control signals are also generated to allow automatic or manually initiated interlocks.

The following design features ensure that the system performs its required functions under all credible accident conditions with a high degree of reliability:

1. Redundancy - Parameters that indicate an unsafe condition have multiple measurement systems. Sufficient measurement systems are provided to allow a coincident logic scheme such that a spurious measurement neither causes nor prevents a reactor trip or engineered safety features actuation. For example, two out of four power range flux channels are required to sense a high flux condition before a reactor trip is initiated. The failure of any one channel cannot cause nor prevent a reactor high flux reactor trip.
2. Independence - Redundant measurement and protection channels are physically and electrically separated from the other channels. Components of different channels are physically separated, penetrate the Containment at different locations, and are supplied by independent electrical power supplies. Independence decreases the probability that a single malfunction or casualty interrupts more than one of the redundant channels or trains.
3. Diversification - Several different methods are used to perform similar functions or to indicate the same condition. For example: reactor power is detected by the nuclear instruments measuring leakage neutrons and by the process instruments measuring differential temperature across the reactor, which is proportional to reactor power for a constant flow. Diversity is provided through systems and equipment, interlocks, and trip features.
4. Fail safe - The system is designed to supply the safest signal for a failure. Loss of power to a trip bistable assumes that a trip condition exists and supplies a trip signal to the protective logics. Loss of power to the Rod Control System due to a power failure or the

appropriate trip signals results in the control rods falling into the core.

5. Testability - The Reactor Protection Systems are capable of being calibrated or tested at power without the loss of protection.
6. Control system interactions do not degrade reliability -  
The control systems are designed to maintain steady-state operating conditions, assuring adequate margin to trip settings, and to suppress excursions imposed by operational transients before protective action is required. These signals require instruments that measure the same major plant variables that the protection systems require. As a result, some of the primary sensor and transmitting equipment used in the protection systems is also used for the control systems. Isolation amplifiers are used to maintain the control systems separate and distinct from the protection systems. (An isolation amplifier is an amplifier that does not have a physical connection between its input and output.) They are used to ensure that there is no feedback from the control systems to the protection systems.

The Reactor Protection System (RPS) automatically trips the reactor whenever the plant conditions reach limiting safety system settings. A sketch of the RPS logic is shown in Figure A.17-1. When the appropriate logic conditions are met, RPS receives a trip signal from the nuclear or process instruments. RPS then sends a signal to deenergize the undervoltage coils and energize the shunt trip coils of the reactor trip breakers. The system also provides alarms that alert the plant operator when manual action is required to prevent a plant trip. RPS also generates signals that are used for turbine load reductions (turbine runback) or blocking of rod control system operations if certain trip setpoints are approached.

There are two reactor trip breakers, one for each logic train. The trip breakers are arranged in series so that only one breaker must trip to interrupt power to the Rod Control System. When power is interrupted to the control rod drive mechanism, the latch mechanism retracts by spring pressure from the drive shaft, and the rod control cluster assemblies drop into the core.

Safety limits are established to prevent exceeding parameters that could breach system integrity by rupturing the Reactor Coolant System, by rupturing or melting the clad, or by melting the fuel. A peak system pressure is established to ensure the Reactor Coolant System integrity. Fuel melting is prevented by limiting the linear power density (kilowatts per foot) of the fuel to ensure that heat is not generated at a rate greater than it can be removed. The integrity of the clad is ensured by preventing the conditions from existing that cause departure from nucleate boiling (DNB) with the

subsequent reduction of heat transfer capability at the fuel cladding surface.

### **Engineered Safety Features**

RPS automatically initiates the Engineered Safety Features (ESF) to limit the consequences of infrequent faults and to mitigate limiting fault conditions to reduce the potential for a significant release of radioactive materials. When the protection system trip logic senses a condition requiring safeguards actuation, it sends a signal to activate the appropriate master relays. Each master relay actuates up to four heavy-duty slave relays that supply operating current to up to eight safeguard actuation devices.

The ESF are used to provide protection against the release of radioactive materials in the event of a loss of coolant accident, a main steam line break, a steam generator tube rupture, or rod ejection accident. The systems function to maintain the reactor in a shutdown condition, to provide sufficient core cooling to limit the extent of fuel and fuel cladding damage, and to ensure the integrity of the RCS and Containment. The engineered safety features systems include

1. Safety Injection System,
2. Containment,
3. Containment Isolation System,
4. Containment Atmosphere Cleanup System, and
5. Containment Depressurization Systems.

The monitored parameters that can actuate one or more ESF systems include

1. containment pressure,
2. steam line flows,
3. pressurizer pressure,
4. steam line pressure, and
5. RCS  $T_{avg}$ .

### **A.17.2 AMSAC**

The AMSAC system is diverse from the Reactor Protection System, however, it does use some of the same sensing devices as the

Reactor Protection System. A sketch of the AMSAC logic is shown in Figure A.17-2.

### **System Design and Purpose**

The purpose of the AMSAC system is to initiate a turbine trip, a reactor trip, and Auxiliary Feedwater system flow upon detection of an ATWS event and preventing a loss of heat sink with a failure of the turbine to trip. An ATWS event is described as a postulated operational occurrence or design basis event coincident with a failure of the Reactor Protection System to shutdown the reactor.

The reason for the installation of the AMSAC system comes from the NRC concern of being able to prevent a loss of heat sink due to an ATWS. This loss of heat sink with an ATWS could overpressurize the Primary System challenging one of the fission barriers, namely the Reactor Coolant System. The worst case condition analyzed is a four loop plant where peak Primary pressure can reach approximately 3200psig. A three loop plant does not peak as high; therefore, a three loop plant is conservative. At first, the industry did not feel ATWS as a concern due to designed automatic actuations and expected operator actions. The NRC concern was proven correct due to two different incidents, namely:

- The Salem incident, where the Reactor Trip Breakers failed to open.
- The TMI incident where Operator action was not taken in a timely manner.

### **Inputs**

The input signals are wired to three programmable logic controllers (PLC) located in the AMSAC panel. Isolation devices are used between the signal sensing devices in the 7300 system and AMSAC. One PLC is dedicated to each steam generator and the two turbine impulse chamber pressure signals are wired to each PLC. The PLCs perform timing, logic functions, and provide outputs to various loads. The outputs to safety-related circuits are wired through safety-related qualified class 1E isolation relays.

The steam generator level signals are from the narrow range channels of each steam generator. ("A" steam generator CH 474, 475, 476; "B" steam generator CH 484, 485, 486; "C" steam generator CH 494, 495, 496). The turbine load signals are from turbine impulse pressure channels III & IV (P-446, 447).

The AMSAC panel is located in the instrument rack room. The AMSAC panel is powered from the TSC uninterruptible power supply through a breaker panel located in the HP office in the TSC.

## **Actuation Logic**

The AMSAC is initiated when the turbine load is greater than 40 percent and a complete loss of feedwater is detected. Loss of feedwater is the condition of any 2 of the 3 level transmitters in any 2 out of 3 steam generators  $\leq$  13 percent of narrow range level span for greater than 27 seconds. The 27 second time delay is performed by the PLCs to allow the Reactor Protection System to respond first. Turbine load is a newly installed permissive (C-20) for AMSAC and is initiated when 2 of 2 first stage turbine pressures indicate power 40%. Permissive C-20 stays locked in when power goes above 40 percent and stays locked in for 6 minutes when power is reduced below 40 percent. The 27 second steam generator low level timer does not function unless C-20 for the respective PLC is present.

## **Automatic Actuations Performed**

When the AMSAC system is actuated the following is initiated after the time delay:

- Main turbine trip via 20AST-1 & 20AST-2.
- All 3 Auxiliary Feedwater pumps will receive start signals.
- The supply breakers for the rod drive MG set will receive a trip signal.
- The steam generator blowdown trip valves and sample isolation valves will receive a trip signal.

Outputs from the AMSAC panel is through two AMSAC output relays powered from the AMSAC system. The output contacts of these 2 relays are installed across the relay control power to the component which is to be actuated. This configuration eliminates the use of slave relays.

When actuated, AMSAC locks in and must be reset in order to be able to make any AMSAC actuated equipment operational. System reset is located on the main control board.

## **RPS Fault Tree Modeling Assumptions**

1. The fault tree is a simplified representation of the reactor protection system. The key components included in the model are the input logic signal, the reactor trip breakers and the control rods. A similar approach is used in WCAP-10271.

2. The reactor trip bypass breakers are assumed to be open. Interlocks prevent both bypass breakers from being simultaneously closed. During reactor trip breaker testing, a bypass breaker is closed while the corresponding main breaker is tested. Typically a main and its bypass breaker will only be simultaneously closed for a very short period of time. The length of time is less than the total time to perform the test procedure. Each bypass and main breaker pair receive their trip open signals from opposite trains of reactor protection. The bypass breakers are physically identical to the main breakers. Due to these facts the reactor protection fault tree will only include the main reactor trip breakers and will not model the bypass breakers.
3. WCAP-11993 provided the probability for the control rods failing to insert due to mechanical binding =  $1.80\text{E-}6$ .



**TABLE A.0-1**  
**COMPONENT NAMING SCHEME FOR NORTH ANNA PRA MODEL**

<u>IDENTIFIER</u>	<u>COMPONENT</u>
ACC	Accumulator
ANN	Annunciator
AOD	Air operated damper
AOV	Air Operated Valve (or cite by Function)
BAT	Battery
BCH	Battery Charger
BKR	Breaker
BLR	Boiler
BUS	Bus
CBL	Cable
CHU	Chiller
CKV	Check Valve
CLR	Cooler
CMP	Compressor
CON	Condenser
DDP	Diesel Driven Pump
EDG	Emergency Diesel Generator
EHR	Electrical Heater
ELG	Electrical Generator
FAN	Fan
FCV	Flow Control Valve (air operated)
FIC	Flow Instrument Channel
FLT	Filter
FUS	Fuse
HCV	Hand Control Valve (air operated)
HEP	Human Error Probability
HEX	Heat Exchanger
HTT	Heat Tracing
INV	Inverter
LCV	Level Control Valve (air operated)
LIC	Level Instrument Channel
LMS	Limit Switch
MCC	Motor Control Center
MVD	Motor Operated Damper
MOT	Motor
MOV	Motor Operated Valve
MV-	Manual Valve (no actuator)
NRV	Non Return Valve (Main Steam System only)
PAT	Alternating Motor Driven Pump
PCV	Pressure Control Valve (air operated)
PIC	Pressure Instrument Channel
PIP	Piping

**TABLE A.0-1 (Continued)**  
**COMPONENT NAMING SCHEME FOR NORTH ANNA PRA MODEL**

<u>IDENTIFIER</u>	<u>COMPONENT</u>
PSB	Standby Motor Driven Pump
REC	Rectifier
RLY	Relay
RPD	Rupture Disk
RV-	Relief Valve
SCN	Screen
SJE	Steam Jet Ejector
SOD	Solenoid Operated Damper
SOV	Solenoid Operated Valve
SST	Transformer, Station Service (22.5Kv/230Kv)
STR	Strainer
SV-	Safety Valve
SWG	Switchgear
TCV	Temperature Control Valve (air operated)
TFM	Transformer
TIC	Temperature Instrument Channel
TNK	Tank
TRB	Turbine Driven Pump
TRU	Trip Unit
TV-	Trip Valve
TXR	Timer
UPS	Uninterruptable Power Supply
VLV	Miscellaneous Valve

**Note**

Some component groups have been subdivided, i.e., Alternating pumps (PAT) and standby pumps (PSB).

**TABLE A.0-2**  
**FAILURE MODE CODES**

<u>Code</u>	<u>Failure Mode</u>	<u>Type</u>
FO	Fails in the open position	3
FC	Fails in the closed position	3
FR	Fails to continue running	4
FS	Fails to start	3
SO	Spurious opening	4
SP	Spurious opening	2
SC	Spurious closure	2, 4
LF	Loss of Function	2, 3, 4
LU	Loss of Function	4
LP	Fails to Supply Power	4, 2
MC	Calibration Error (miscalibration- Human interaction)	3
UM	Unscheduled Maintenance	3
TM	Scheduled test and maintenance	3
CC	Common Cause Failure	3
PG	Plug	2, 4
PL	Plug	4

**Note**

The NUPRA failure mode type is shown in column 3. It is necessary to differentiate between failures in standby (type 2) and running failures (type 4) for some components and therefore two failure mode codes are identified.

In the case of loss of function, for some components the words "loss of function" imply a failure on demand (type 3). Provided this component type does not also have type 2 failures it is permissible to use the letters LF for the type 3 failure.

**TABLE A.0-2 (Continued)**  
**FAILURE MODE TYPE CODES**

These NUPRA failure mode models are used in the North Anna PRA as follows:

<u>Mode Type</u>	<u>Failure Mode Description</u>	<u>Comment</u>
2	Periodically tested	Used for standby components whose failure is detected on test or on demand
3	Failure on demand	Average probability of failure on demand for standby components
4	Running failure	Model for component with constant failure rate during its mission

**TABLE A.1-1  
COMPONENT COOLING WATER  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-CC-P-1A	4160 V, BUS 1H	BATT 1-I, DIST CAB CKT 14	Stops on CDA Signal	---	None Required	---
1-CC-P-1B	4160 V, BUS 1J	BATT 1-III, DIST CAB CKT 16	Stops on CDA Signal	---	None Required	---
1-CC-MOV-100A	MCC 1A1-1, BKR C2	480 V	---	---	None Required	---
1-CC-MOV-100B	MCC 1B1-2, BKR C2	480 V	---	---	None Required	---
1-CC-TV-101A	Instrument Air thru 1-CC-SOV-101A	120 VAC from Vital BUS 1-I	Containment Isolation, Phase B Signal Present	---	None Required	Fails Closed
1-CC-TV-101B	Instrument Air thru 1-CC-SOV-101B	120 VAC from Vital BUS 1-III	Containment Isolation, Phase B Signal Present	---	None Required	Fails Closed
1-CC-TV-103A	Instrument Air thru 1-CC-SOV-103A	120 VAC from Vital BUS 1-I	Containment Isolation, Phase B Signal Present	---	None Required	Fails Closed
1-CC-TV-103B	Instrument Air thru 1-CC-SOV-103B	120 VAC from Vital BUS 1-III	Containment Isolation, Phase B Signal Present	---	None Required	Fails Closed
1-CC-TV-104A (ESK-6ME)	Instrument Air thru 1-CC-SOV-104A-1 and 1-CC-SOV-104A-2	Vital SOV Panel B BUS 1-III	Tripped by Containment Isolation Phase B Signal	---	None Required	Fails Closed

\*Interlocks or other functional dependencies included in this column

**TABLE A.1-1 (Continued)  
COMPONENT COOLING WATER  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-CC-TV-104B (ESK-6ME)	Instrument Air thru 1-CC-SOV-104B-1 and 1-CC-SOV-104B-2	Vital SOV Panel B BUS 1-III	Tripped by Containment Isolation Phase B Signal	---	None Required	Fails Closed
1-CC-TV-104C (ESK-6ME)	Instrument Air thru 1-CC-SOV-104C-1 and 1-CC-SOV-104C-2	Vital SOV Panel B BUS 1-III	Tripped by Containment Isolation Phase B Signal	---	None Required	Fails Closed
1-CC-TV-116A (ESK-6ME)	Instrument Air thru 1-CC-SOV-116A	120 VAC DIST Panel SDS CKT 23	Closes if flow greater than 59 gpm for more than 10 seconds	---	None Required	Fails Closed
1-CC-TV-116B (ESK-6ME)	Instrument Air thru 1-CC-SOV-116B	120 VAC DIST Panel SDS CKT 24	Closes if flow greater than 59 gpm for more than 10 seconds	---	None Required	Fails Closed
1-CC-TV-116C (ESK-6ME)	Instrument Air thru 1-CC-SOV-116C	120 VAC DIST Panel SDS CKT 25	Closes if flow greater than 59 gpm for more than 10 seconds	---	None Required	Fails Closed
MOV-SW-108A	MCC 1H1-1S, BKR A1	480 V	Closes on CDA Signal	---	None Required	---
MOV-SW-108B	MCC 1J1-1S, BKR A5	480 V	Closes on CDA Signal	---	None Required	---

\*Interlocks or other functional dependencies included in this column

**TABLE A.2-1  
CHARGING SYSTEM  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-CH-P-1A	4160 V Bus 1H 15H6	125V DC 1-I	SI-A Relay K609	Charging Pump SW System		
1-CH-P-1B	4160 V Bus 1J 15J6	125V DC 1-III	SI-B Relay K609	Charging Pump SW System		
1-CH-P-1C	4160 V Bus 1H-Norm. 1J-ALT	125V DC 1-I (Normal) 1-III (Alternate)	SI-A Relay K608	Charging Pump SW System		No Auto actuation on BUS 1J
1-CH-MOV-1115B	MCC 1J1-2N E3	Motive	SI-B Relay K604	None	None	
1-CH-MOV-1115C	MCC 1H1-2N F1	Motive	SI-A Relay K603	None	None	Interlocked with 1115D to not close until 1115D is open
1-CH-MOV-1115D	MCC 1H1-2N F2	Motive	SI-A Relay K603	None	None	
1-CH-MOV-1115E	MCC 1J1-2N F3	Motive	SI-B Relay K603	None	None	Interlocked with 1115B to not close until 1115B is open
1-CH-MOV-1267A	MCC 1H1-2S B3	Motive	None	None	None	
1-CH-MOV-1269A	MCC 1J1-2S C2	Motive	None	None	None	
1-CH-MOV-1270A	MCC 1H1-2S C3	Motive	None	None	None	
1-CH-MOV-1286A	MCC 1H1-2S D4	Motive	None	None	None	

**TABLE A.2-1 (Continued)**  
**CHARGING SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-CH-MOV-1286B	MCC 1J1-2S C3	Motive	None	None	None	
1-CH-MOV-1286C	MCC 1H1-2S E2	Motive	None	None	None	
1-CH-MOV-1350	MCC 1H1-2S F4	Motive	None	None	None	
1-CH-MOV-1370	MCC 1H1-2S K1	Motive	None	None	None	
1-CH-P-2A	MCC 1H1-2S L3	Motive	None	None Needed	None Needed	
1-CH-P-2B	MCC 1J1-2S H3	Motive	None	None	None	
1-CH-MOV-1275A	MCC-1H1-2S 2J	Motive				
1-CH-MOV-1275B	MCC-1H1-2N F3	Motive	None	None	None	
1-CH-MOV-1373	MCC-1J1-2S E3	Motive	None	None	None	
1-CH-RV-1257	None	None	None	None	None	
1-CH-AOV-1115A	Instrument Air	None	None	None	None	
1-SW-TCV-102B	Instrument Air	None	None	None	None	



**TABLE A.2-1 (Continued)**  
**CHARGING SYSTEM**  
**DEPENDENCY MATRIX**

**Notes to Charging Dependency Matrix**

1. Charging Pump 1C is normally racked in to Bus H and put in the auto-after-stop position. Pump 1C can also be racked into Bus J. When 1C is racked into J bus, it must be the running pump and 1B must be racked out.
2. Pump 1C gets no auto signals to start when it is on bus J. In order to meet the design basis, 1C must be running if it is on J bus.
3. Pump 1C gets all auto signals on bus H.
4. Charging pumps will start on a low discharge header pressure signal. The Charging Pumps will also auto start on low voltage on the other bus.
5. In addition to an SI signal to open, MOVs 1115B and D will open on low level in the volume control tank.
6. Service water is supplied to the seal cooler, the gear box cooler and the lube oil cooler. Failure to supply water was specifically modeled for the lube oil cooler and the gear box. The seal cooler gets water from the very same header as the gearbox cooler without any additional valves in the flow path. Thus, water is de facto required for the seal cooler. Whether or not service water is actually required for the seal cooler is not known. In the Surry IPE, it was shown that the seal cooler is unnecessary for pumped stream temperatures less than 250°F. Similar analysis was not done for North Anna, but the Surry results are probably applicable, as the charging pumps are of similar design.
7. Charging Pump control power is DC power from the DC emergency buses.

**TABLE A.3-1  
MAIN STEAM  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-MS-PCV-101A	instrument air (MS-012)	Vital bus 1-I 1-EP-CB-4A		---	None Required		air to open fails closed
1-MS-PCV-101B	instrument air (MS-013)	Vital bus 1-II 1-EP-CB-4B		---	None Required		air to open fails closed
1-MS-PCV-101C	instrument air (MS-014)	Vital bus 1-III 1-EP-CB-4C		---	None Required		air to open fails closed
1-MS-TCV-1408A	instrument air (MS-163)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408B	instrument air (MS-164)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408C	instrument air (MS-165)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408D	instrument air (MS-166)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed

**TABLE A.3-1 (Continued)**  
**MAIN STEAM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-MS-TCV-1408E	instrument air  (MS-167)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408F	instrument air  (MS-168)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408G	instrument air  (MS-169)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed
1-MS-TCV-1408H	instrument air  (MS-170)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B		---	None Required		air to open fails closed

**TABLE A.3-1 (Continued)**  
**MAIN STEAM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-MS-TV-101A	instrument air  (MS-110)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B (ESK-6PN)	see SOV-MS101A-1 SOV-MS101A-2 SOV-MS101A-6 SOV-MS101A-7	---	None Required	all 4 SOVs have to be de-energized to open 1-MS-TV-101A	air to open fails closed
1-MS-TV-101B	instrument air  (MS-111)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B (ESK-6PP)	see SOV-MS101B-1 SOV-MS101B-2 SOV-MS101B-6 SOV-MS101B-7	---	None Required	all 4 SOVs have to be de-energized to open 1-MS-TV-101B	air to open fails closed
1-MS-TV-101C	instrument air  (MS-112)	125 VDC Battery 1-I and 1-III 1-EP-CB-23A & 1-EP-CB-23B (ESK-6PQ)	see SOV-MS101C-1 SOV-MS101C-2 SOV-MS101C-6 SOV-MS101C-7	---	None Required	all 4 SOVs have to be de-energized to open 1-MS-TV-101C	air to open fails closed
1-MS-SOV-101A-1	  (MS-110)	125 VDC  1-EP-CB-23A (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101A-2	  (MS-110)	125 VDC 1-EP-CB-23B (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101A-6	  (MS-110)	125 VDC 1-EP-CB-20 (FE-18D) MCC 101-1 (FE-9GQ)		---	None Required		energized to vent air
1-MS-SOV-101A-7	  (MS-110)	125 VDC 1-EP-CB-21 (FE-18C) 1-EP-CB-16B (FE-11C)		---	None Required		energized to vent air

**TABLE A.3-1 (Continued)**  
**MAIN STEAM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-MS-SOV-101B-1	(MS-111)	125 VDC 1-EP-CB-23A (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101B-2	(MS-111)	125 VDC 1-EP-CB-23B (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101B-6	(MS-111)	125 VDC 1-EP-CB-20 (FE-18D) MCC 1J1-1 (FE-9GQ)		---	None Required		energized to vent air
1-MS-SOV-101B-7	(MS-111)	125 VDC 1-EP-CB-21 (FE-18C) 1-EP-CB-16B (FE-11C)		---	None Required		energized to vent air
1-MS-SOV-101C-1	(MS-112)	125 VDC 1-EP-CB-23A (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101C-2	(MS-112)	125 VDC 1-EP-CB-23B (FE-18M)		---	None Required		energized to vent air
1-MS-SOV-101C-6	(MS-112)	125 VDC 1-EP-CB-20 (FE-18D) MCC 1J1-1 (FE-9GQ)		---	None Required		energized to vent air

**TABLE A.3-1 (Continued)**  
**MAIN STEAM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-MS-SOV-101C-7	(MS-112)	125 VDC 1-EP-CB-21 (FE-18C) 1-EP-CB-168 (FE-11C)		---	None Required		energized to vent air

**TABLE A.4-1  
CDA DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
CDA Logic & Output Relays Train A	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	CDA Input Signals Train A	None	Emergency Switchgear Room Cooling	
CDA Logic & Output Relays Train B	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	CDA Input Signals Train B	None	Emergency Switchgear Room Cooling	
1-LM-PT-100A Cont. Press	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	None	None		
1-LM-PT-100B Cont. Press	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-LM-PT-100C Cont. Press	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-LM-PT-100D Cont. Press	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		

**TABLE A.4-2  
PIPING PENETRATIONS**

<b>Pen. No.</b>	<b><u>Service Description</u></b>
1	component cooling from RHR heat exchanger
2	component cooling to RHR heat exchanger
4	component cooling to RHR heat exchanger
5	component cooling from RHR heat exchanger
7	high head safety injection
8	component cooling from RCP thermal barrier
9	air recirc cooling water
10	air recirc cooling water
11	air recirc cooling water
12	air recirc cooling water
13	air recirc cooling water
14	air recirc cooling water
15	charging
16	comp cooling to RCP & Rx shroud cooling coils
17	comp cooling to RCP & Rx shroud cooling coils
18	comp cooling to RCP & Rx shroud cooling coils
19	seal water return
20	safety injection accumulator makeup
22	high head safety injection
24	RHR to RWST
25	comp cooling from RCP & Rx shroud cooling coils
26	comp cooling from RCP & Rx shroud cooling coils
27	comp cooling from RCP & Rx shroud cooling coils
28	letdown
31	containment atmosphere cleanup
32	wet layup system
33	primary drain transfer pump discharge
34	fire protection
35	injection seal water to RCPs
36	injection seal water to RCPs
37	injection seal water to RCPs
38	sump pump discharge
39	steam generator blowdown
40	steam generator blowdown
41	steam generator blowdown
42	service air
43	air monitor sample
44	air monitor sample
45	primary grade water
46	loop fill
47	instrument air
48	primary vent header
50	nitrogen
53	nitrogen to PRT
54	primary vent pot vent



**TABLE A.4-2 (Continued)**  
**PIPING PENETRATIONS**

<b>Pen. No.</b>	<b><u>Service Description</u></b>
55	containment leakage monitoring
55*	reactor vessel level system
55*	reactor vessel level system
55*	reactor vessel level system
56*	RCS cold leg sample
56*	RCS hot leg sample
56*	pressurizer liquid space sample
56*	steam generator blowdown sample
57*	PRT gas space sample
57*	containment leakage monitoring
57*	pressurizer vapor space sample
60	low head safety injection discharge
61	low head safety injection discharge
62	low head safety injection discharge
63	quench spray pump discharge
64	quench spray pump discharge
66	recirc spray pump suction from sump
67	recirc spray pump suction from sump
68	low head SI pump suction from sump
69	low head SI pump suction from sump
70	recirc spray pump discharge
71	recirc spray pump discharge
73	main steam
74	main steam
75	main steam
76	main feed water
77	main feed water
78	main feed water
79	recirc spray service water
80	recirc spray service water
81	recirc spray service water
82	recirc spray service water
83	recirc spray service water
84	recirc spray service water
85	recirc spray service water
86	recirc spray service water
89	air ejector vent
90	purge duct
91	purge duct
92	containment atmosphere cleanup & vacuum pump
93	containment atmosphere cleanup & vacuum pump
94	vacuum ejector suction
97*	pressurizer dead weight calibrator
97*	containment leakage monitoring
97*	RHR liquid sample

**TABLE A.4-2 (Continued)**  
**PIPING PENETRATIONS**

<u>Pen. No.</u>	<u>Service Description</u>
98*	containment atmosphere cleanup
98*	containment atmosphere cleanup
100	wet layup system
103	refueling purification inlet
104	refueling purification outlet
105*	containment leakage monitoring
105*	containment leakage monitoring
105*	containment leakage monitoring
105*	containment atmosphere cleanup
106	safety injection system test line
108	wet layup system
109	containment atmosphere cleanup
111	post accident sampling return
113	high head safety injection
114	high head safety injection
117*	reactor vessel level system
117*	reactor vessel level system
117*	reactor vessel level system

NOTE: \* indicates a sleeved penetration with multiple pipes.

**TABLE A.5-1**  
**EMERGENCY DIESEL GENERATOR SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-EE-EG-1H	EDG 1H starting air system, EDG fuel oil system	EDG 1H Batteries	UV on 1H, Unit 1 Train A CDA or SI	EDG 1H Lube oil, engine cooling, air intake and exhaust	ventilation louvers	none
1-EE-EG-1J	EDG 1J starting air system, EDG fuel oil system	EDG 1J Batteries	UV on 1J, Unit 1 Train B CSA or SI	EDG 1J Lube oil, engine cooling, air intake and exhaust	ventilation louvers	none
2-EE-EG-2H	EDG 2H starting air system, EDG fuel oil system	EDG 2H Batteries	UV on 2H, Unit 2 Train A CDA or SI	EDG 2H Lube oil, engine cooling, air intake and exhaust	ventilation louvers	none
2-EE-EG-2J	EDG 2J starting air system, EDG fuel oil system	EDG 2J Batteries	UV on 2J, Unit 2 Train B CDA or SI	EDG 2J Lube oil, engine cooling, air intake and exhaust	ventilation louvers	none
1-EG-DG-SBO Station Blackout Diesel	SBO EDG starting air system, EDG fuel oil system	SBO EDG Batteries	Operator Action	SBO EDG Lube oil, engine cooling, air intake and exhaust	ventilation louvers	none
1-EE-BKR-15H3	Internal Springs & Motor	Battery I 1-EE-BAT-I	Undervoltage on 1H	none	Emergency Switchgear Room HVAC	none
1-EE-BKR-15J3	Internal Springs & Motor	Battery III 1-EE-BAT-III	Undervoltage on 1J	none	Emergency Switchgear Room HVAC	none
2-EE-BKR-25H3	Internal Springs & Motor	Battery I 2-EE-BAT-I	Undervoltage on 2H	none	Emergency Switchgear Room HVAC	none
2-EE-BKR-25J3	Internal Springs & Motor	Battery III 2-EE-BAT-III	Undervoltage on 2J	none	Emergency Switchgear Room HVAC	none

**TABLE A.6-1**  
**PRIMARY PRESSURE RELIEF SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-RC-PCV-1455C	containment air with backup N <sub>2</sub> supply  (RC-133)	125 VDC Panel 1A 1-EP-CB-23A 1-EP-CB-12A  (FE-18M, FE-10A, ESK-6NR)	>92% output on Master Pressure Controller	---	None Required	from SOV 1455-1, SOV 1455-2 & SOV 1455-3 (RC-111, (RC-151)	
1-RC-PCV-1456	containment air with backup N <sub>2</sub> supply  (RC-109)	125 VDC Panel 1B 1-EP-CB-23B 1-EP-CB-12C  (FE-18M, FE-10B, ESK-6NR)	High RCS Pressure > 2335 psig	---	None Required	from SOV 1456-1, SOV 1456-2 & SOV 1456-3	
1-RC-MOV-1535	480 V MCC 1J1-2S 1-EP-MC-22  (FE-1R)	480 V / 125 V Stepdown Trans. from MCC  (ESK-6DP-1)		---	None Required		
1-RC-MOV-1536	480 V MCC 1H1-2S 1-EP-MC-20  (FE-1Q)	480 V / 125 V Stepdown Trans. from MCC  (ESK-6DP-1)		---	None Required		

**TABLE A.6-1 (Continued)**  
**PRIMARY PRESSURE RELIEF SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-RC-SV-1551A			High RCS Pressure 2485 psig	---	None Required		
1-RC-SV-1551B			High RCS Pressure 2485 psig	---	None Required		
1-RC-SV-1551C			High RCS Pressure 2485 psig	---	None Required		

**TABLE A.7-1  
ACCUMULATOR SYSTEM  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTRDL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-SI-MOV-1865A	480 V MCC 1H1-2N	Stepdown Transformer From 480 V MCC	K628A K603A	None Provided	None Required	None
1-SI-MOV-1865B	480 V MCC 1H1-2N	Stepdown Transformer From 480 V MCC	K628A K603A	None Provided	None Required	None
1-SI-MOV-1865C	480 V MCC 1J1-2N	Stepdown Transformer From 480 V MCC	K628B K603B	None Provided	None Required	None

**TABLE A.7-2**  
**LOW HEAD SAFETY INJECTION SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-SI-P-1A	4160V Bus 1H 15H9	125V DC 1-I	SI-A Relay K 604A	None Provided	None Provided	ESK-5AY
1-SI-P-1B	4160V Bus 1J 15J9	125V DC 1-III	SI-B Relay K 604B	None Provided	None Provided	ESK-5AZ
1-SI-MOV-1862A	480V MCC 1H1-2S D2	480/120V Step down transformer from MCC	LS-2 from 1860A for recirc.	None	None	Interlock 1860A-OPEN- to allow 1862A CLOSE/ESK-6EP
1-SI-MOV-1862B	480V MCC 1J1-2N G2	480/120V Step down transformer from MCC	LS-2 from 1860B for recirc.	None	None	Interlock 1860B-OPEN- to allow 1862B CLOSE/ESK-6EP
1-SI-MOV-1860A	480V MCC 1H1-2N G2	480/120V Step down transformer from MCC	LS-5 on 1885 A & C and K647A and K630A for recirc.	None	None	ESK-6ET
1-SI-MOV-1860B	480V MCC 1J1-2N G2	480/120V Step down transformer from MCC	LS-5 on 1885 A & C and K647B and K630B for recirc.	None	None	ESK-6ET
1-SI-MOV-1885A	480V MCC 1H1-2S	Step down transformer from MCC	Close on K647A, K630A, and LS-9 from 1863A. Open on LS-11/1860A.	None	None	ESK-6EQ

**TABLE A.7-2 (Continued)**  
**LOW HEAD SAFETY INJECTION SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-SI-MOV-1885B	480V MCC 1J1-2S	Step down transformer from MCC	Close on K647B, K630B, and LS-9/1863B. Open on LS-13/1860B.	None	None	ESK-6EQ
1-SI-MOV-1885C	480V MCC 1H1-2S	Step down transformer from MCC	Close on K647A, K630A, and LS-10/1863A. Open on LS-12/1860A.	None	None	ESK-6ER
1-SI-MOV-1885D	480V MCC 1J1-2S	Step down transformer from MCC	Close on K647B, K630B, and LS-10/1863B. Open on LS-14/1860B.	None	None	ESK-6ER
1-SI-MOV-1863A	480V MCC 1H1-2N	Step down transformer from MCC	K647A and K630A	None	None	ESK-6ES
1-SI-MOV-1863B	480V MCC 1J1-2N	Step down transformer from MCC	K647B and K630B	None	None	ESK-6ES
1-SI-MOV-1864A	480V MCC 1H1-2N	Step down transformer from MCC	None	None	None	ESK-6DU
1-SI-MOV-1864B	480V MCC 1J1-2N	Step down transformer from MCC	None	None	None	ESK-6DU
1-SI-MOV-1890A	480V MCC 1H1-2N	Step down transformer from MCC	None	None	None	ESK-6DX



**TABLE A.7-2 (Continued)**  
**LOW HEAD SAFETY INJECTION SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-SI-MOV-1890B	480V MCC 1J1-2N	Step down transformer from MCC	None	None	None	ESK-6DY
1-SI-MOV-1890C	480V MCC 1H1-2N	Step down transformer from MCC	None	None	None	ESK-6DY
1-SI-MOV-1890D	480V MCC 1J1-2N	Step down transformer from MCC	None	None	None	ESK-6DY

**TABLE A.7-3  
HIGH HEAD SAFETY INJECTION  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-CH-P-1A	4160 V Bus 1H 15H6	125 V DC 1-I	S1-A Relay K609	Charging Pump SW System		
1-CH-P-1B	4160 V Bus 1J 15J6	125 V DC 1-III	S1-B Relay K609	Charging Pump SW System		
1-CH-P-1C	4160 V Bus 1H (normal) 1J (alternate)	125 V DC 1-I (normal) 1-III (alternate)	S1-B Relay K608	Charging Pump SW System		No auto actuation on Bus 1J
1-CH-MOV-1115B	MCC 1J1-2N E3	Motive	S1-B Relay K604	None	None	Same as MOV-1115D
1-CH-MOV-1115C	MCC 1H1-2N F1	Motive	S1-A Relay K603	None	None	Interlocked with 1115D to close. Valve will not close unless MOV-H15 is open.
1-CH-MOV-1115D	MCC 1H1-2N F2	Motive	S1-A Relay K603	None	None	Open on Low VCT level LC-112B and LC-115B
1-CH-MOV-1115E	MCC 1J1-2N F3	Motive	S1-B Relay K603	None	None	Interlocked with 1115B to close. Valve will not close unless MOV-1115B is open.
1-CH-MOV-1267A	MCC 1H1-2S B3	Motive	None	None	None	

**TABLE A.7-3 (Continued)**  
**HIGH HEAD SAFETY INJECTION**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-CH-MOV-1269A	MCC 1J1-2S C2	Motive	None	None	None	
1-CH-MOV-1270A	MCC 1H1-2S C3	Motive	None	None	None	
1-CH-MOV-1267B	MCC 1H1-2S	Motive	None	None	None	
1-CH-MOV-1269B	MCC 1J1-2S	Motive	None	None	None	
1-CH-MOV-1270B	MCC 1J1-2S	Motive	None	None	None	
1-CH-MOV-1286A	MCC 1H1-2S D4	Motive	None	None	None	
1-CH-MOV-1286B	MCC 1J1-2S C3	Motive	None	None	None	
1-CH-MOV-1286C	MCC 1H1-2S E2	Motive	None	None	None	
1-CH-MOV-1287A	MCC 1H1-2S	Motive	None	None	None	
1-CH-MOV-1287B	MCC 1J1-2S	Motive	None	None	None	

**TABLE A.7-3 (Continued)**  
**HIGH HEAD SAFETY INJECTION**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-CH-MOV-1287C	MCC 1J1-2S	Motive	None	None	None	
1-SI-MOV-1867A	MCC 1H1-2N	Motive	SI-A Relay K604	None	None	
1-SI-MOV-1867B	MCC 1J1-2N C3	Motive	SI-B Relay K604	None	None	
1-SI-MOV-1867C	MCC 1H1-2N	Motive	SI-A Relay K603	None	None	
1-SI-MOV-1867D	MCC 1J1-2N	Motive	SI-B Relay K603	None	None	
1-SI-MOV-1836	MCC 1J1-2S D4	Motive	None	None	None	
1-SI-MOV-1869A	MCC 1H1-2N G3	Motive	None	None	None	
1-SI-MOV-1869B	MCC 1J1-2N J1	Motive	None	None	None	

**TABLE A.7-3 (Continued)**  
**HIGH HEAD SAFETY INJECTION**  
**DEPENDENCY MATRIX**

**Notes to HHSI Dependency Matrix**

1. Charging Pump 1C is normally racked in to Bus H and the control switch is placed in auto-after-stop. Pump 1C can also be racked into Bus J. When 1C is racked into J bus, it must be the running pump and 1B must be racked out.
2. Pump 1C gets no auto signals to start when it is on bus J. In order to meet the design basis, 1C must be running if it is on J bus.
3. Pump 1C gets all auto signals on bus H, if the breaker is racked and the switch is in "auto."
4. Charging pumps will start on a low discharge header pressure signal. A charging pump will also auto start on low voltage on the other bus.
5. In addition to an SI signal open, MOV-1115B and D will open on low level in the volume control tank.
6. Changing pump control power is the DC power supply at the bus.
7. The possibility of switching pump 1C from one bus to another during an accident is not modeled.
8. Service water is supplied to the seal cooler, the gear box cooler and the lube oil cooler. Failure to supply water was specifically modeled for the lube oil cooler and the gear box. The seal cooler gets water from the very same header as the gearbox cooler without any additional valves in the flow path. Thus, water is de facto required for the seal cooler. Whether or not service water is actually required for the seal cooler is not known. In the Surry IPE, it was shown that the seal cooler is unnecessary for pumped stream temperatures less than 250°F. Similar analysis was not done for North Anna, but the Surry results are probably applicable, as the charging pumps are of similar design.

**TABLE A.7-4**  
**SAFETY INJECTION ACTUATION DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
SI Logic & Output Relays Train A	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	SI Input Signals Train A	None	Emergency Switchgear Room Cooling	
SI Logic & Output Relays Train B	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	SI Input Signals Train B	None	Emergency Switchgear Room Cooling	
1-LM-PT-100B Cont. Press	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-LM-PT-100C Cont. Press	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-PT-100D Cont. Press	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		
1-MS-FI-1474 Main Steamline Flow	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-FI-1475 Main Steamline Flow	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		
1-MS-FI-1494 Main Steamline Flow	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-FI-1495 Main Steamline Flow	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		
1-MS-FI-1484 Main Steamline Flow	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-FI-1485 Main Steamline Flow	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		

**TABLE A.7-4 (Continued)**  
**SAFETY INJECTION ACTUATION DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-RC-PT-1455 Pressurizer Pressure	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	None	None		
1-RC-PT-1456 Pressurizer Pressure	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-RC-PT-1457 Pressurizer Pressure	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-PT-1474 Main Steamline Pressure	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-MS-PT-1484 Main Steamline Pressure	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-MS-PT-1494 Main Steamline Pressure	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-MS-PT-1485 Main Steamline Pressure	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-PT-1475 Main Steamline Pressure	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-PT-1495 Main Steamline Pressure	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-MS-PT-1476 Main Steamline Pressure	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		
1-MS-PT-1486 Main Steamline Pressure	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		

**TABLE A.7-4 (Continued)**  
**SAFETY INJECTION ACTUATION DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-MS-PT-1496 Main Steamline Pressure	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		
RMT Logic & Output Relays Train A	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	RMT Input Signals Train A	None	Emergency Switchgear Room Cooling	
RMT Logic & Output Relays Train B	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	RMT Input Signals Train B	None	Emergency Switchgear Room Cooling	
1-LM-PM-100A RWST Level	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	None	None		
1-LM-PM-100B RWST Level	None	120 VAC Vital Bus 1-II 1-EP-CB-4B	None	None		
1-LM-PM-100C RWST Level	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	None	None		
1-LM-PM-100D RWST Level	None	120 VAC Vital Bus 1-IV 1-EP-CB-4D	None	None		



**TABLE A.9-1**  
**ELECTRICAL POWER DISTRIBUTION SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-EP-BKR-G12		1-EP-CB-12A (DC 1-I)	opens on UV of main generator	none	none	none
1-EP-BKR-15A1	Charged Springs	1-EP-CB-12C (DC 1-III)	opens on UV or fault of RSST 1A	none	none	none
1-EP-BKR-15A2	Charged Springs	1-EP-CB-12C (DC 1-III)	opens on UV of 1A	none	none	none
1-EP-BKR-15B1	Charged Springs	1-EP-CB-12B (DC 1-II)	opens on UV or fault of RSST 1B	none	none	none
1-EP-BKR-15B2	Charged Springs	1-EP-CB-12B (DC 1-II)	opens on UV of 1B	none	none	none
1-EP-BKR-15B11	Charged Springs	1-EP-CB-12B (DC 1-II)	none	none	none	none
1-EP-BKR-15C1	Charged Springs	1-EP-CB-12A (DC 1-I)	opens on UV or fault of RSST 1C	none	none	none
1-EP-BKR-15C2	Charged Springs	1-EP-CB-12A (DC 1-I)	opens on UV of 1C	none	none	none
1-EP-BKR-15D1	Charged Springs	1-EP-CB-12C (DC 1-III)	opens on UV of 1D	none	none	none
1-EP-BKR-15D3	Charged Springs	1-EP-CB-12D (DC 1-IV)	opens on RSST A fault, UV on 1D, or UV on 1J	none	none	none
1-EP-BKR-15E1	Charged Springs	1-EP-CB-12B (DC 1-II)	opens on UV of 1E	none	none	none
1-EP-BKR-15E3	Charged Springs	2-EP-CB-12B (DC 2-II)	opens on RSST B fault, UV on 1E, or UV on 2H	none	none	none
1-EP-BKR-15F1	Charged Springs	1-EP-CB-12A (DC 1-I)	opens on UV of 1F	none	none	none
1-EP-BKR-15F3	Charged Springs	1-EP-CB-12B (DC 1-II)	opens on RSST C fault, opens on UV on 1F, opens on UV on 1H	none	none	none
1-EP-BKR-15F4	Charged Springs	2-EP-CB-12D (DC 2-IV)	opens on RSST C fault, UV on 1F, or UV on 2J	none	none	none

**TABLE A.9-1 (Continued)**  
**ELECTRICAL POWER DISTRIBUTION SYSTEM**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS
1-EP-BKR-15G1	Charged Springs	1-EP-CB-12A (DC 1-1)	opens on UV of 1G	none	none	none
2-EP-BKR-25G1	Charged Springs	2-EP-CB-12A (DC 2-1)	opens on UV of 2G	none	none	none
1-EE-BKR-15H1	Charged Springs	1-EP-CB-12A (DC 1-1)	opens on UV on 1H	none	ESGR	none
1-EE-BKR-15H2	Charged Springs	1-EP-CB-12A (DC 1-1)	none	none	ESGR	none
1-EE-BKR-15H11	Charged Springs	1-EP-CB-12A (DC 1-1)	opens on UV on 1H	none	ESGR	none
1-EE-BKR-15H12	Charged Springs	1-EP-CB-12A (DC 1-1)	opens on UV on 1H closes after UV clears	none	ESGR	none
1-EE-BKR-15J1	Charged Springs	1-EP-CB-12C (DC 1-III)	none	none	ESGR	none
1-EE-BKR-15J2	Charged Springs	1-EP-CB-12C (DC 1-III)	none	none	ESGR	none
1-EE-BKR-15J11	Charged Springs	1-EP-CB-12C (DC 1-III)	opens on UV on 1J	none	ESGR	none
1-EE-BKR-15J12	Charged Springs	1-EP-CB-12C (DC 1-III)	opens on UV on 1J closes after UV clears	none	ESGR	none
2-EE-BKR-25H1	Charged Springs	2-EP-CB-12A (DC 2-1)	none	none	ESGR	none
2-EE-BKR-25H2	Charged Springs	2-EP-CB-12A (DC 2-1)	none	none	ESGR	none
2-EE-BKR-25H11	Charged Springs	2-EP-CB-12A (DC 2-1)	opens on UV on 2H	none	ESGR	none
2-EE-BKR-25H12	Charged Springs	2-EP-CB-12A (DC 2-1)	opens on UV on 2H closes after UV clears	none	ESGR	none
2-EE-BKR-25J1	Charged Springs	2-EP-CB-12C (DC 2-III)	none	none	ESGR	none
2-EE-BKR-25J2	Charged Springs	2-EP-CB-12C (DC 2-III)	none	none	ESGR	none
2-EE-BKR-25J11	Charged Springs	2-EP-CB-12C (DC 2-III)	opens on UV on 2J	none	ESGR	none
2-EE-BKR-25J12	Charged Springs	2-EP-CB-12C (DC 2-III)	opens on UV on 2J closes after UV clears	none	ESGR	none

**TABLE A.10-1  
RESIDUAL HEAT REMOVAL  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-RH-P-1A	4160 V, BUS 1H, BKR 14 (STUB BUS)	BATT 1-I DIST CAB CKT 14	None	1-RH-E-2A Seal Cooling from CC	None Required	None
1-RH-P-1B	4160 V, BUS 1J, BKR 16 (STUB BUS)	BATT 1-III DIST CAB CKT 16	None	1-RH-E-2B Seal Cooling from CC	None Required	None
1-RH-MOV-1700	480V MCC 1H2-2S, BKR D1	stepdown transformer from MCC 1H2-2S	Automatically closes if RCS pressure > 582 psig	---	None Required	Open permissive interlock on low RCS pressure
1-RH-MOV-1701	480V MCC 1J1-2S, BKR F3	stepdown transformer from MCC 1J1-2S	Automatically closes if RCS pressure > 582 psig	---	None Required	Open permissive interlock on low RCS pressure
1-RH-MOV-1720A	480V MCC 1H1-2S, BKR C2	stepdown transformer from MCC 1H1-2S	---	---	None Required	Fails as is
1-RH-MOV-1720B	480V MCC 1J1-2S, BKR C1	stepdown transformer from MCC 1J1-2S	---	---	None Required	Fails as is
1-RH-FCV-1605	Instrument Air	Primary Plant Processing Cab. G	---	---	None Required	Fails closed

\*Interlocks or other functional dependencies included in this column

**TABLE A.10-1 (Continued)  
RESIDUAL HEAT REMOVAL  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-RH-HCV-1758	Instrument Air	Vital Bus 1-III , Breaker 23	---	---	None Required	Fails open
1-RH-PT-1403	---	Vital Bus 1-III (1-EI-CB-57)	---	---	None Required	---
1-RH-PT-1402	---	Vital Bus 1-I (1-EI-CB-55)	---	---	None Required	---

\*Interlocks or other functional dependencies included in this column

**TABLE A.11-1  
SERVICE WATER  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-SW-P-1A	4160 V, Bus 1H, BKR 15H5	125 VDC @ 4160 V, SWGR 1H from BATT 1-I DIST CAB CKT 14	Pump starts on receipt of SI or LOOP signal	None provided	Not required	1-SW-P-4 Not running
1-SW-P-1B	4160 V, Bus 1J, BKR 15J5	125 VDC @ 4160 V SWGR 1J from BATT 1-III DIST CAB CKT 16	Pump starts on receipt of SI or LOOP signal	None provided	Not required	None
2-SW-P-1A	4160 V, Bus 2H, BKR 25H5	125 VDC @ 4160 V SWGR 2H from BATT 2-I DIST CAB CKT 14	Pump starts on receipt of SI or LOOP signal	None provided	Not required	2-SW-P-4 Not running
2-SW-P-1B	4160 V, Bus 2J, BKR 25J5	125 VDC @ 4160 V SWGR 2J from BATT 2-III DIST CAB CKT 16	Pump starts on receipt of SI or LOOP signal	None provided	Not required	None
1-SW-P-4	4160 V, Bus 1H, BKR 15H4	125 VDC @ 4160 V SWGR 1H, from BATT 1-I DIST CAB CKT 14	None	None provided	Not required	1-SW-P-1A Not running
2-SW-P-4	4160 V, Bus 2H, BKR 25H4	125 VAC @ 4160 V SWGR 2H, from BATT 2-I DIST CAB CKT 14	None	None provided	Not required	2-SW-P-1A Not running

\*Interlocks or other functional dependencies included in this column

**TABLE A.11-1 (Continued)**  
**SERVICE WATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-SW-MOV-117	MCC 1H1-1, BKR B1	480 V	None	None	Not required	None
2-SW-MOV-217	MCC 2H1-1, BKR	480 V	None	None	Not required	None
1-SW-MOV-118	MCC 1H1-1, BKR A3	480 V	None	None	Not required	None
1-SW-MOV-115A	MCC 1H1-1, BKR B2	480 V	None	None	Not required	None
1-SW-MOV-115B	MCC 1H1-1, BKR C2	480 V	None	None	Not required	None
2-SW-MOV-215A	MCC 2H1-1, BKR	480 V	None	None	Not required	None
2-SW-MOV-215B	MCC 2H1-1, BKR	480 V	None	None	Not required	None
1-CW-P-2A	MCC 2G1-15	120 V	None	None provided	Not required	None
1-CW-P-2B	MCC 1H1-1	120 V	None	None provided	Not required	None
1-CW-TV-100	Instrument Air	1-CW-SOV-100	None	None	Not required	None
1-CW-SOV-100	120 V AC from CKT 1CMTB04	Motive Force	None	None	Not required	None
Strainer 2-CW-S-3A	MCC-2G1-1N	Motive Force	None	None	Not required	Pump 1-CW-P-2A must be running

\*Interlocks or other functional dependencies included in this column

**TABLE A.11-1 (Continued)**  
**SERVICE WATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
Strainer 1-CW-S-3B	MCC-1G1-1S	Motive Force	None	None	Not required	Pump 1-CW-P-2B must be running
Traveling Screens -						
1-CW-S-1C (6FW) (6FV)	MCC-1G1-1N CKT 1CWT05	---	None	None	Not required	None
1-CW-S-1D	MCC 1G1-1N CKT 1CMTD05	---	None	None	Not required	None
2-CW-S-1A	MCC 2G1-1S CKT 2CWTA05	---	None	None	Not required	None
2-CW-S-1B	MCC 2G1-1S CKT 2CMTD05	---	None	None	Not required	None
1-CW-MOV-104B	MCC 1G1-1S	Motive Force	None	None	Not required	Runs only when strainer 1-CW-S-3B is running
2-CW-MOV-204A	MCC-2G1-1N	Motive Force	None	None	Not required	Runs only when strainer 2-CW-S-3A is running

\*Interlocks or other functional dependencies included in this column

**TABLE A.11-1 (Continued)**  
**SERVICE WATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-CW-TV-200	Instrument Air	SOV-CW-200	None	None	Not required	None
2-CW-SOV-200	120 V AC from CKT 2CWTA04	Motive Force	None	None	Not required	None
2-SW-MOV-223B	MCC 2J1-3A, BKR B3	480 V Stpdwn	None	None	Not required	None
2-SW-1011	--	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-123A	MCC 1H1-3A, BKR B3	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-223A	MCC 2H1-3A, BKR B3	480 V Stpdwn	None	None	Not required	None
2-SW-1001	--	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-123B	MCC 1J1-3A, BKR B3	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-221A	MCC 2H1-3A, BKR A2	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-222A	MCC 2H1-3A, BKR A3	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-121B	MCC 1J1-3A, BKR A2	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-122B	MCC 1J1-3A, BKR A3	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-121A	MCC 1H1-3A, BKR A2	480 V Stpdwn	None	None	Not required	None

\*Interlocks or other functional dependencies included in this column



**TABLE A.11-1 (Continued)**  
**SERVICE WATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-SW-MOV-122A	MCC 1H1-3A, BKR A3	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-221B	MCC 2J1-3A, BKR A2	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-222B	MCC 2J1-3A, BKR A3	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-120A	MCC 1H1-1, BKR B4	480 V Stpdwn	None	None	Not required	None
2-SW-MOV-220A	MCC 2H1-1, BKR G4	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-120B	MCC 1H1-1, BKR C4	480 V Stpdwn	None	None	Not required	None
1-SW-MOV-220B	MCC 2H1-1, BKR H4	480 V Stpdwn	None	None	Not required	None

\*Interlocks or other functional dependencies included in this column

**TABLE A.12-1  
QUENCH SPRAY  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-QS-P-1A	480 V BUS 1H1	480 V SWGR 1H; BATT 1-I	Starts on CDA Signal (Relay K644-XA1)	---	None Required	
1-QS-P-1B	480 V BUS 1J1	480 V SWGR 1J; BATT 1-III	Starts on CDA Signal (Relay K644-XB1)	---	None Required	
1-MOV-QS-100A	MCC-1H1-2S	480 V	CDA Signal to Assure Open	---	None Required	
1-MOV-QS-100B	MCC-1J1-2N	480 V	CDA Signal to Assure Open	---	None Required	
1-MOV-QS-101A	MCC-1H1-2N	480 V	CDA Signal Opens Valve	---	None Required	
1-MOV-QS-101B	MCC-1J1-2N	480V	CDA Signal Opens Valve	---	None Required	

\*Interlocks or other functional dependencies included in this column

**TABLE A.13-1  
AUXILIARY FEEDWATER  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-P-2	main steam		1-TV-MS-111A and/or 1-TV-MS-111B open	---	None Required		
1-FW-P-3A	4160V bus 1H breaker 15H3 (FE-1D)	125 VDC 1H BATT 1-I (ESK-5AA)	Note 1 (5655D33 Sh 14)	---	None Required		
1-FW-P-3B	4160V bus 1J breaker 15J3 (FE-1D)	125 VDC 1J BATT 1-III (ESK-5AB)	Note 1	---	None Required		
1-TV-MS-111A	instr. air or nitrogen (MS-115)	125 VDC MCB panel 1A (ESK-6PR)	Note 2	---	None Required		air to close fails open
1-TV-MS-111B	instr. air or nitrogen (MS-116)	125 VDC MCB panel 1B (ESK-6PR)	Note 2	---	None Required		air to close fails open

Note 1: 1) opening of 1/2 FWP breakers on 3/3 FWP, or  
2) loss of reserve power, or  
3) low-low level in 2/3 channels in 1/3 SG, or  
4) SI, or  
5) AMSAC

Note 2: same as above plus  
6) loss of instrument air header pressure

**TABLE A.13-1 (Continued)**  
**AUXILIARY FEEDWATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-MOV-100A	480V MCC 1J1-2N breaker F4 (FE-1R)	480V/120V step down transformer from MCC (ESK-6CL)	None	---	None Required		
1-FW-MOV-100B	480V MCC 1J1-2N breaker G4 (FE-1R)	480V/120V step down transformer from MCC (ESK-6CL)	None	---	None Required		
1-FW-MOV-100C	480V MCC 1J1-2N breaker H4 (FE-1R)	480V/120V step down transformer from MCC (ESK-6CL)	None	---	None Required		
1-FW-MOV-100D	480V MCC 1J1-2S breaker E4 (FE-1R)	480V/120V step down transformer from MCC (ESK-6CL)	None	---	None Required		
1-FW-PCV-159A	instr. air  (FW-053)	none	None	---	None Required		air to close, fails open
1-FW-PCV-159B	instr. air  (FW-054)	none	None	---	None Required		air to close, fails open

**TABLE A.13-1 (Continued)**  
**AUXILIARY FEEDWATER**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-HCV-100A	instr. air (FW-055)	120 VDC SVB 1A 1-EP-CB-16A	None	---	None Required		air to close, fails open
1-FW-HCV-100B	instr. air (FW-056)	120 VDC SVB 1A 1-EP-CB-16A	None	---	None Required		air to close, fails open
1-FW-HCV-100C	instr. air (FW-057)	120 VDC SVB 1A 1-EP-CB-16A	None	---	None Required		air to close, fails open

**TABLE A.13-2**  
**MFW**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-P-1A Motor 1A1	4160V bus 1A 1-EP-SW-01 bkr 15A5 (FE-1B)	125 VDC at 4160 SWGR 1A Batt 1-III (ESK-5T)	None	---	None Required	(ESK-5Z)	
1-FW-P-1A Motor 1A2	4160V bus 1A 1-EP-SW-01 bkr 15A6 (FE-1B)	125 VDC at 4160 SWGR 1A Batt 1-III (ESK-5U)	None	---	None Required	(ESK-5Z)	
1-FW-P-1B Motor 1B1	4160V bus 1B 1-EP-SW-02 bkr 15B5 (FE-1B)	125 VDC at 4160 SWGR 1B Batt 1-II (ESK-5V)	None	---	None Required	(ESK-5Z)	
1-FW-P-1B Motor 1B2	4160V bus 1B 1-EP-SW-02 bkr 15B6 (FE-1B)	125 VDC at 4160 SWGR 1B Batt 1-II (ESK-5W)	None	---	None Required	(ESK-5Z)	
1-FW-P-1C Motor 1C1	4160V bus 1C 1-EP-SW-03 bkr 15C5 (FE-1C)	125 VDC at 4160 SWGR 1C Batt 1-I (ESK-5X)	None	---	None Required	(ESK-5Z)	
1-FW-P-1C Motor 1C2	4160V bus 1C 1-EP-SW-03 bkr 15C6 (FE-1C)	125 VDC at 4160 SWGR 1C Batt 1-I (ESK-5Y)	None	---	None Required	(ESK-5Z)	

**TABLE A.13-2 (Continued)**  
**MFW**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-CN-P-1A	4160V bus 1A 1-EP-SW-01 bkr 15A4  (FE-1B)	125 VDC at 4160V SWGR 1A Batt 1-III  (ESK-5G)	None	---	None Required		
1-CN-P-1B	4160V bus 1B 1-EP-SW-02 bkr 15B4  (FE-1B)	125 VDC at 4160V SWGR 1B Batt 1-II  (ESK-5H)	None	---	None Required		
1-CN-P-1C	4160V bus 1C 1-EP-SW-03 bkr 15C4  (FE-1C)	125 VDC at 4160V SWGR 1C Batt 1-I  (ESK-5J)	None	---	None Required		

**TABLE A.13-2 (Continued)**  
**MFW**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-MOV-154A	MCC 1A1-2 1-EP-MC-07 bkr E2 (FE-1H)	480V/120V step down transformer from MCC 1A1-2 (ESK-6CL)	None	---	None Required		
1-FW-MOV-154B	MCC 1B1-3 1-EP-MC-06 bkr C3 (FE-1H)	480V/120V step down transformer from MCC 1B1-3 (ESK-6CL-1)	None	---	None Required		
1-FW-MOV-154C	MCC 1A2-2 1-EP-MC-05 bkr F3 (FE-1J)	480V/120V step down transformer from MCC 1A2-2 (ESK-6CL-1)	None	---	None Required		
1-FW-MOV-150A	MCC 1B1-3 1-EP-MC-06 bkr F2 (FE-1H)	480V/120V step down transformer from MCC 1B1-3 (ESK-6CG)	None	---	None Required		
1-FW-MOV-150B	MCC 1A1-2 1-EP-MC-07 bkr A3 (FE-1H)	480V/120V step down transformer from MCC 1A1-2 (ESK-6CG)	None	---	None Required		
1-FW-MOV-150C	MCC 1B1-3 1-EP-MC-06 bkr F3 (FE-1H)	480V/120V step down transformer from MCC 1B1-3 (ESK-6CG)	None	---	None Required		



**TABLE A.13-2 (Continued)**  
**MFW**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-FW-FCV-1478	instr. air	125 VDC 1A (SOV-1478-1) 125 VDC 1B (SOV 1478-2) (ESK-6QJ)	None	---	None Required	SOV-1478-1 and -1478-2 are energized to open FCV-1478 (FW-112)	air to open fails closed
1-FW-FCV-1479	instr. air	125 VDC 1A (SOV-1479-1) 125 VDC 1B (SOV 1479-2) (ESK-6QJ)	None	---	None Required	SOV-1479-1 and -1479-2 are energized to open FCV-1479 (FW-061)	air to open fails closed
1-FW-FCV-1488	instr. air	125 VDC 1A (SOV-1488-1) 125 VDC 1B (SOV 1488-2) (ESK-6QJ)	None	---	None Required	SOV-1488-1 and -1488-2 are energized to open FCV-1488 (FW-113)	air to open fails closed
1-FW-FCV-1489	instr. air	125 VDC 1A (SOV-1489-1) 125 VDC 1B (SOV 1489-2) (ESK-6QJ)	None	---	None Required	SOV-1489-1 and -1489-2 are energized to open FCV-1489 (FW-062)	air to open fails closed
1-FW-FCV-1498	instr. air	125 VDC 1A (SOV-1498-1) 125 VDC 1B (SOV 1498-2) (ESK-6QJ)	None	---	None Required	SOV-1498-1 and -1498-2 are energized to open FCV-1498 (FW-114)	air to open fails closed
1-FW-FCV-1499	instr. air	125 VDC 1A (SOV-1499-1) 125 VDC 1B (SOV 1499-2) (ESK-6QJ)	None	---	None Required	SOV-1499-1 and -1499-2 are energized to open FCV-1499 (FW-063)	air to open fails closed

**TABLE A.13-2 (Continued)**  
**MFW**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS	COMMENTS
1-CN-LCV-109-1	instr. air	instr. air (CN-028)	None	---	None Required		air to open fails closed
1-CN-LCV-109-2	instr. air	instr. air (CN-028)	None	---	None Required		air to open fails closed
1-FW-FCV-150A	instr. air	120 VAC from non vital SOV panel - ckt 34 (ESK-6PG) (FW-076)	None	---	None Required	FCV-150A/B/C interlock 120 VAC from cond polishing dist panel (ESK-6PG-1)	air to close fails open
1-FW-FCV-150B	instr. air	120 VAC from non vital SOV panel - ckt 35 (ESK-6PG) (FW-077)	None	---	None Required	FCV-150A/B/C interlock 120 VAC from cond polishing dist panel (ESK-6PG-1)	air to close fails open
1-FW-FCV-150C	instr. air	120 VAC from non vital SOV panel - ckt 36 (ESK-6PG) (FW-078)	None	---	None Required	FCV-150A/B/C interlock 120 VAC from cond polishing dist panel (ESK-6PG-1)	air to close fails open

**TABLE 14-1  
RECIRCULATION SPRAY  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-RS-P-1A	480 V BUS 1H1	125 VDC BAT 1-I	* CDA Signal - Start	---	None Required	
1-RS-P-1B	480 V BUS 1J1	125 VDC BATT 1-III	CDA Signal - Start	---	None Required	
1-RS-P-2A	4160 V BUS 1H	125 VDC BATT 1-I	CDA Signal - Start	---	None Required	
1-RS-P-2B	4160 V BUS 1J	125 VDC BATT 1-III	CDA Signal - Start	---	None Required	
1-RS-P-3A	480 V MCC-1H1-2S	480 V	CDA Signal - Start	---	None Required	
1-RS-P-3B	480 V MCC-1J1-2S	480 V	CDA Signal - Start	---	None Required	
1-RS-MOV-100A	MCC-1H1-2S	480 V	CDA Signal - Open	---	None Required	Close on low casing cooling tank level
1-RS-MOV-100B	MCC-1J1-2N	480 V	CDA Signal - Open	---	None Required	Close on low casing cooling tank level
1-RS-MOV-101A	MCC-1J1-2N	480 V	CDA Signal - Assures Open	---	None Required	Closed on low casing cooling pump discharge flow

\*Interlocks or other functional dependencies included in this column

**TABLE 14-1 (Continued)  
RECIRCULATION SPRAY  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-RS-MOV-101B	MCC-1H1-2S	480 V	CDA Signal - Assures Open	---	None Required	Closed on low casing cooling pump discharge flow
1-RS-MOV-155A	MCC-1H1-2N	480 V	CDA Signal - Assures Open	---	None Required	
1-RS-MOV-155B	MCC-1J1-2N	480 V	CDA Signal - Assures Open	---	None Required	
1-RS-MOV-156A	MCC-1H1-2N	480 V	CDA Signal - Assures Open	---	None Required	
1-RS-MOV-156B	MCC-1J1-2N	480 V	CDA Signal - Assures Open	---	None Required	
1-SW-MOV-101A	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-101B	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-101C	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-101D	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-103A	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-103B	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-103C	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-103D	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	

\*Interlocks or other functional dependencies included in this column

**TABLE 14-1 (Continued)**  
**RECIRCULATION SPRAY**  
**DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-SW-MOV-104A	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-104B	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-104C	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-104D	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-105A	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-105B	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-105C	MCC-1H1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-105D	MCC-1J1-2N	480 V	Open on CDA Signal	---	None Required	
1-SW-MOV-102A	MCC-1H1-2S	480 V	---	---	---	
1-SW-MOV-102B	MCC-1J1-2S	480 V	---	---	---	
1-SW-MOV-106A	MCC-1H1-2S	480 V	---	---	---	
1-SW-MOV-106B	MCC-1J1-2S	480 V	---	---	---	

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-1**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 1**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-HV-AC-6	480V MCC 1H1-4 bkr 83 ESK-6KC FE-9EH	480V/120VAC Stepdown Transformer	None	None	None	1-HV-MOD-137 is opened when fan is energized HV-078
1-HV-AC-7	480V MCC 1J1-1 bkr ESK-6KC FE-9GS	480V/120VAC Stepdown Transformer	None	None	None	1-HV-MOD-138 is opened when fan is energized HV-079
1-HV-MOD-137	120VAC from 1-HV-AC-6 HV-078 FE-3CV FE-9EH ESK-6KC	None	None	None	None	Opens when 1-HV-AC-6 fan is energized. Fails closed HV-078
1-HV-MOD-138	120VAC from 1-HV-AC-7 HV-079 FE-3CV FE-9GS ESK-6KC	None	None	None	None	Opens when 1-HV-AC-7 fan is energized. Fails closed HV-079
1-HV-TCV-166	120VAC from 1-HV-AC-6 HV-078 FE-3CV FE-9EH	None	None	None	None	Spring return to block flow to AHU when de-energized HV-078

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-1 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 1**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-HV-TCV-167	120VAC from 1-HV-AC-7 HV-079 FE-3CV FE-9GS	None	None	None	None	Spring return to block flow to AHU when de-energized HV-078
1-HV-E-4A	480V MCC 1H1 bkr G2 FE-9EE	Stepdown Transformer <u>W</u> 595C773 SWEC File 10.1-12A	None	None	None	HV-045 HV-058 HV-070 FE-9EE <u>W</u> 595C773
1-HV-E-4B	480V MCC 1J1-1 bkr A1 FE-9GQ	Stepdown Transformer <u>W</u> 595C773 SWEC File 10.1-12A	None	None	None	HV-046 HV-059 HV-071 FE-9GQ <u>W</u> 595C773
1-HV-E-4C	480V MCC 1H1-1 bkr D3 FE-9EJ	Stepdown Transformer <u>W</u> 595C773 SWEC File 10.1-12A	None	None	None	HV-047 HV-060 HV-072 FE-9EJ <u>W</u> 595C773
1-HV-P-20A	480V MCC 1H1-1 bkr E3 ESK-6JR FE-9ED	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-E-4A ESK-6JR, 6EK 1-HV-MOV-111A must be open

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-1 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 1**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-HV-P-20B	480V MCC 1J1-1 bkr C4 ESK-6JR FE-9GR	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-E-4B Comp Str ESK-6JR, 6EK 1-HV-MOV-111B must be open
1-HV-P-20C	480V MCC 1H1-1 bkr E4 ESK-6JR FE-9ED	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-E-4C ESK-6JR, 6EK 1-HV-MOV-111C must be open
1-HV-P-22A	480V MCC 1H1-1 bkr F3 ESK-6JS FE-9EE	480V/120VAC Stepdown Transformer	None	1-HV-SOV-1200A packing gland, annunciator only HV-051	None	1-HV-MOV-113A must be open ESK-6CM, 6JS
1-HV-P-22B	480V MCC 1J1-1 bkr D4 ESK-6JS FE-9GR	480V/120VAC Stepdown Transformer	None	1-HV-SOV-1200B packing gland, annunciator only HV-051	None	1-HV-MOV-113B must be open
1-HV-P-22C	480V MCC 1H1-1 bkr F4 ESK-6JS FE-9EE	480V/120VAC Stepdown Transformer	None	1-HV-SOV-1200C packing gland, annunciator only HV-051	None	1-HV-MOV-113C must be open

\*Interlocks or other functional dependencies included in this column



**TABLE A.15-1 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 1**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-HV-MOV-111A	480V MCC 1H1-1 bkr E1 ESK-6EK FE-9ED	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-20A ESK-6JR
1-HV-MOV-111B	480V MCC 1J1-1 bkr C3 ESK-6EK FE-9GR	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-20B ESK-6JR
1-HV-MOV-111C	480V MCC 1H1-1 bkr E2 ESK-6EK FE-9ED	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-20A ESK-6JR
1-HV-MOV-113A	480V MCC 1H1-1 bkr F1 ESK-6CM FE-9EE	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-22A ESK-6CM ESK-6JS
1-HV-MOV-113B	480V MCC 1J1-1 bkr D3 ESK-6CM FE-9GR	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-22B ESK-6CM ESK-6JS
1-HV-MOV-113C	480V MCC 1H1-1 bkr F2 ESK-6CM FE-9EE	480V/120VAC Stepdown Transformer	None	None	None	To 1-HV-P-22C ESK-6CM ESK-6JS

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-1 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 1**

COMPONENT	MOTIVE FORCE	CONTROL POWER -	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
1-HV-PCV-1235A-1	Instrument Air HV-058	1-HV-PC-1235A HV-058	None	None	None	Fails closed
1-HV-PCV-1235A-2			None	None	None	Fails open
1-HV-PCV-1235B-1	Instrument Air HV-059	1-HV-PC-1235B HV-059	None	None	None	Fails closed
1-HV-PCV-1235B-2			None	None	None	Fails open
1-HV-PCV-1235C-1	Instrument Air HV-060	1-HV-PC-1235C HV-060	None	None	None	Fails closed
1-HV-PCV-1235C-2			None	None	None	Fails open
1-HV-S-1A (for information only)	None	120VAC Vital Bus I ESK-6JT FE-11D HV-056	None	None	None	Hi delta Press diverter valve control for 1-MOV-HV-115-1 and 1-MOV-HV-115-2
1-HV-S-1B (for information only)	None	120VAC Vital Bus III ESK-6JT FE-11D HV-057	None	None	None	Hi delta Press diverter valve control for 1-MOV-HV-116-1 and 1-MOV-HV-116-2

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-2**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 2**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-HV-AC-6	480V 2J1-4 83 ESK-6KC FE-9GC	480V/120VAC Stepdown Transformer	None	None	None	2-HV-MOD-237 is opened when fan is energized HV-004
2-HV-AC-7	480V 2H1-1 C4 ESK-6KC FE-9EB	480V/120VAC Stepdown Transformer	None	None	None	2-HV-MOD-238 is opened when fan is energized HV-005
2-HV-MOD-237	120VAC from 2-HV-AC-6 2J1-1 ESK-6KC HV-004 FE-9GC	None	None	None	None	Opens when 2-HV-AC-6 fan is energized. Fails closed HV-004
2-HV-MOD-238	120VAC from 2-HV-AC-7 2H1-1 ESK-6KC HV-005 FE-9EB	None	None	None	None	Opens when 2-HV-AC-7 fan is energized. Fails closed HV-005
2-HV-TCV-266	120VAC from 2-HV-AC-6 HV-004 FE-9GC ESK-6KC	None	None	None	None	Spring return to block flow to AHU when de-energized HV-004

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-2 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 2**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-HV-TCV-267	120VAC from 2-HV-AC-7 HV-005 FE-9EB FE-6KC	None	None	None	None	Spring return to block flow to AHU when de-energized HV-005
2-HV-E-4A	480V 2H1-4 D3 FE-9EJ	Stepdown Transformer W 595C773 SWECC File 10.1-12A	None	None	None	HV-006 HV-015 HV-037 FE-9EJ W 595C773
2-HV-E-4B	480V 2J1-1 F1 FE-9GE	Stepdown Transformer W 595C773 SWECC File 10.1-12A	None	None	None	HV-007 HV-016 HV-038 FE-9GE W 595C773
2-HV-E-4C	480V 2H1-4 D4 FE-9EJ	Stepdown Transformer W 595C773 SWECC File 10.1-12A	None	None	None	HV-008 HV-017 HV-039 FE-9EJ W 595C773
2-HV-P-20A	480V 2H1-1 C2 ESK-6JR FE-9EB	480V/120VAC Stepdown Transformer	None	None	None	To 2-HV-E-4A ESK-6JR, 6EK 2-HV-MOV-211A must be open

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-2 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 2**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-HV-P-20B	480V 2J1-1 A2 ESK-6JR FE-9GC	480V/120VAC Stepdown Transformer	None	None	None	To 2-HV-E-4B ESK-6JR, 6EC 2-HV-MOV-211B must be open
2-HV-P-20C	480V 2H1-1 C3 ESK-6JR FE-9EB	480V/120VAC Stepdown Transformer	None	None	None	To 2-HV-E-4C ESK-6JR, 6EK 2-HV-MOV-211C must be open
2-HV-P-22A	480V 2H1-1 B4 ESK-6JS FE-9EA	480V/120VAC Stepdown Transformer	None	2-HV-SOV-2200A packing gland, annunciator only HV-012	None	2-HV-MOV-213A must be open ESK-6CM
2-HV-P-22B	480V 2J1-1 A3 ESK-6JS FE-9GC	480V/120VAC Stepdown Transformer	None	2-HV-SOV-2200B packing gland, annunciator only HV-012	None	2-HV-MOV-213B must be open ESK-6CM
2-HV-P-22C	480V 2H1-1 B1 ESK-6JS FE-9EA	480V/120VAC Stepdown Transformer	None	2-HV-SOV-2200C packing gland, annunciator only HV-012	None	2-HV-MOV-213C must be open ESK-6CM

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-2 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 2**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-HV-MOV-211A	480V 2H1-4 B3 ESK-6EK FE-9EH	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-20A ESK-6JR
2-HV-MOV-211B	480V 2J1-1 C3 ESK-6EK FE-9GD	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-20B ESK-6JR
2-HV-MOV-211C	480V 2H1-4 A1 ESK-6EK FE-9EH	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-20C ESK-6JR
2-HV-MOV-213A	480V 2H1-1 D3 ESK-6CM FE-9EB	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-22A ESK-6JS
2-HV-MOV-213B	480V 2J1-1 D3 ESK-6CM FE-9GD	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-22B ESK-6JS
2-HV-MOV-213C	480V 2H1-1 D2 ESK-6CM FE-9EB	480V to 120VAC Stepdown Transformer	None	None	None	To 2-HV-P-22C ESK-6JS

\*Interlocks or other functional dependencies included in this column

**TABLE A.15-2 (Continued)**  
**ESGR COOLING SYSTEM**  
**DEPENDENCY MATRIX - UNIT 2**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
2-HV-PCV-2235A-1	Instrument Air HV-015	2-HV-PC-2235A HV-015	None	None	None	Fails closed
2-HV-PCV-2235A-2			None	None	None	Fails open
2-HV-PCV-2235B-1	Instrument Air HV-016	2-HV-PC-2235B HV-016	None	None	None	Fails closed
2-HV-PCV-2235B-2			None	None	None	Fails open
2-HV-PCV-2235C-1	Instrument Air HV-017	2-HV-PC-2235C HV-017	None	None	None	Fails closed
2-HV-PCV-2235C-2			None	None	None	Fails open
2-HV-S-1A (for information only)	None	120VAC Vital Bus 2-I ESK-6JT FE-11D HV-013	None	None	None	Hi delta Press diverter valve control for 2-MOV-HV-215-1 and 2-MOV-HV-215-2
2-HV-S-1B (for information only)	None	120VAC Vital Bus 2-III ESK-6JT FE-11D HV-014	None	None	None	Hi delta Press diverter valve control for 2-MOV-HV-216-1 and 2-MOV-HV-216-2

\*Interlocks or other functional dependencies included in this column

**TABLE A.17-1  
REACTOR PROTECTION  
DEPENDENCY MATRIX**

COMPONENT	MOTIVE FORCE	CONTROL POWER	AUTO ACTUATION	COMPONENT COOLING	ROOM COOLING	INTERLOCKS*
RPS Logic & Output Relays Train A	None	120 VAC Vital Bus 1-I 1-EP-CB-4A	RPS Input Signals Train A	None	Emergency Switchgear Room Cooling	
RPS Logic & Output Relays Train B	None	120 VAC Vital Bus 1-III 1-EP-CB-4C	RPS Input Signals Train B	None	Emergency Switchgear Room Cooling	

\*Interlocks or other functional dependencies included in this column



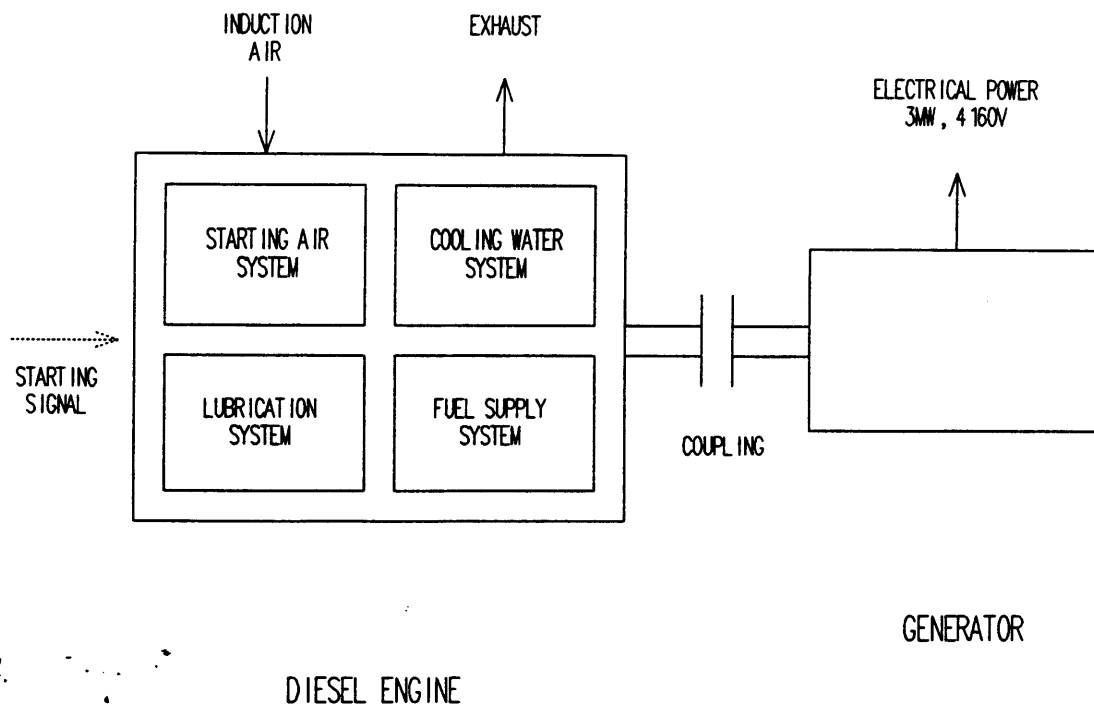


FIGURE A.O-1  
COMPONENT BOUNDARY- DIESEL GENERATOR

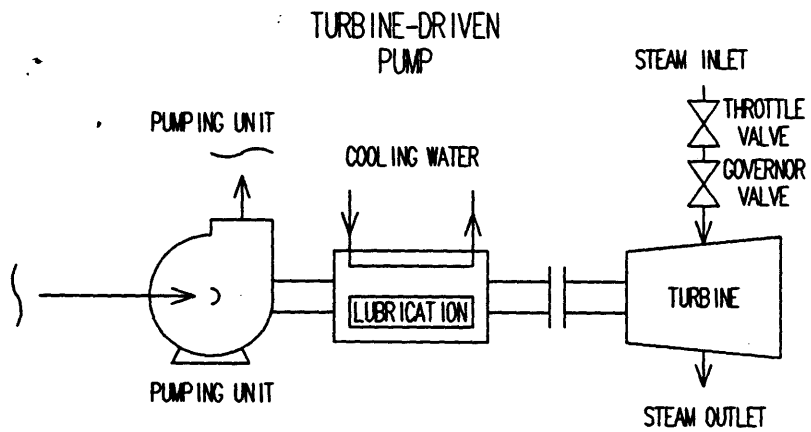
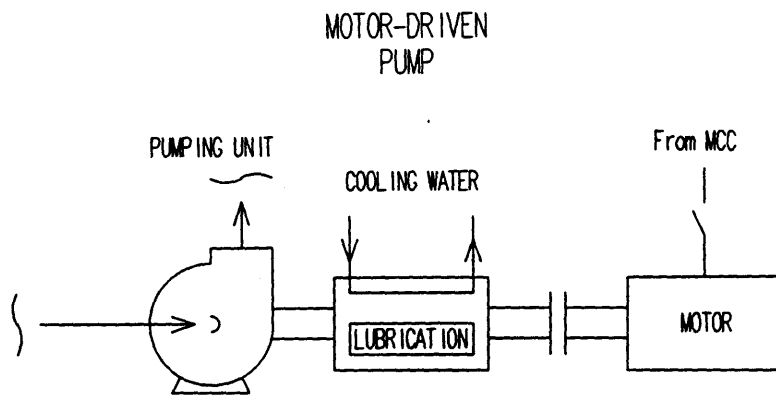
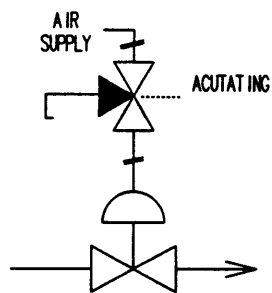
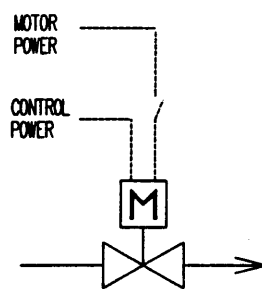


FIGURE A.0-2  
COMPONENT BOUNDARIES FOR PUMPS

AIR OPERATED  
VALVE



MOTOR OPERATED  
VALVE



SOLENOID OPERATED  
VALVE

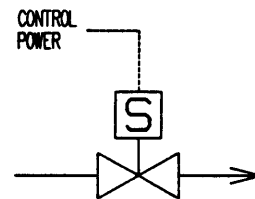


FIGURE A.0-3  
COMPONENT BOUNDARIES FOR VALVES

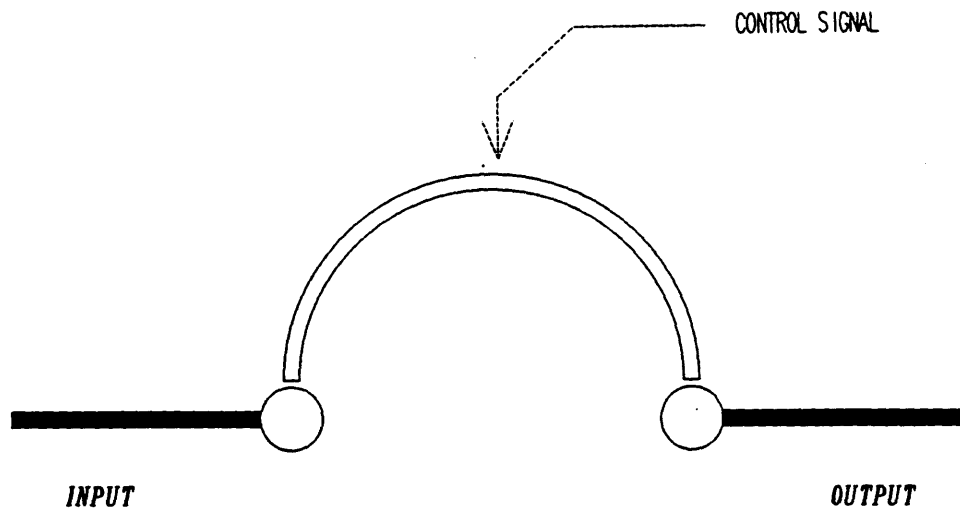


FIGURE A.0-4  
COMPONENT BOUNDARY FOR A BREAKER

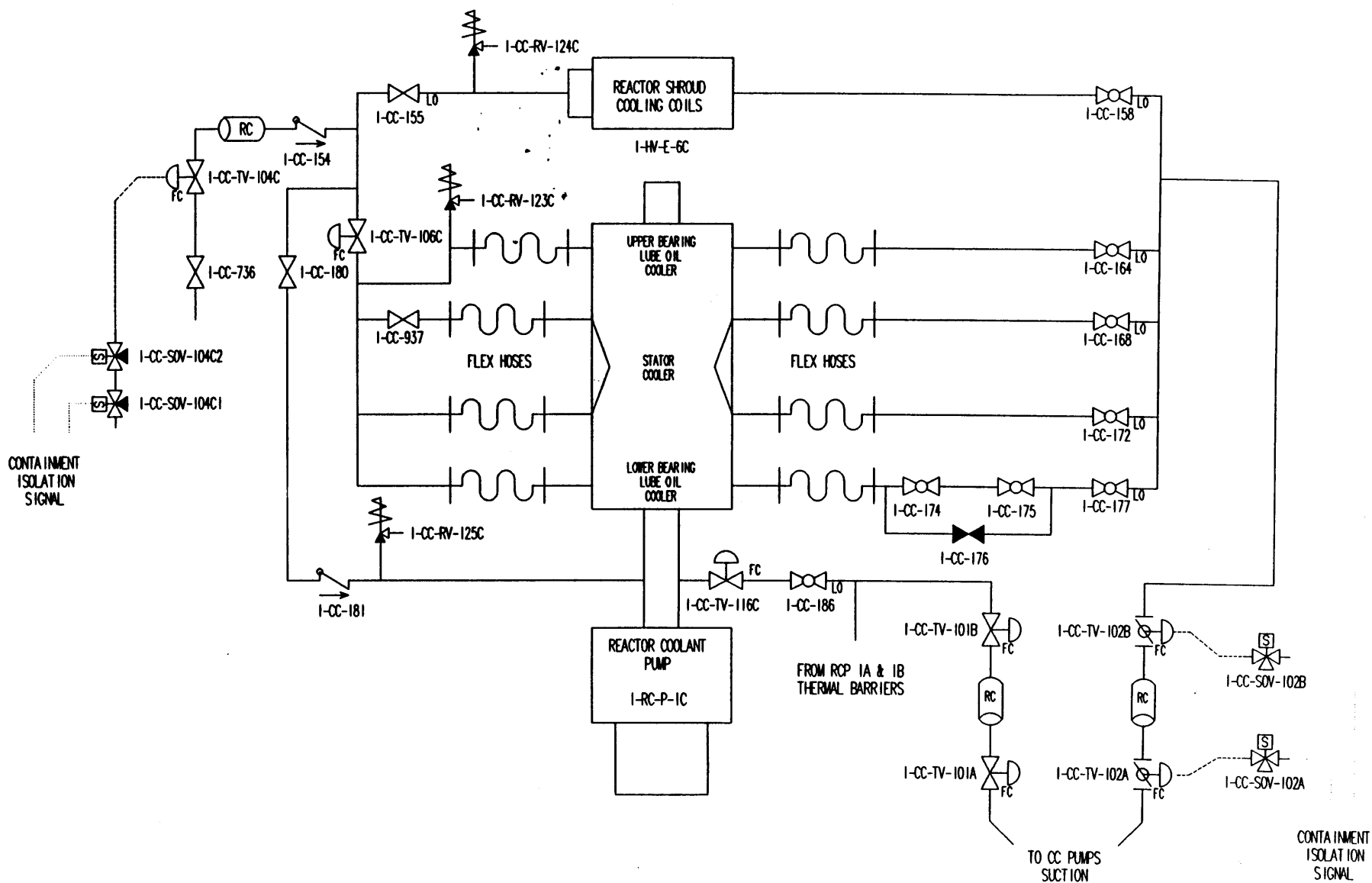


FIGURE A.1-1  
COMPONENT COOLING SYSTEM

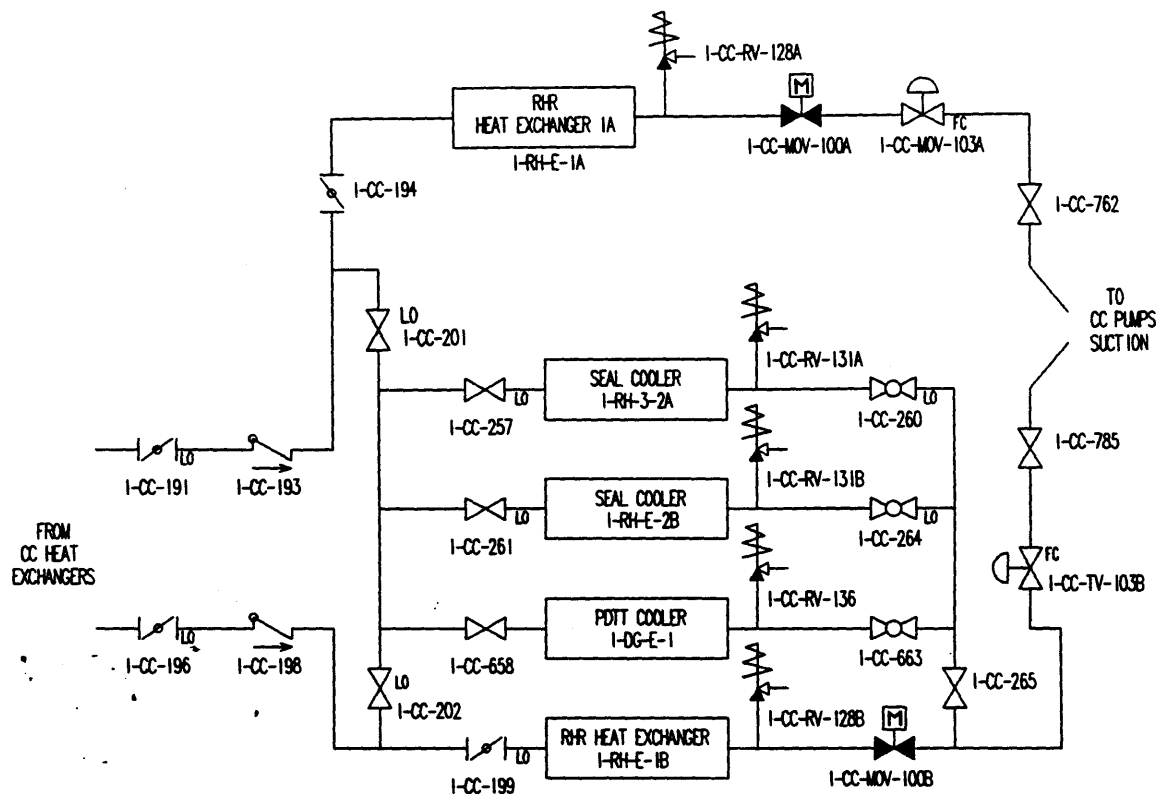


FIGURE A.1-2  
COMPONENT COOLING SYSTEM  
HX/COOLERS

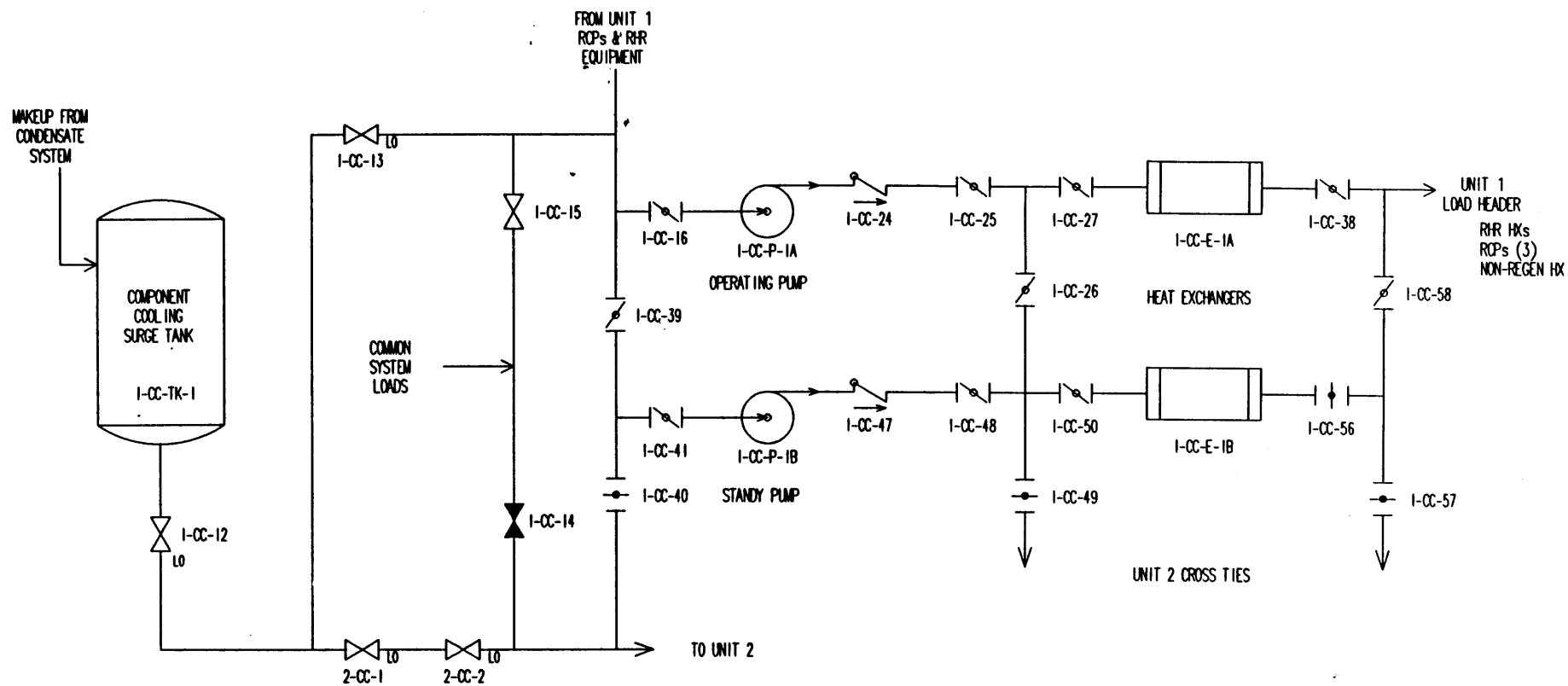


FIGURE A.1-3  
COMPONENT COOLING WATER SYSTEM  
PUMPS AND HEAT EXCHANGERS

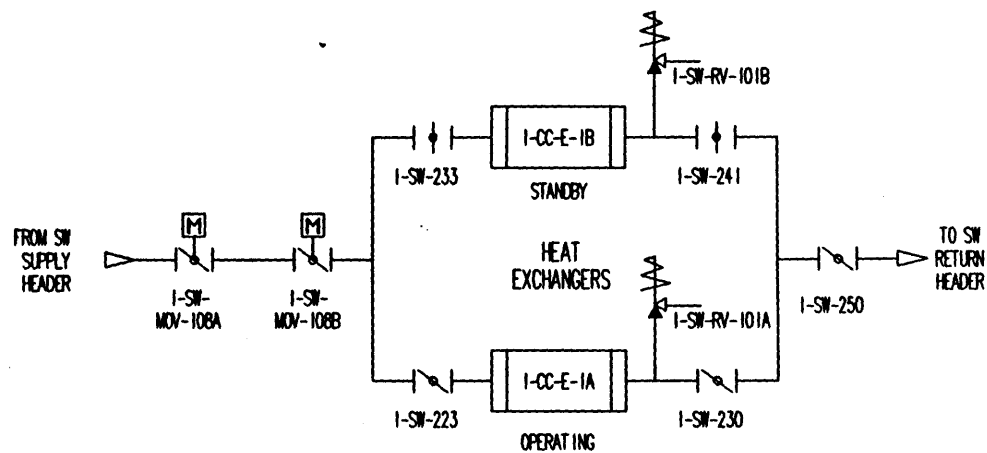
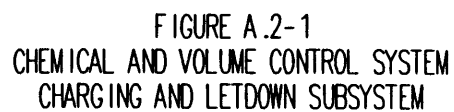


FIGURE A.1-4  
COMPONENT COOLING SYSTEM  
SERVICE WATER SUPPLY





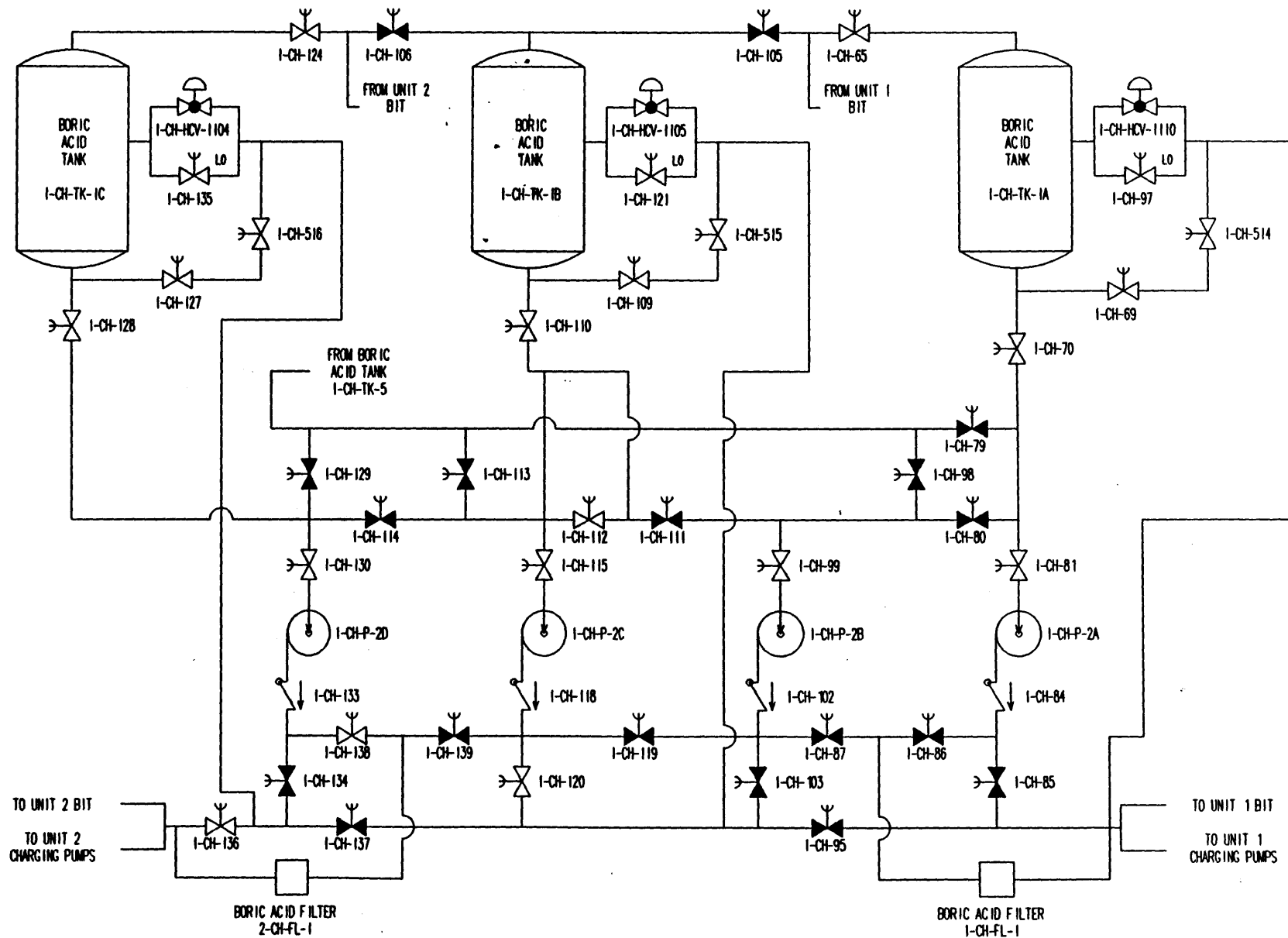


FIGURE A.2-2  
CHEMICAL AND VOLUME CONTROL SYSTEM  
BORIC ACID MAKEUP SUBSYSTEM

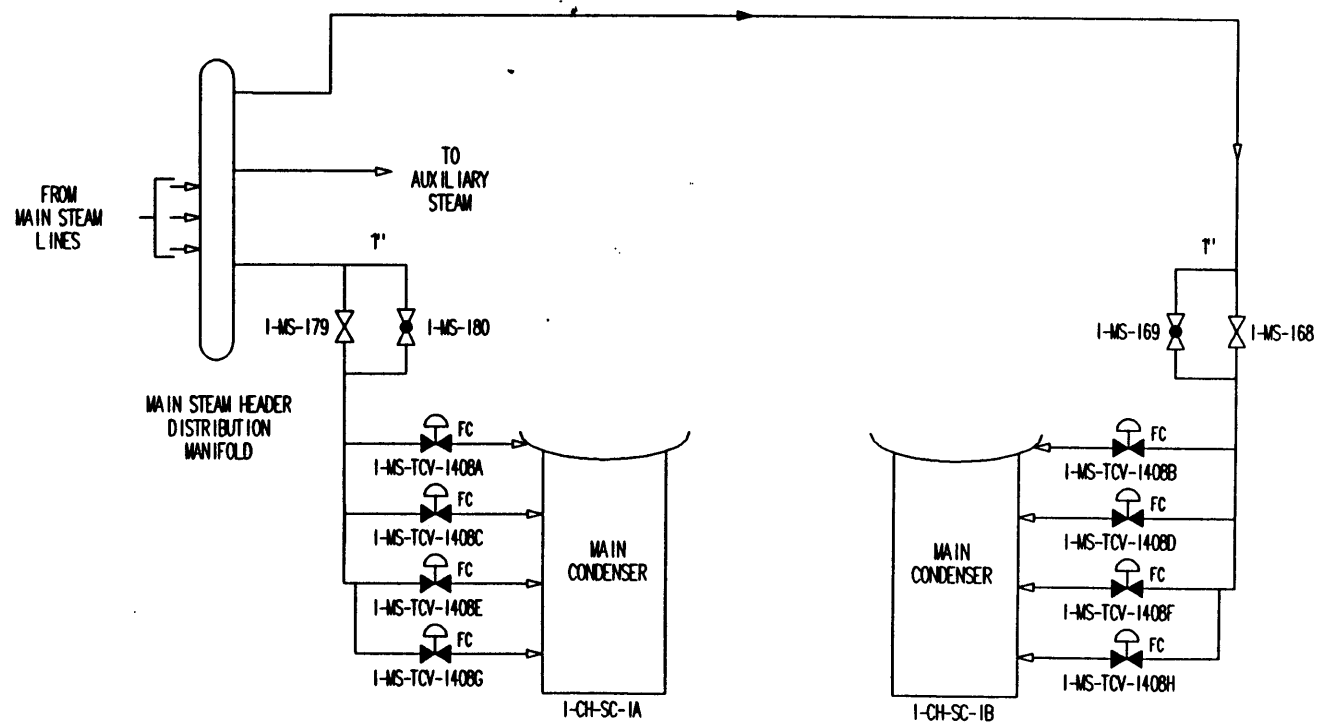


FIGURE A.3-1  
MAIN STEAM CONDENSER  
STEAM DUMP VALVES

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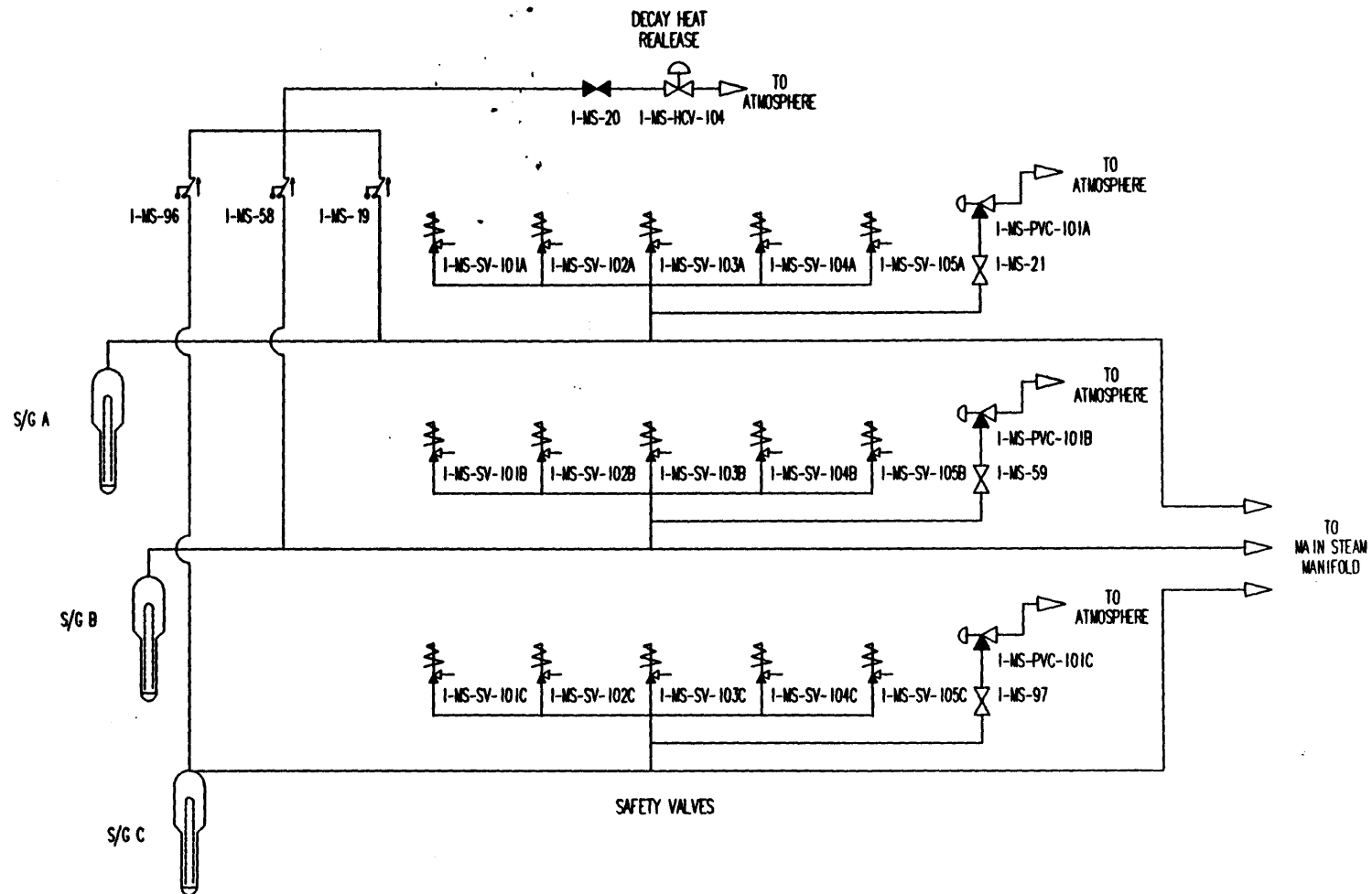
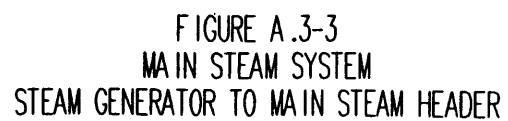


FIGURE A.3-2  
STEAM GENERATOR PRESSURE RELIEF



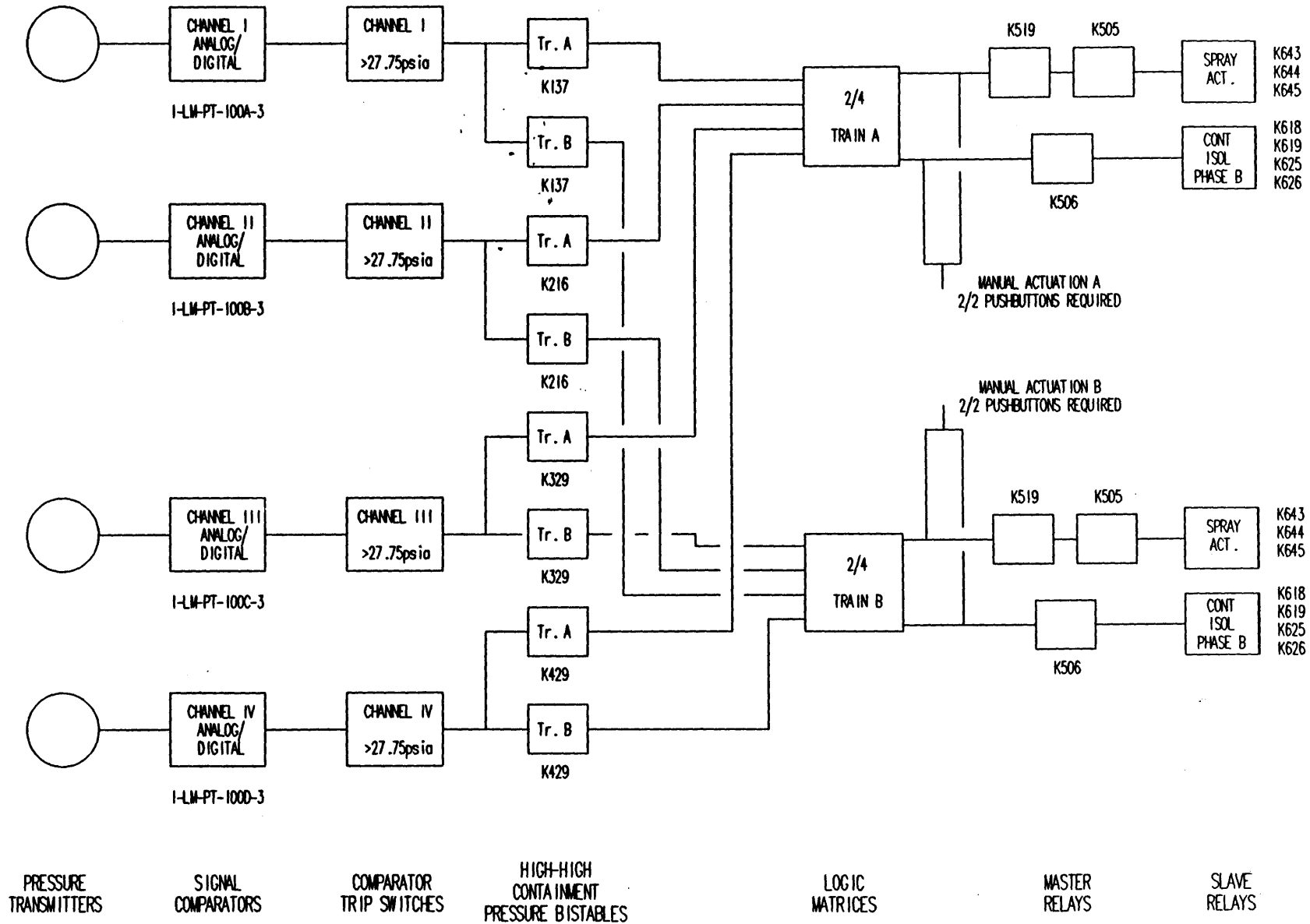


FIGURE A.4-1  
CONTAINMENT DEPRESSURIZATION ACTUATION

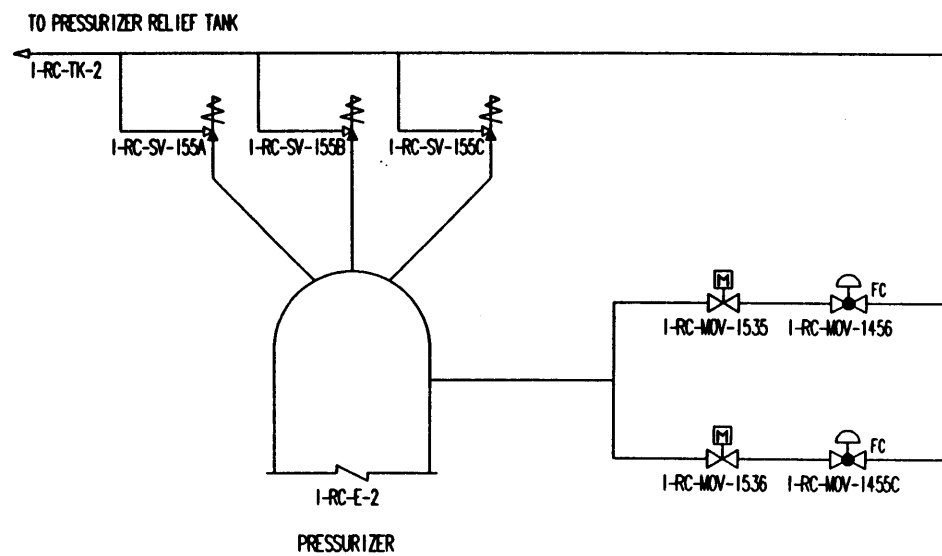


FIGURE A.6-1  
PRESSURIZER PRESSURE RELIEF SYSTEM

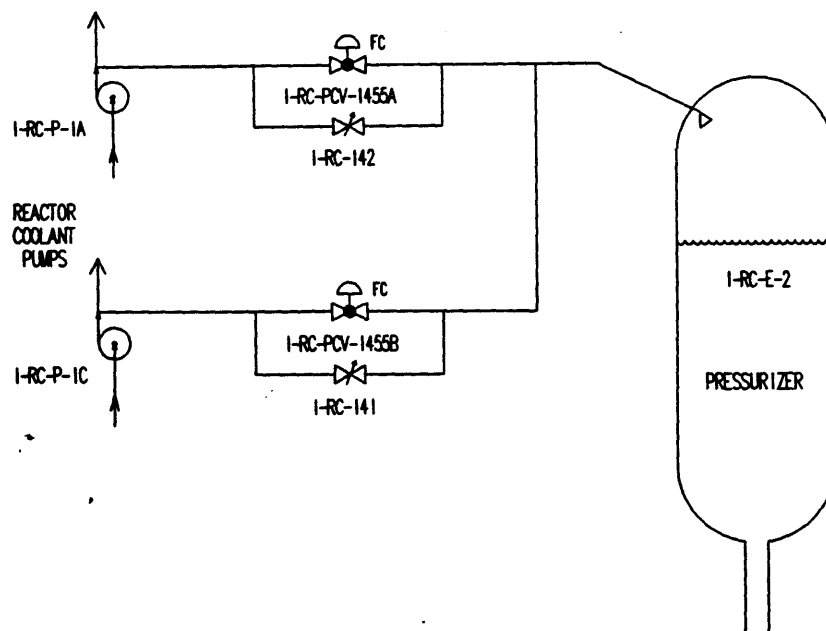


FIGURE A.6-2  
PRESSURIZER SPRAY



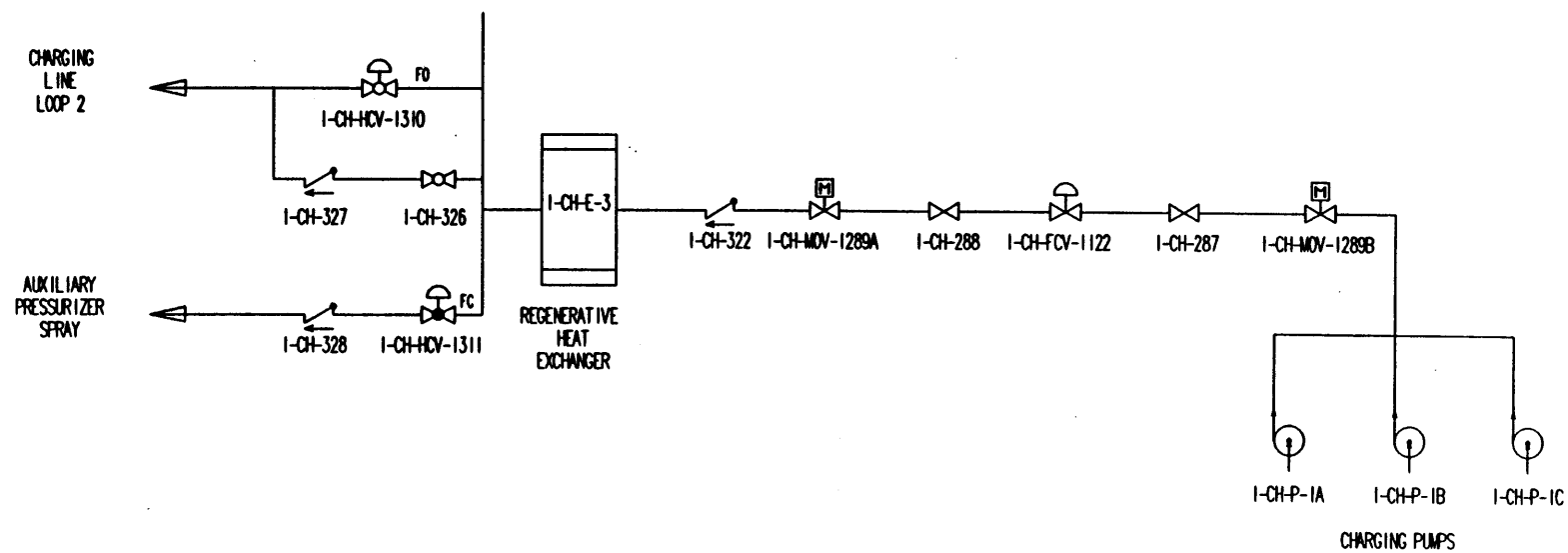


FIGURE A.6-3  
AUXILIARY PRESSURIZER SPRAY



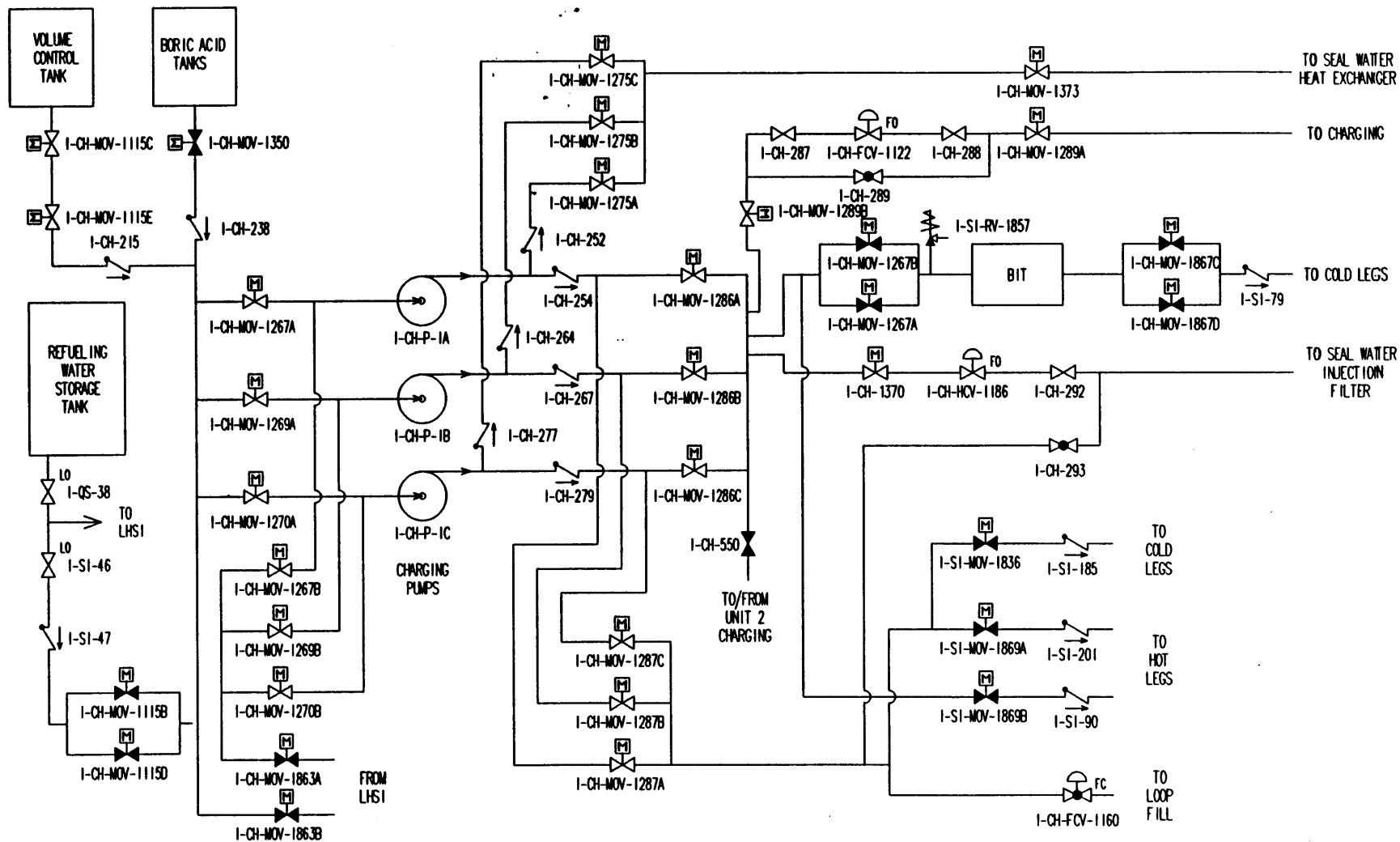


FIGURE A.7-2  
HIGH HEAD SAFETY INJECTION

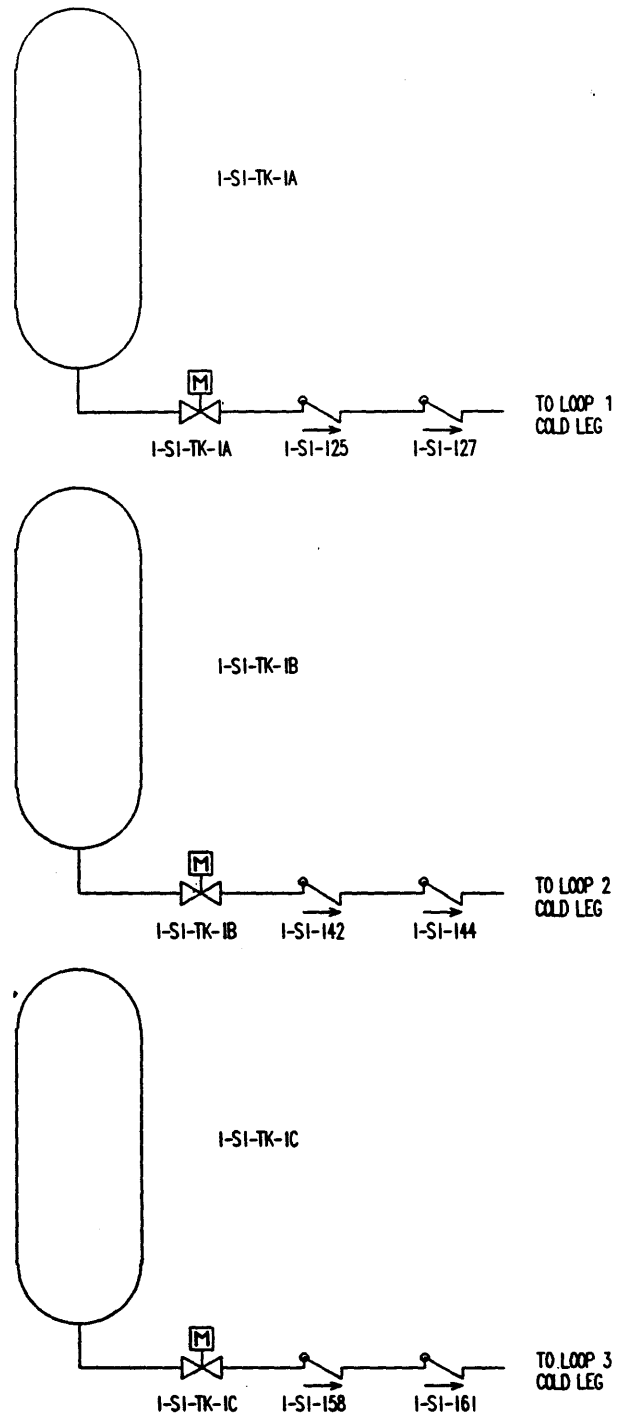


FIGURE A.7-3  
ACCUMULATOR SYSTEM

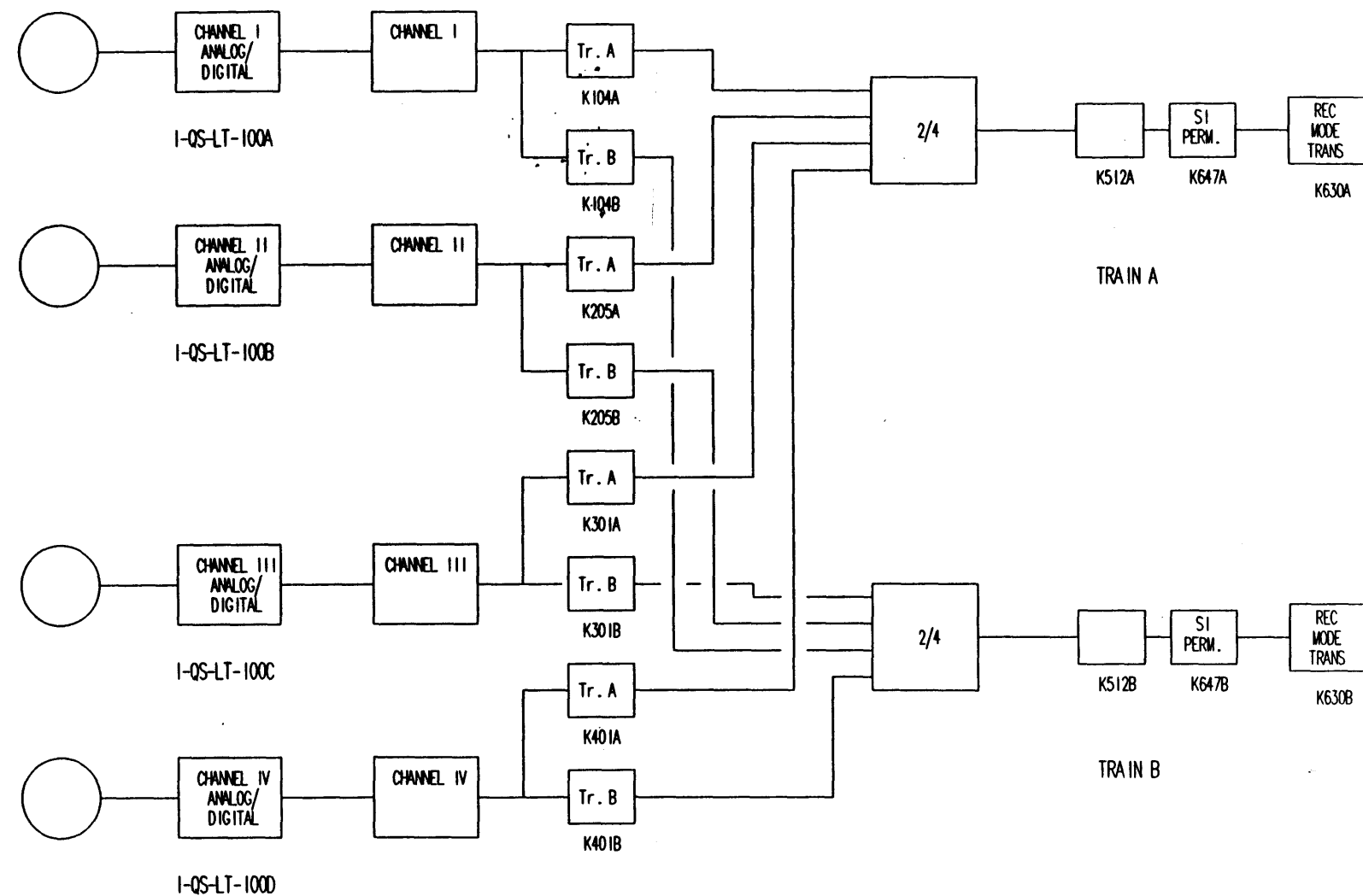


FIGURE A.7-4  
RECIRCULATION MODE TRANSFER

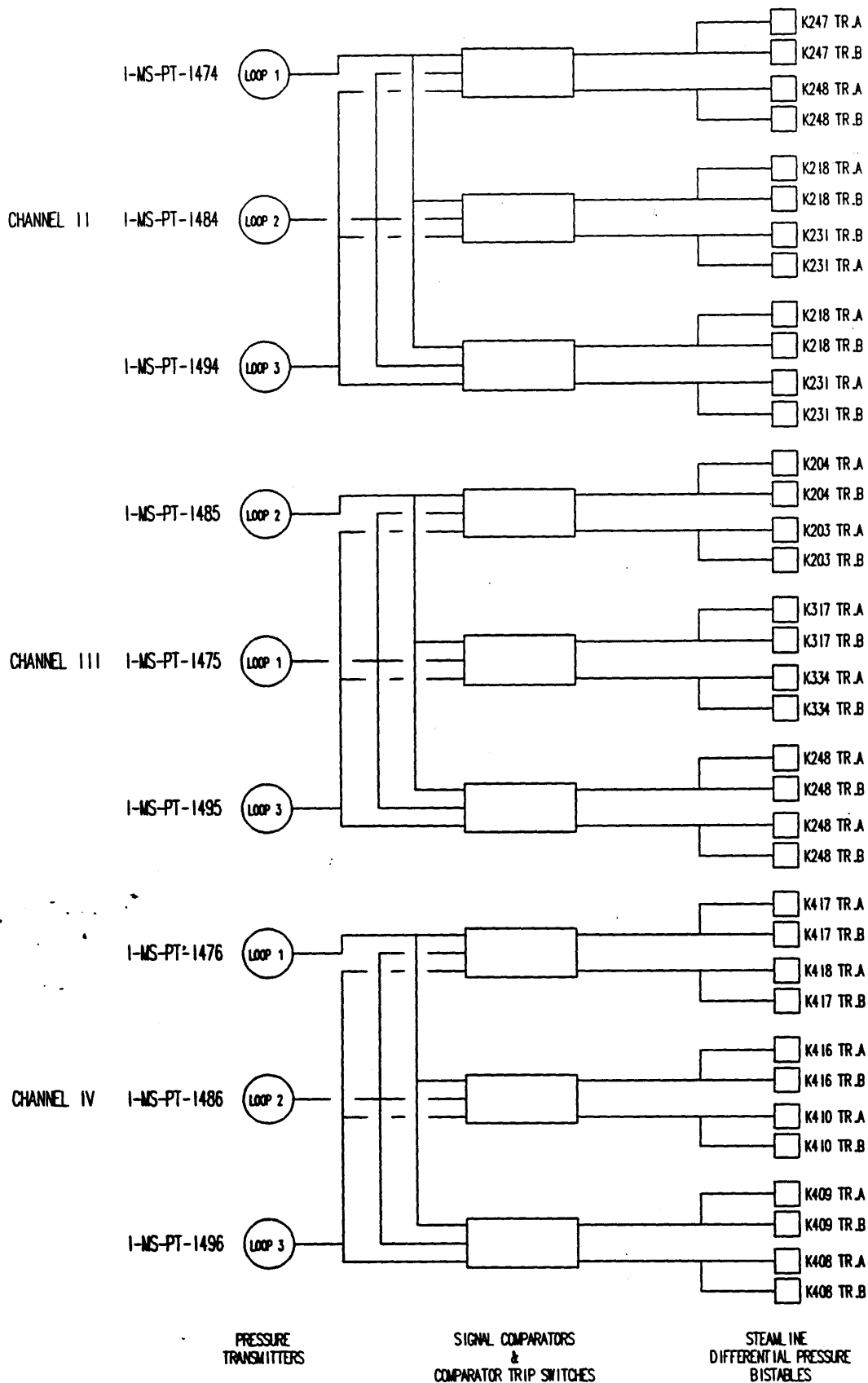


FIGURE A.7-5  
SAFETY INJECTION ACTUATION  
STEAM LINE DIFFERENTIAL PRESSURE

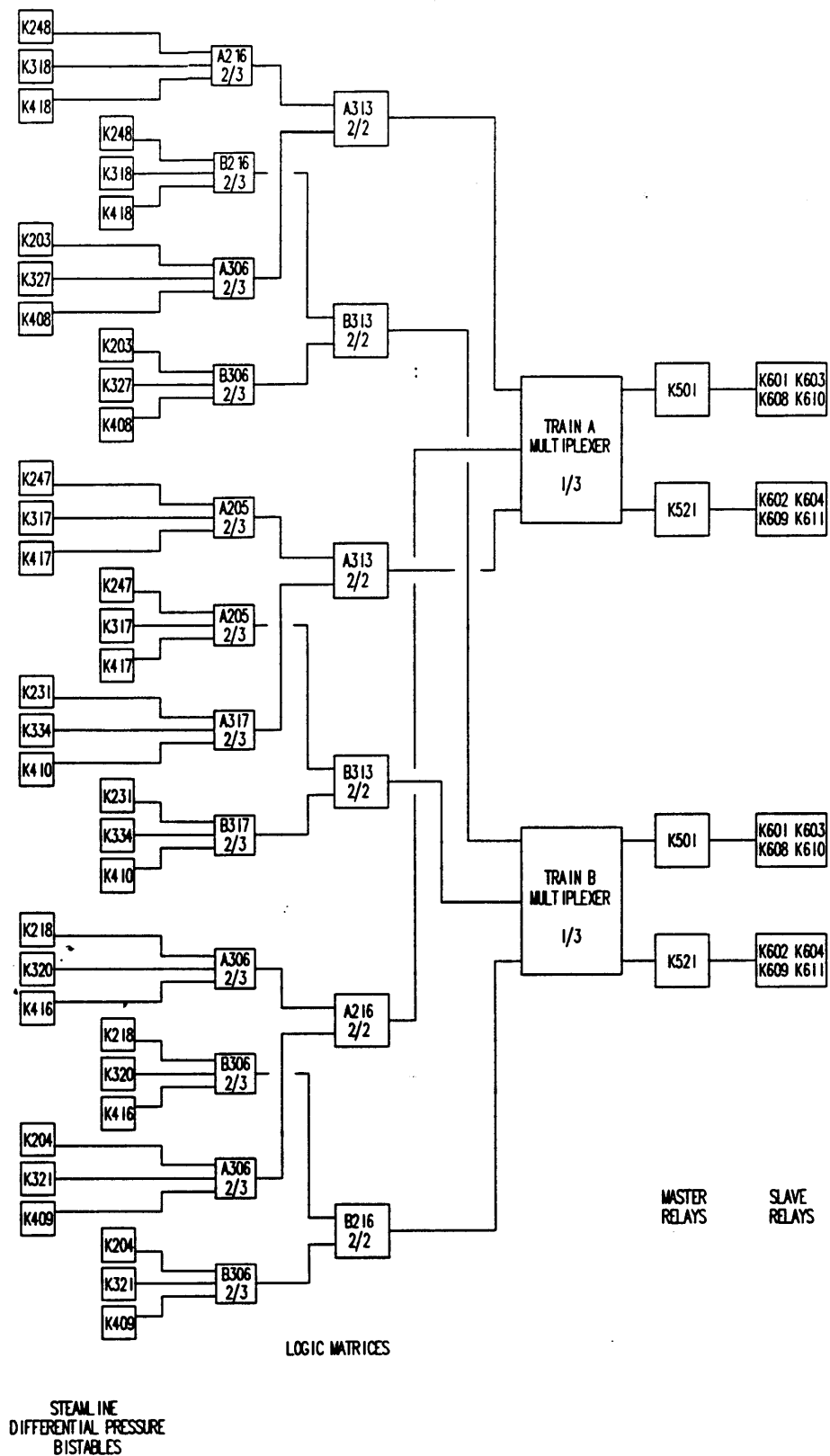


FIGURE A.7-6  
SAFETY INJECTION ACTUATION  
STEAM LINE DIFFERENTIAL PRESSURE

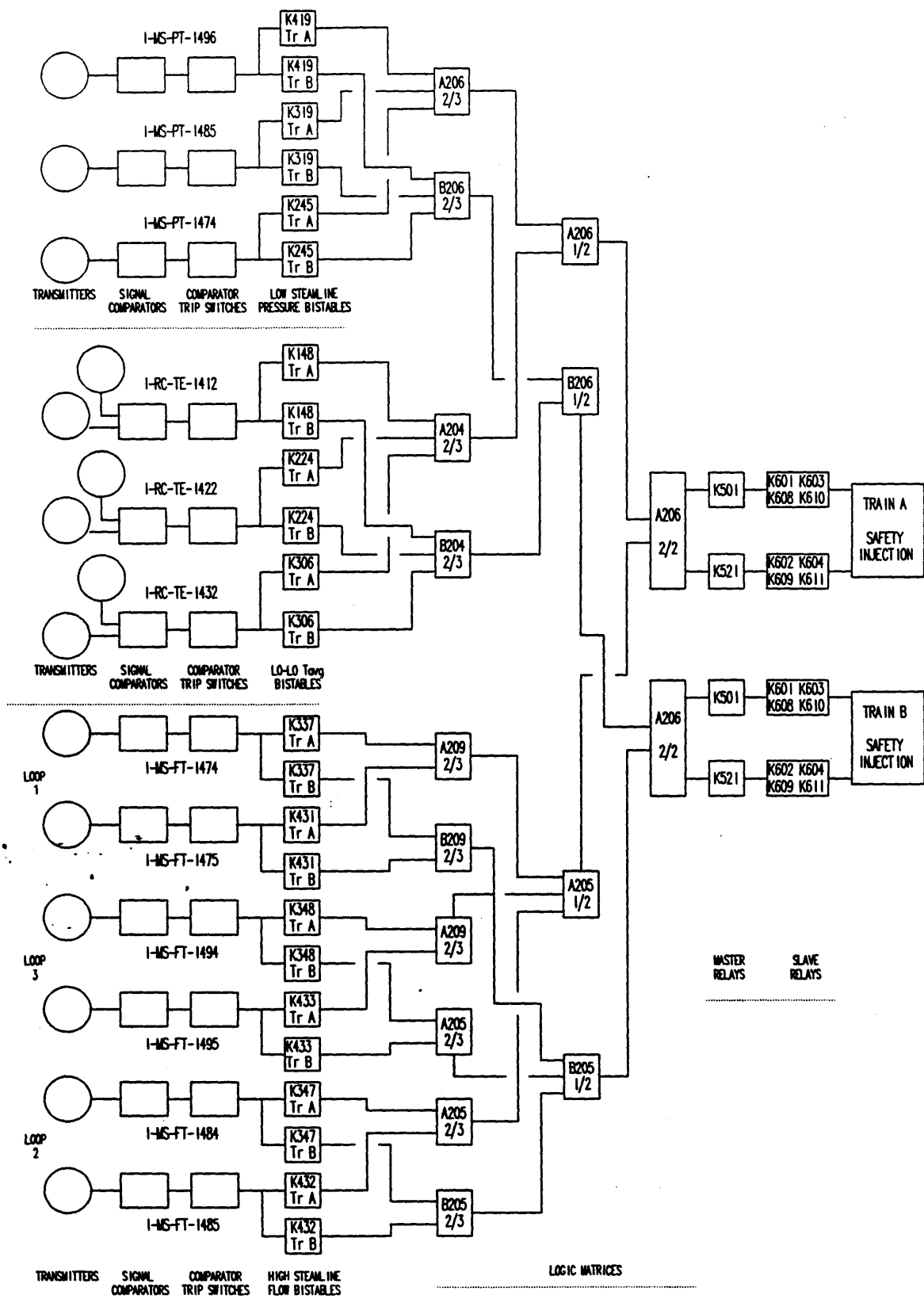


FIGURE A.7-7  
SAFETY INJECTION ACTUATION  
HIGH STEAMLINE FLOW/LOW STEAMLINE PRESSURE



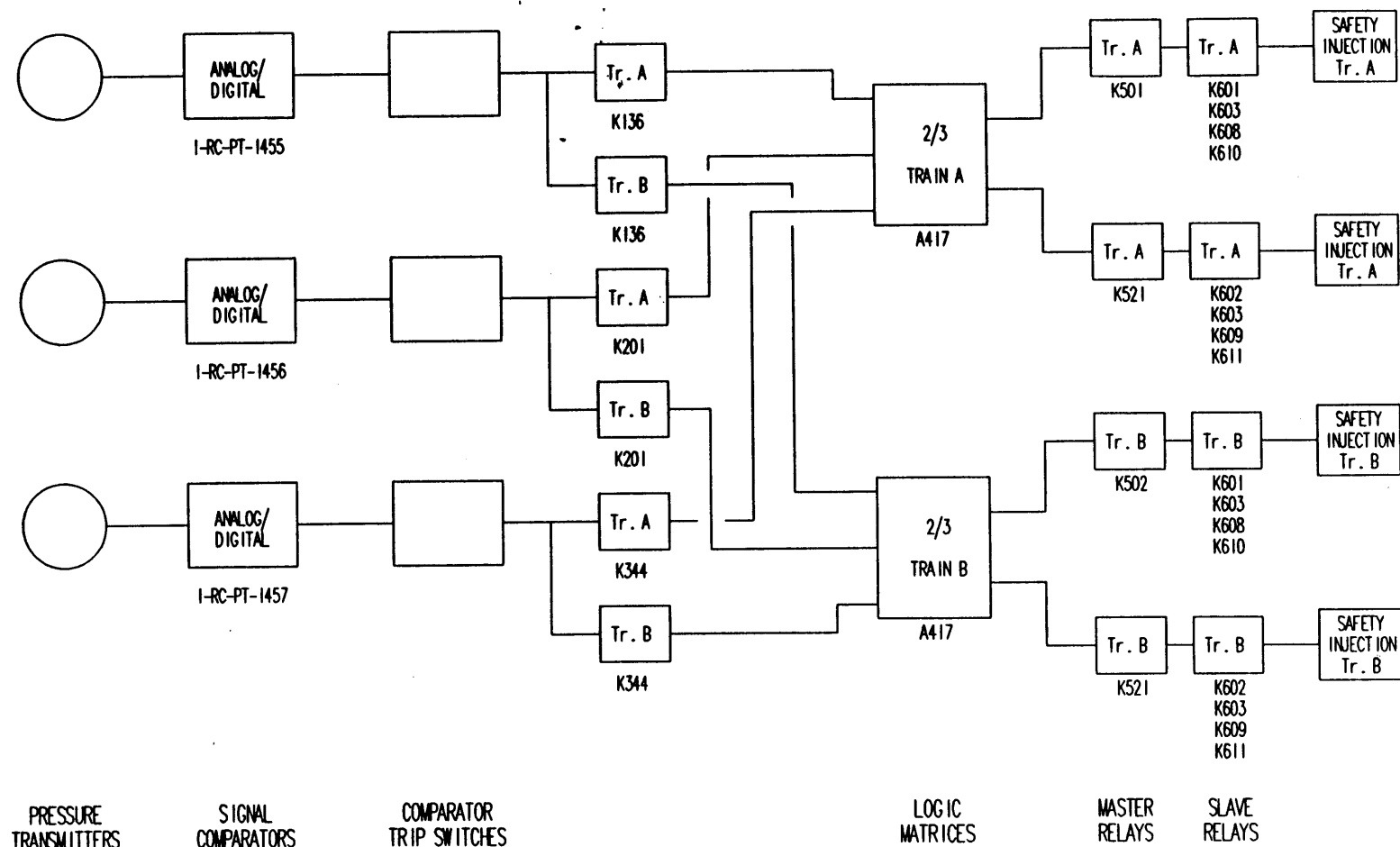


FIGURE A.7-8  
SAFETY INJECTION ACTUATION  
LOW-LOW PRESSURIZER PRESSURE

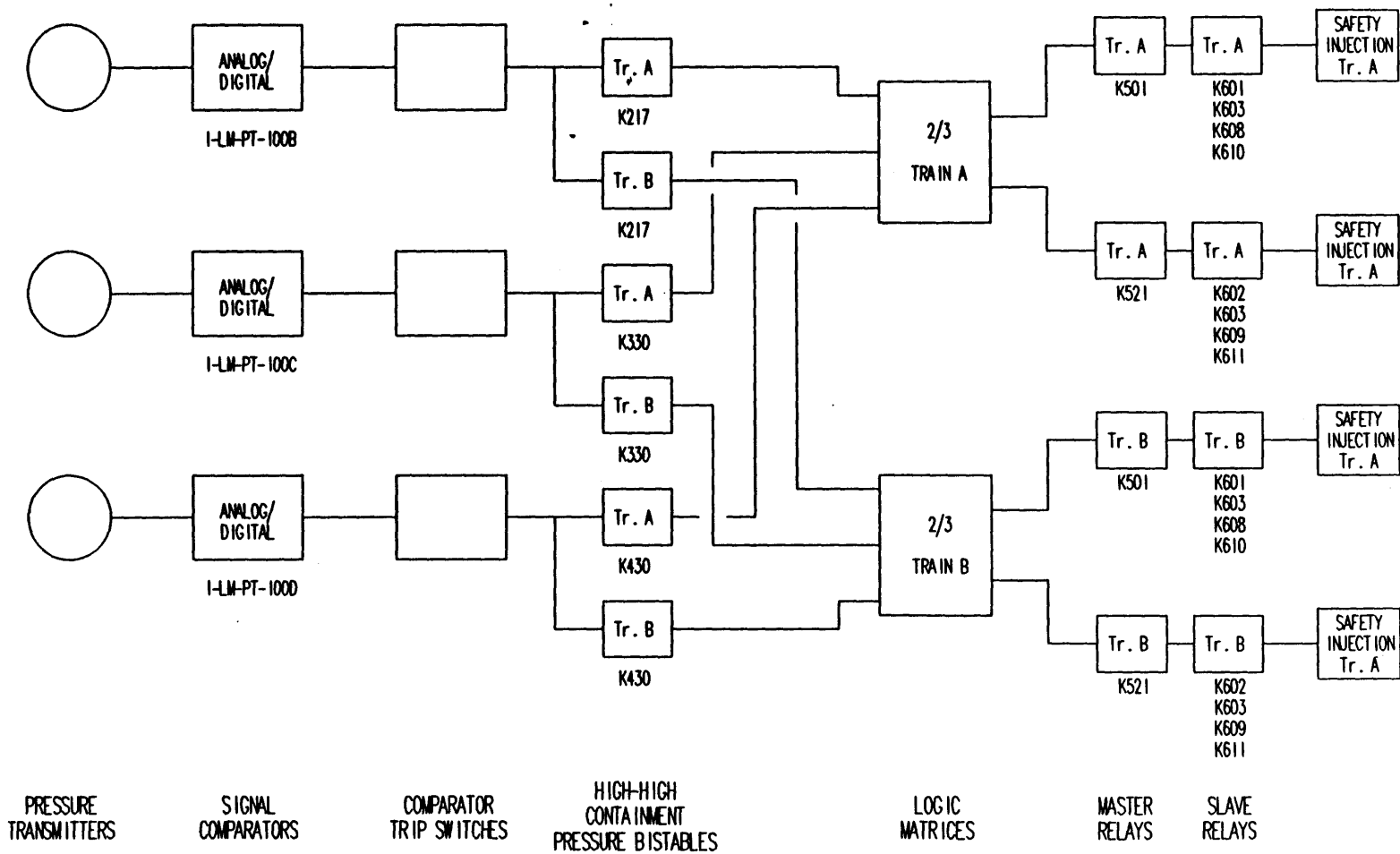


FIGURE A.7-9  
SAFETY INJECTION ACTUATION  
HIGH CONTAINMENT PRESSURE

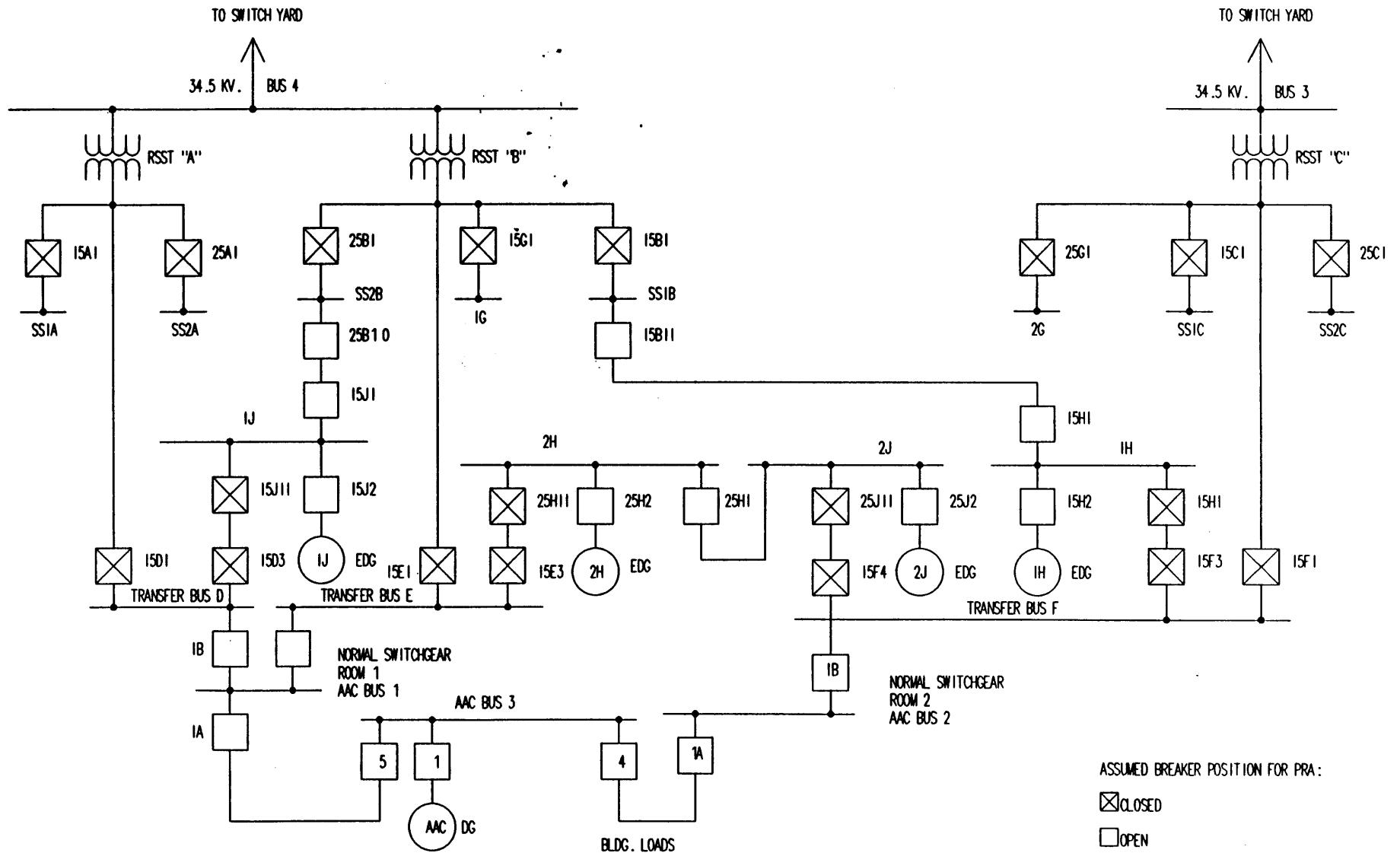


FIGURE A.9-1  
STATION BLACKOUT  
ALTERNATE AC DISTRIBUTION

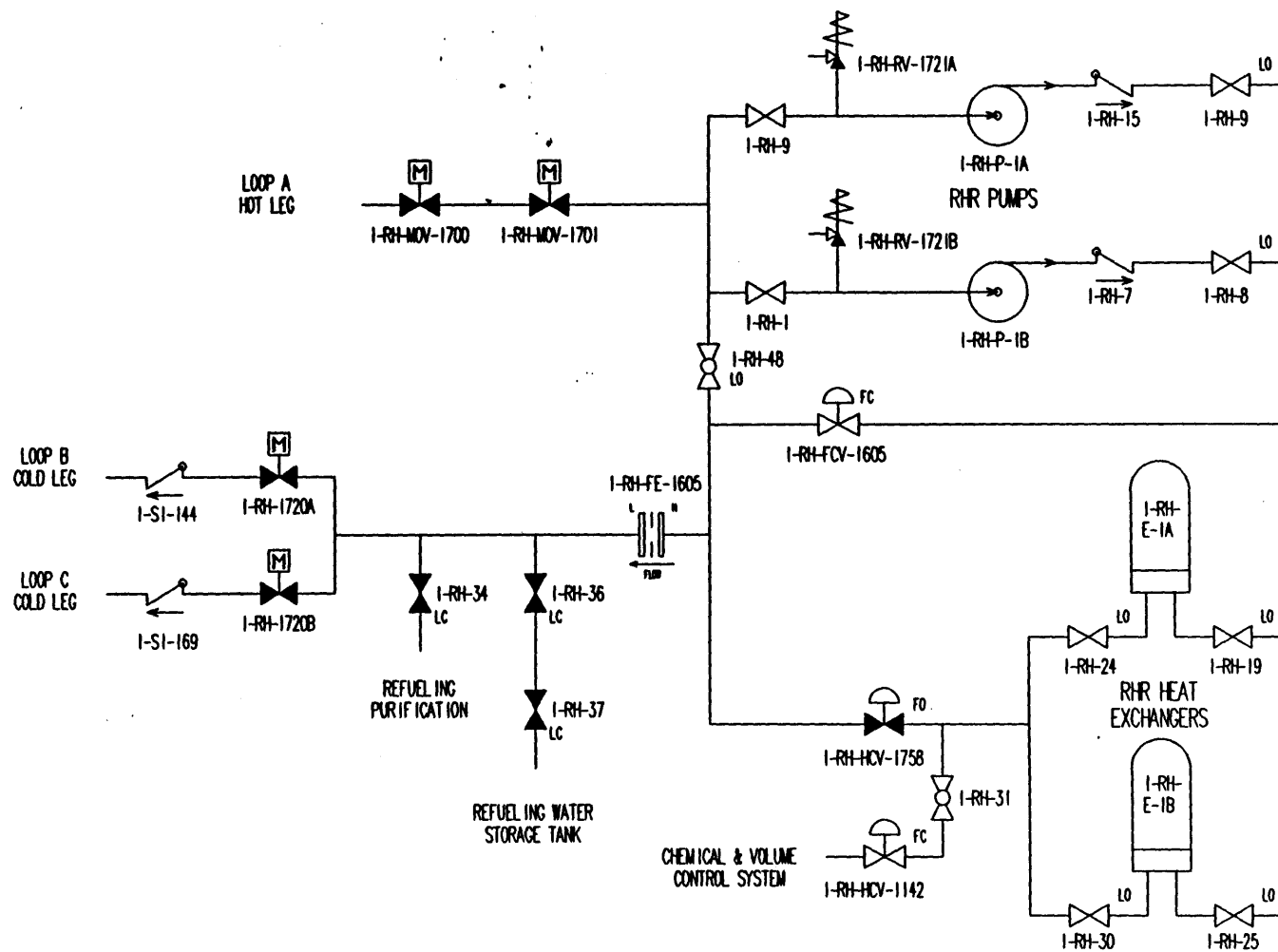


FIGURE A.10-1  
RESIDUAL HEAT REMOVAL SYSTEM

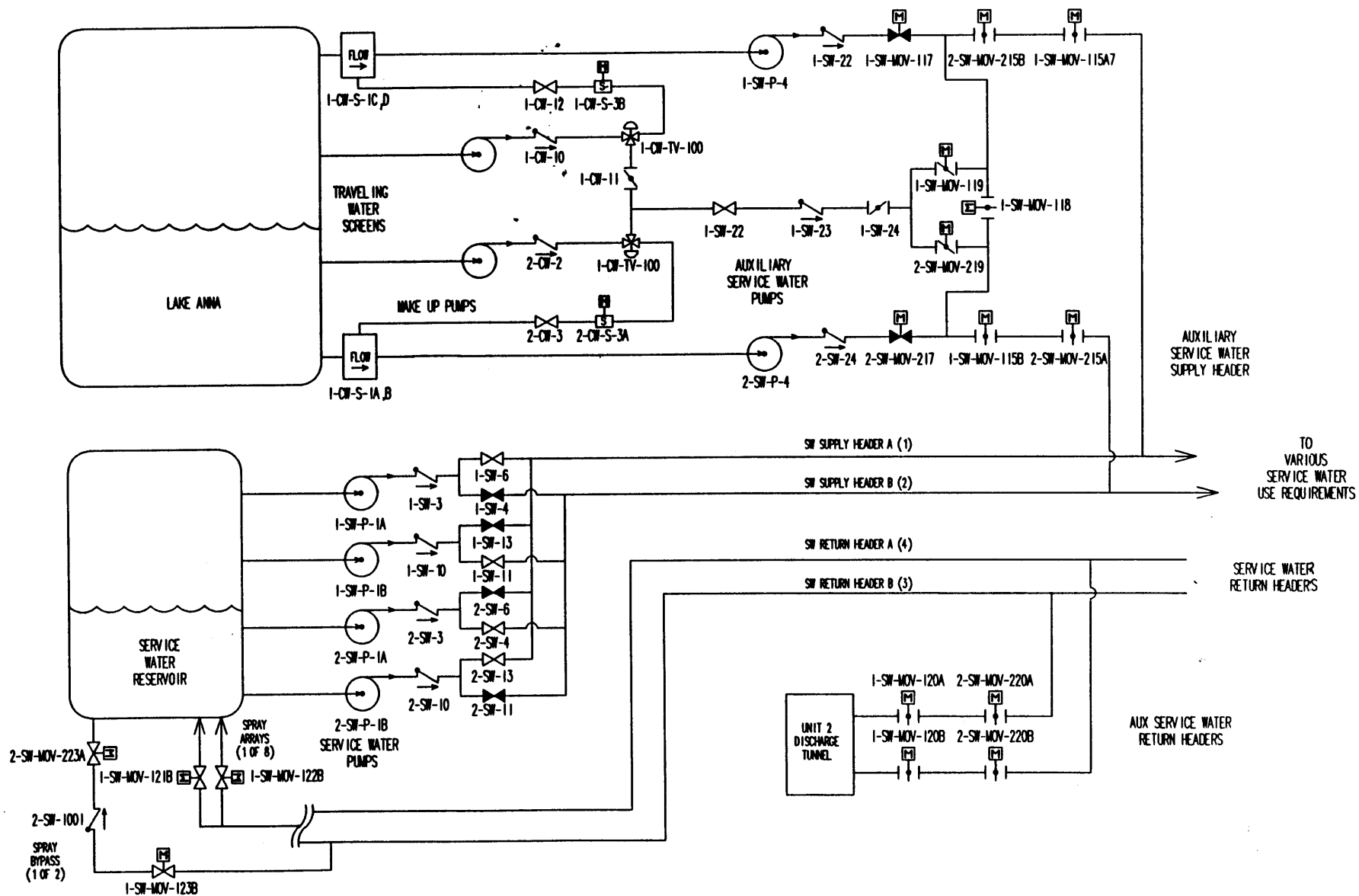


FIGURE A.11-1  
SERVICE WATER SYSTEM  
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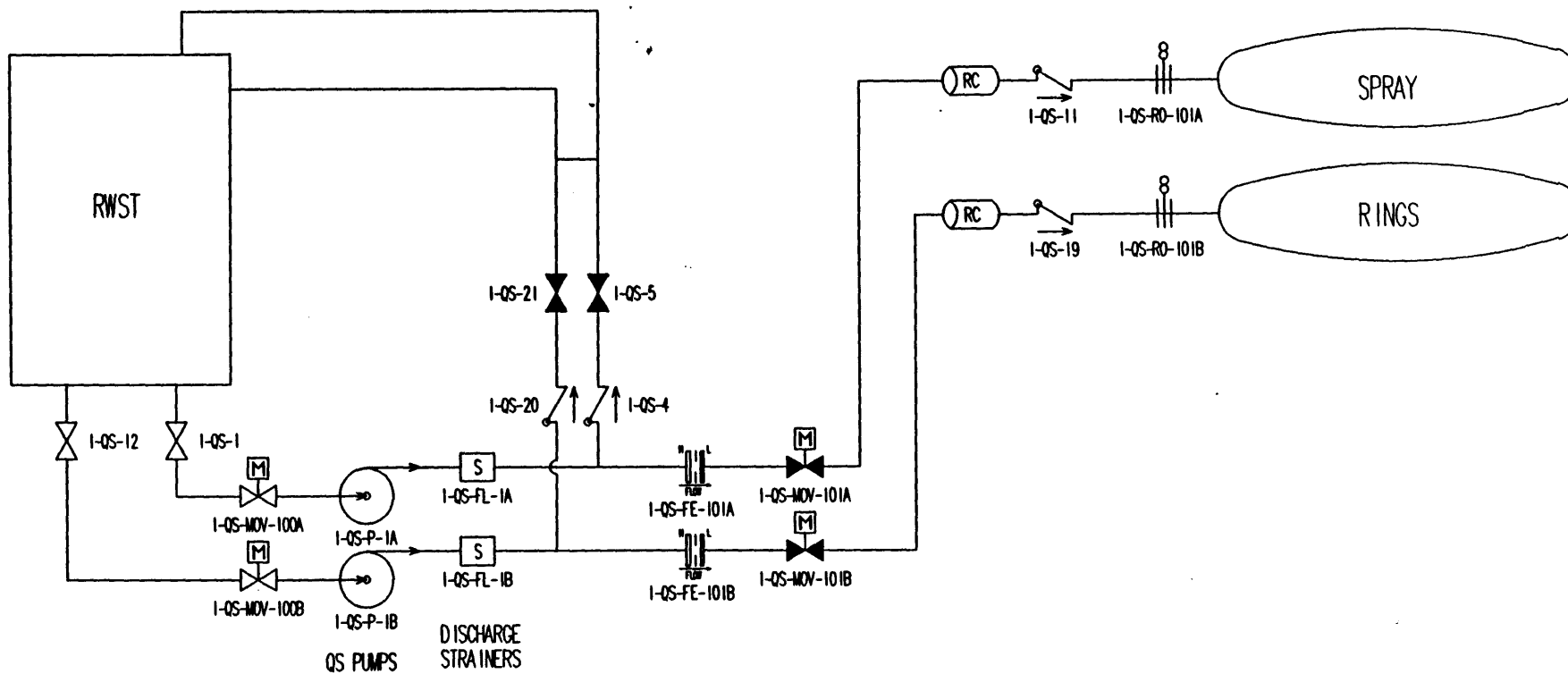


FIGURE A.12-1  
QUENCH SPRAY SYSTEM

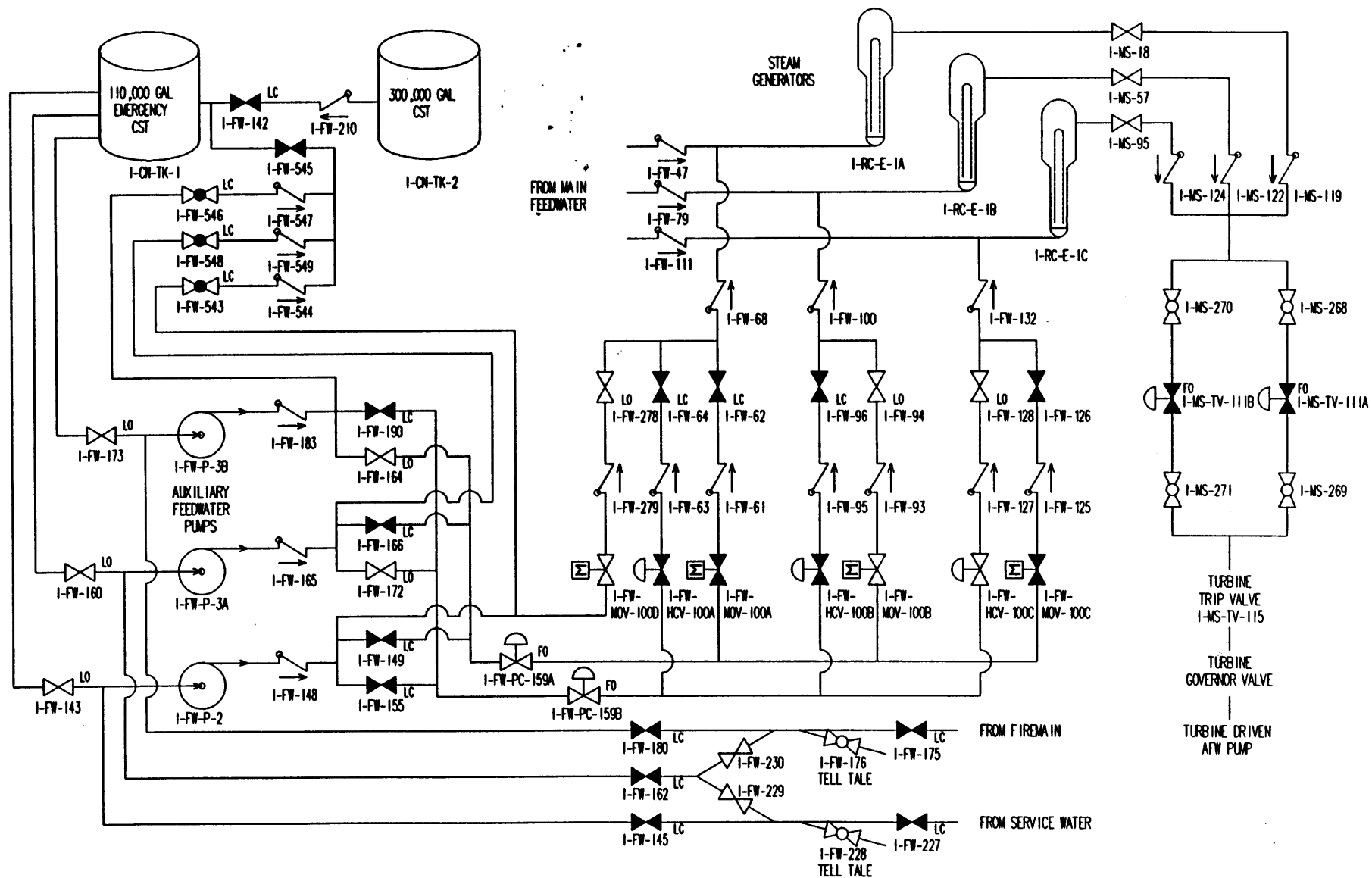


FIGURE A.13-1  
AUXILIARY FEEDWATER SYSTEM

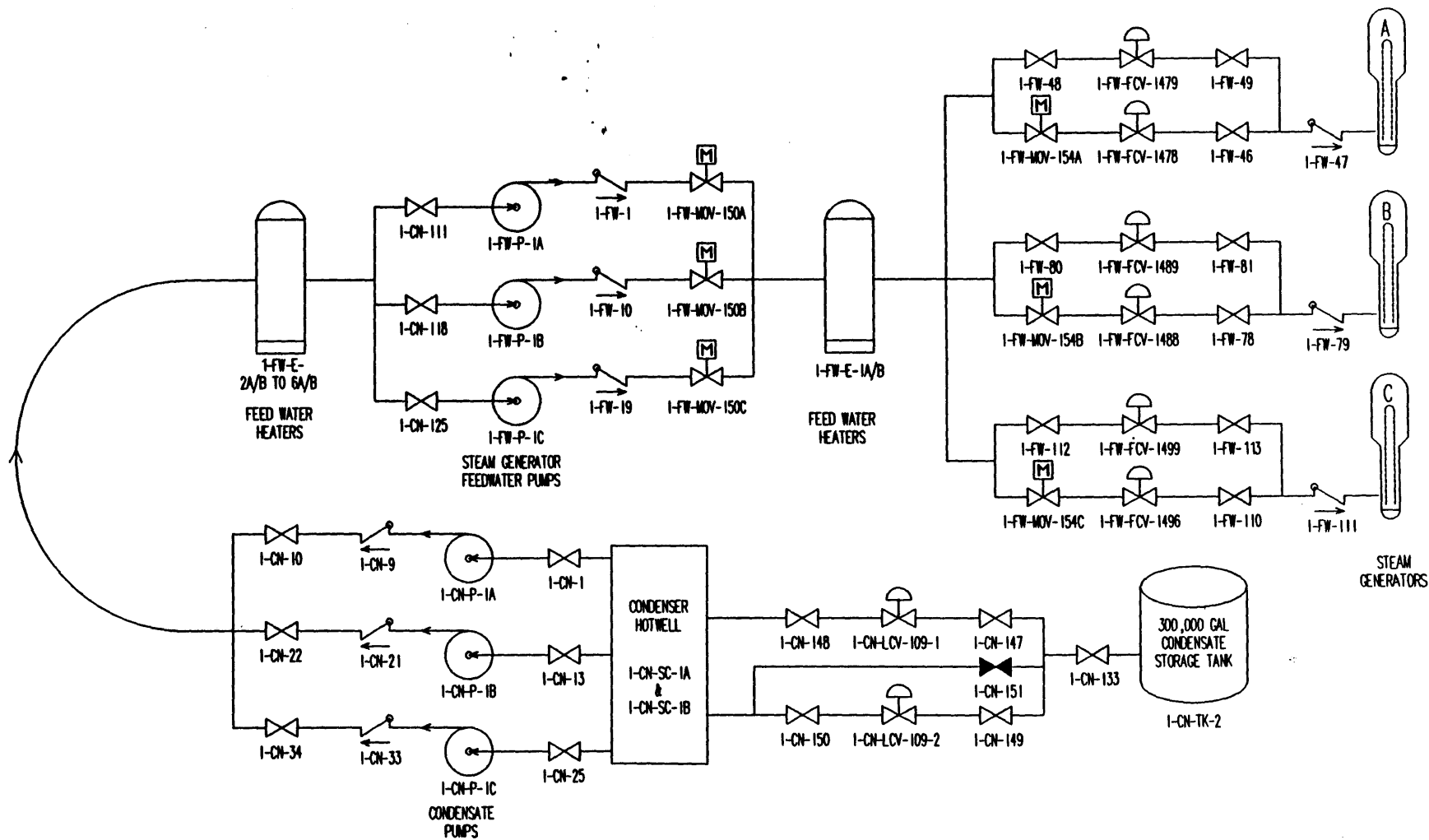


FIGURE A.13-2  
MAIN FEED WATER SYSTEM



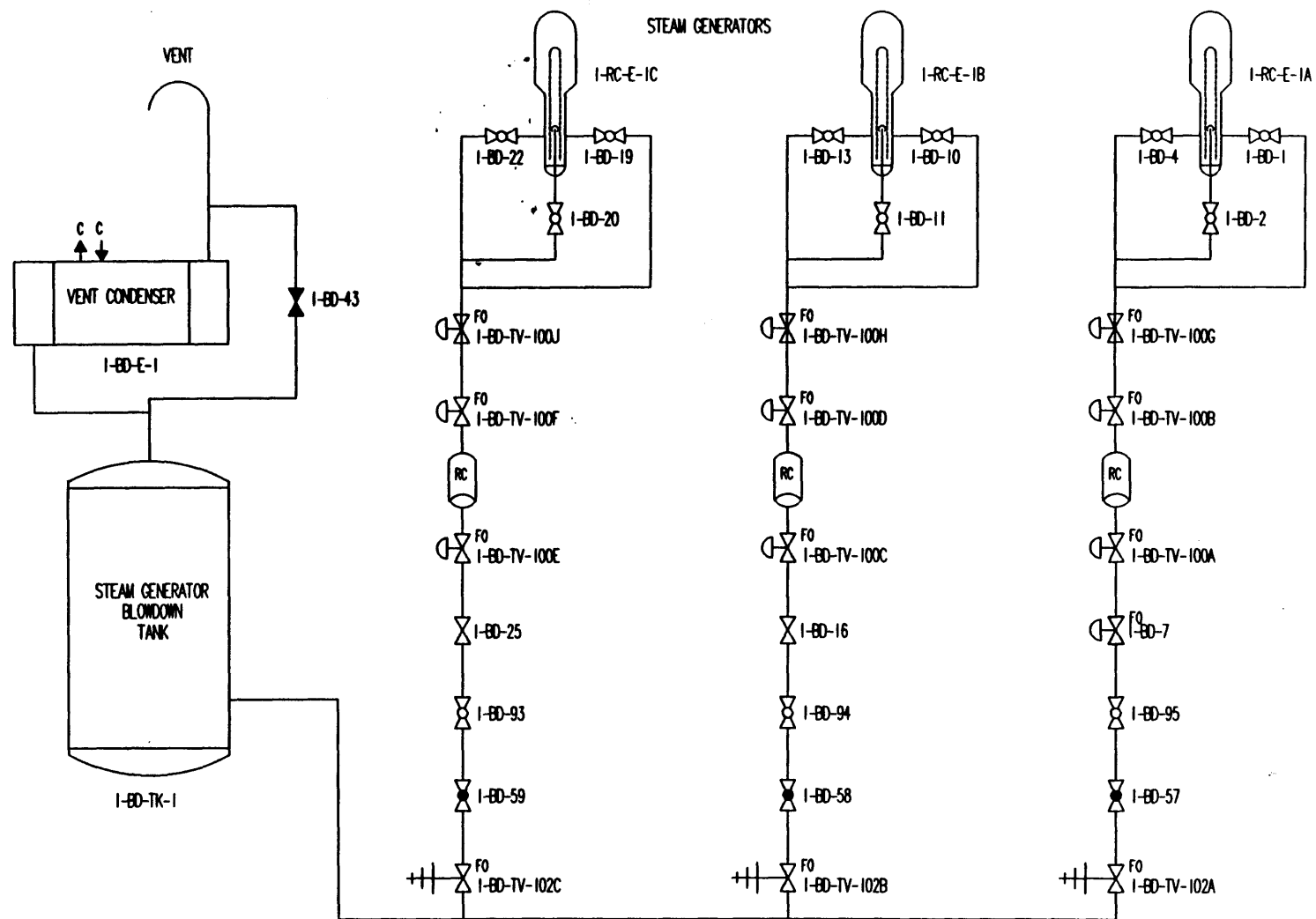


FIGURE A.13-3  
STEAM GENERATOR BLOWDOWN SYSTEM

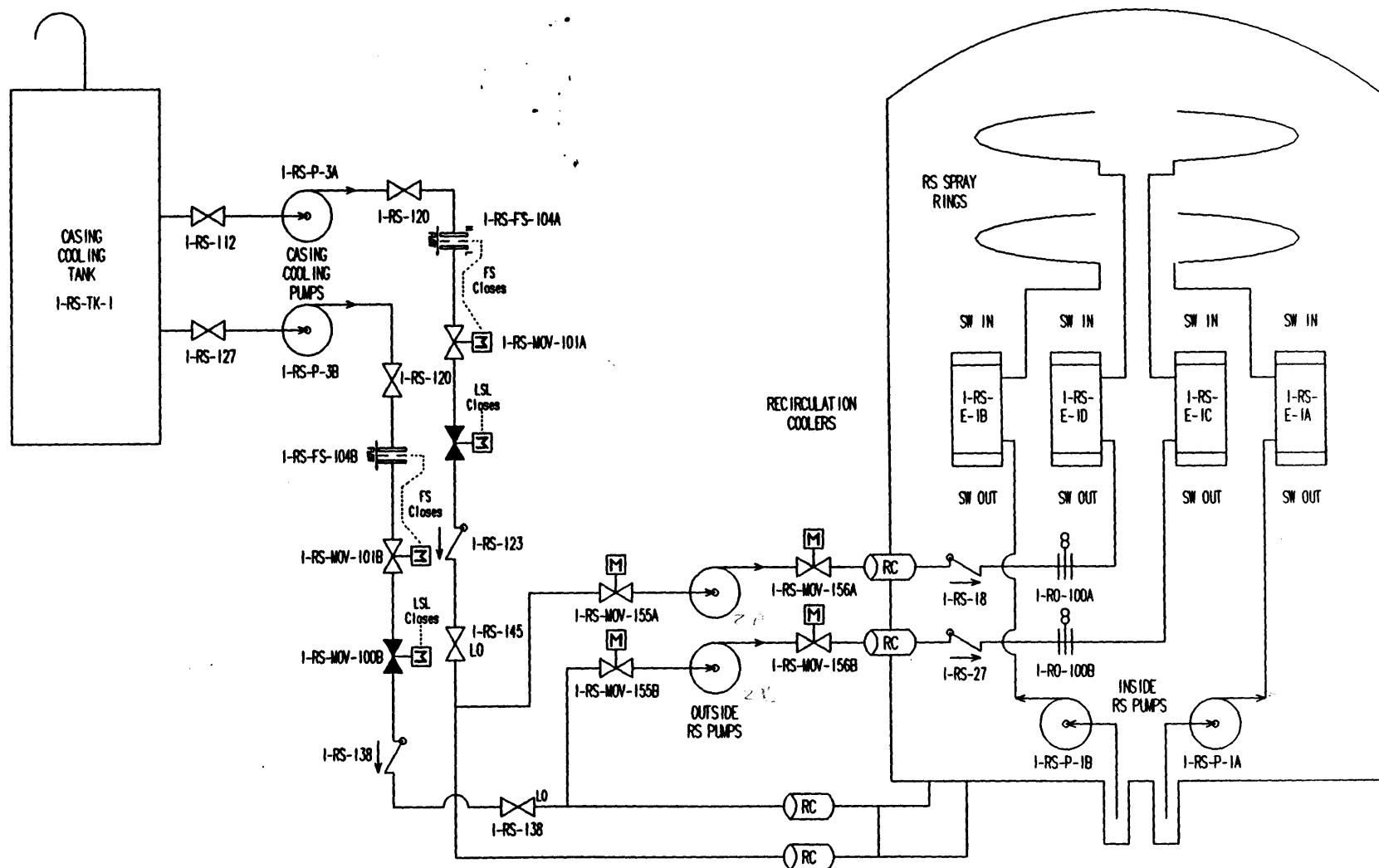


FIGURE A.14-1  
RECIRCULATION SPRAY SYSTEM

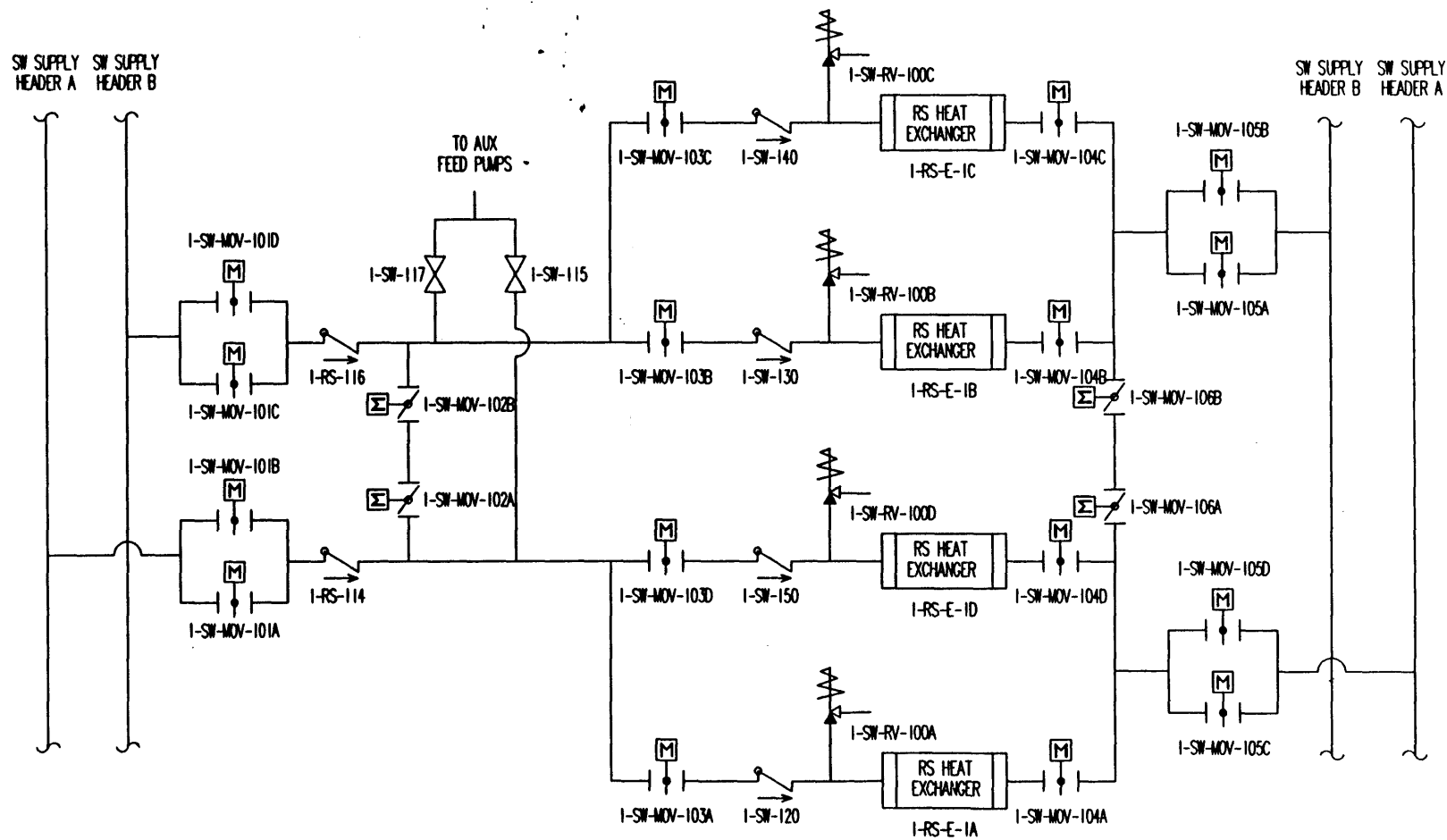


FIGURE A.14-2  
RS SYSTEM, SW COOLING

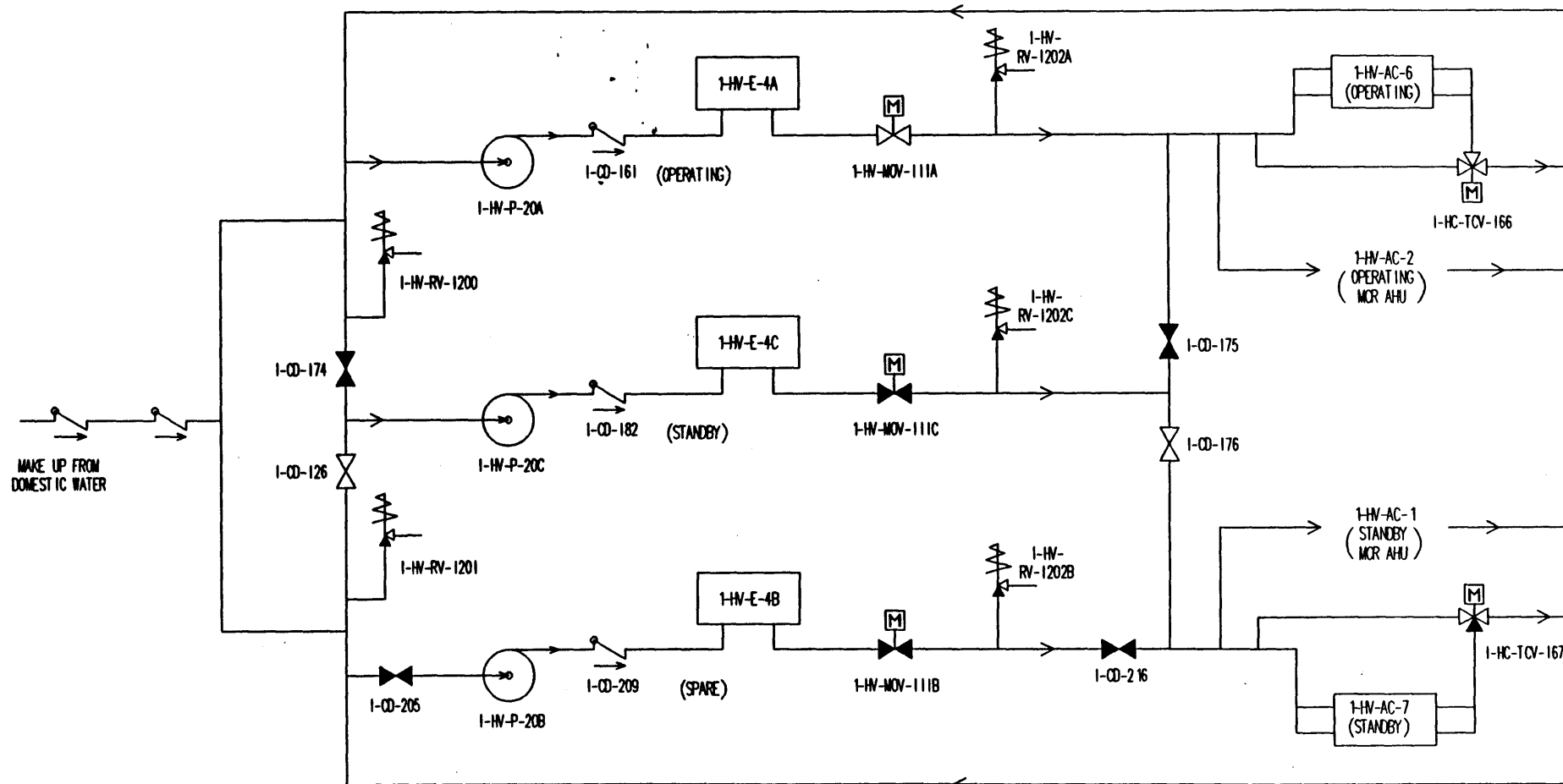


FIGURE A.15-1  
UNIT 1 EMERGENCY SWITCHGEAR ROOM VENTILATION SYSTEM  
CHILLED WATER SIDE

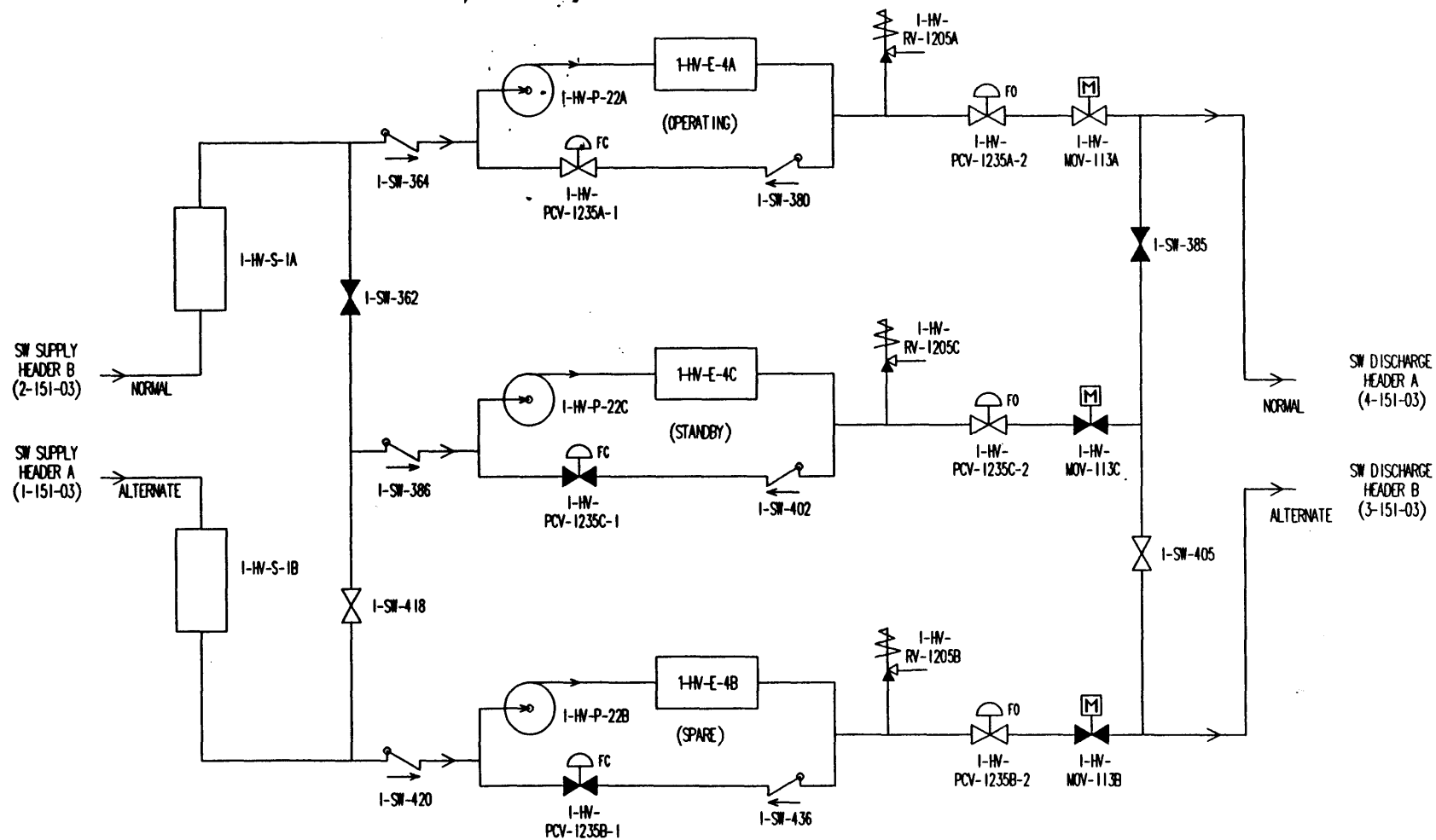


FIGURE A.15-2  
UNIT 1 EMERGENCY SWITCHGEAR ROOM VENTILATION SYSTEM  
SERVICE WATER SIDE

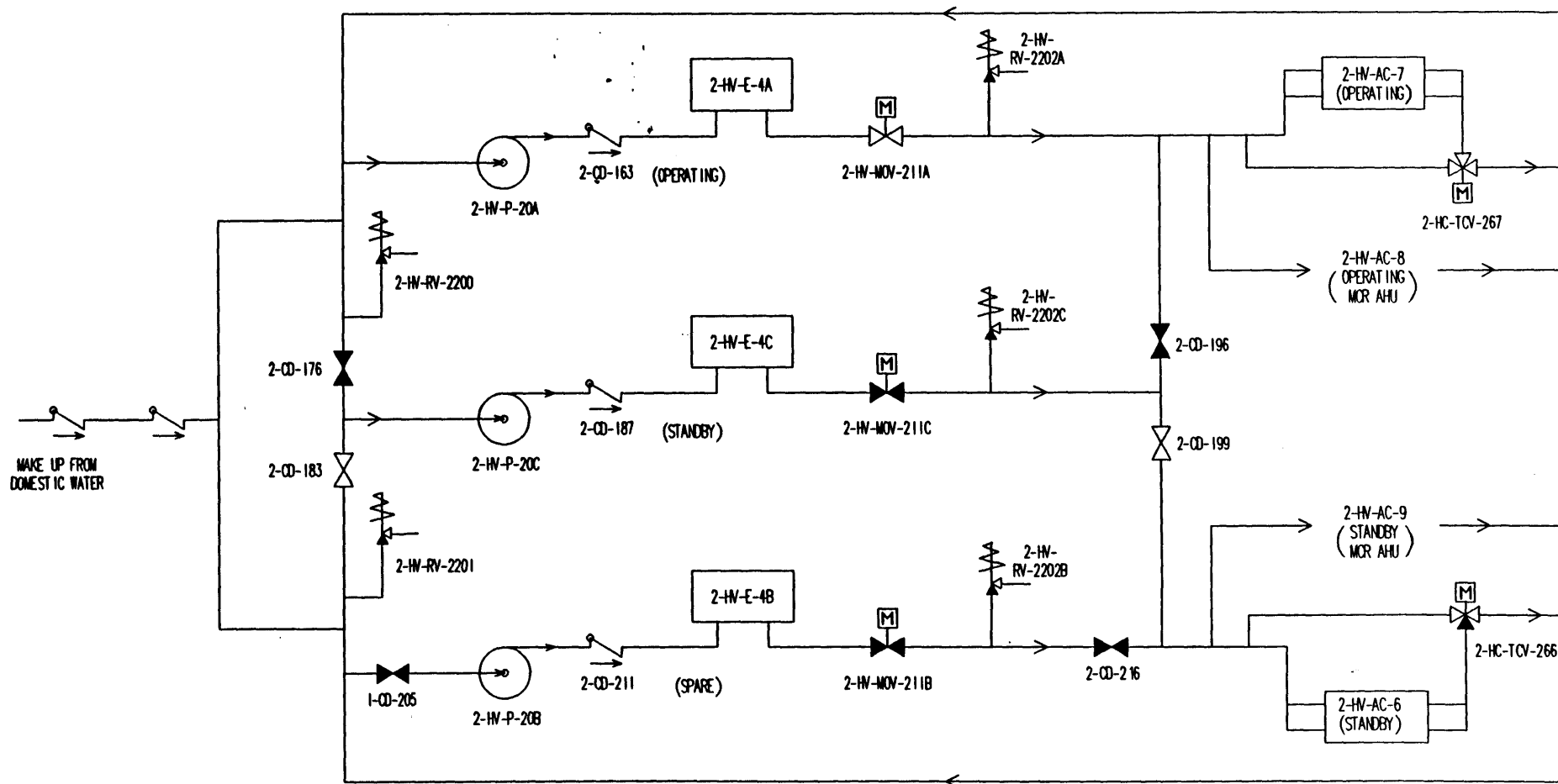


FIGURE A.15-3  
UNIT 2 EMERGENCY SWITCHGEAR ROOM VENTILATION SYSTEM  
CHILLED WATER SIDE

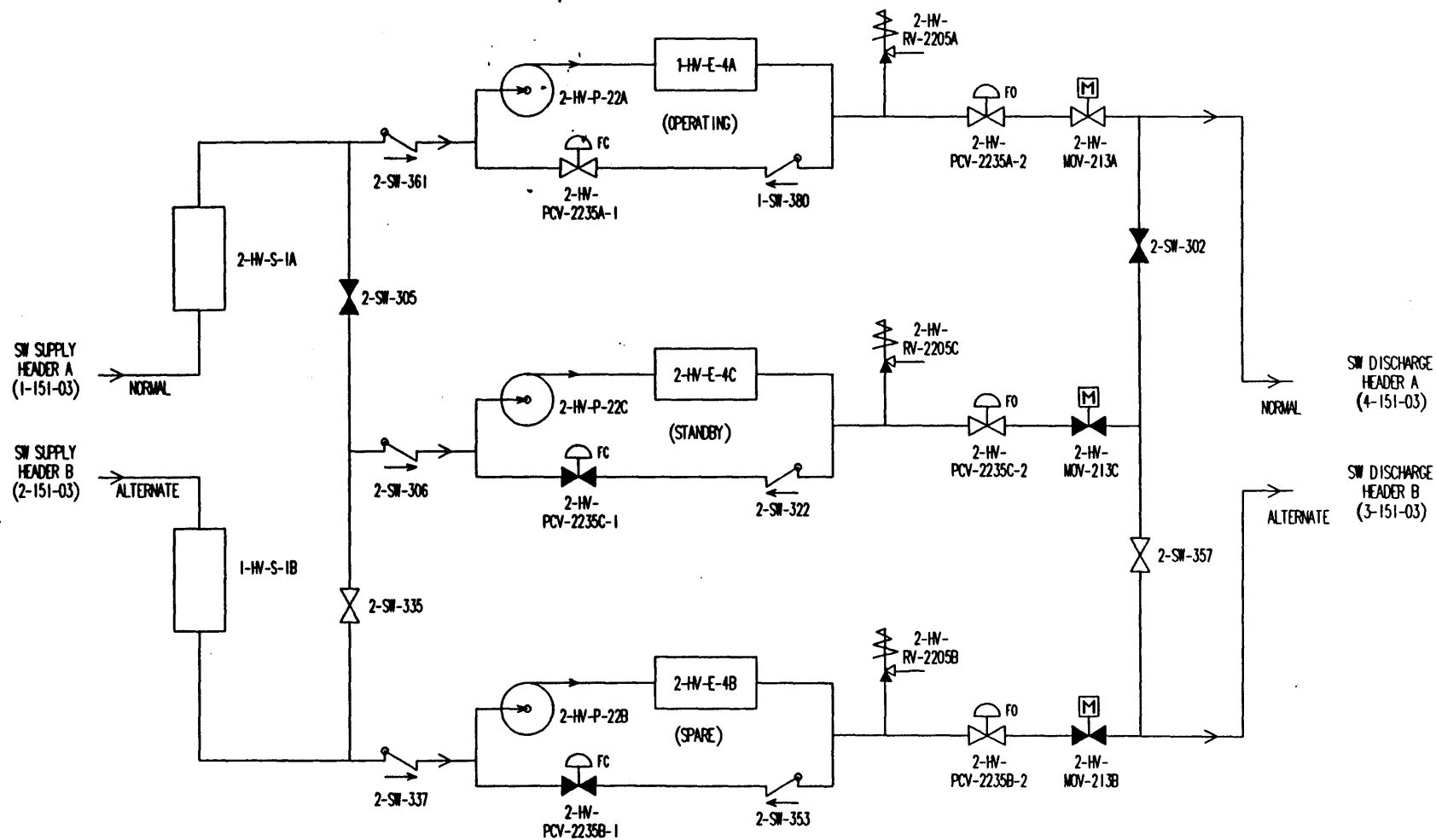


FIGURE A.15-4  
UNIT 2 EMERGENCY SWITCHGEAR ROOM VENTILATION SYSTEM  
SERVICE WATER SIDE

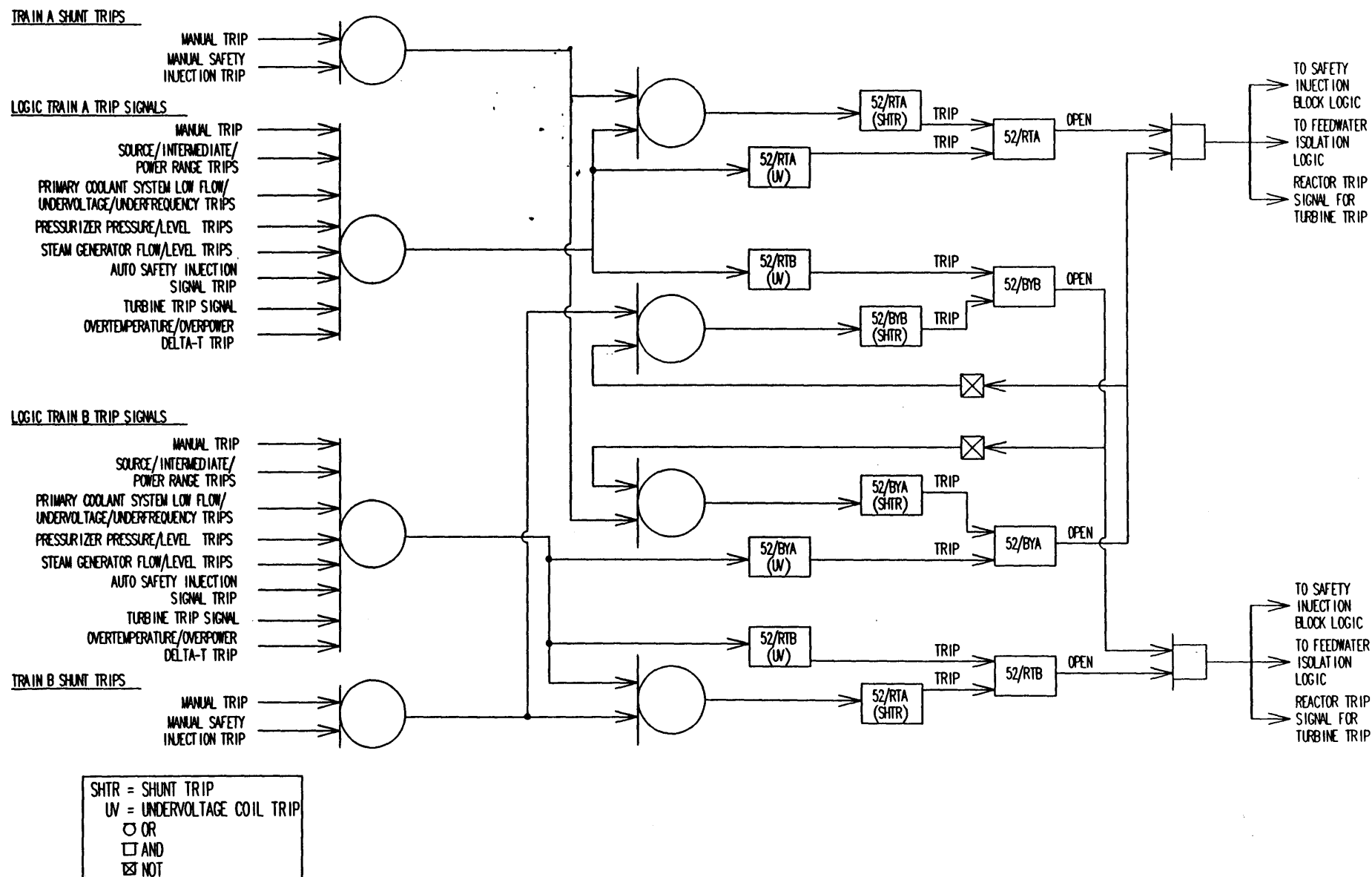


FIGURE A.17-1  
REACTOR TRIP SYSTEM



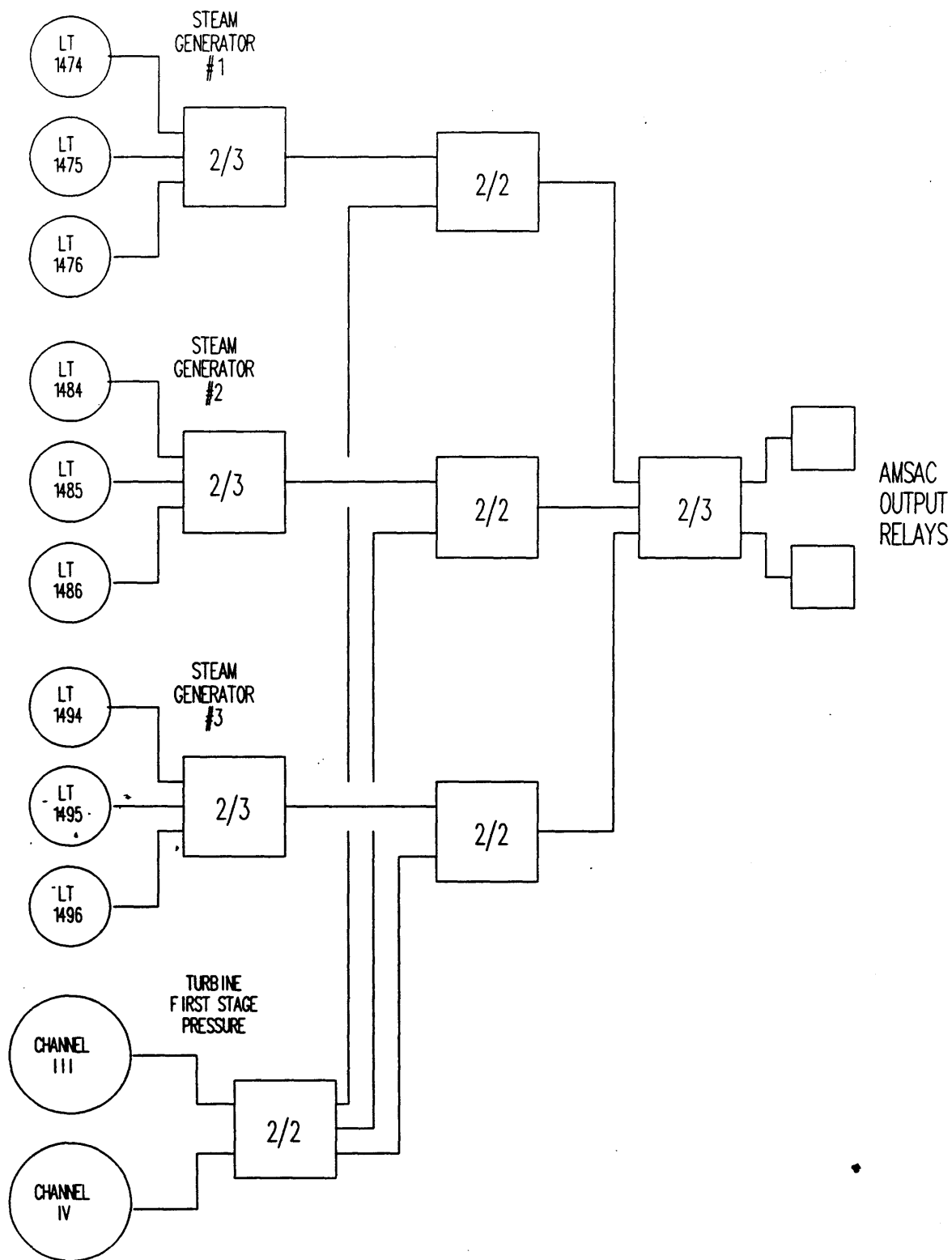
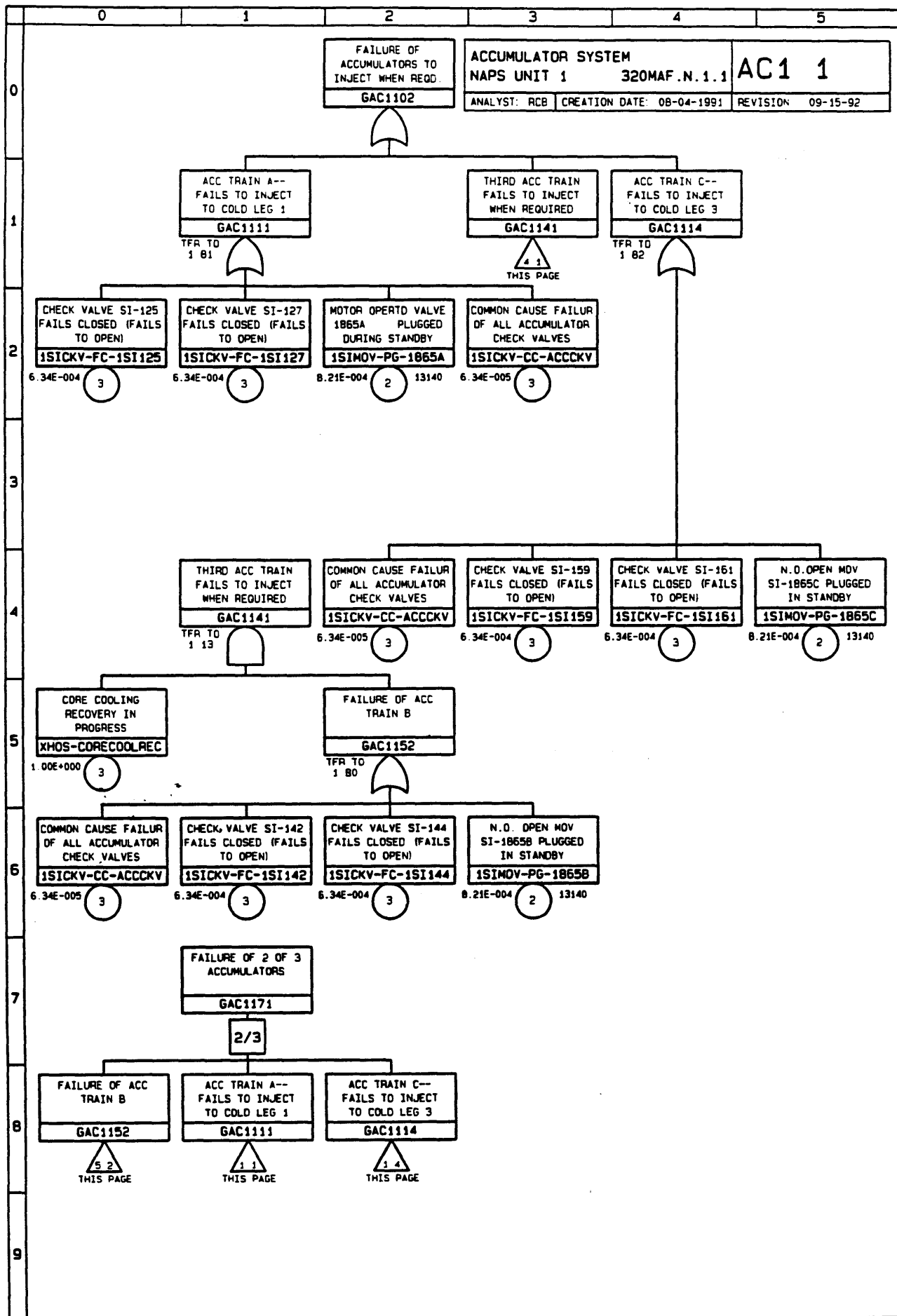
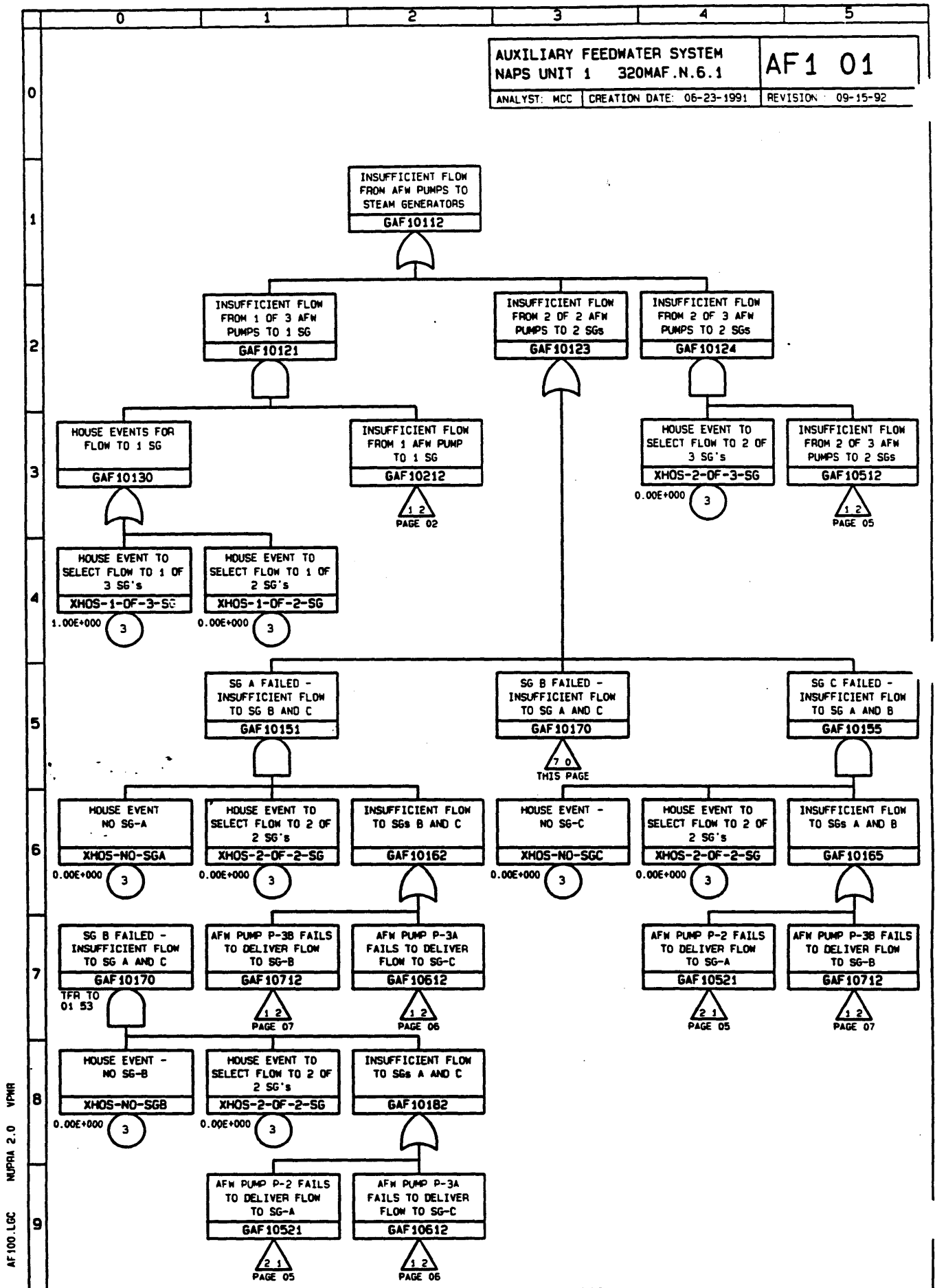
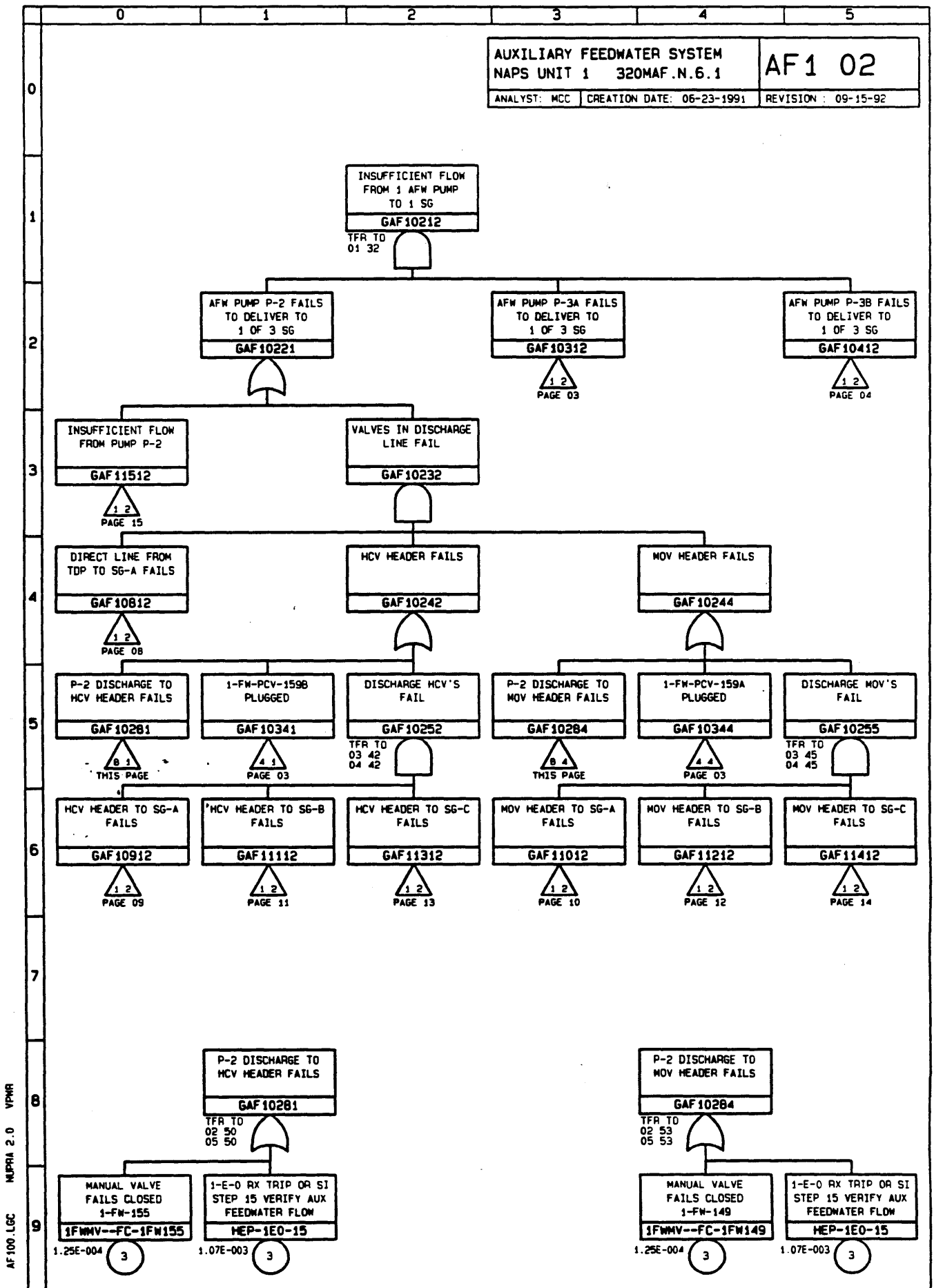


FIGURE A.17-2  
AMSAC LOGIC

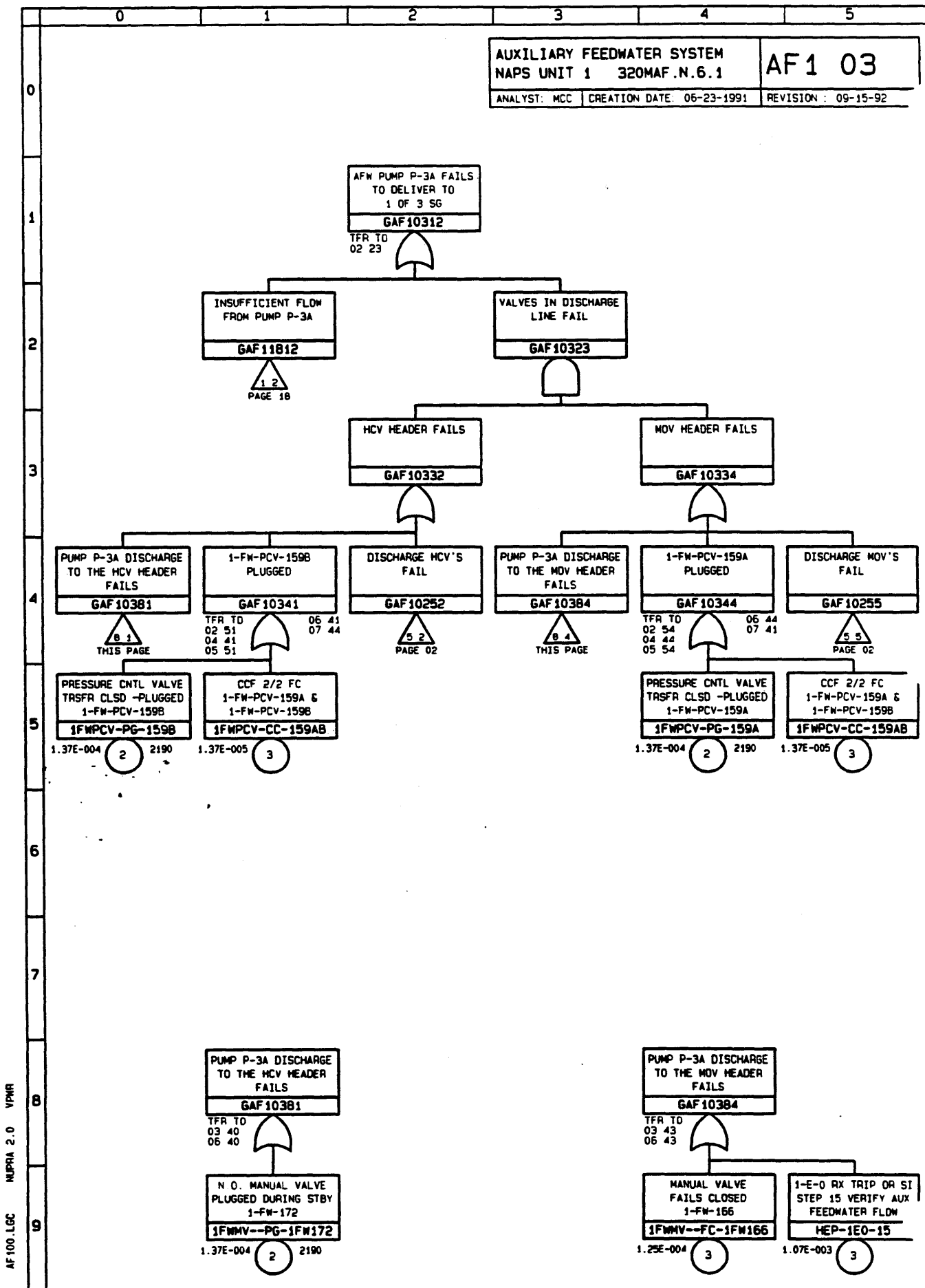
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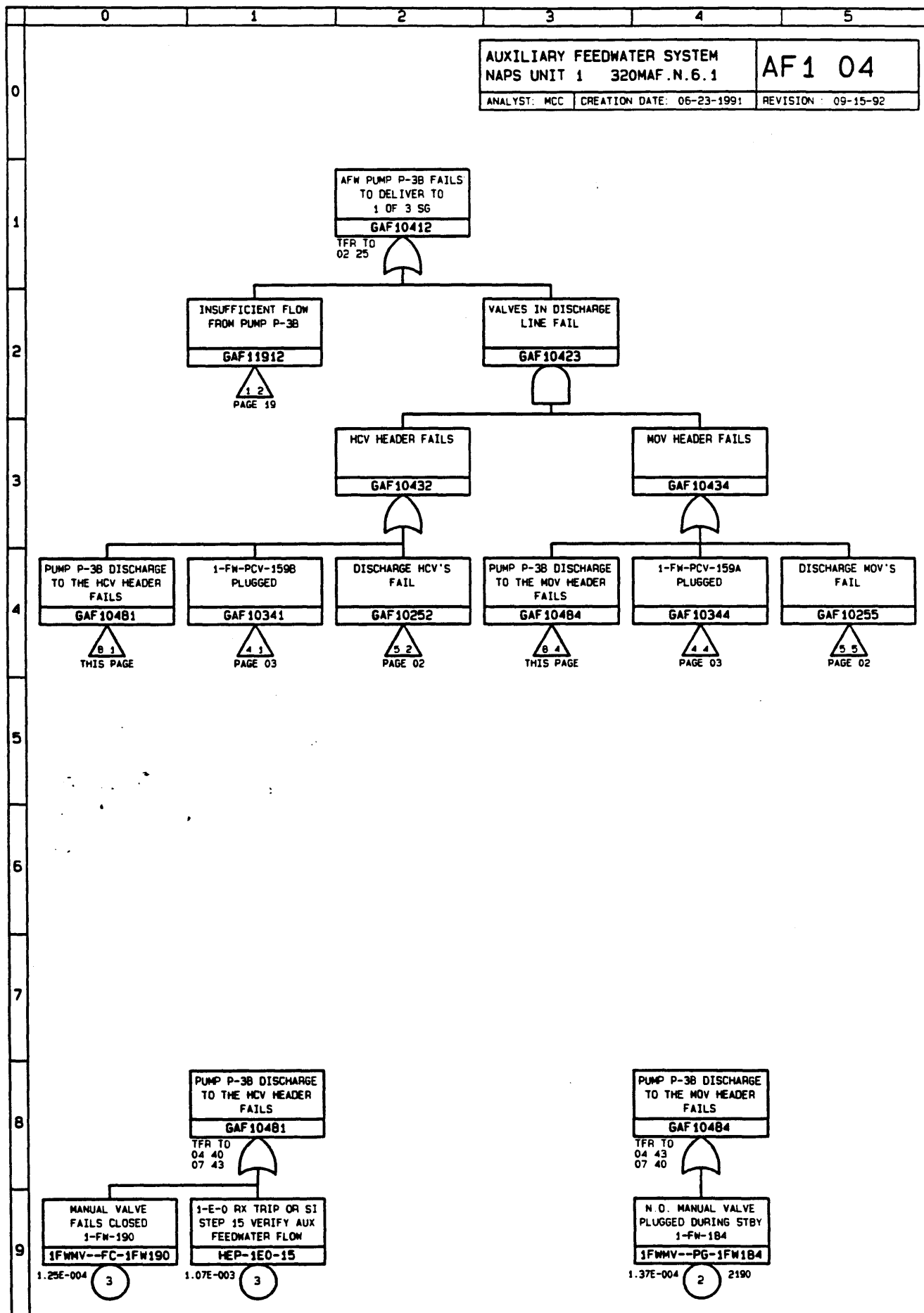




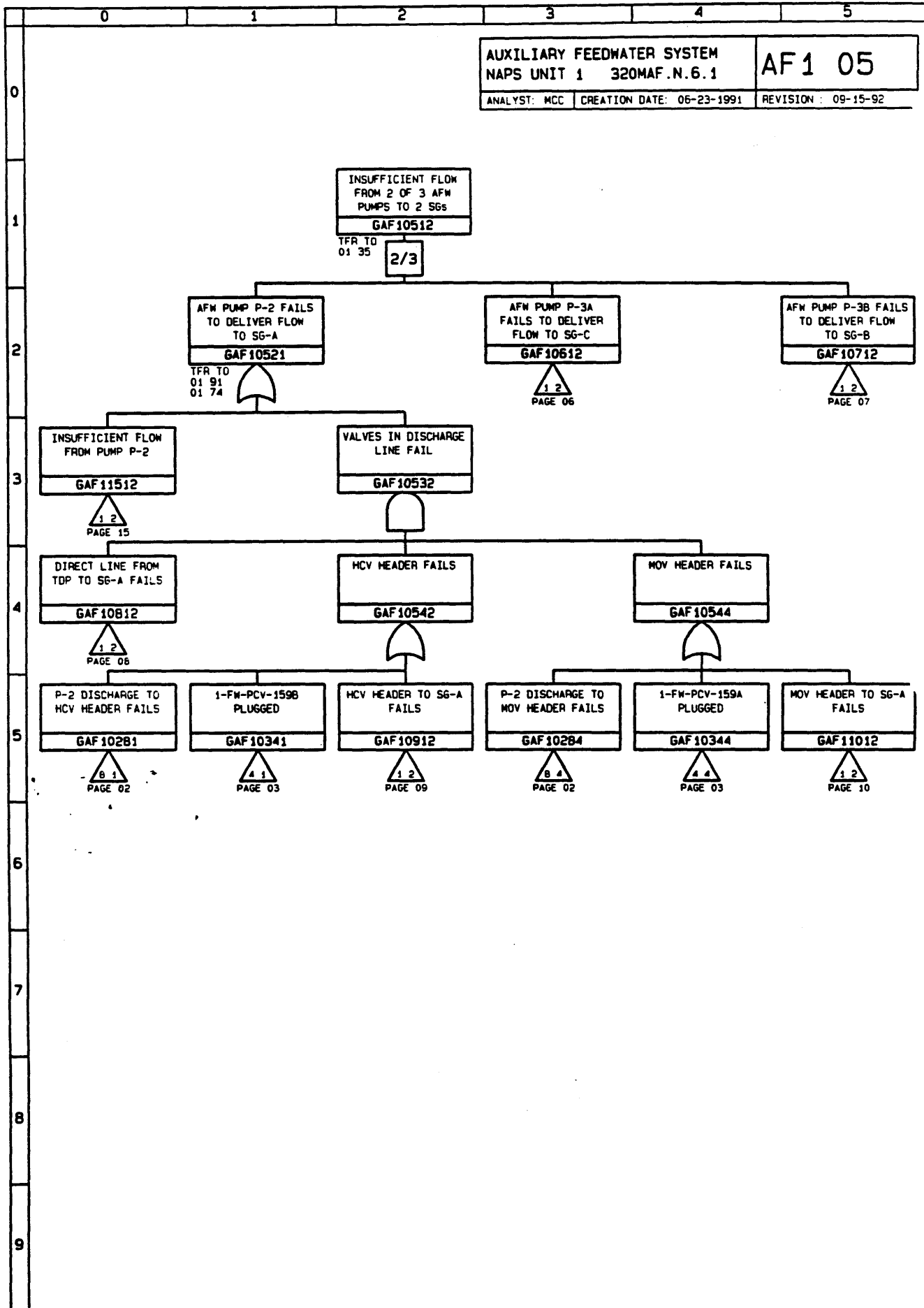


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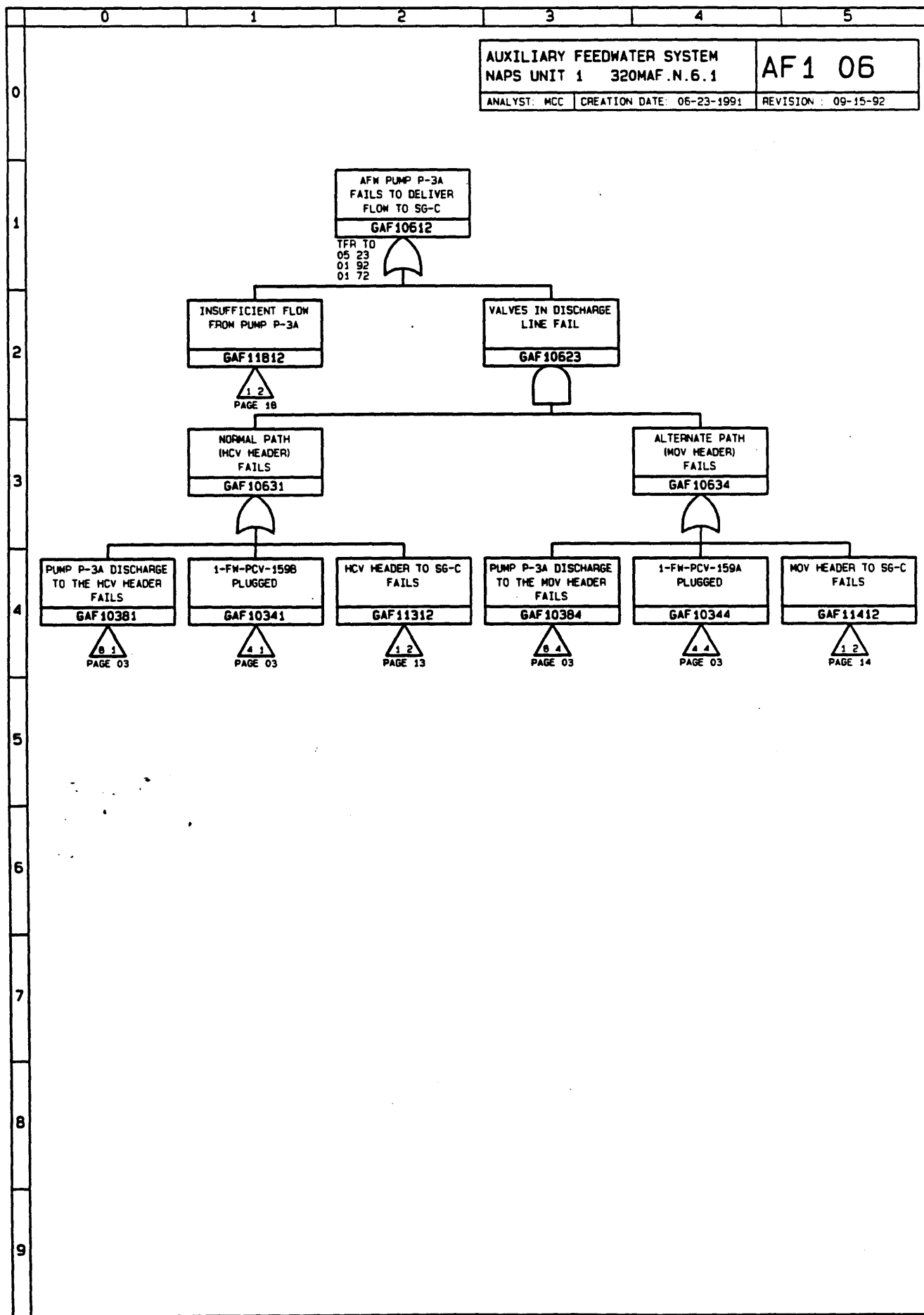




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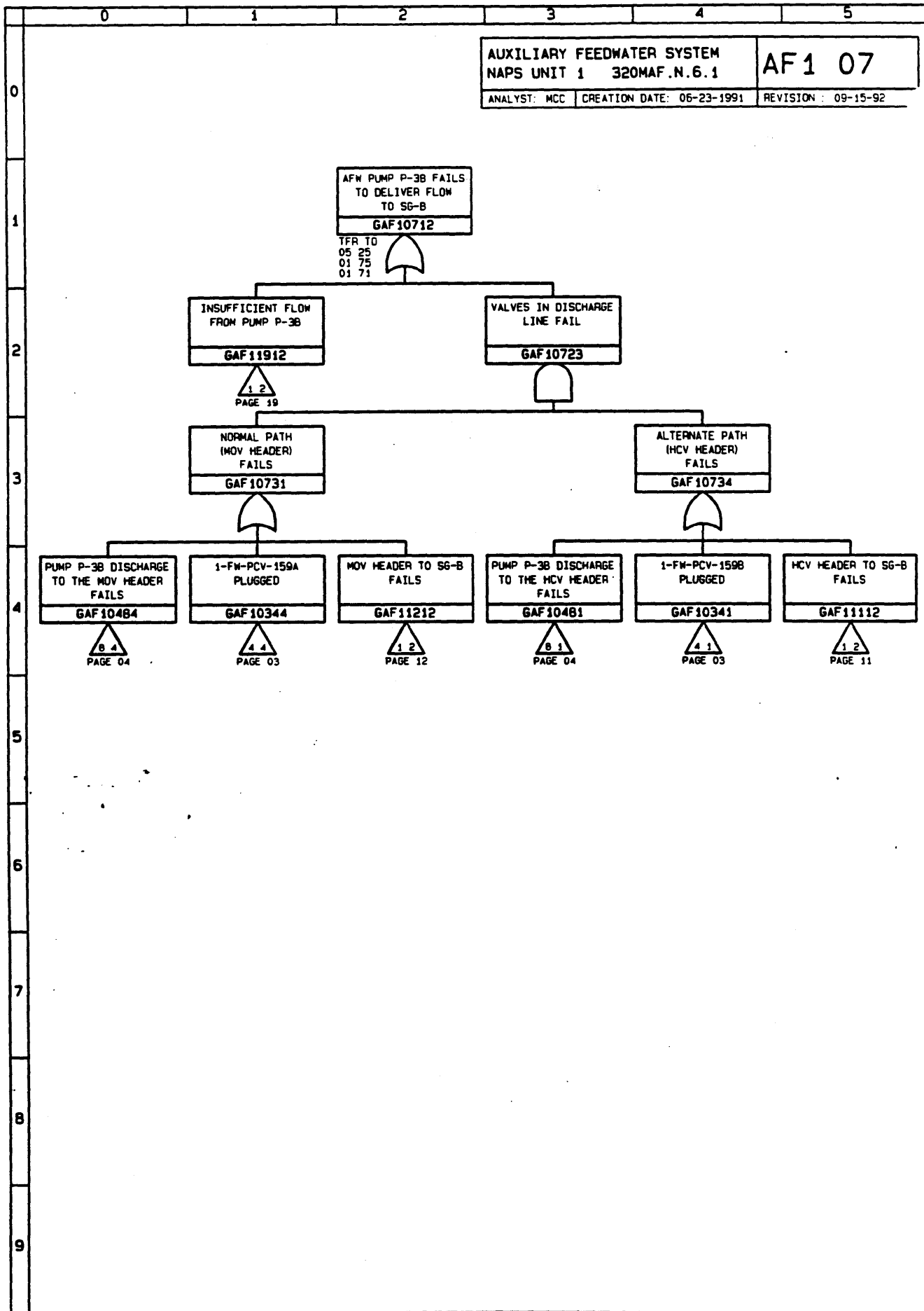




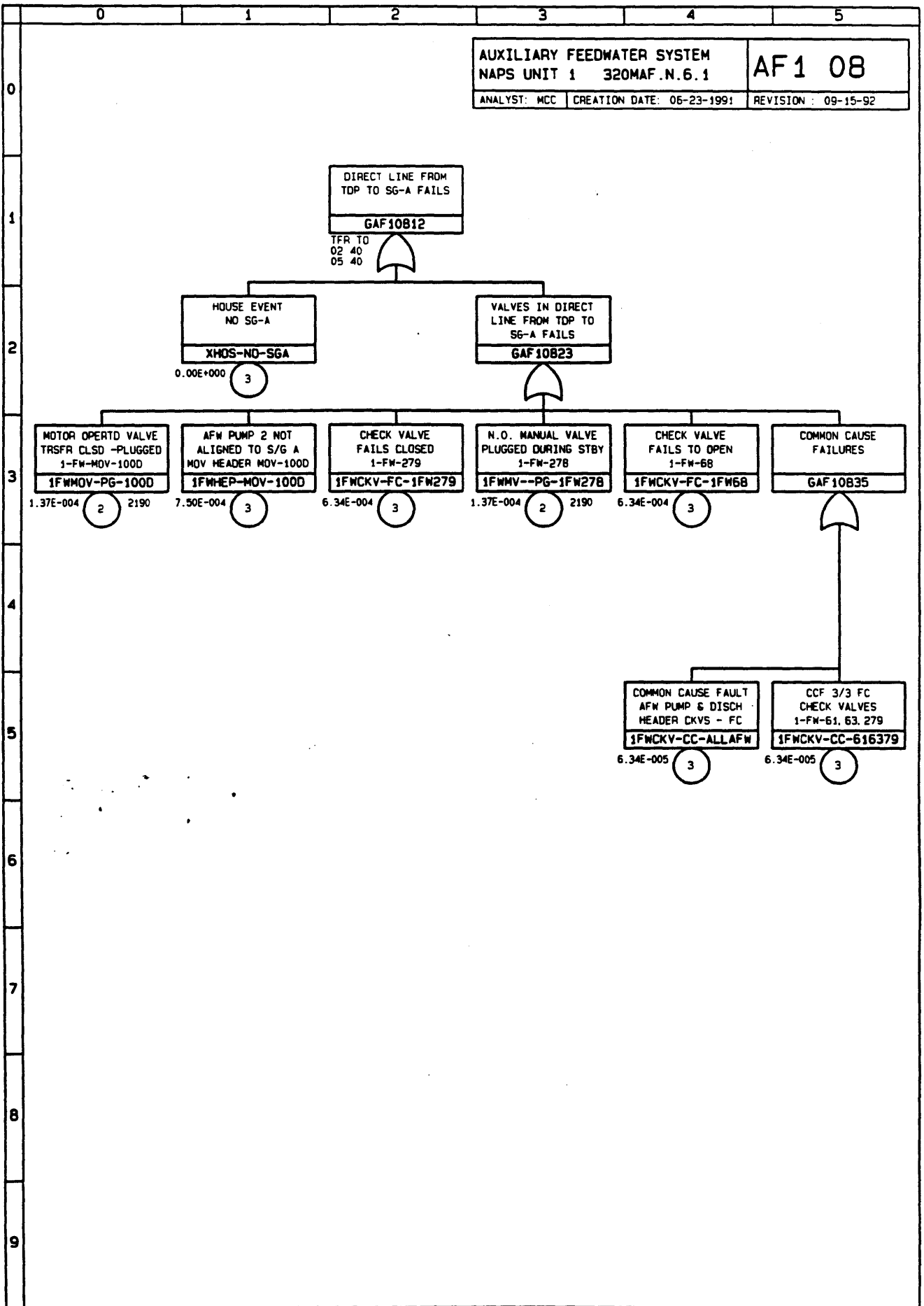


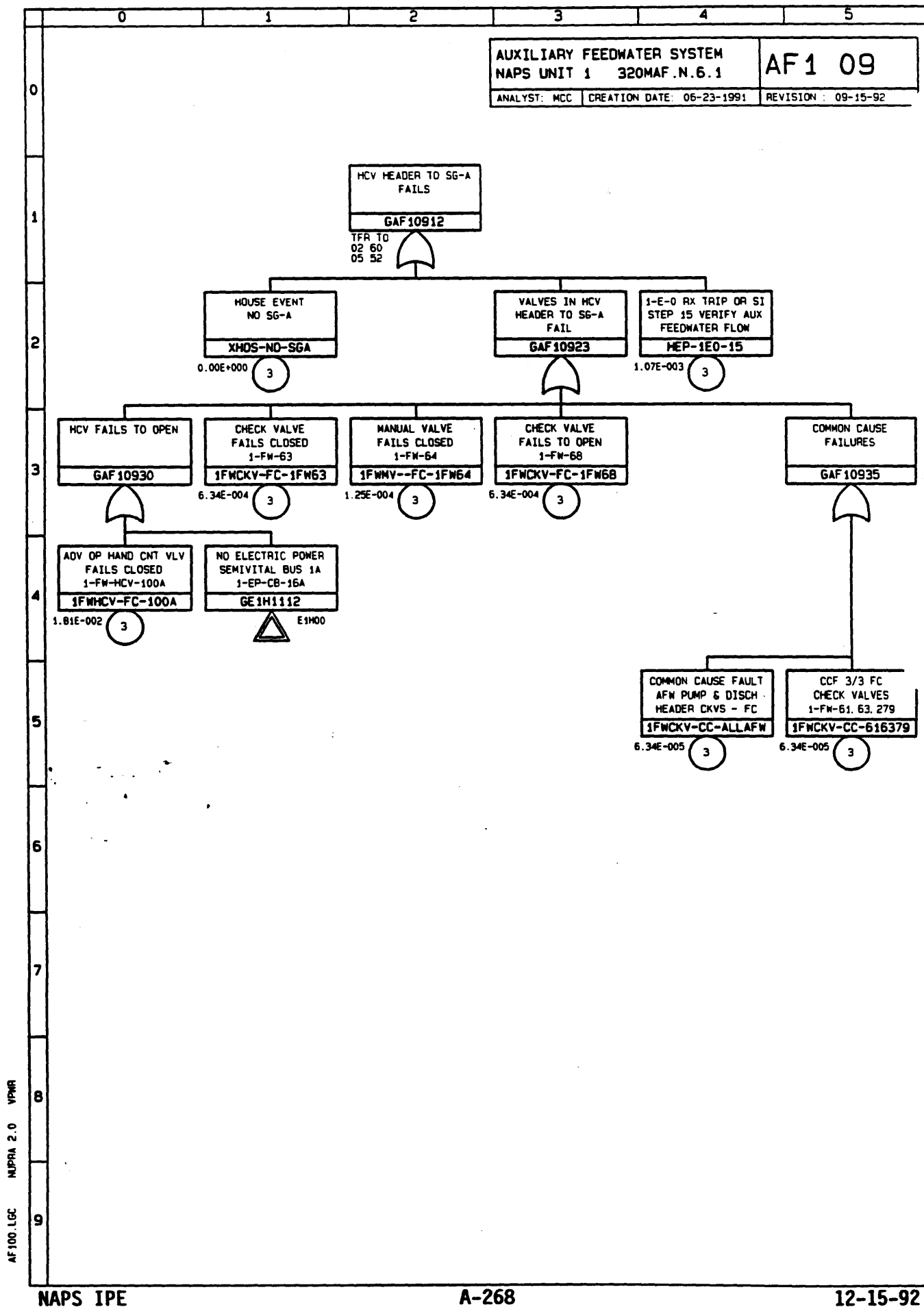
AF 100 LGC    NUPRA 2.0    VPMR

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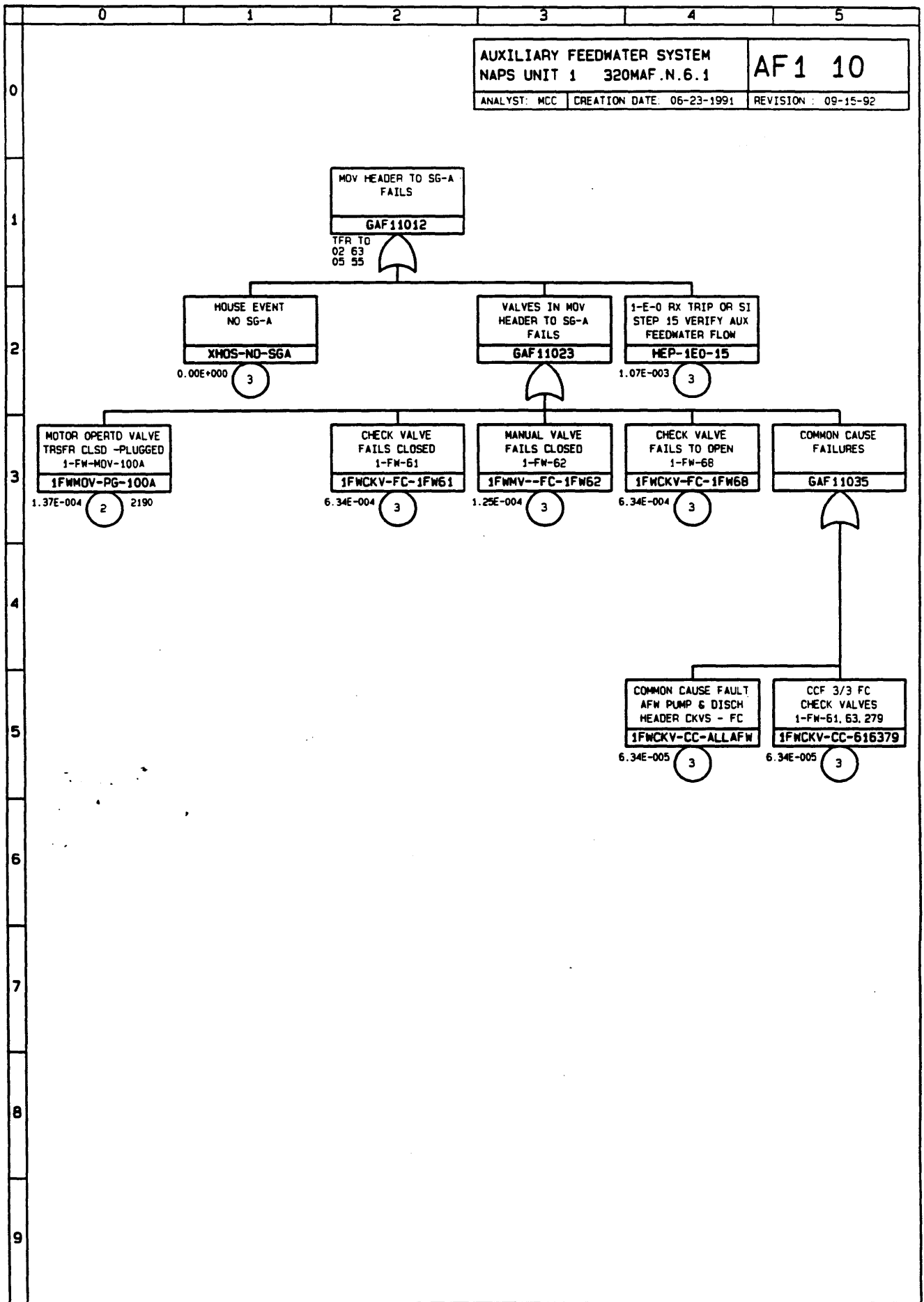


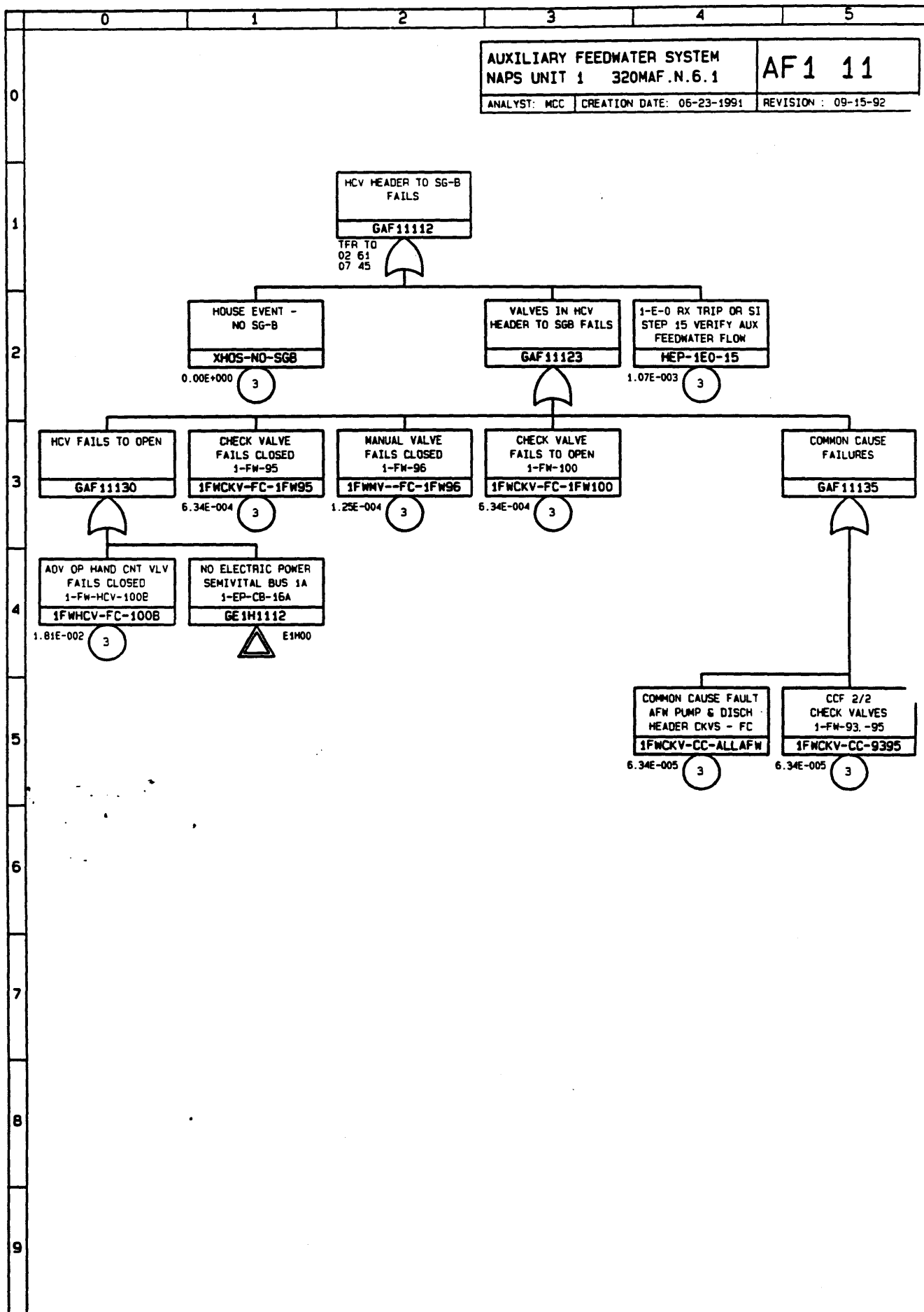
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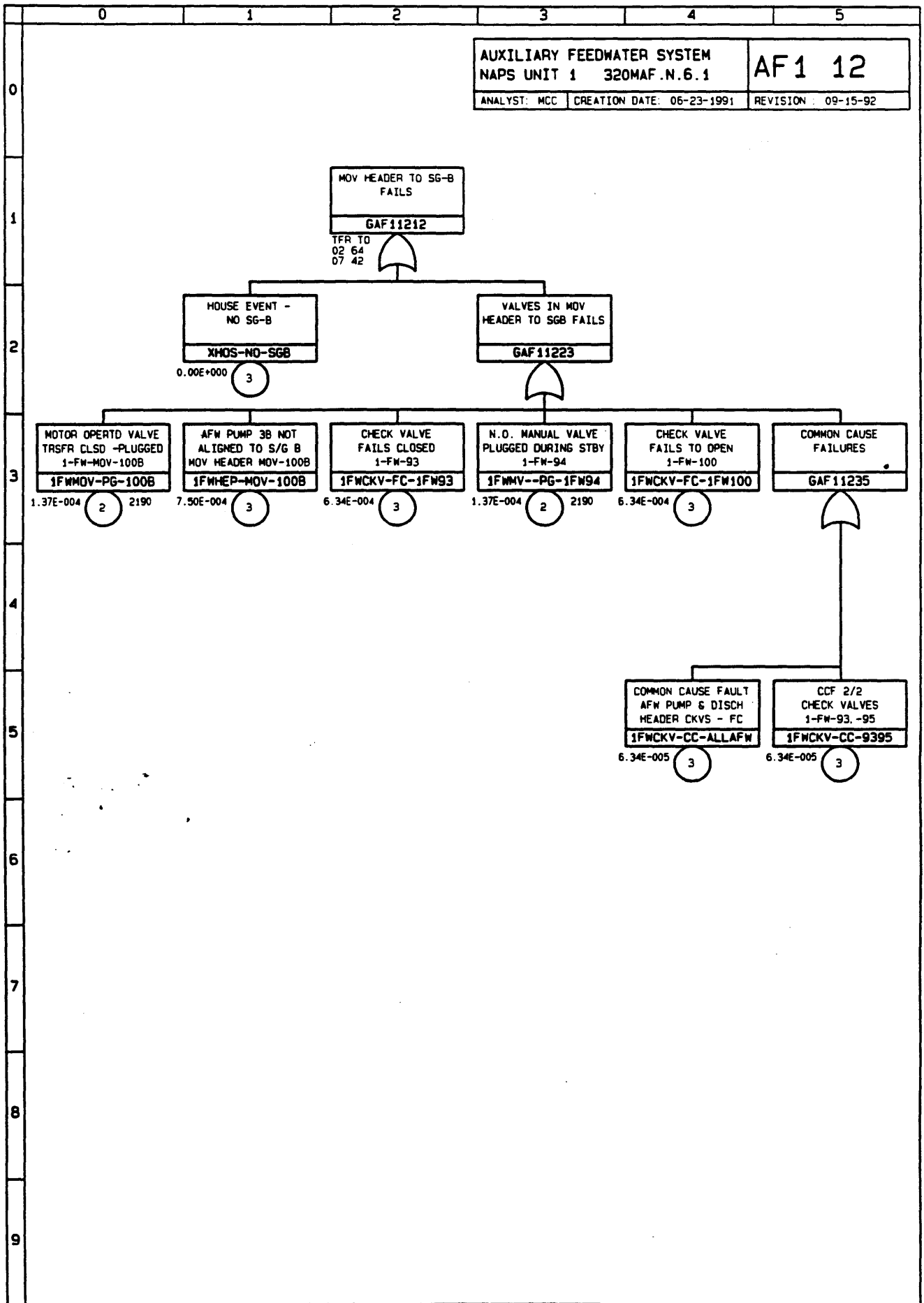




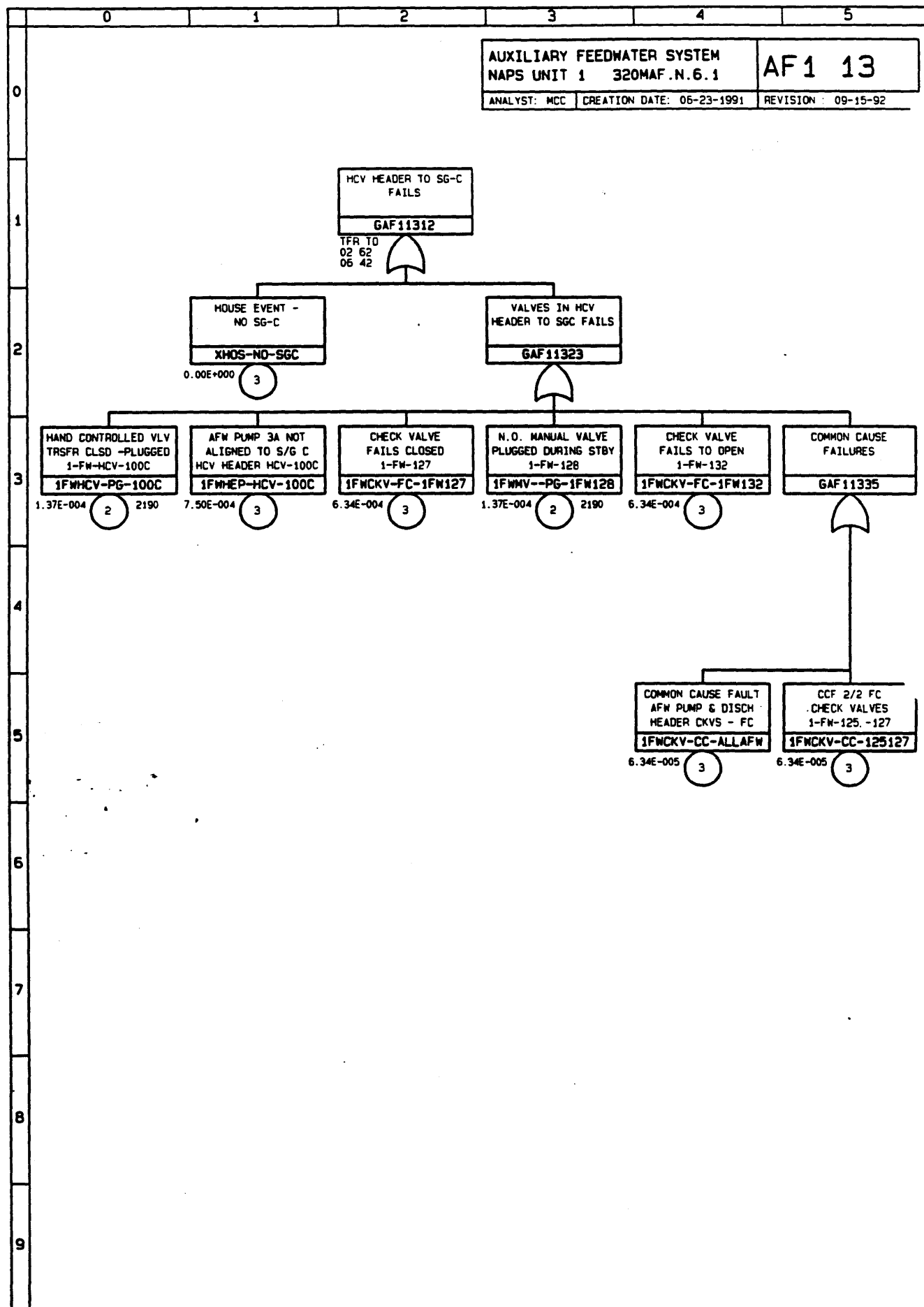
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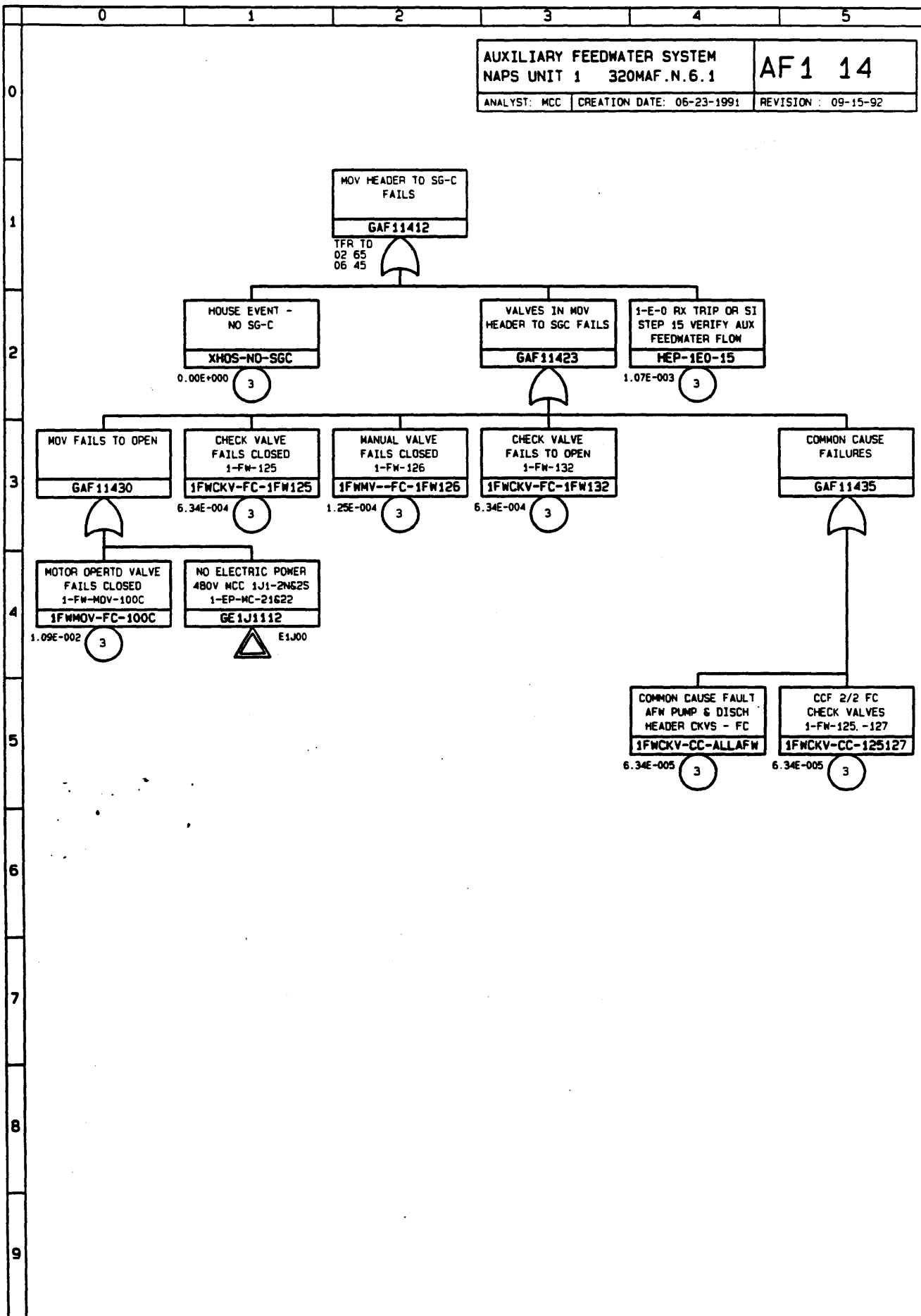


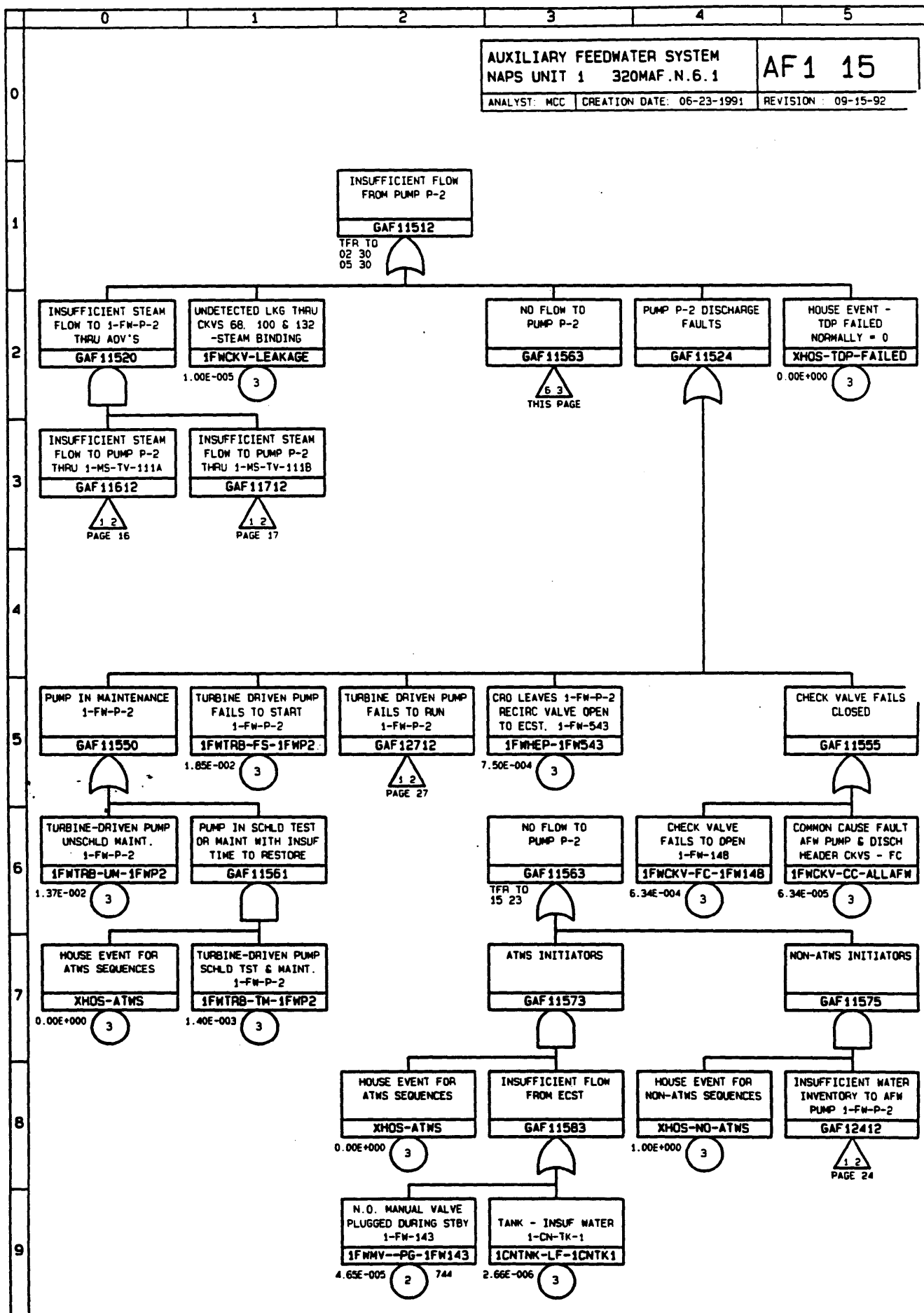
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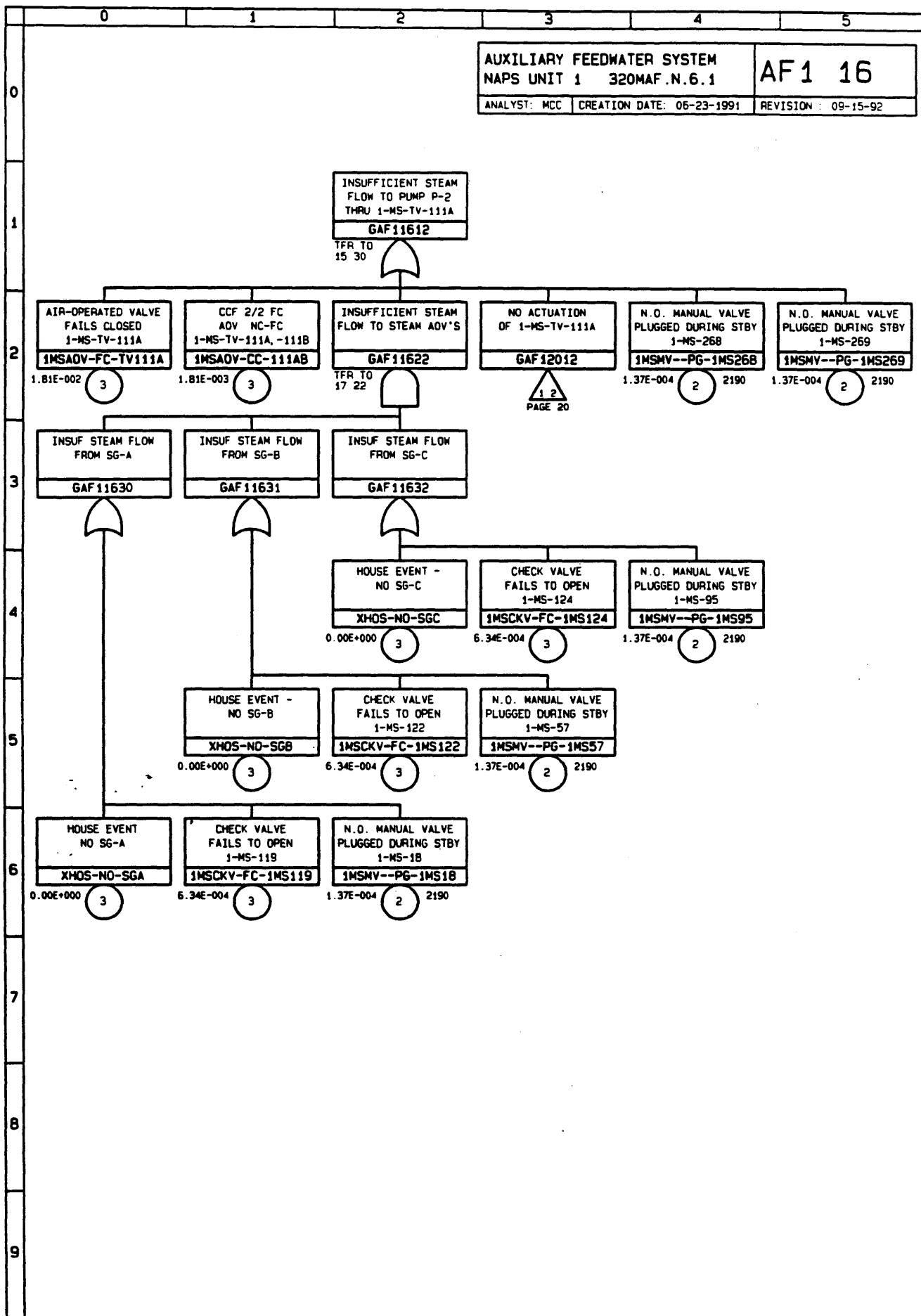




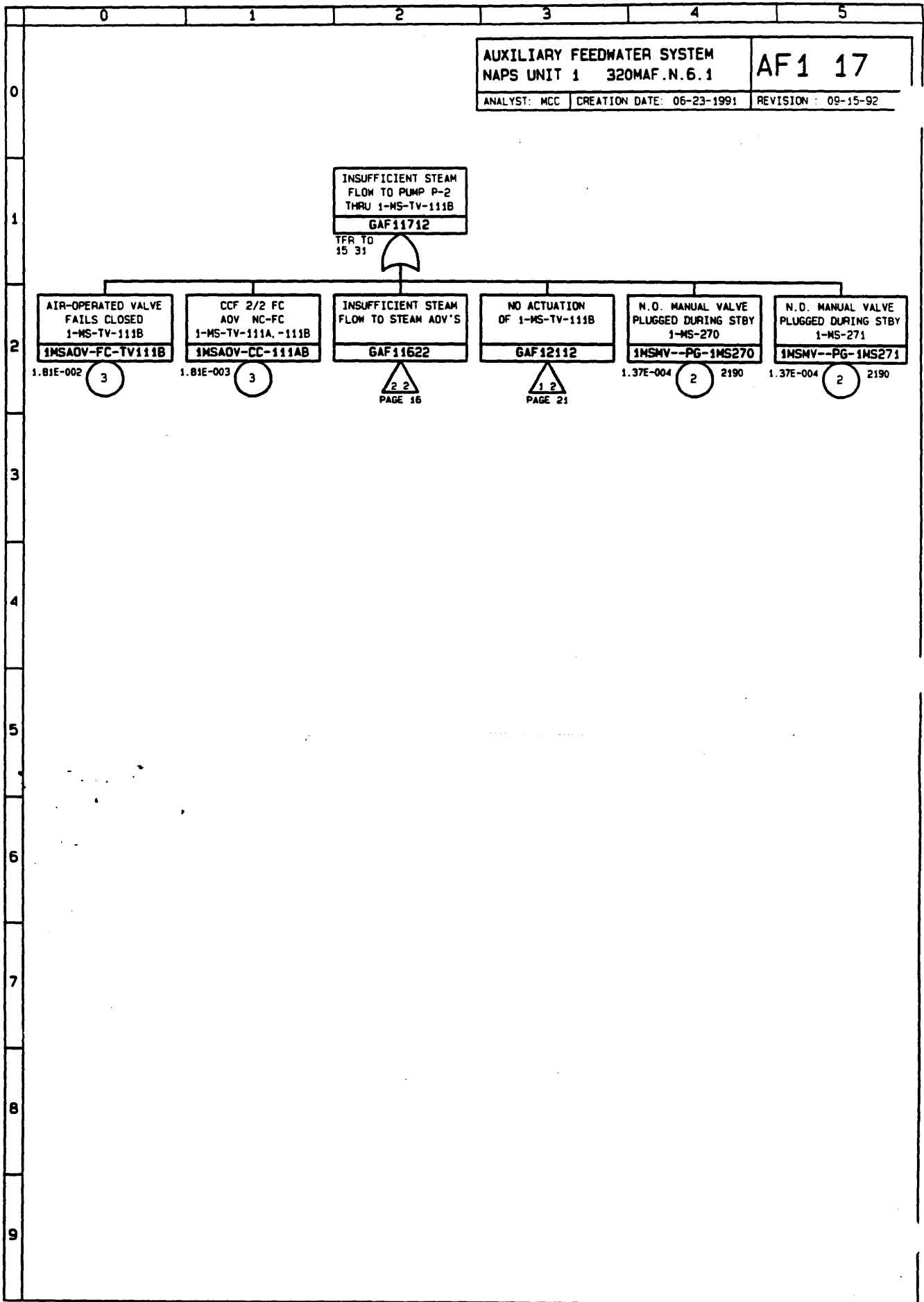
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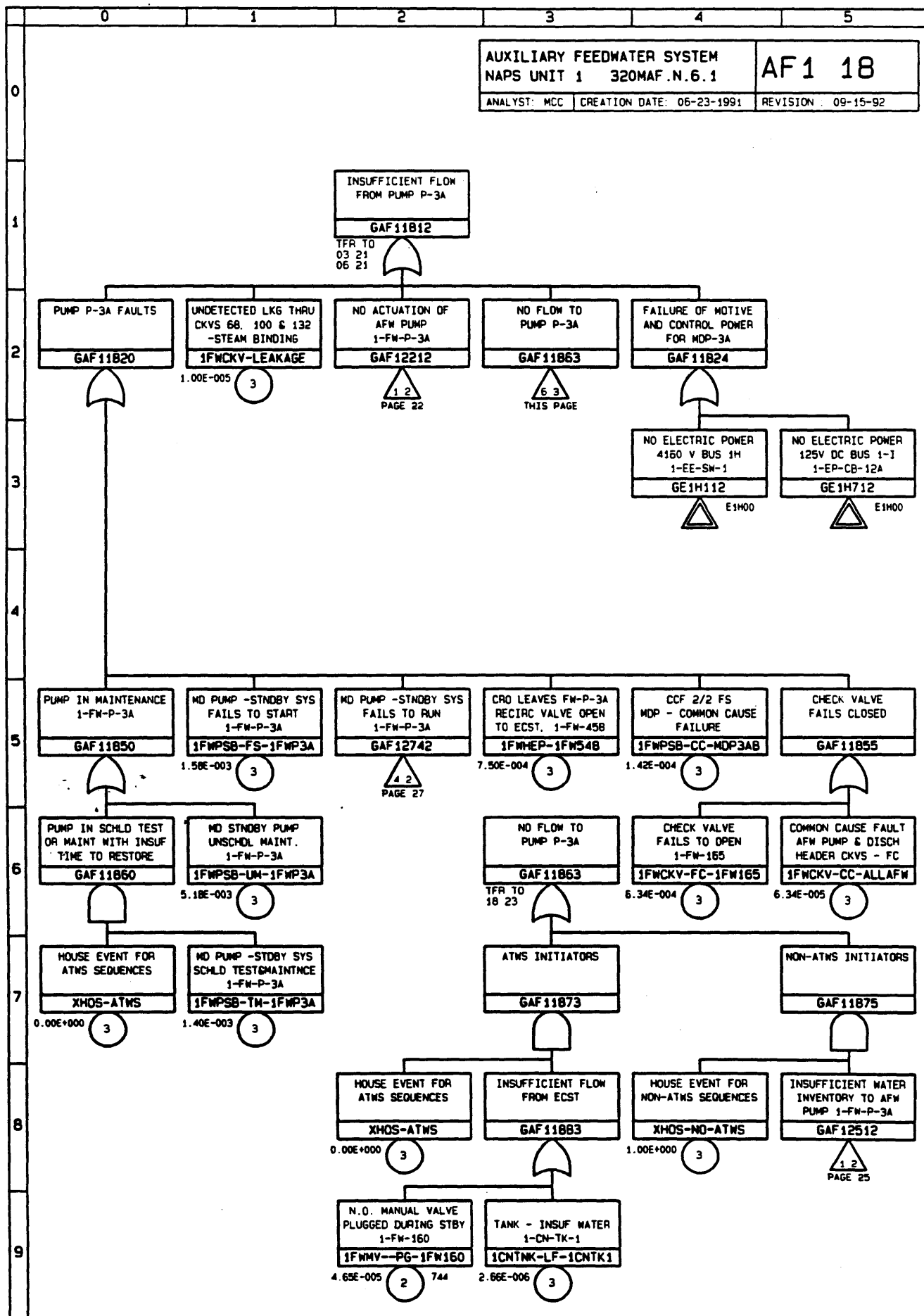


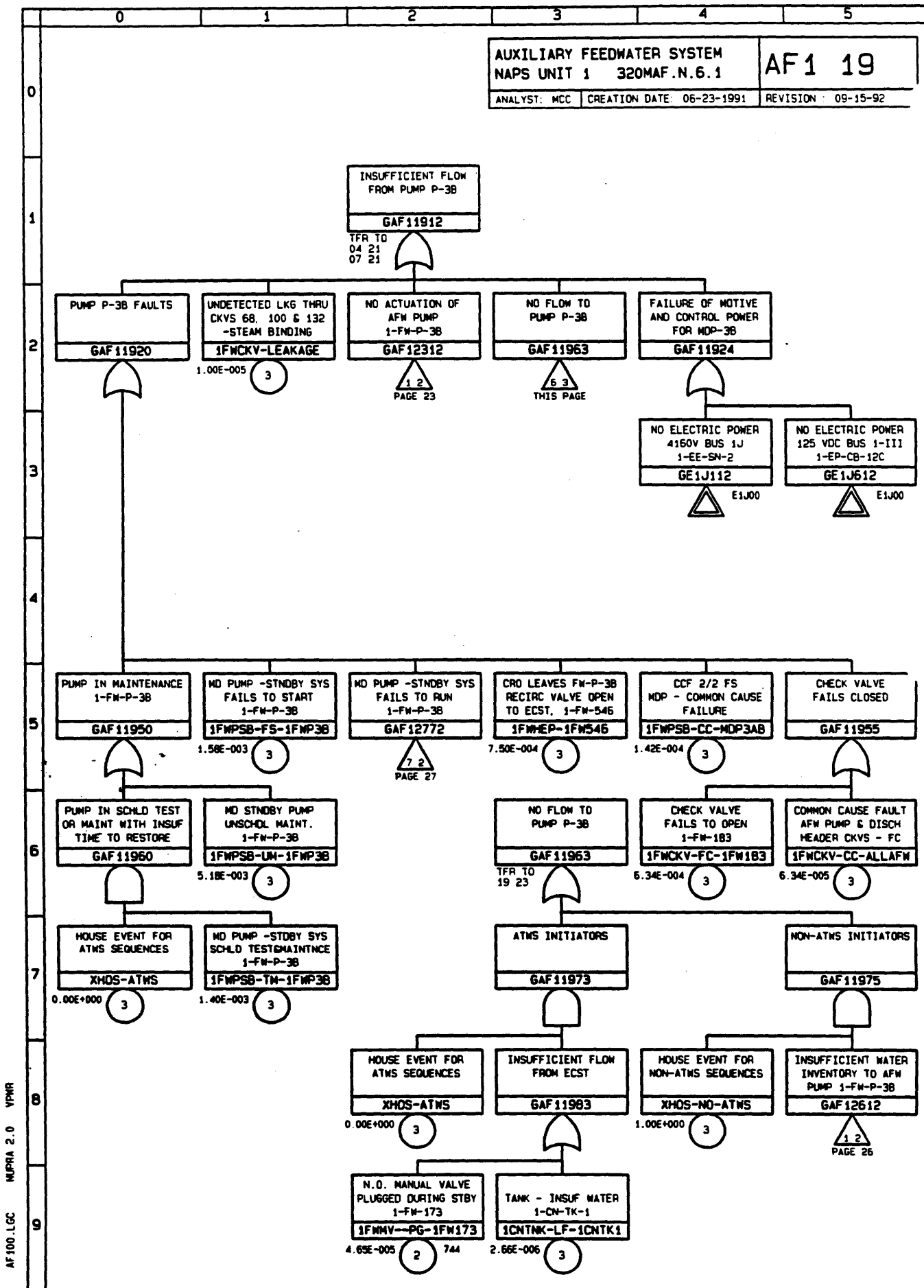


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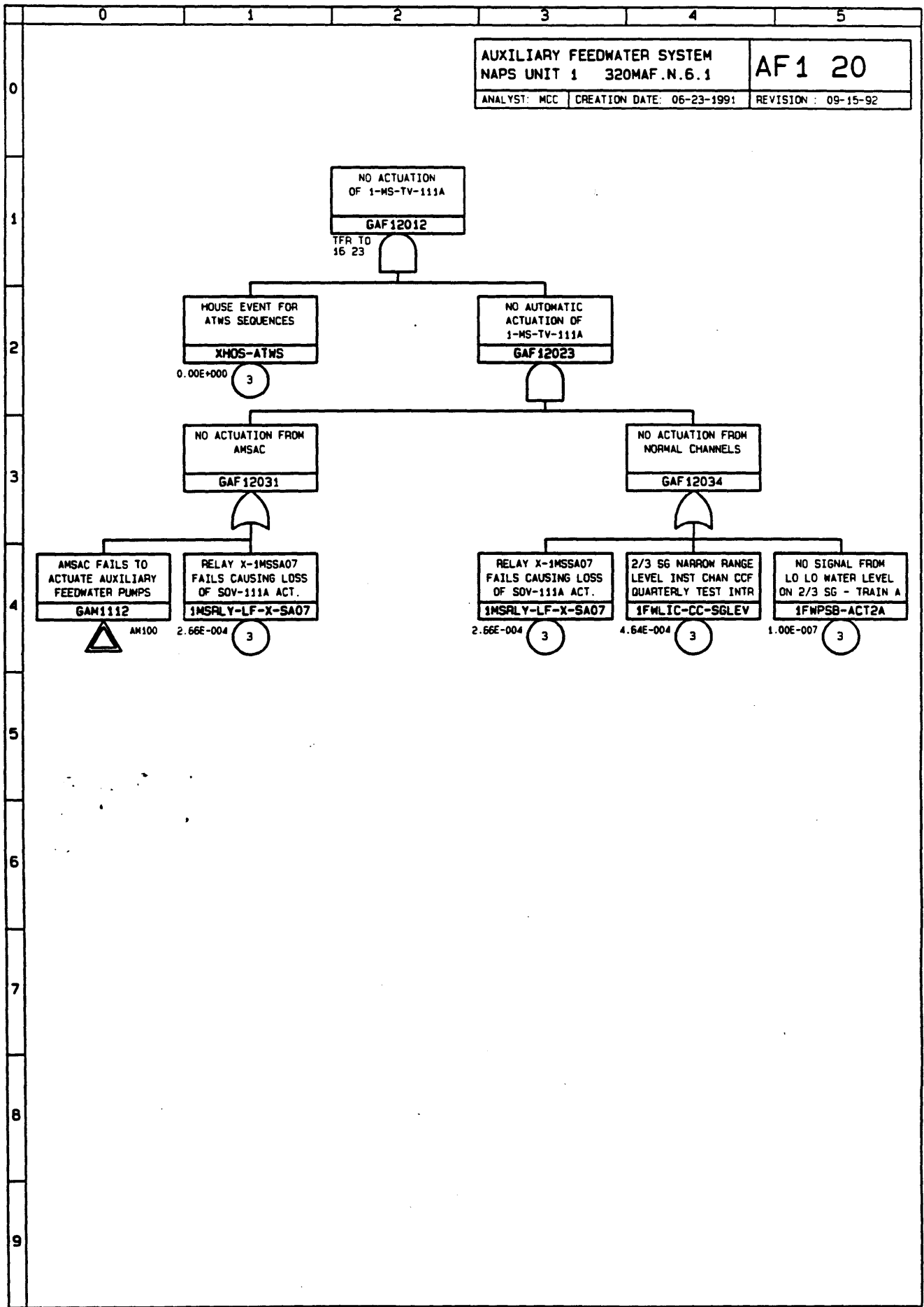


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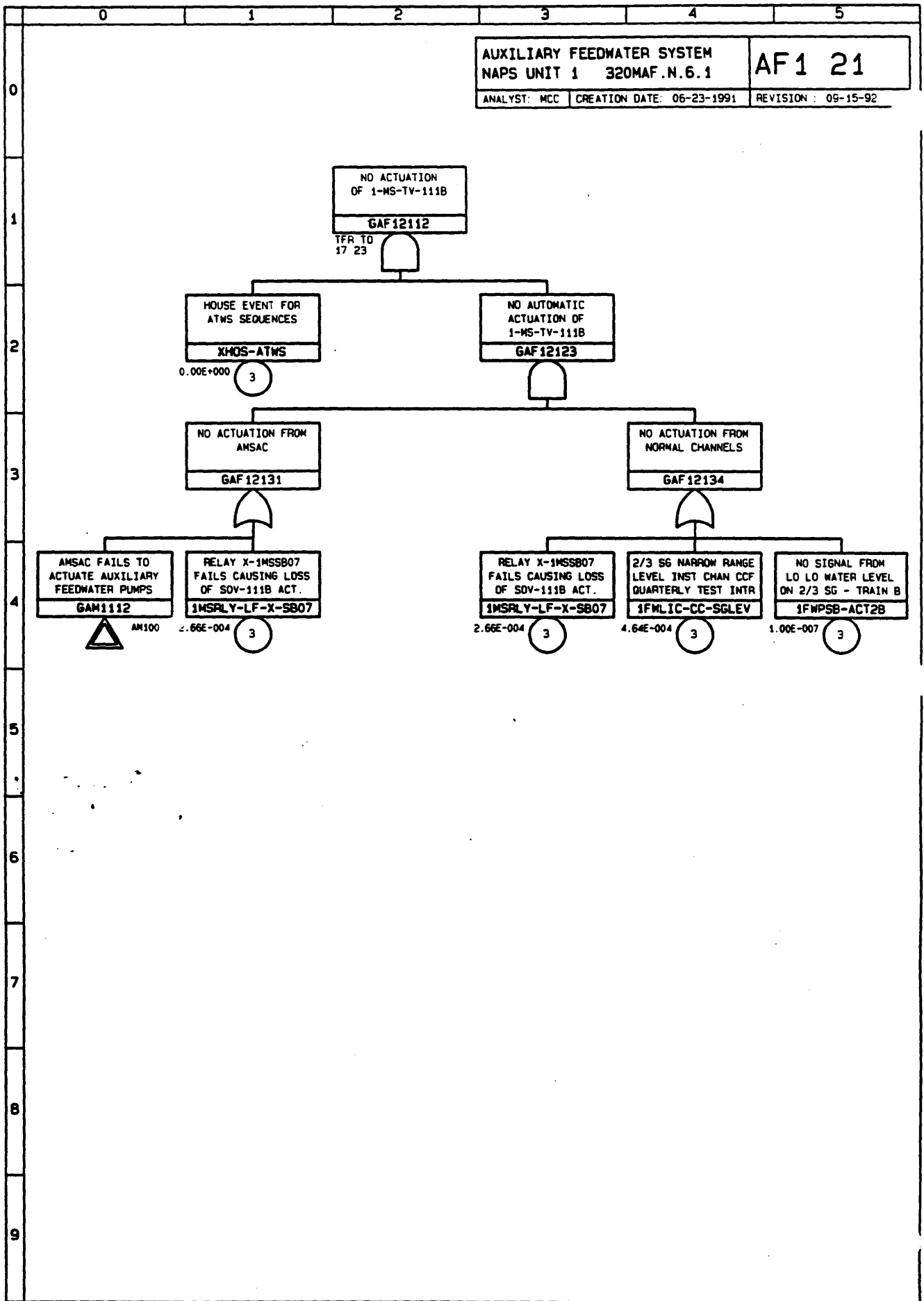




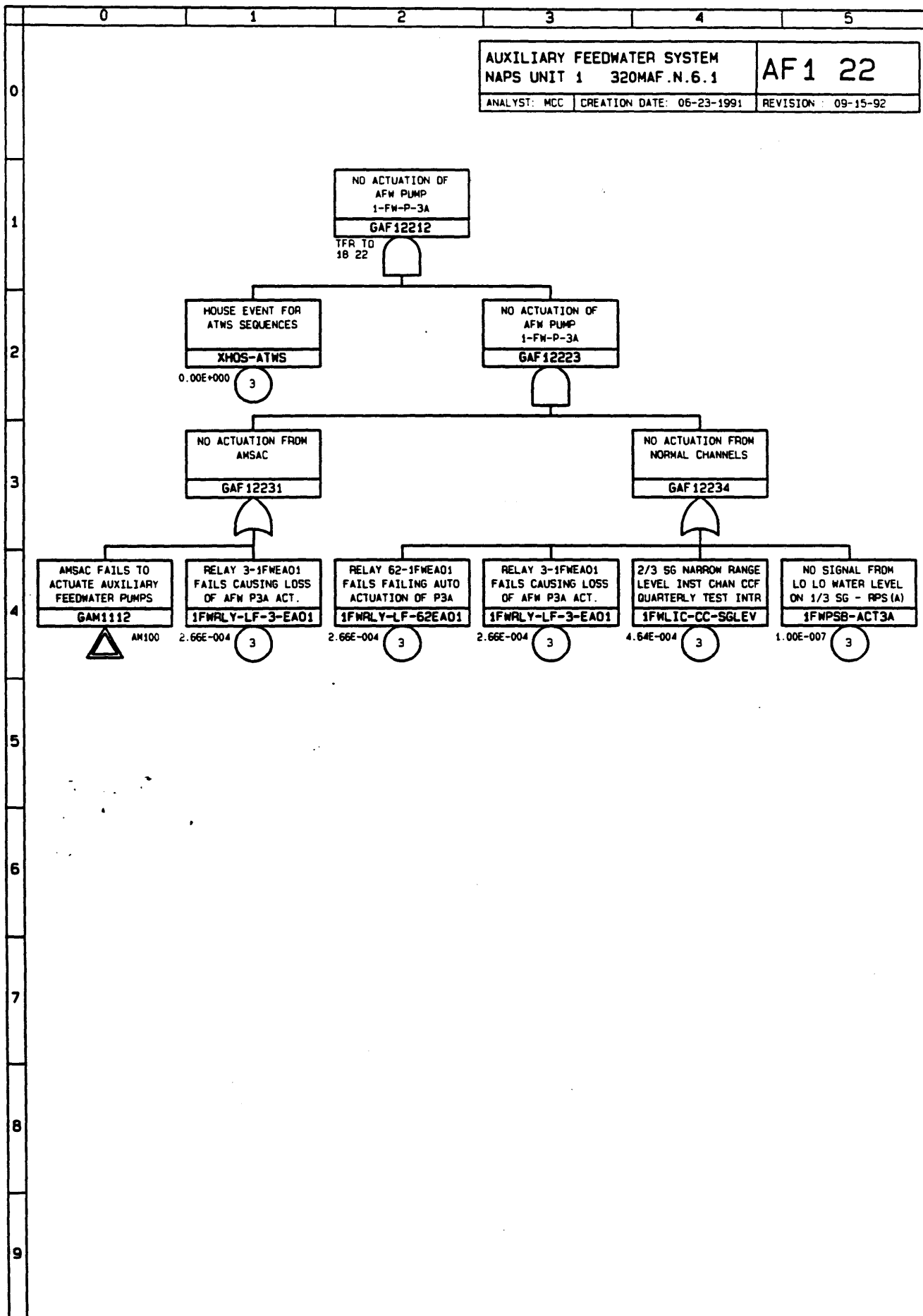
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VPWR



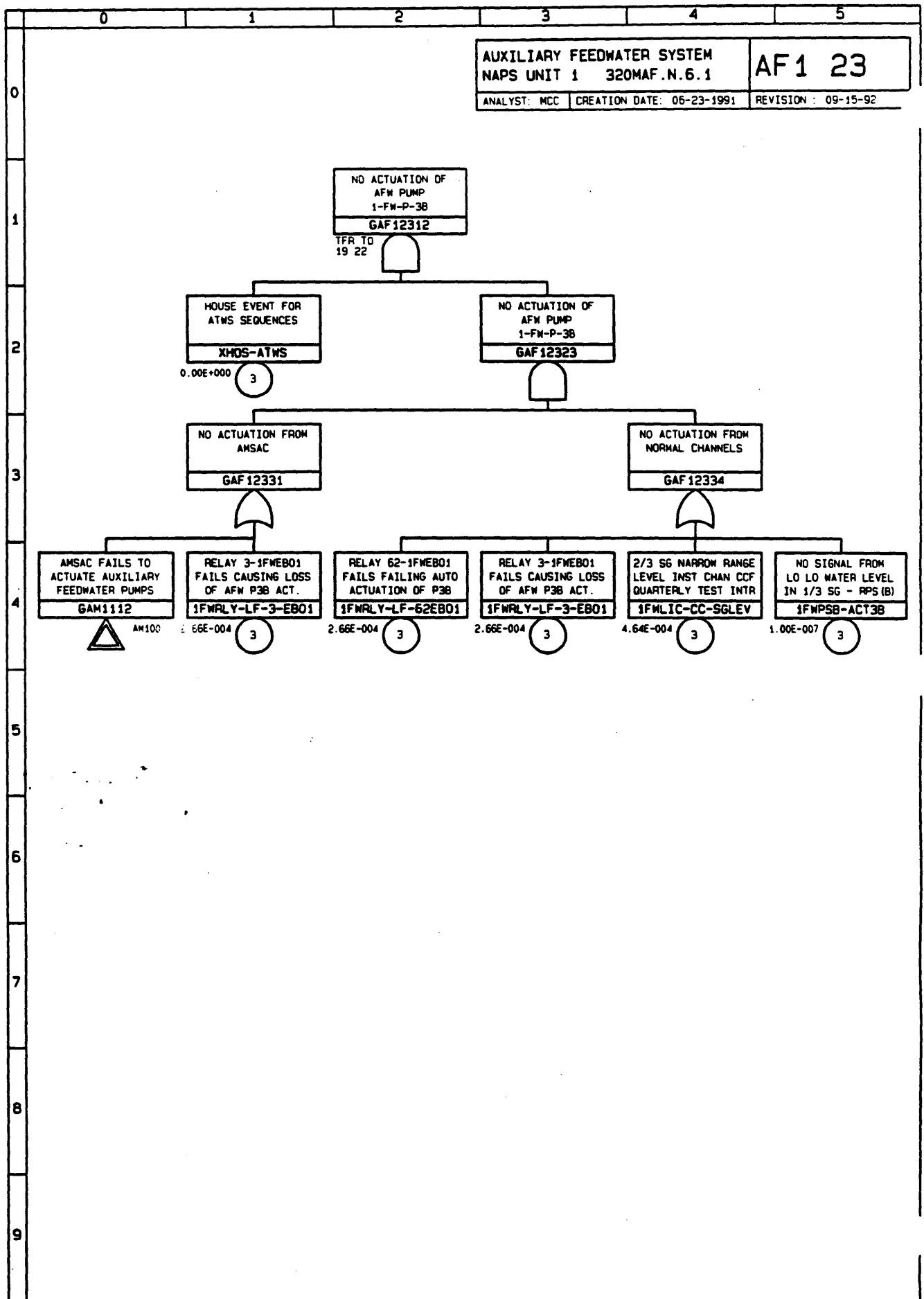
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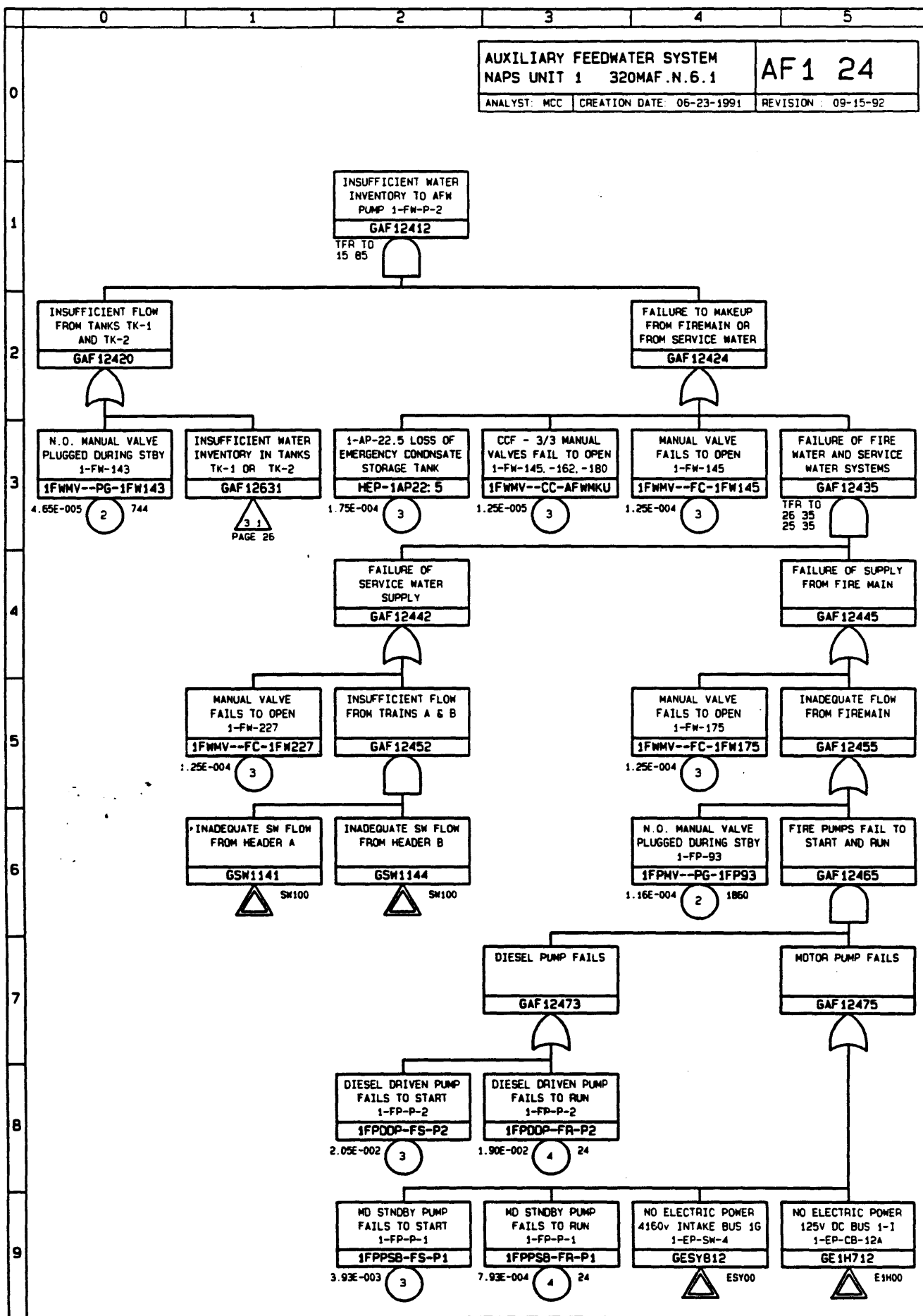


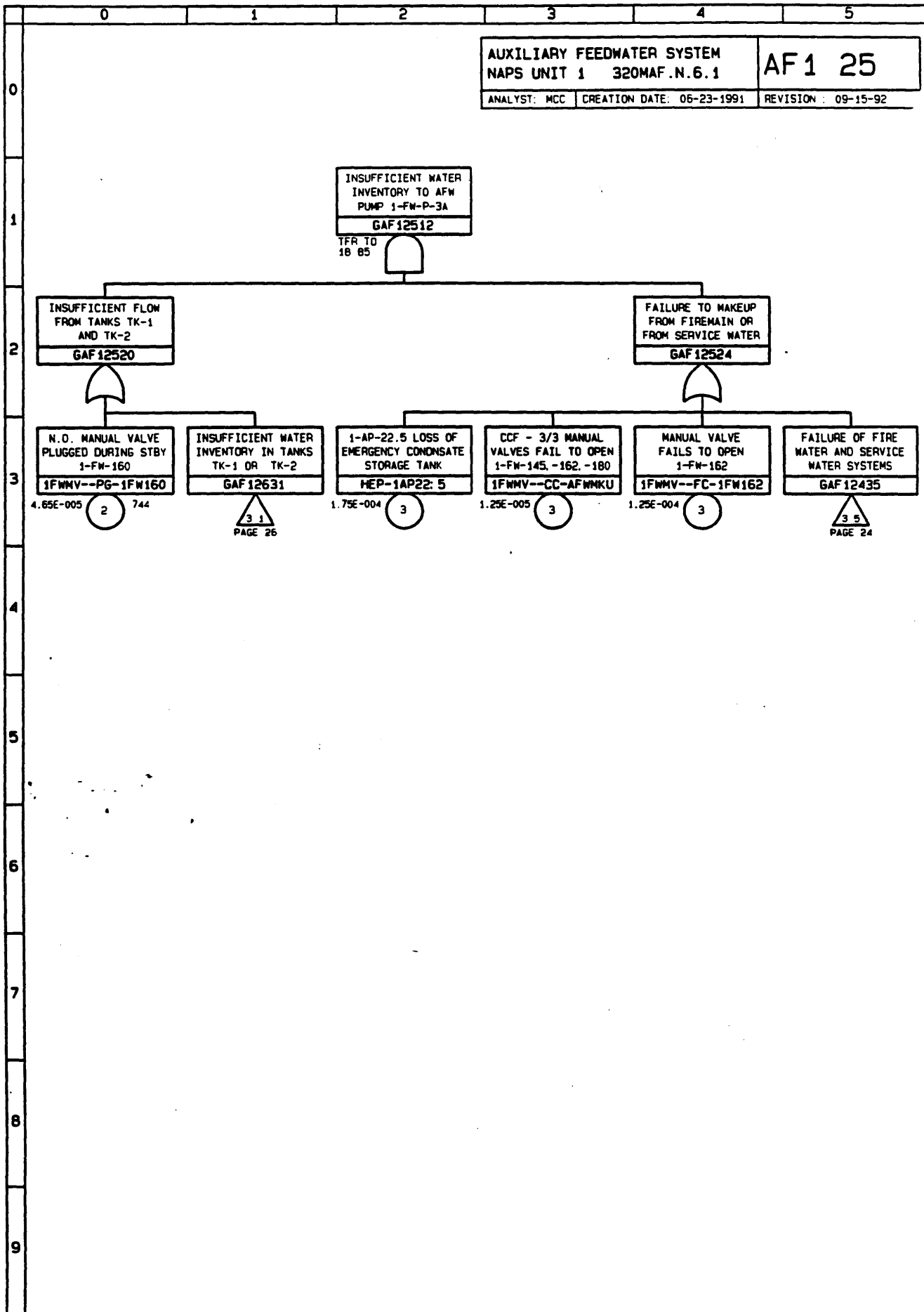




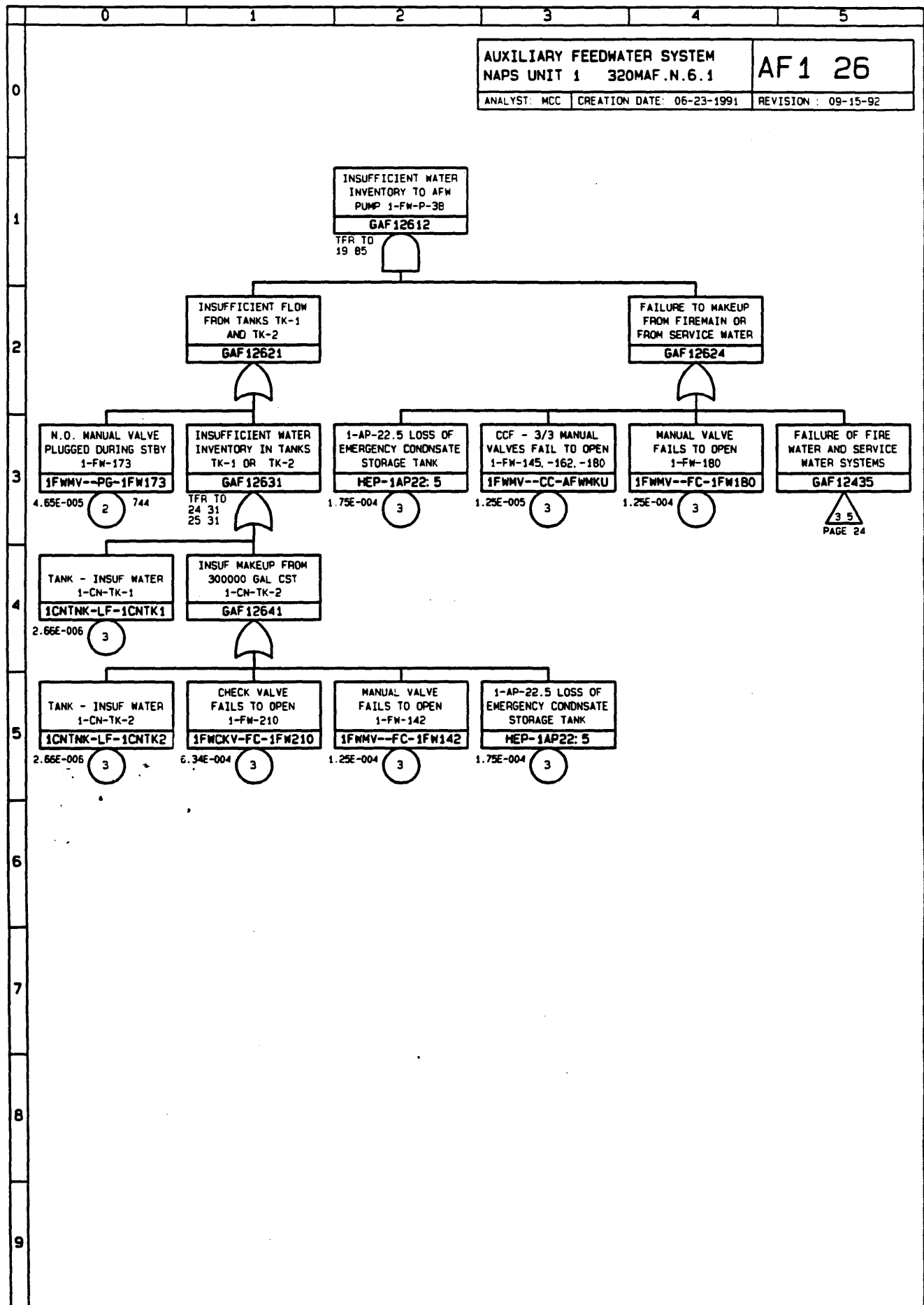
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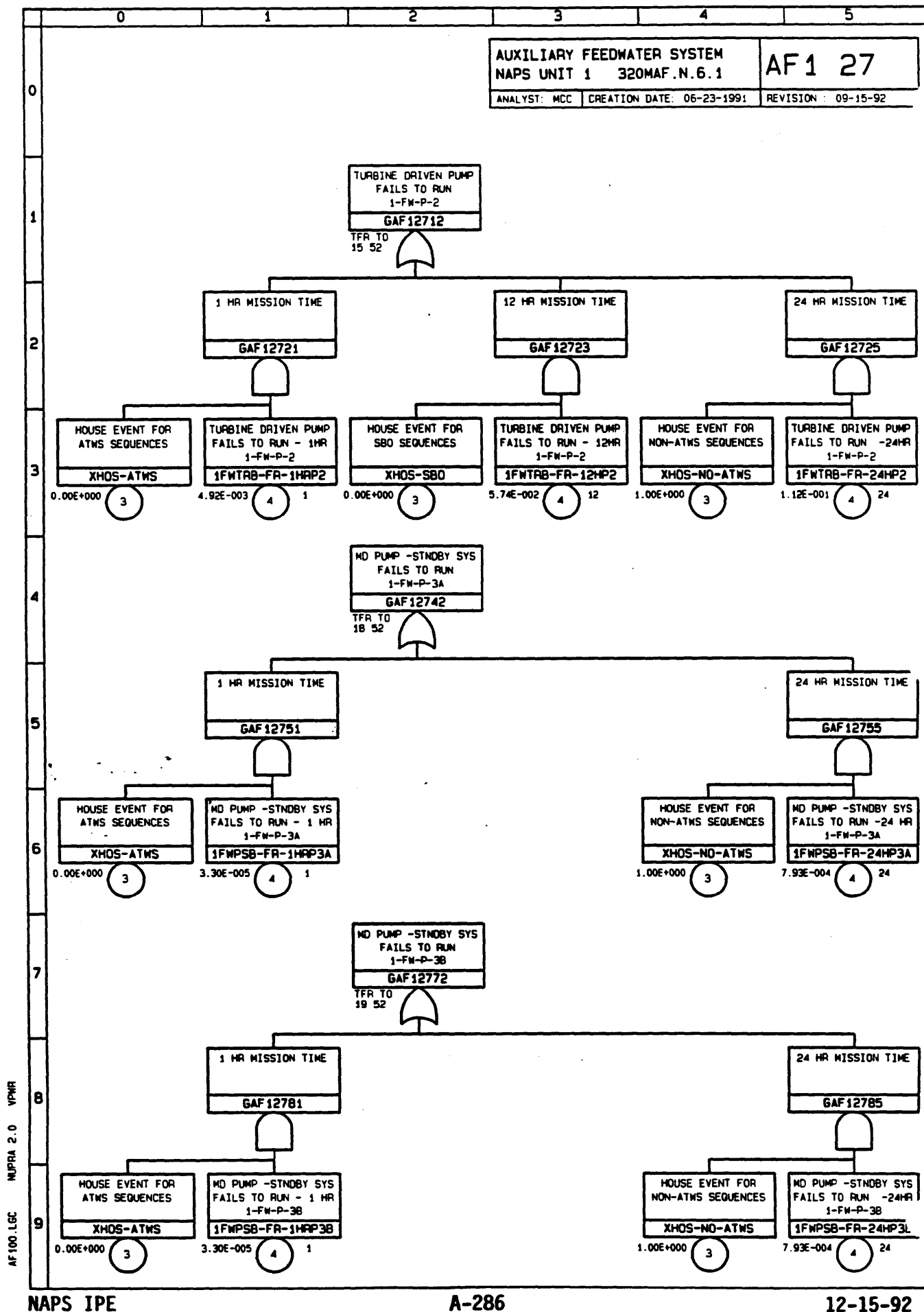


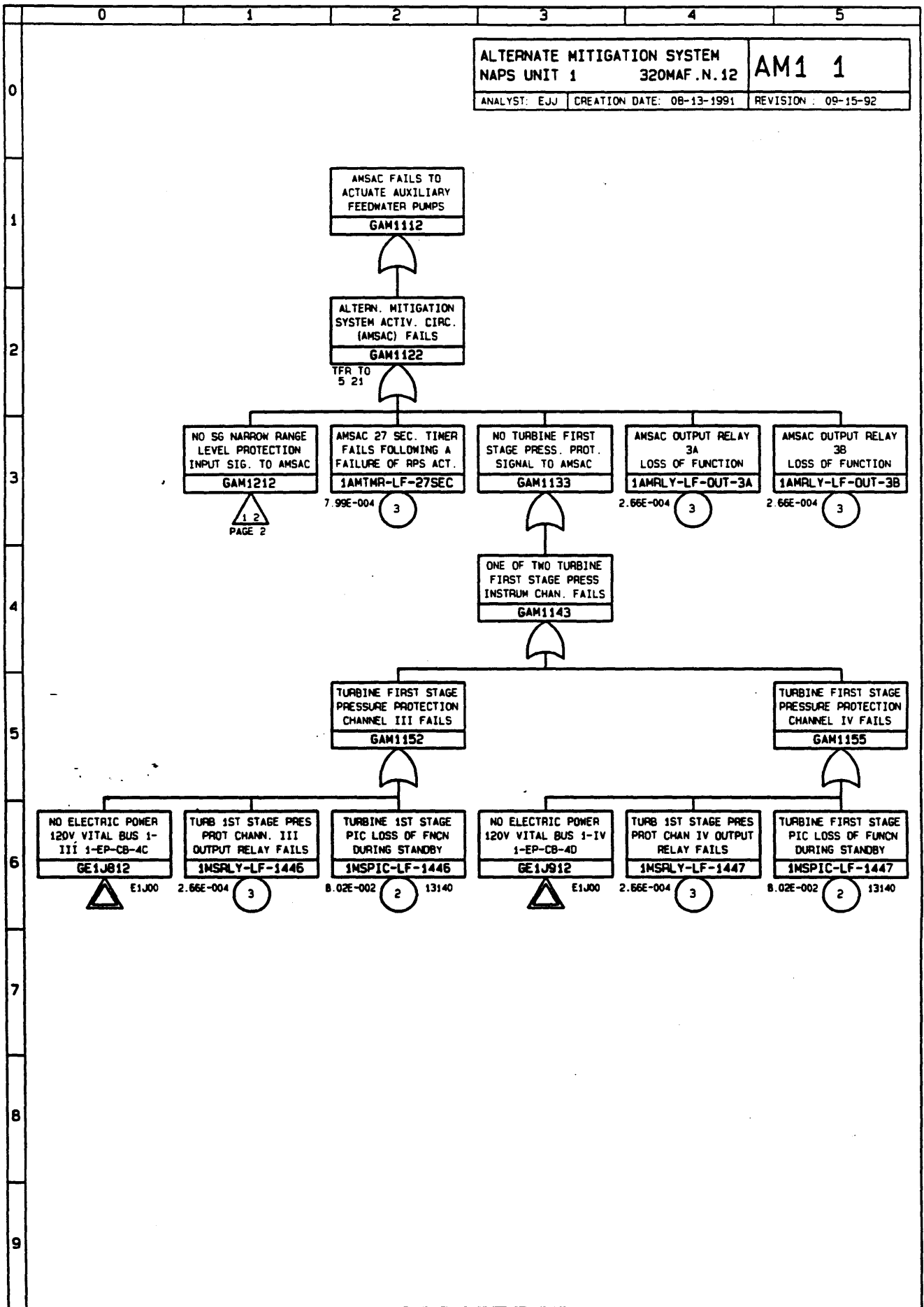


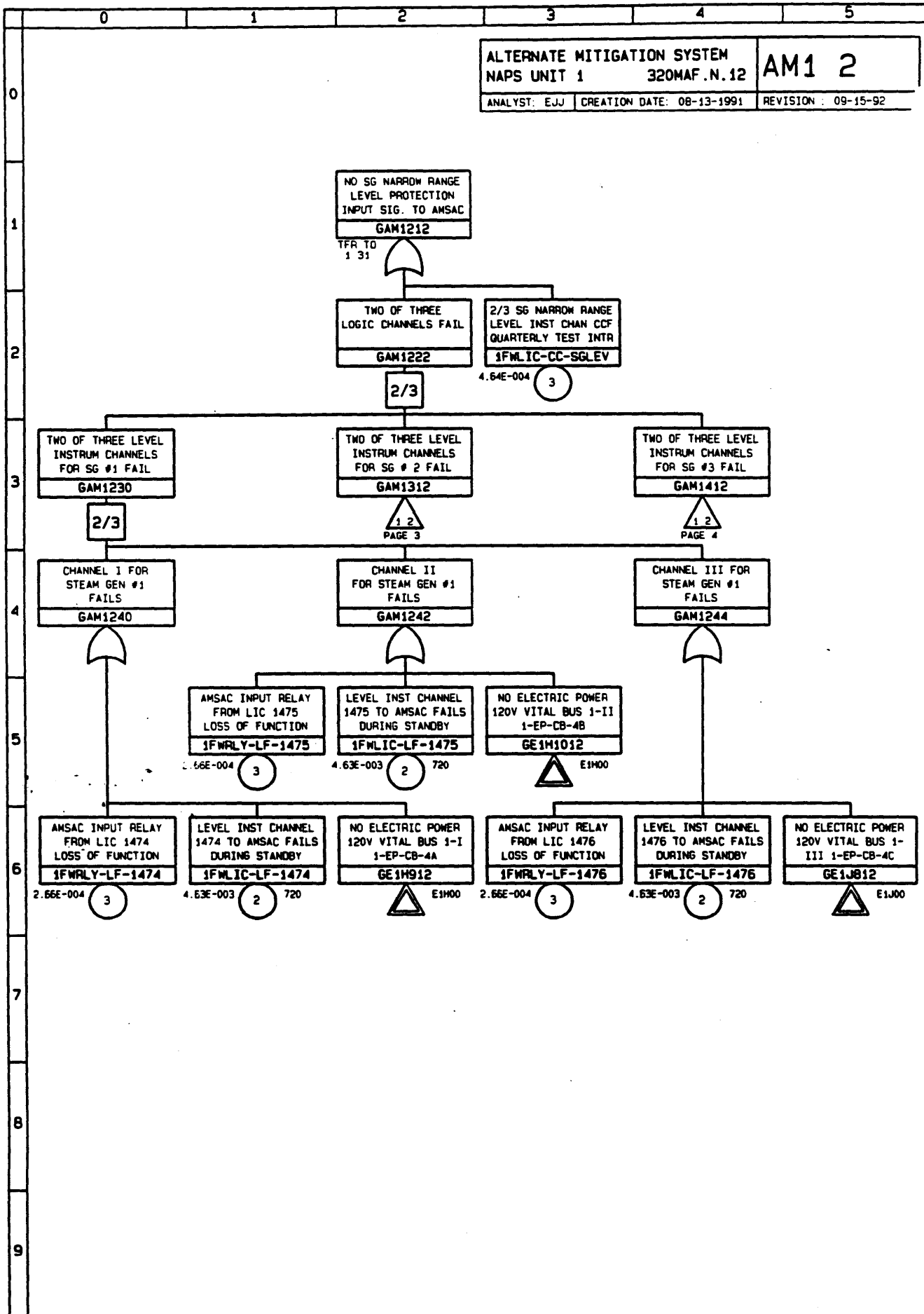
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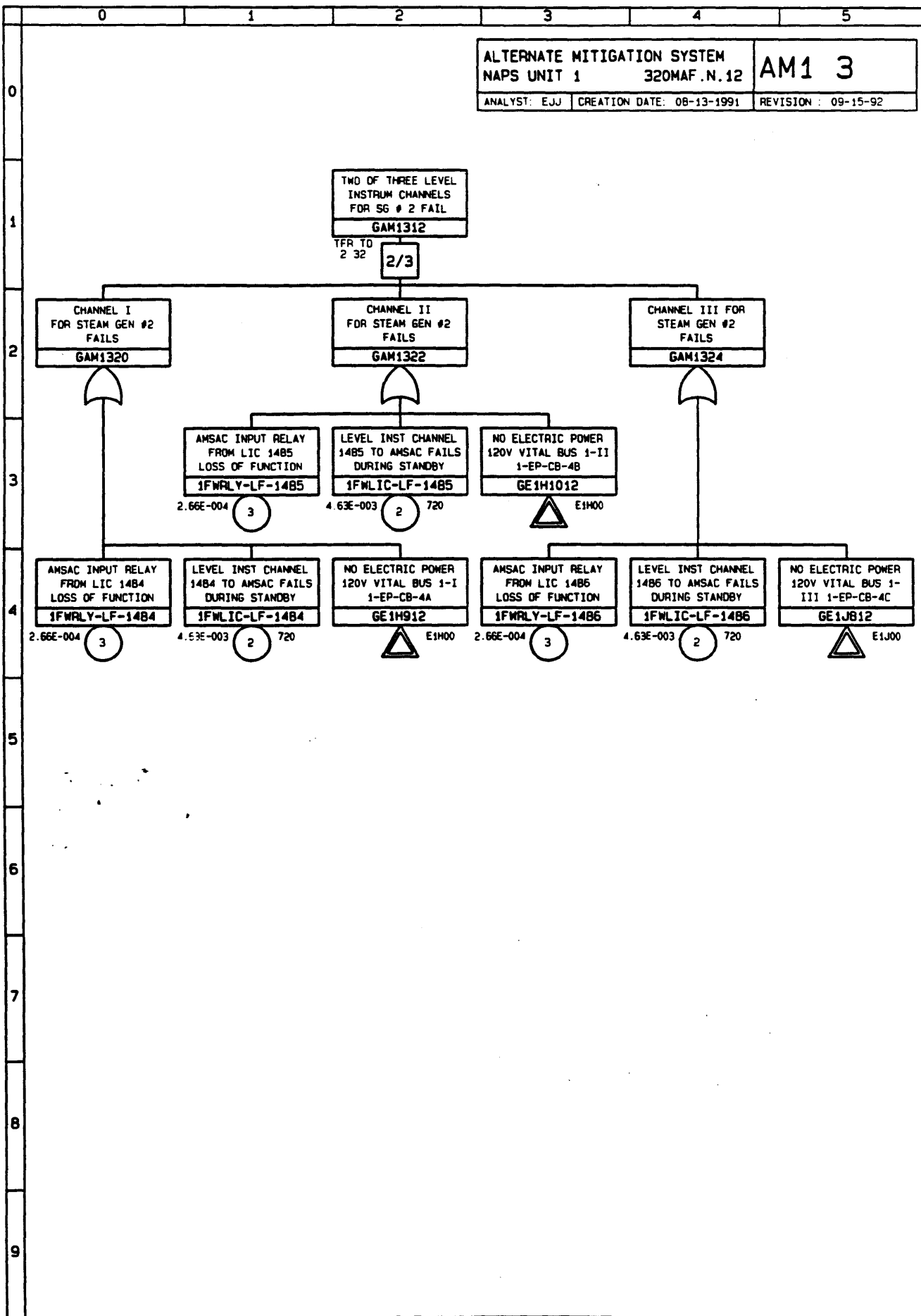




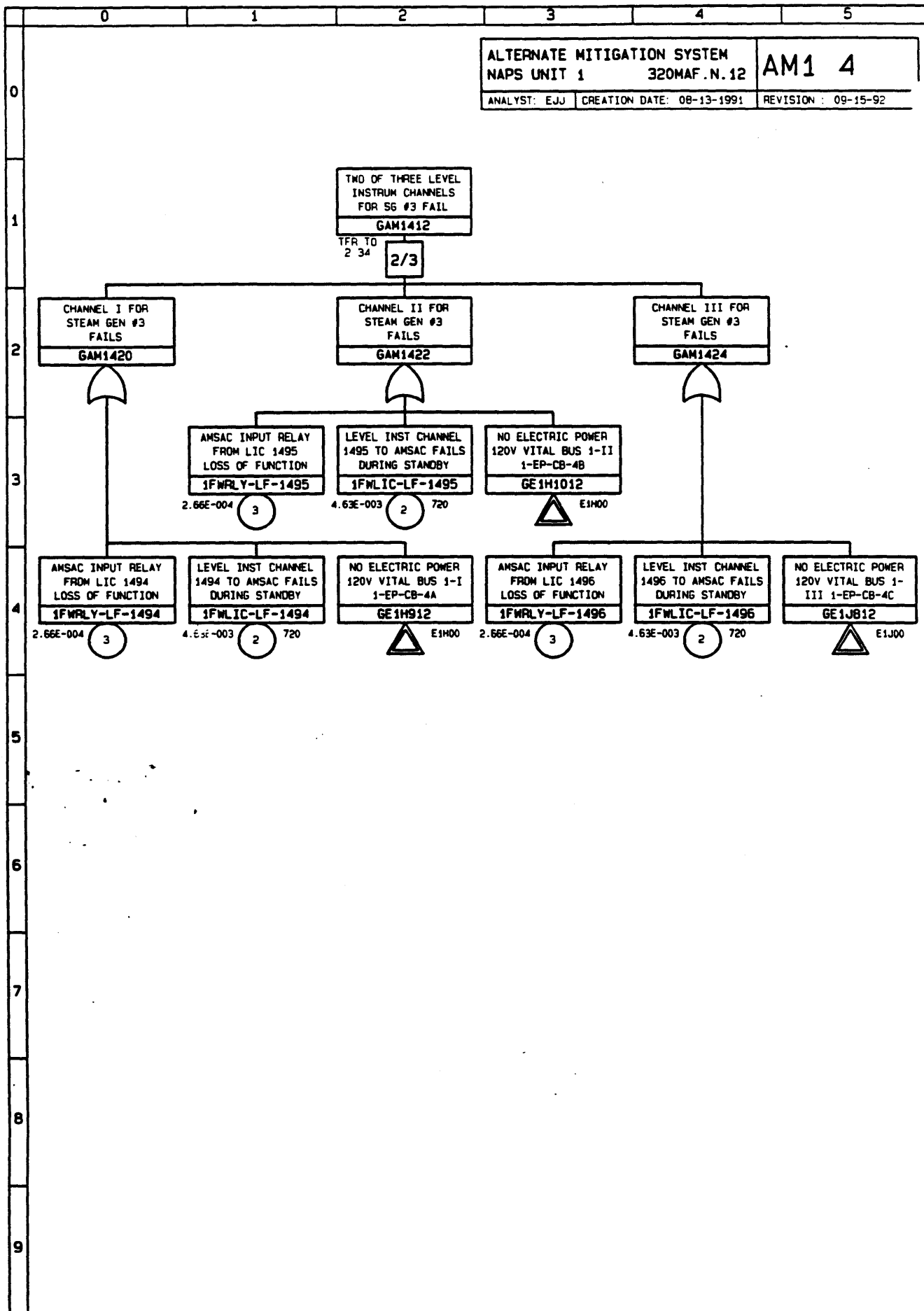
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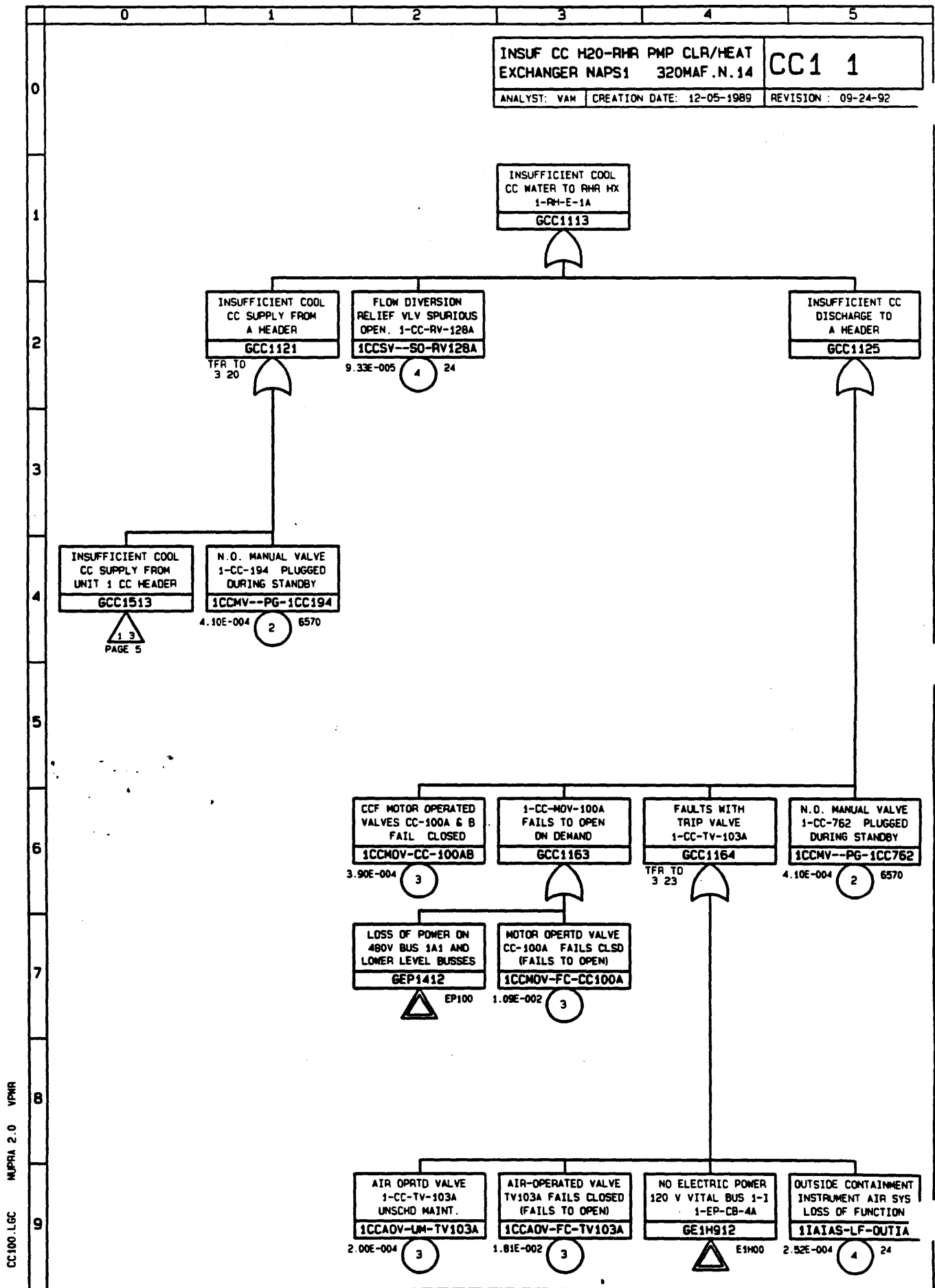
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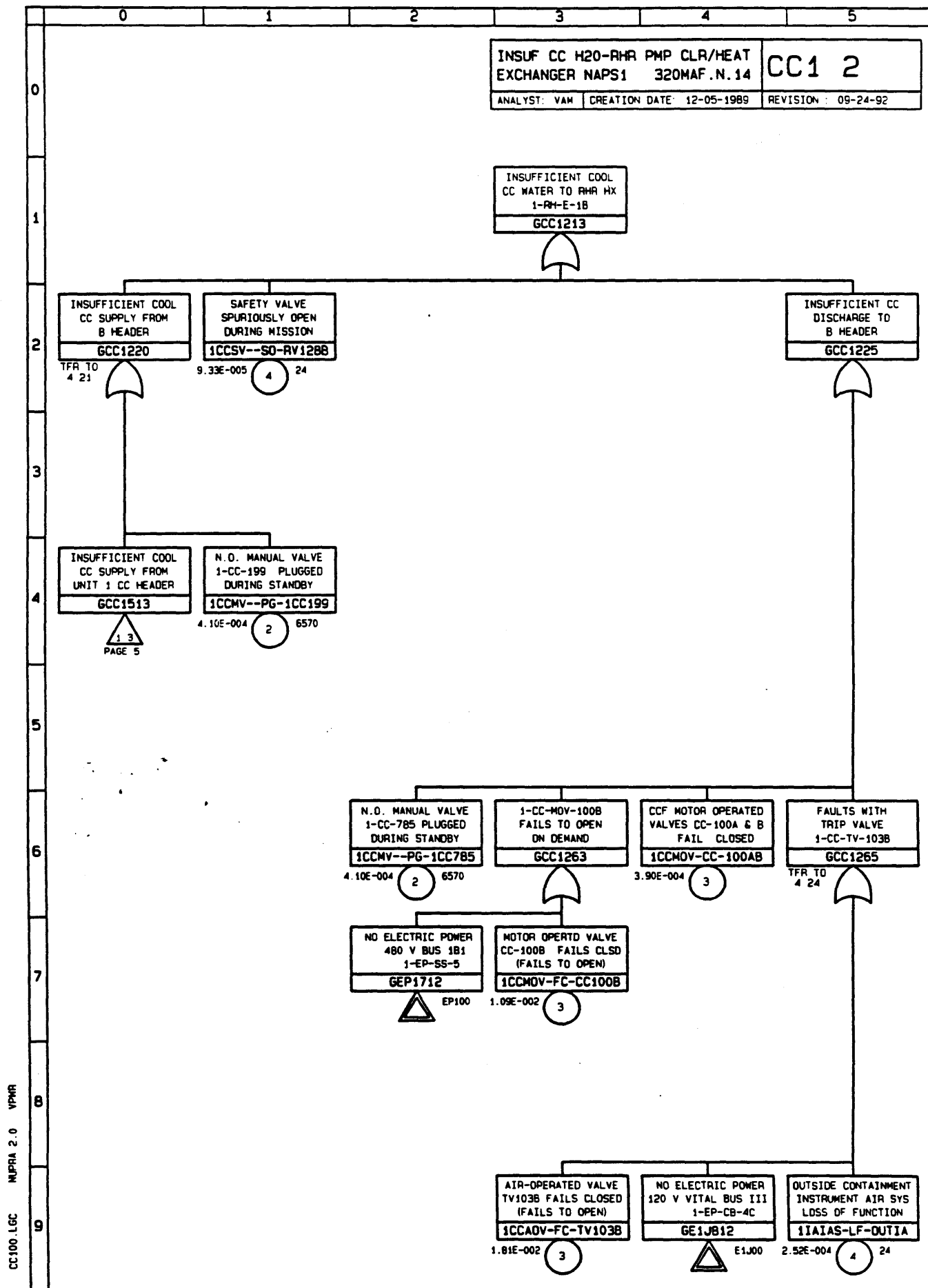


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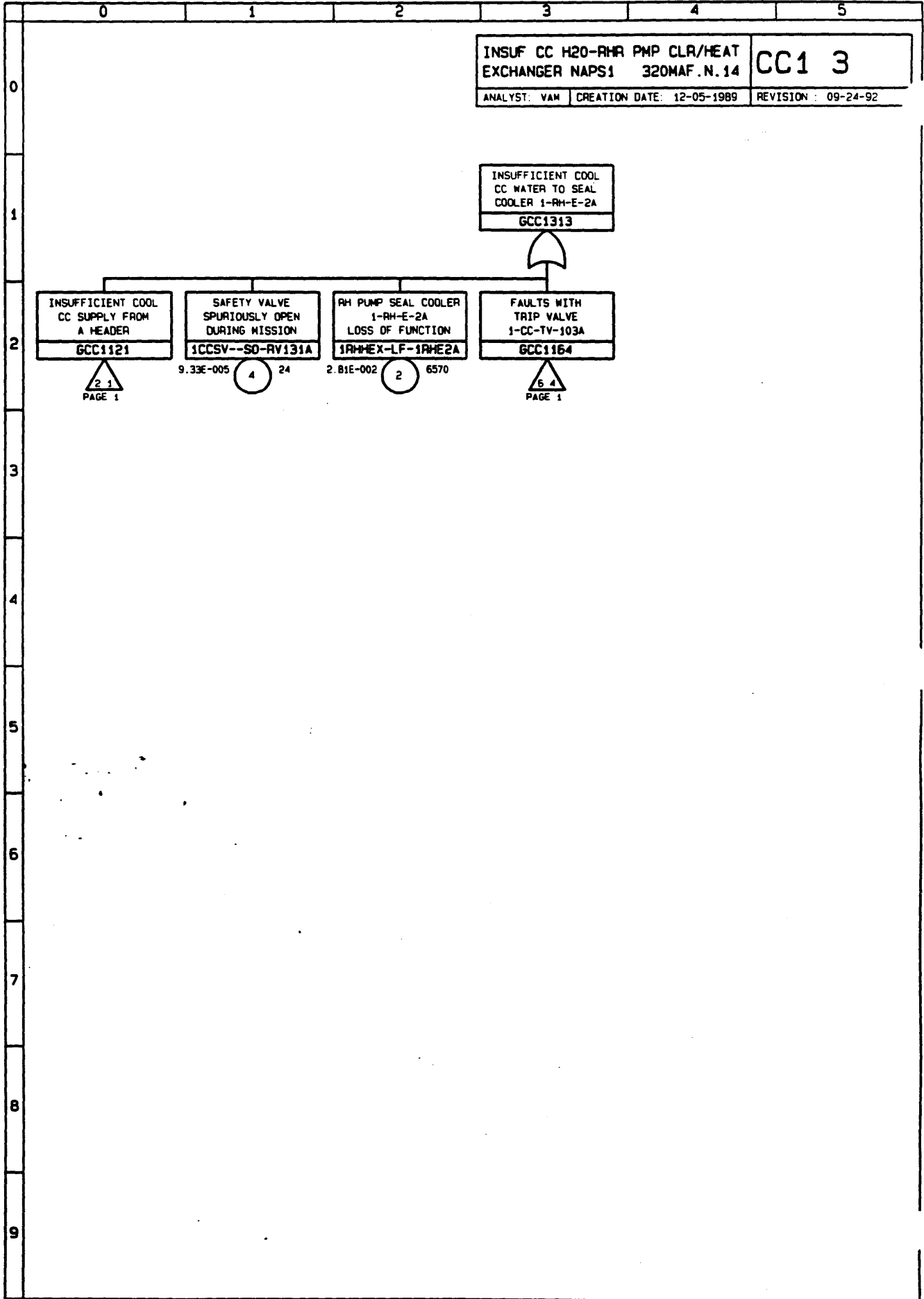




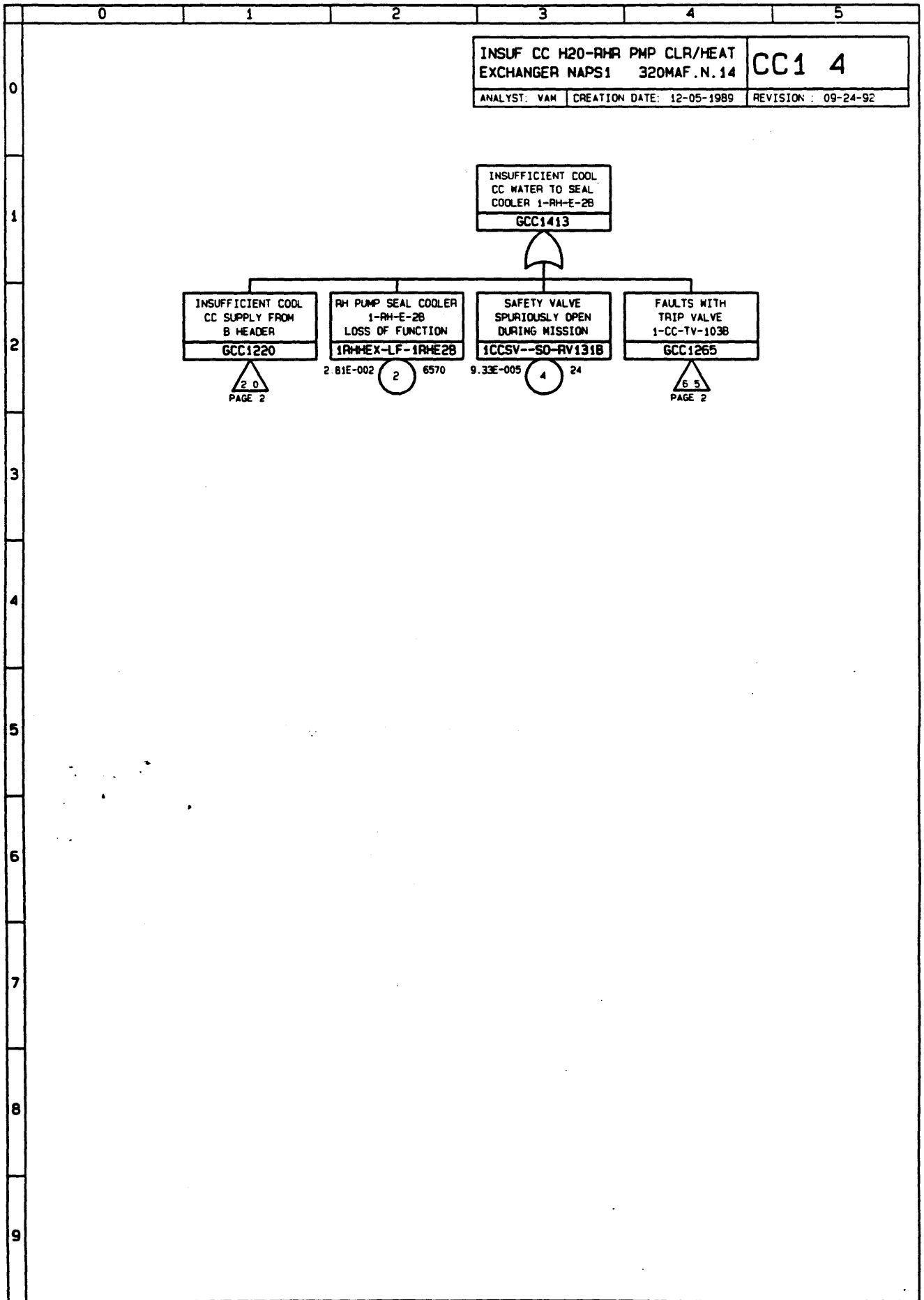




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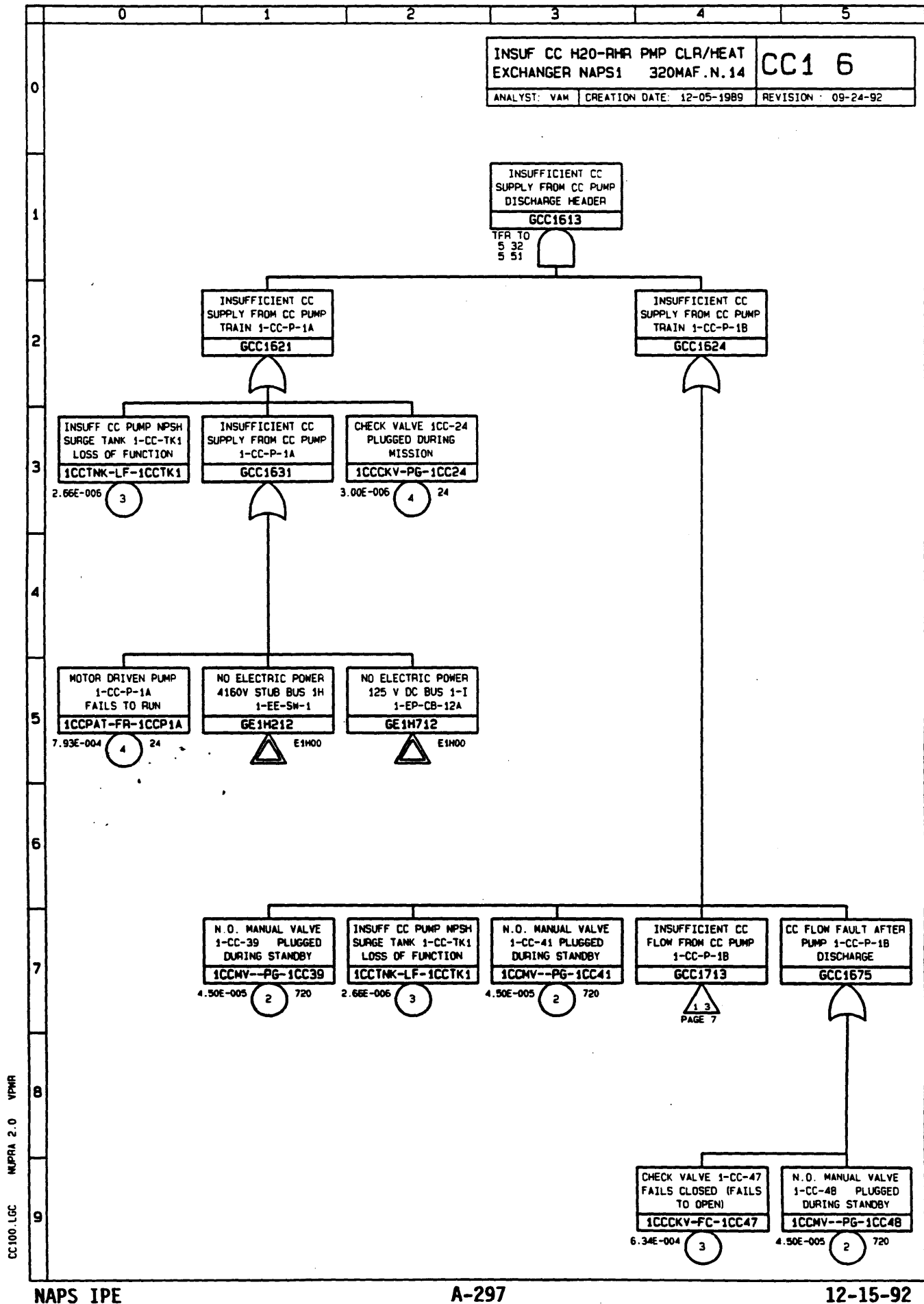


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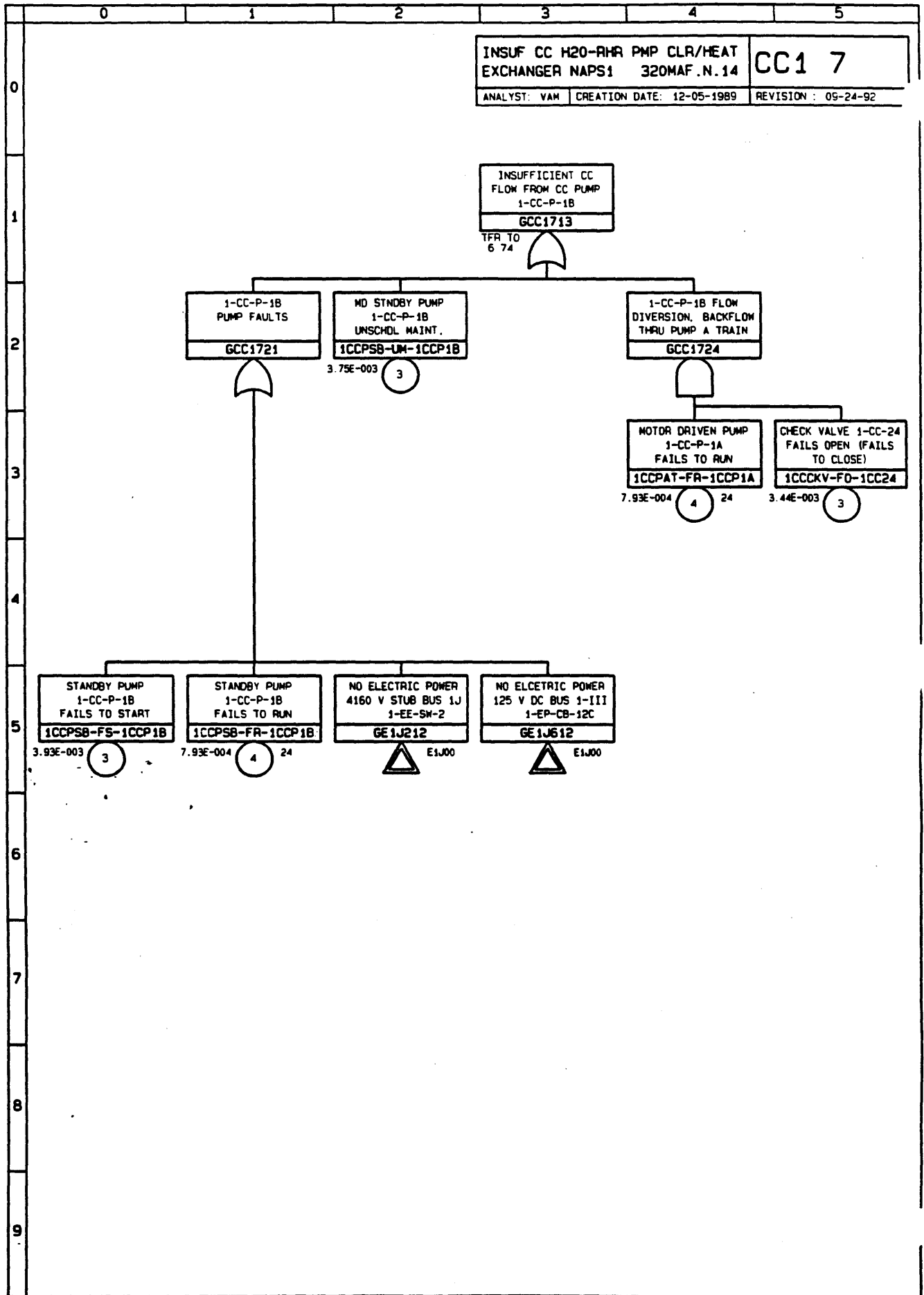


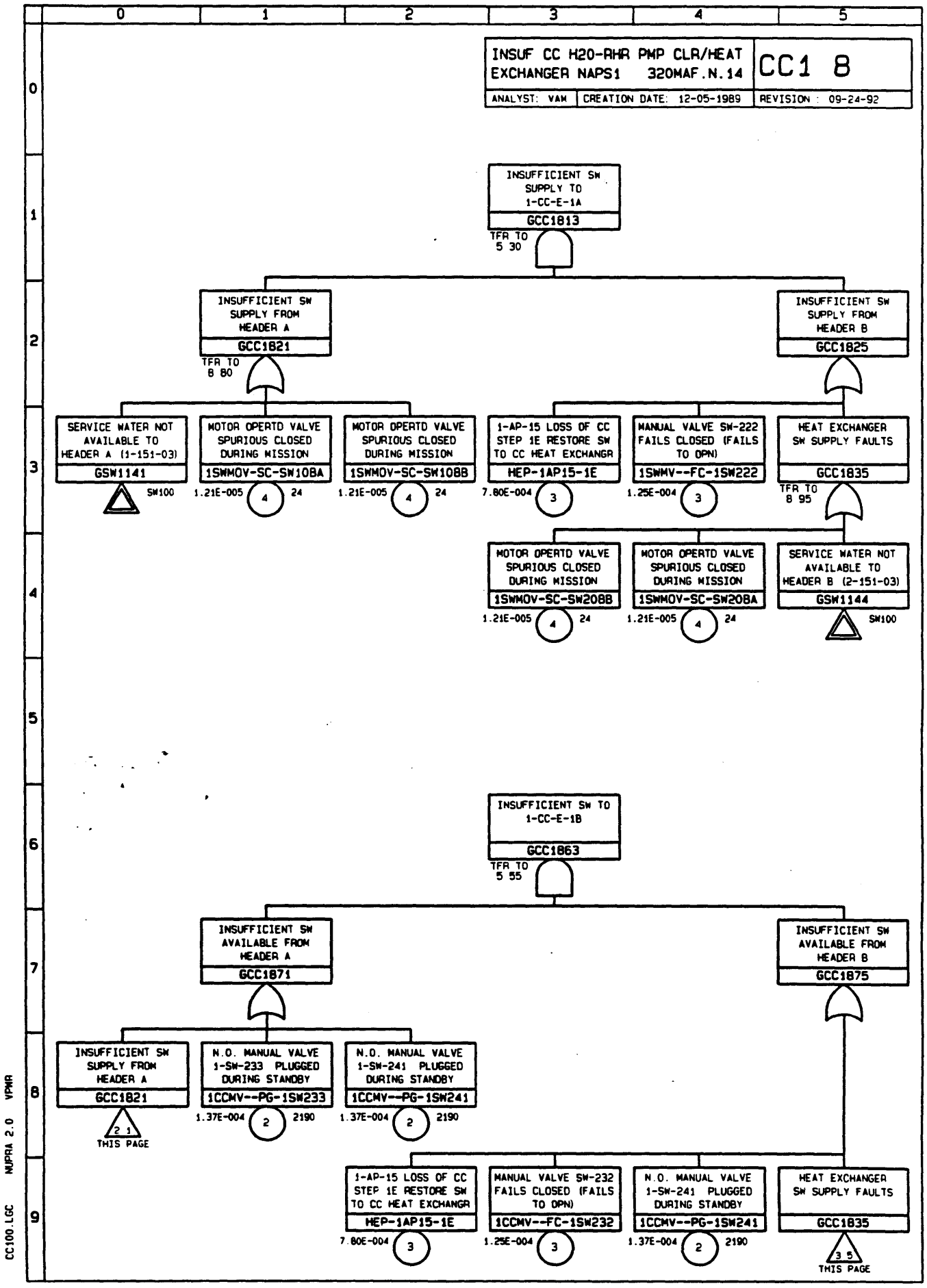






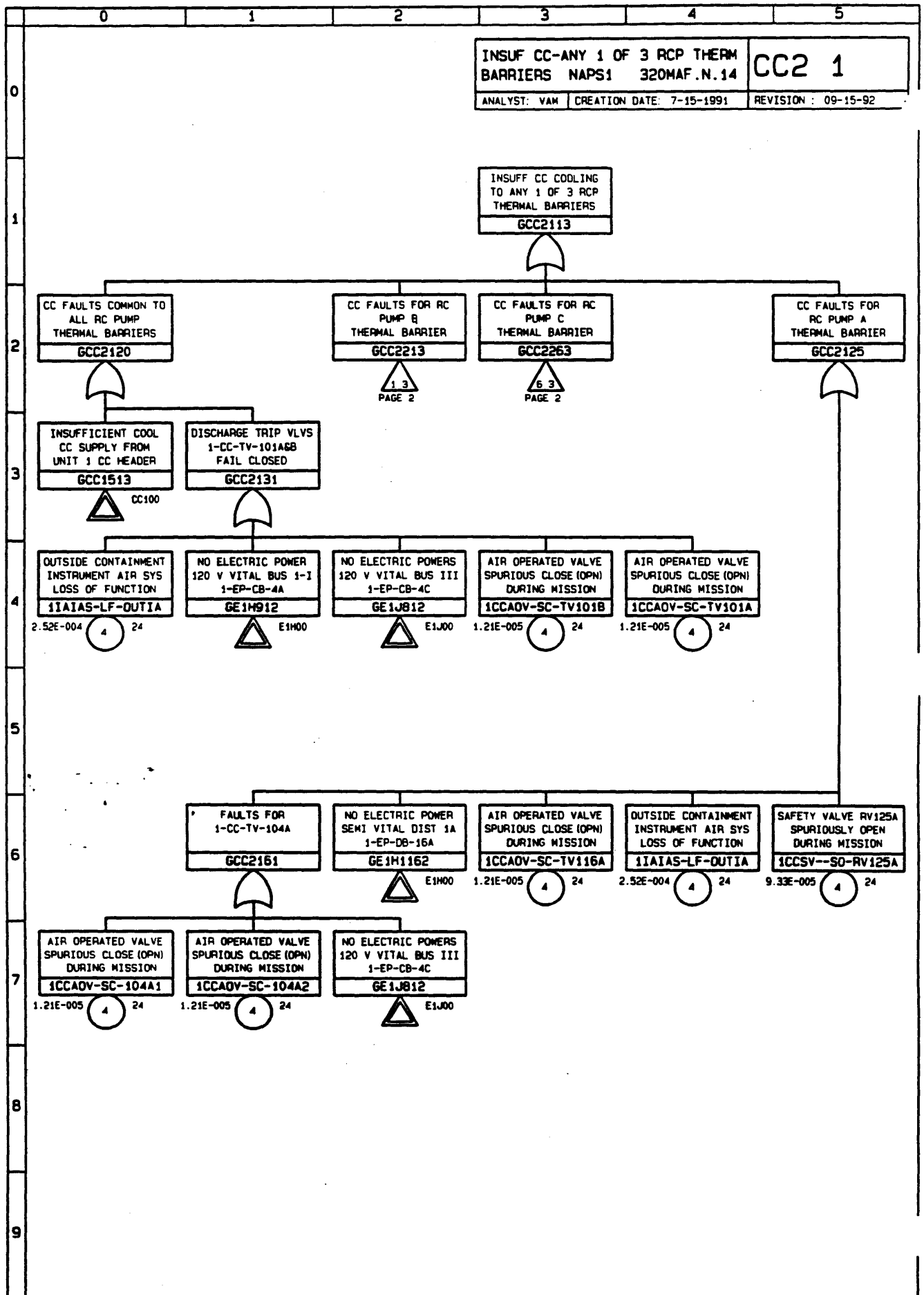
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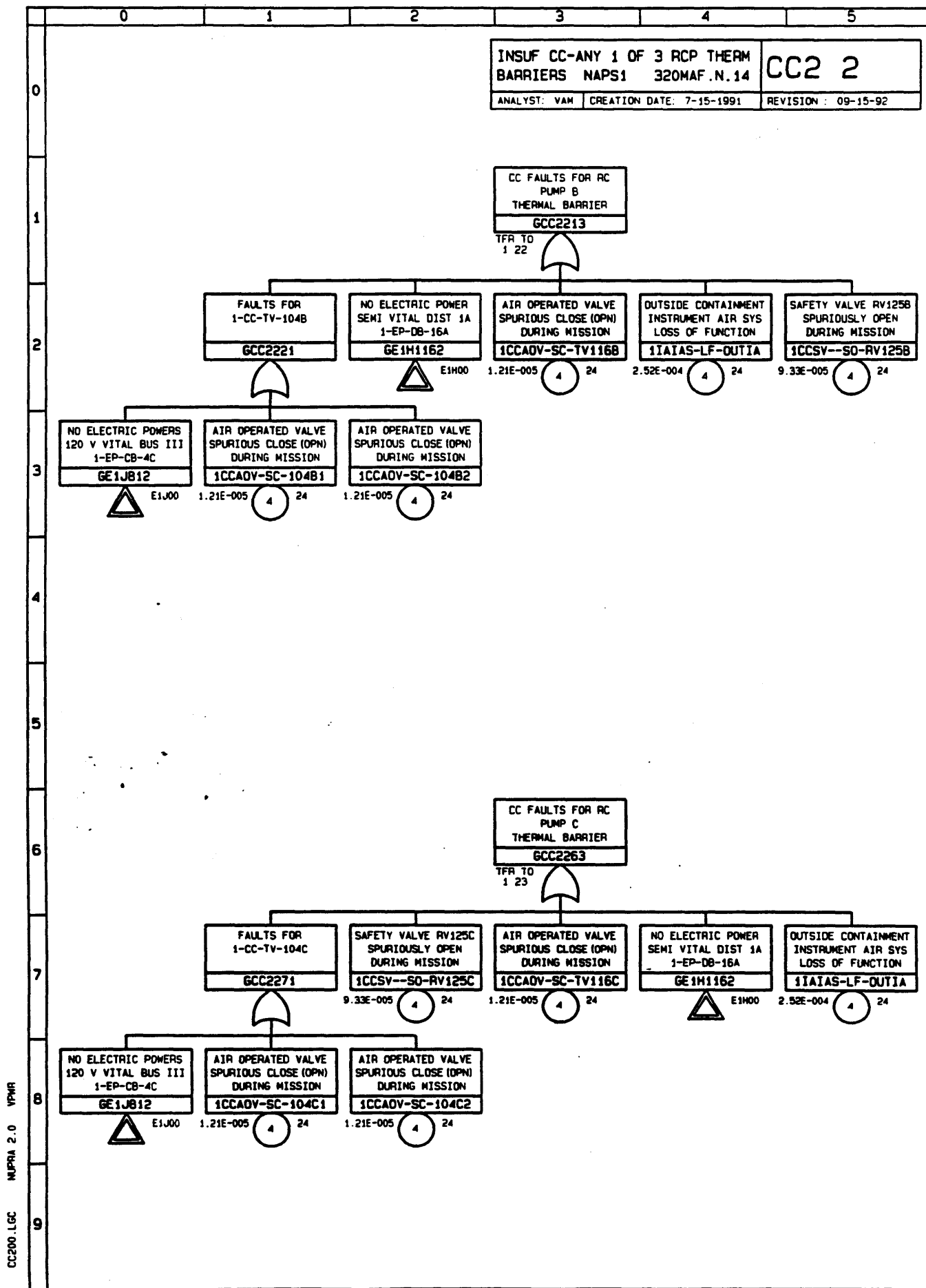




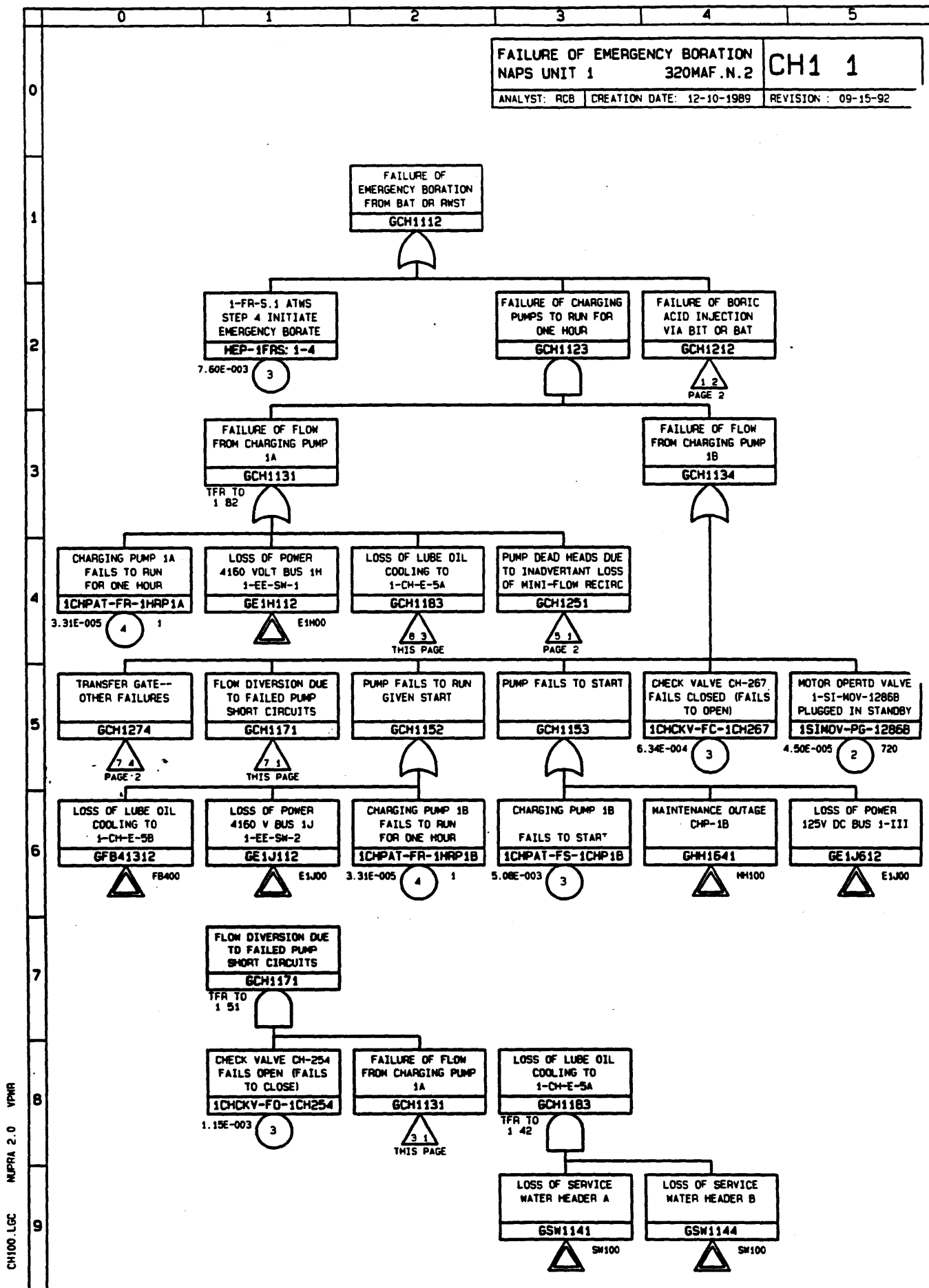
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CC200.LGC  
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VPMR

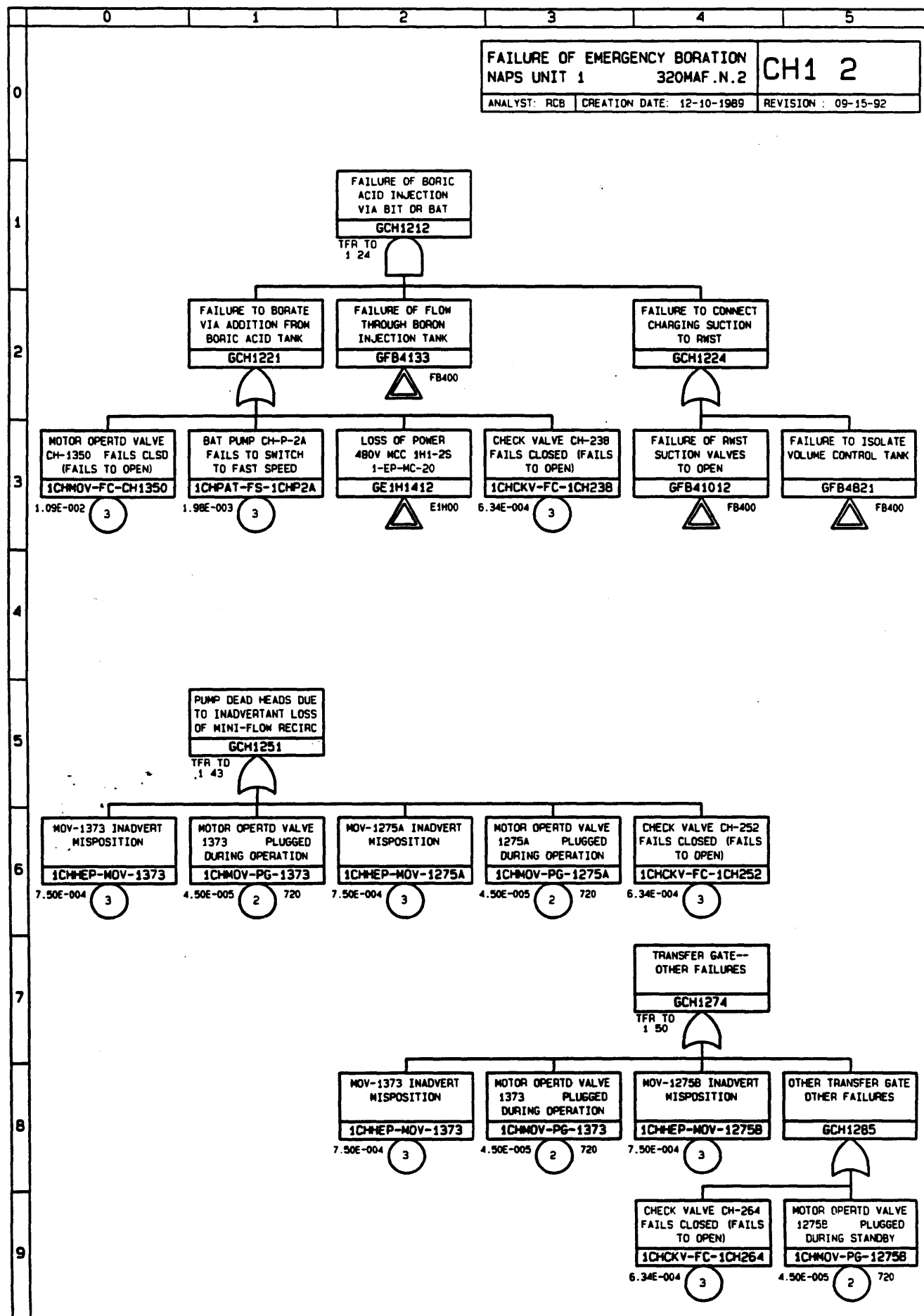




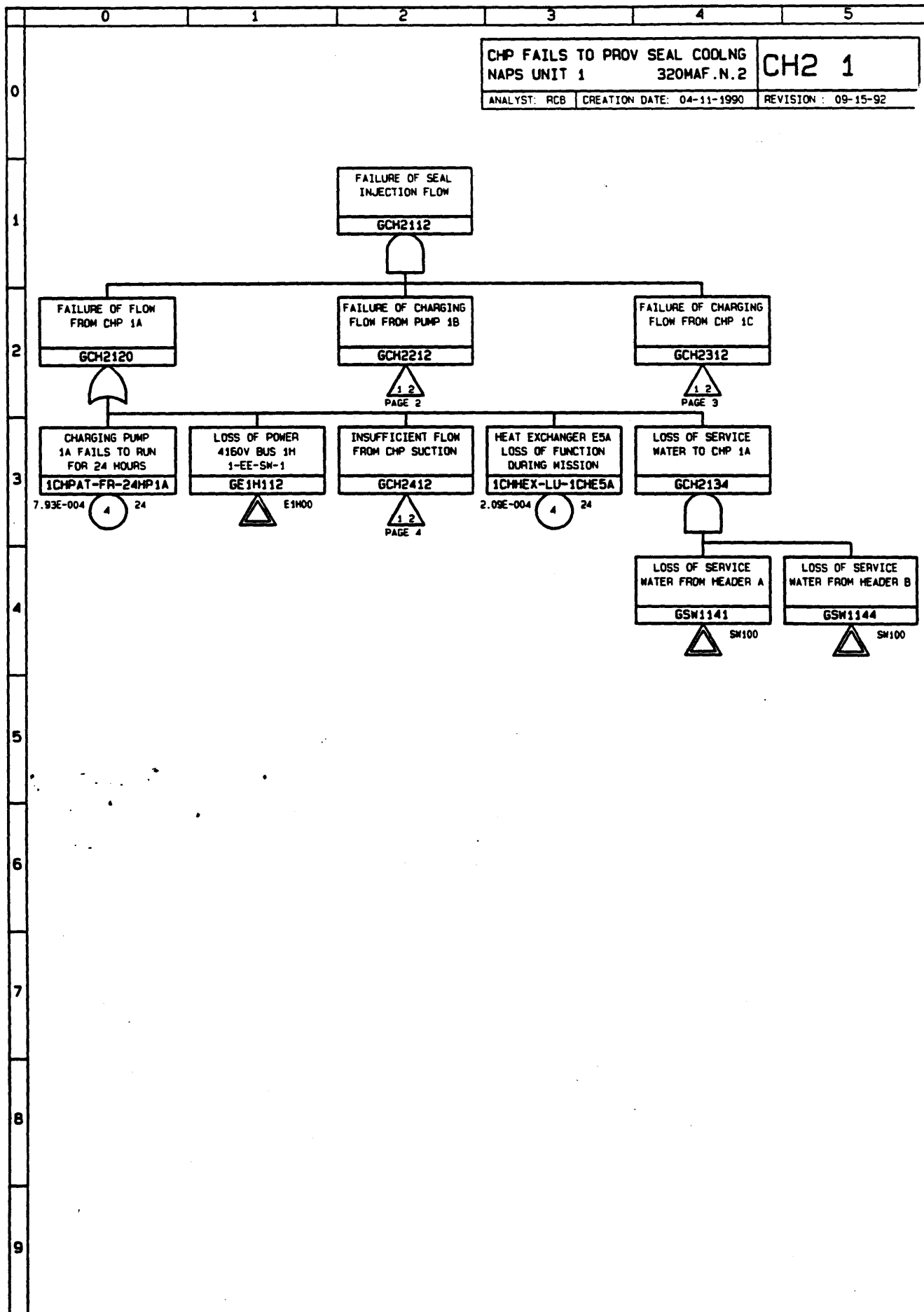
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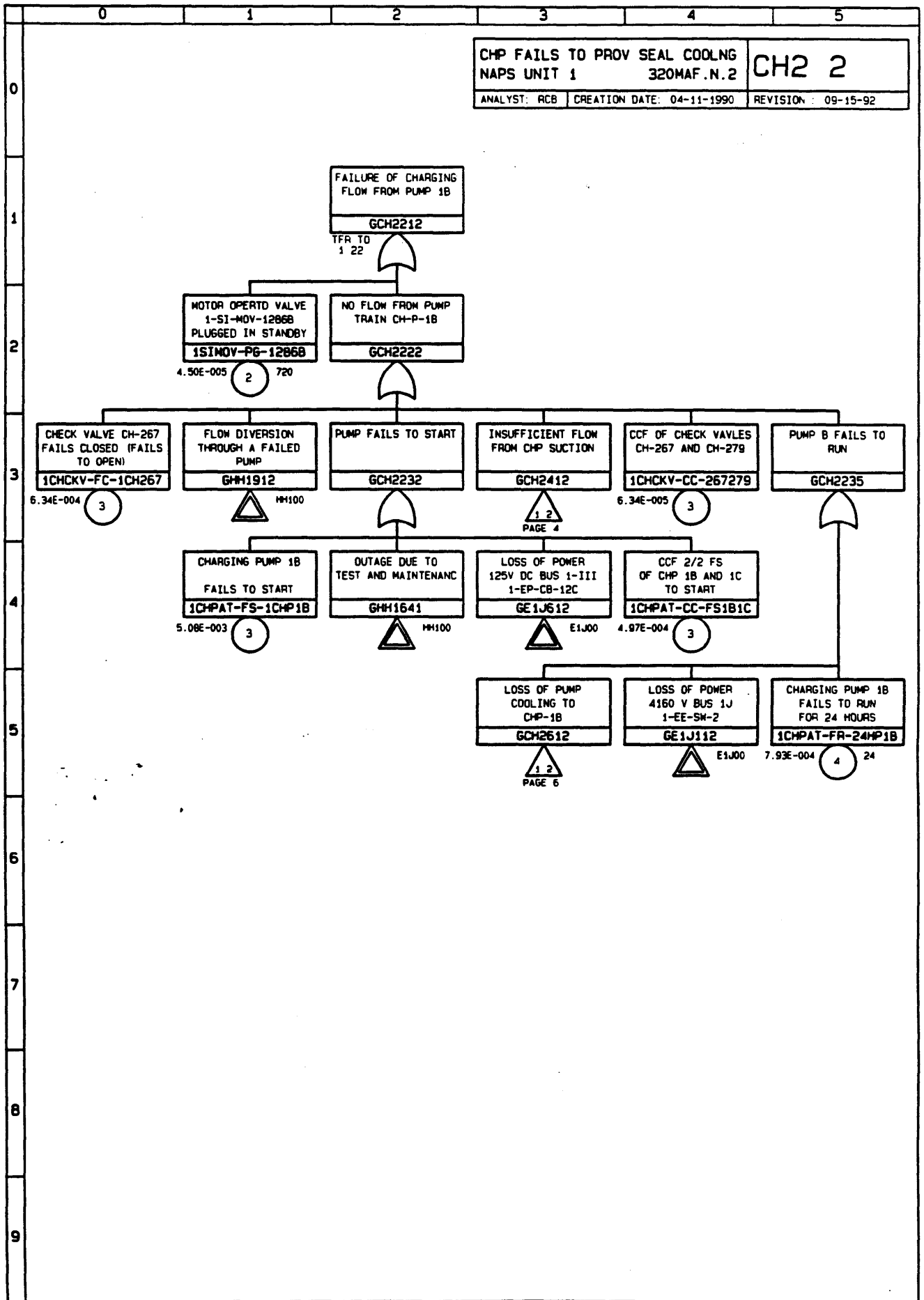


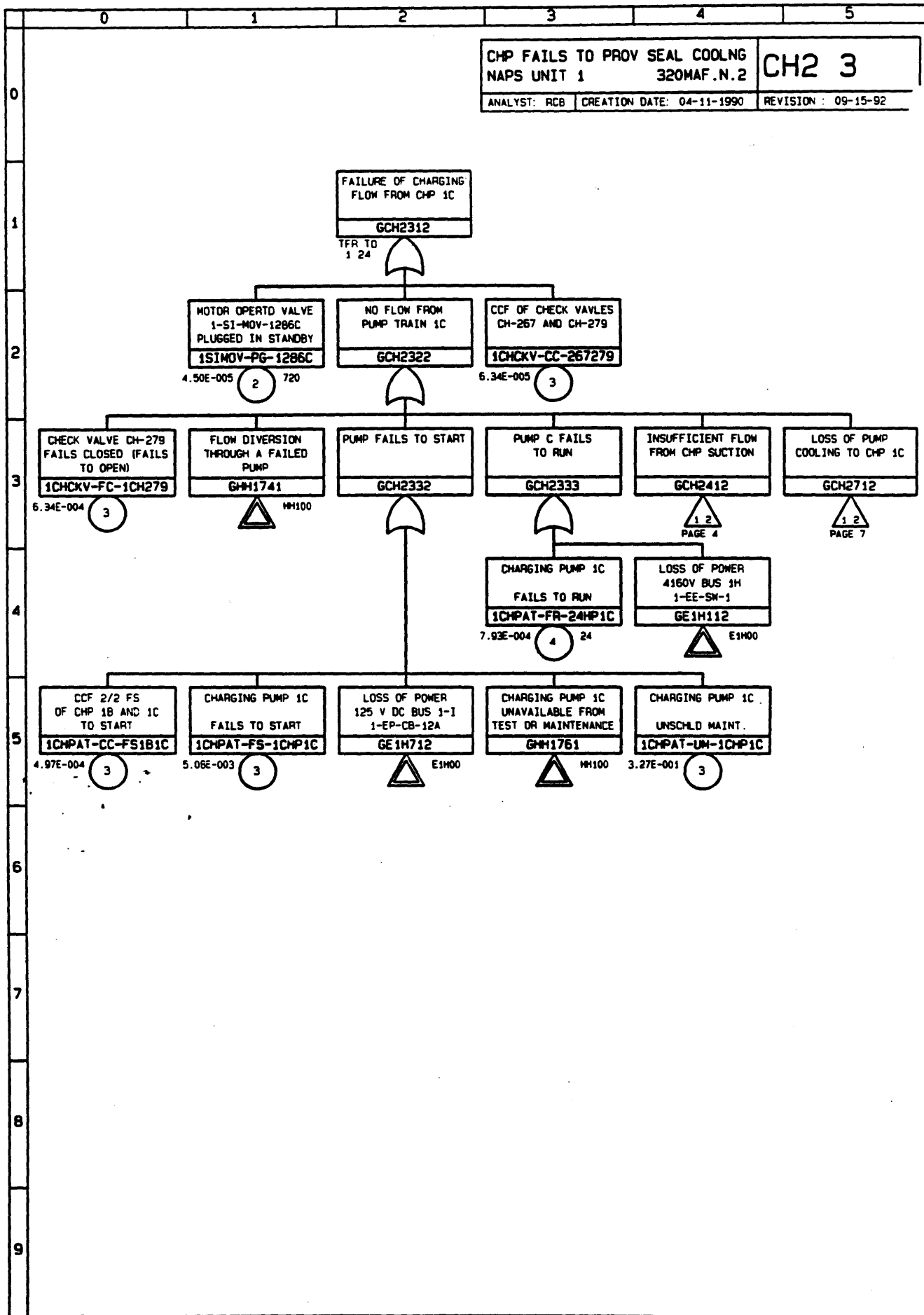
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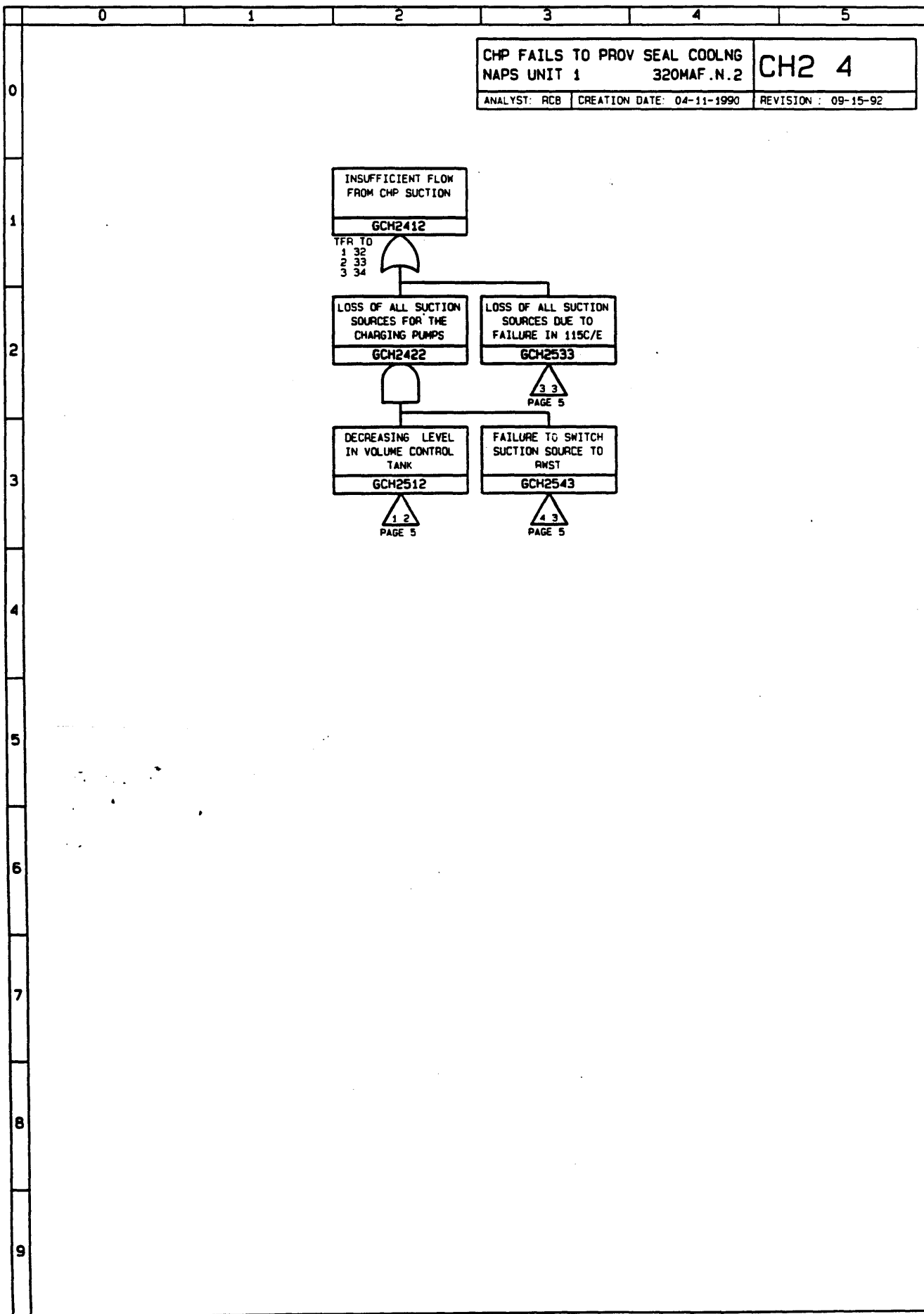


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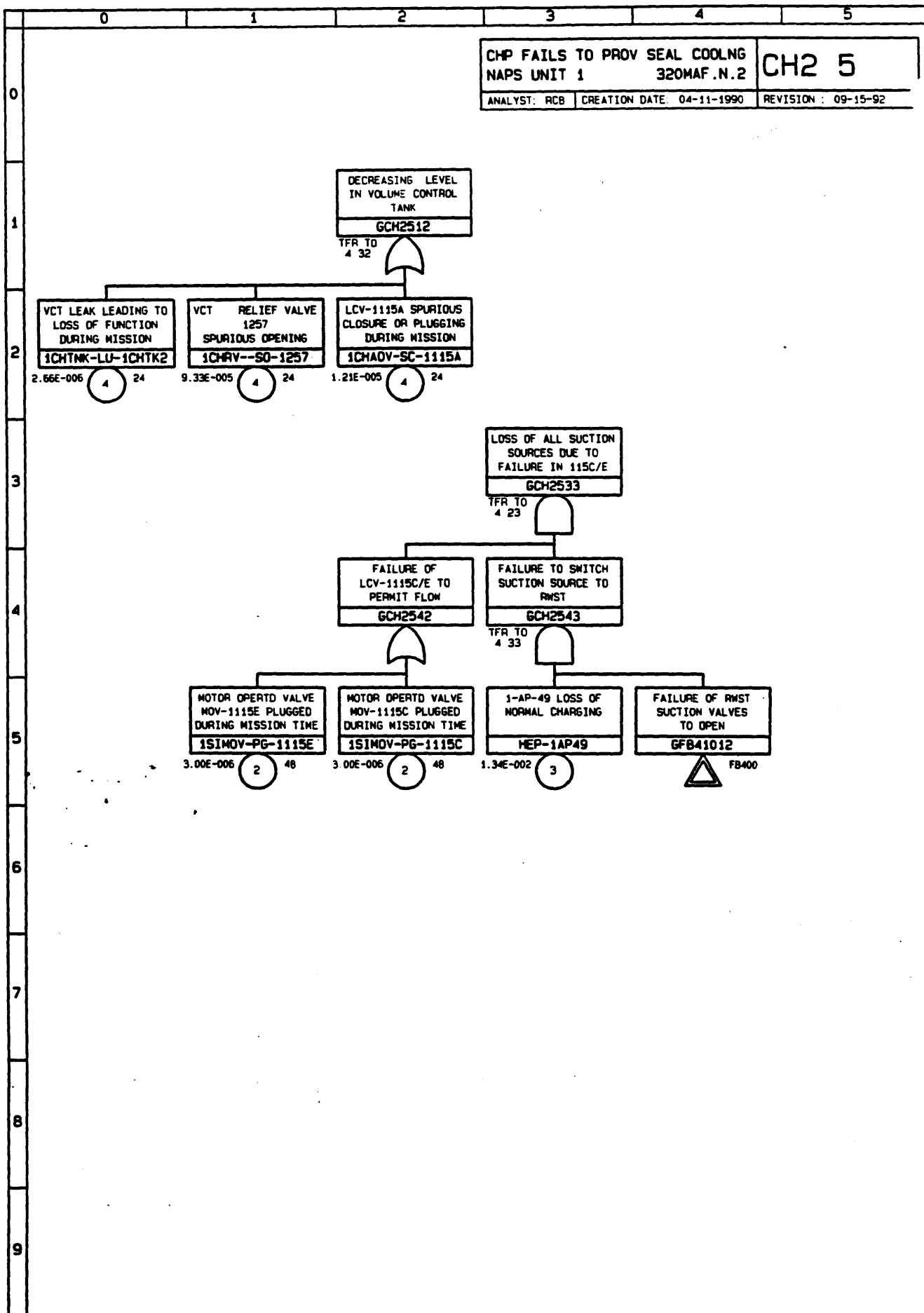




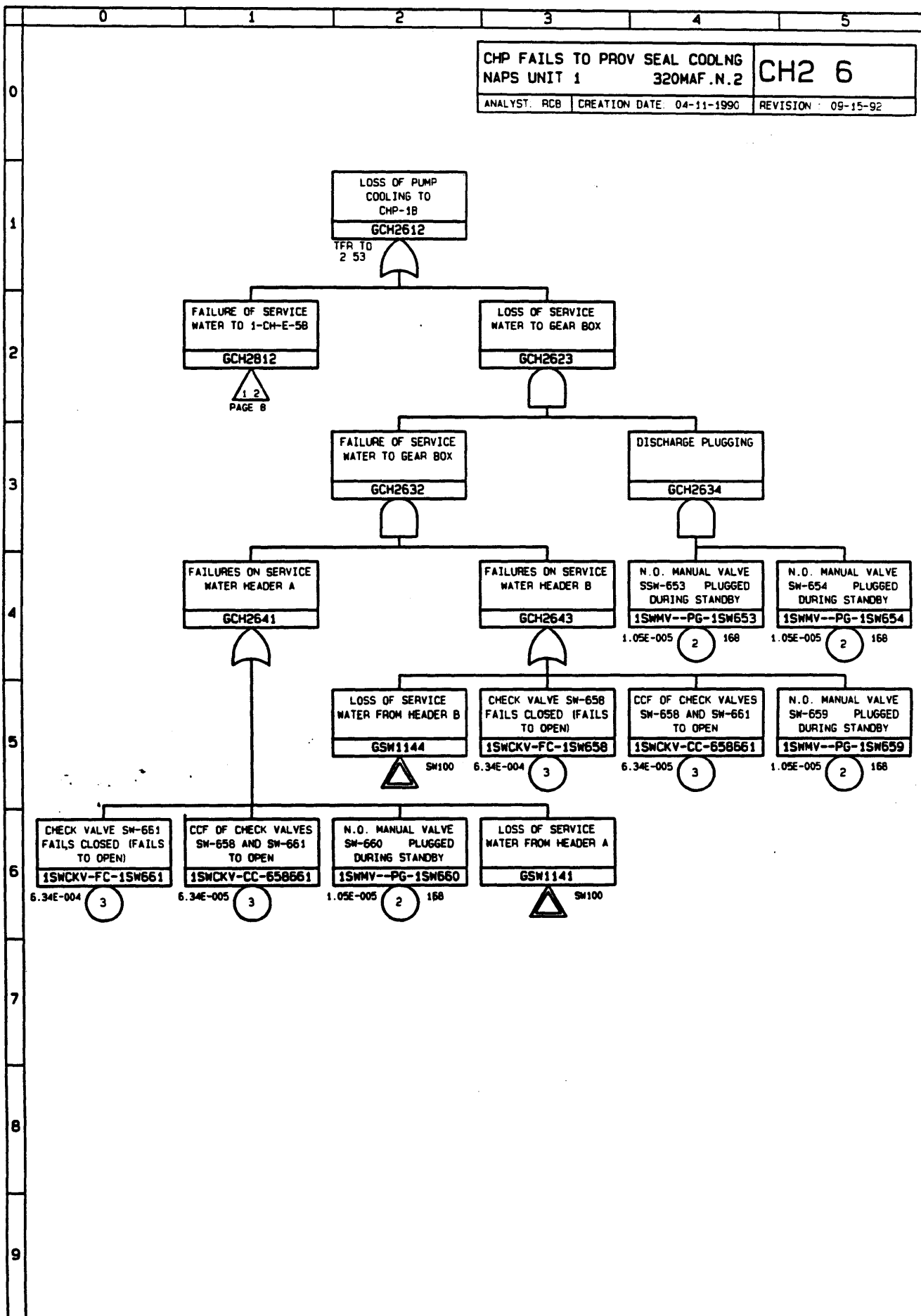
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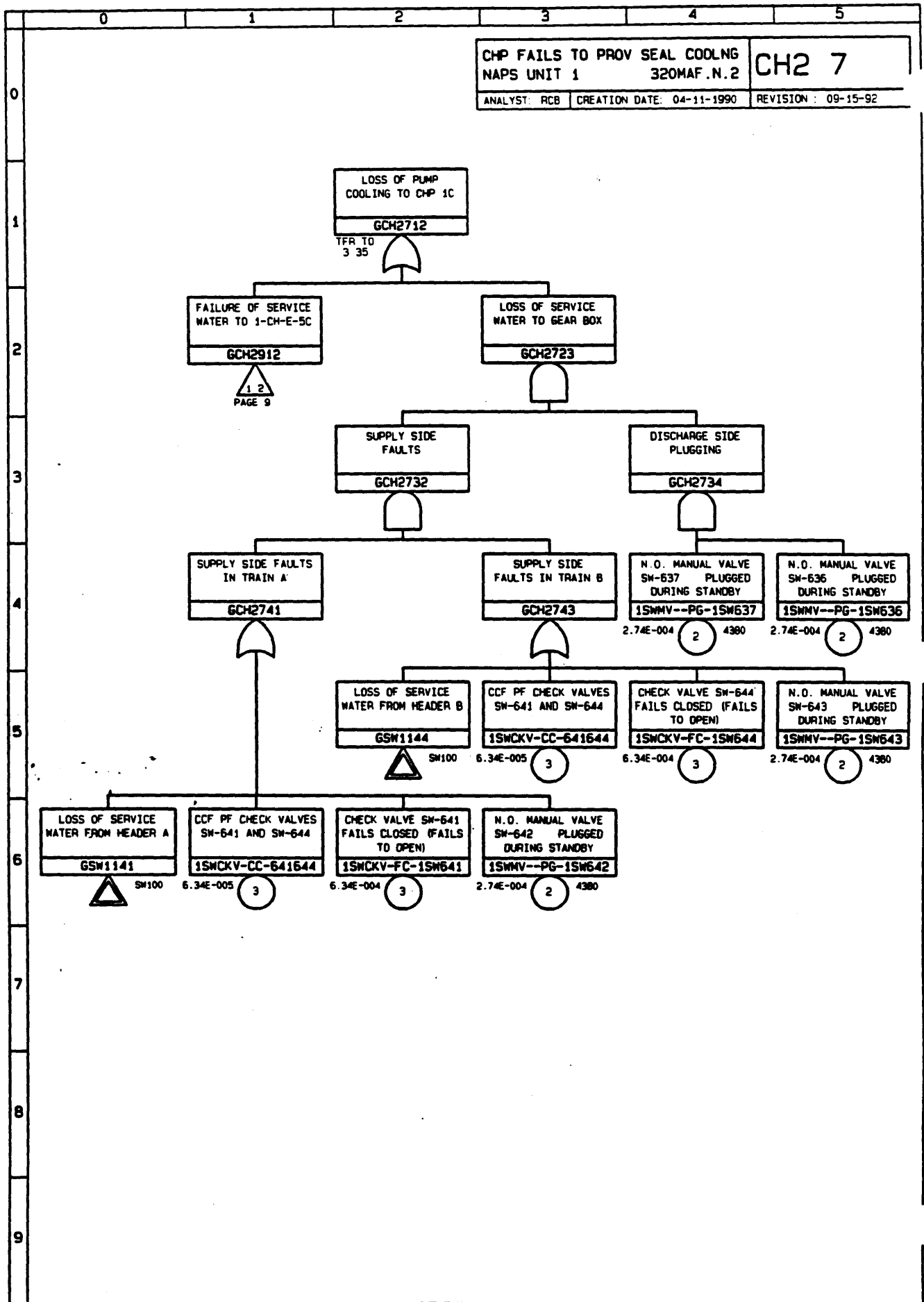
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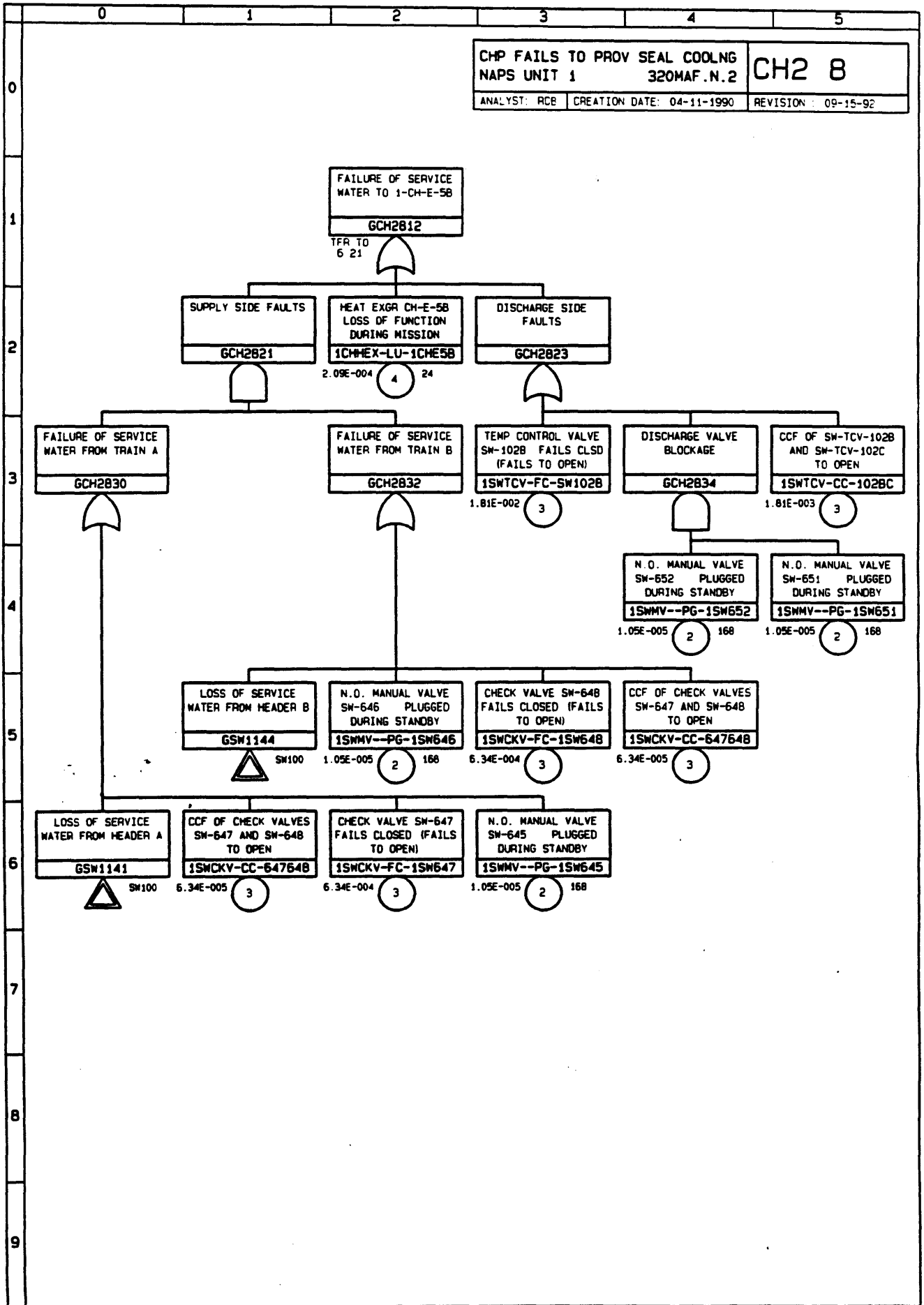


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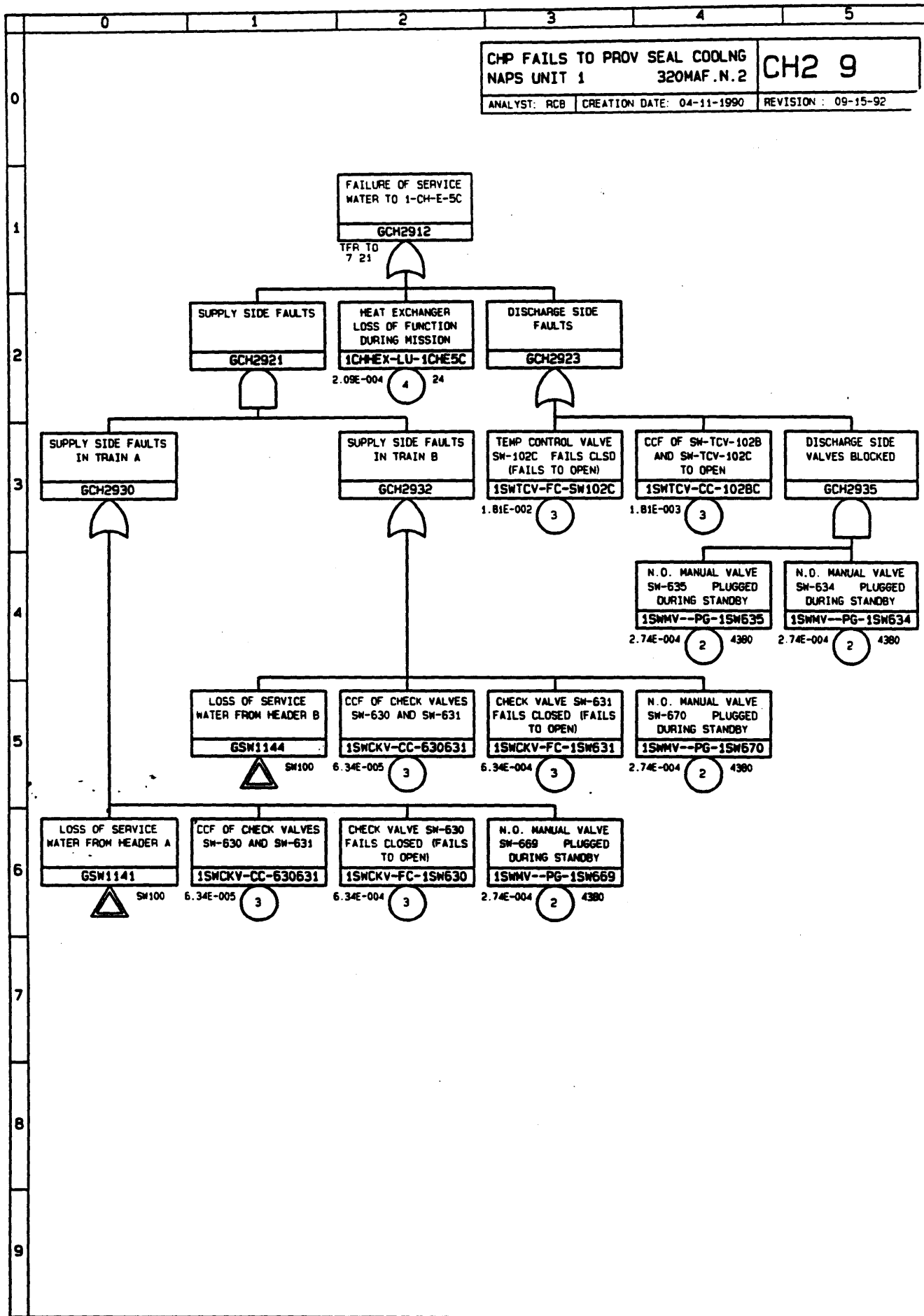


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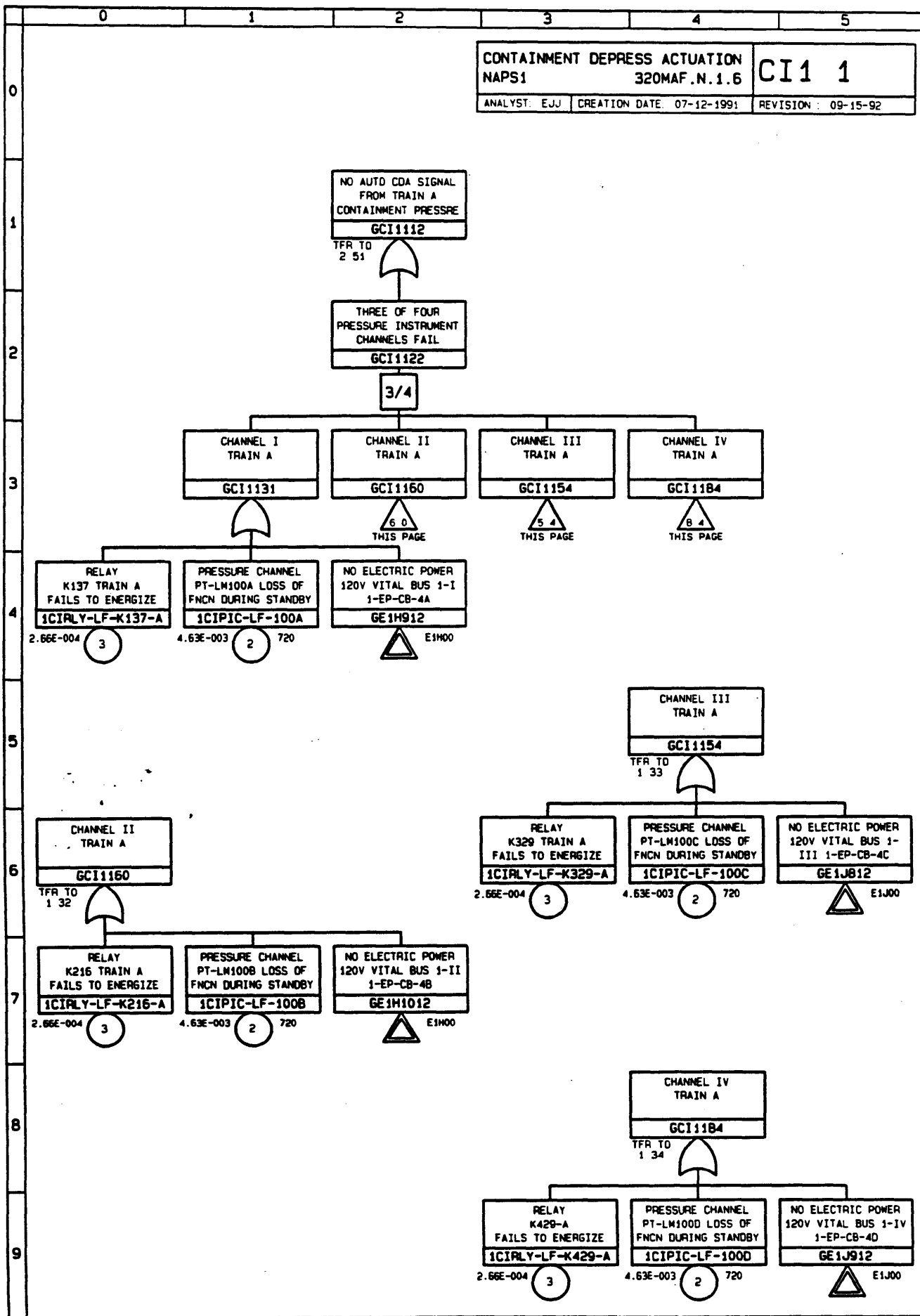


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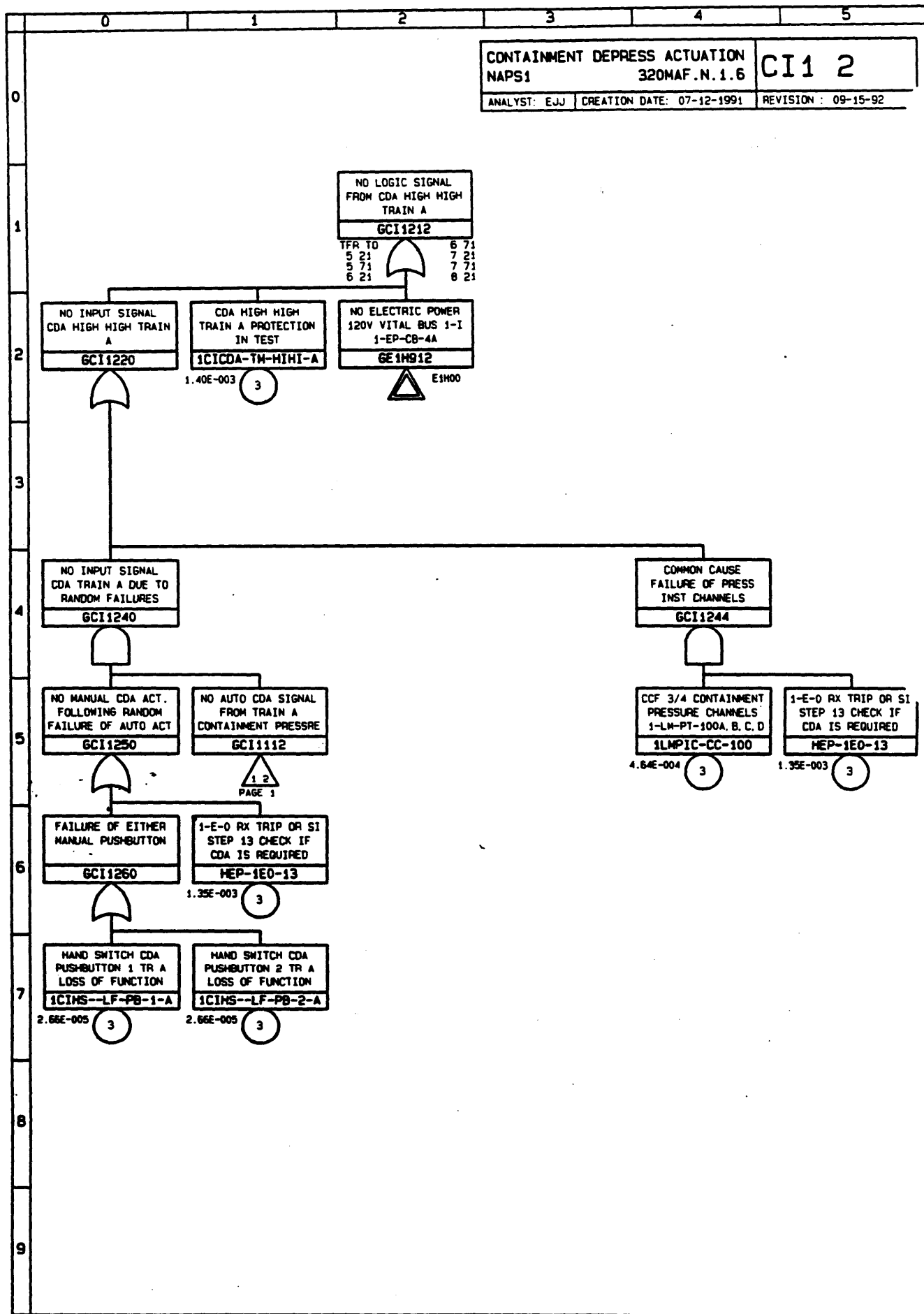


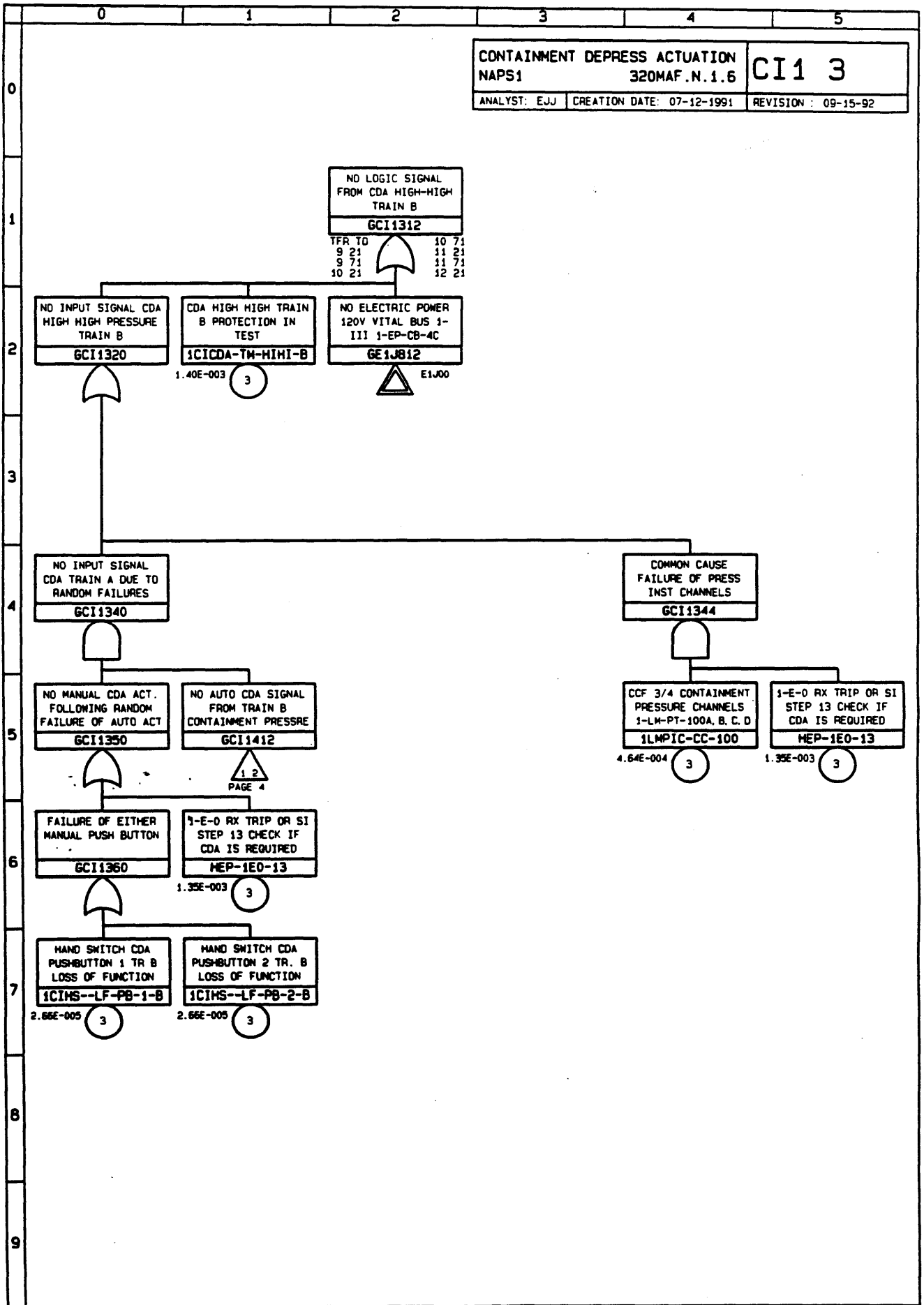


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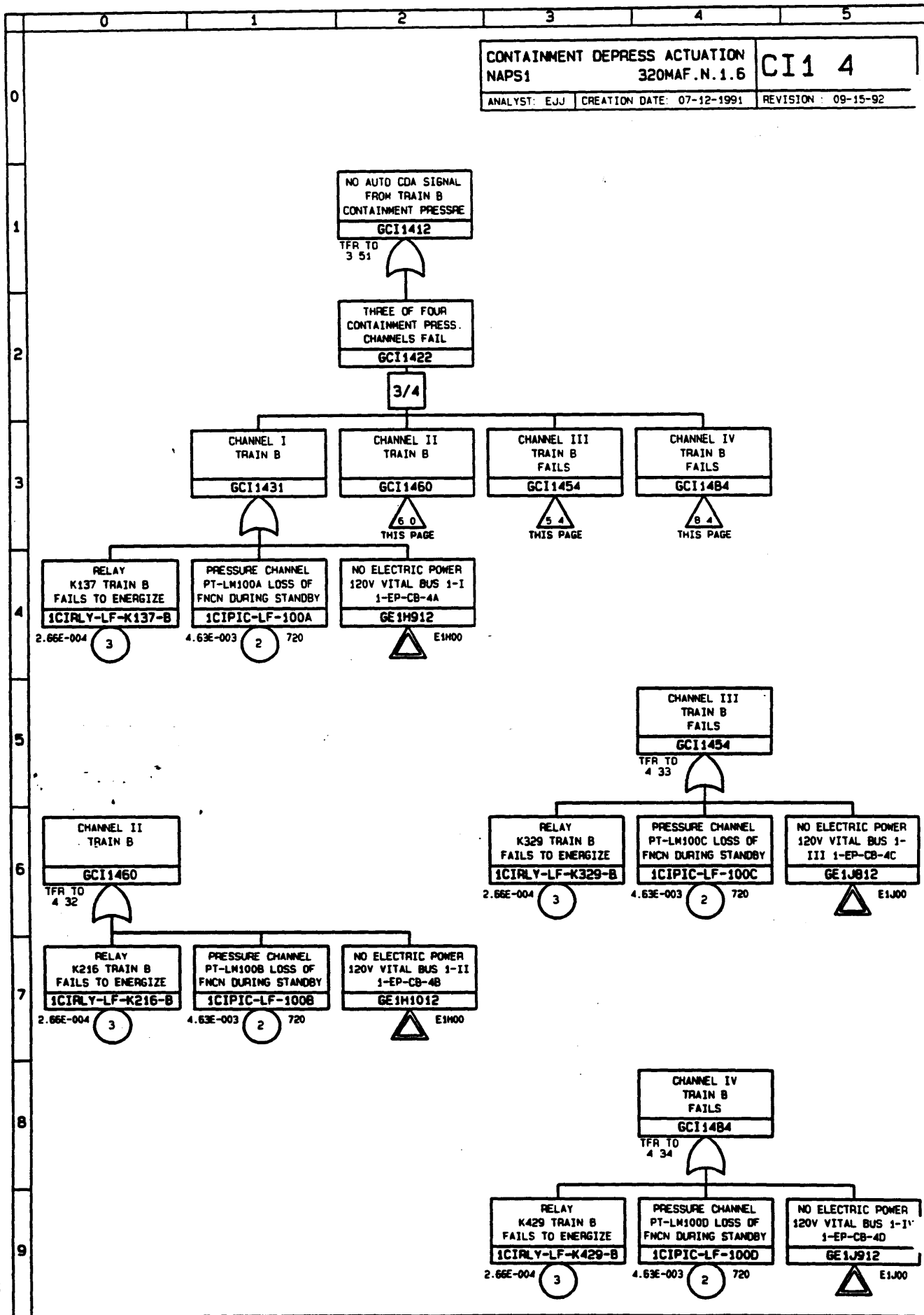


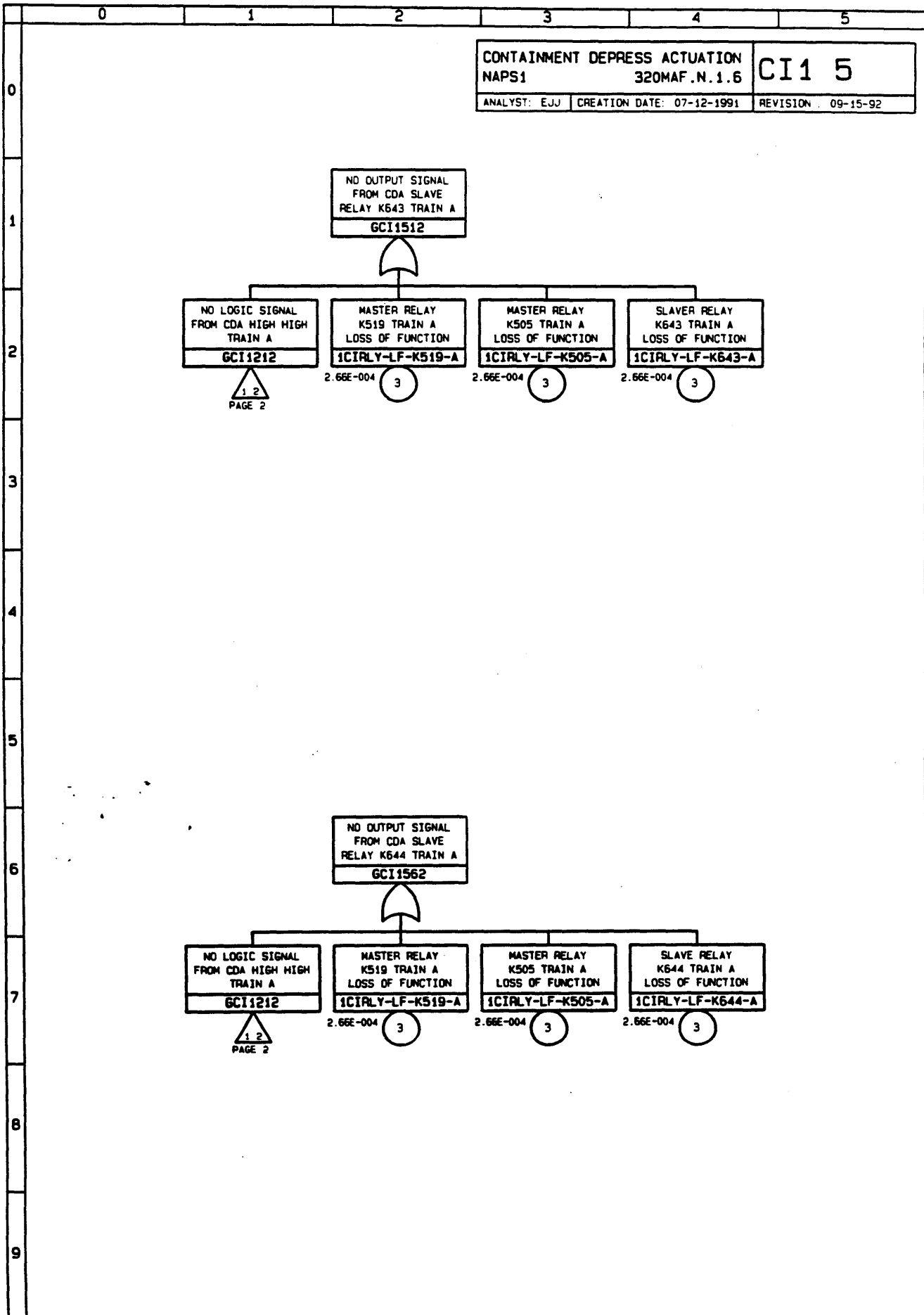
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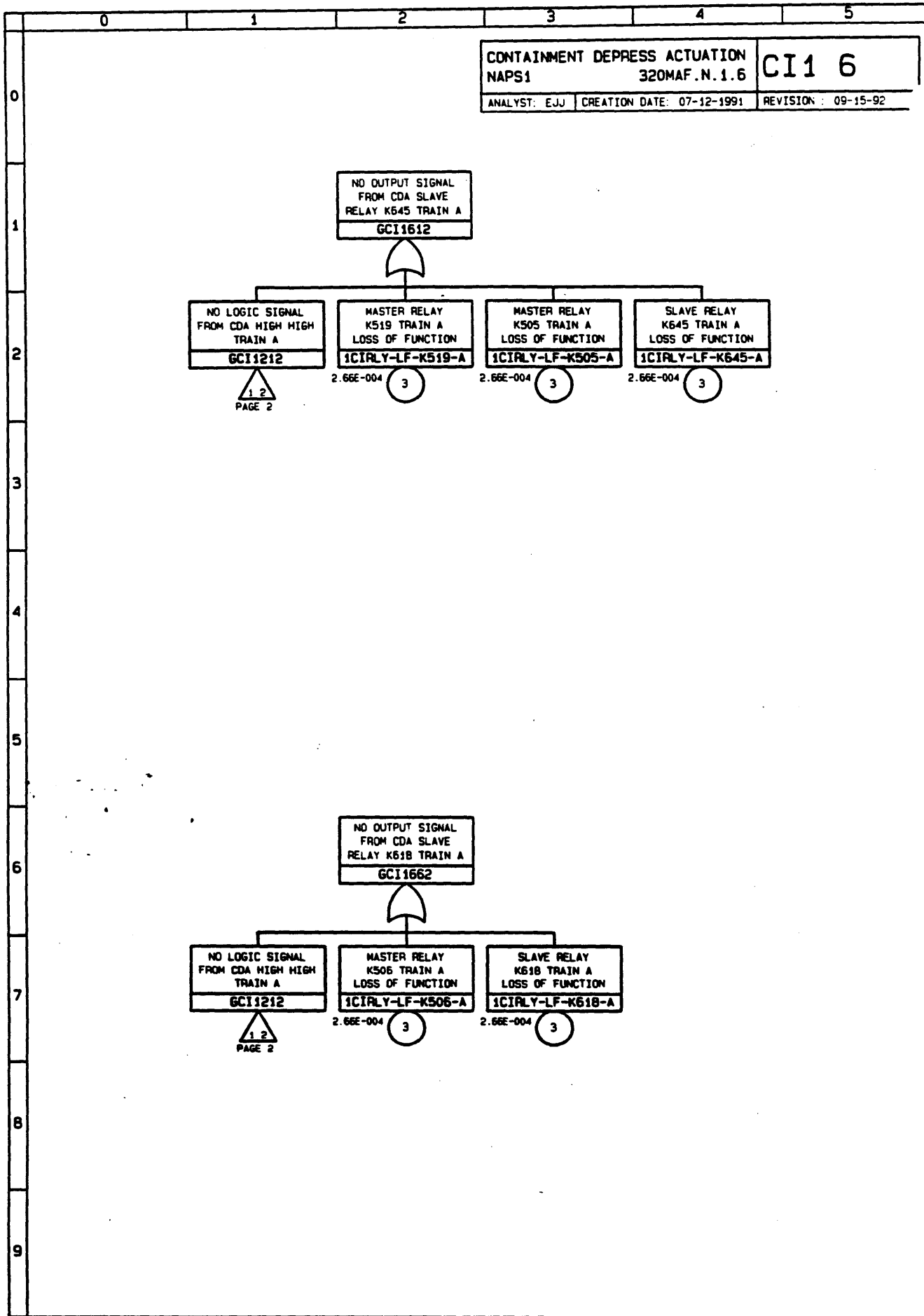


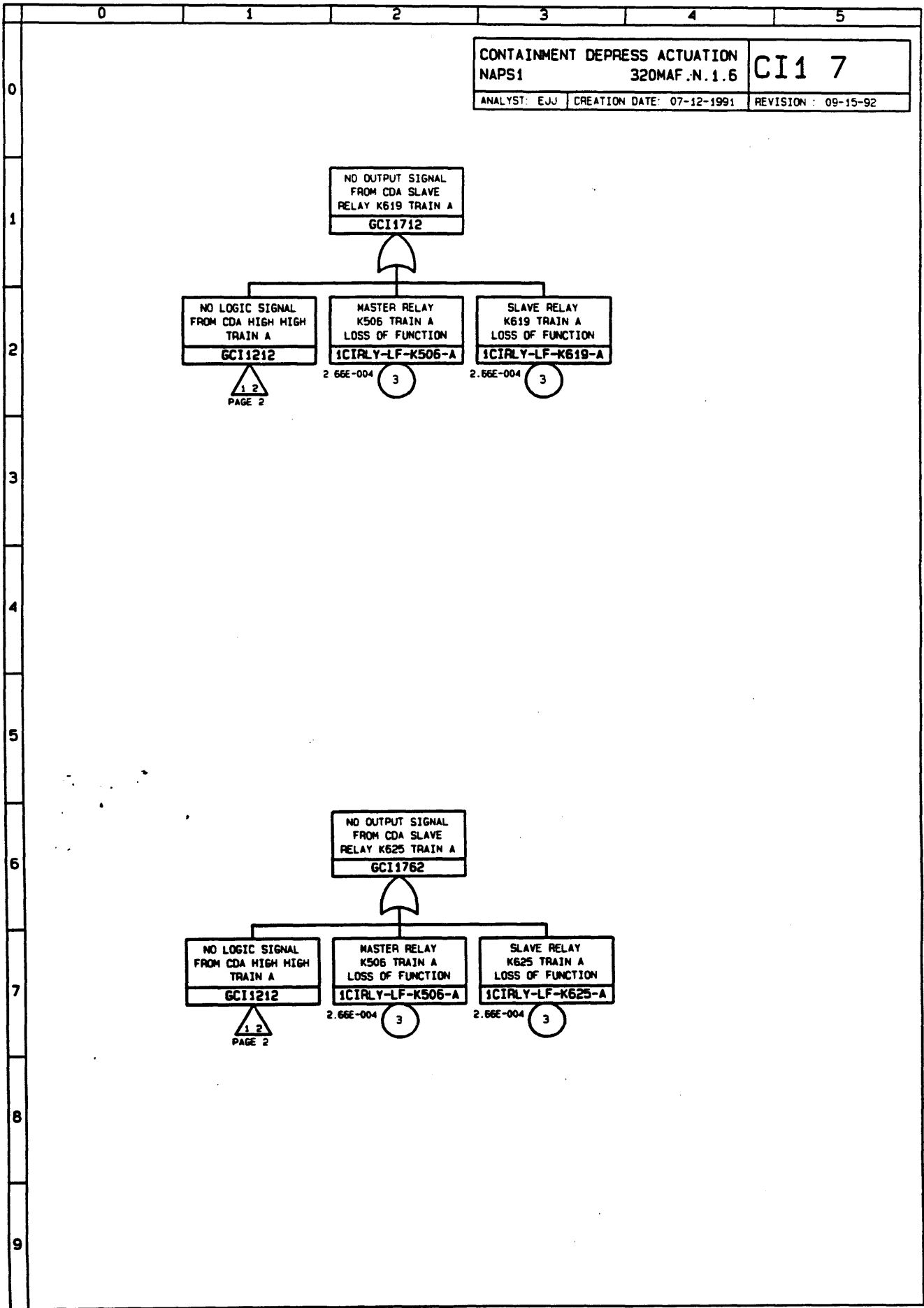
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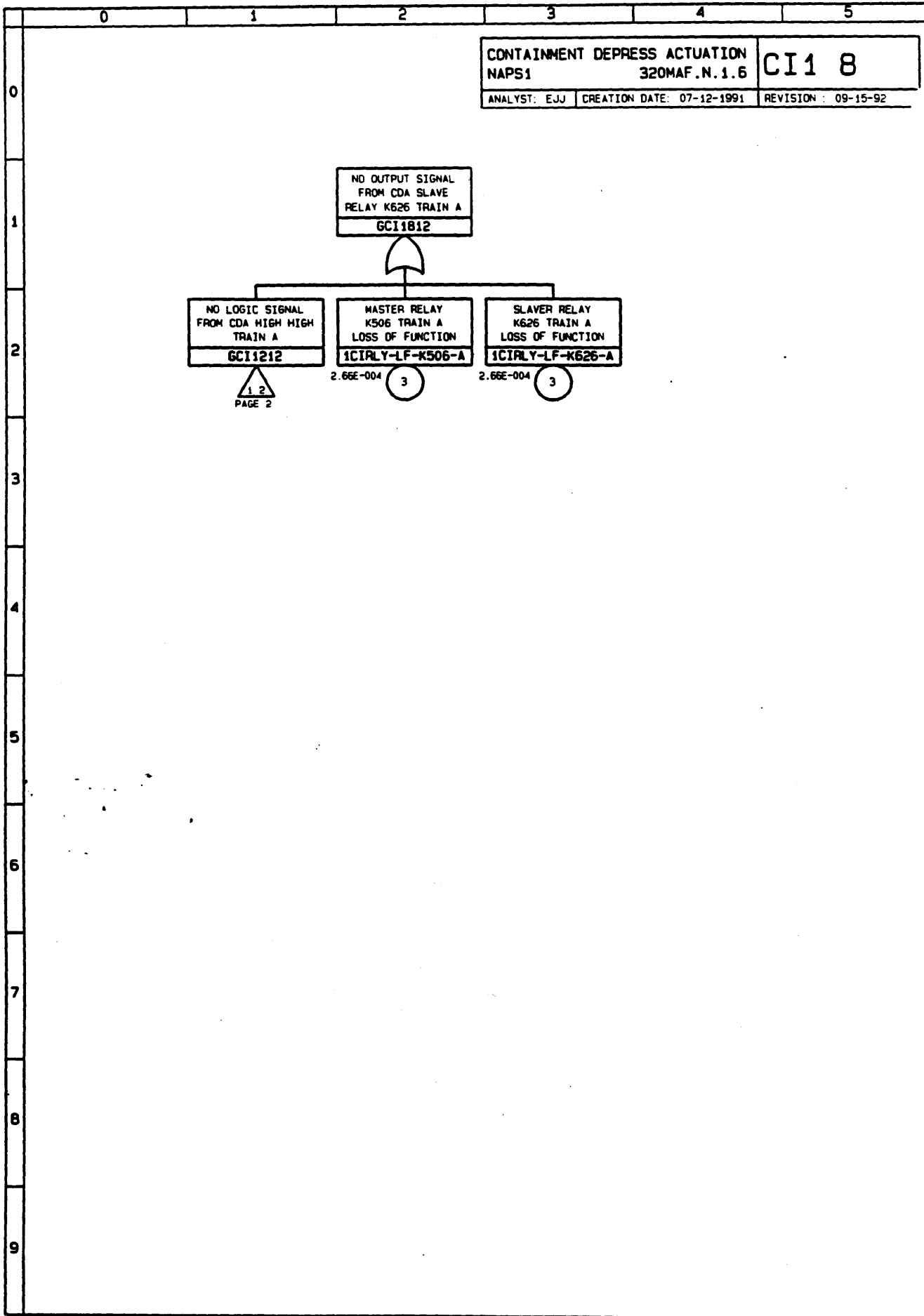
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CONTAINMENT DEPRESS ACTUATION		CI1 7
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ANALYST: EJJ	CREATION DATE: 07-12-1991	REVISION: 09-15-92

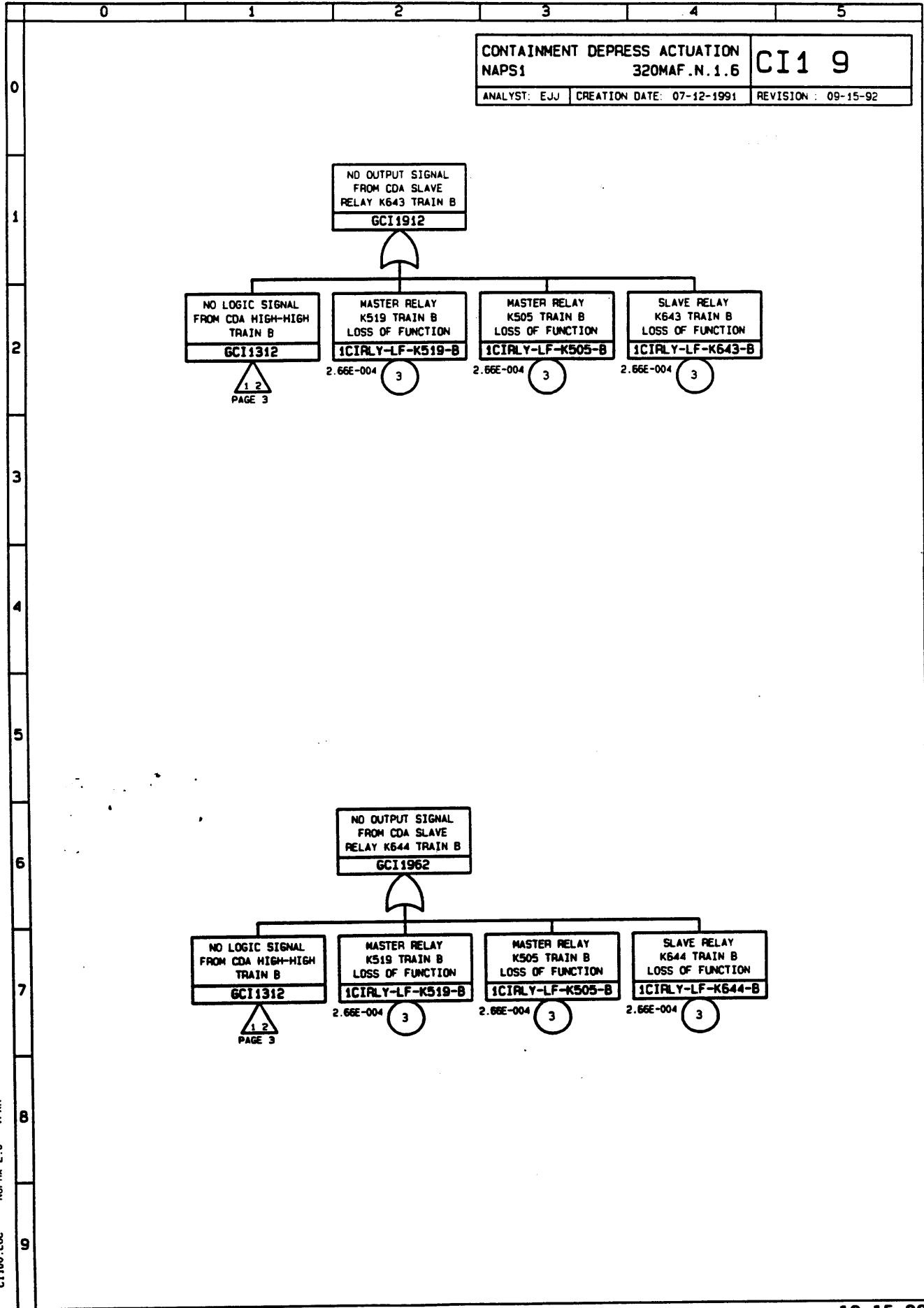
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VPWR

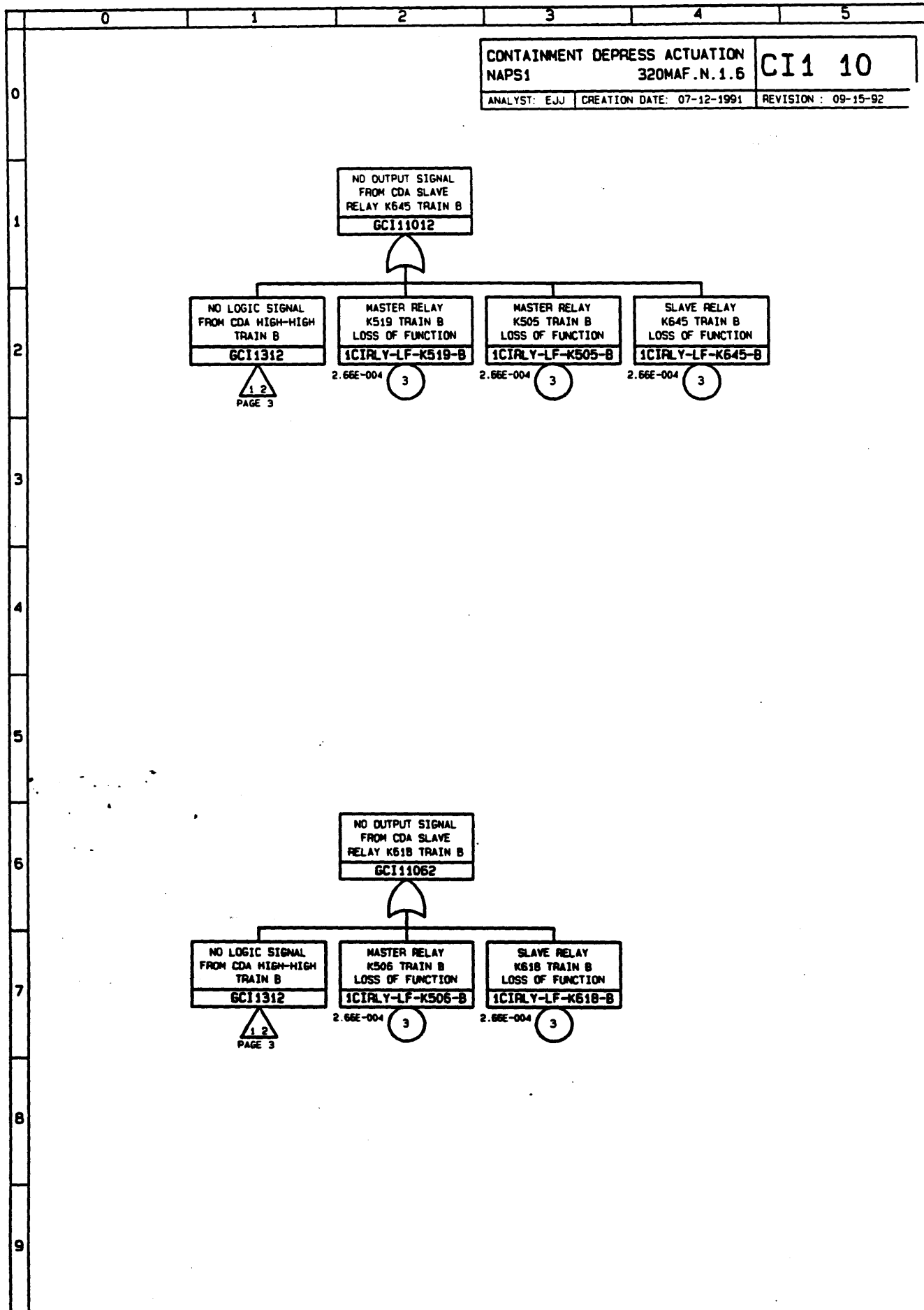


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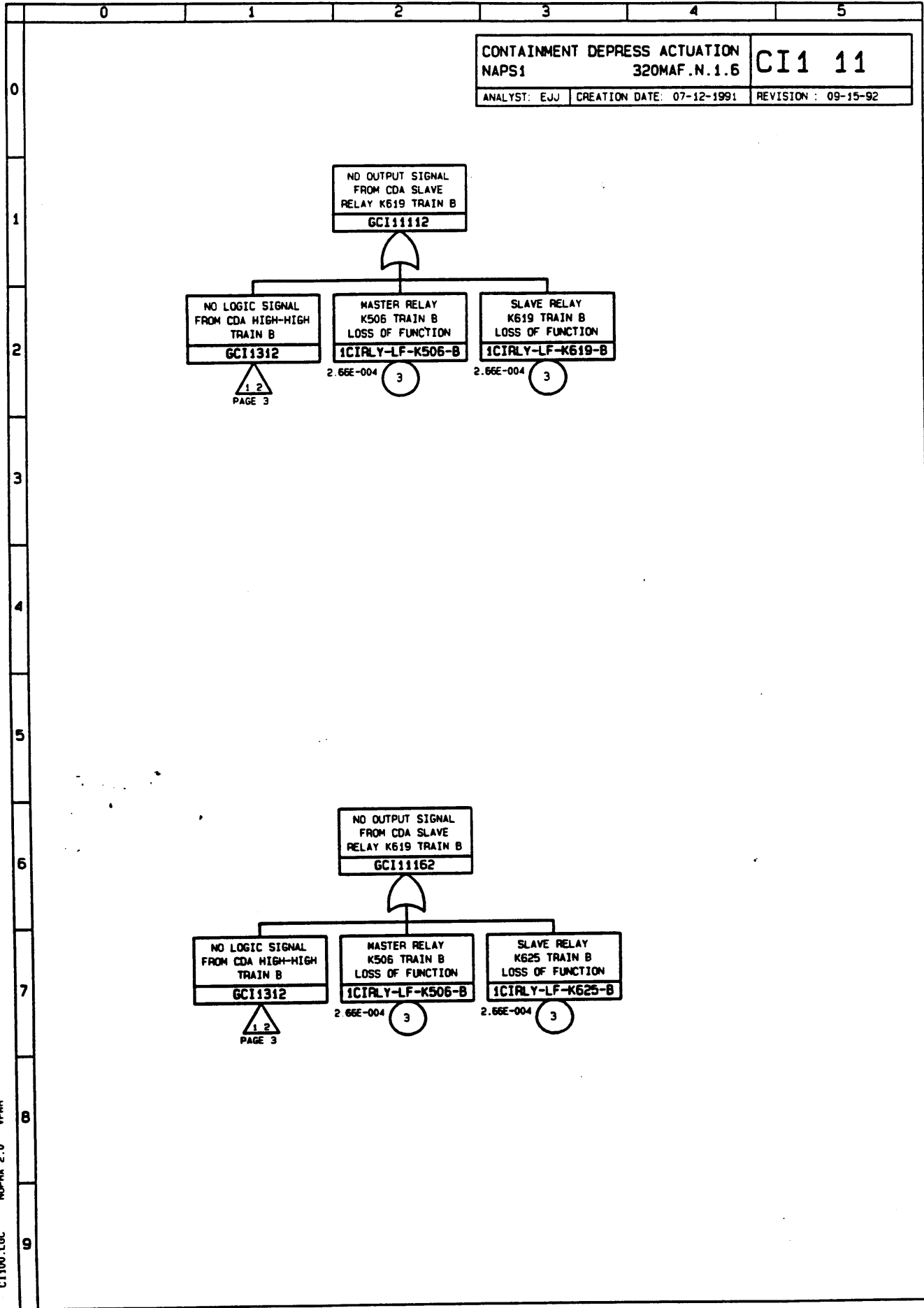
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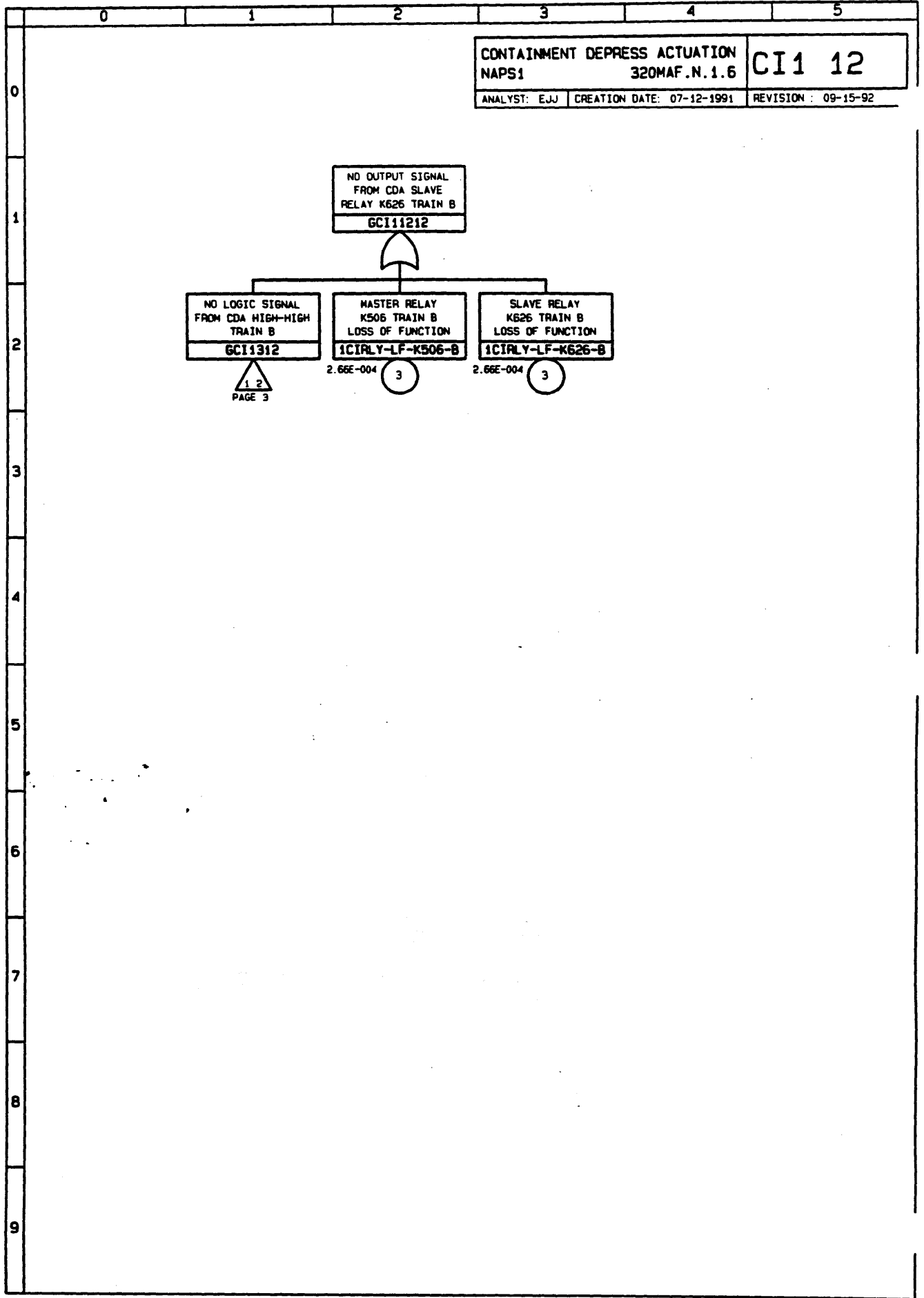
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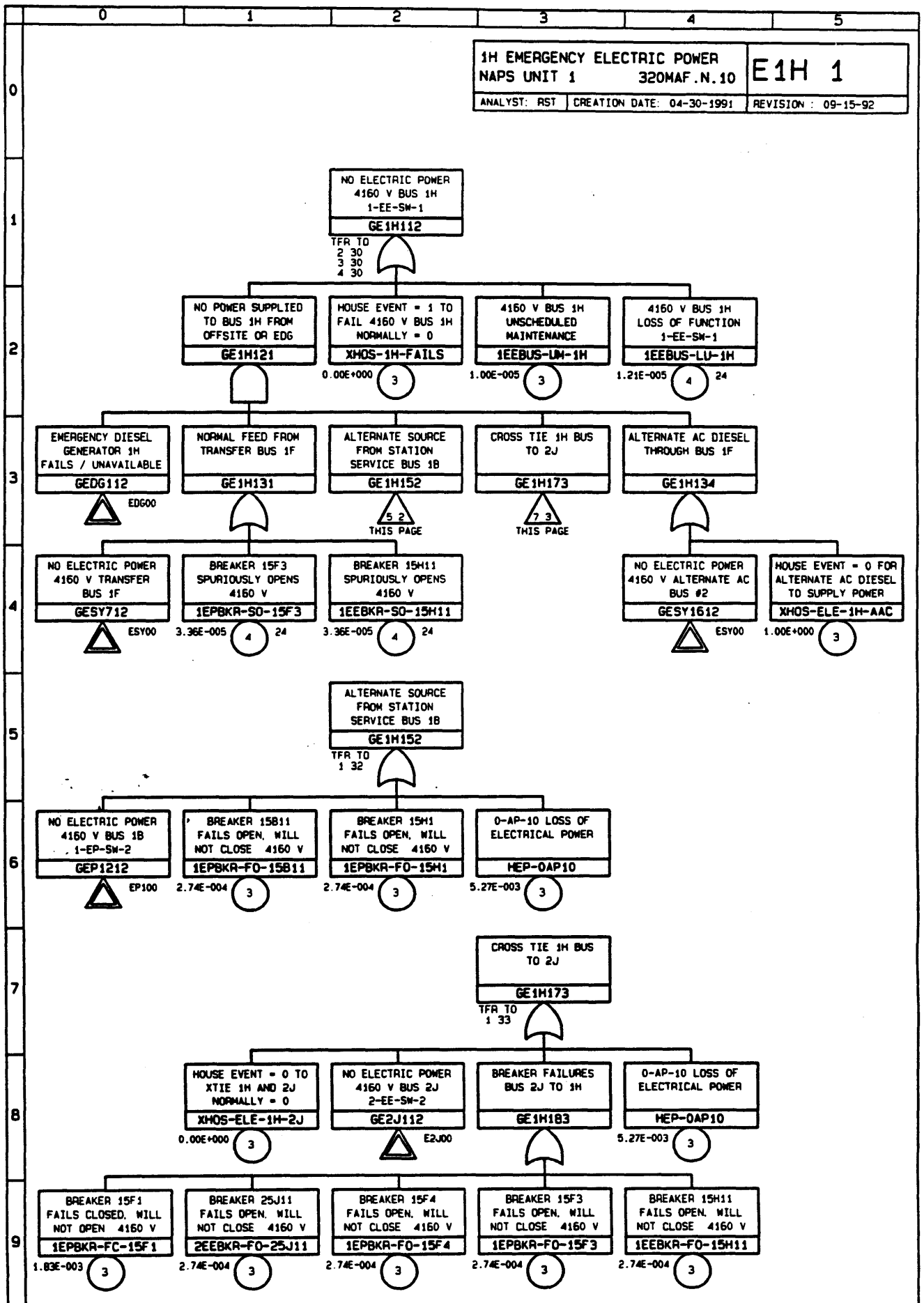


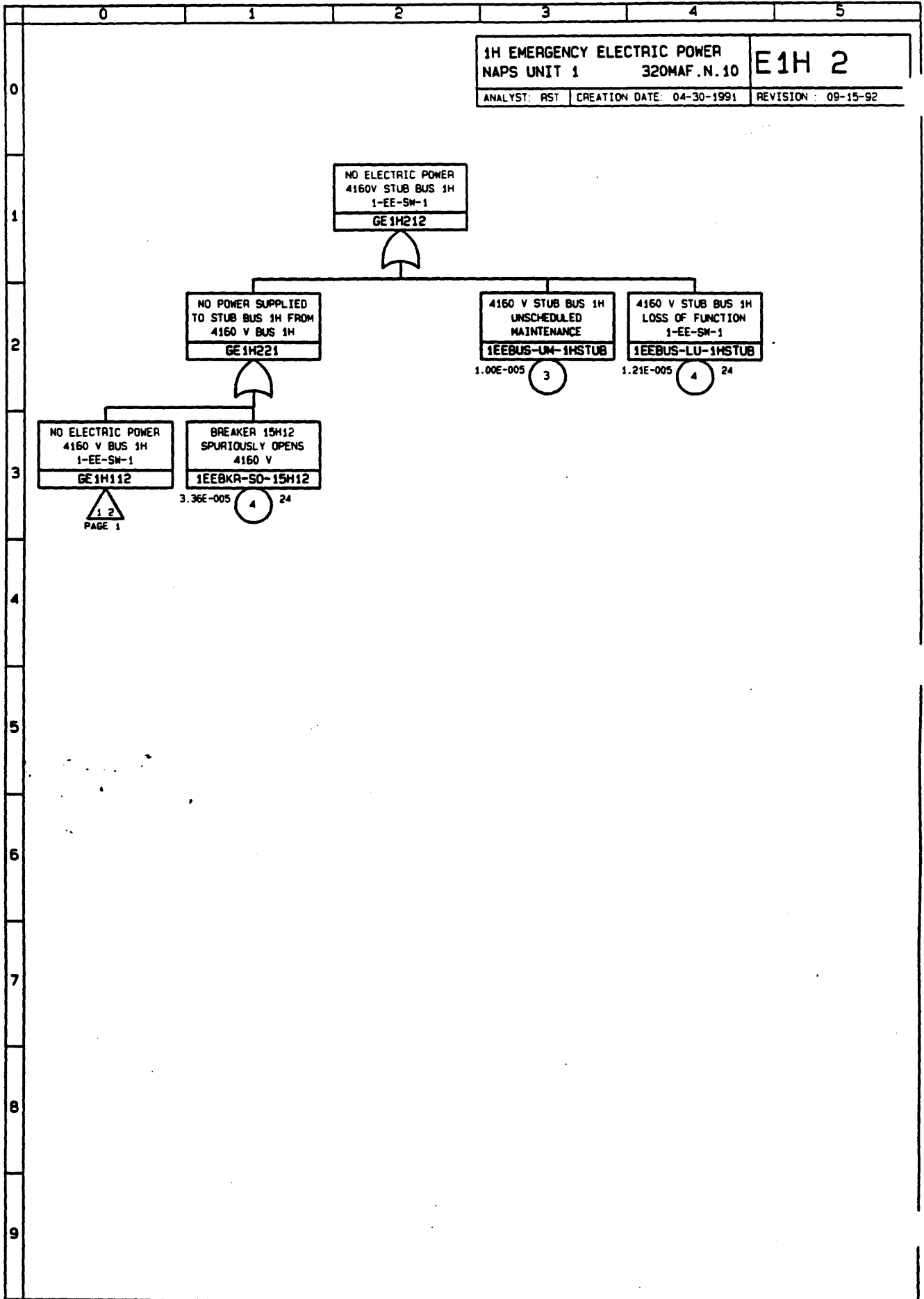
CONTAINMENT DEPRESS ACTUATION		CI1 11
NAPS1	320MAF.N.1.6	
ANALYST: EJJ	CREATION DATE: 07-12-1991	REVISION : 09-15-92

C1100 LGC NUPRA 2.0 VPMR

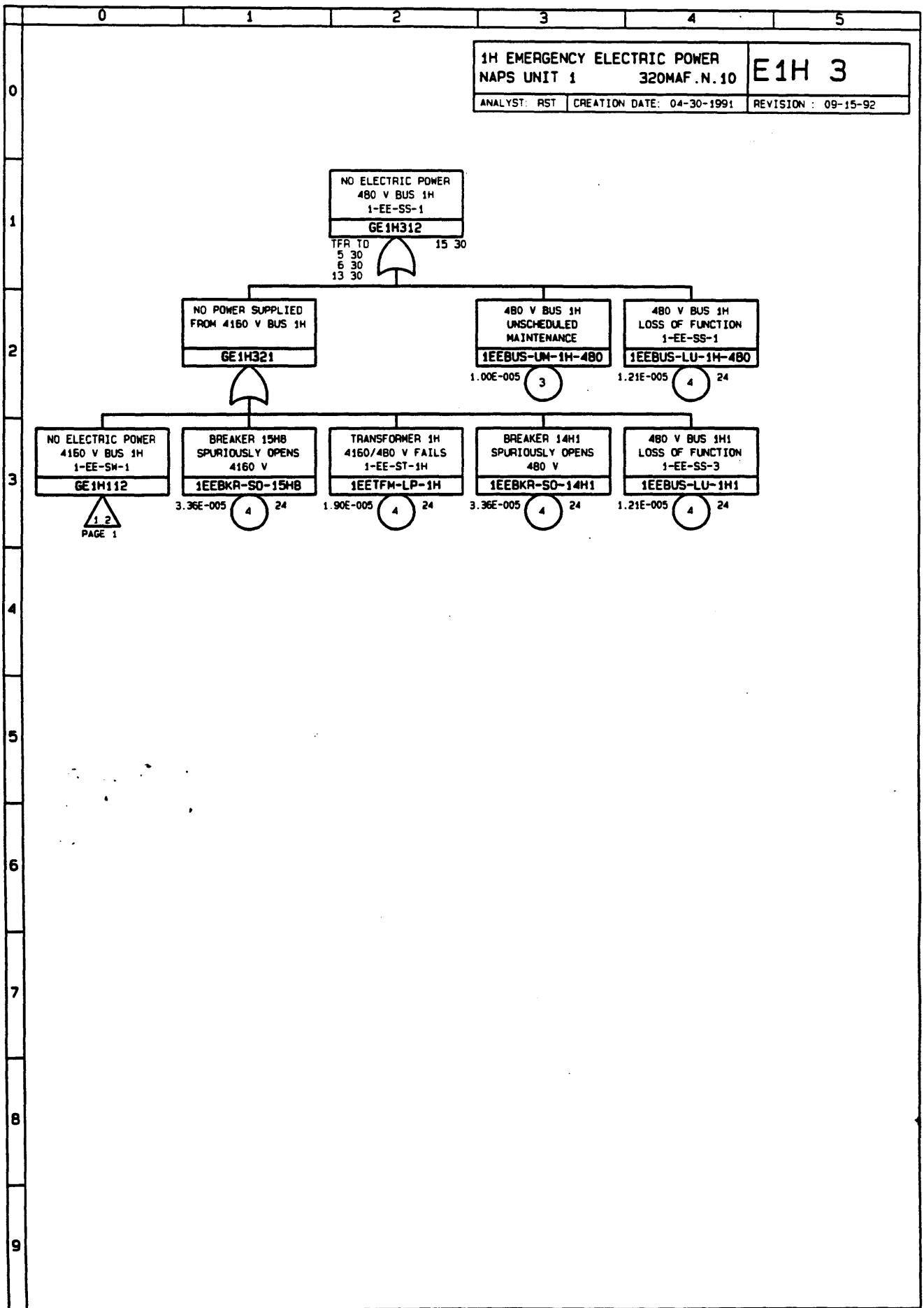


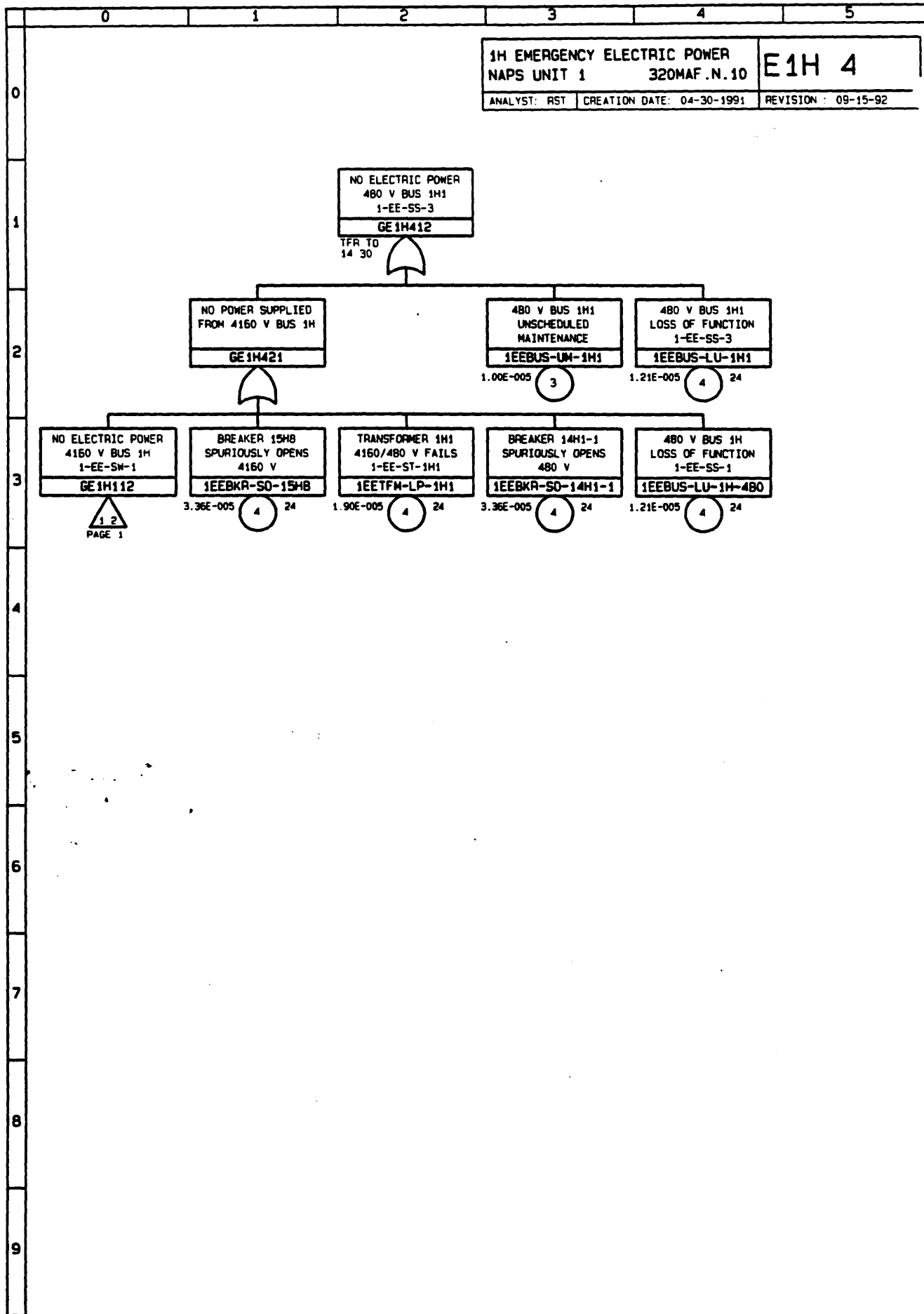
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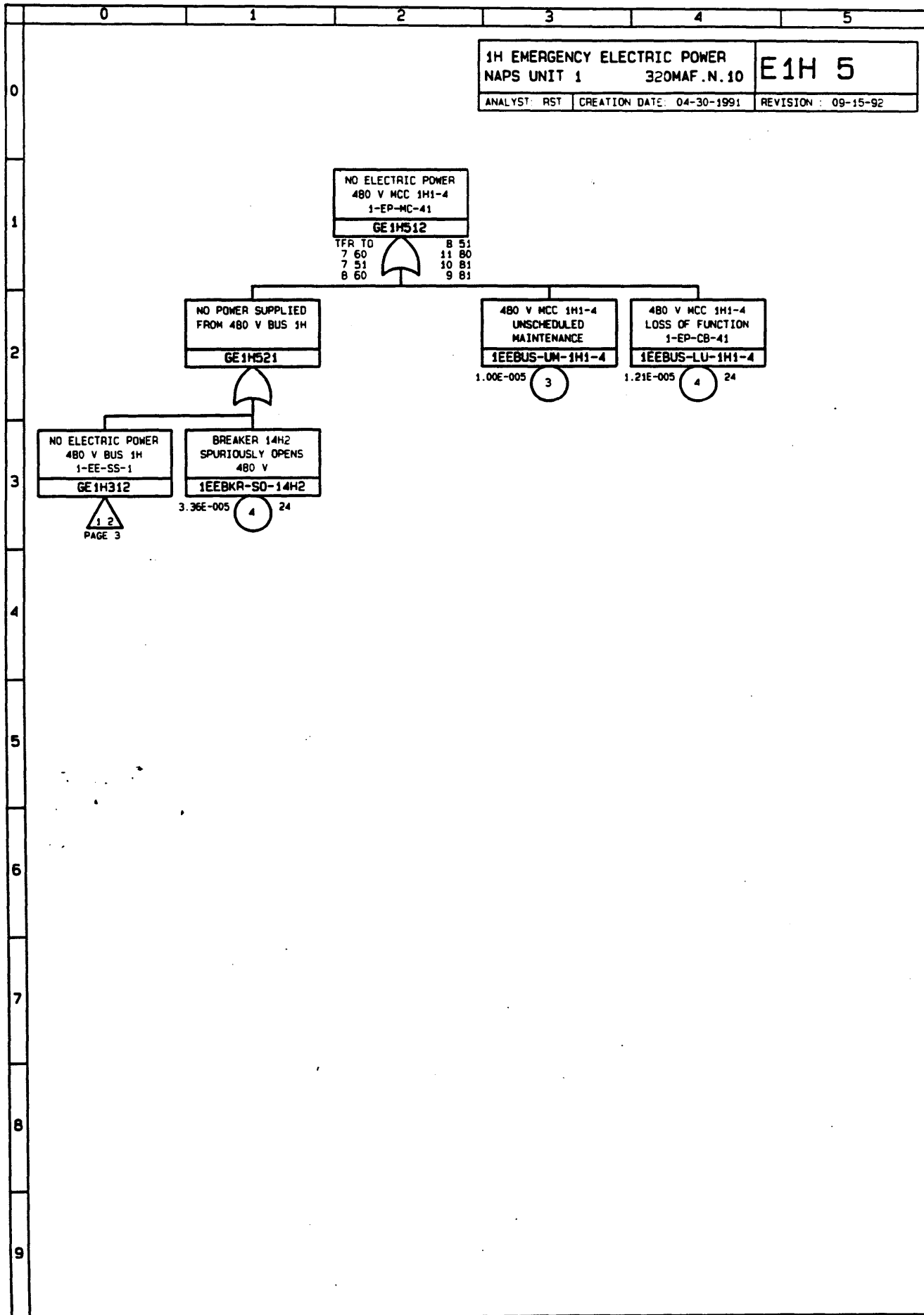
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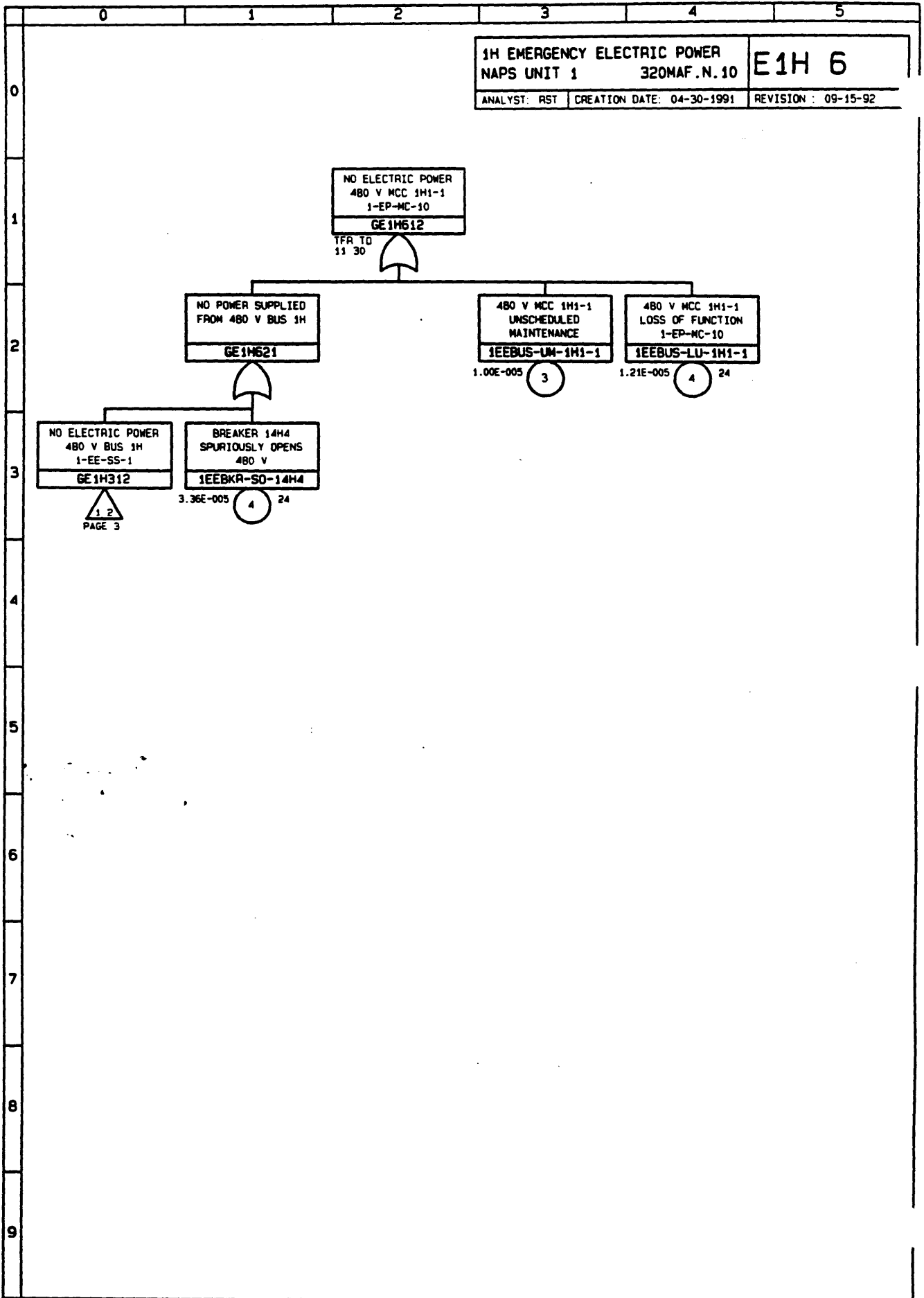
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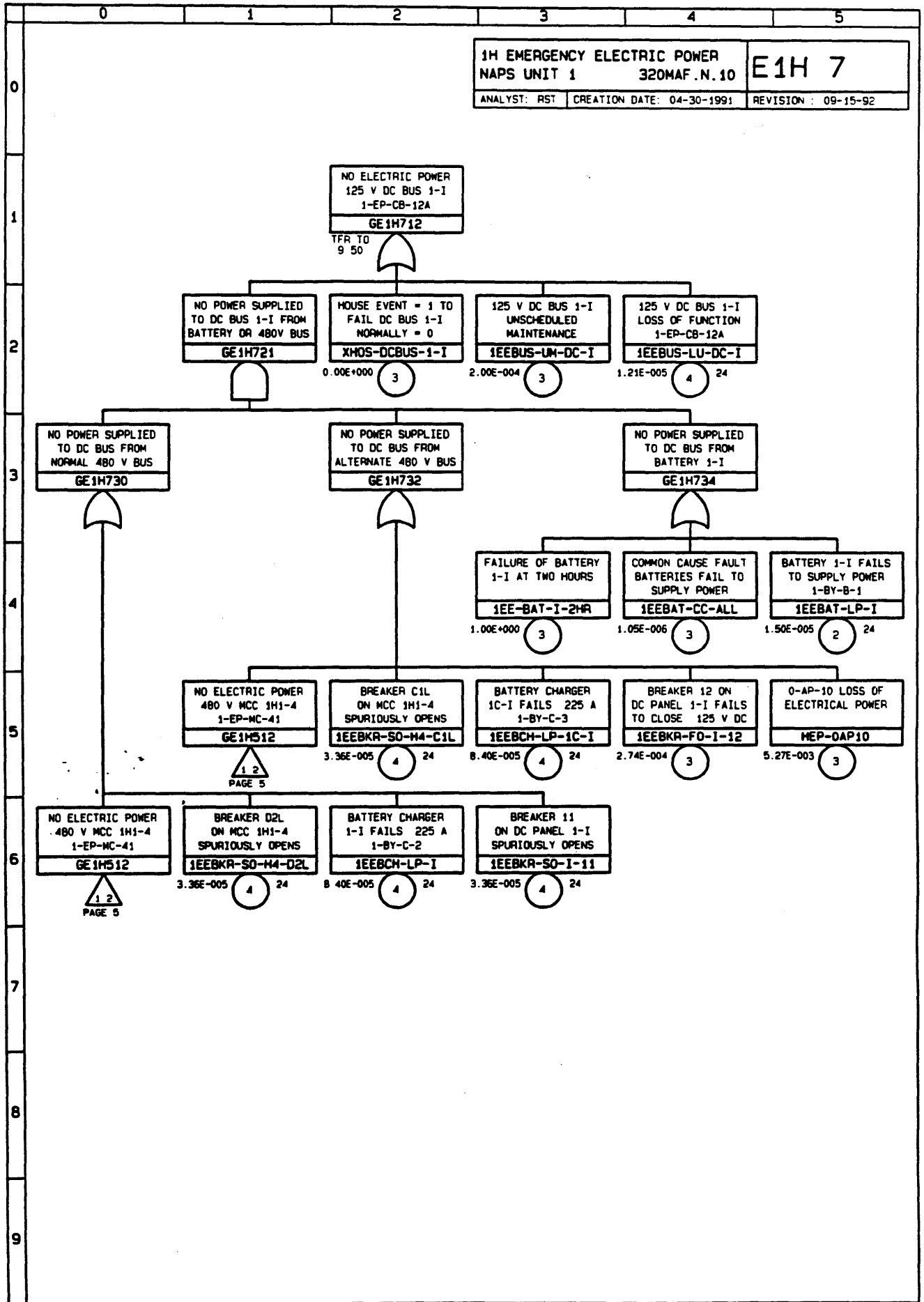


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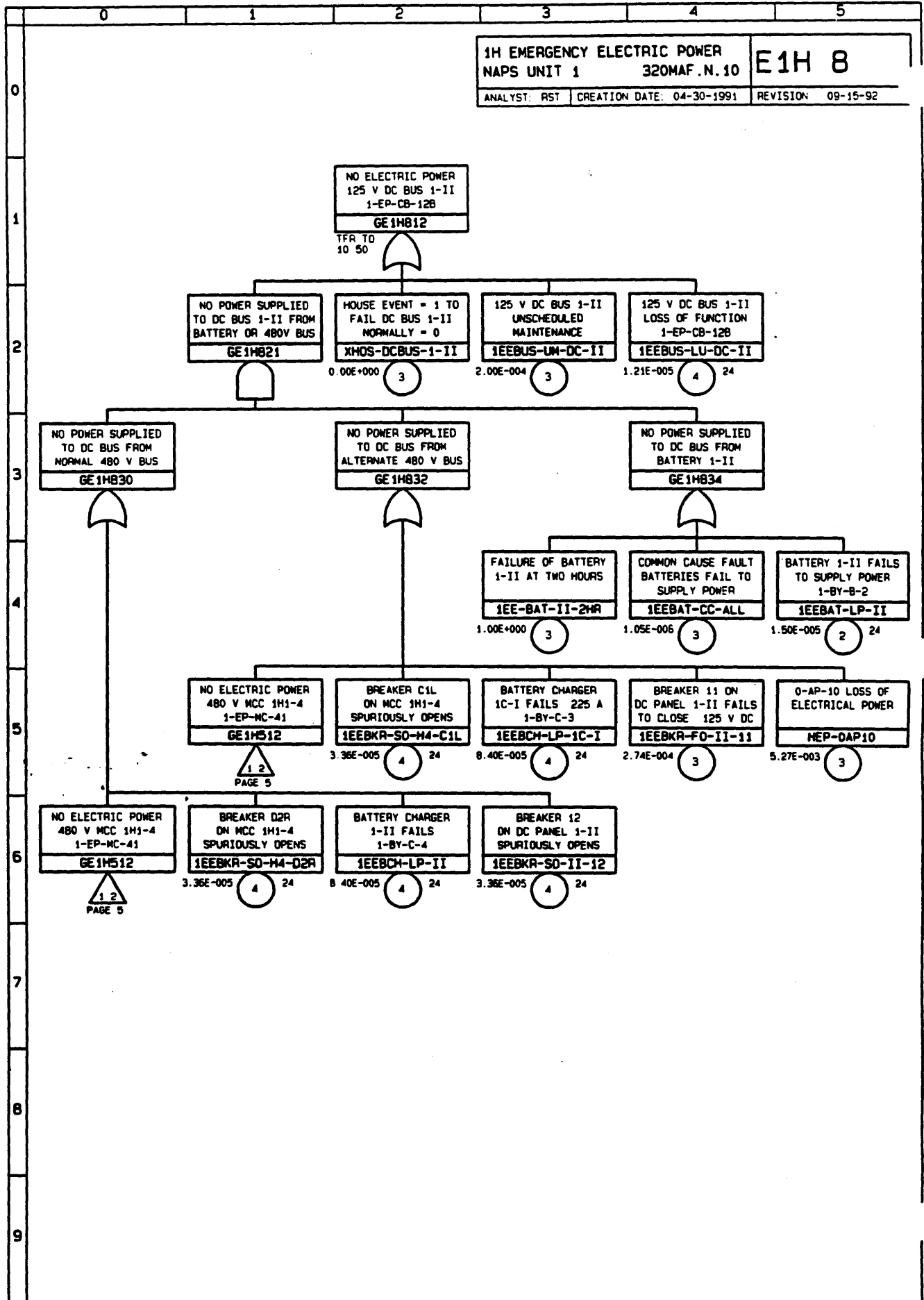
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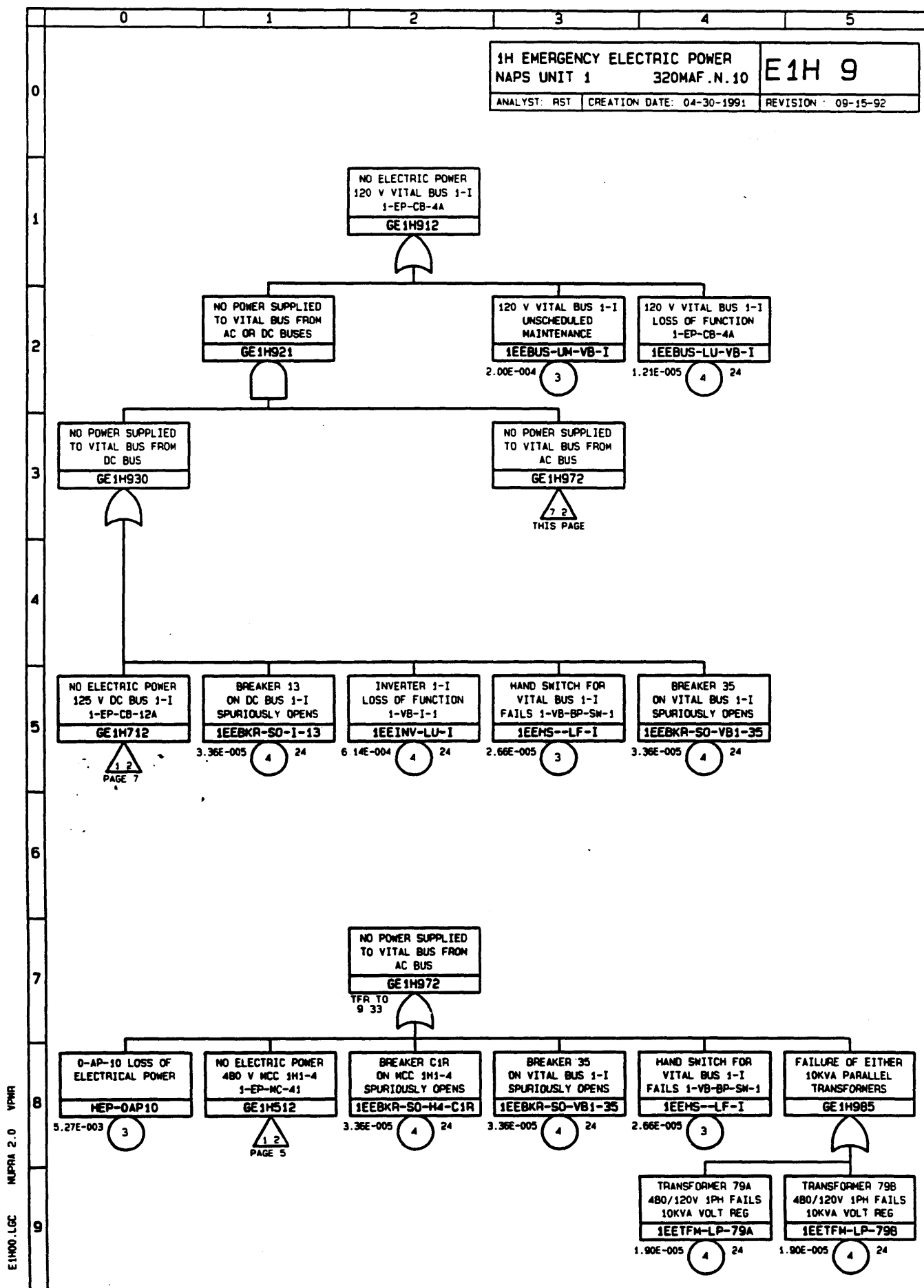


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E1H00.LGC NUPRA 2.0 VPMR

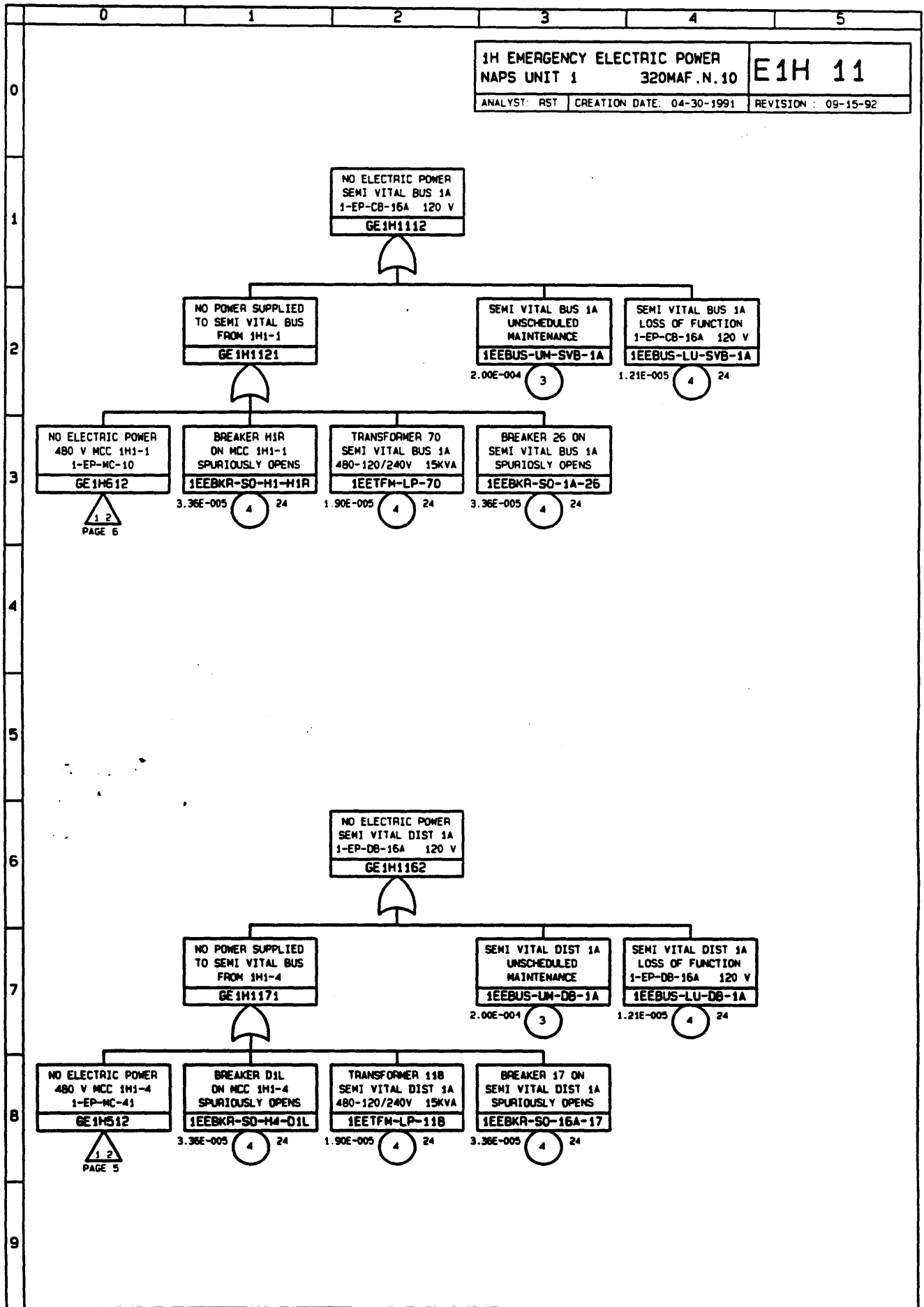


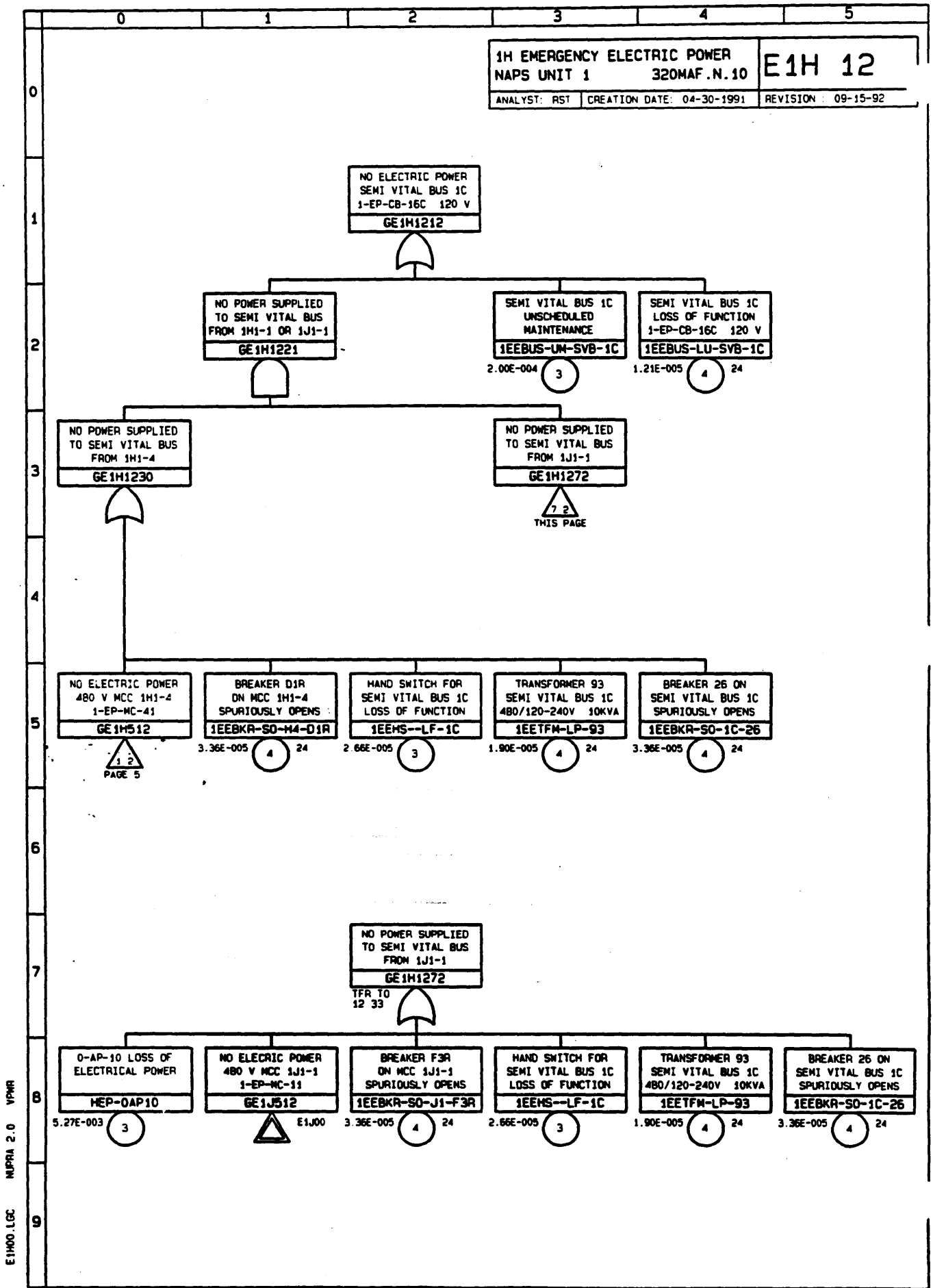


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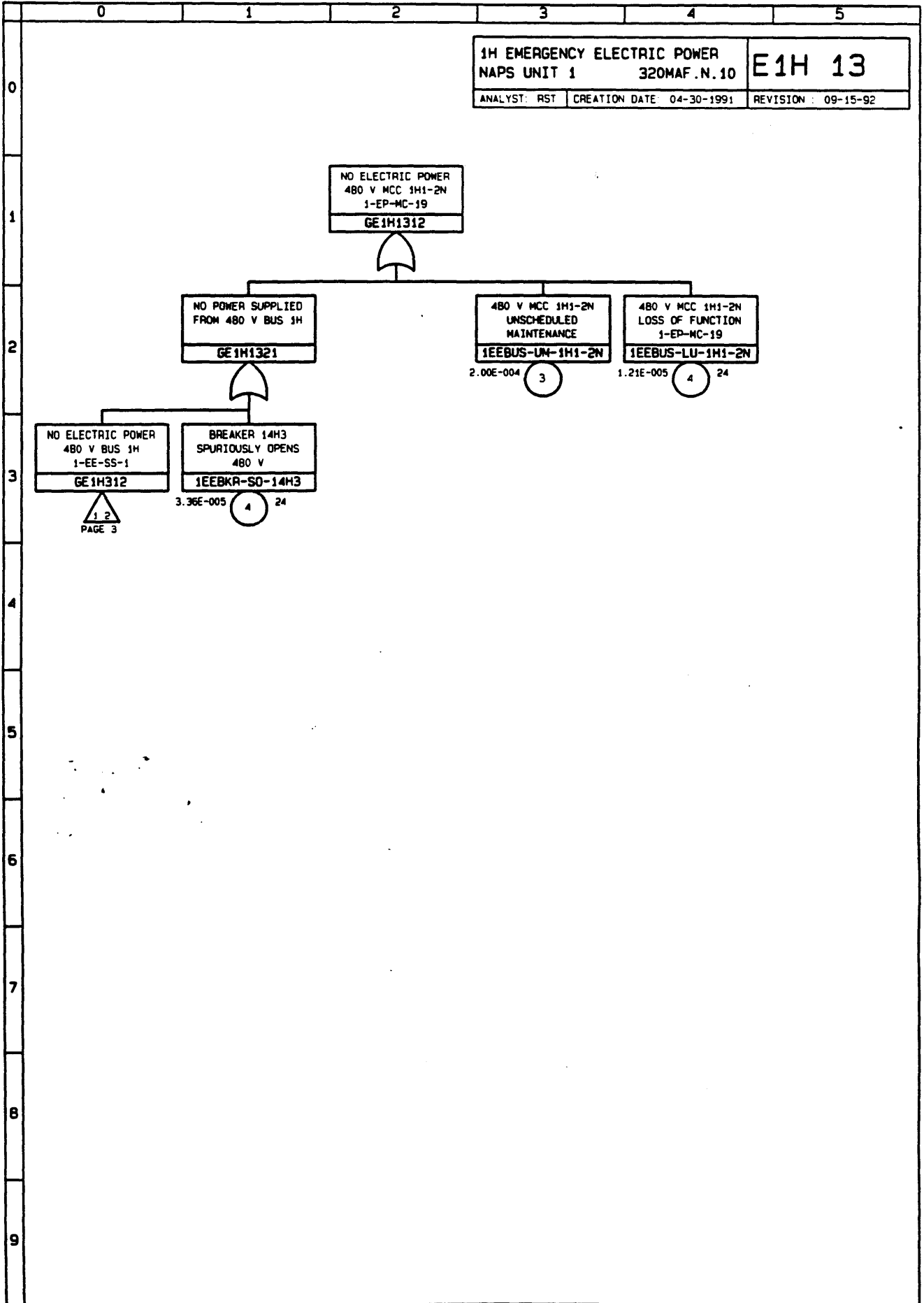
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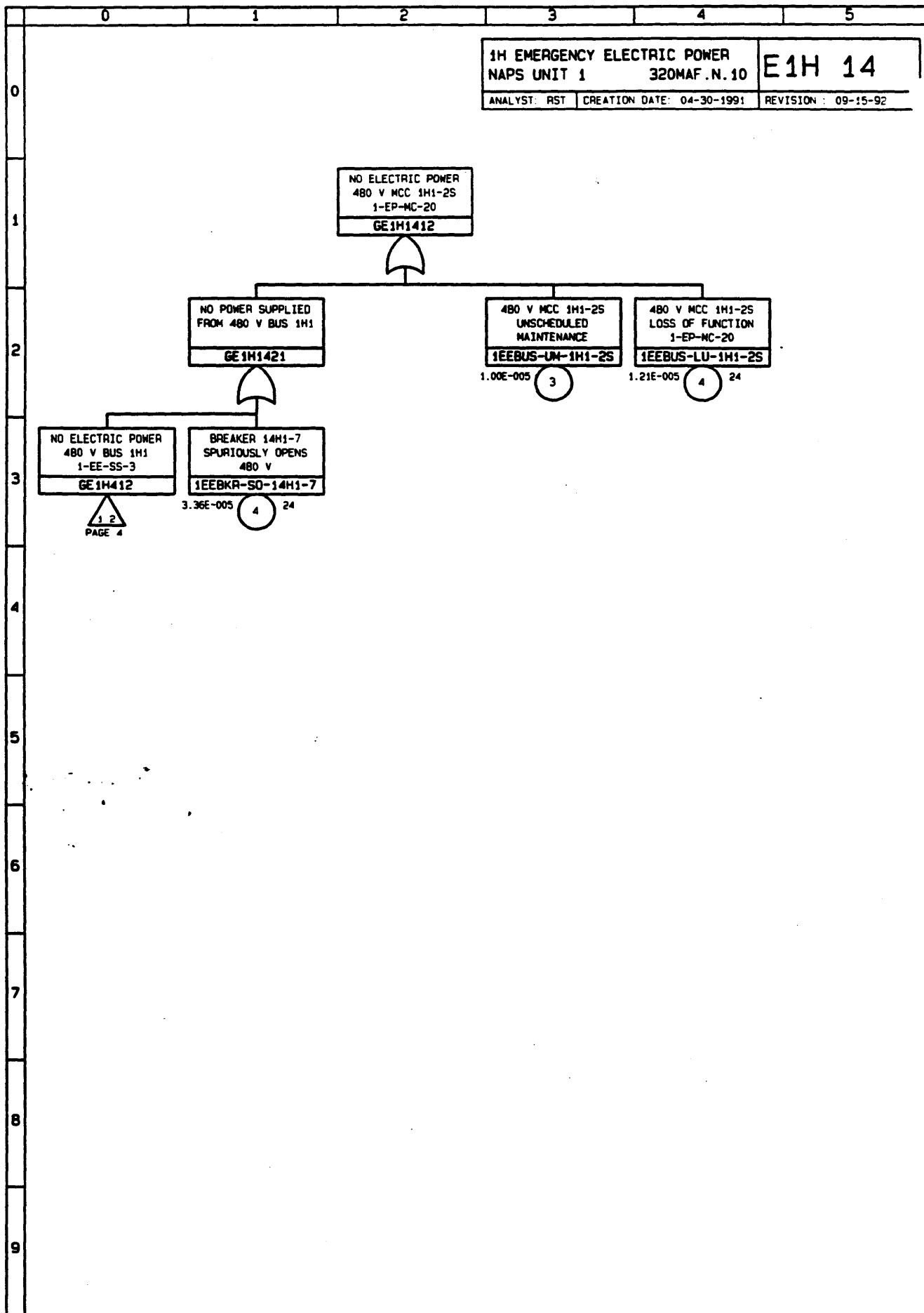




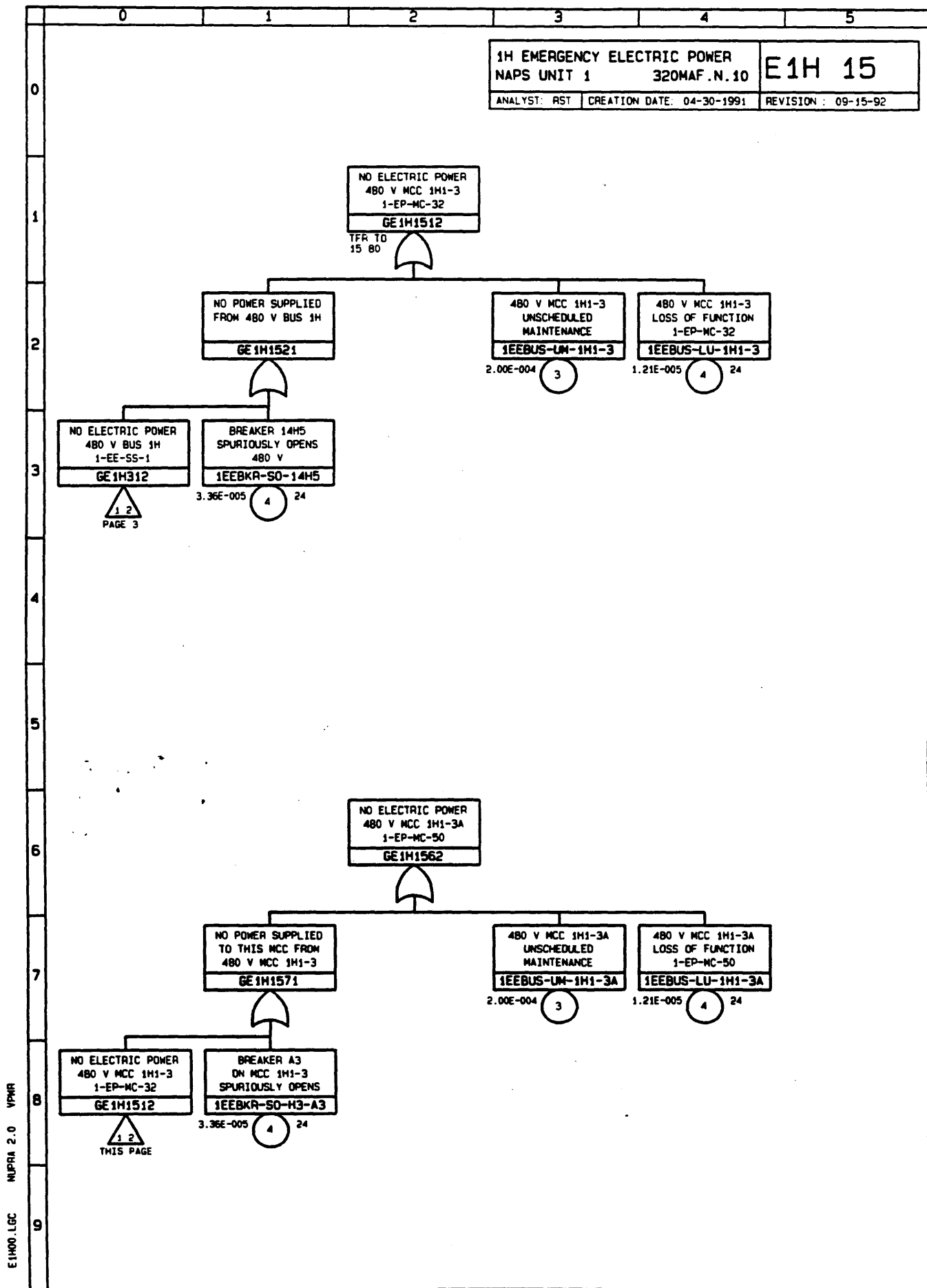
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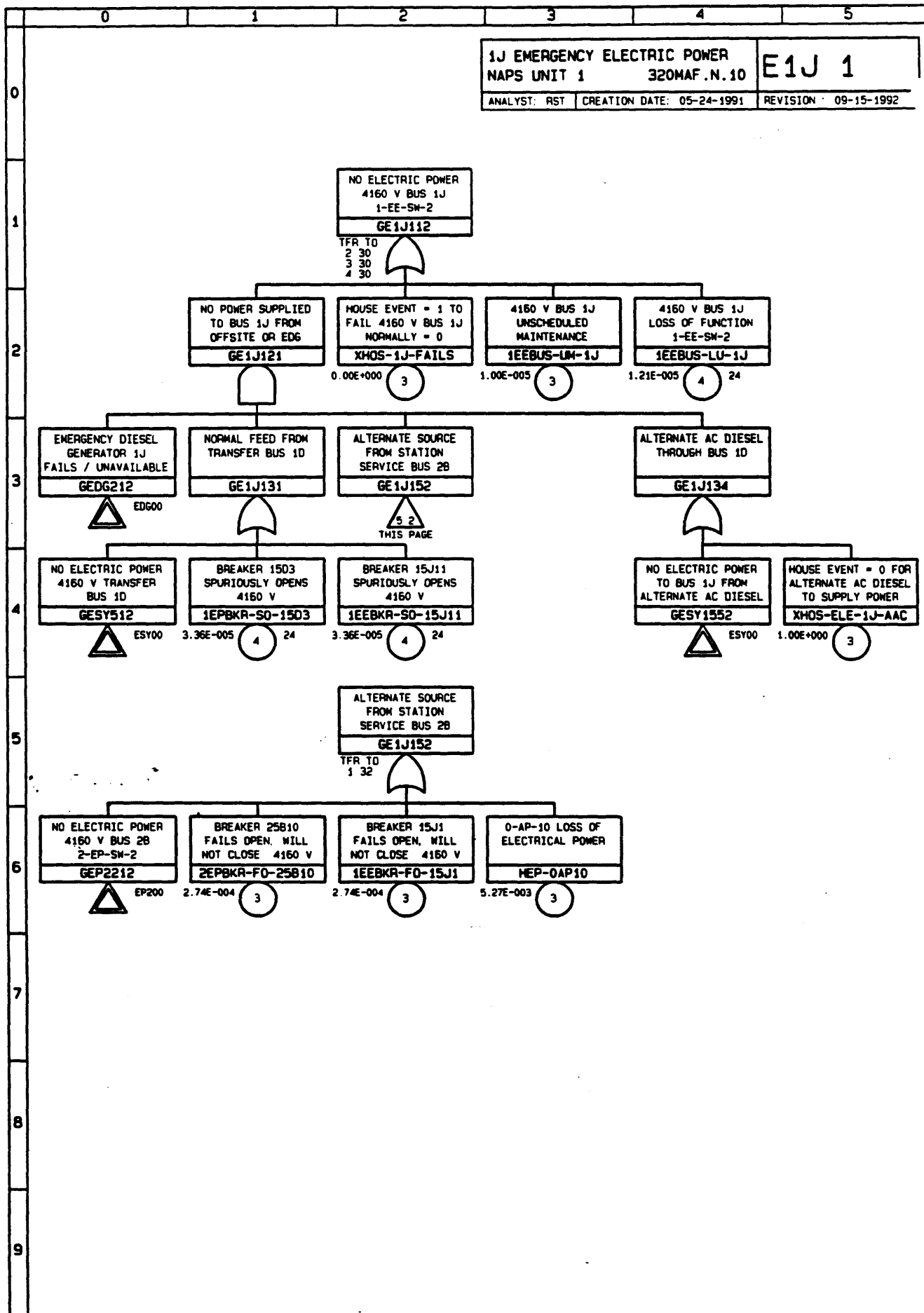




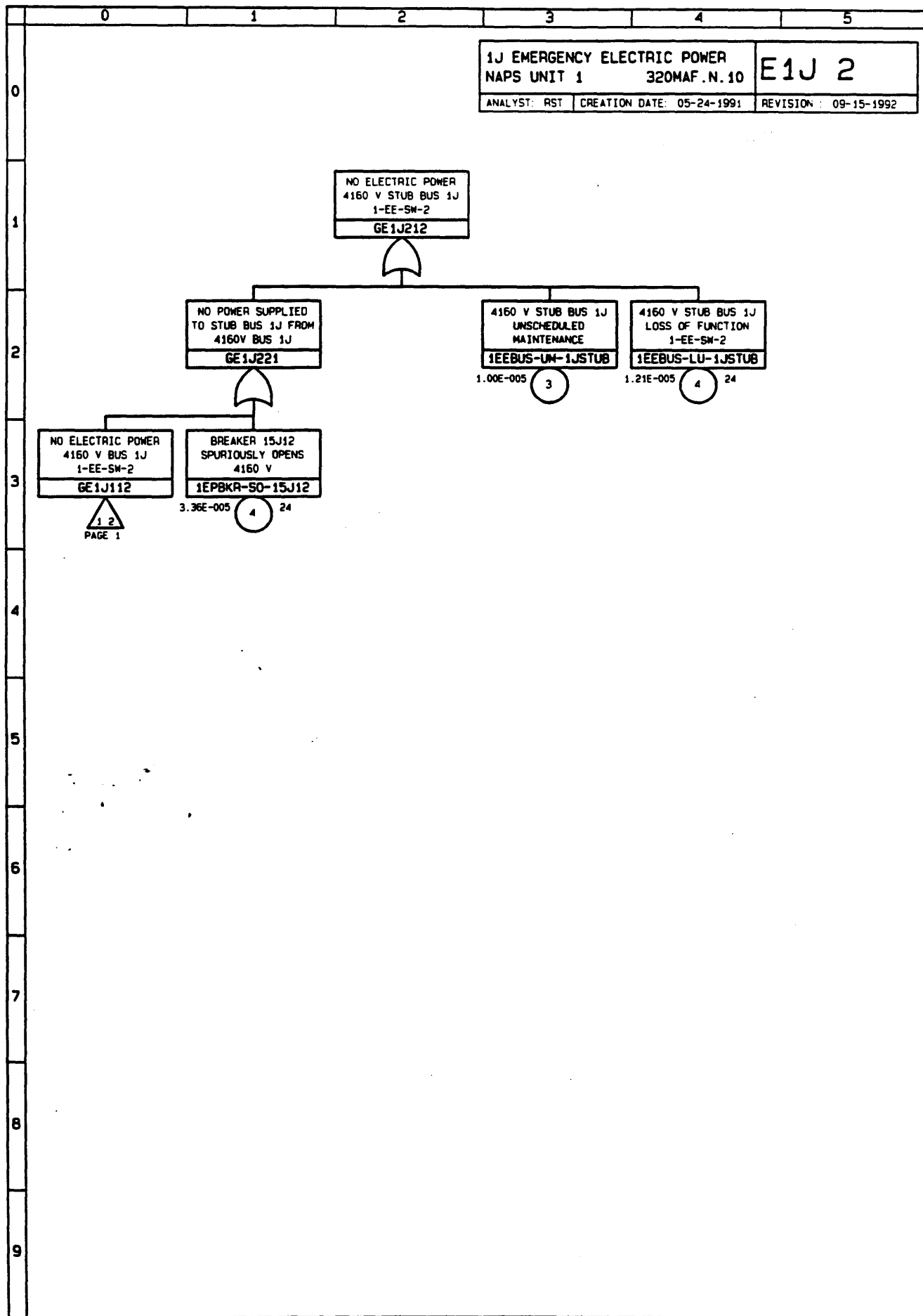
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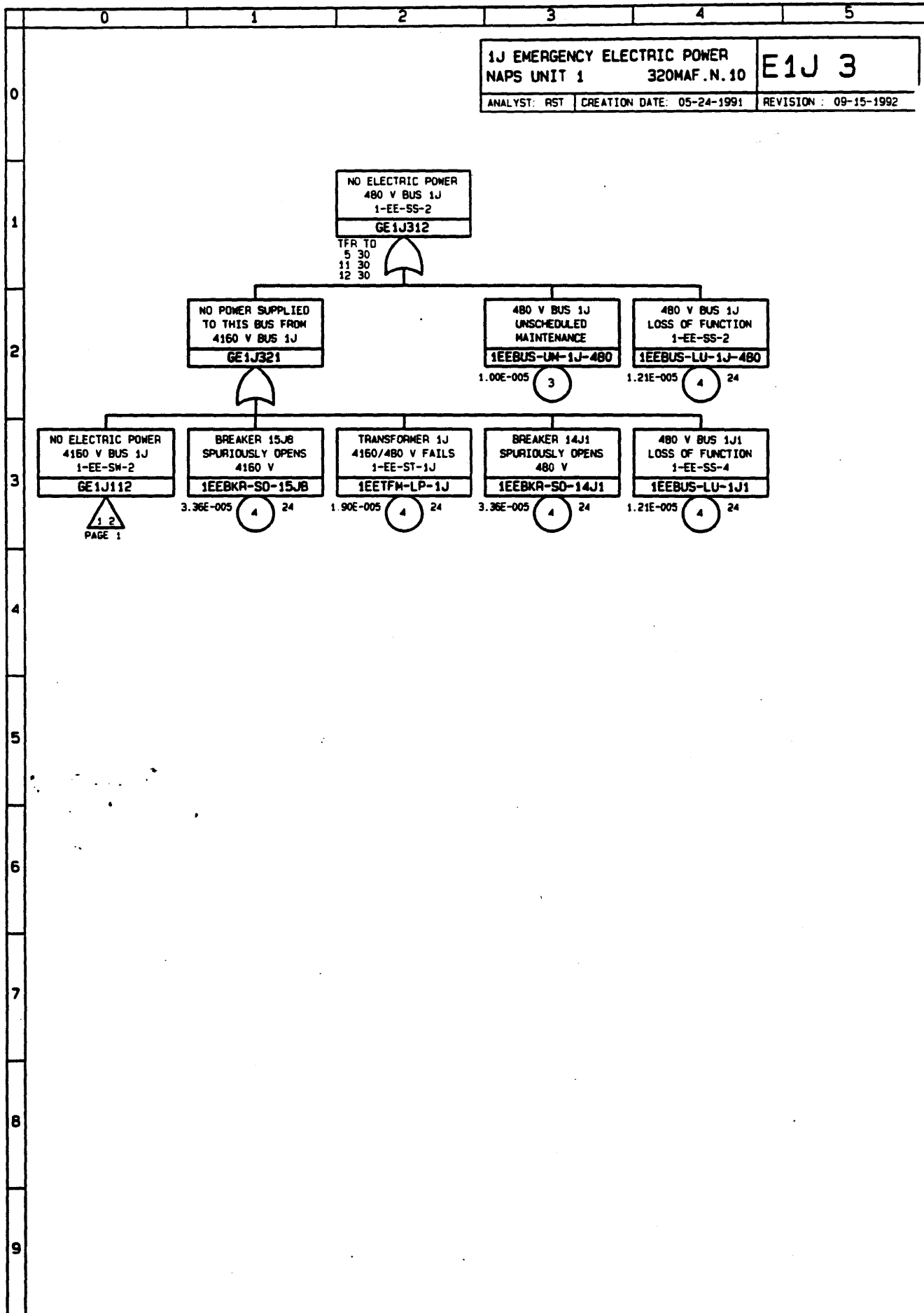


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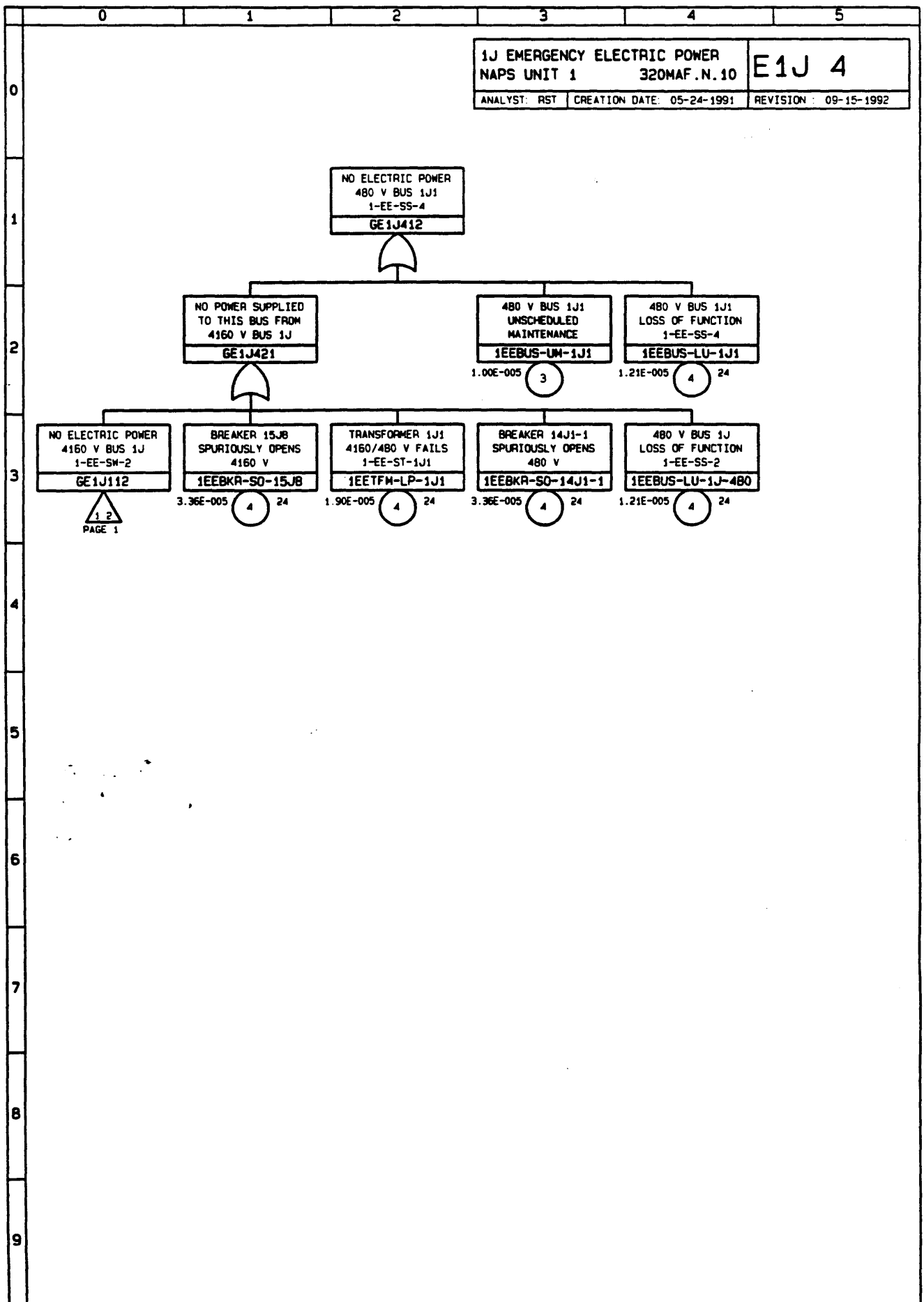
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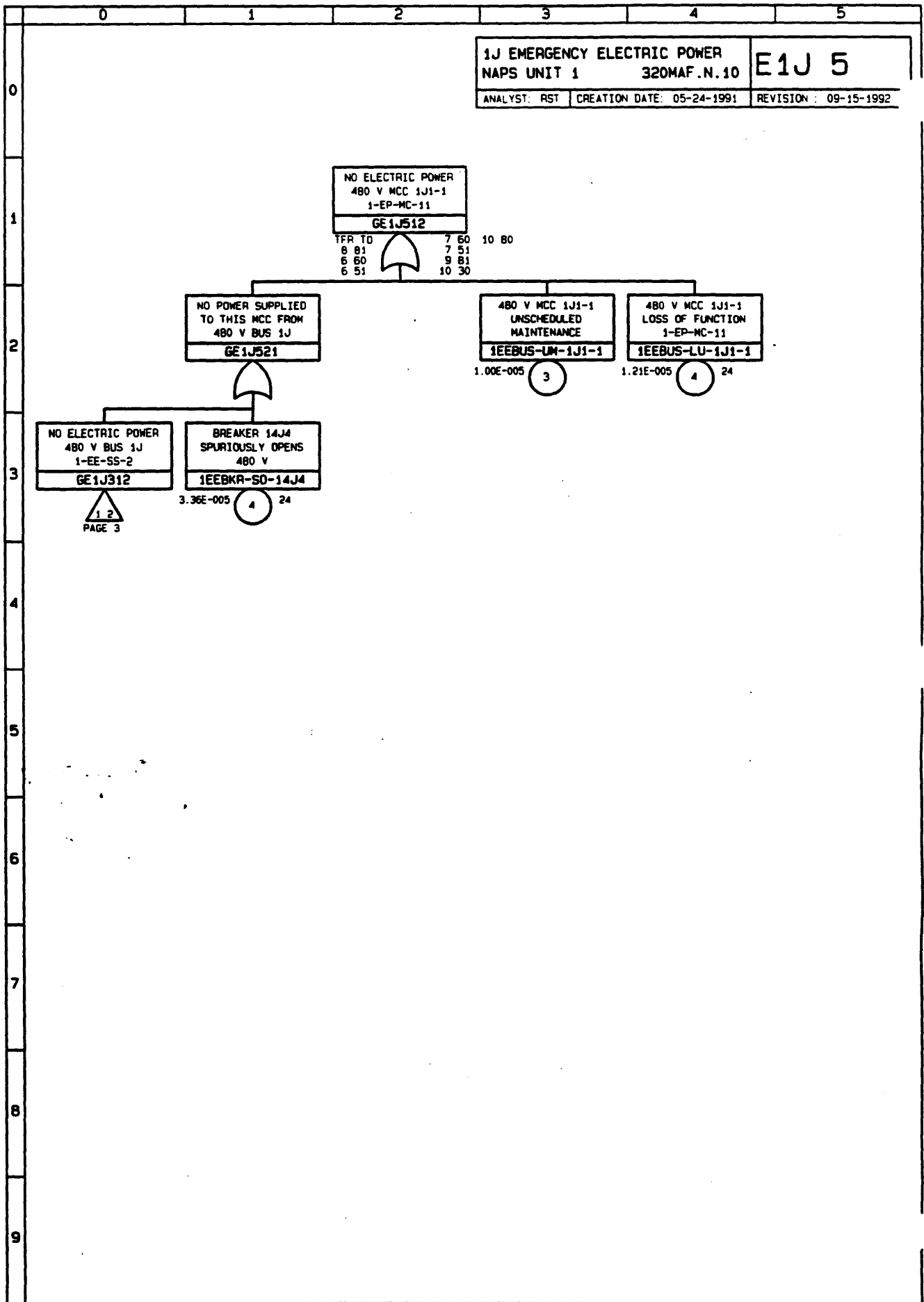


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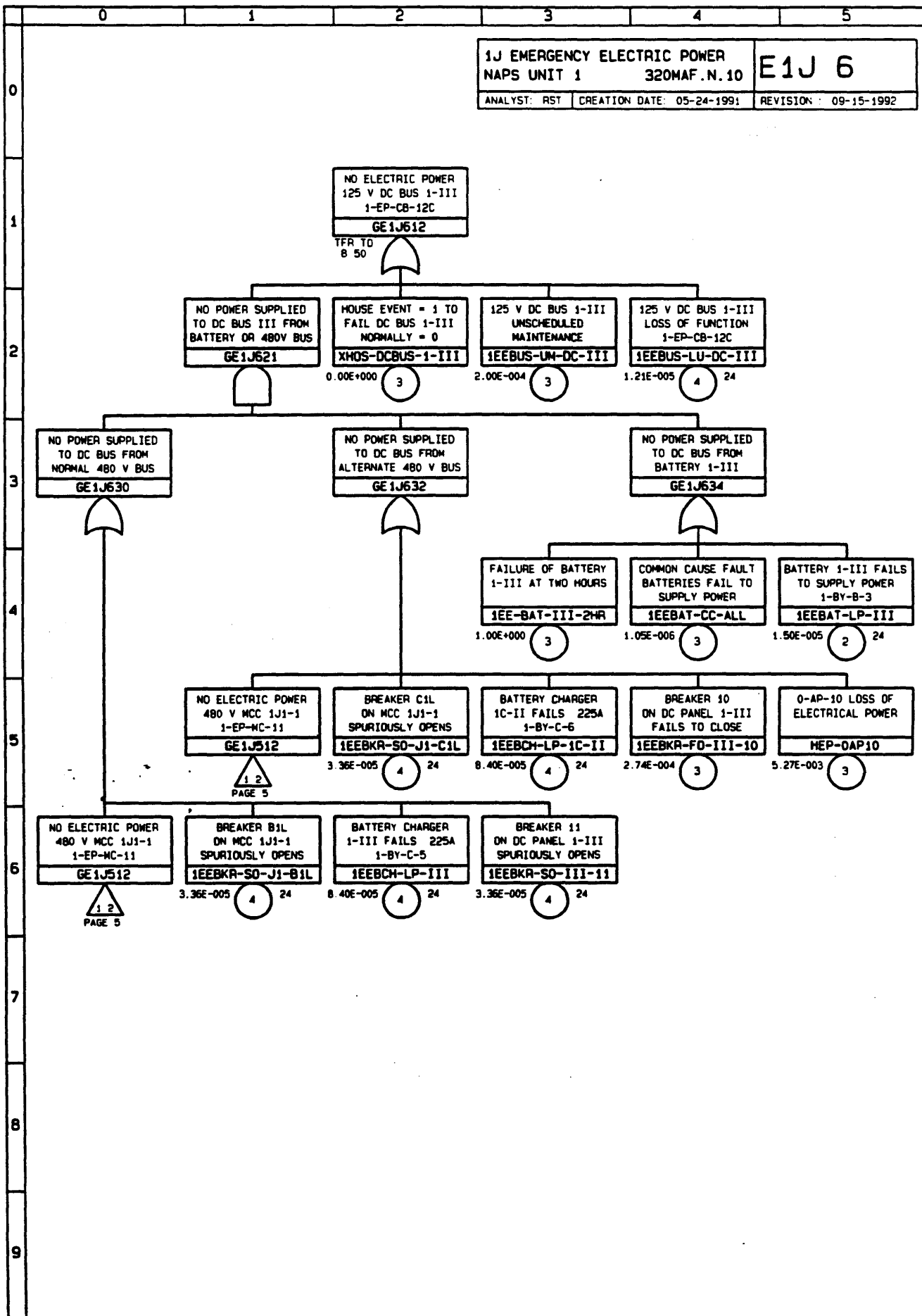
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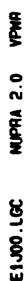


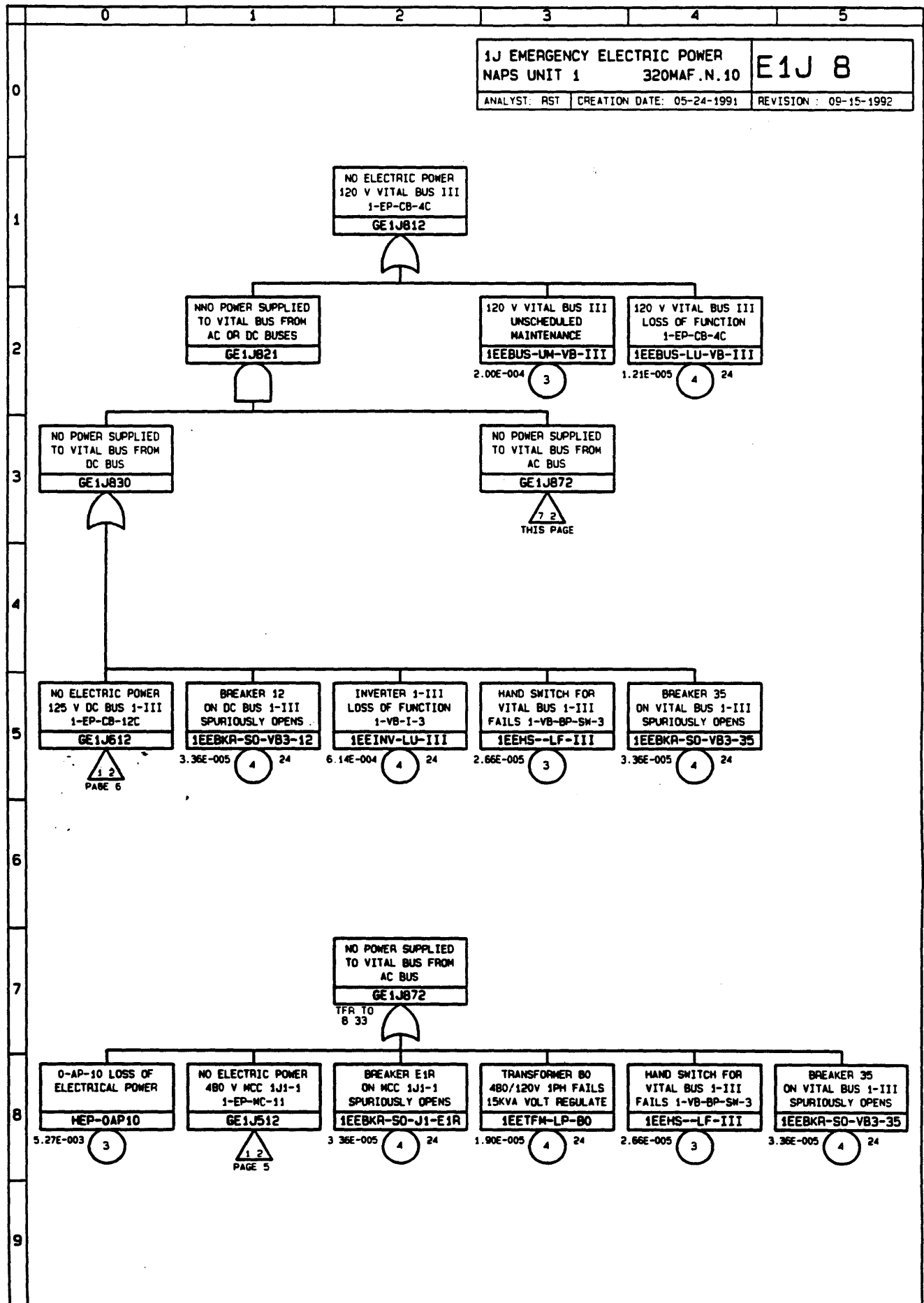
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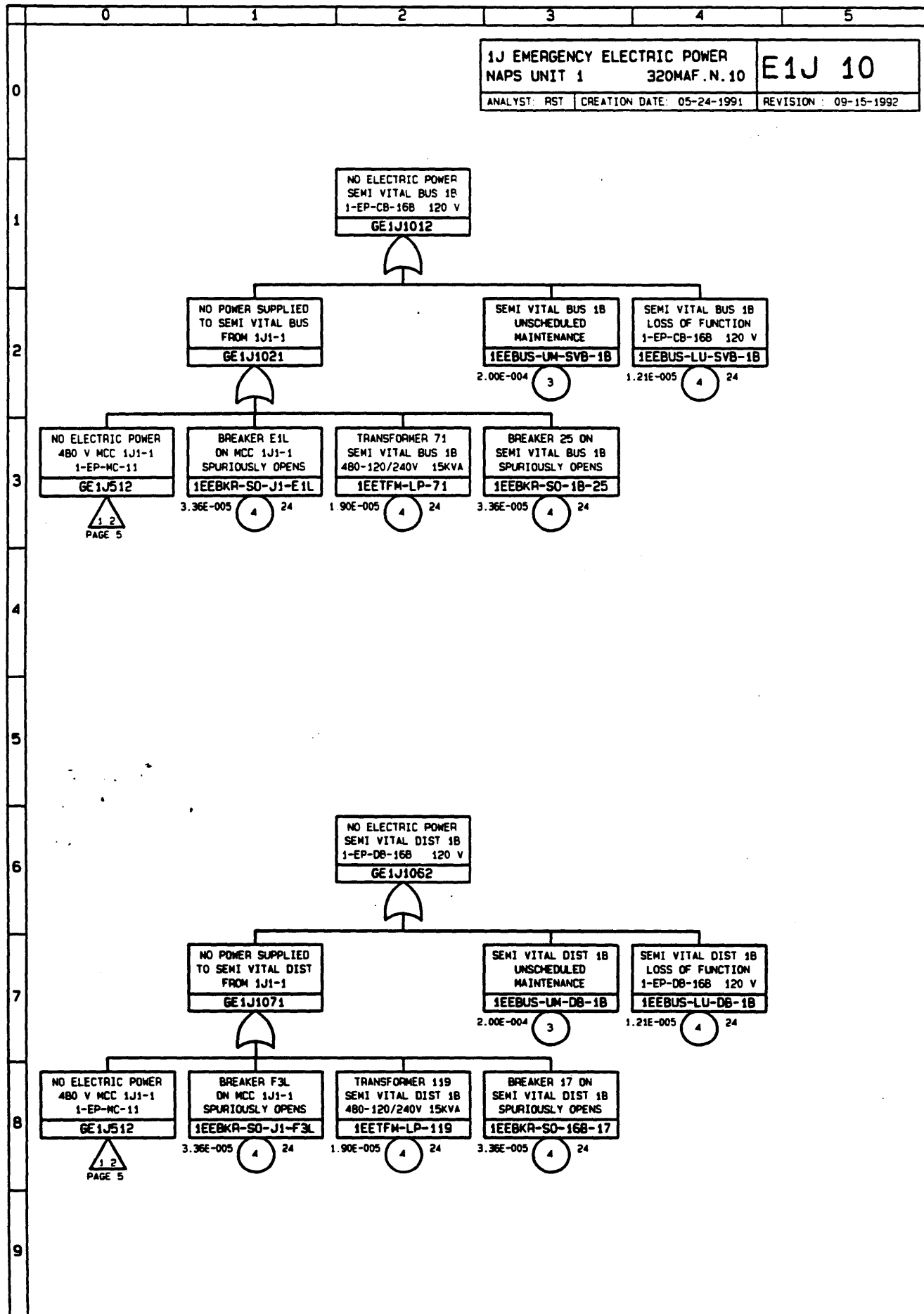




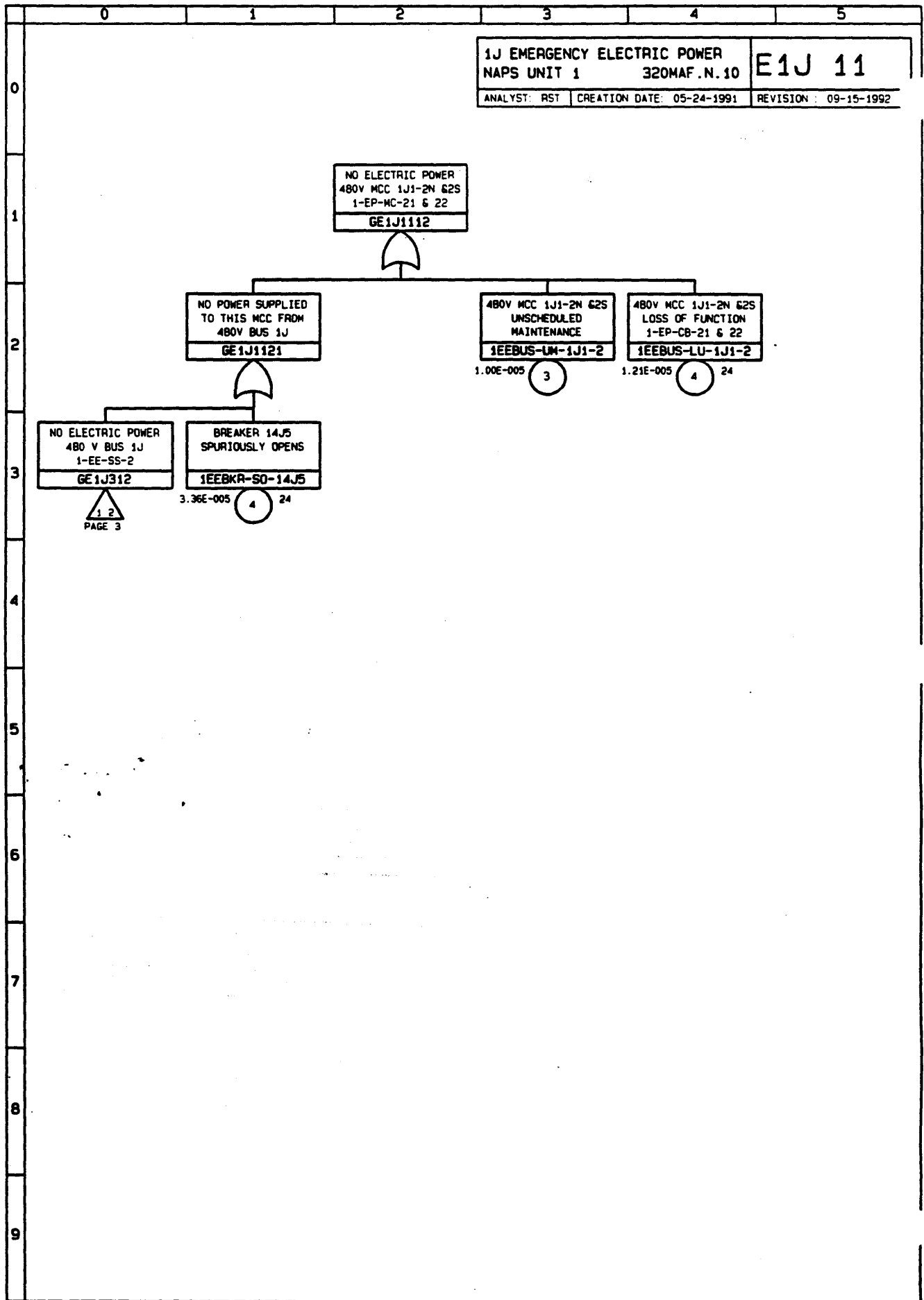




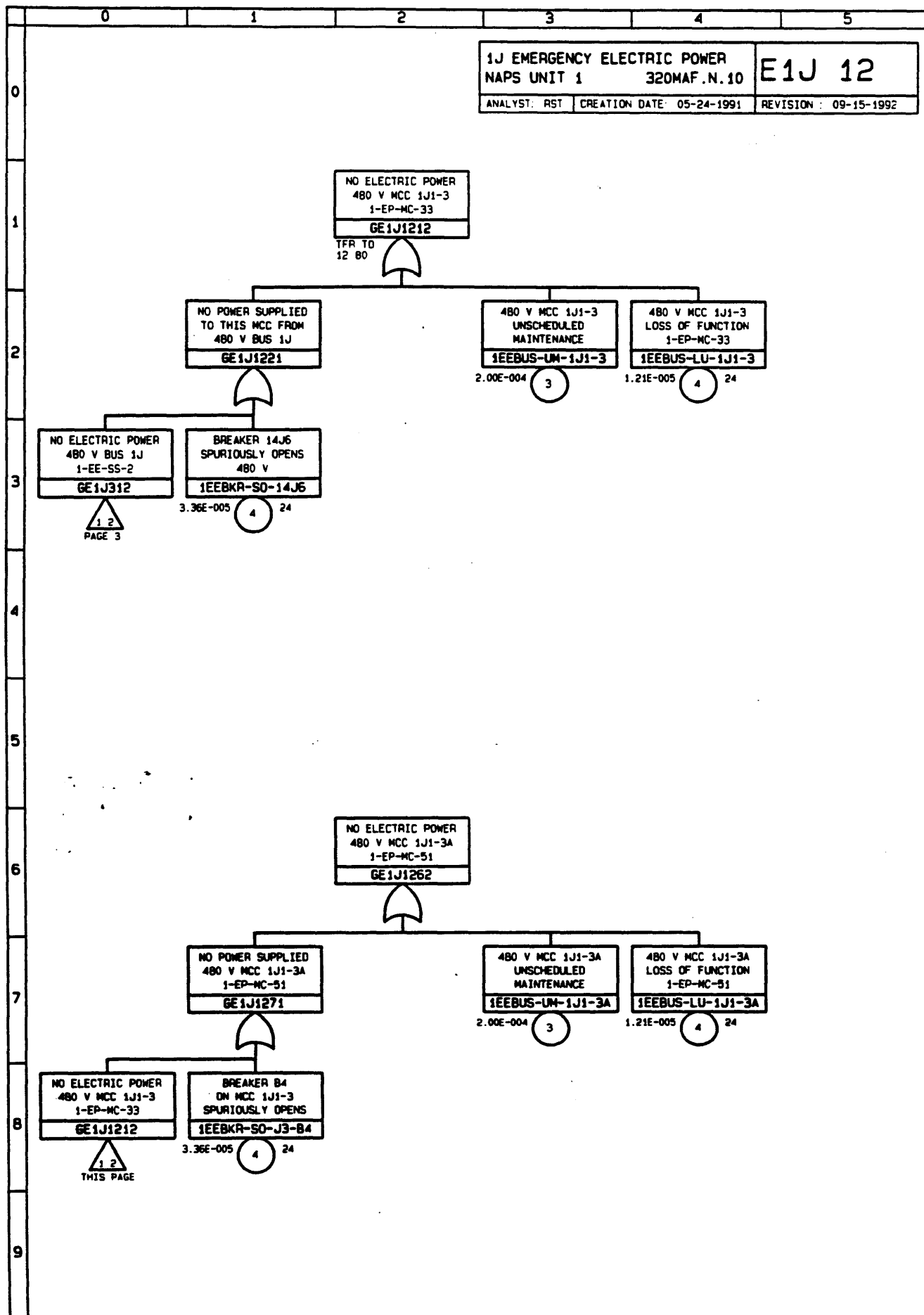




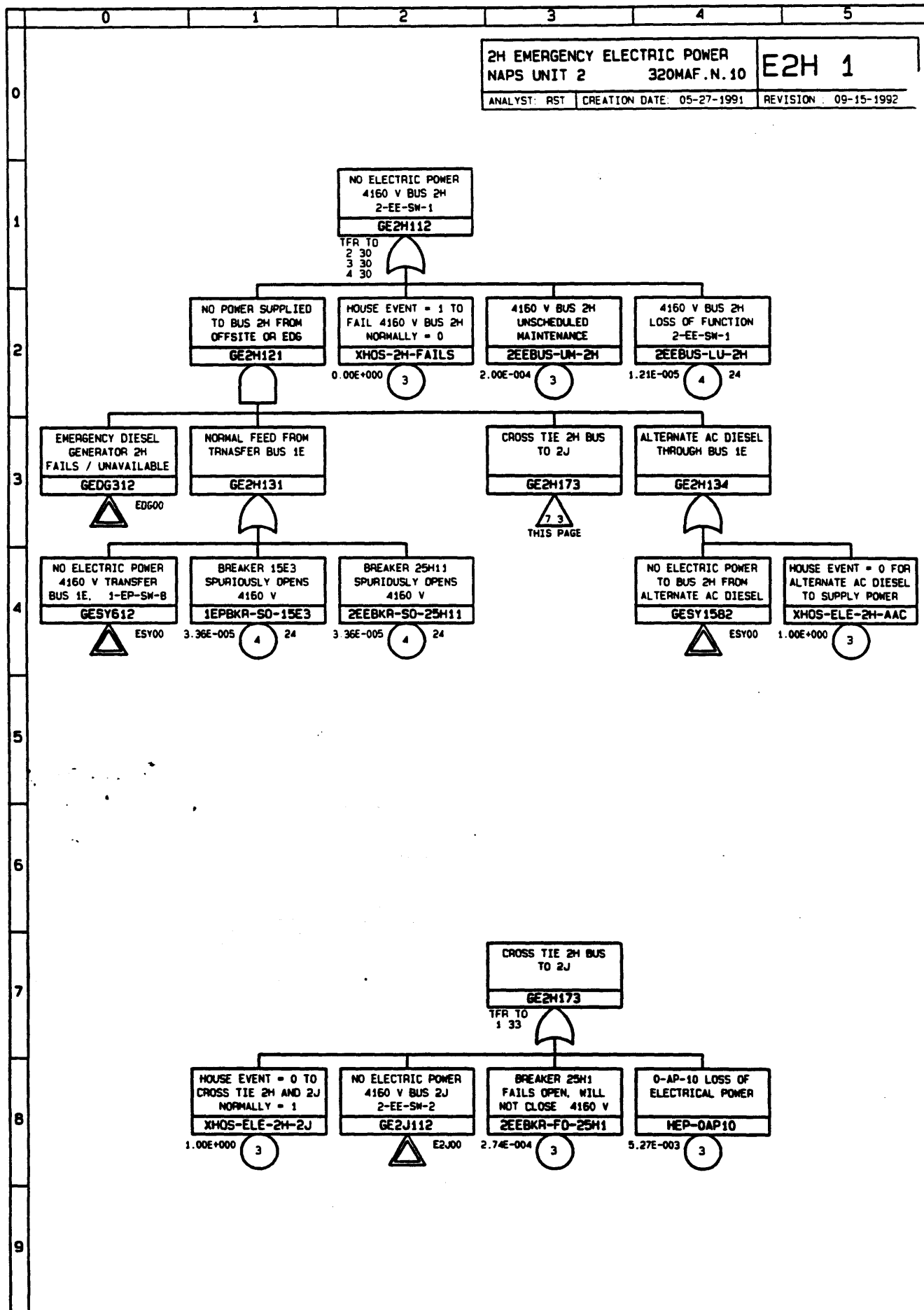
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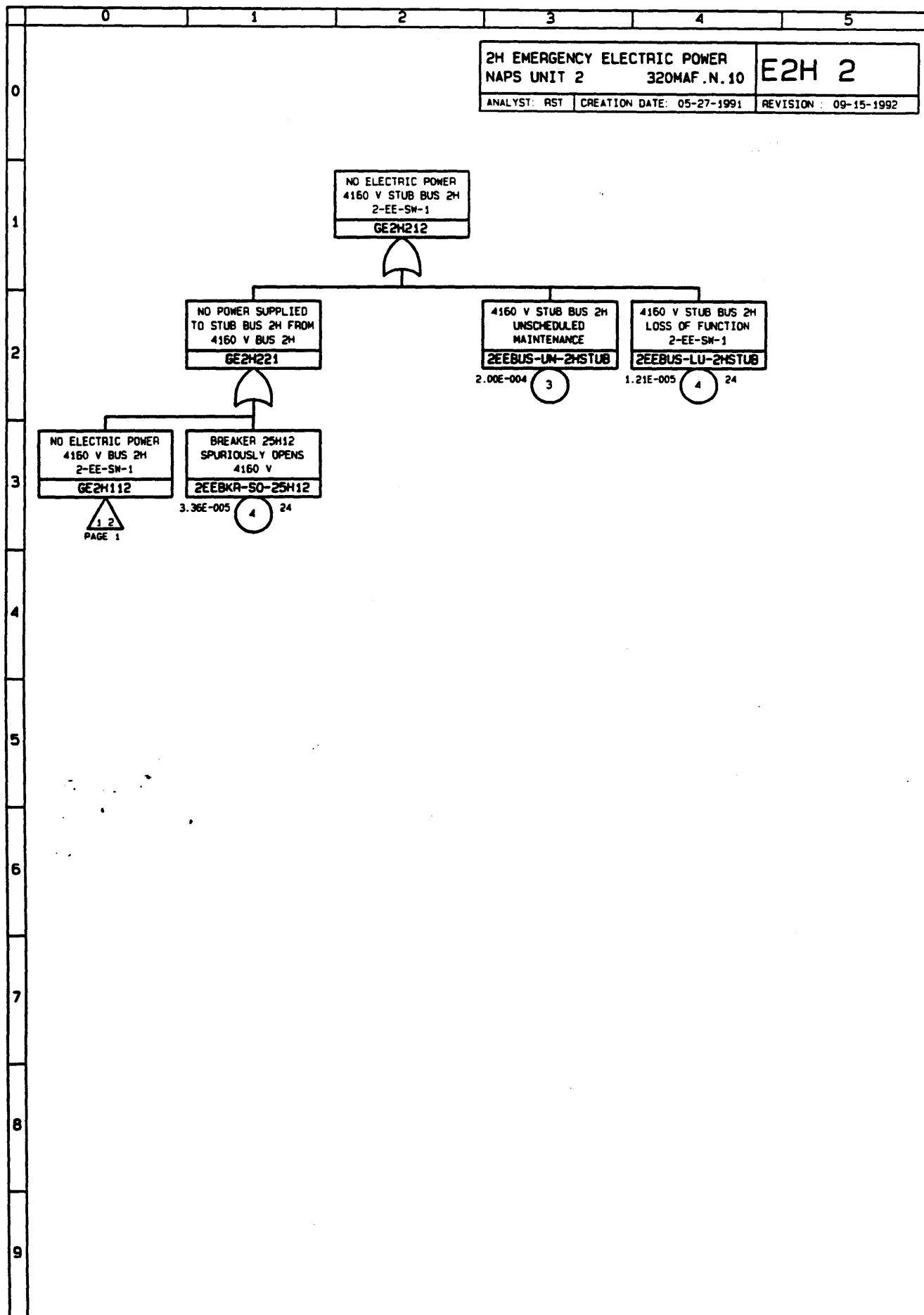
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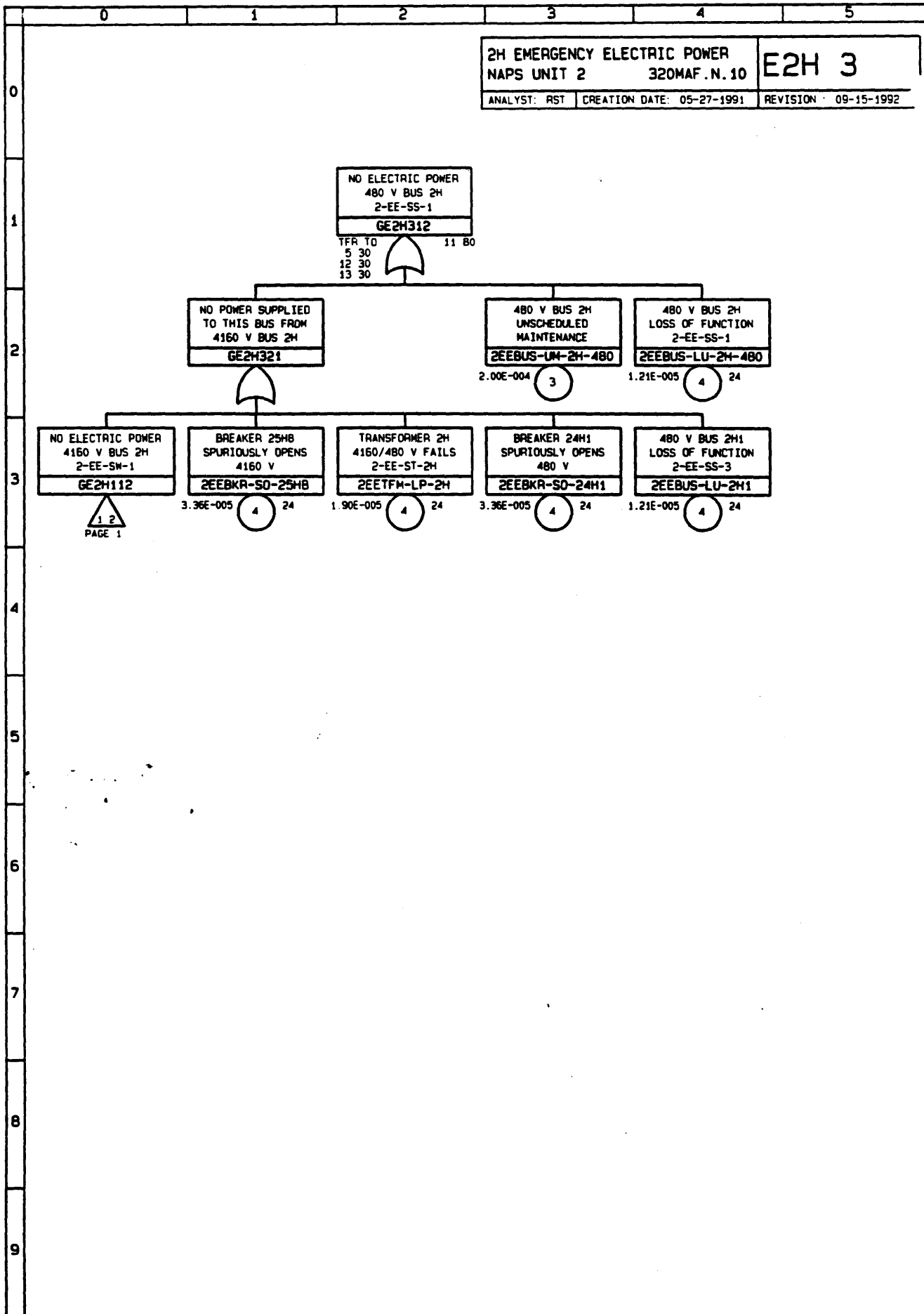
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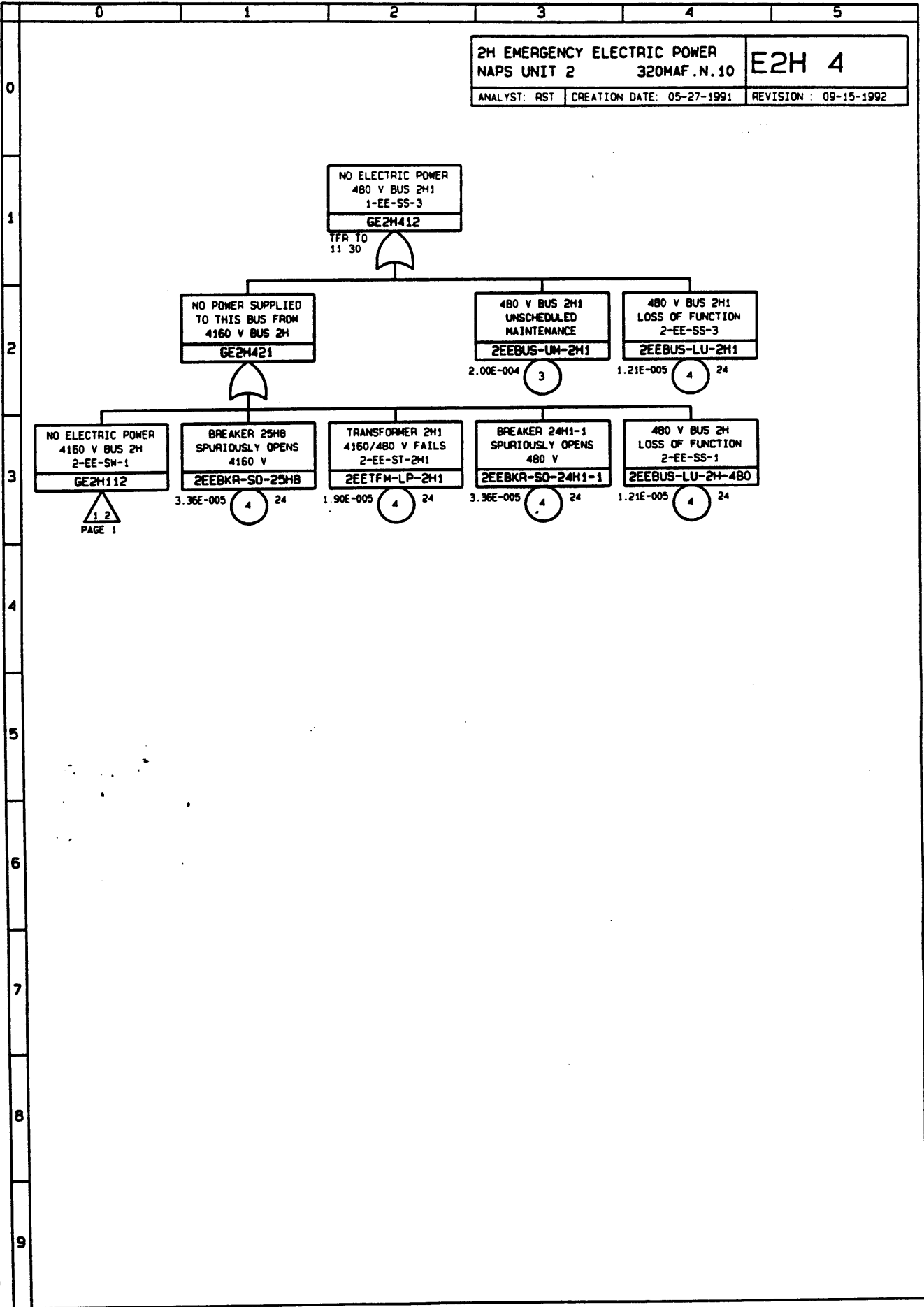


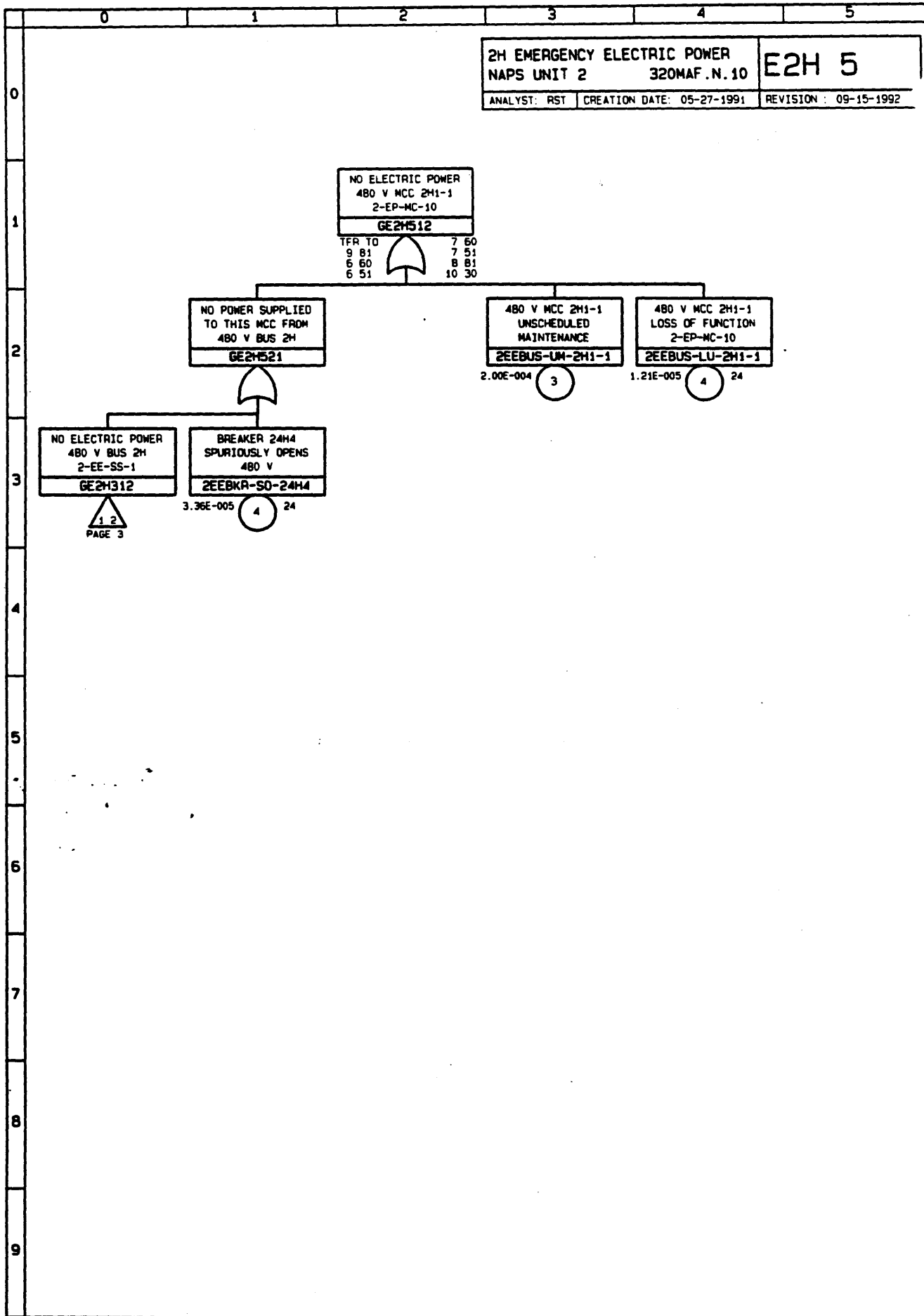
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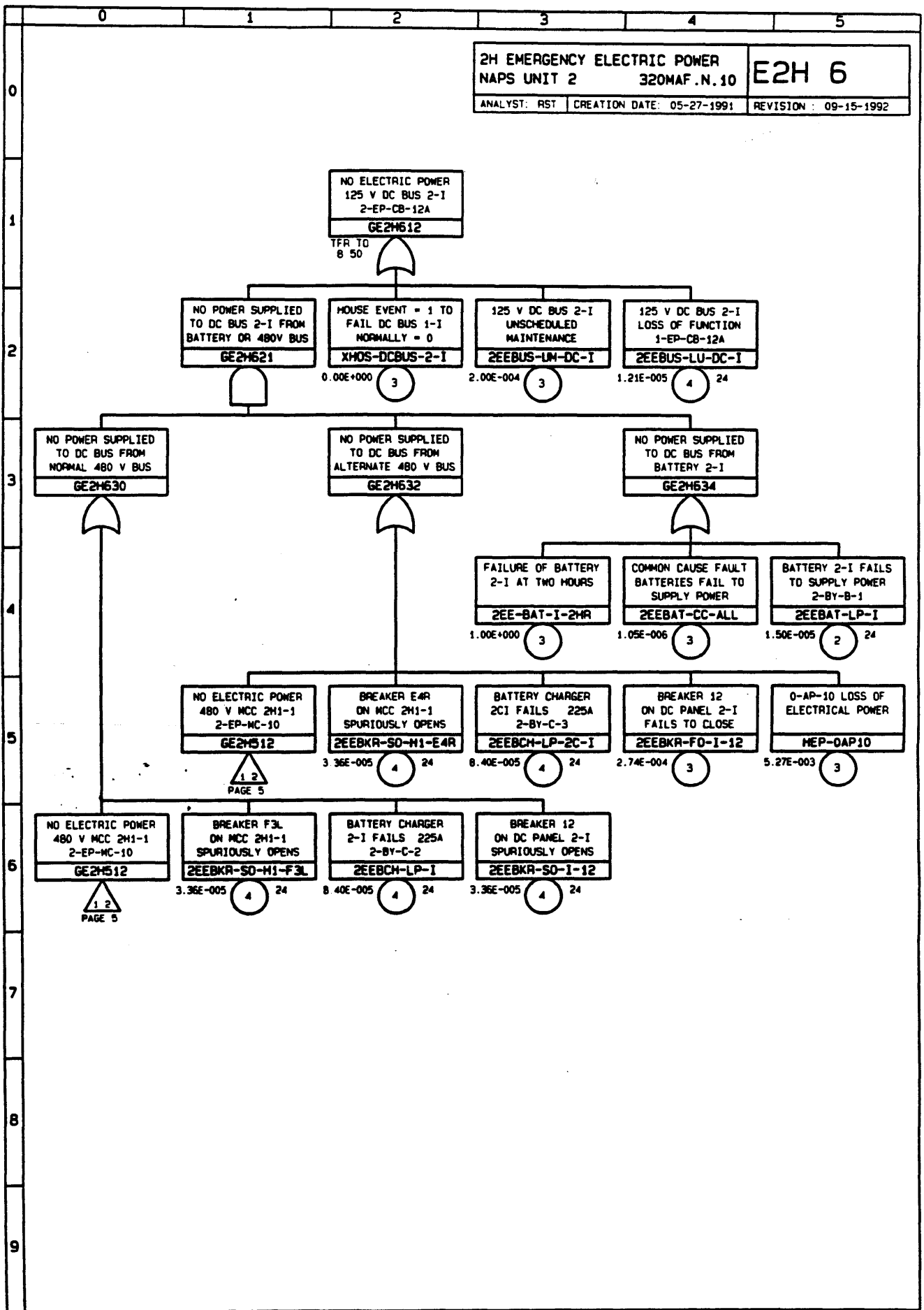
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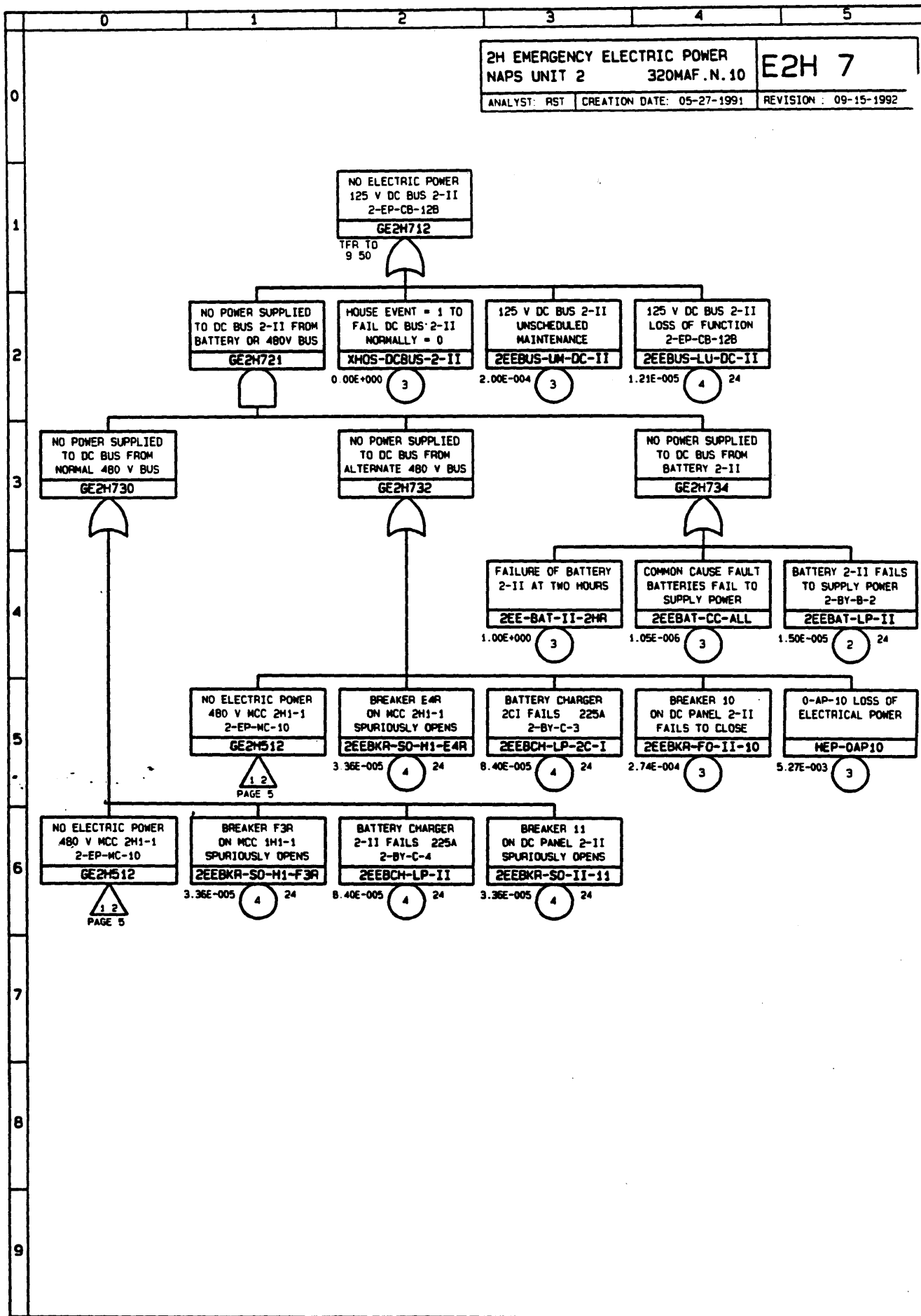
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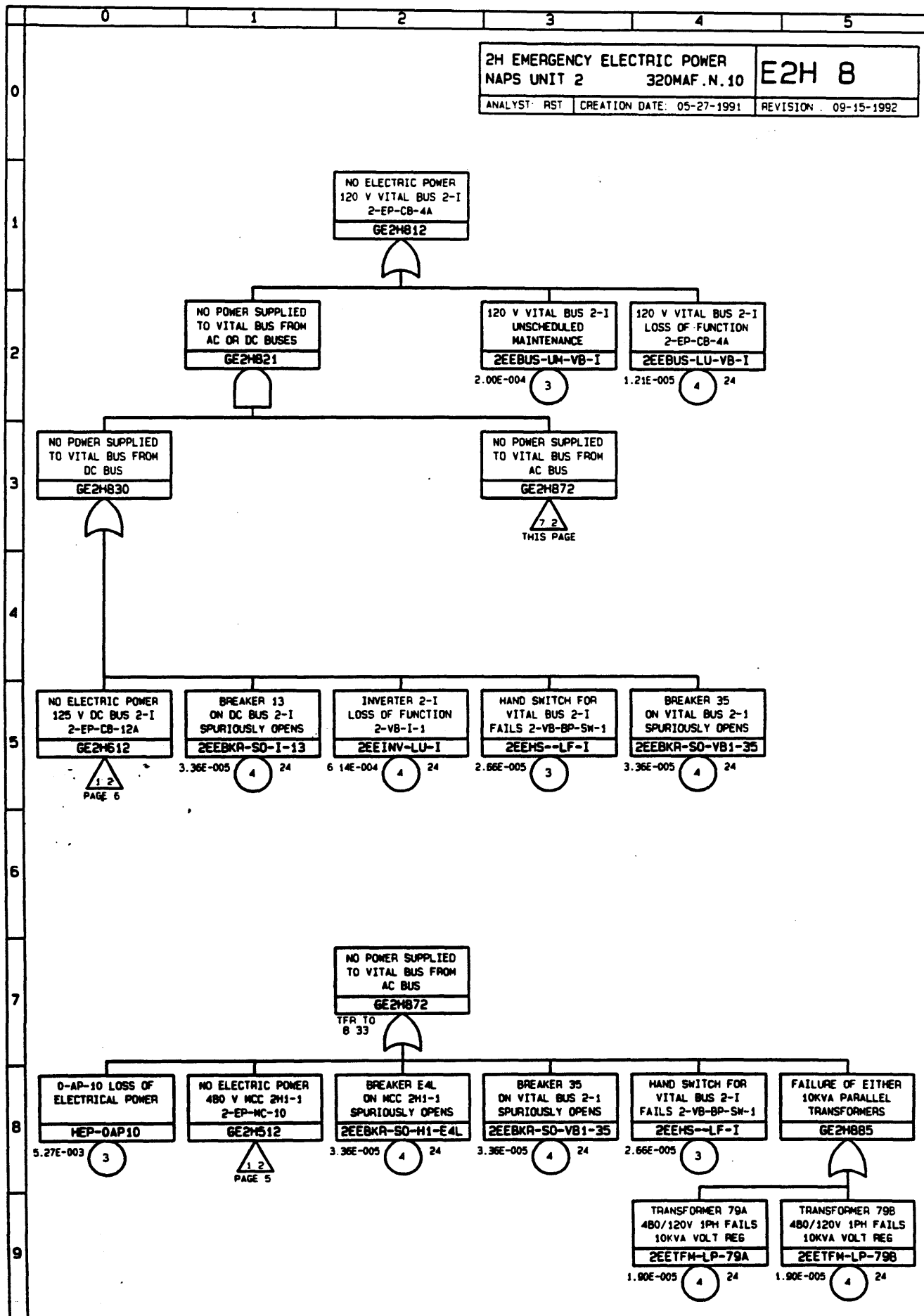


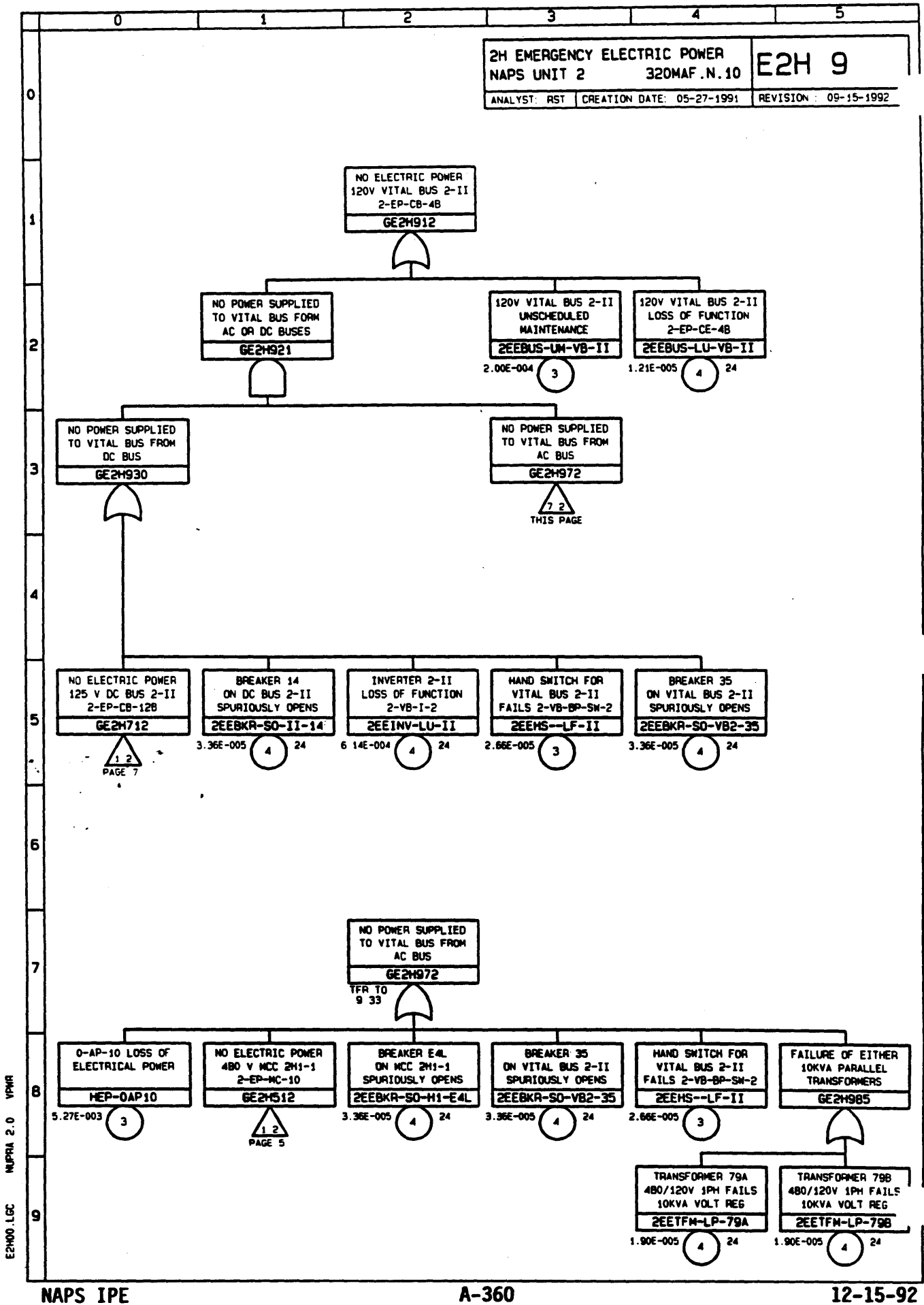
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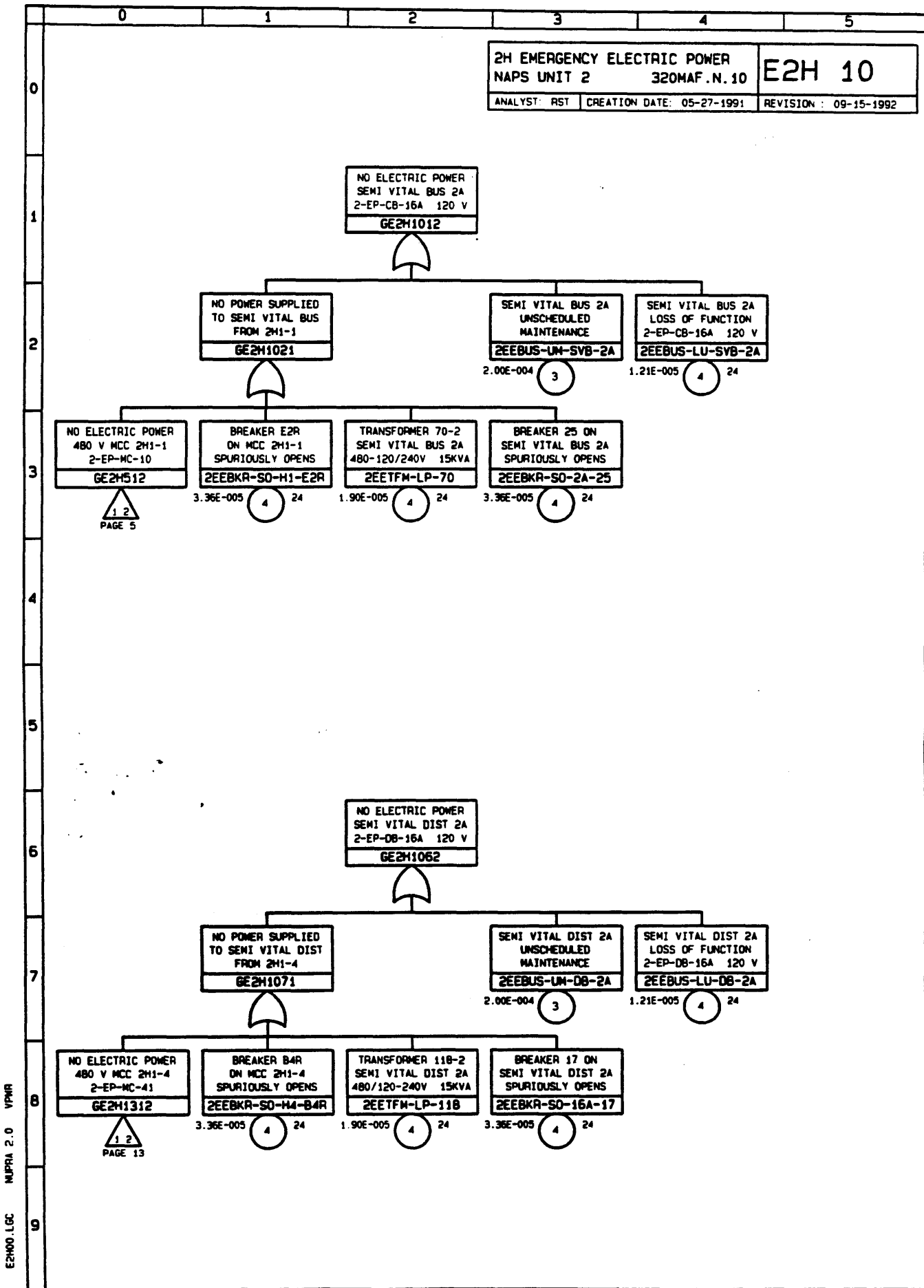


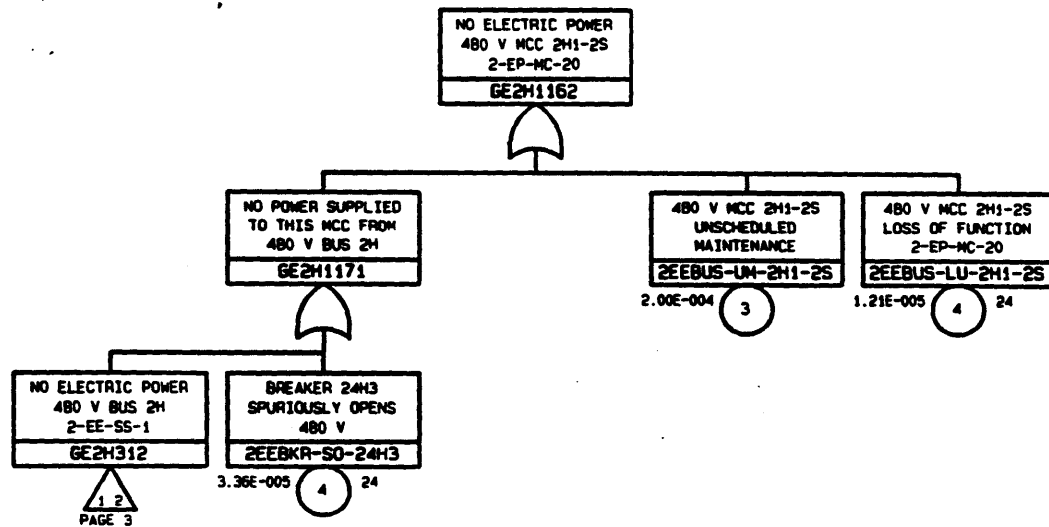
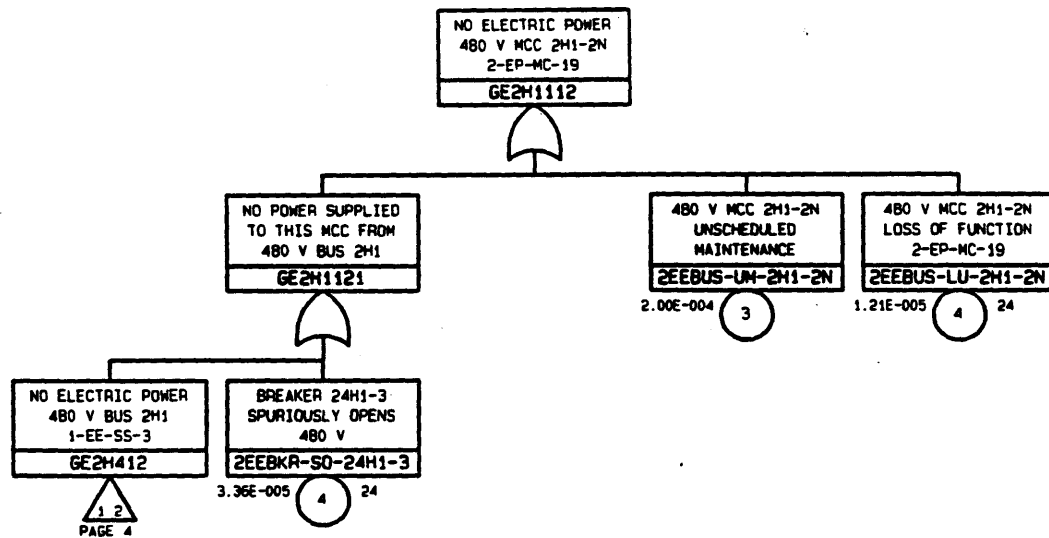
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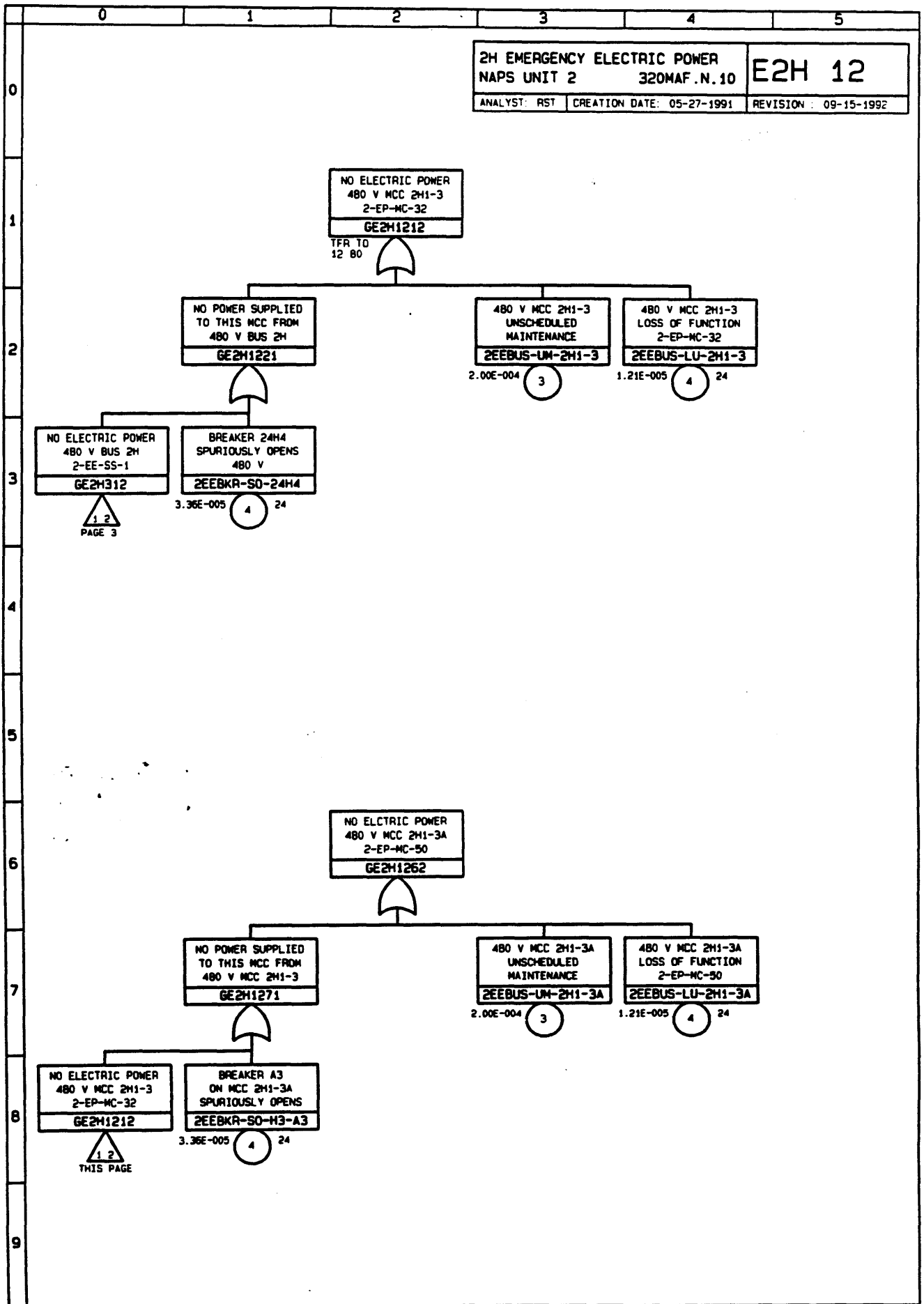


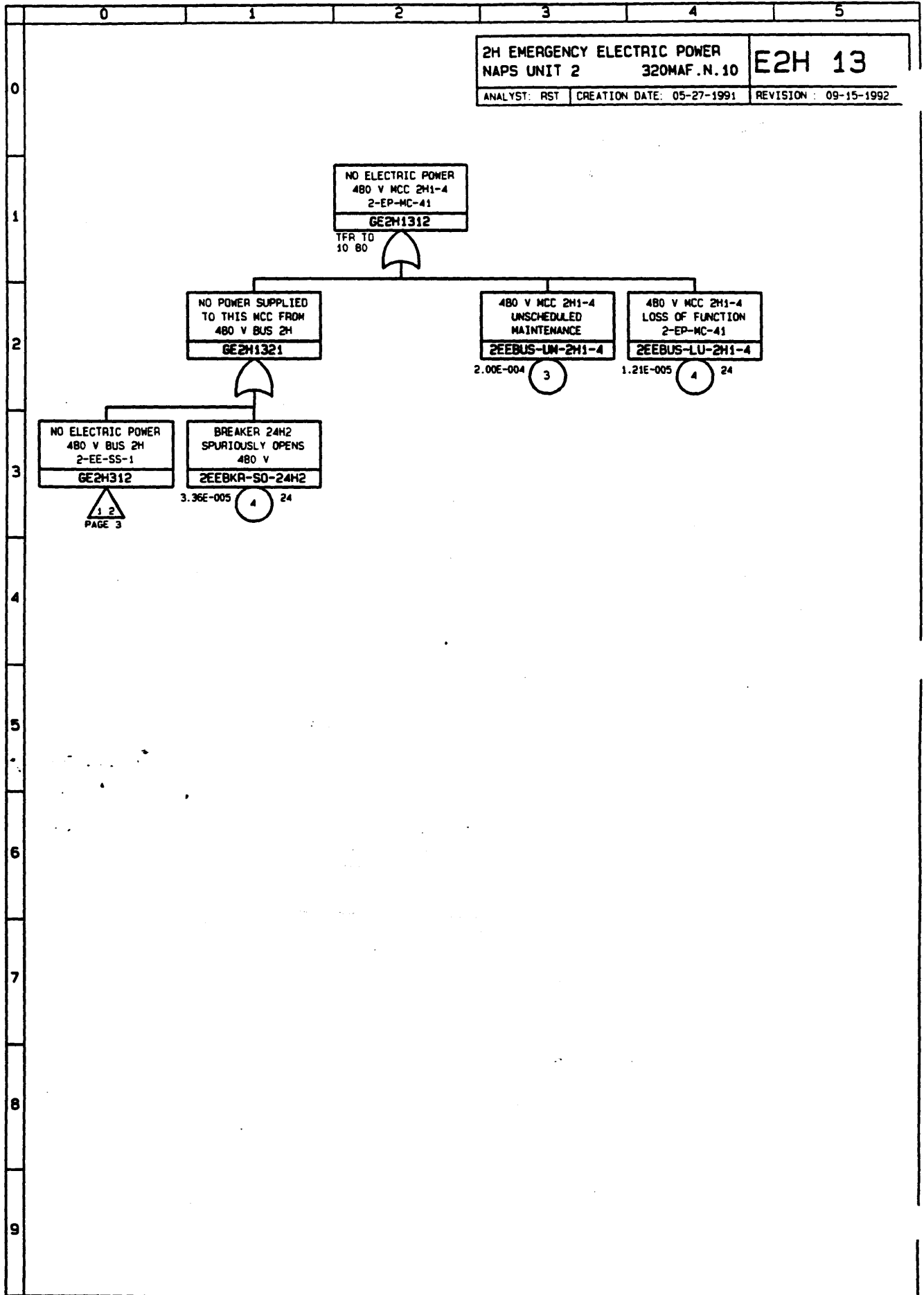






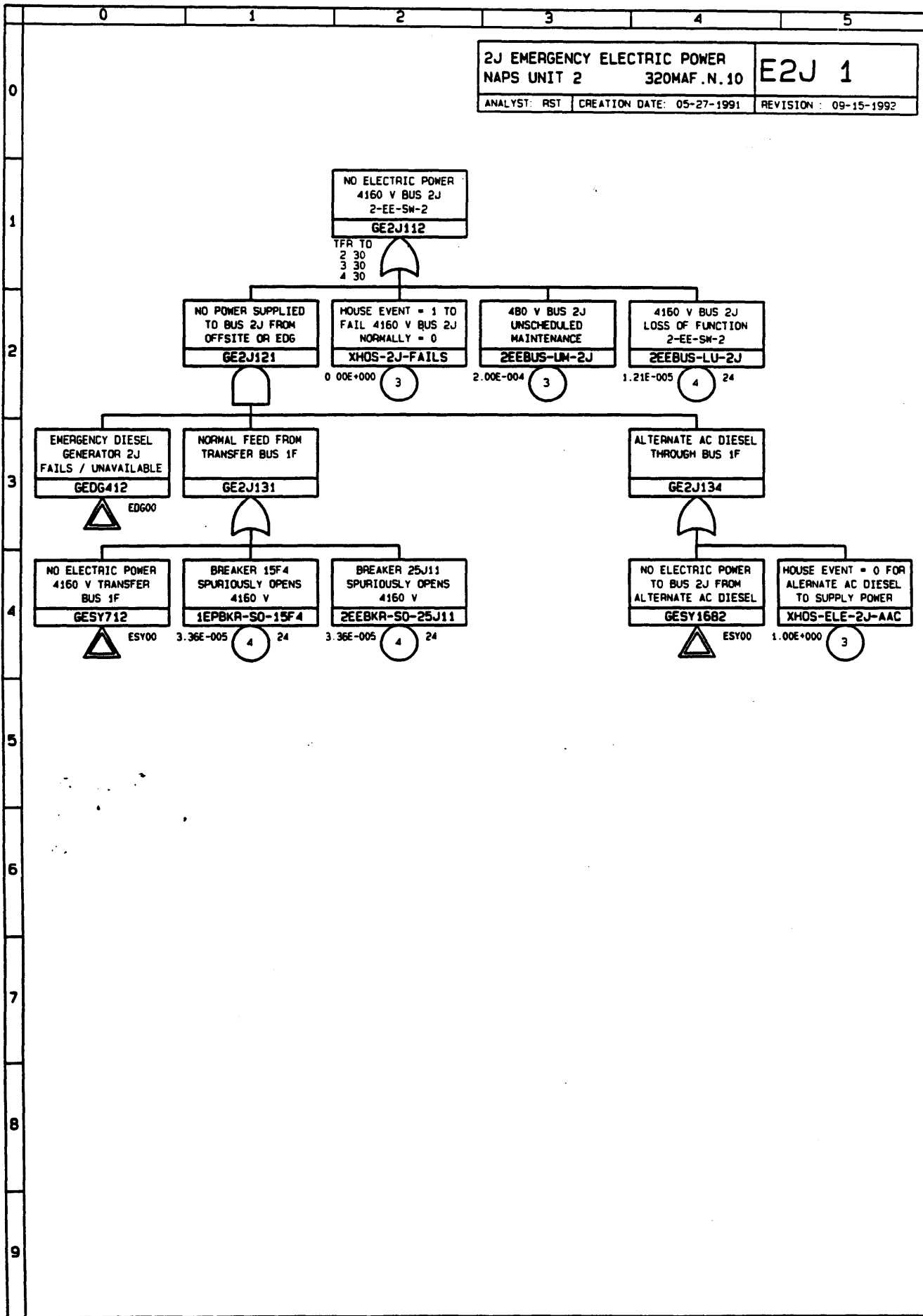




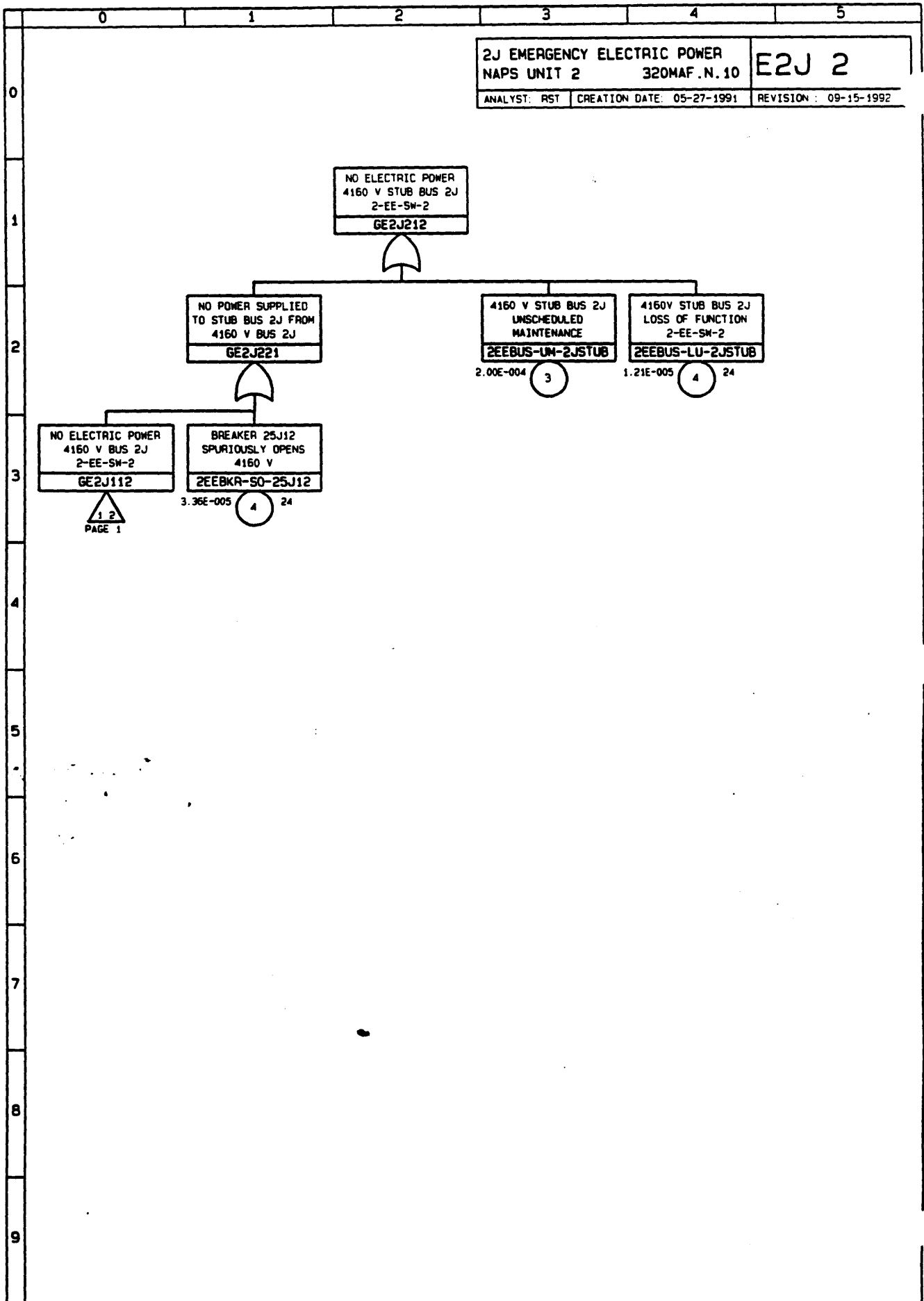


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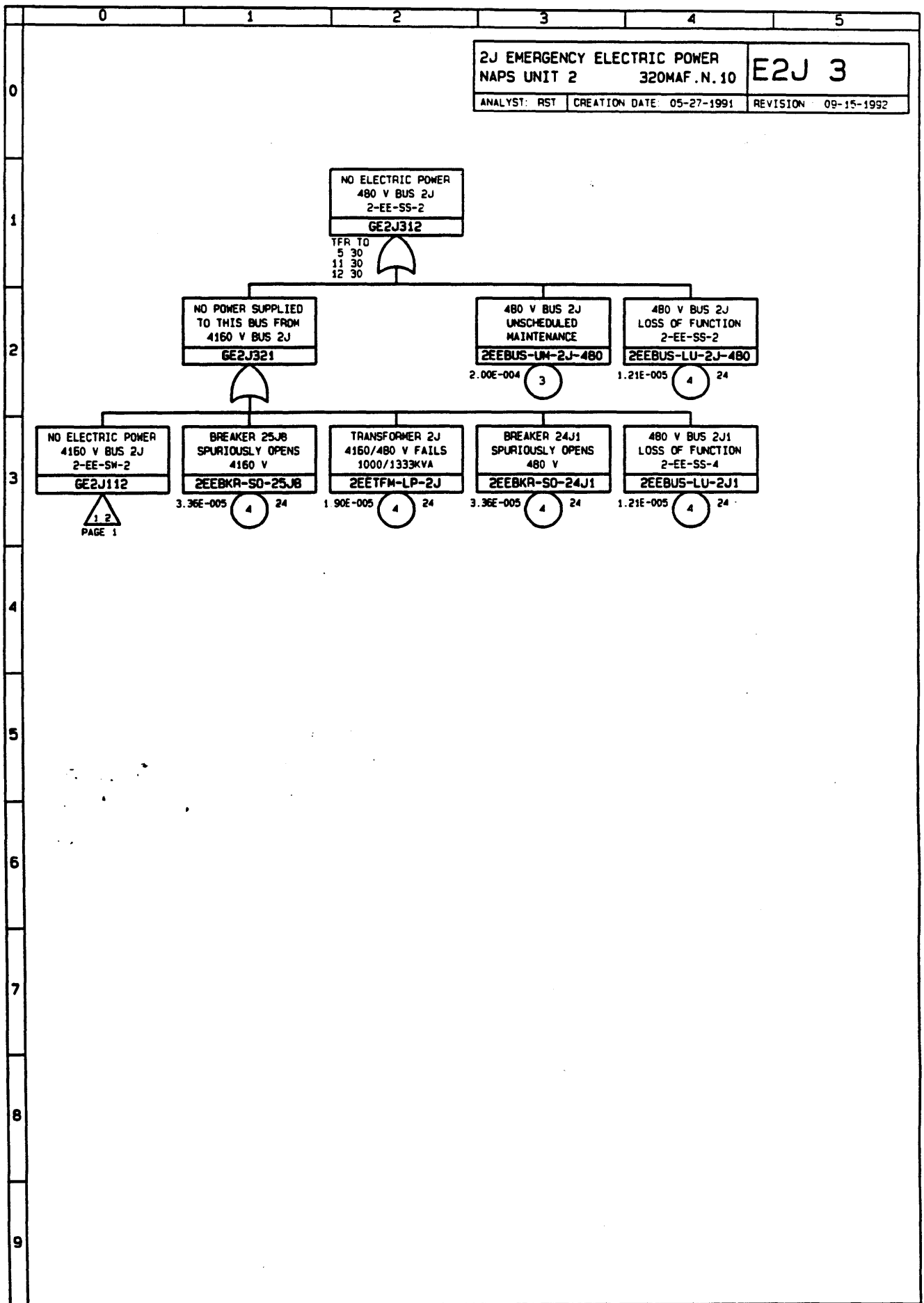
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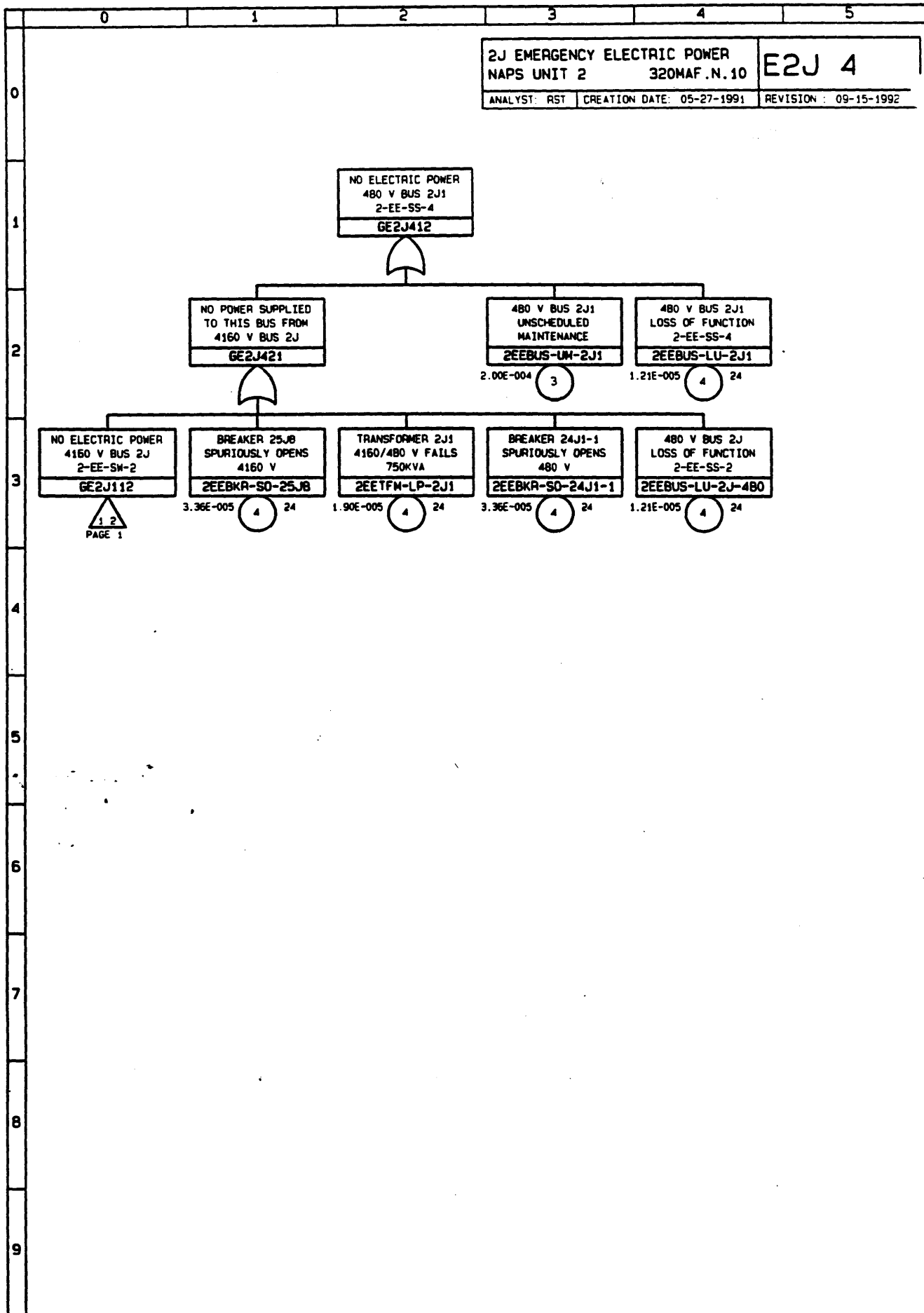


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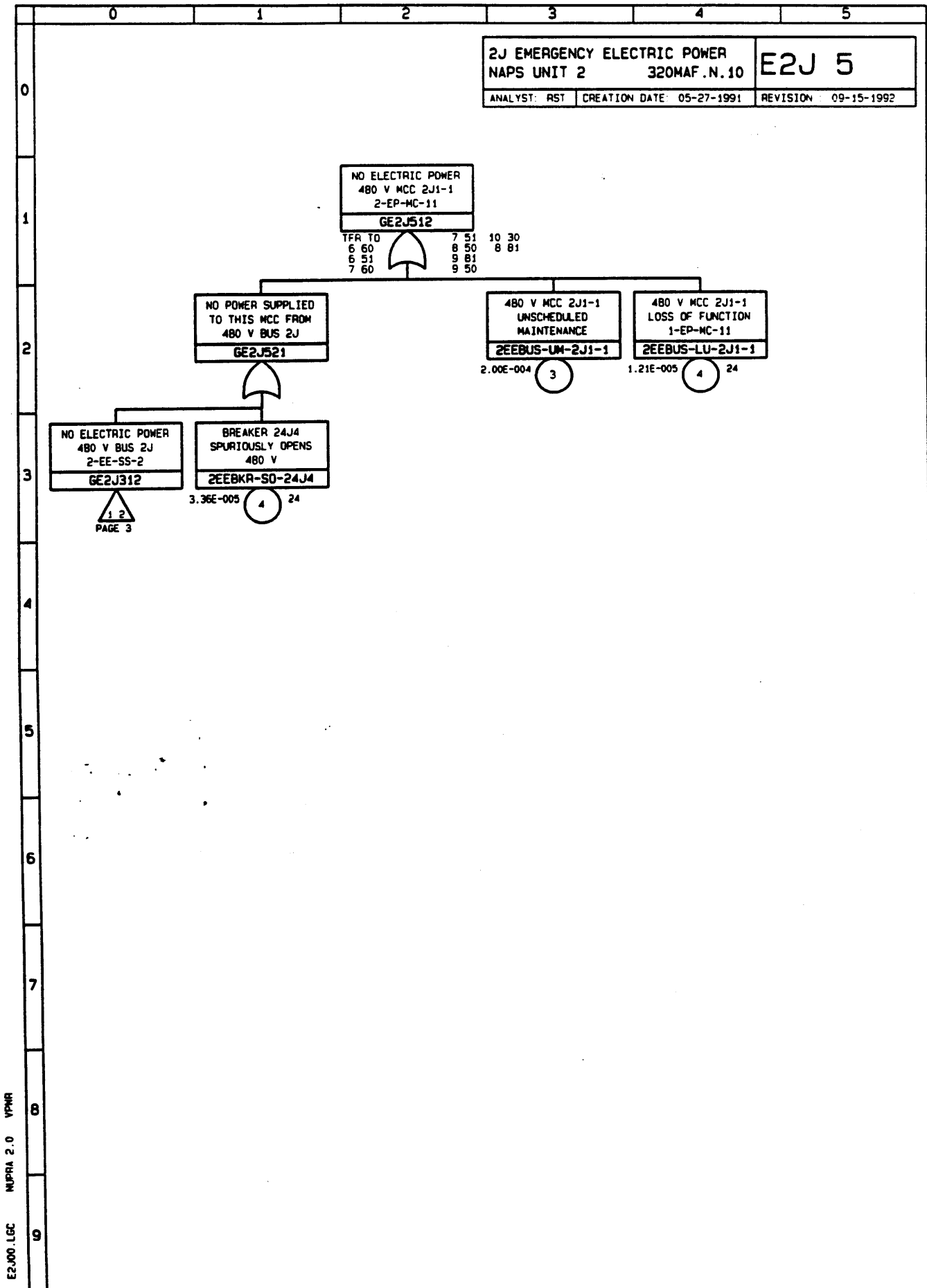


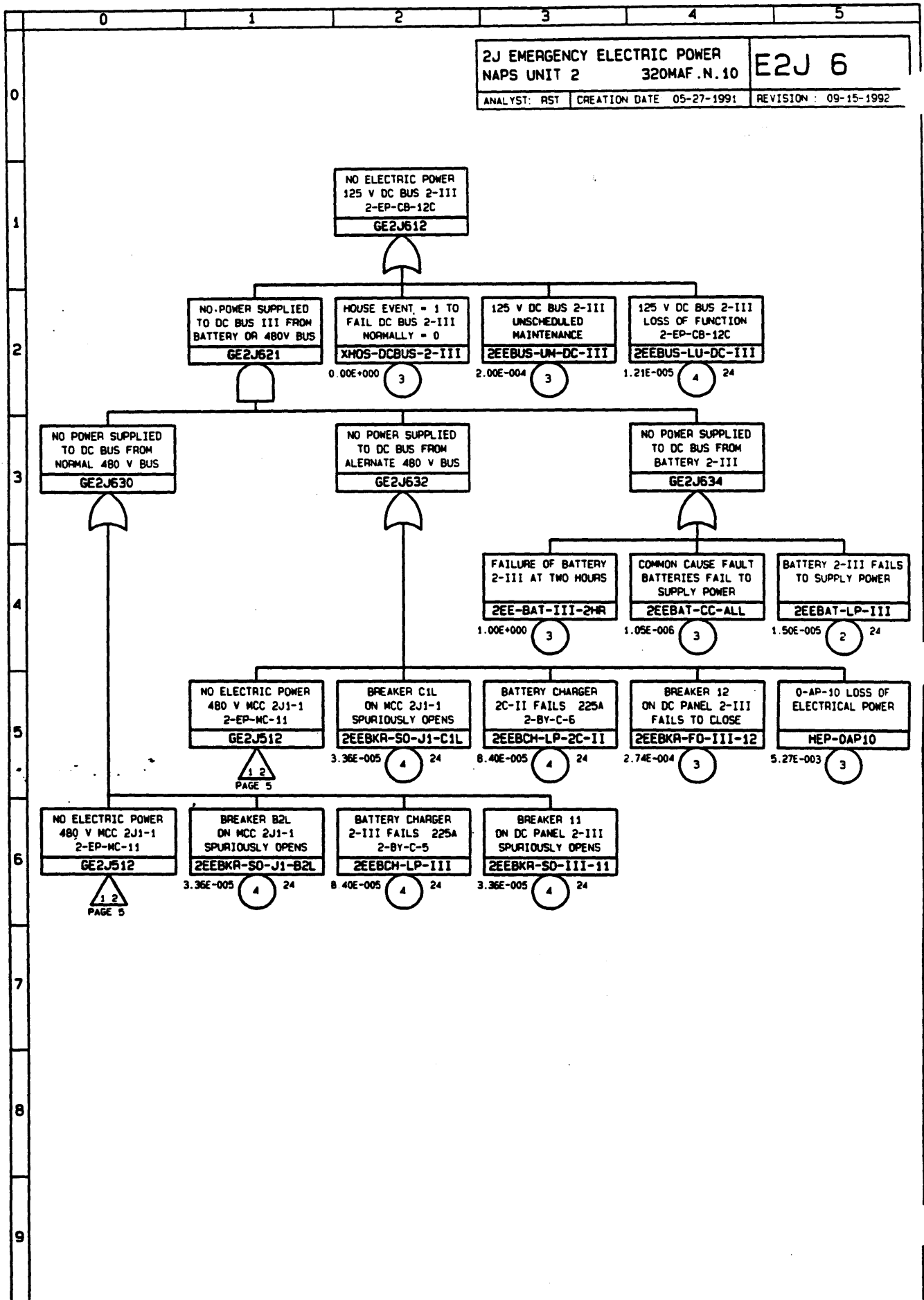
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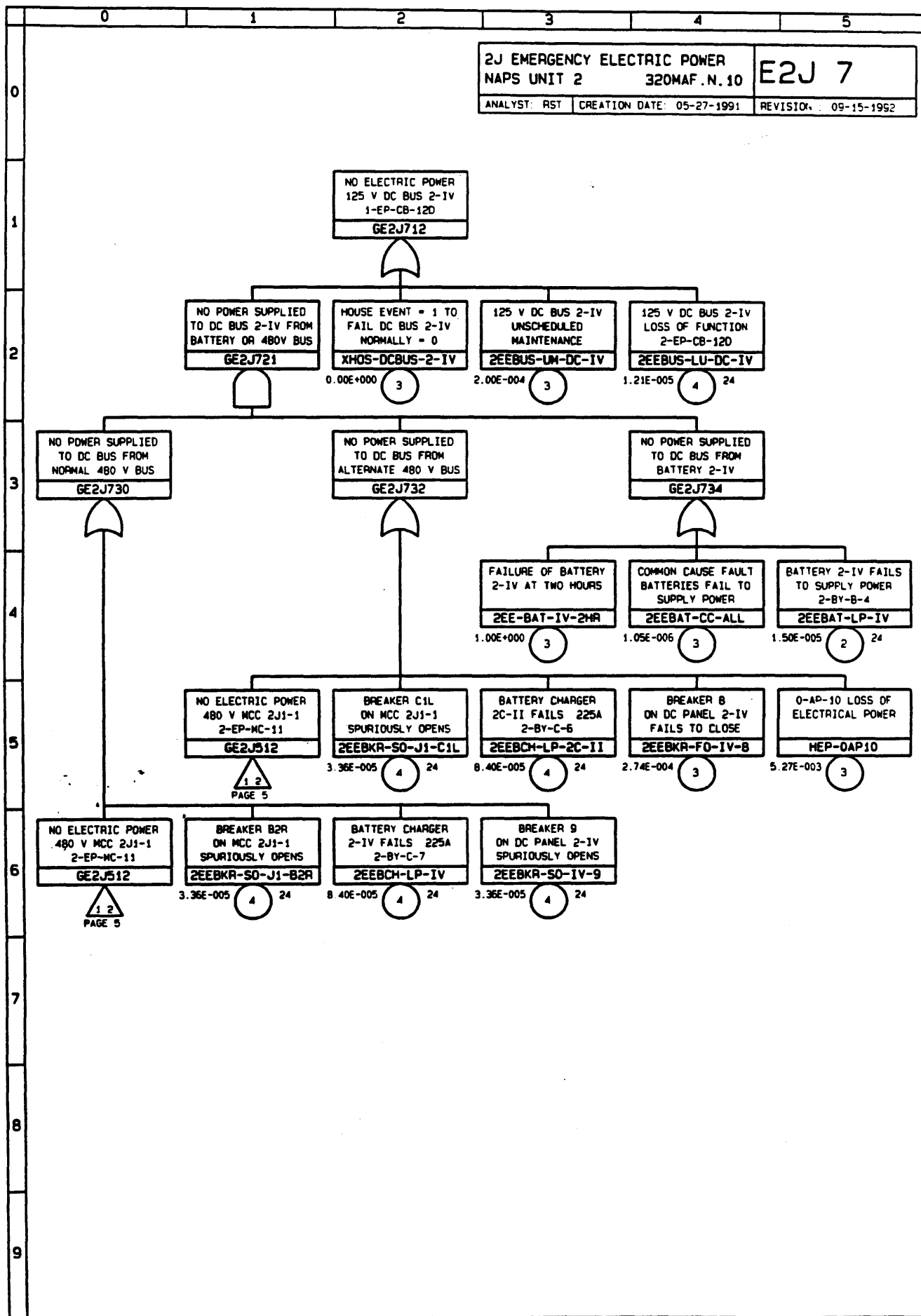


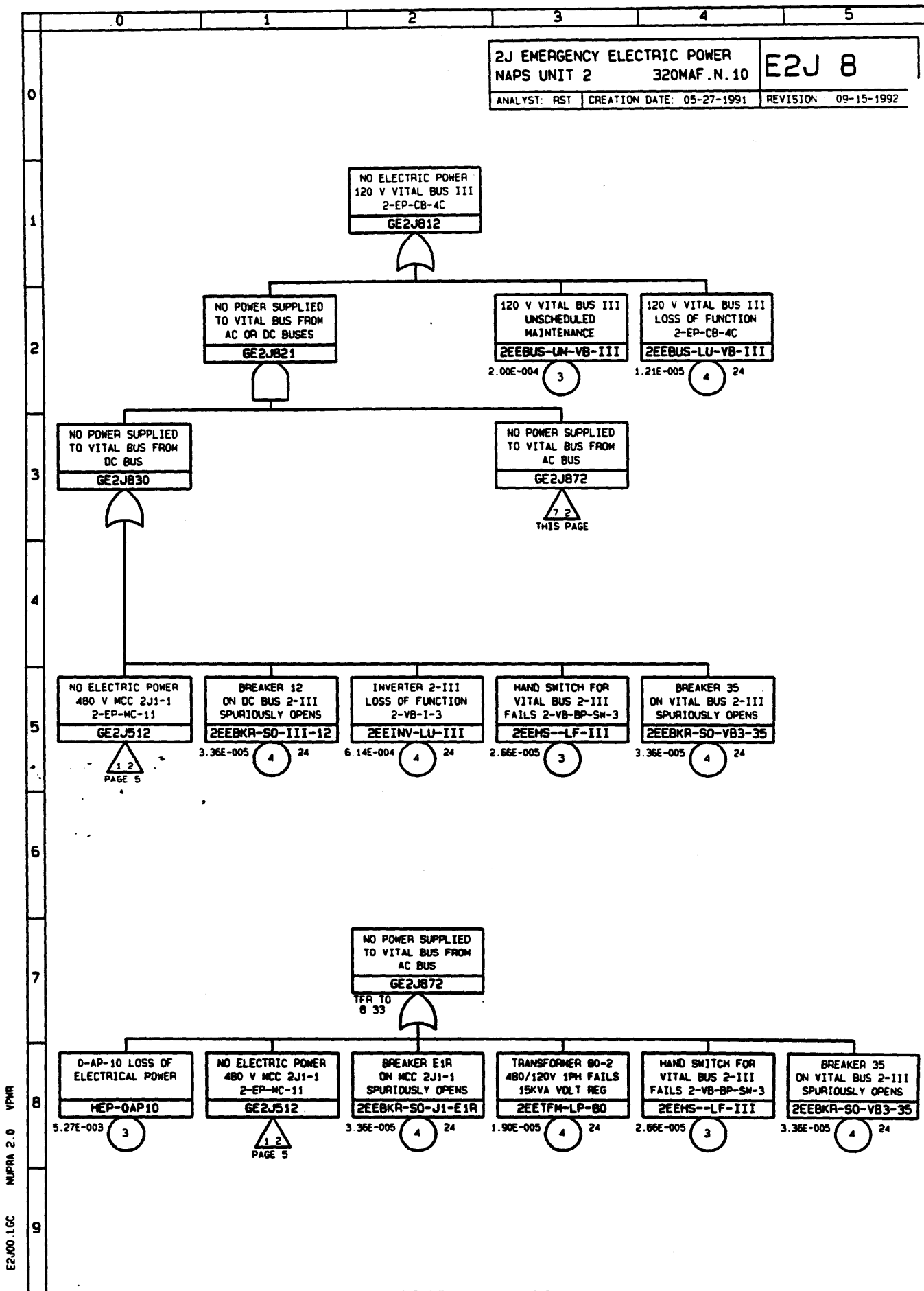


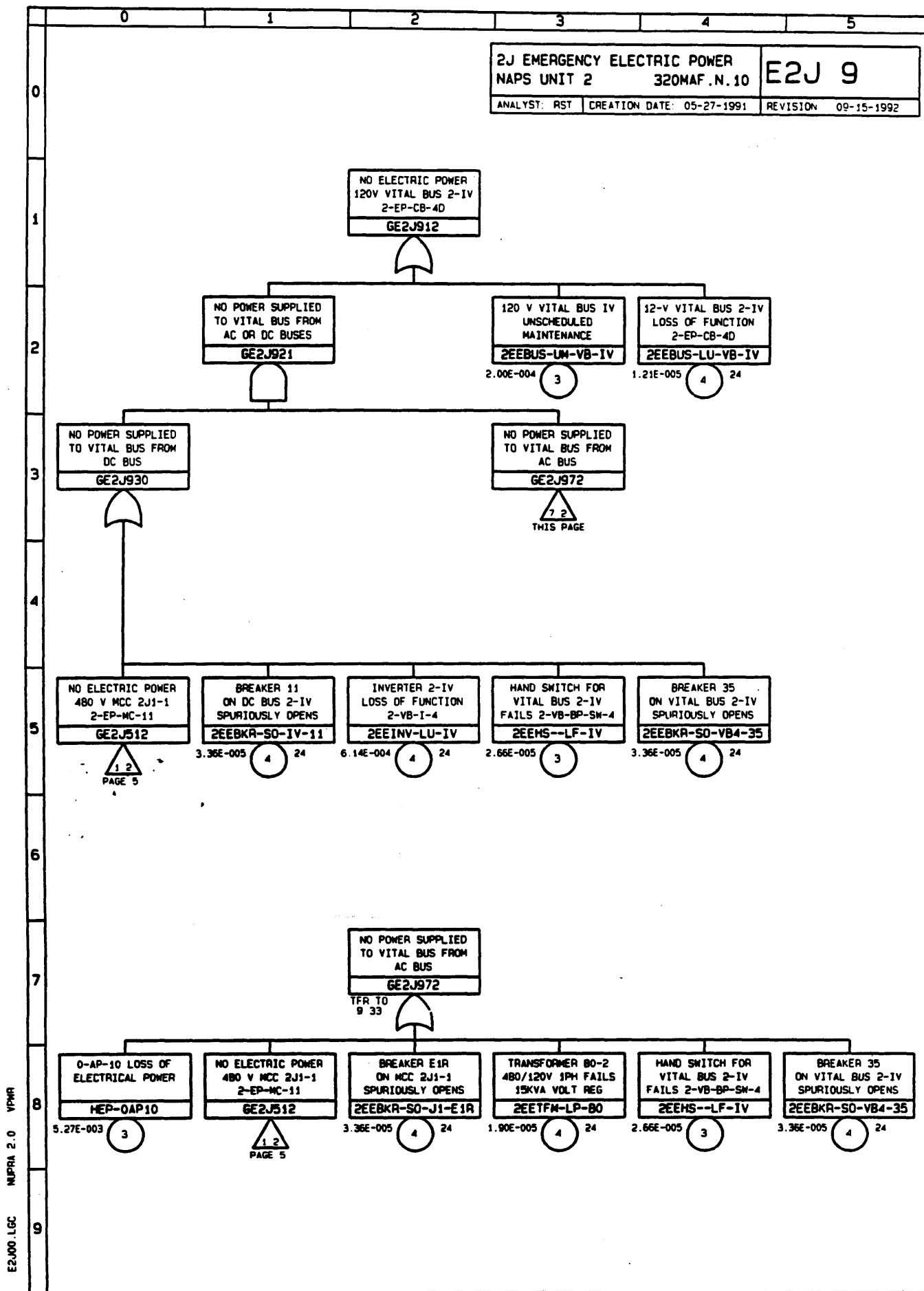




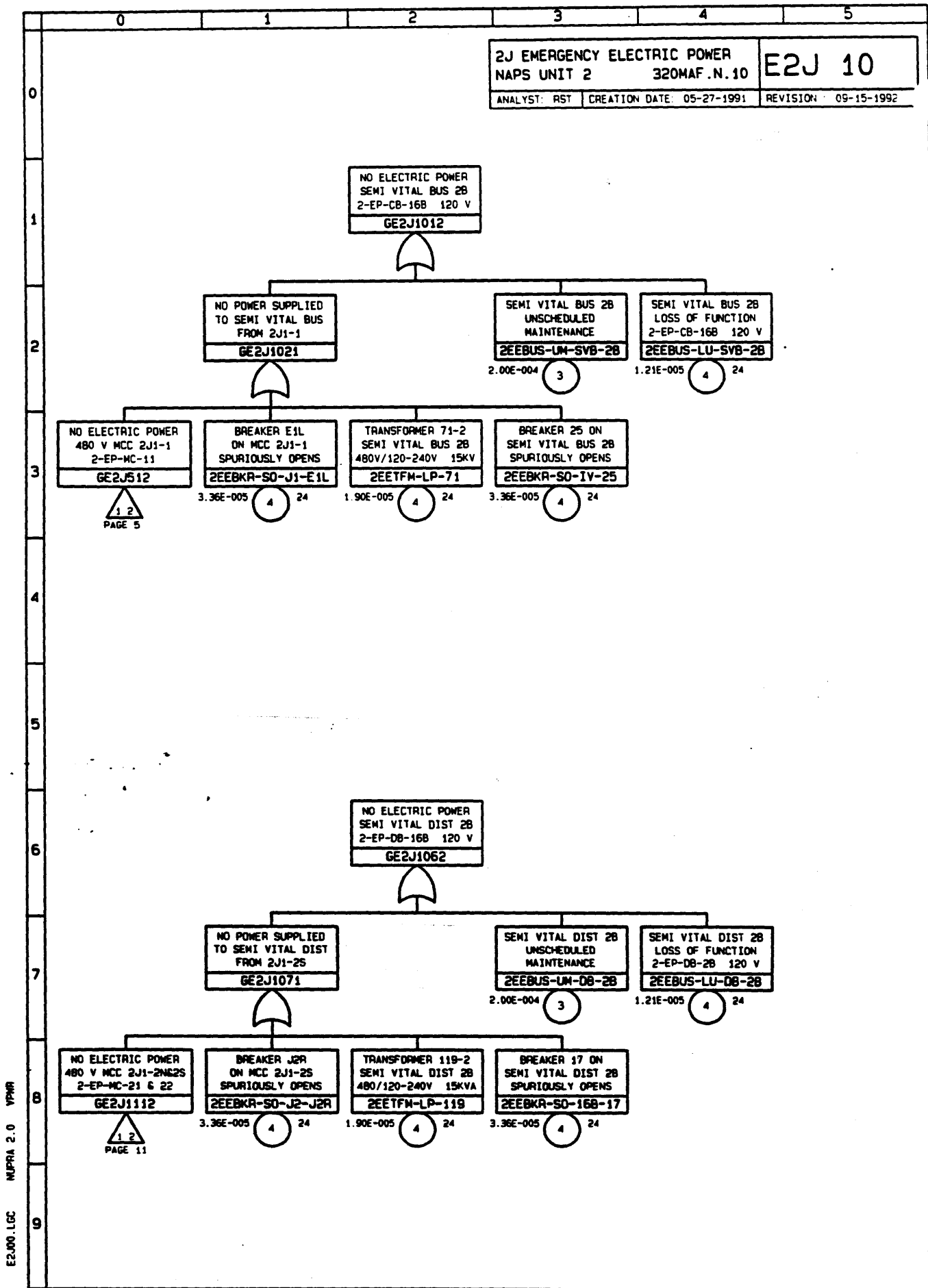
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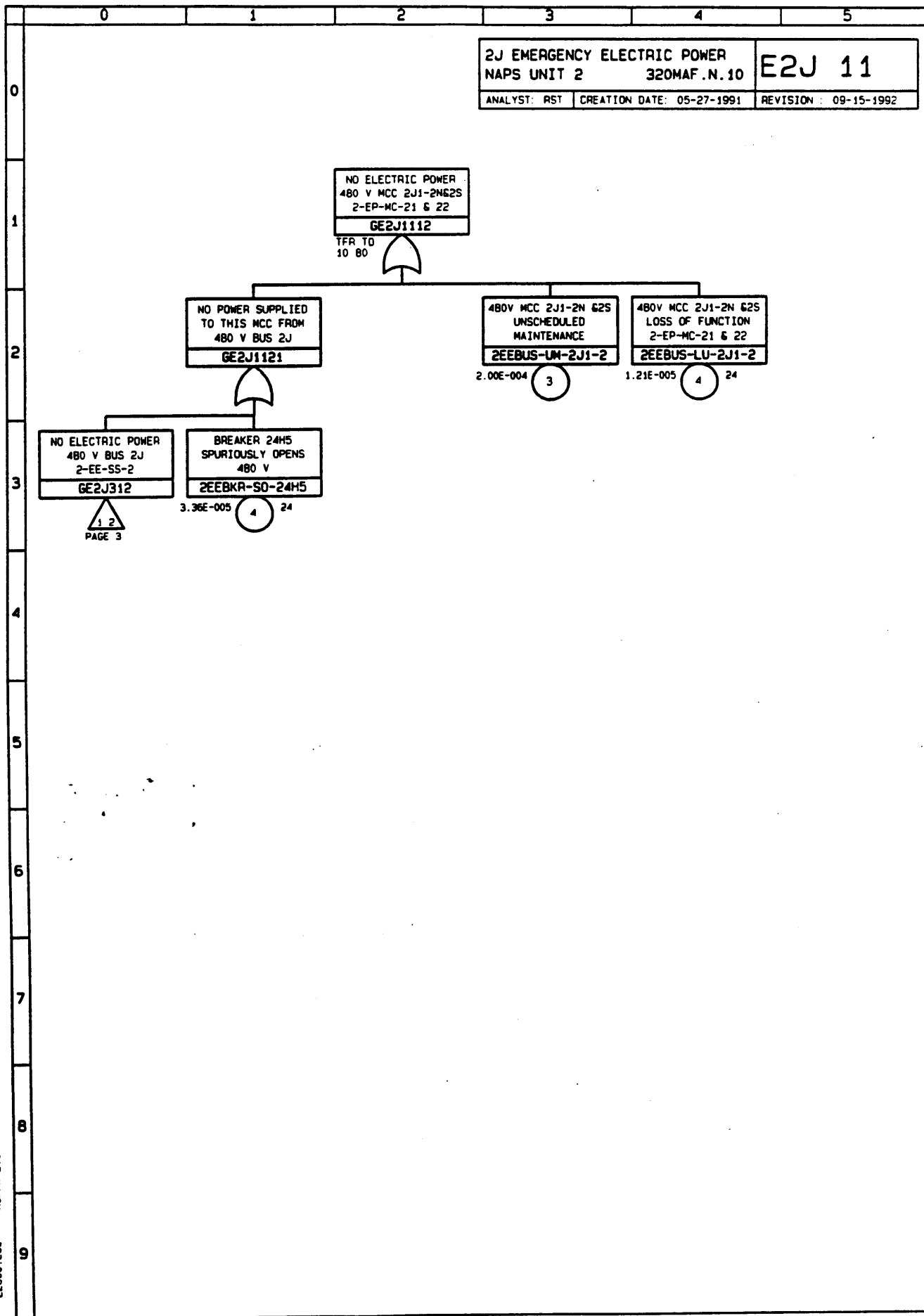




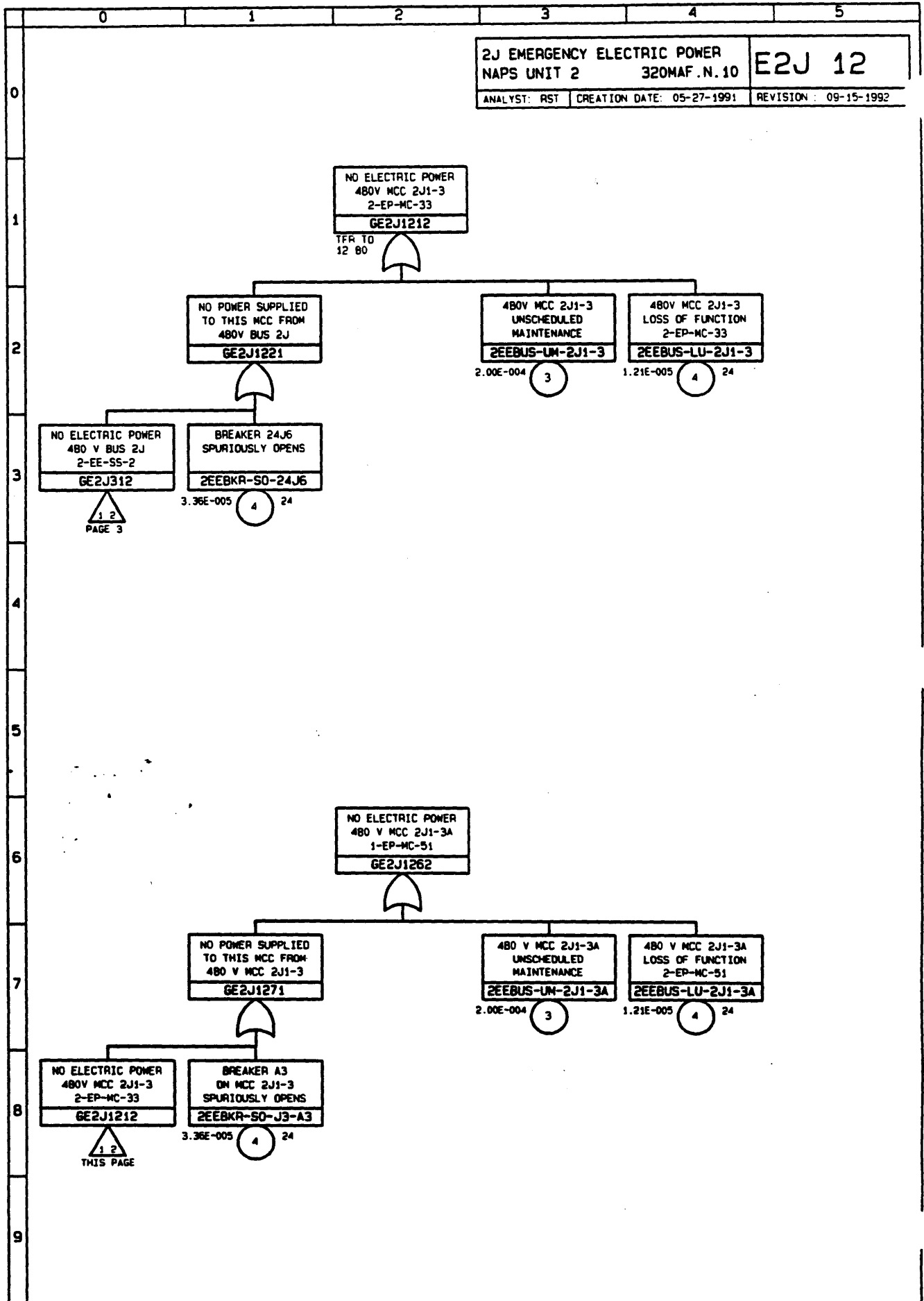
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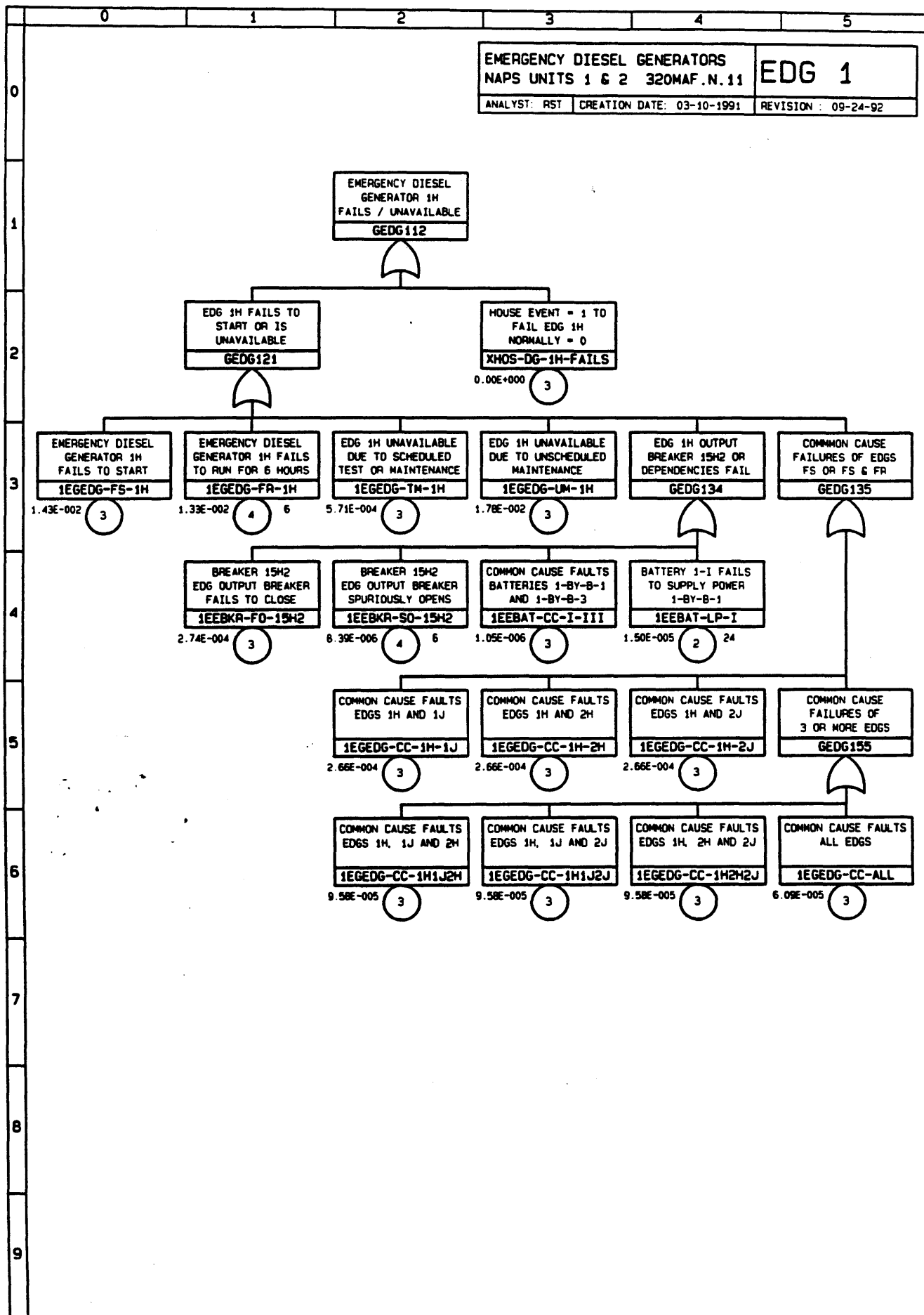


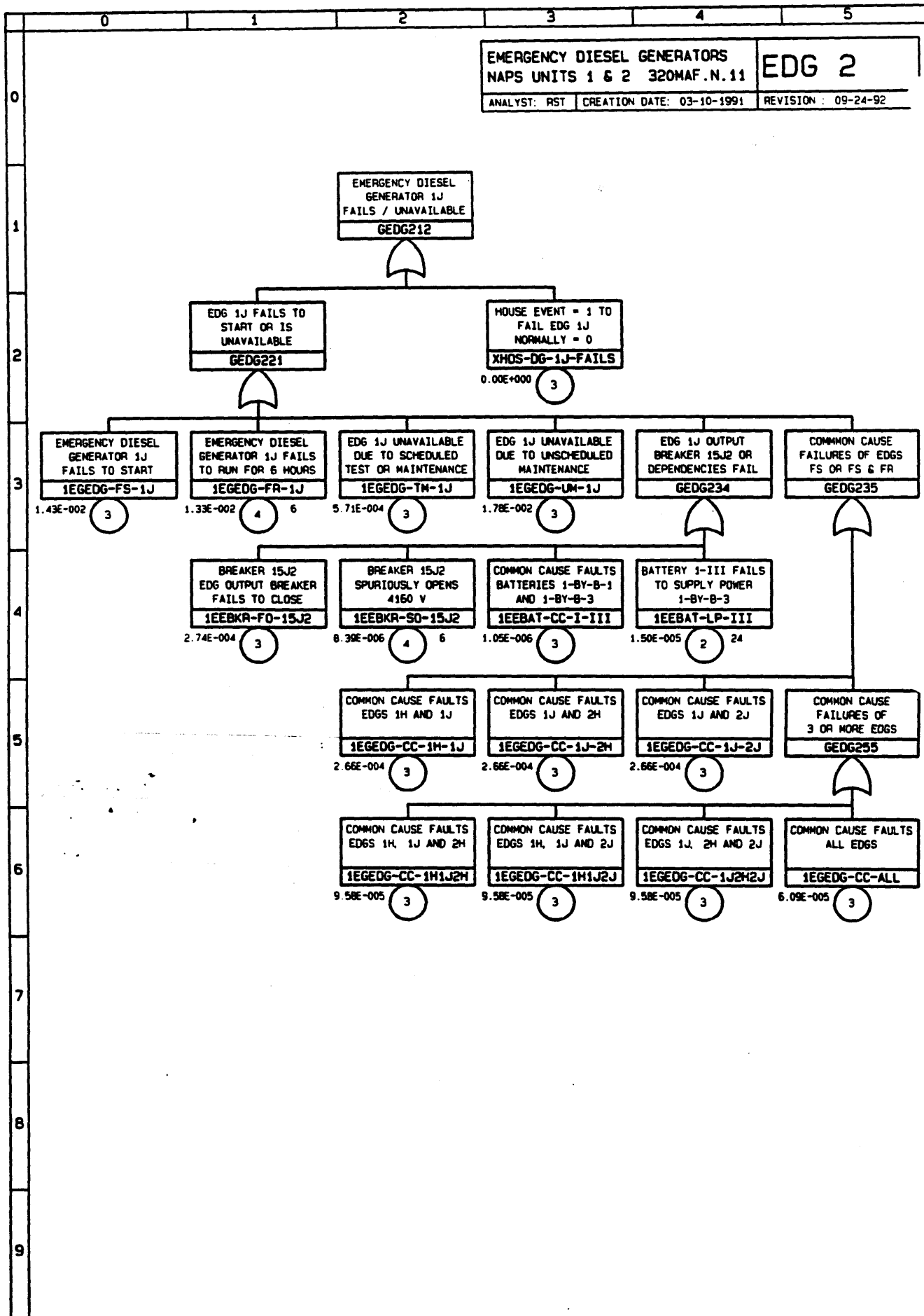
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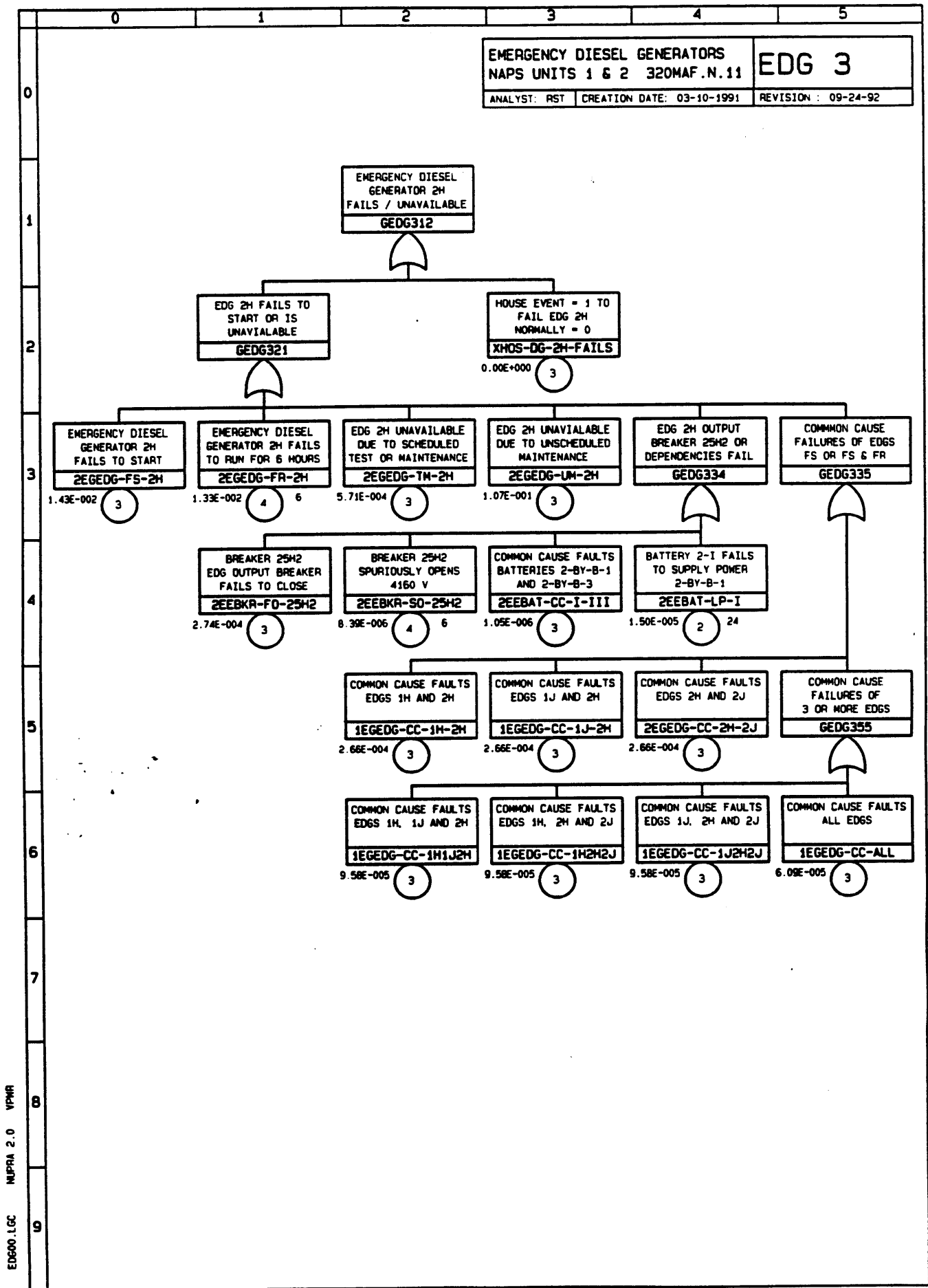


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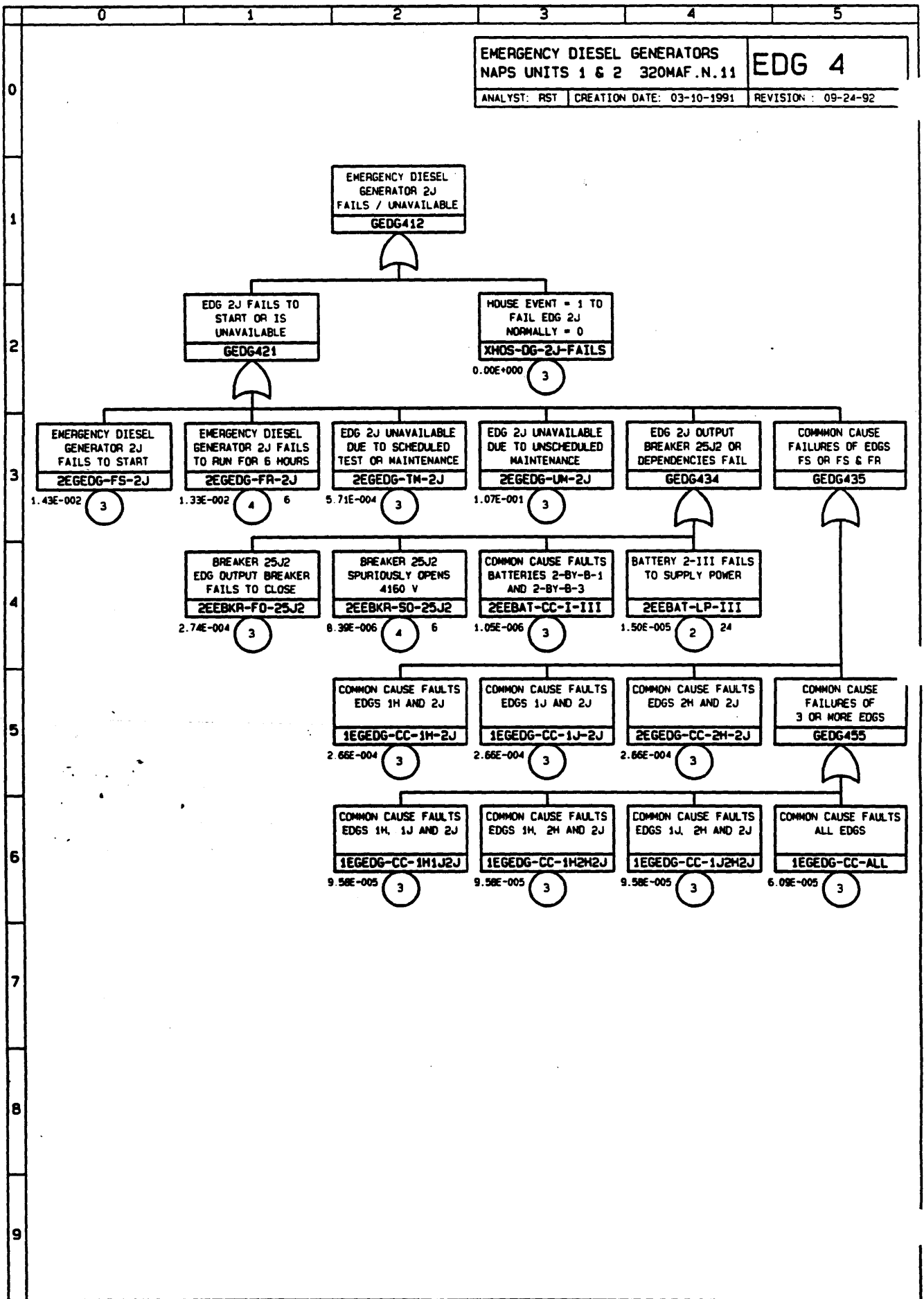


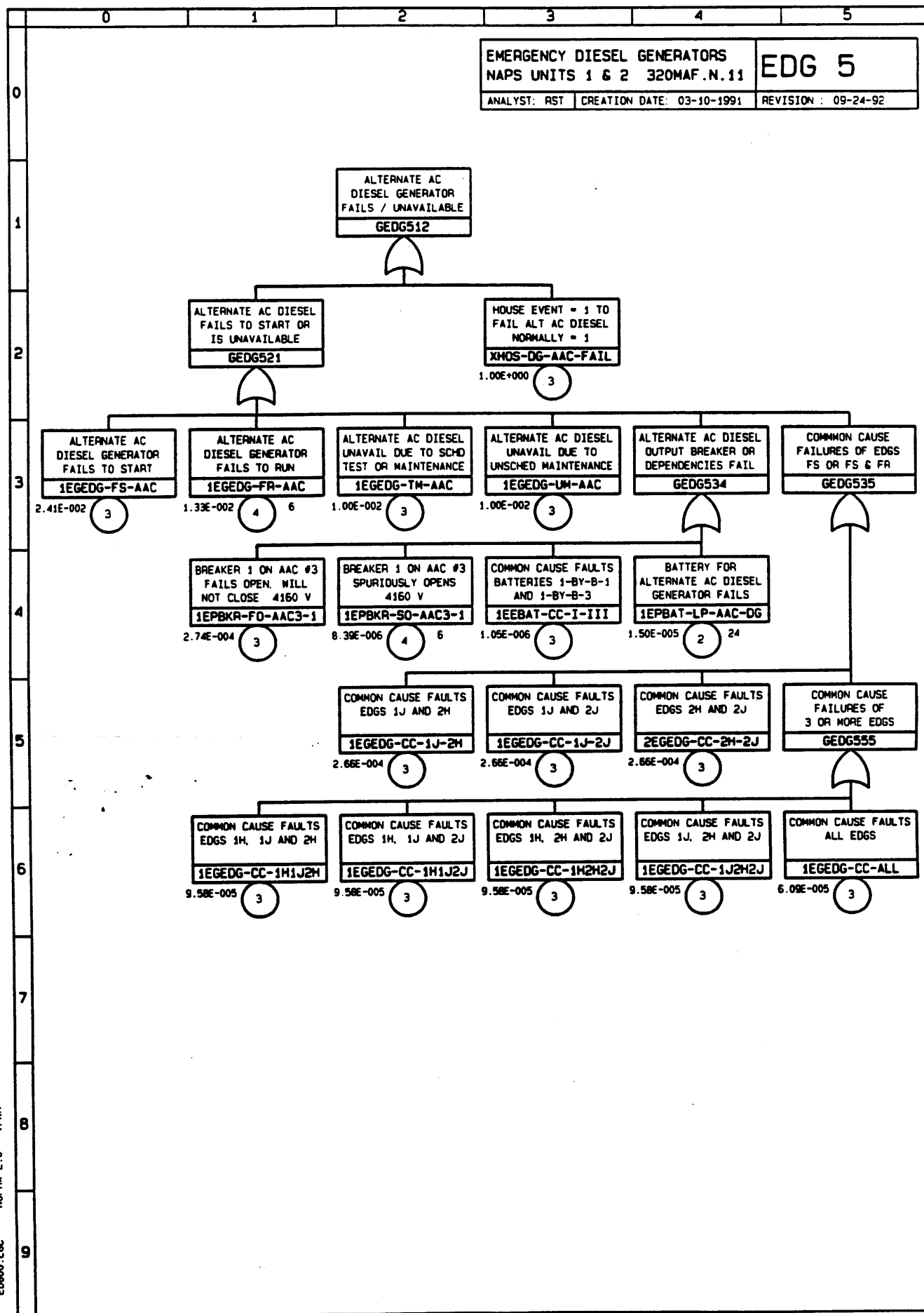




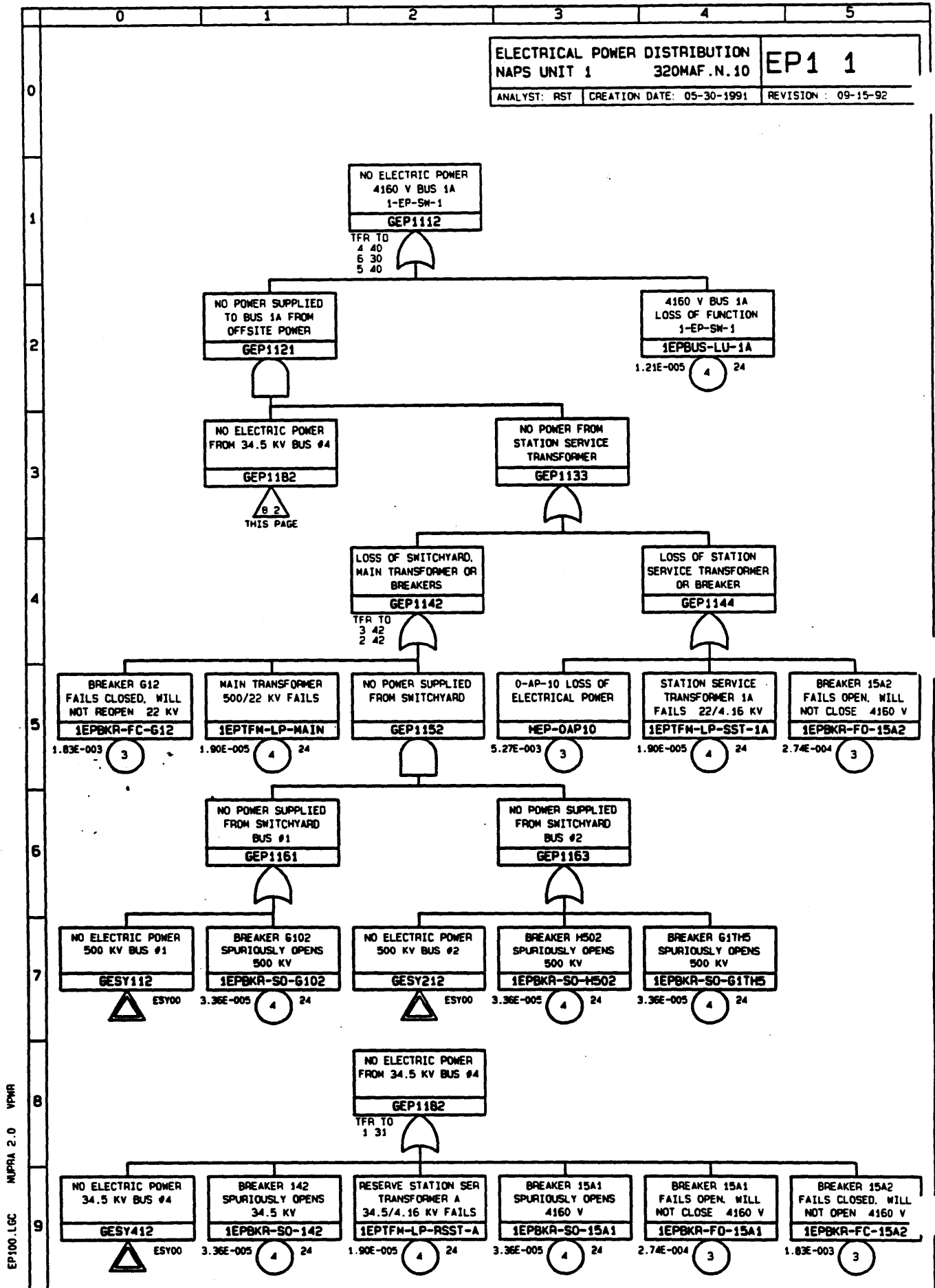


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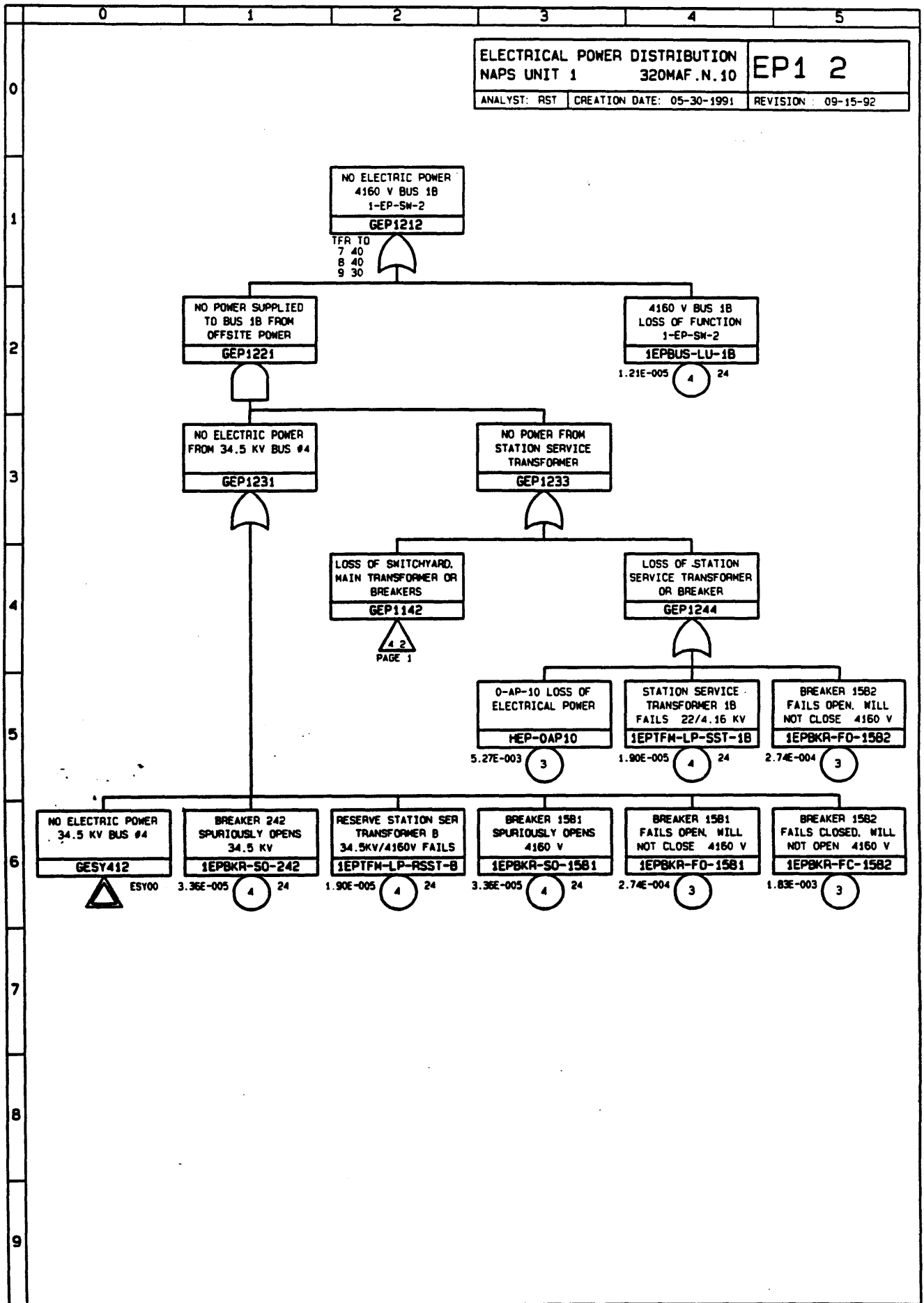


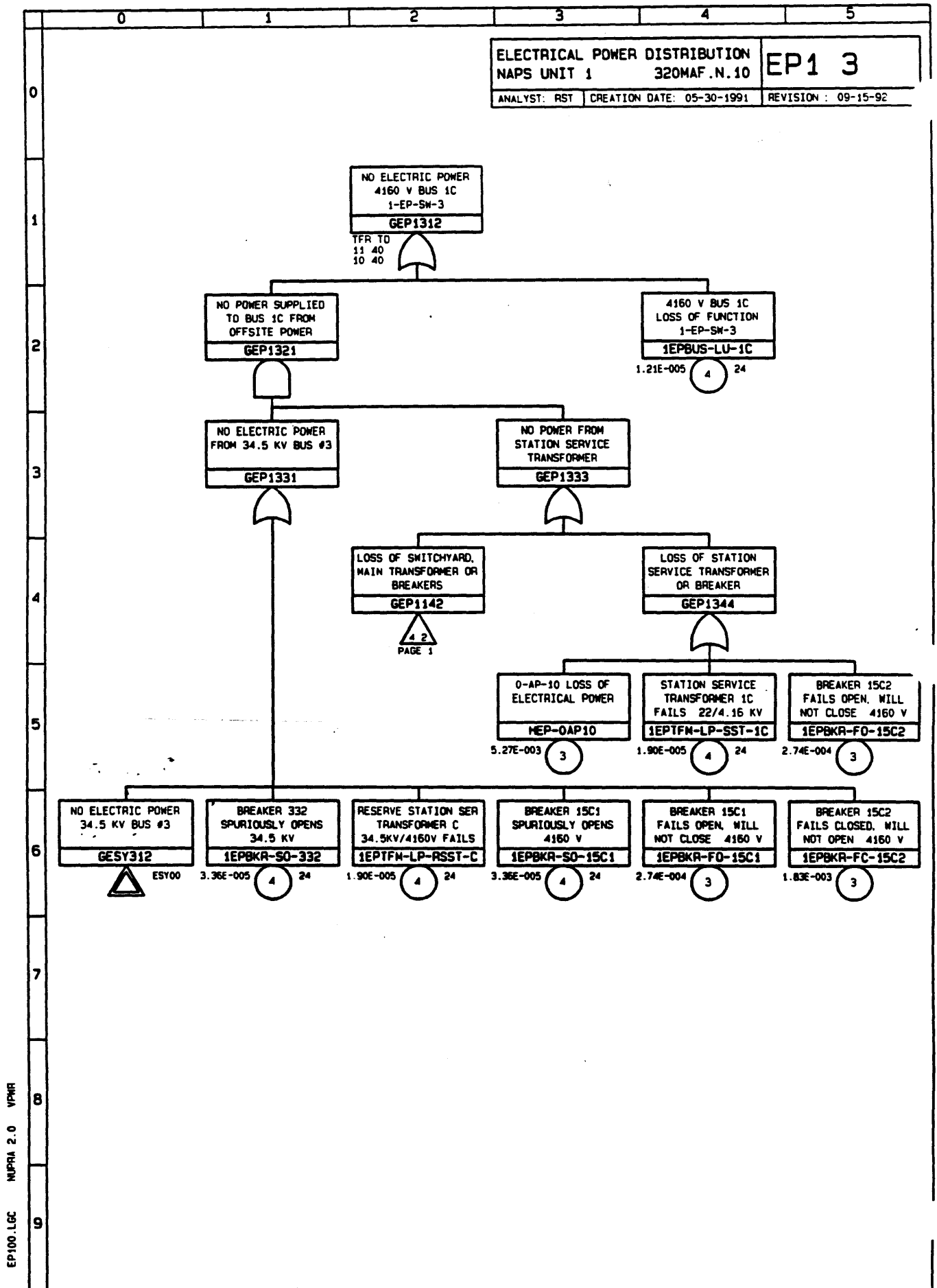
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EP100.LGC NUPRA 2.0 VPMR

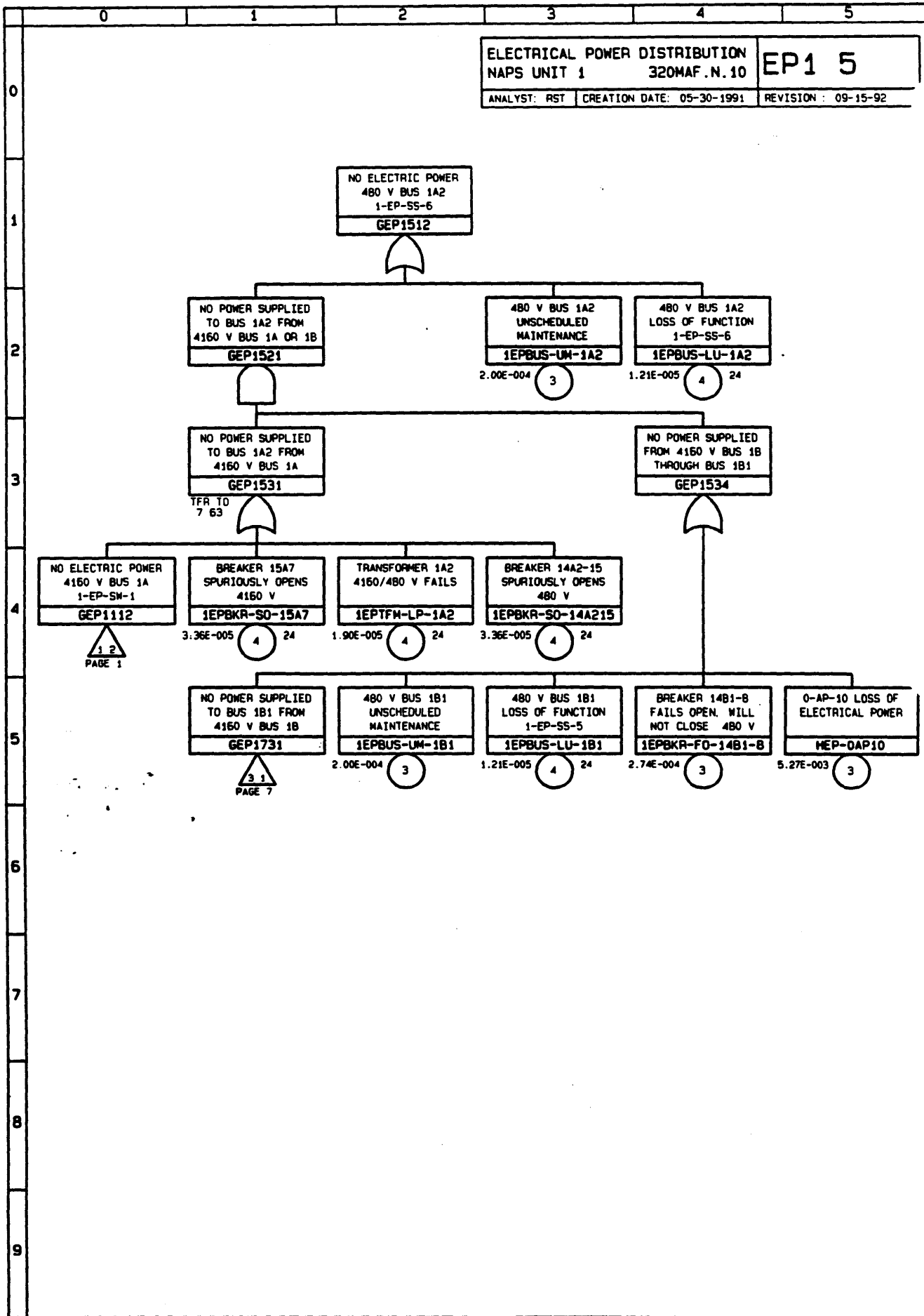
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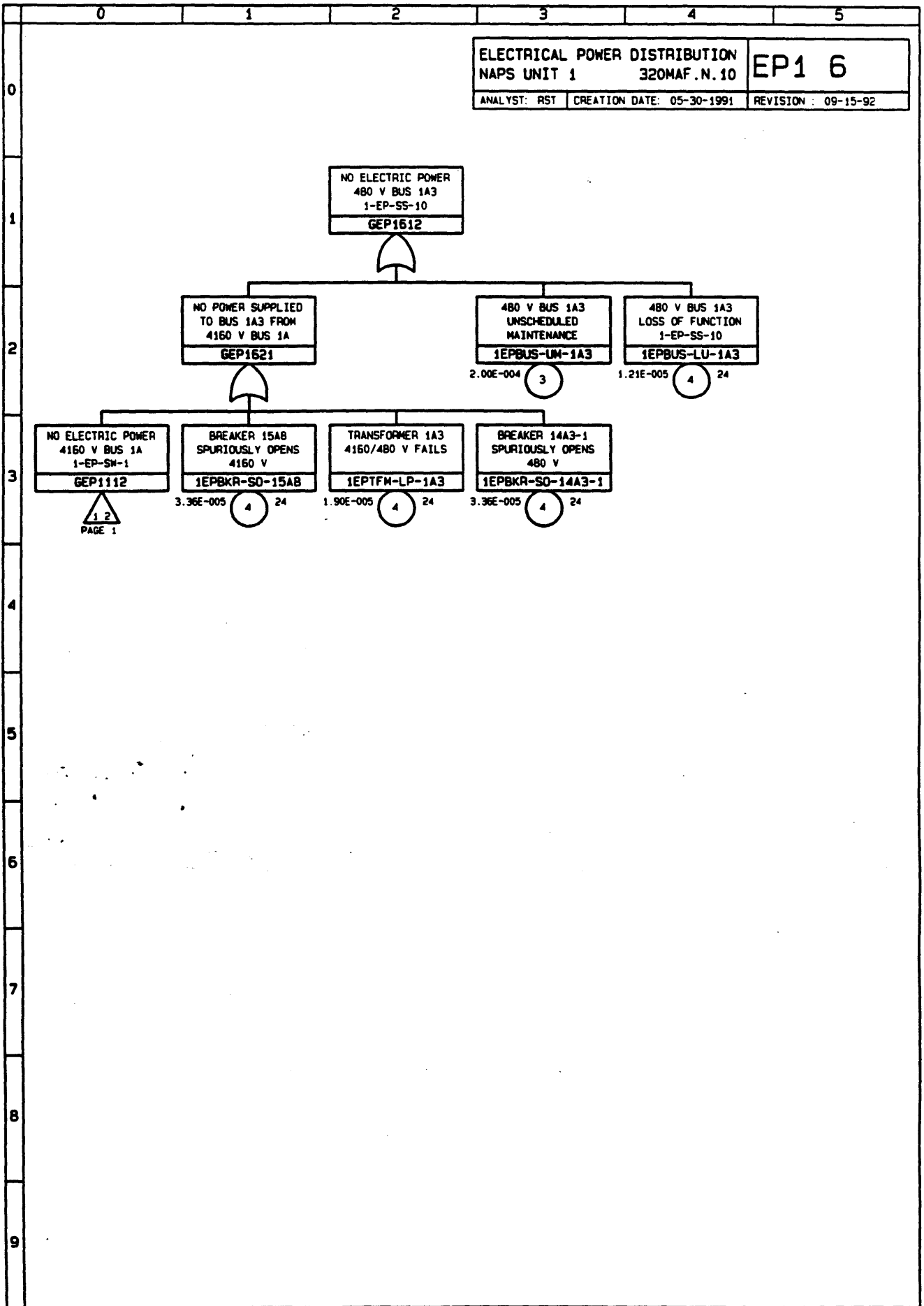


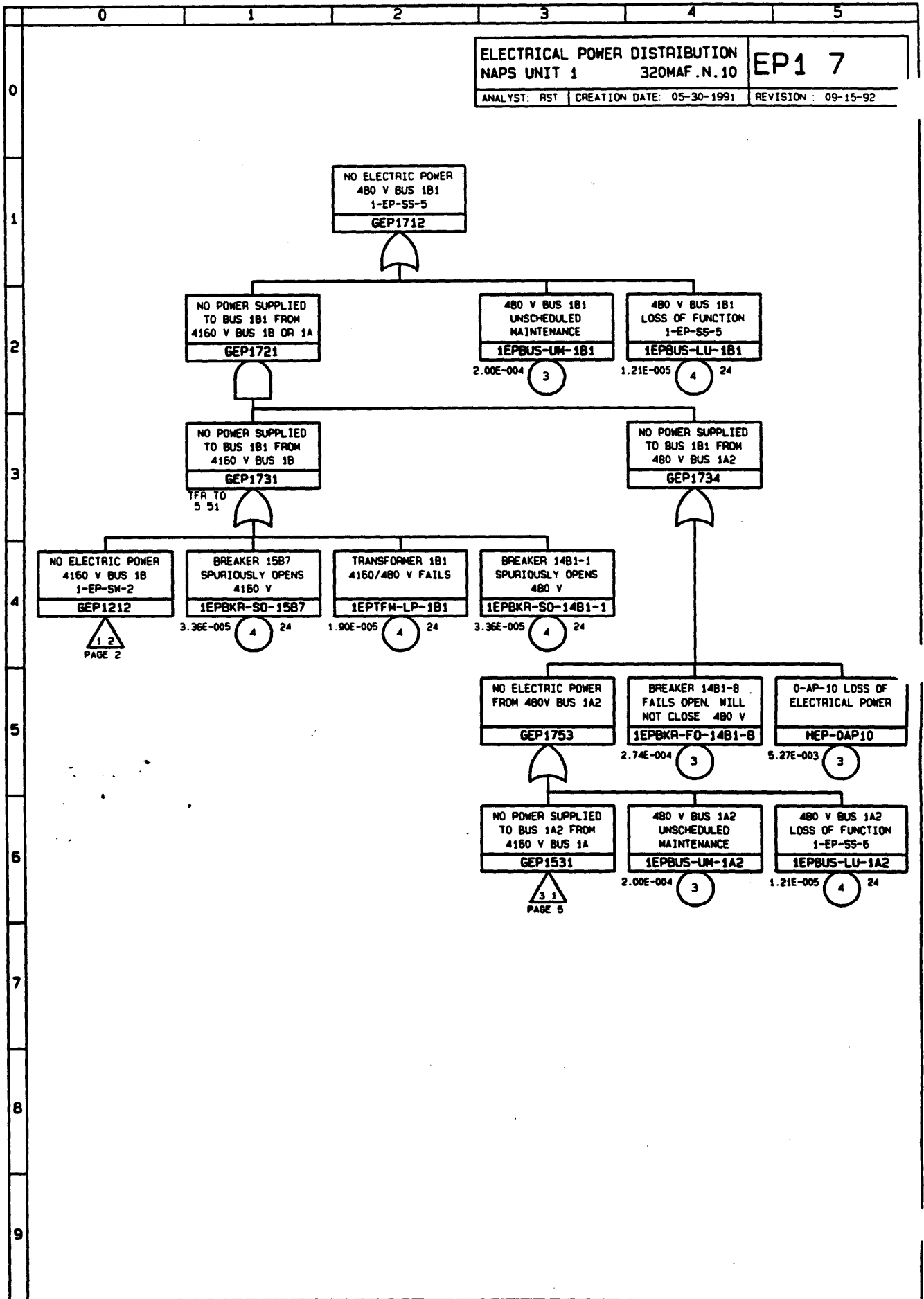




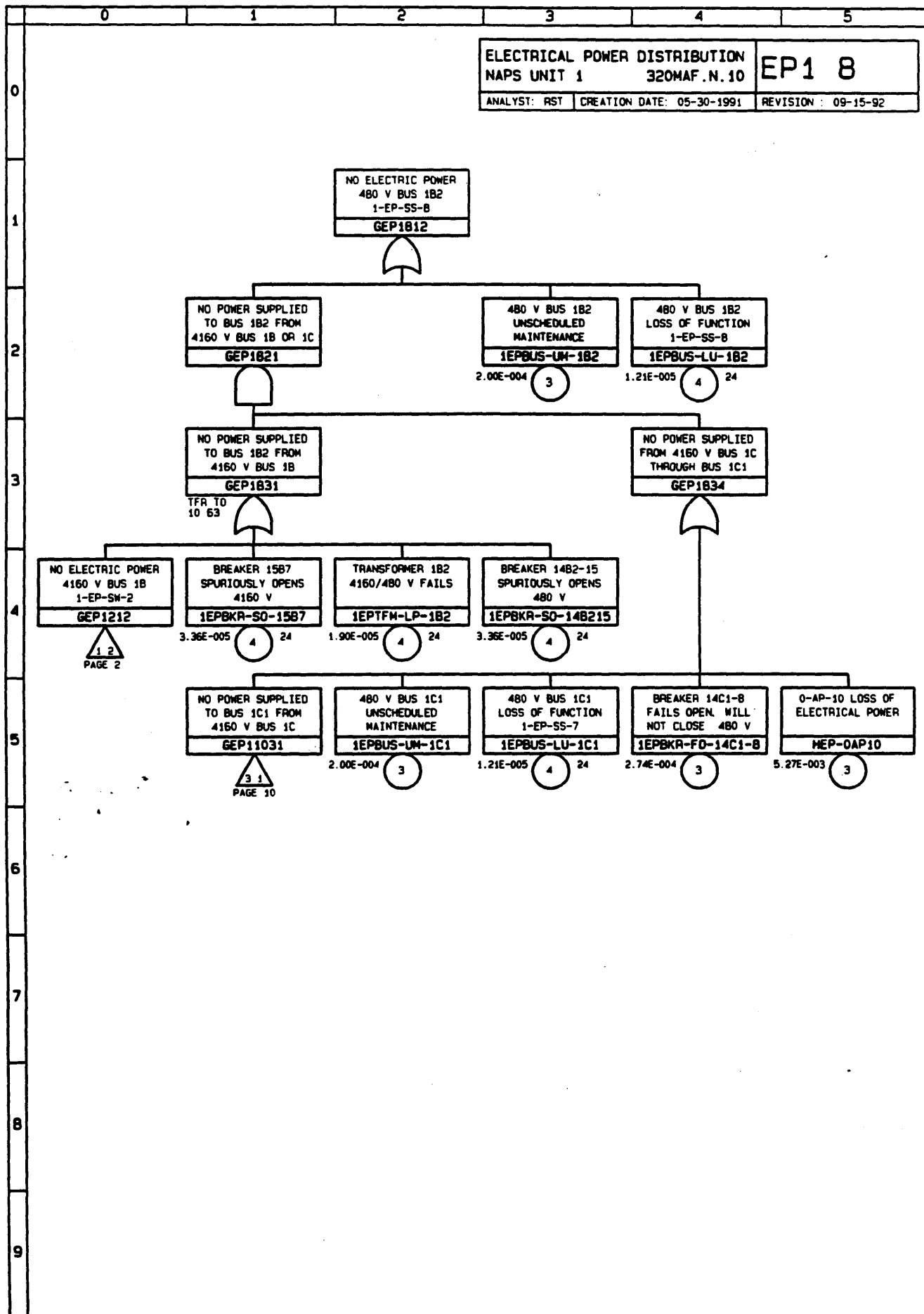
EP100.LGC NUPRA 2.0 VPMR

EP100.LGC NUPRA 2.0 VPMR

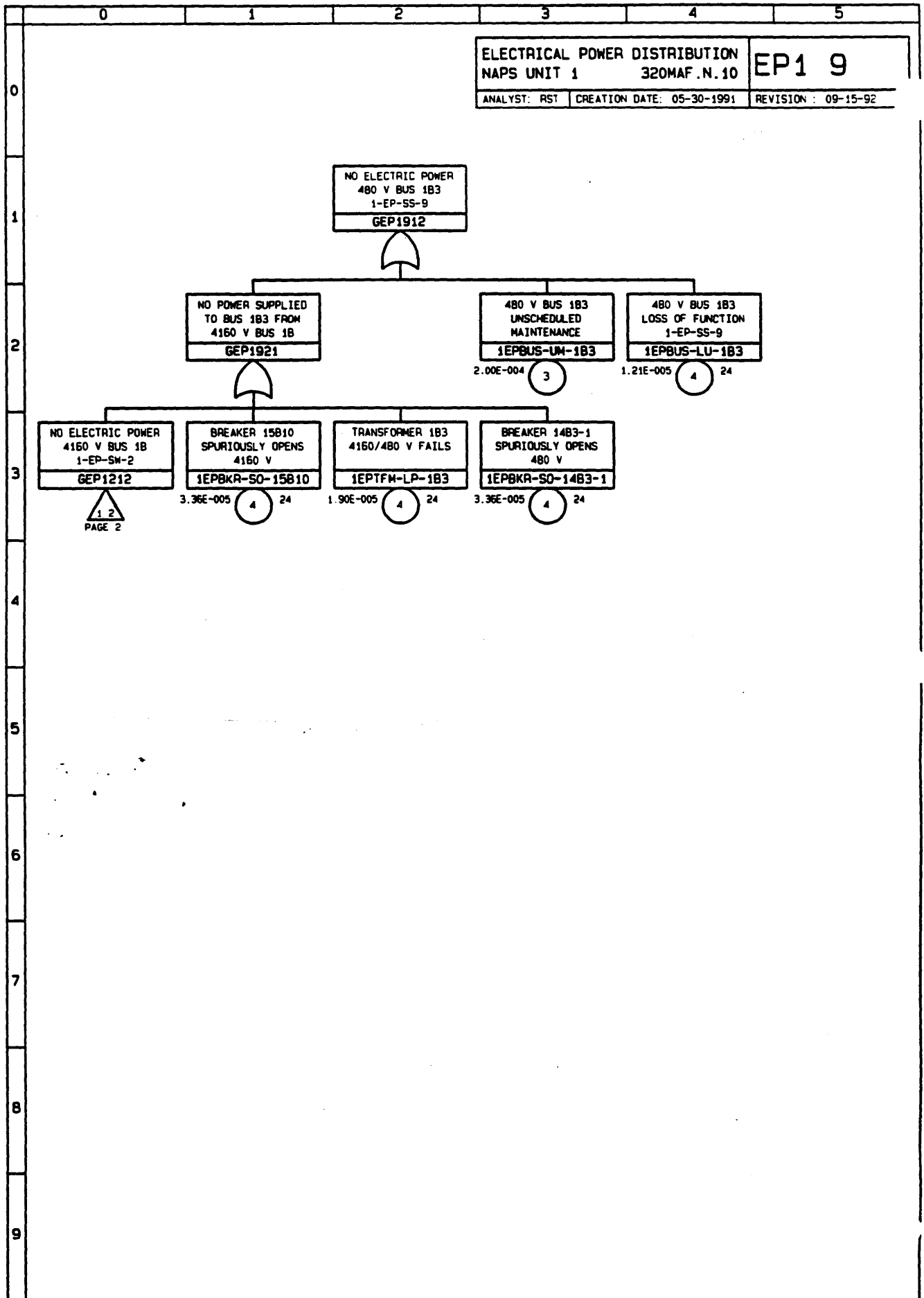




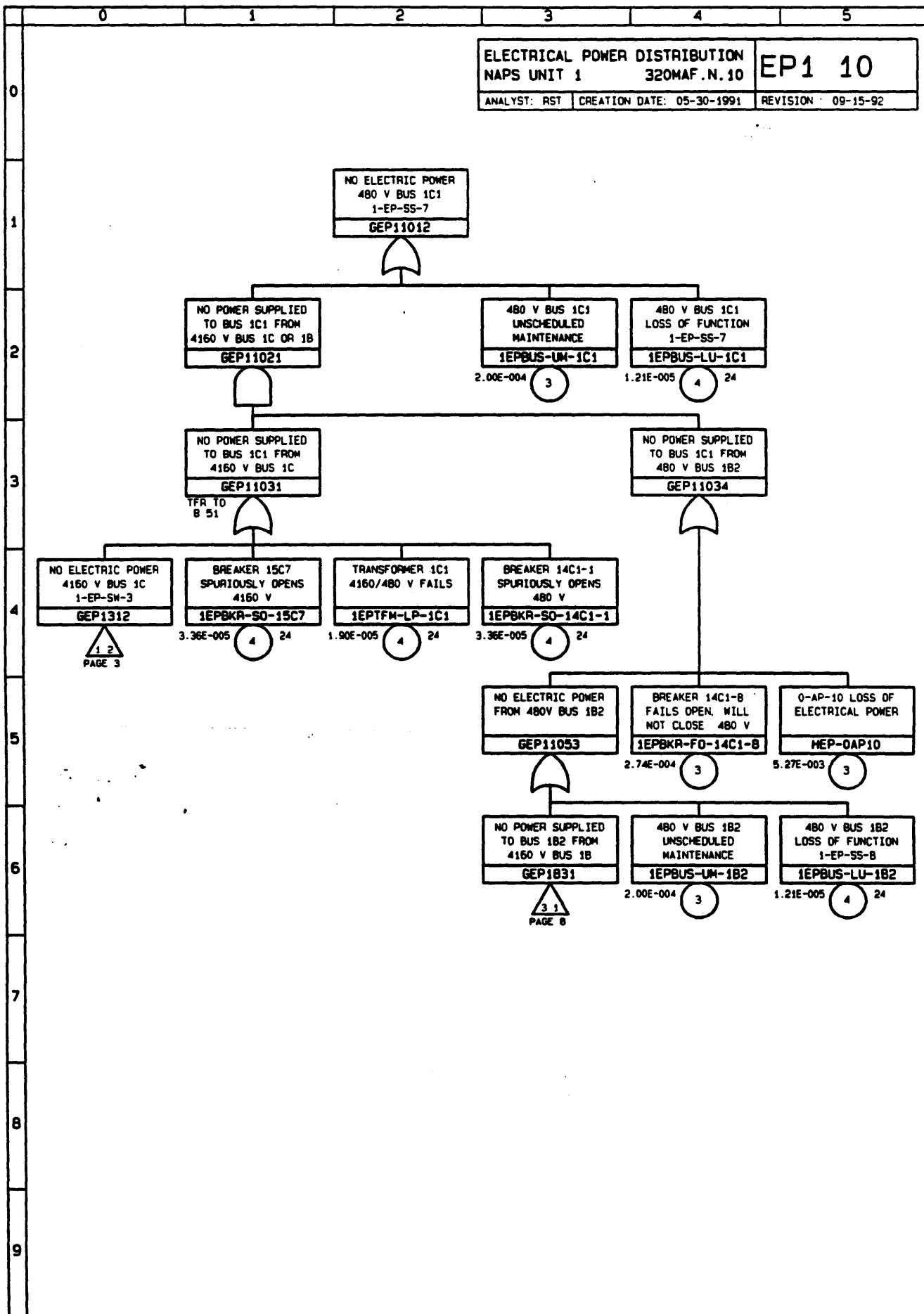
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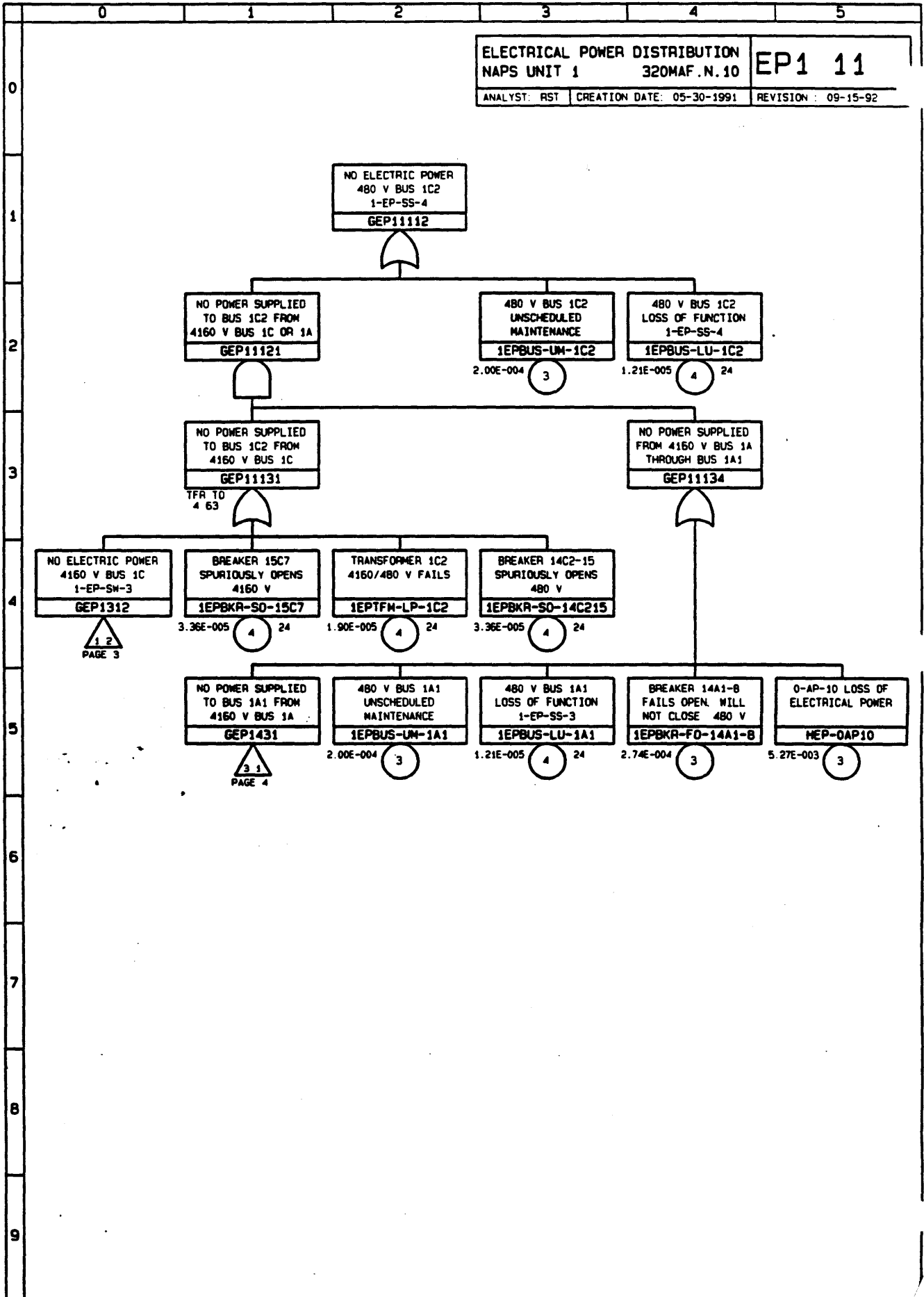
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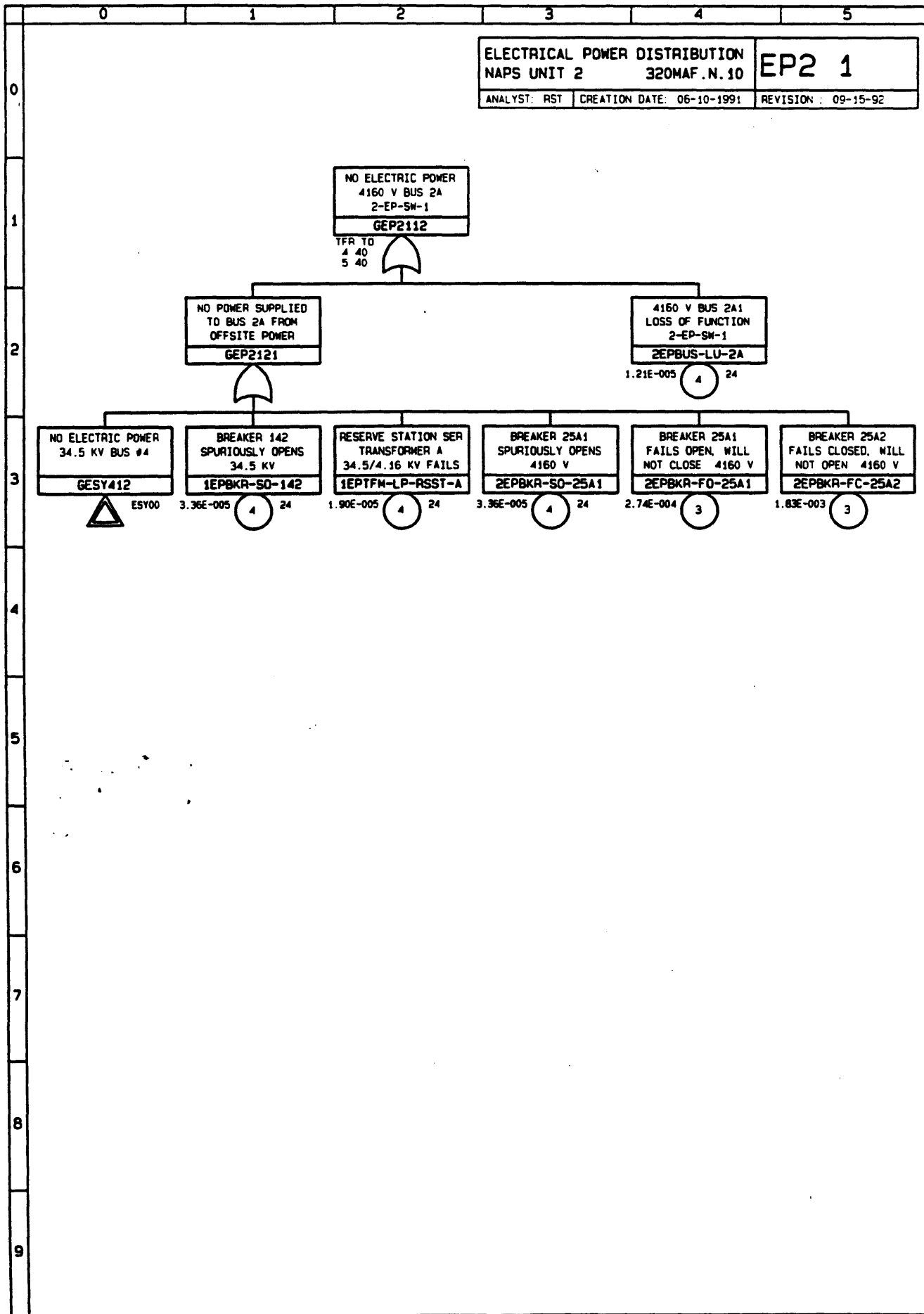
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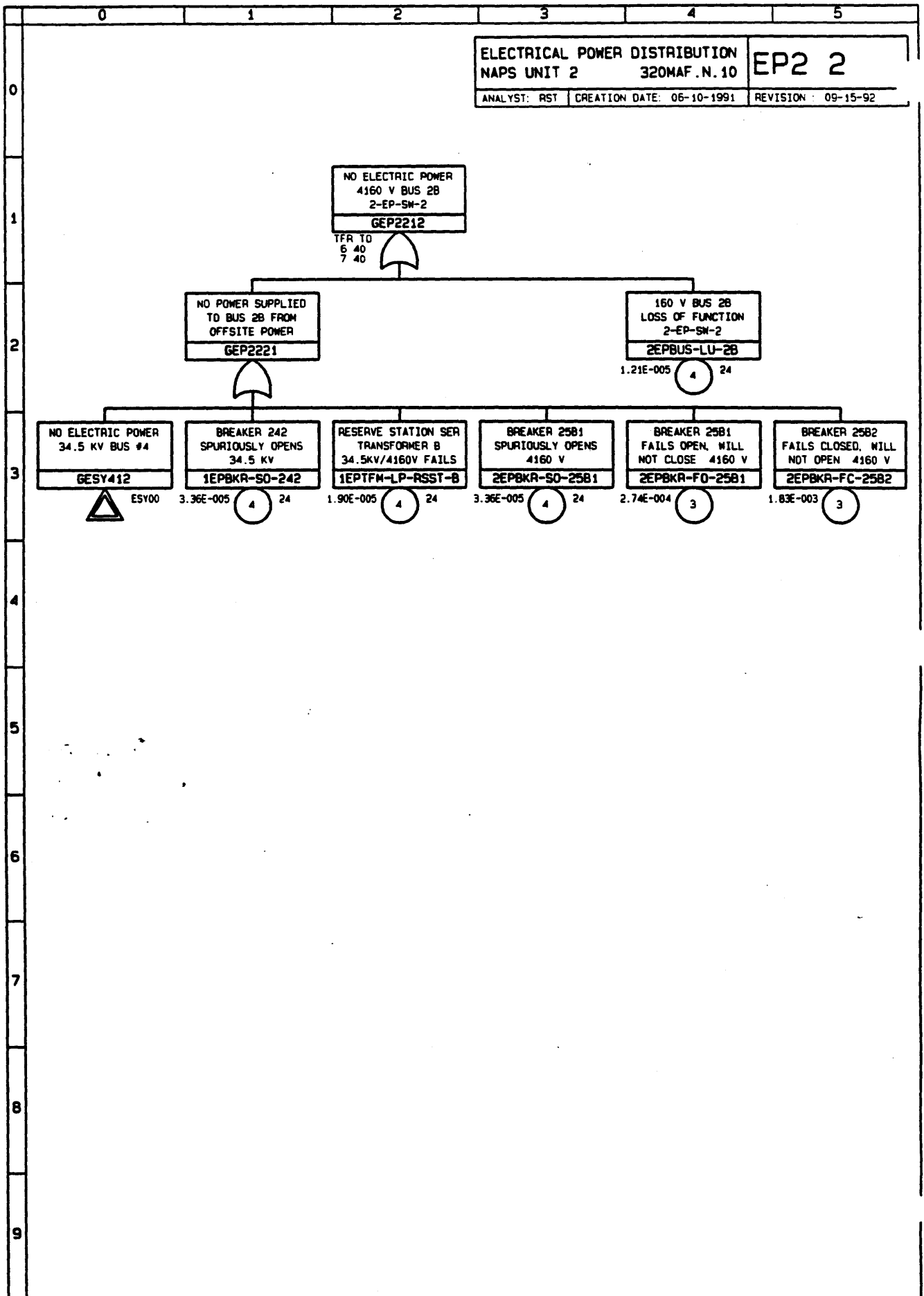


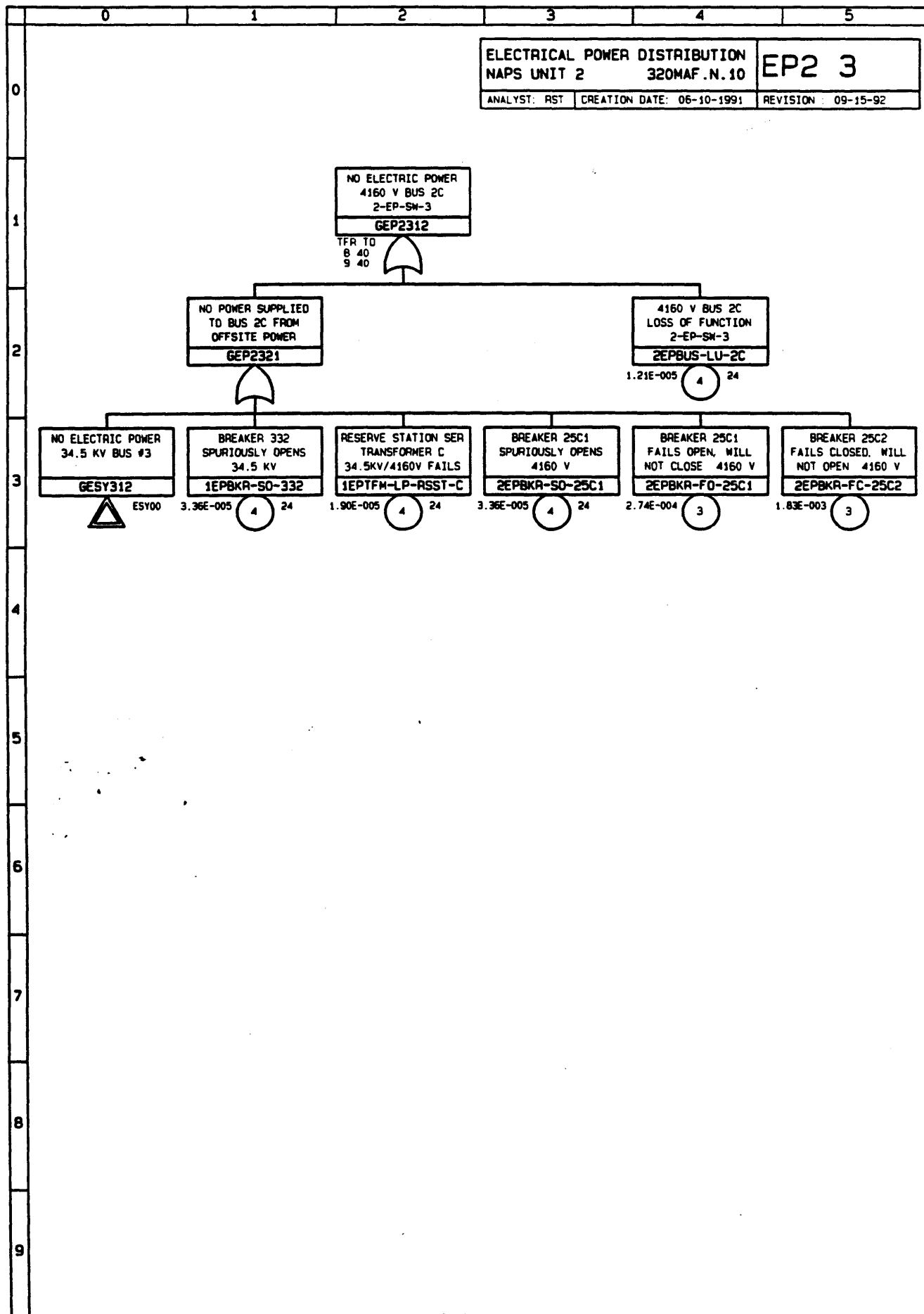




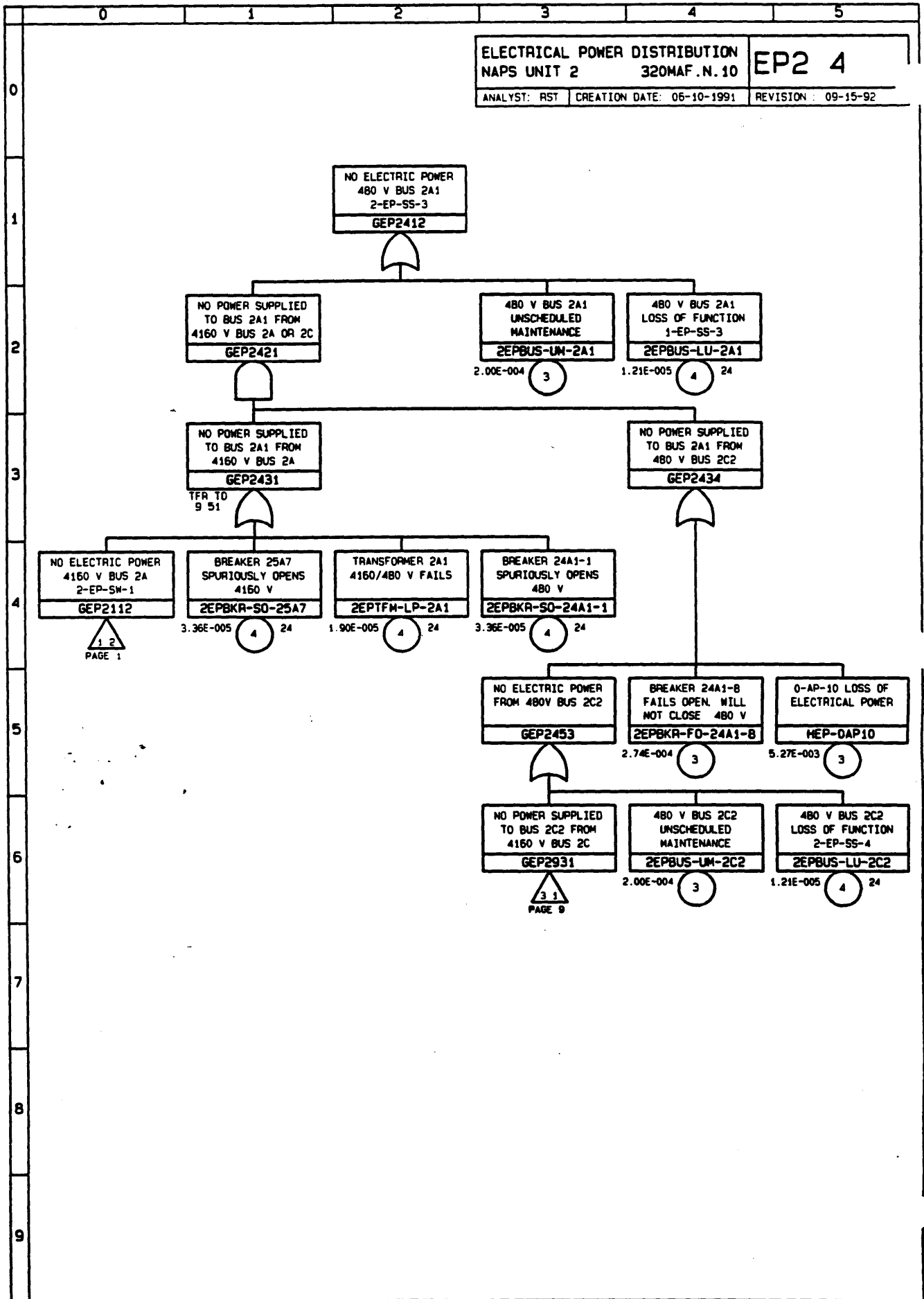
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EP200.LGC MUPRI 2.0 VPMR



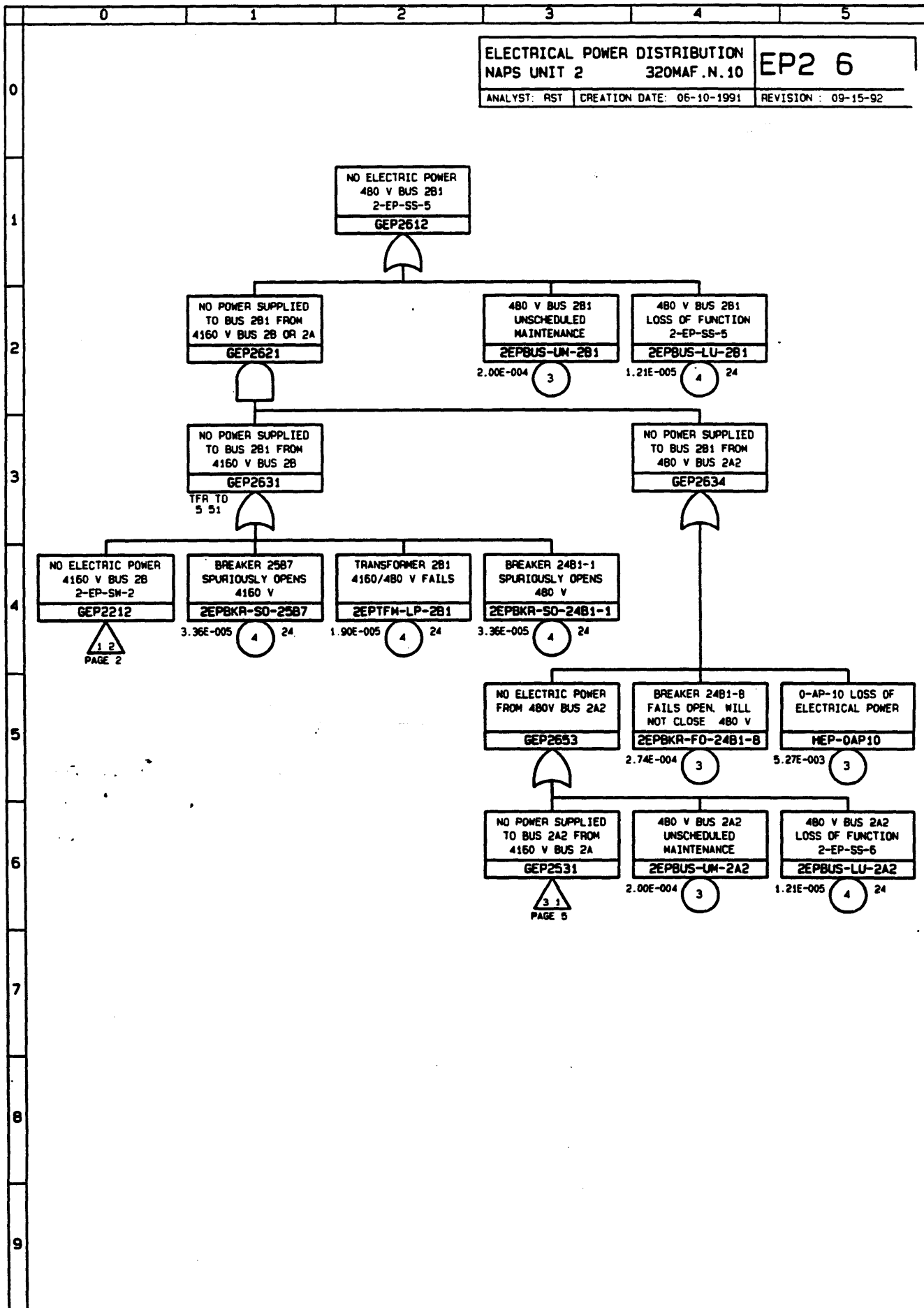


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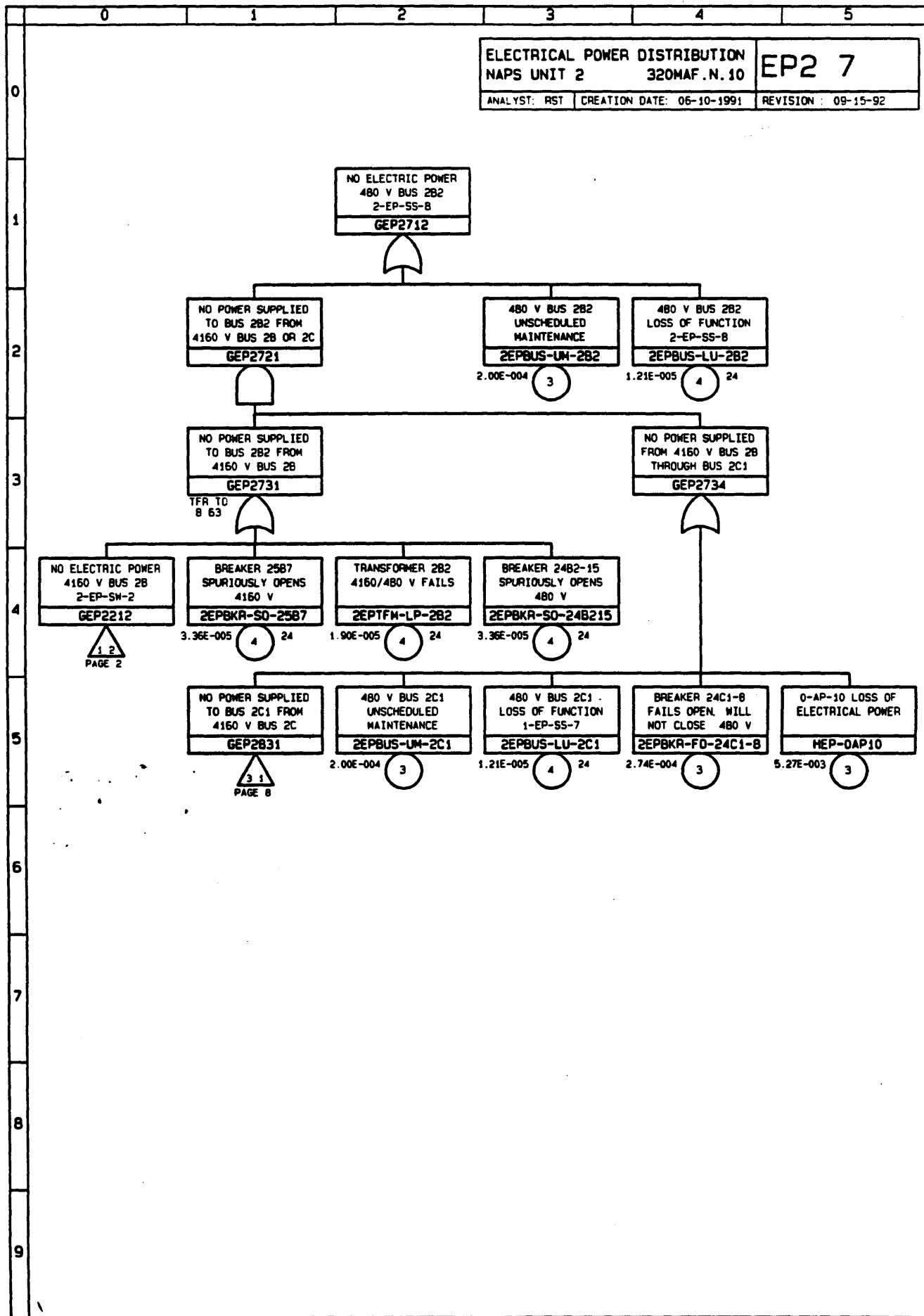


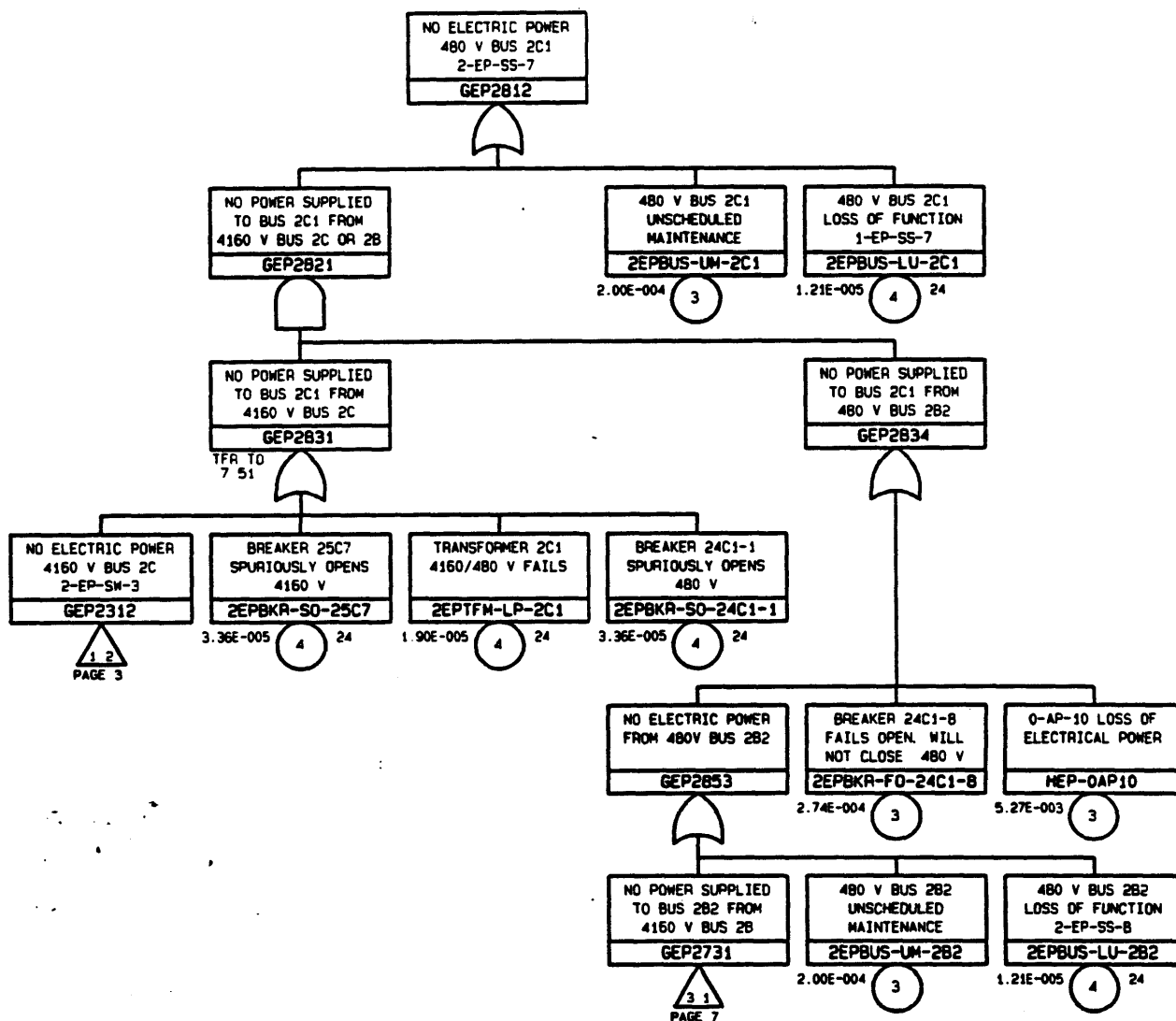


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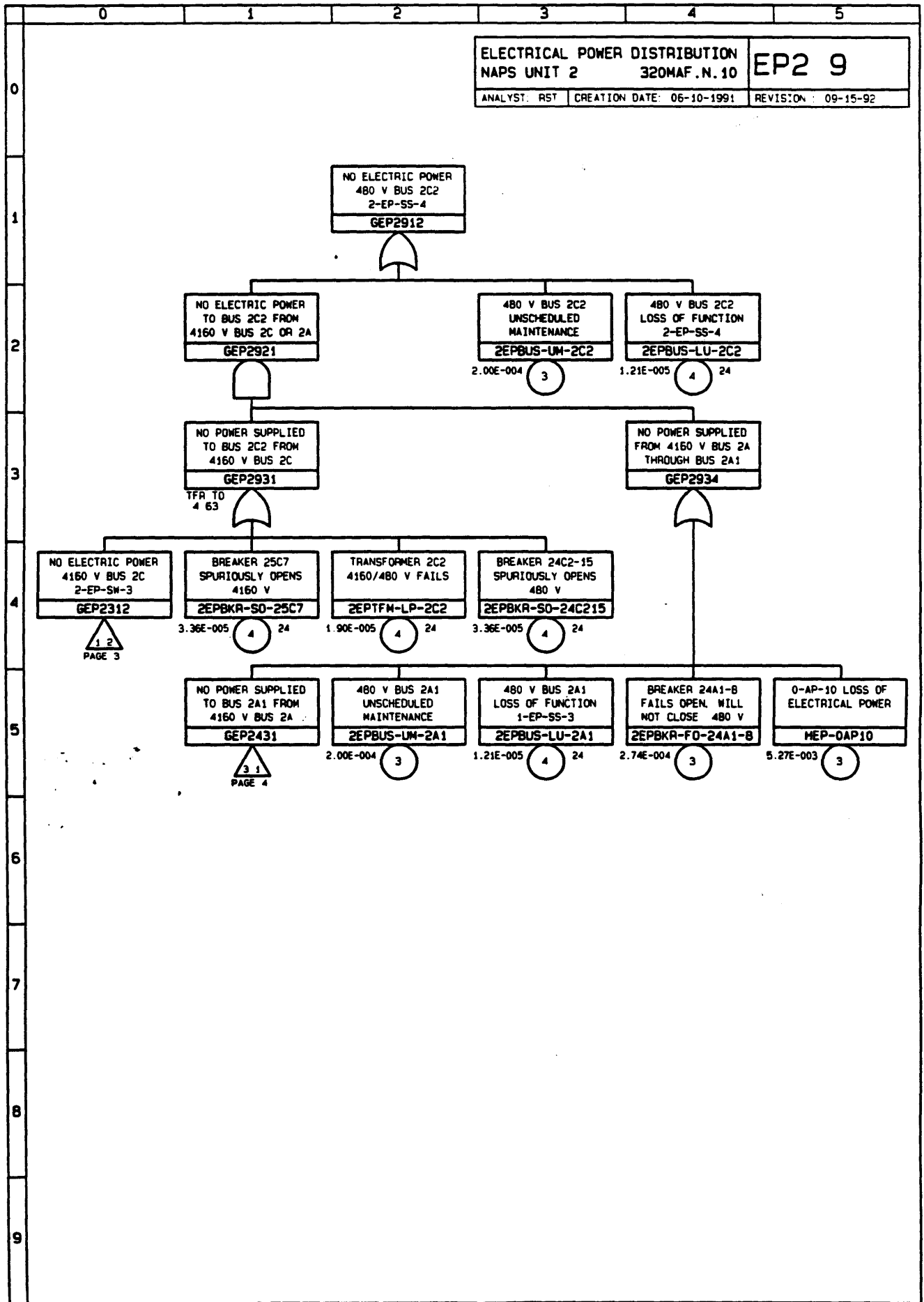
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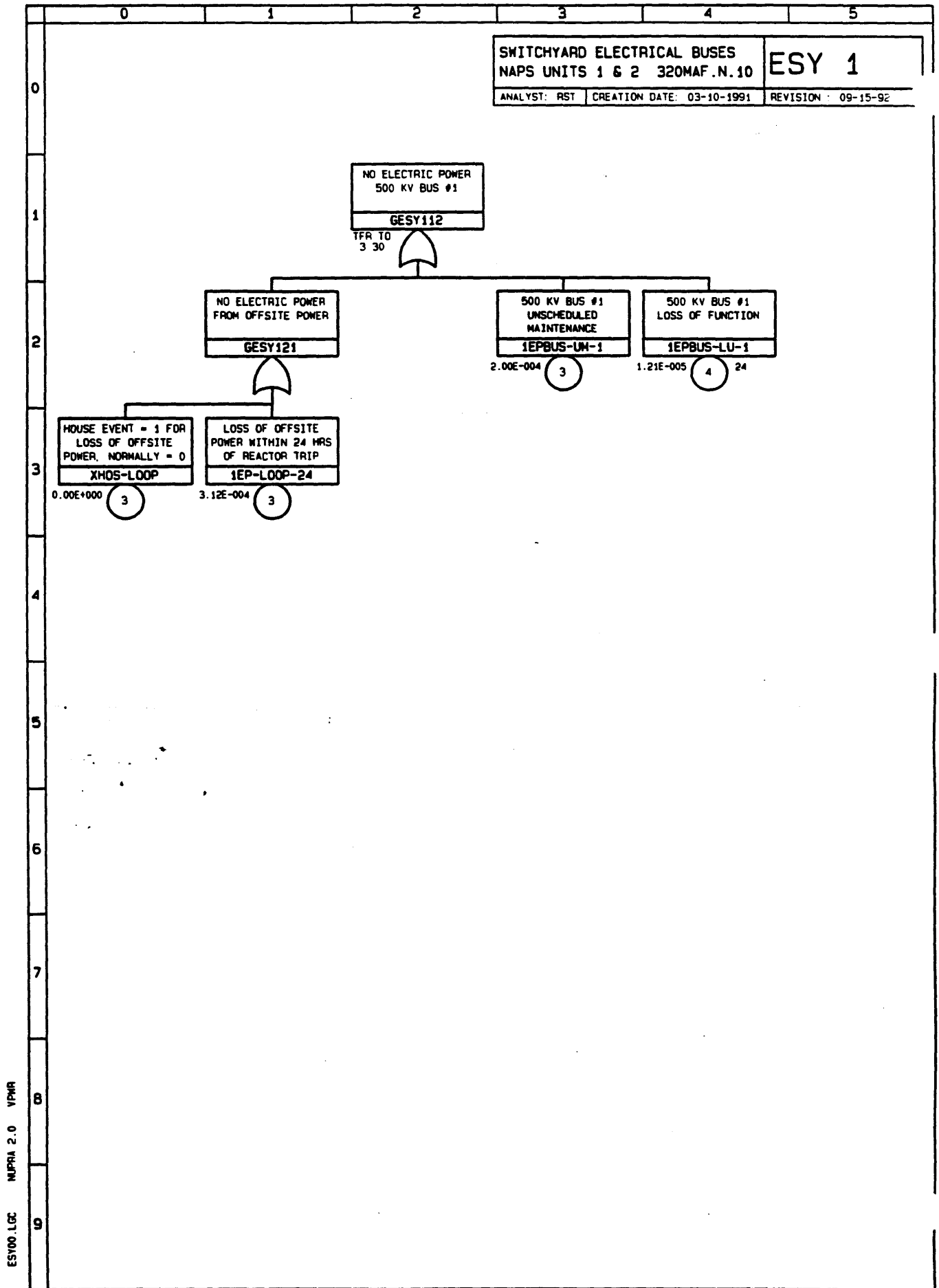




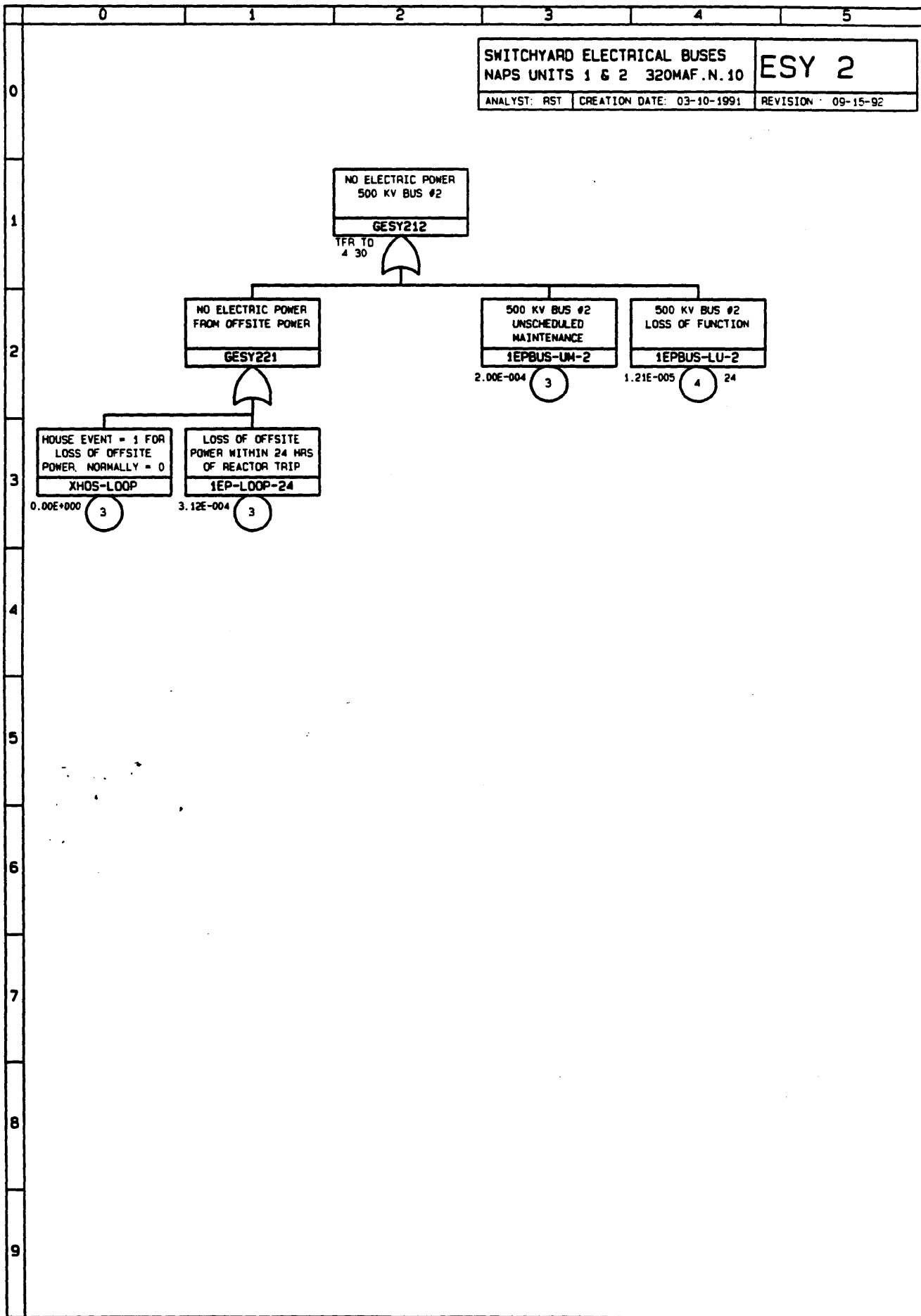


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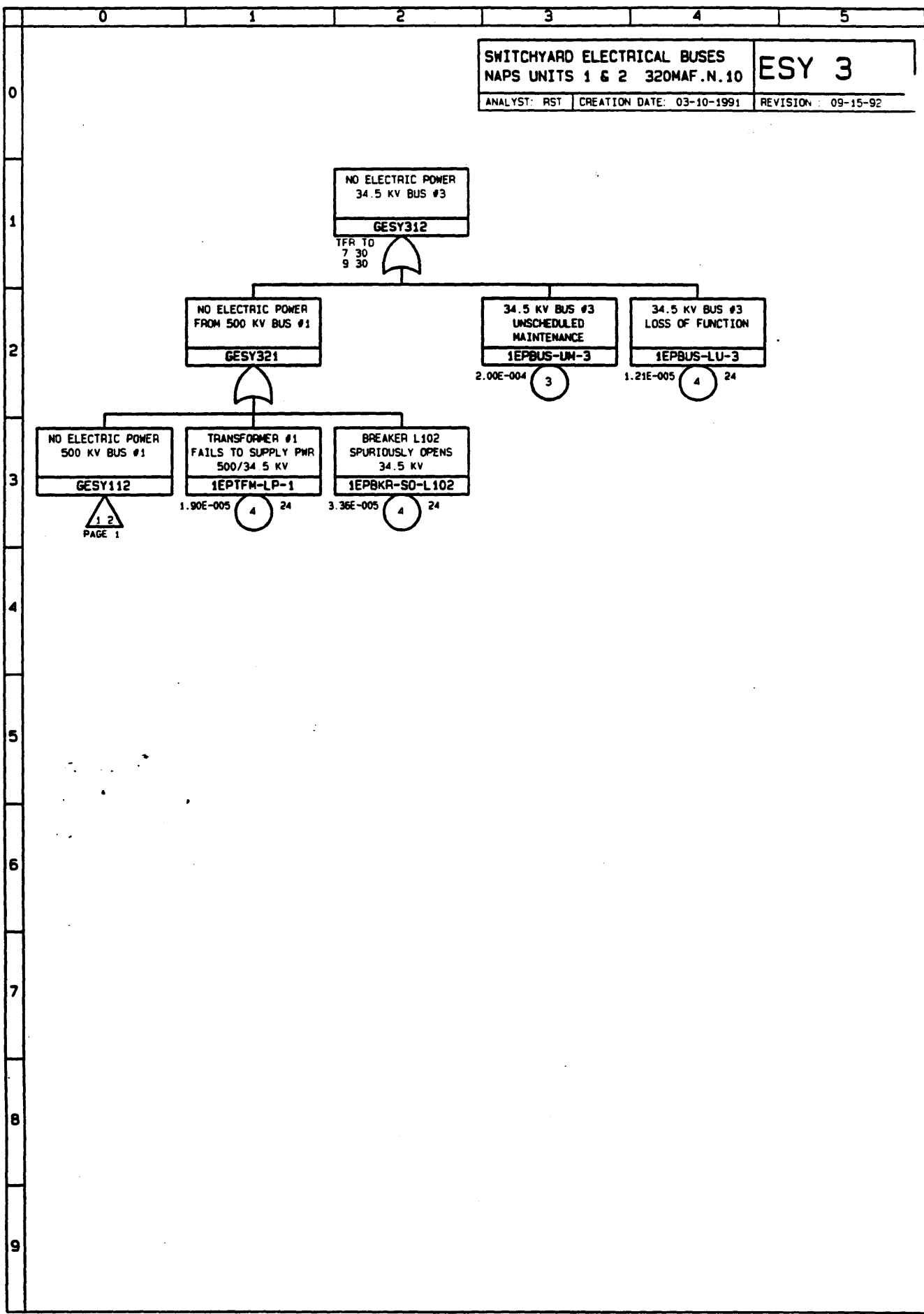




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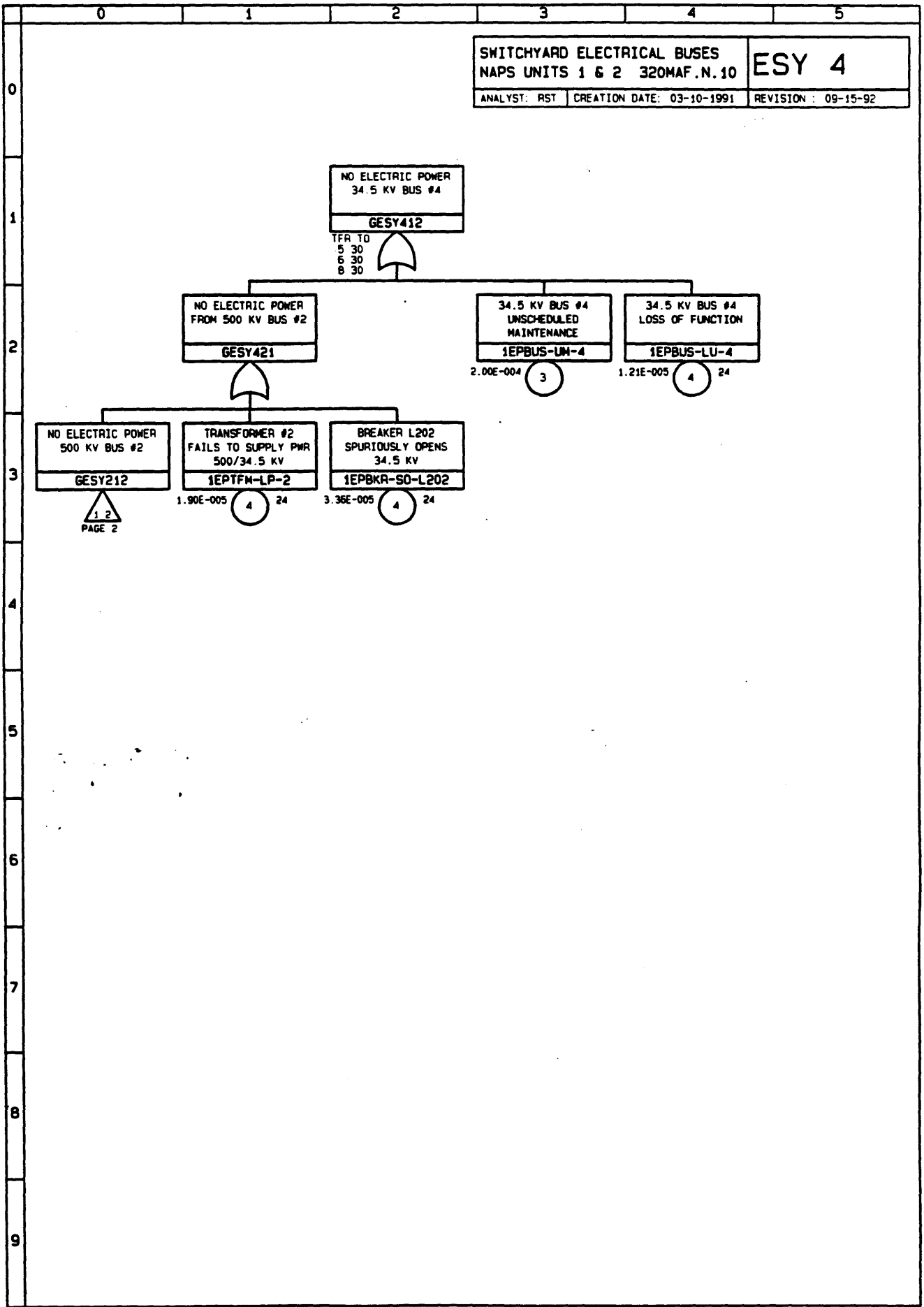


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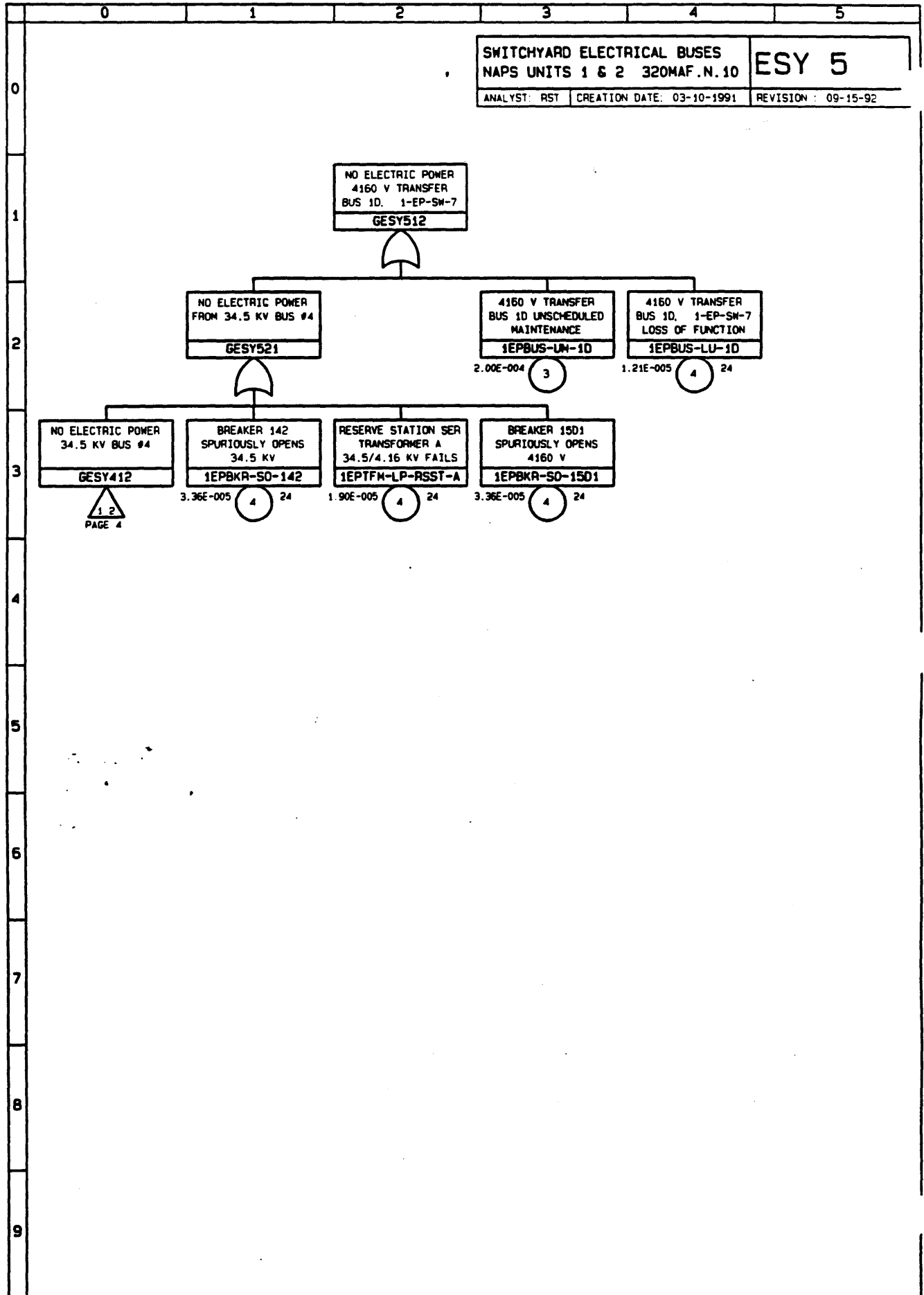


SWITCHYARD ELECTRICAL BUSES		ESY 3
NAPS UNITS 1 & 2 320MAF.N.10		
ANALYST: RST	CREATION DATE: 03-10-1991	REVISION: 09-15-92

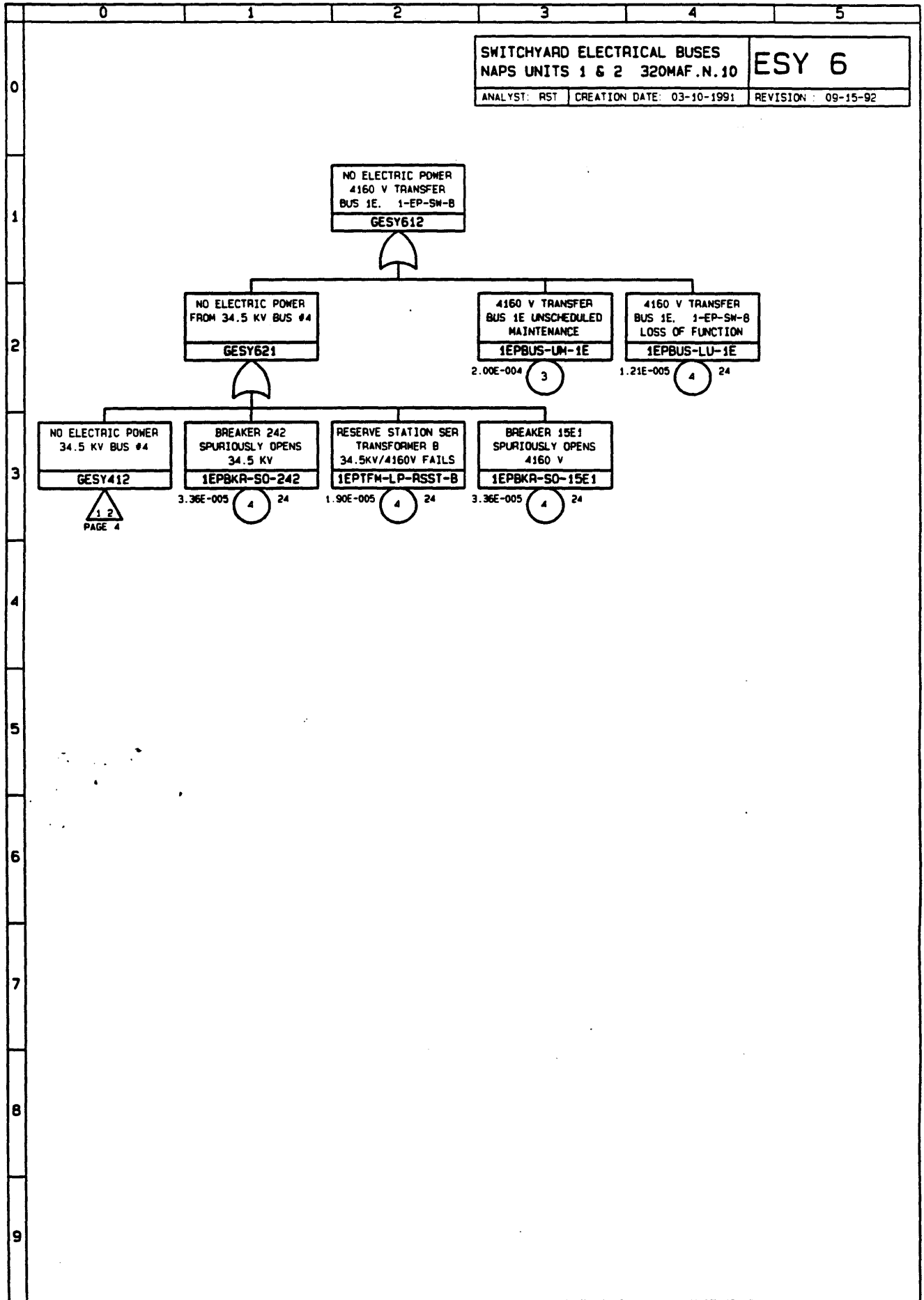
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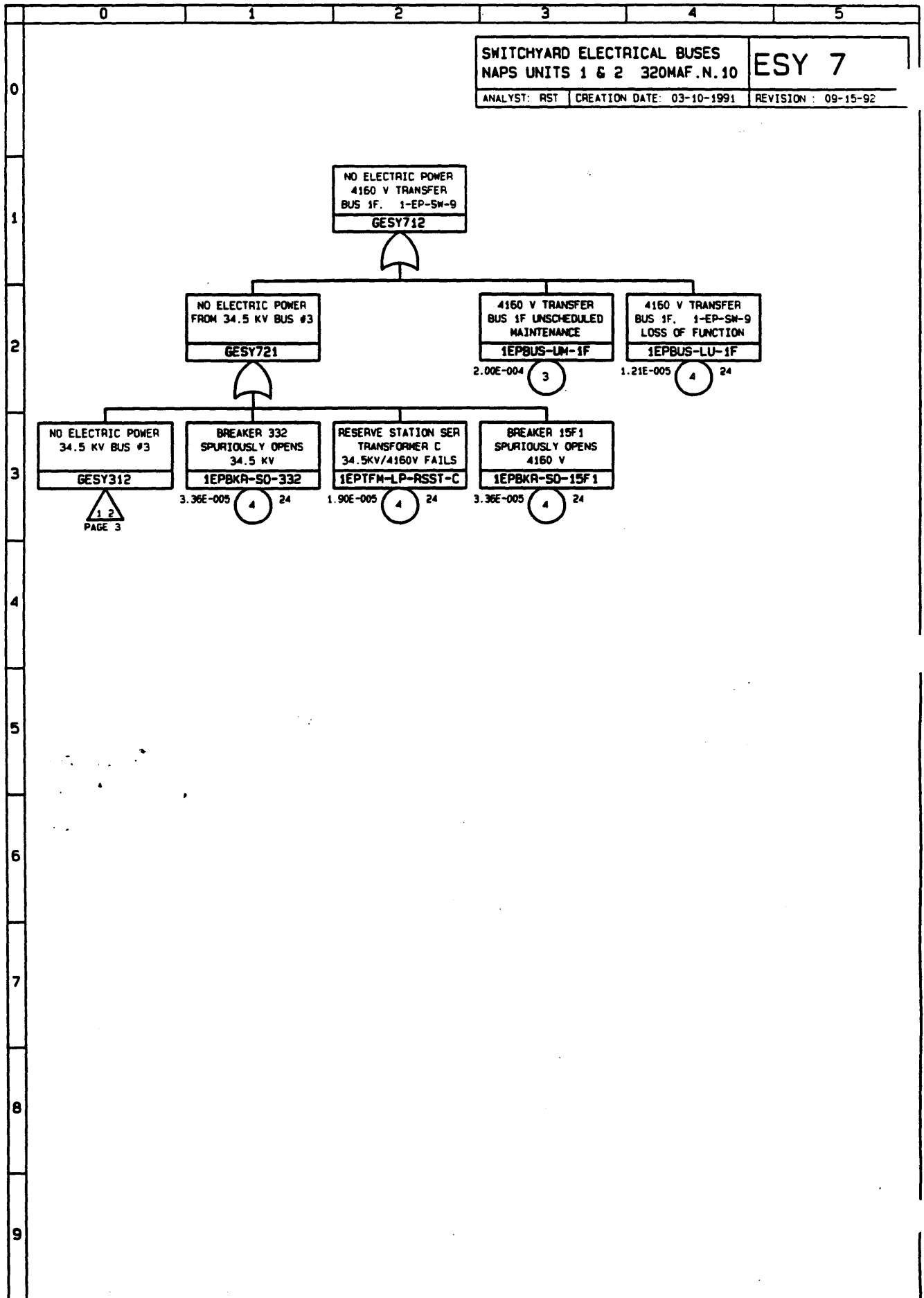
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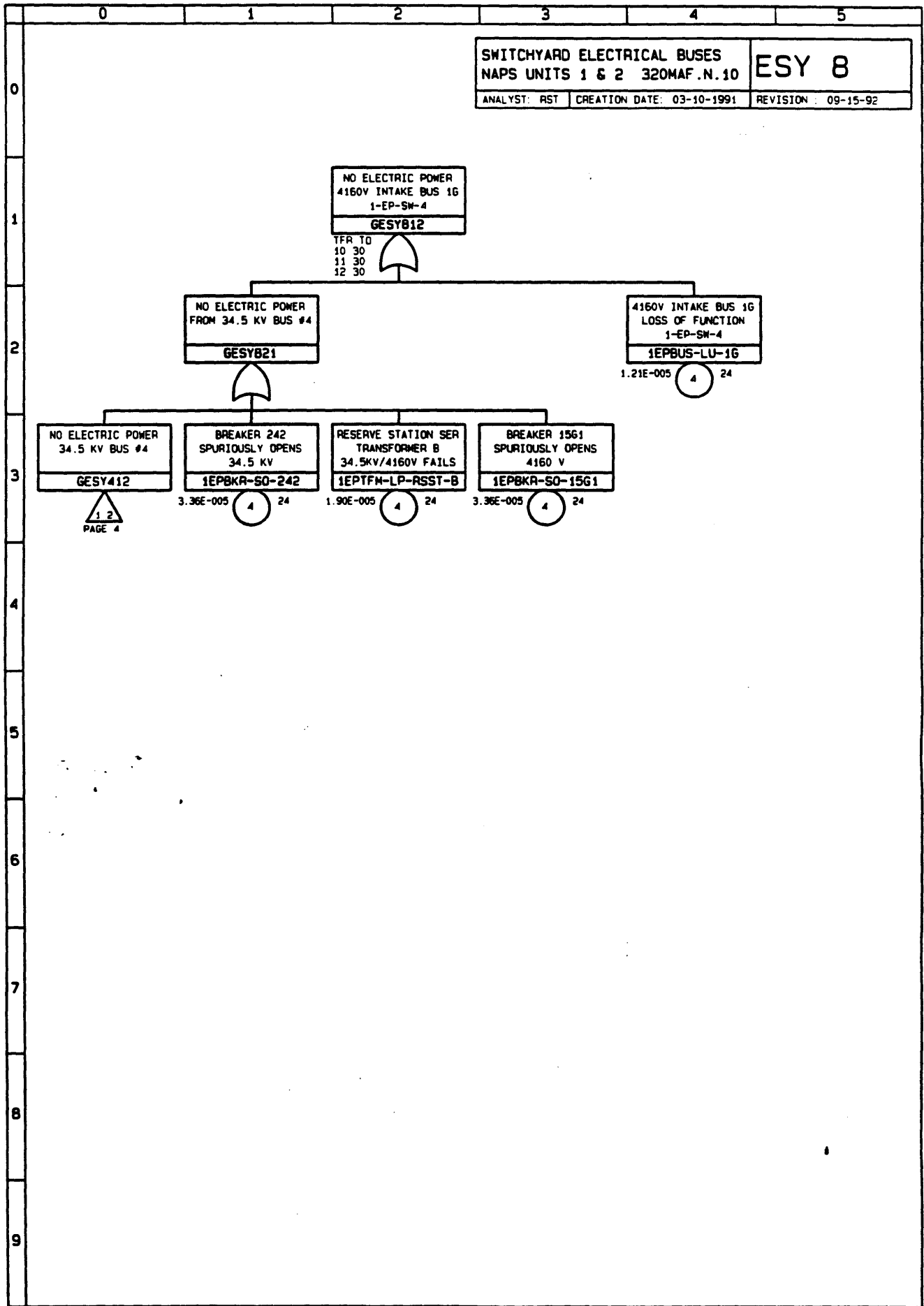
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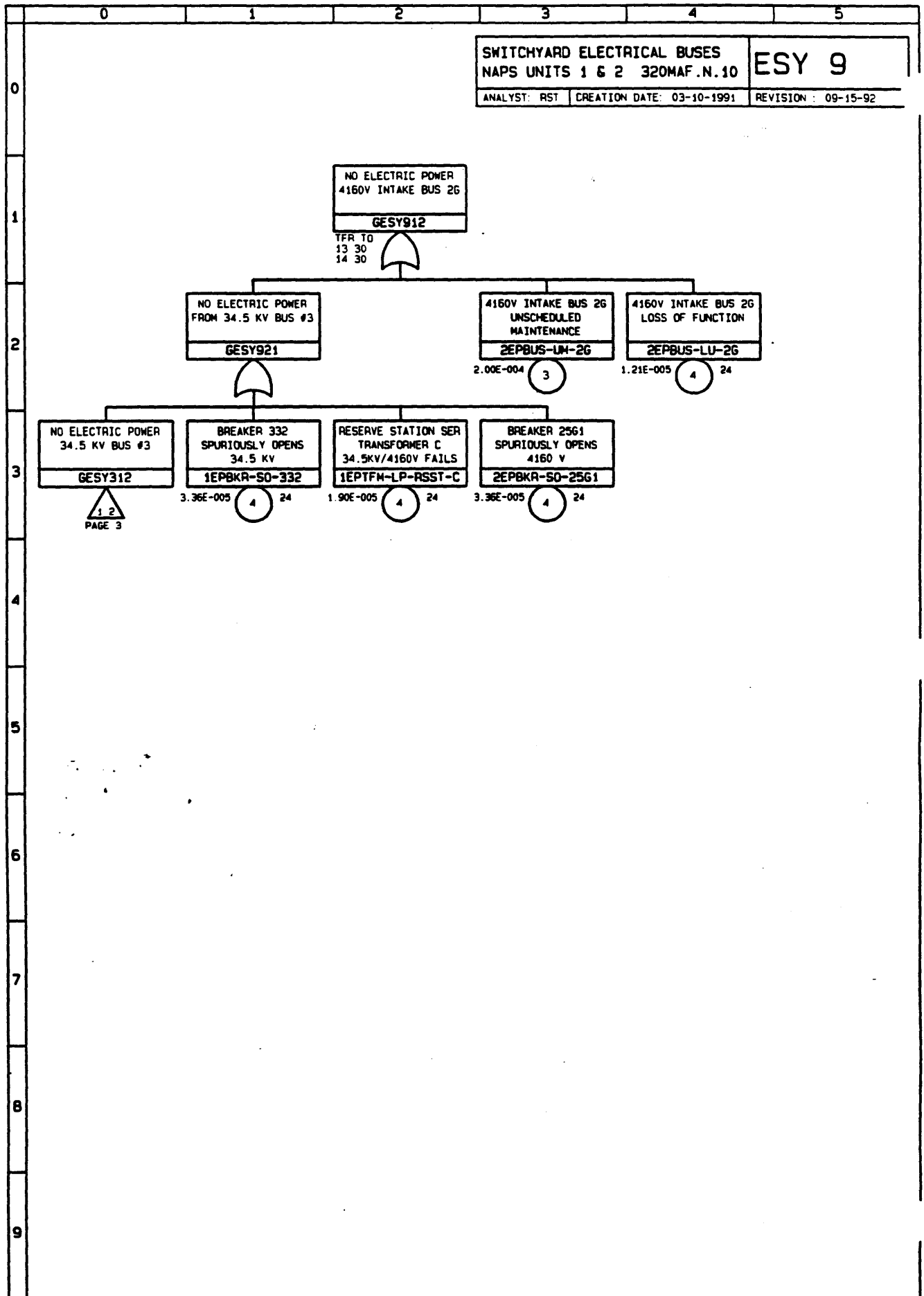
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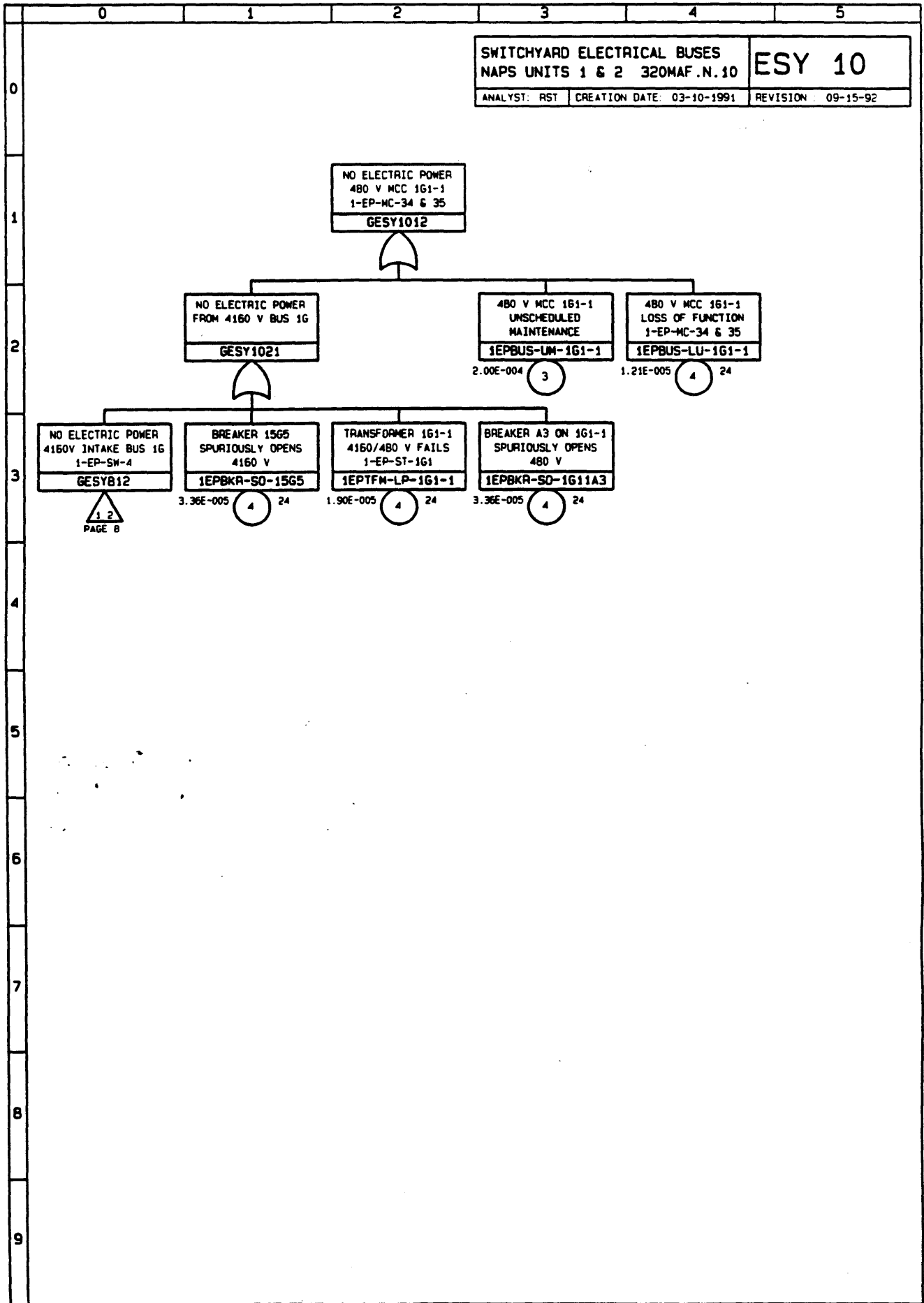




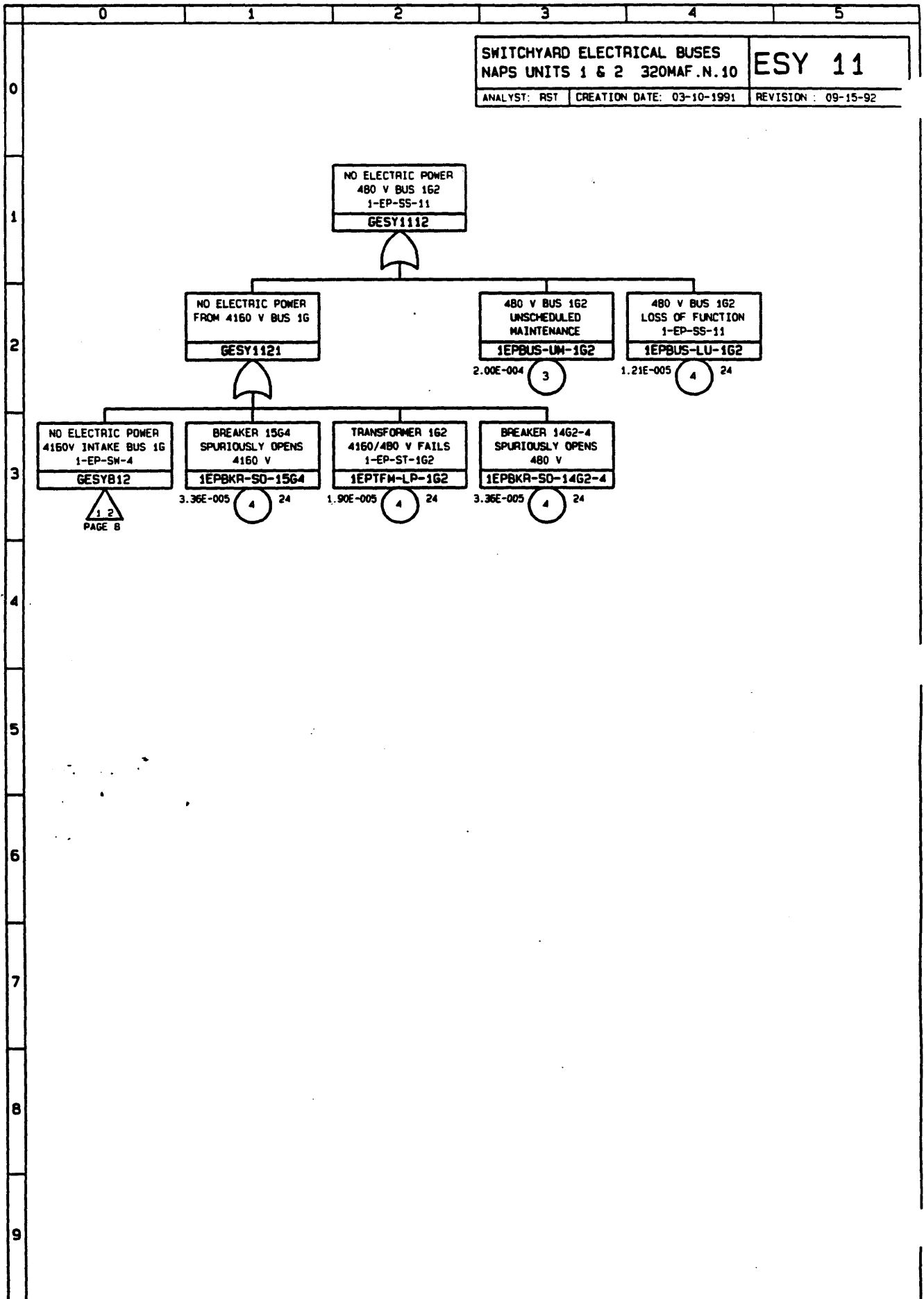
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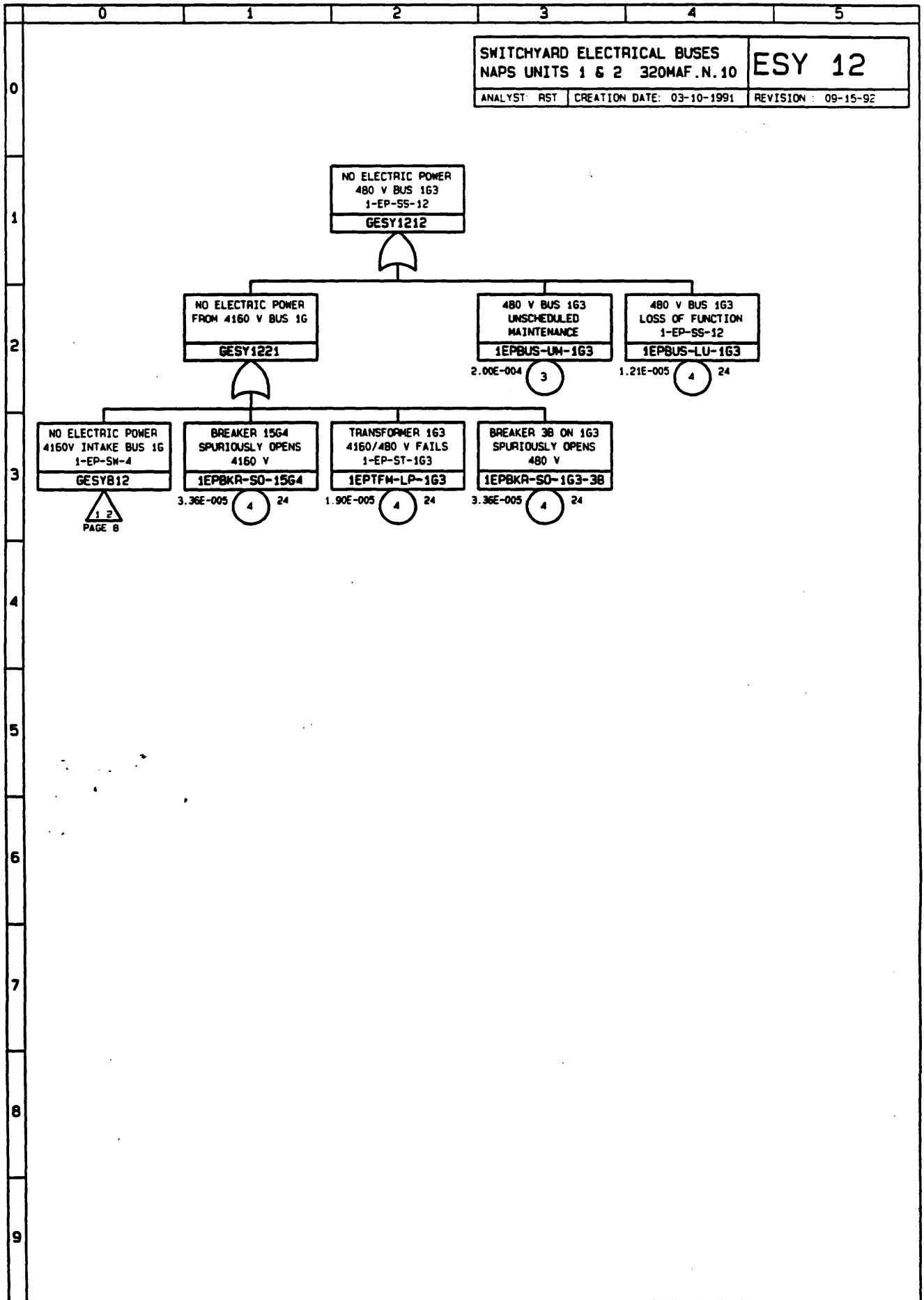
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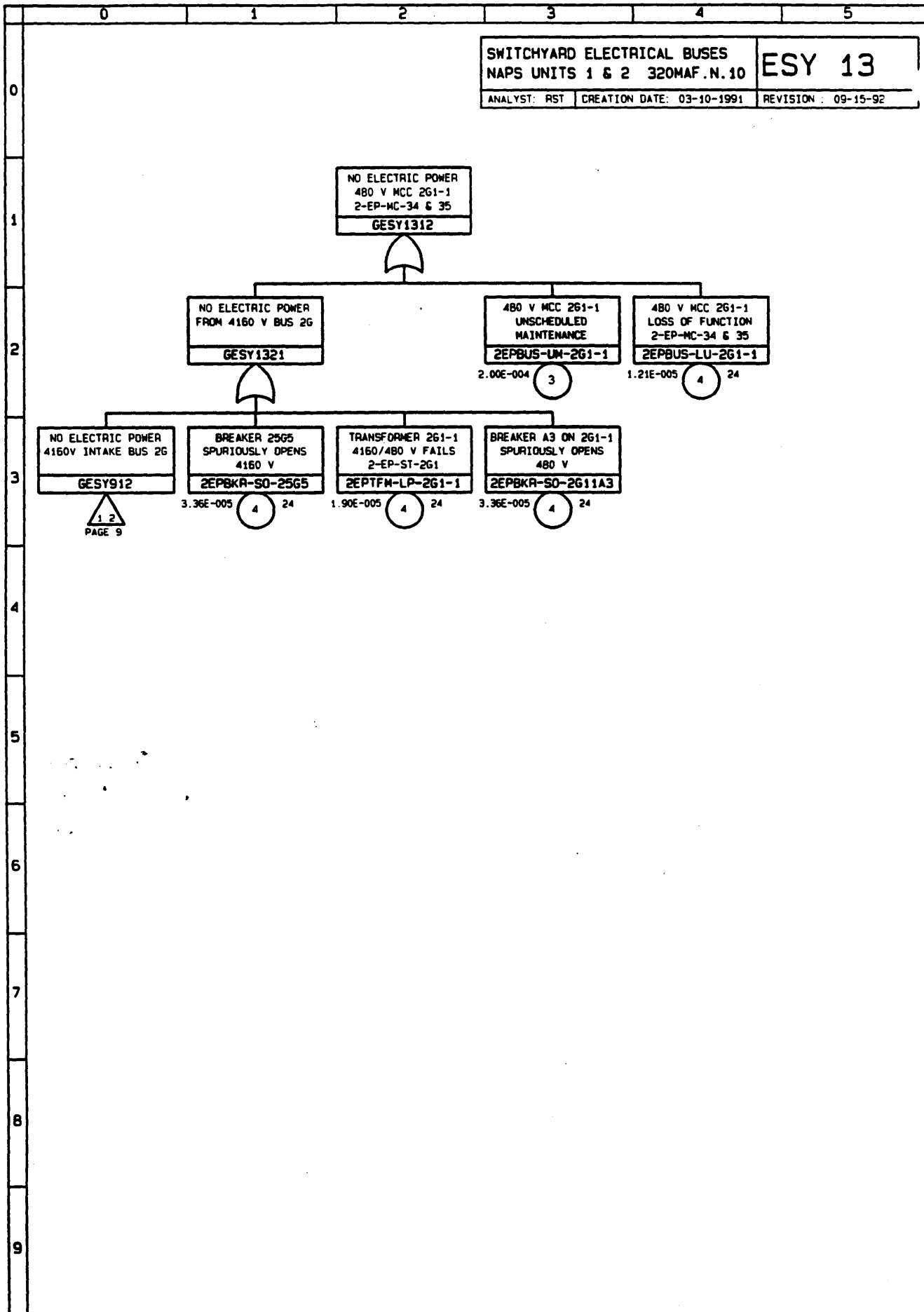
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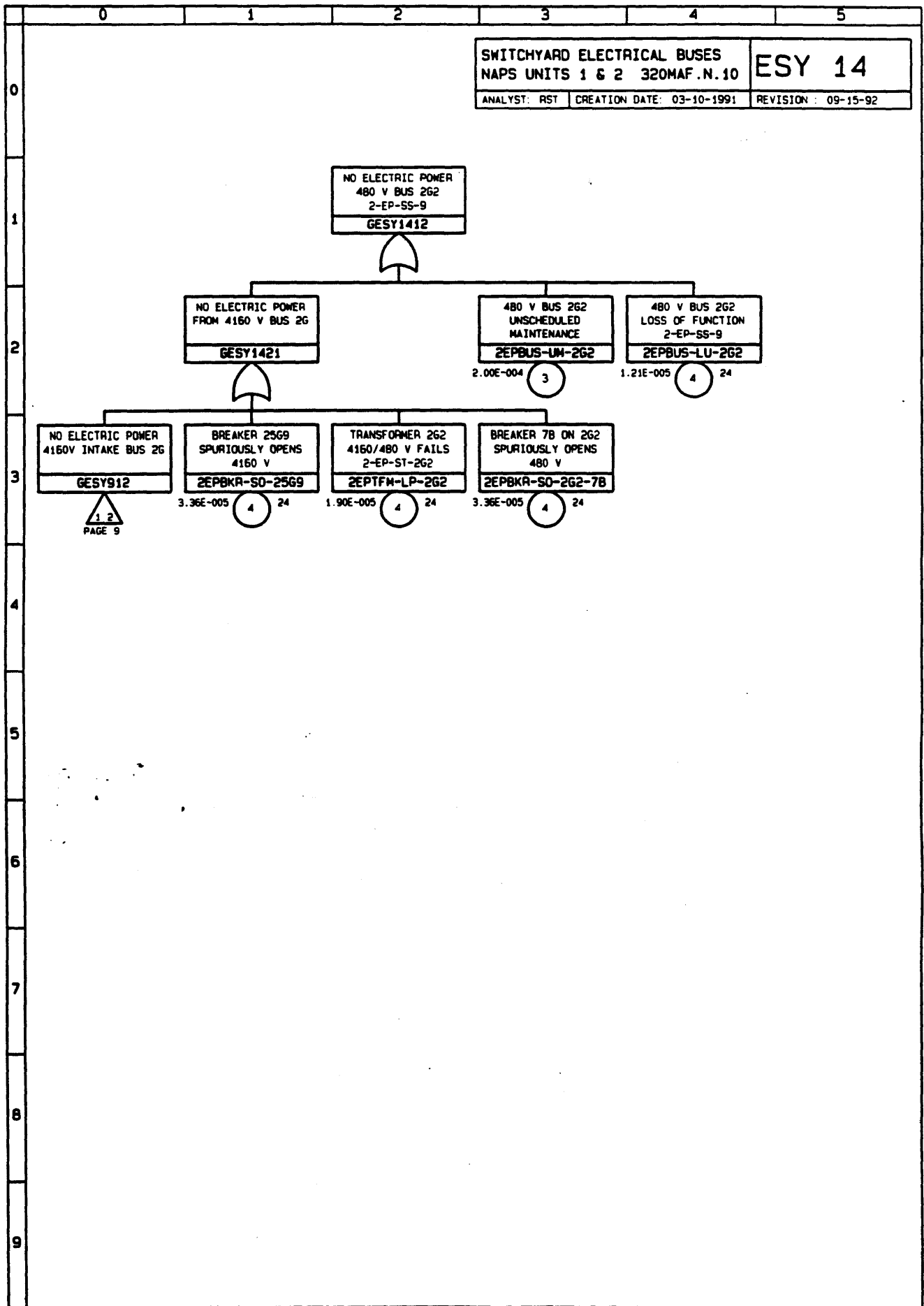
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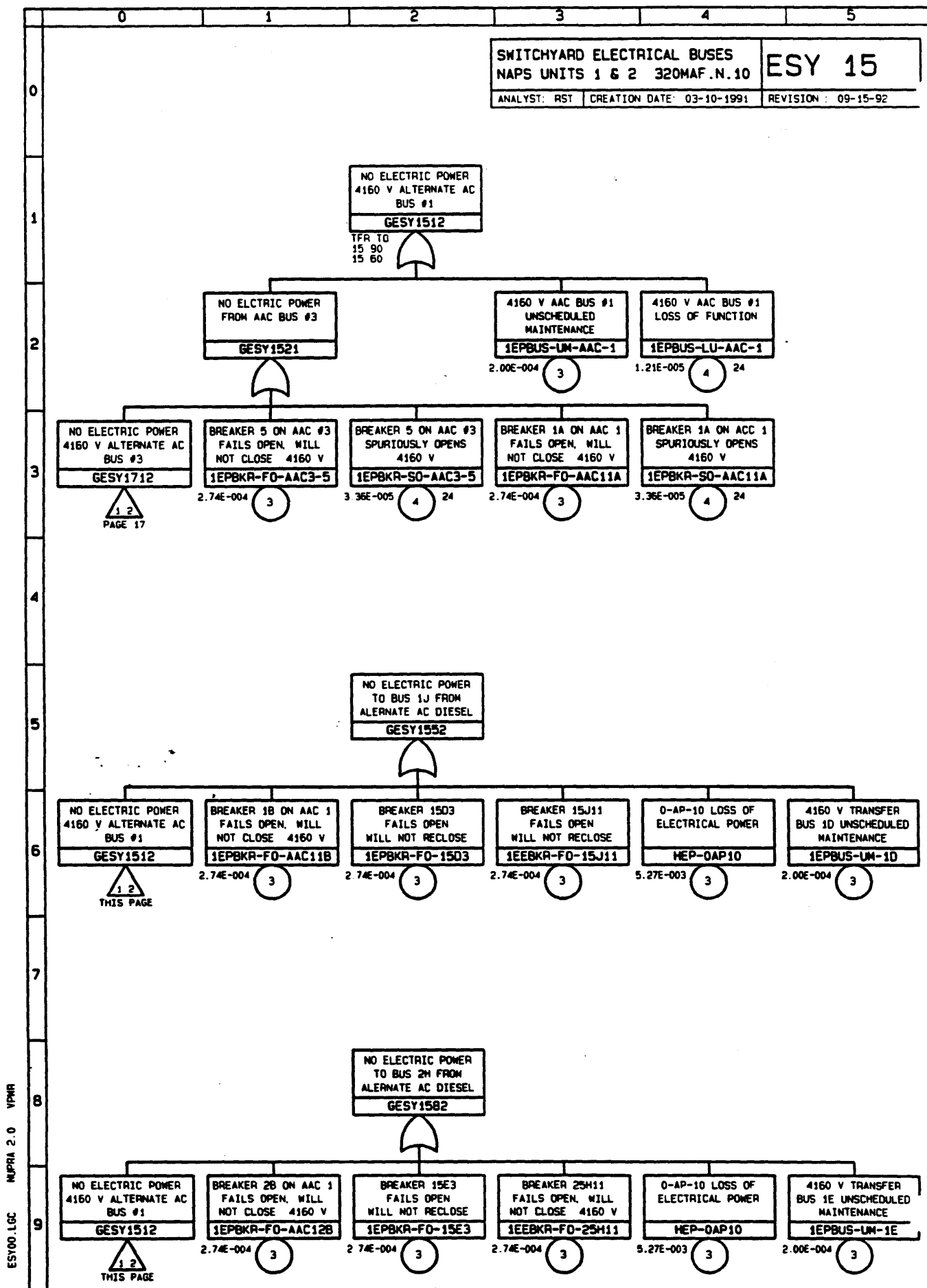
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ESY00 LGC    NUPRA 2.0    VPMR

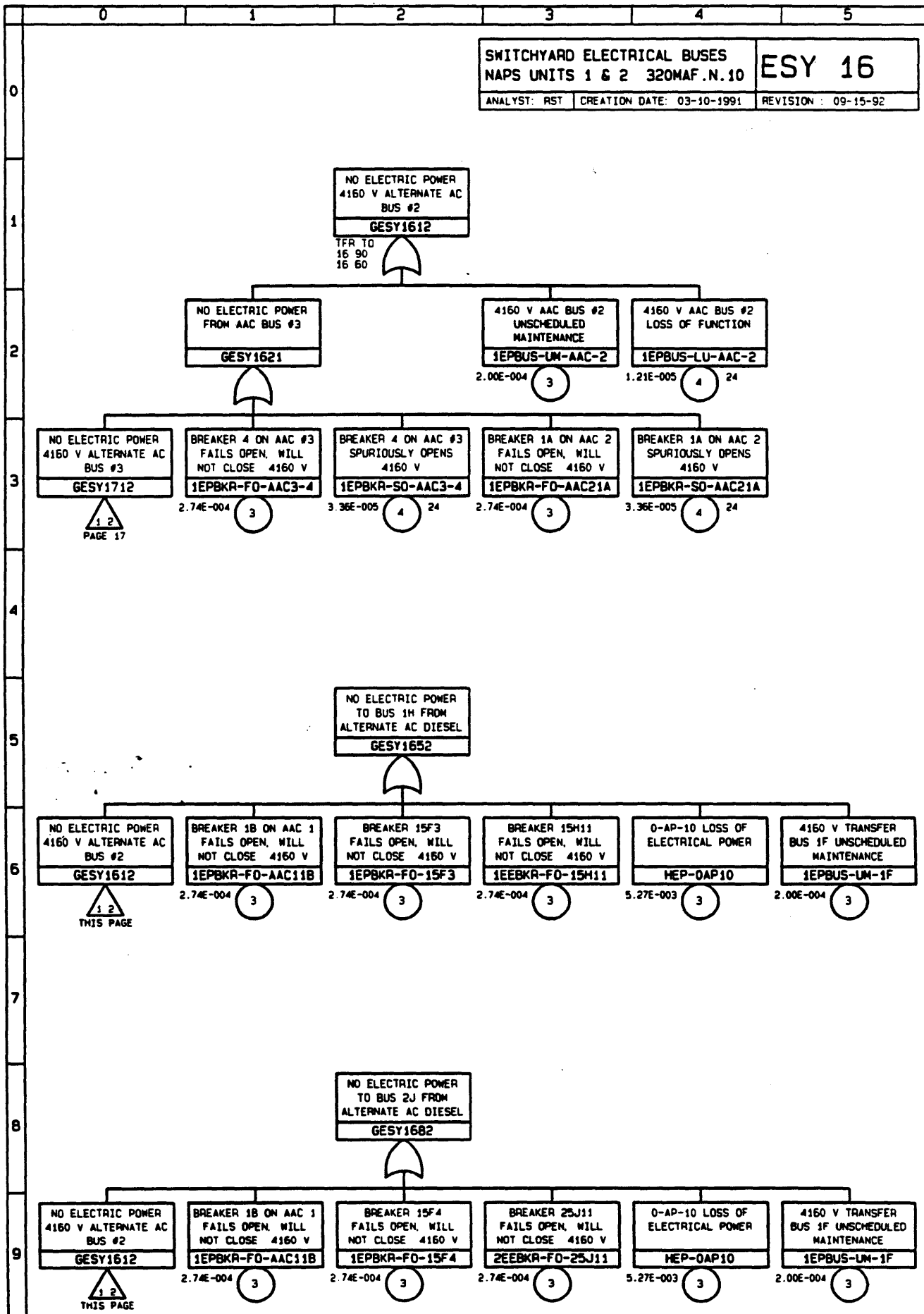


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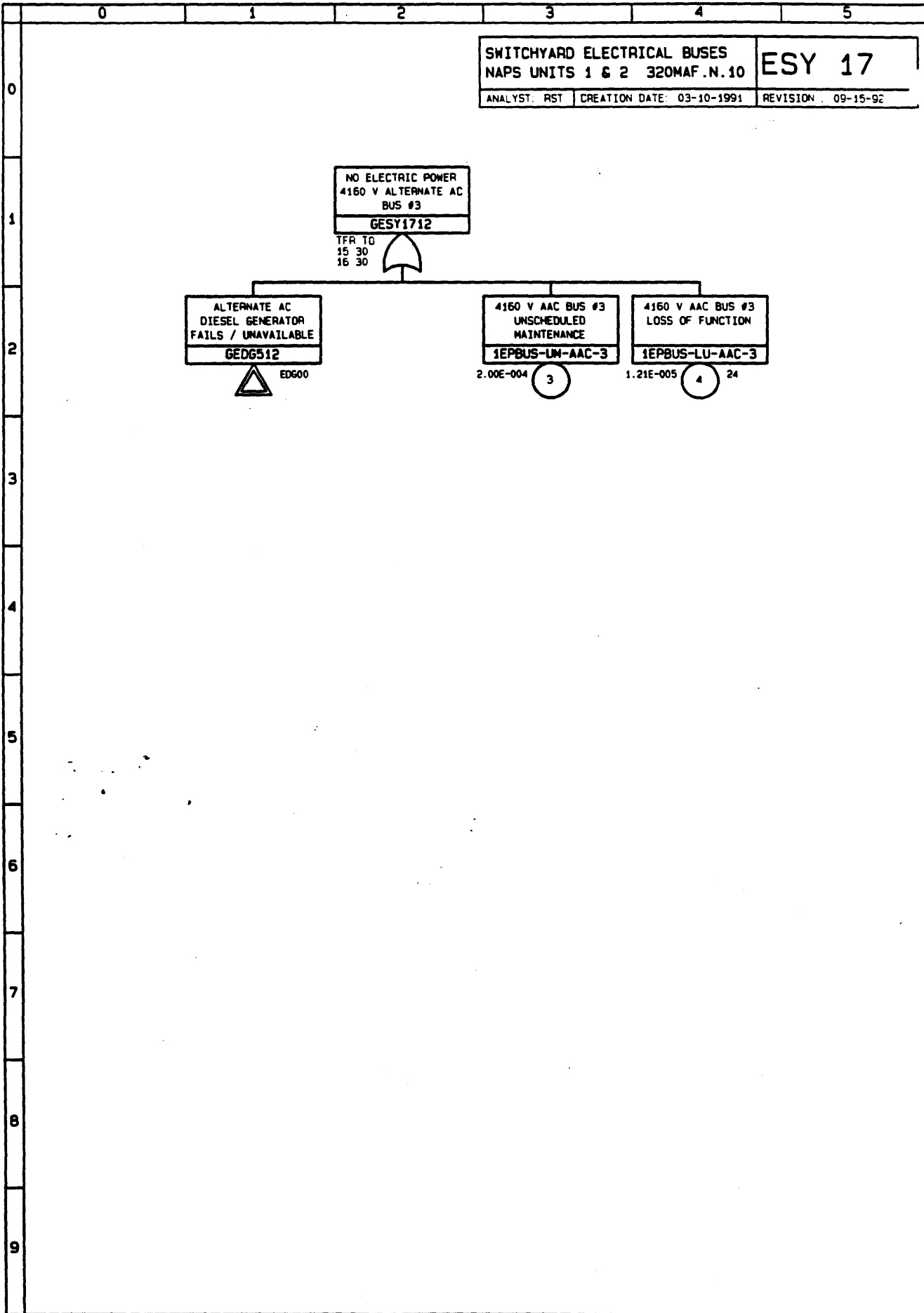
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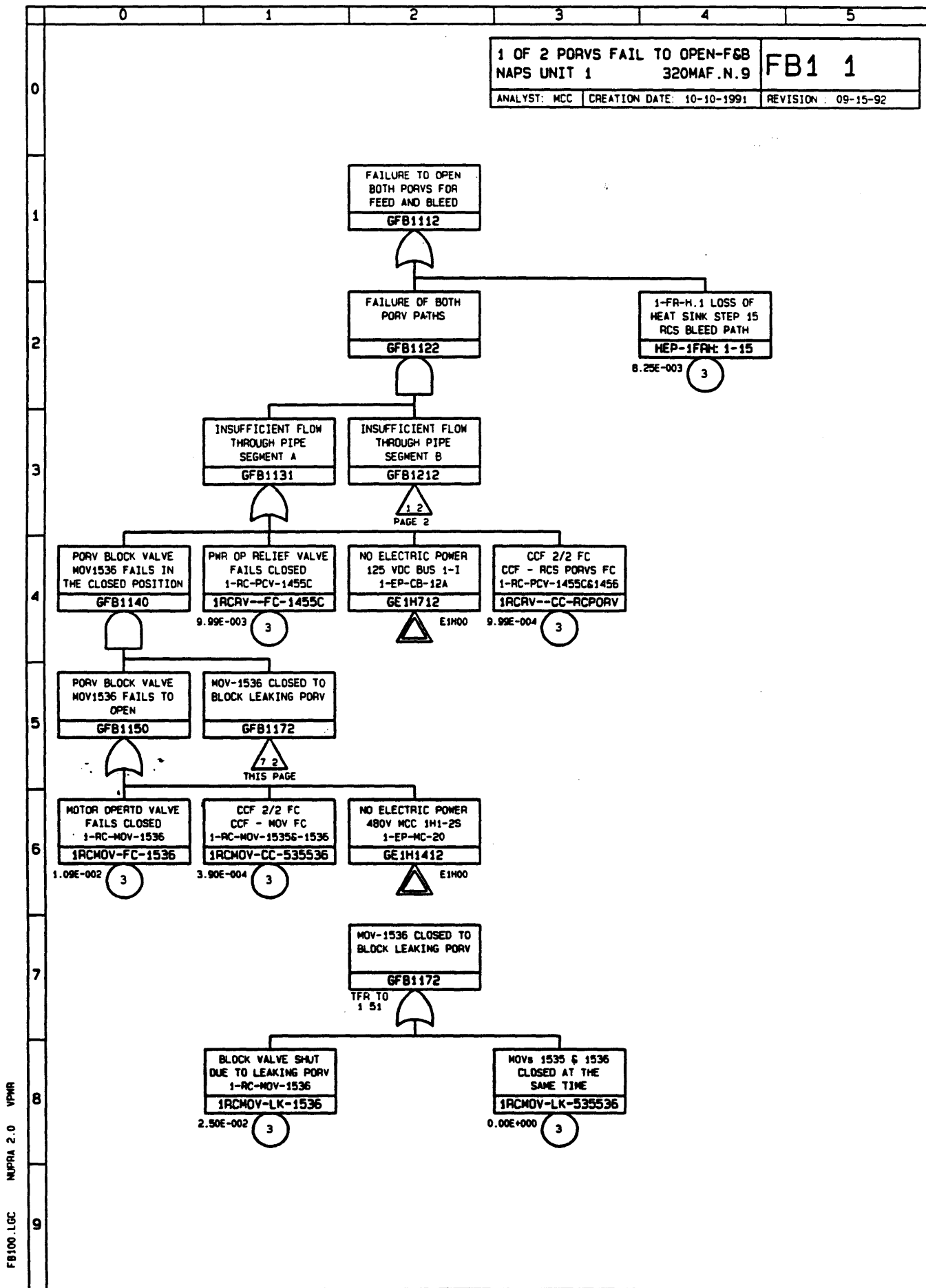




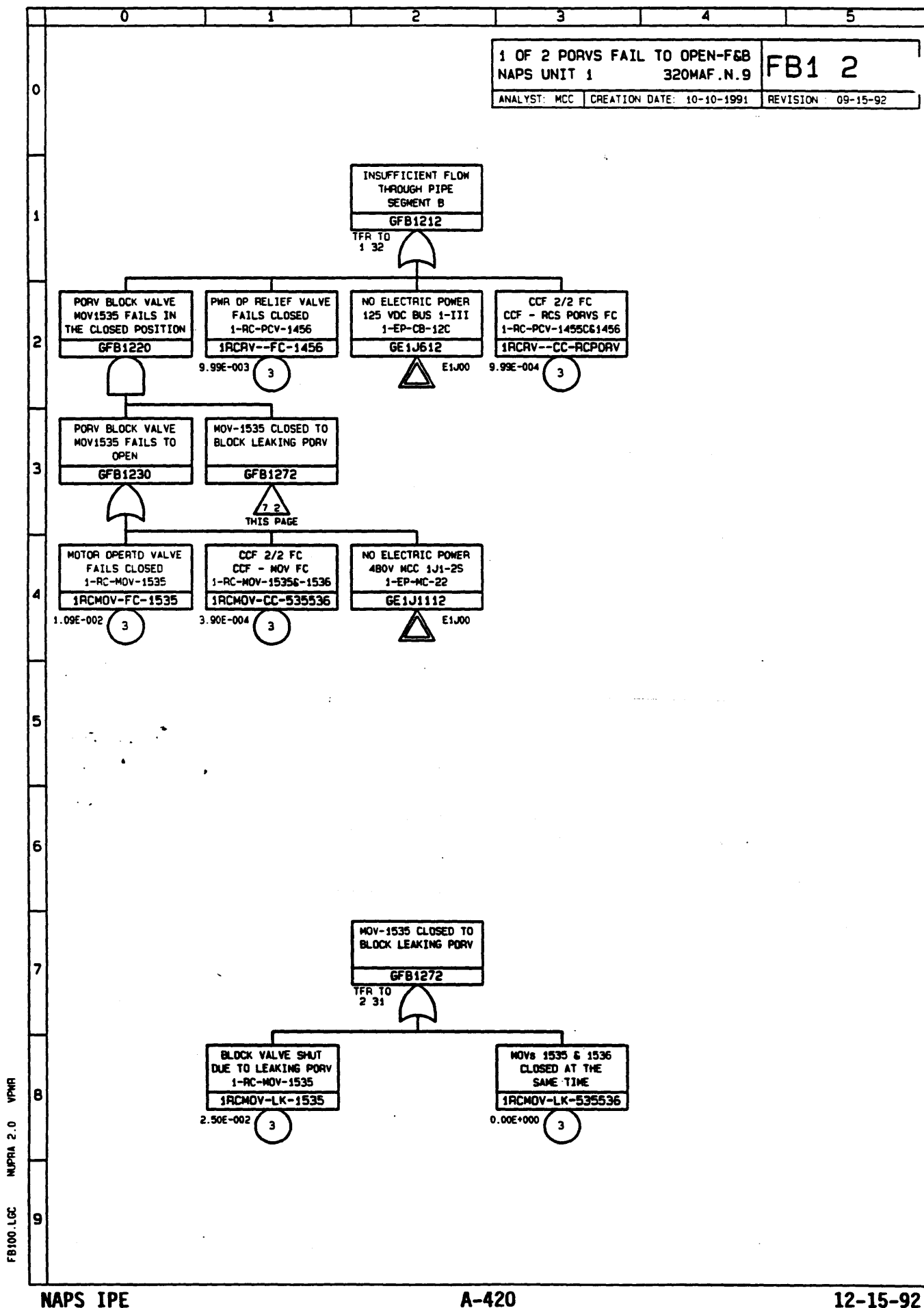
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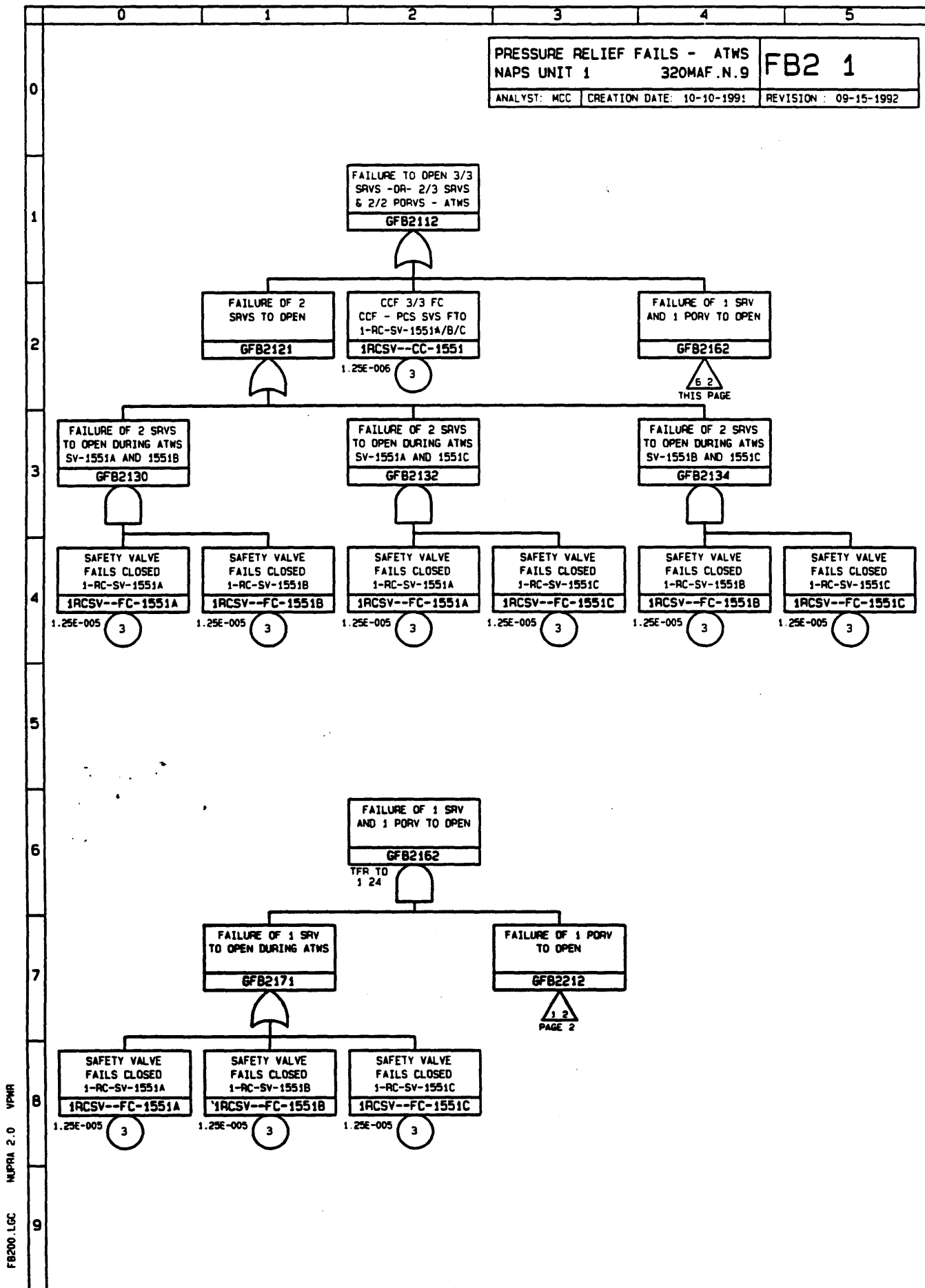
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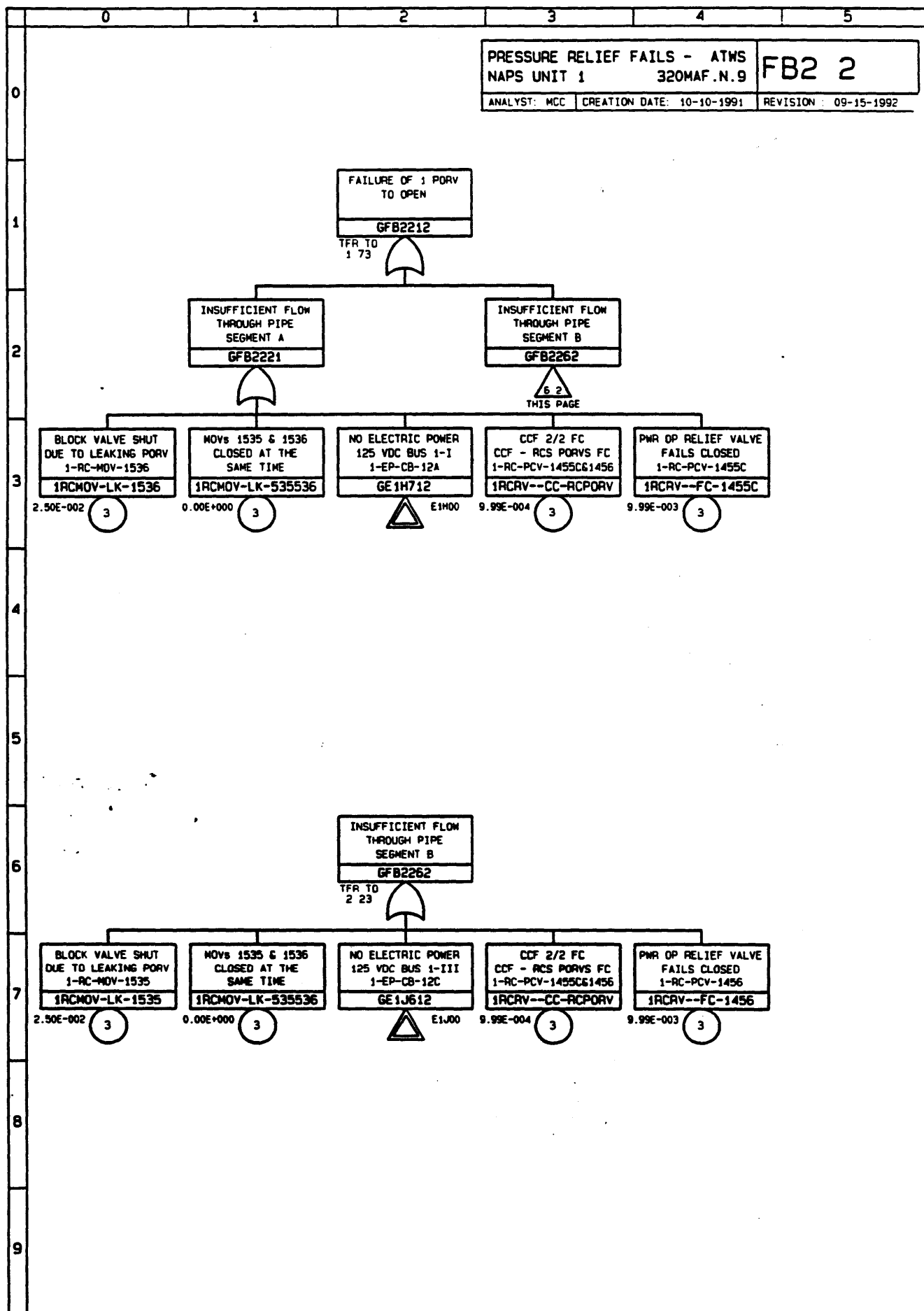


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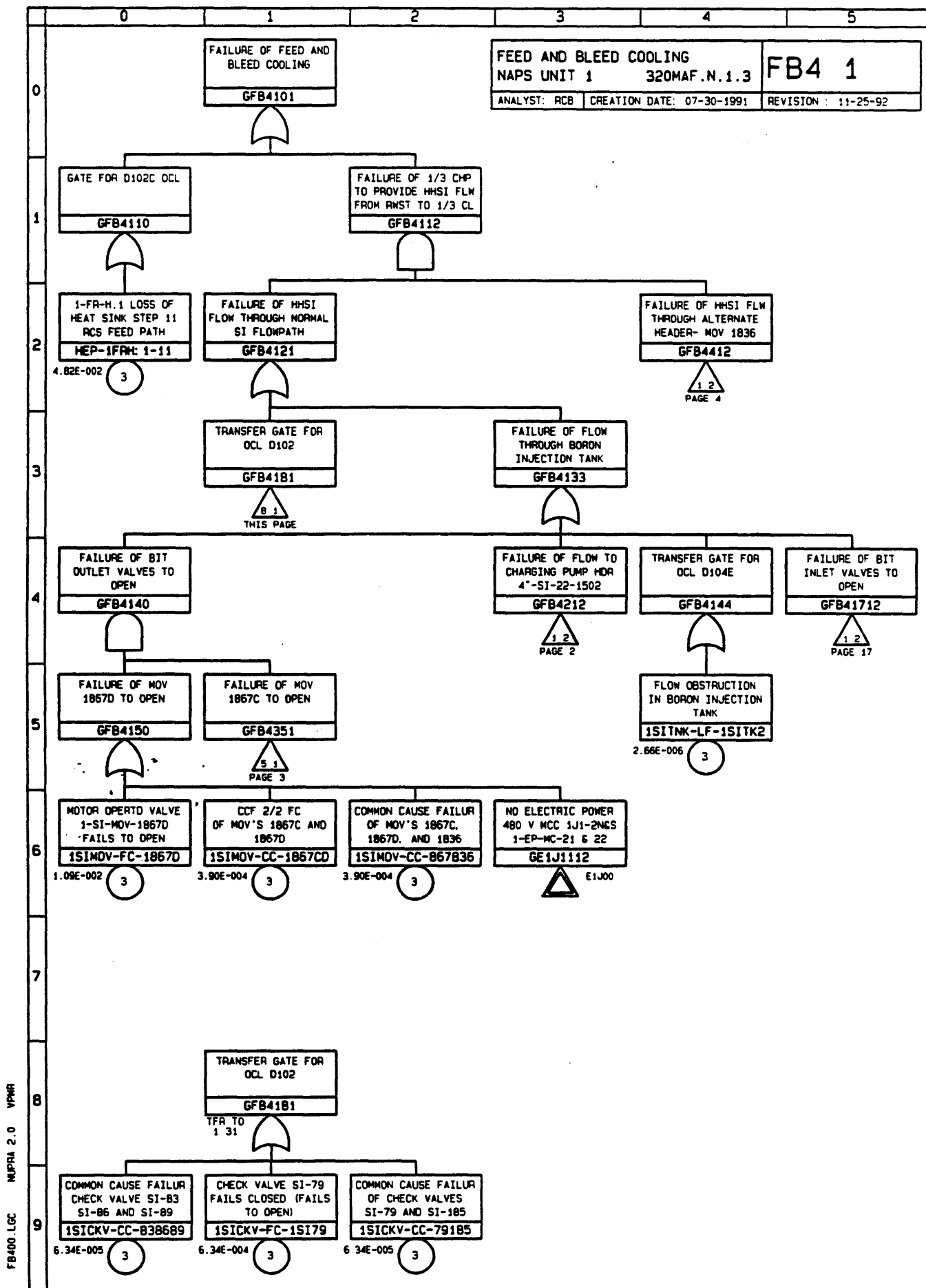


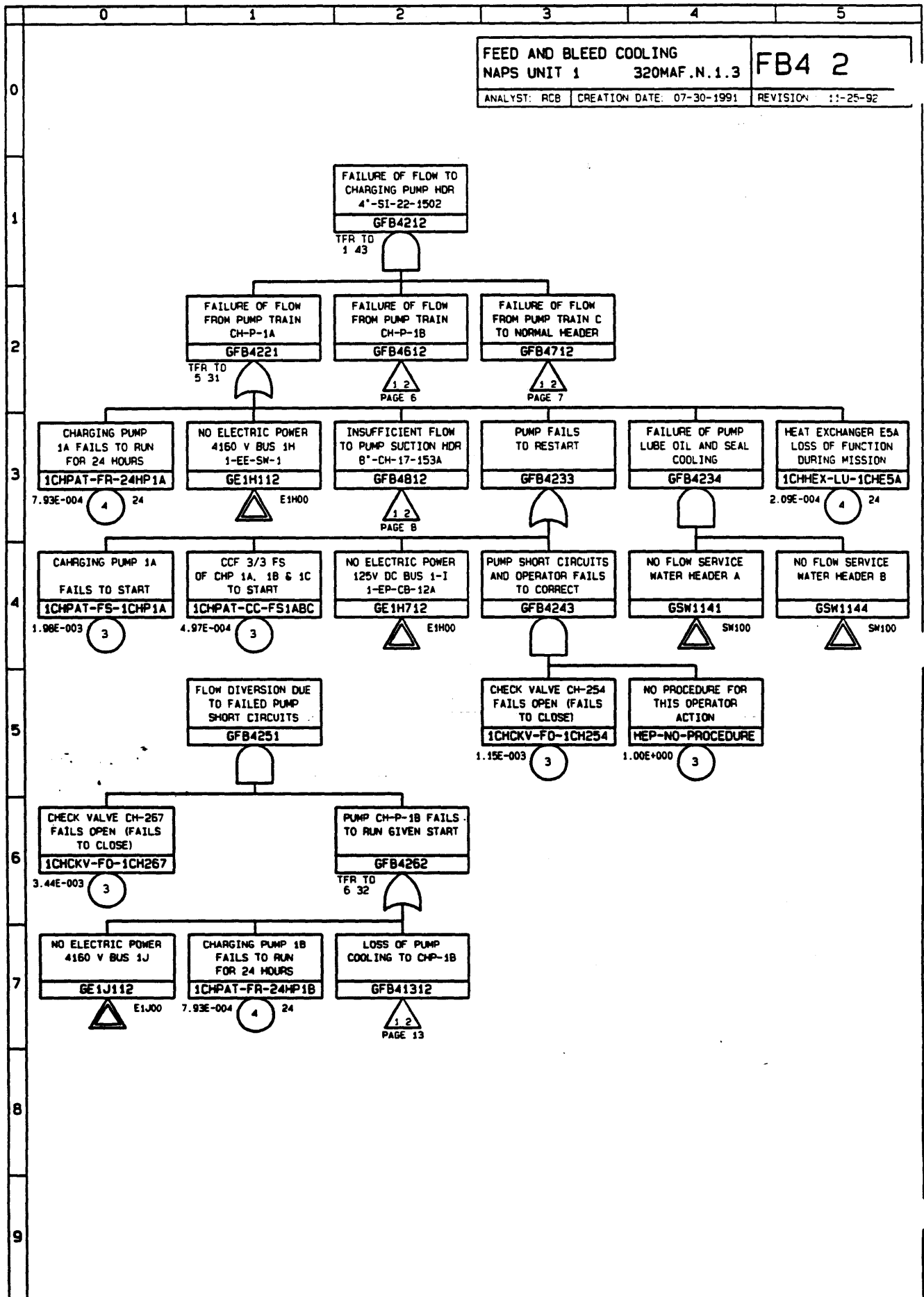


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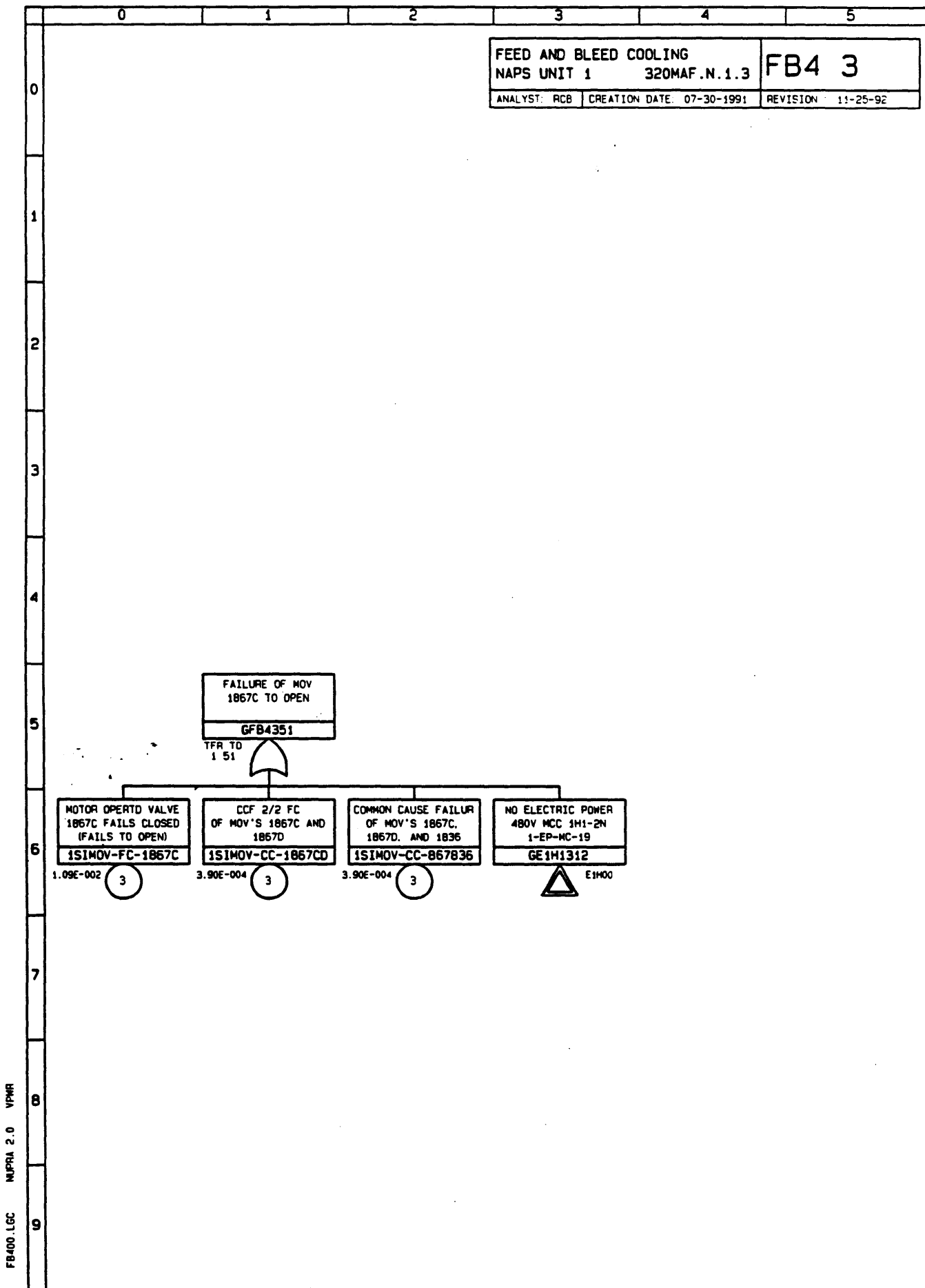


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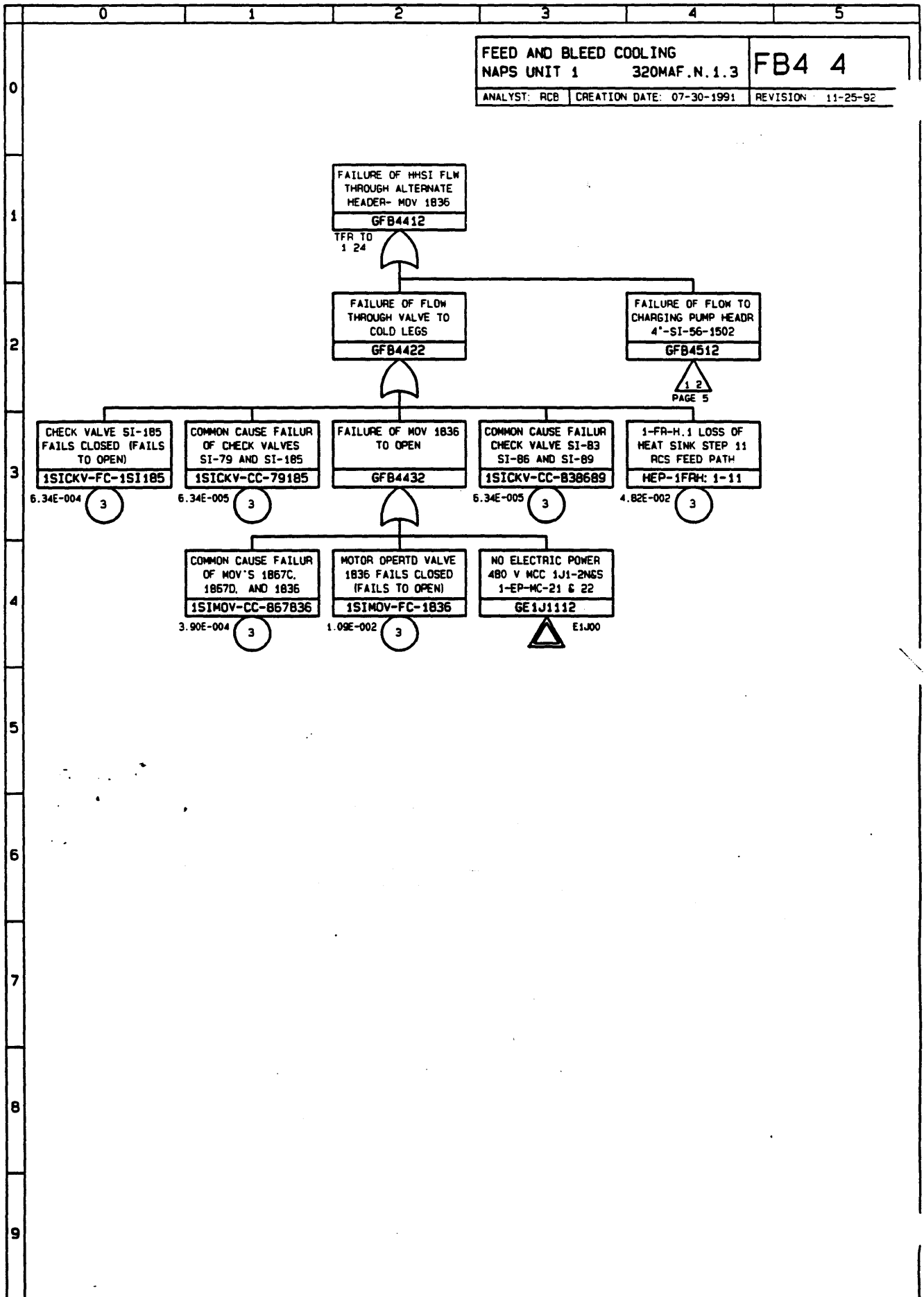


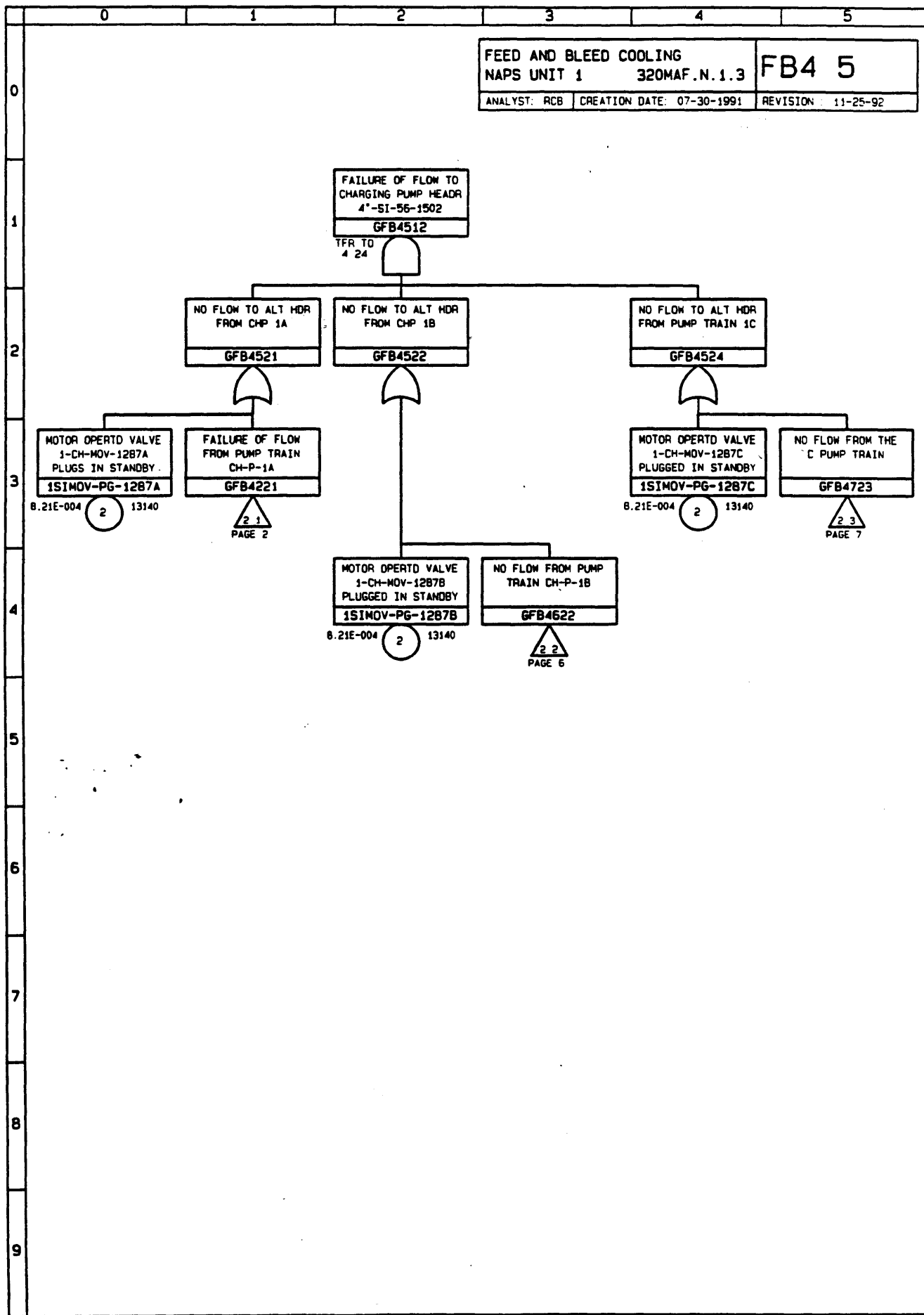


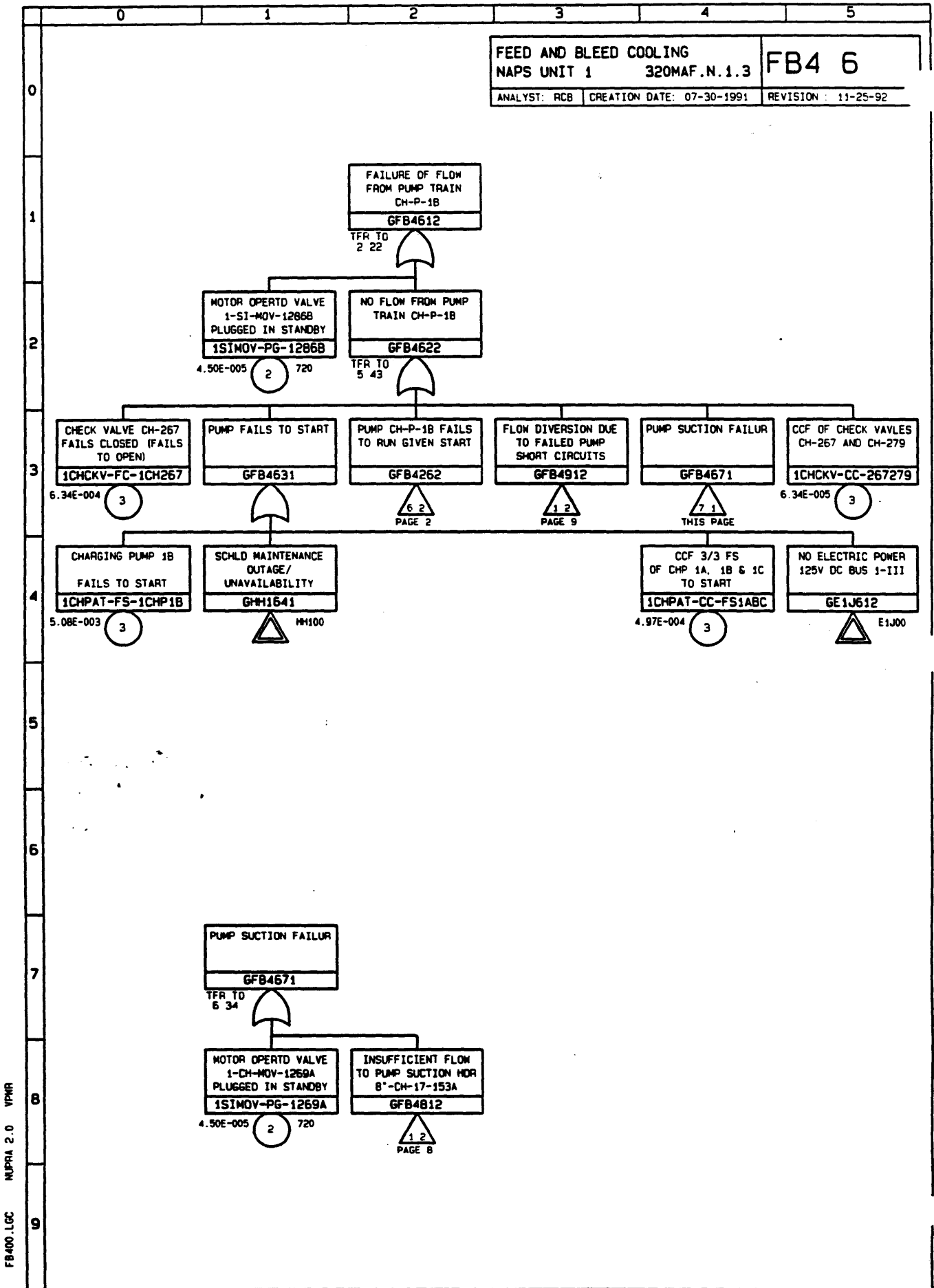


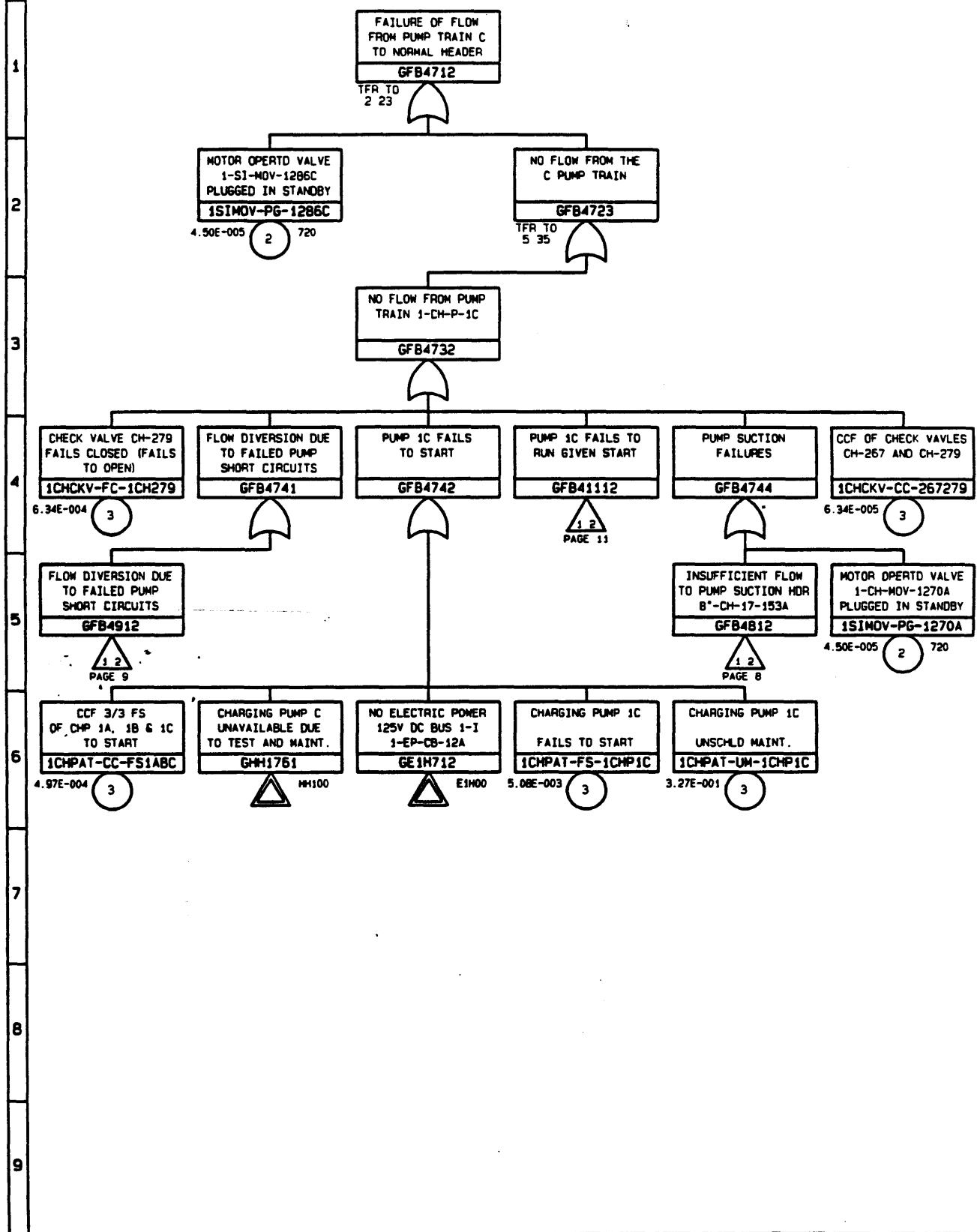


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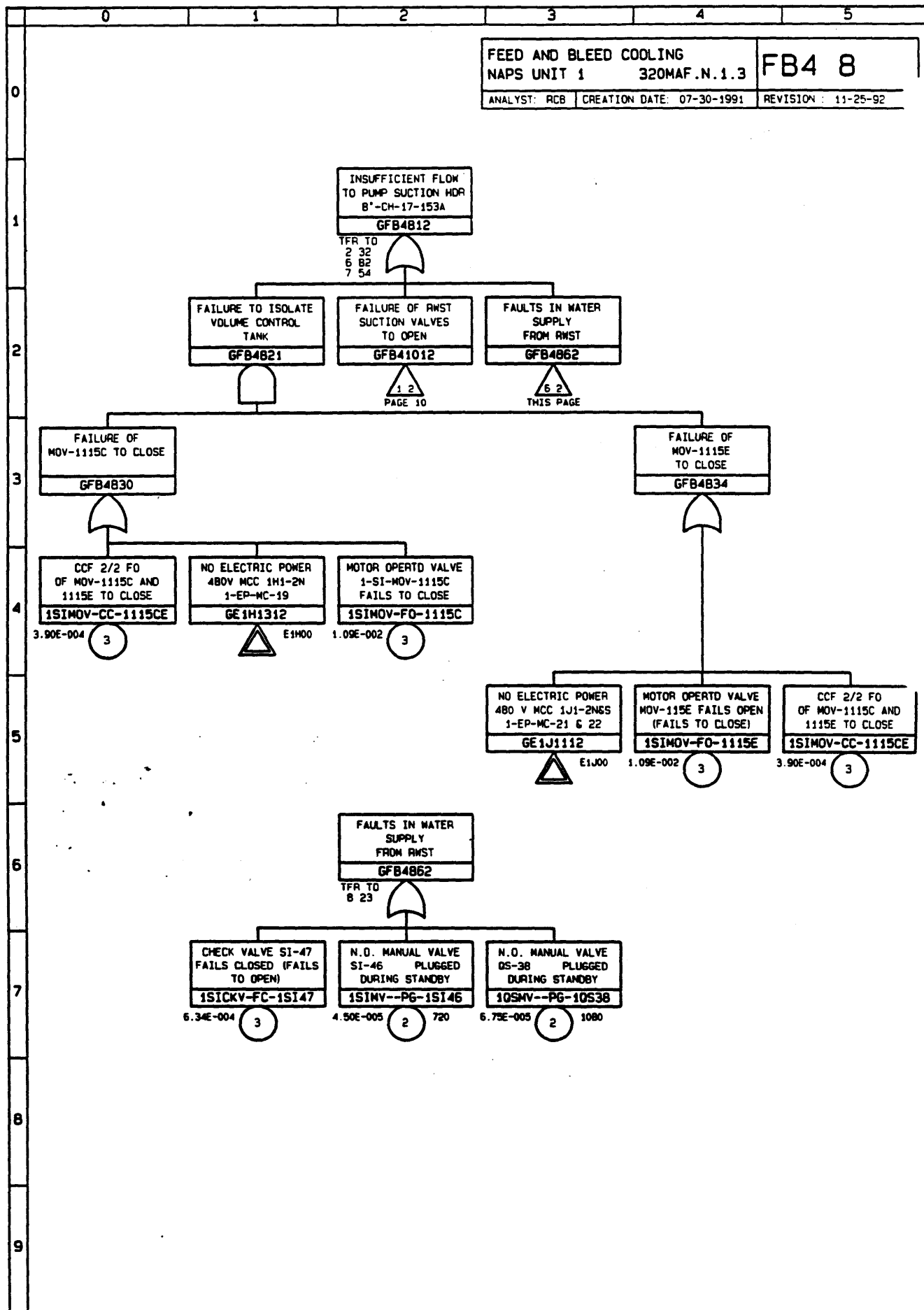


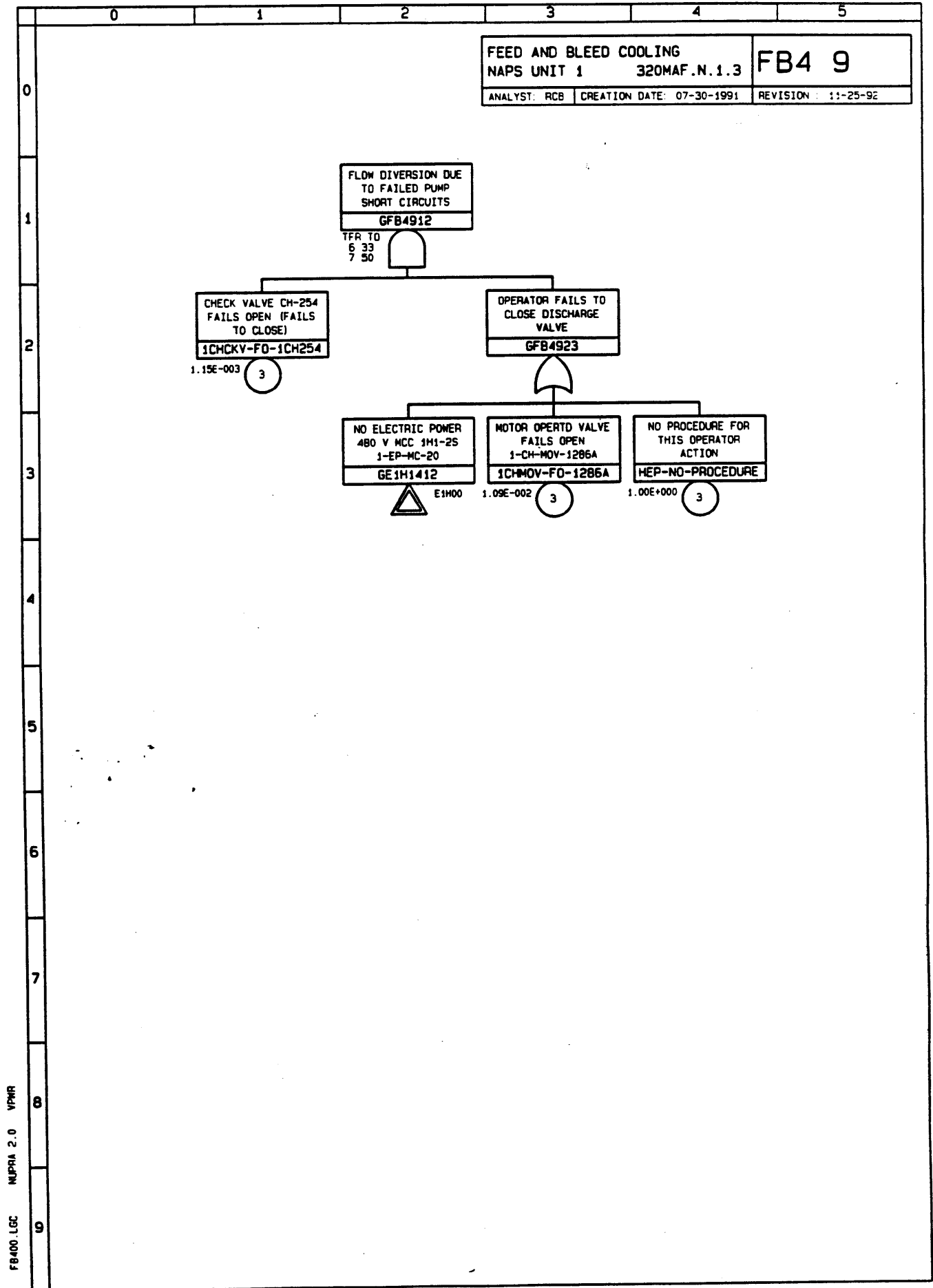






FB400.LCC NUPRA 2.0 VPMR





FEED AND BLEED COOLING		FB4 9
NAPS UNIT 1	320MAF.N.1.3	
ANALYST: RCB	CREATION DATE: 07-30-1991	REVISION: 11-25-92

FLOW DIVERSION DUE  
TO FAILED PUMP  
SHORT CIRCUITS  
GFB4912

TFR TO  
6 33  
7 50

CHECK VALVE CH-254  
FAILS OPEN (FAILS  
TO CLOSE)  
1CHCKV-FO-1CH254

1.15E-003 3

OPERATOR FAILS TO  
CLOSE DISCHARGE  
VALVE  
GFB4923

NO ELECTRIC POWER  
480 V MCC 1M1-25  
1-EP-MC-20  
GE1H1412

E1H00

MOTOR OPERTD VALVE  
FAILS OPEN  
1-CH-MOV-1286A  
1CHMOV-FO-1286A

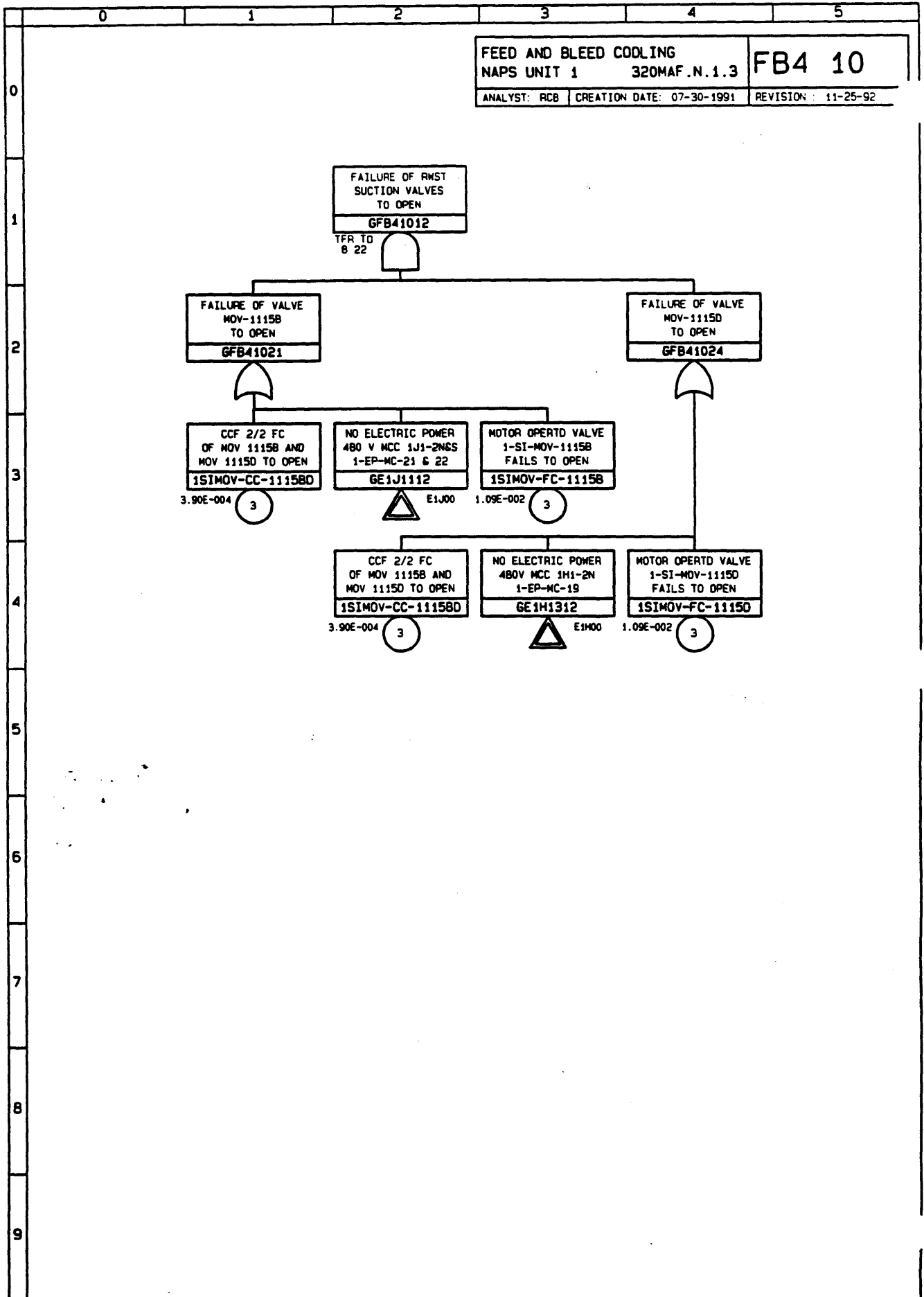
1.09E-002 3

NO PROCEDURE FOR  
THIS OPERATOR  
ACTION  
HEP-NO-PROCEDURE

1.00E+000 3

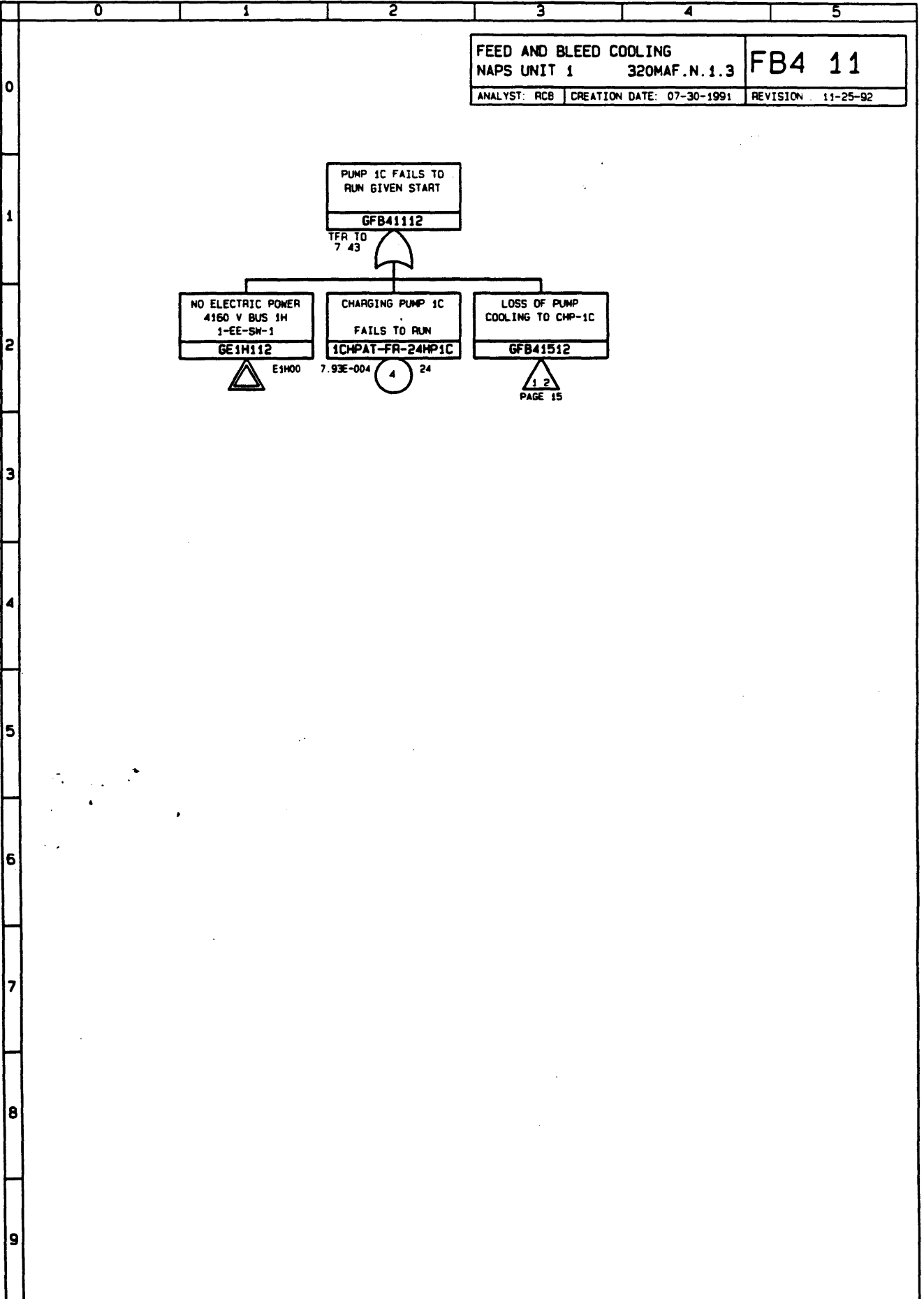
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FB400.LGC MUPRA 2.0 VPHR



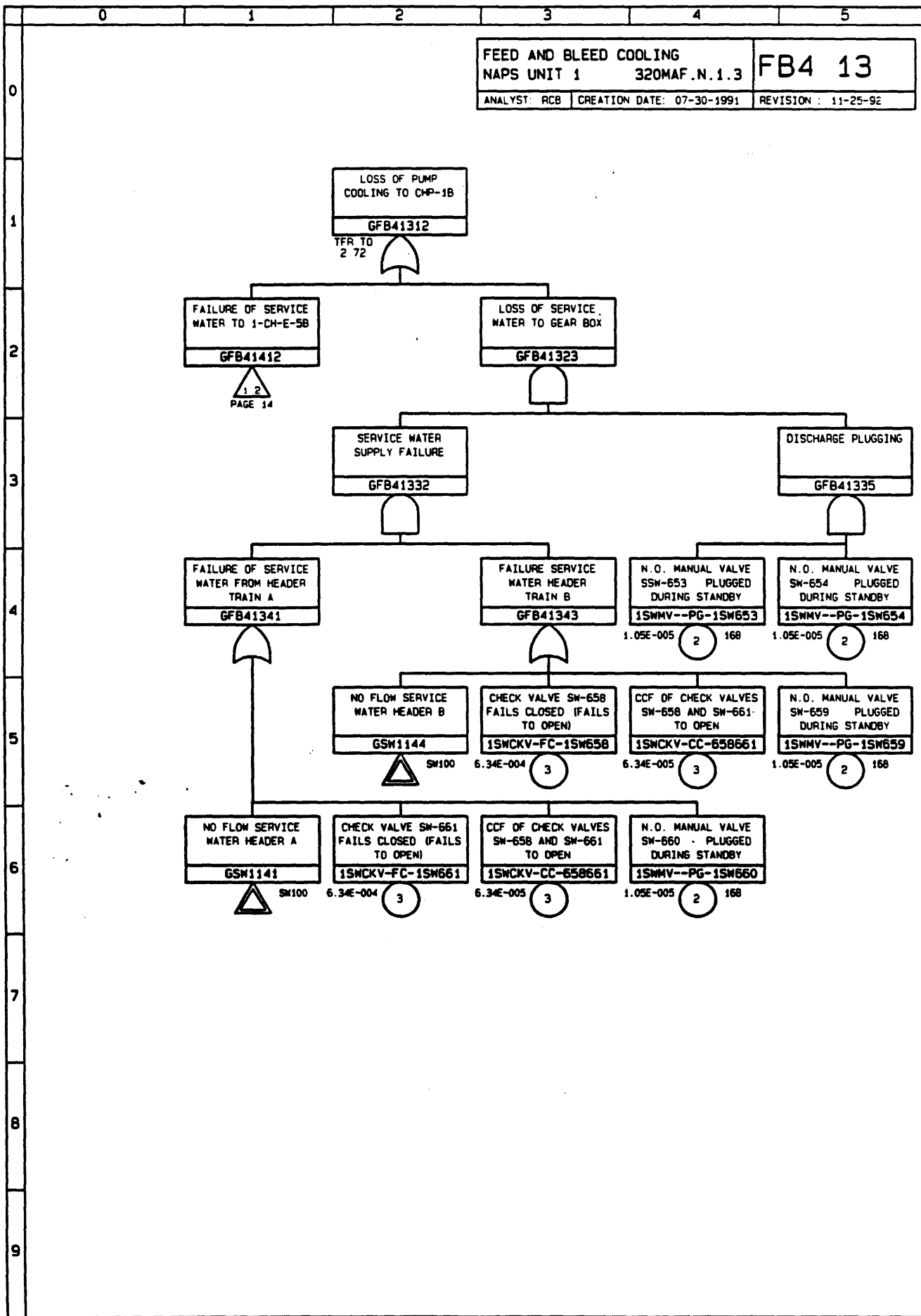


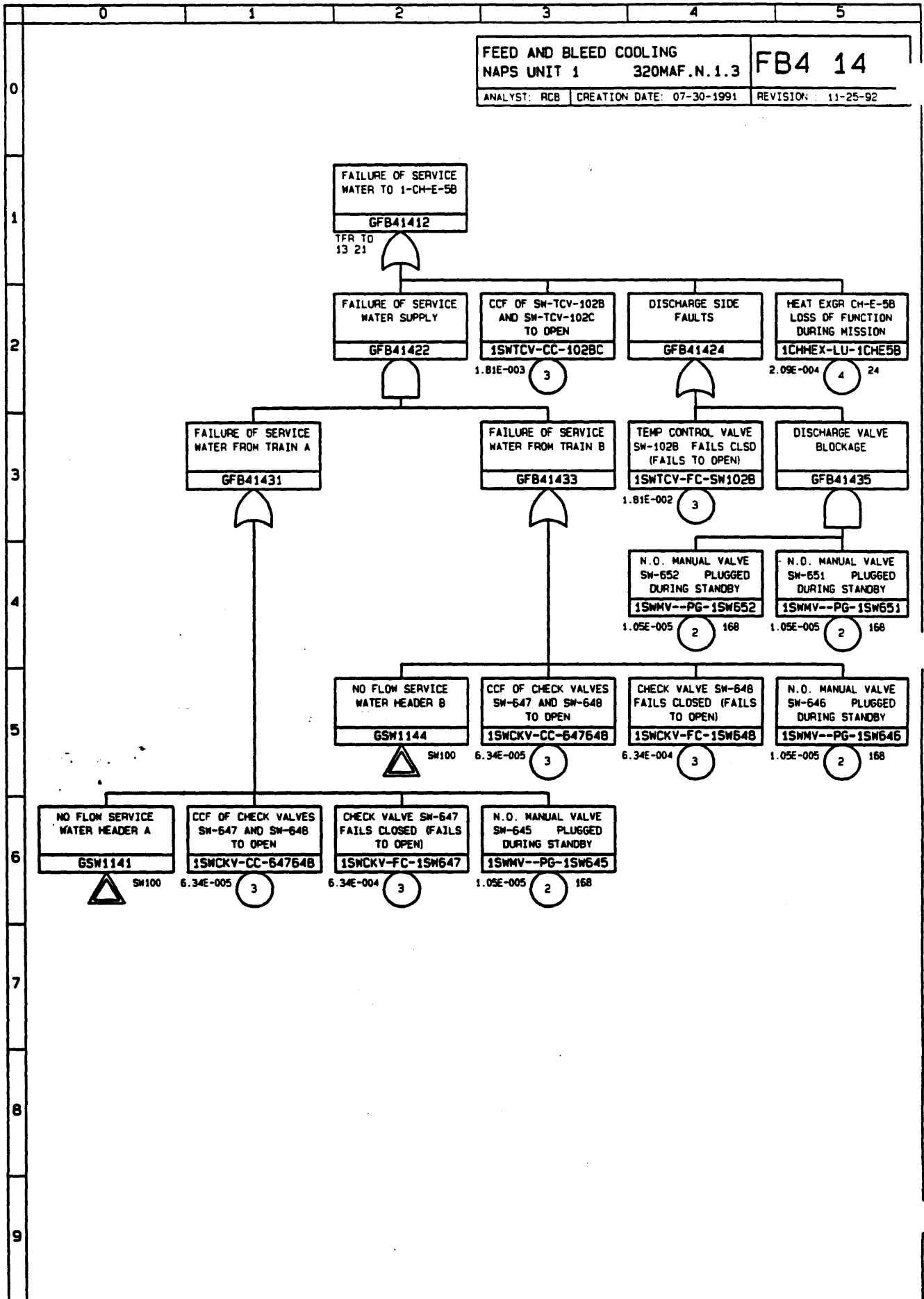
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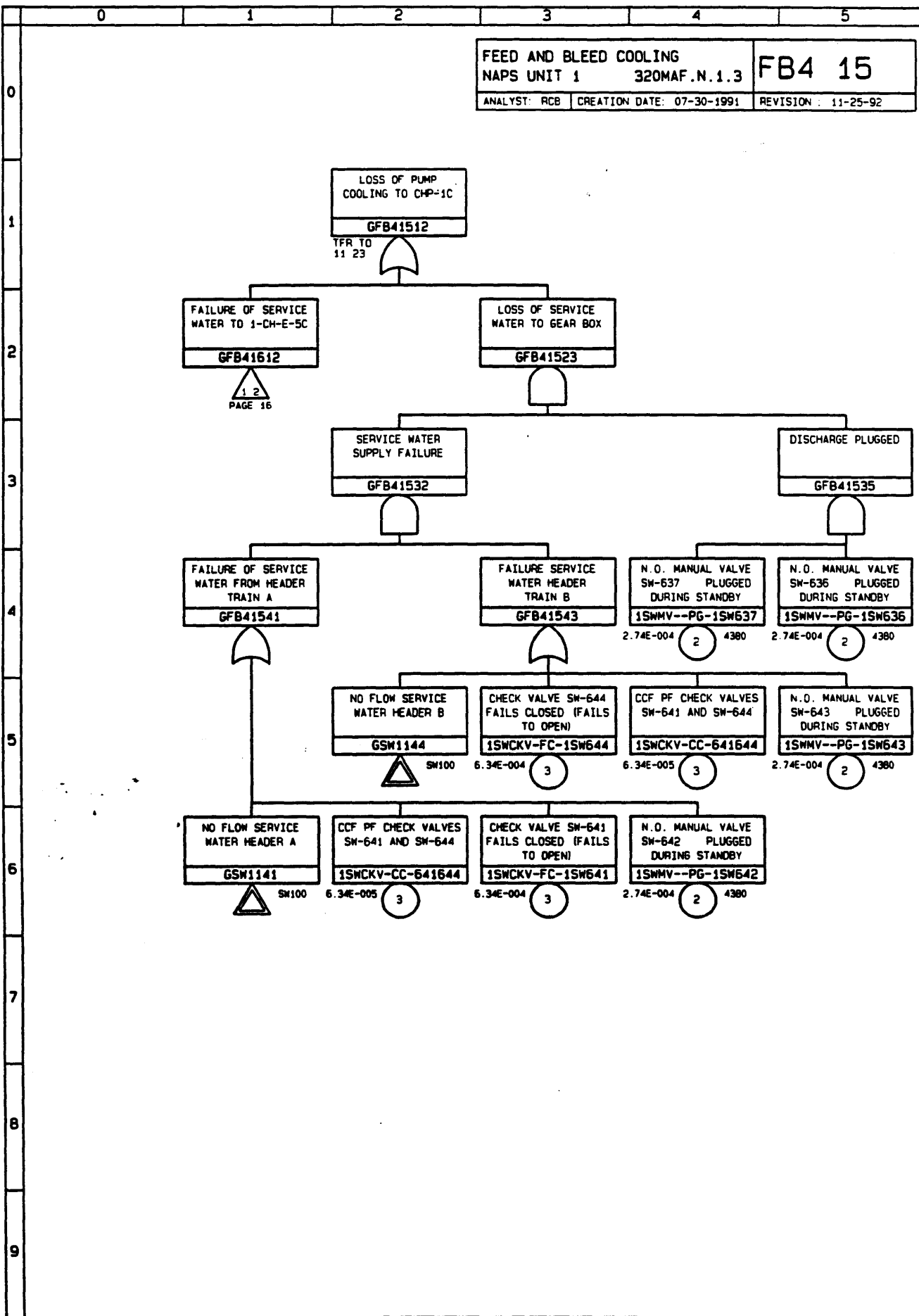
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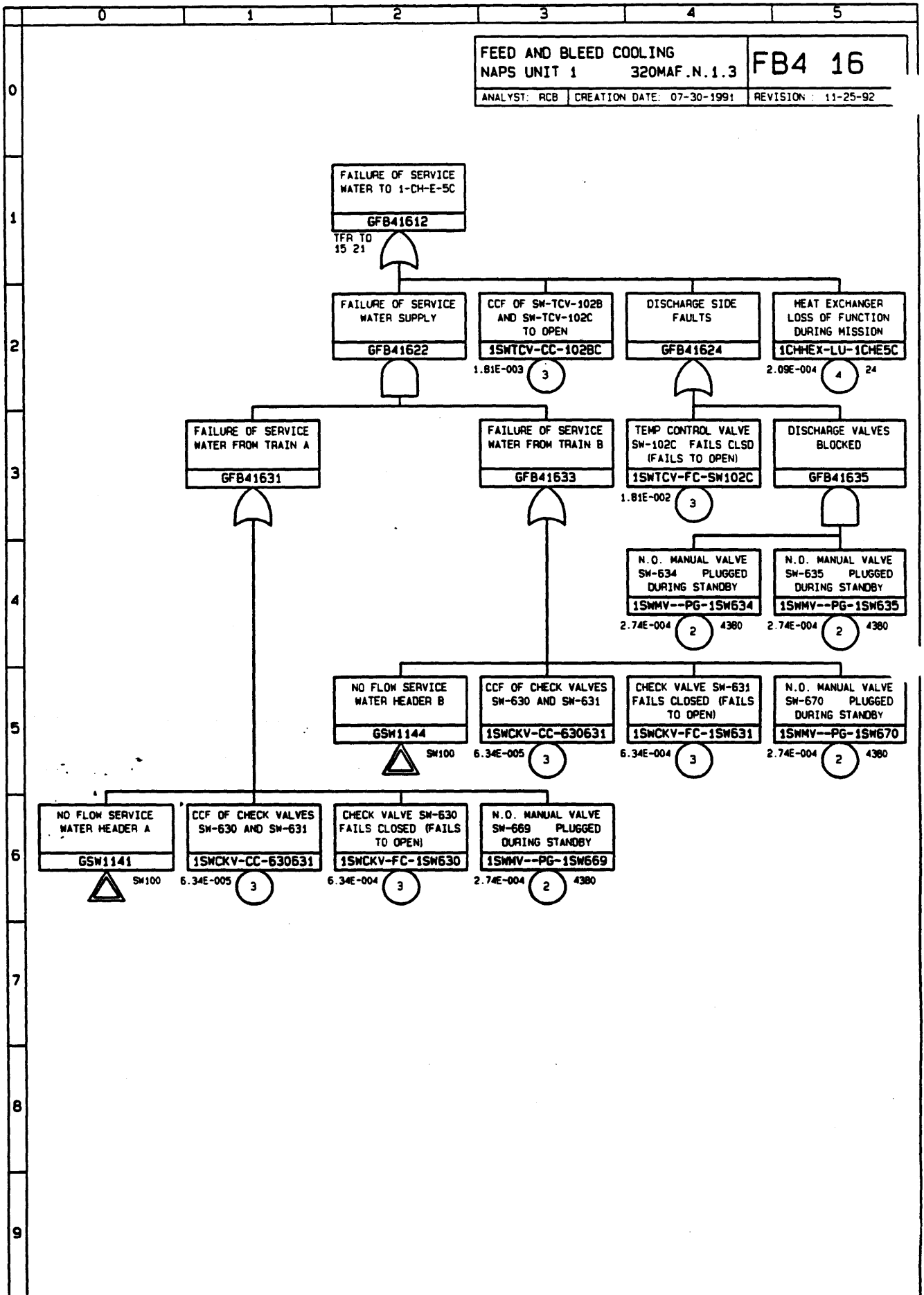
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Fault Tree FB400**

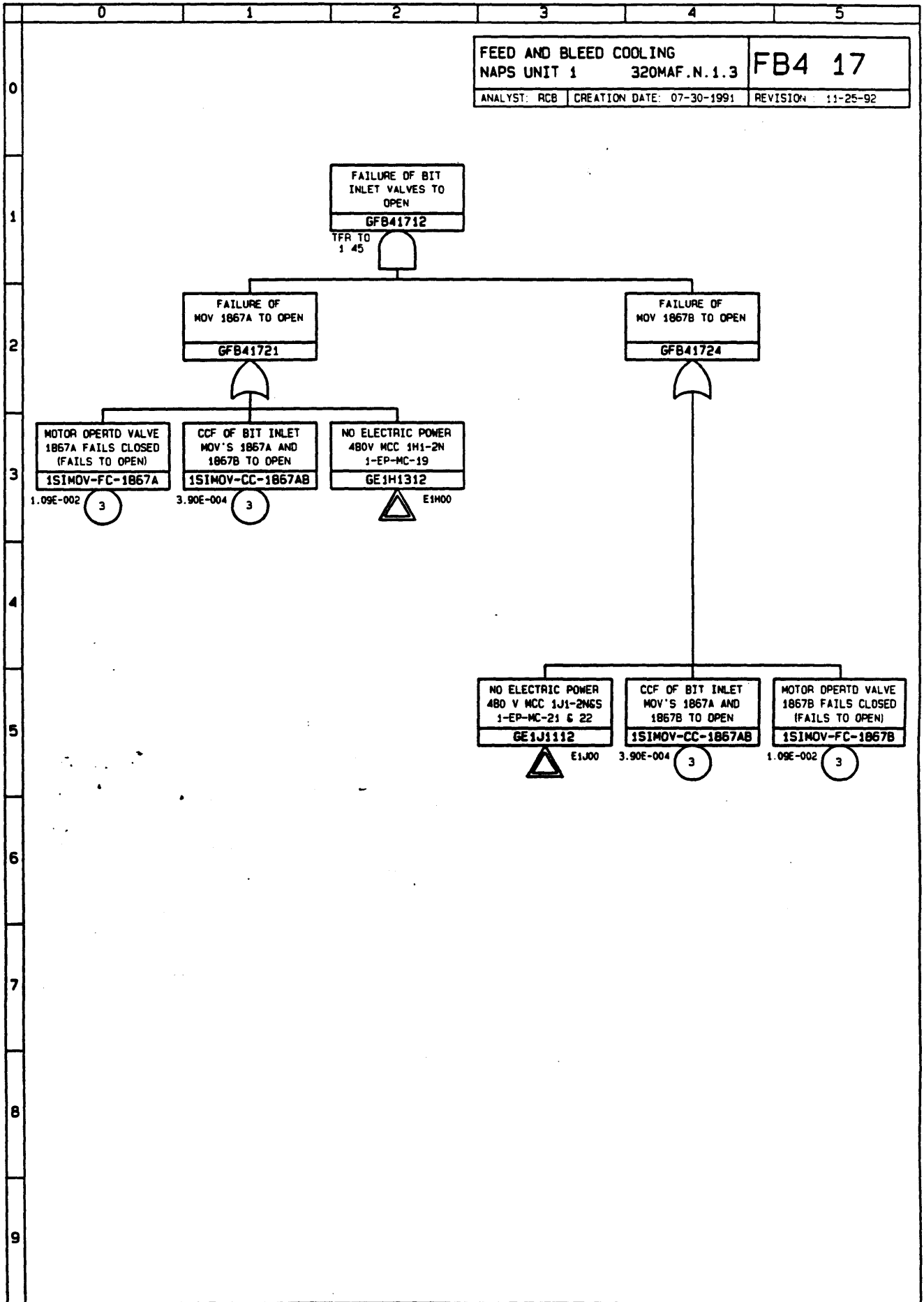


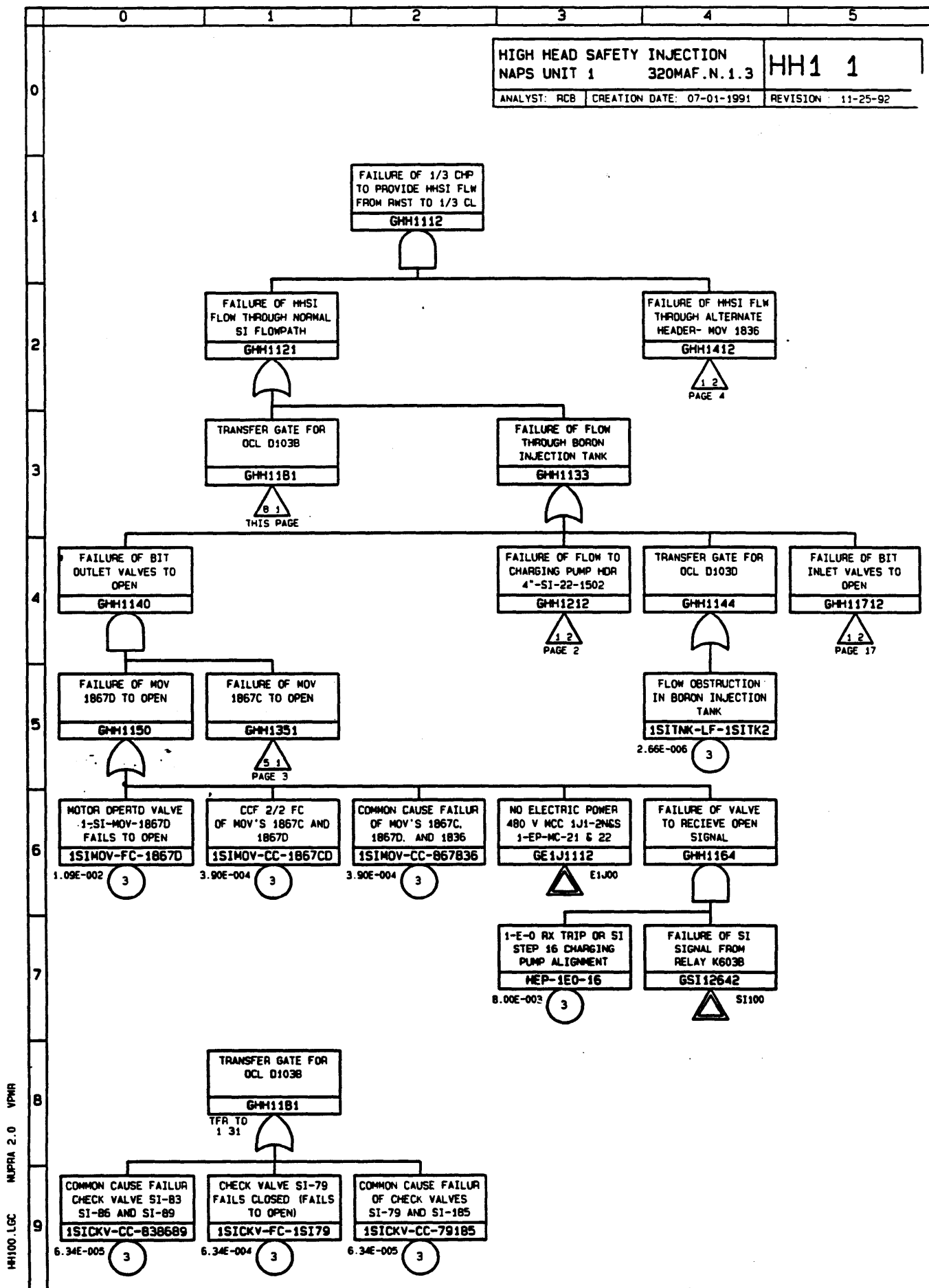


FB400 LGC NUPRA 2.0 VPMR

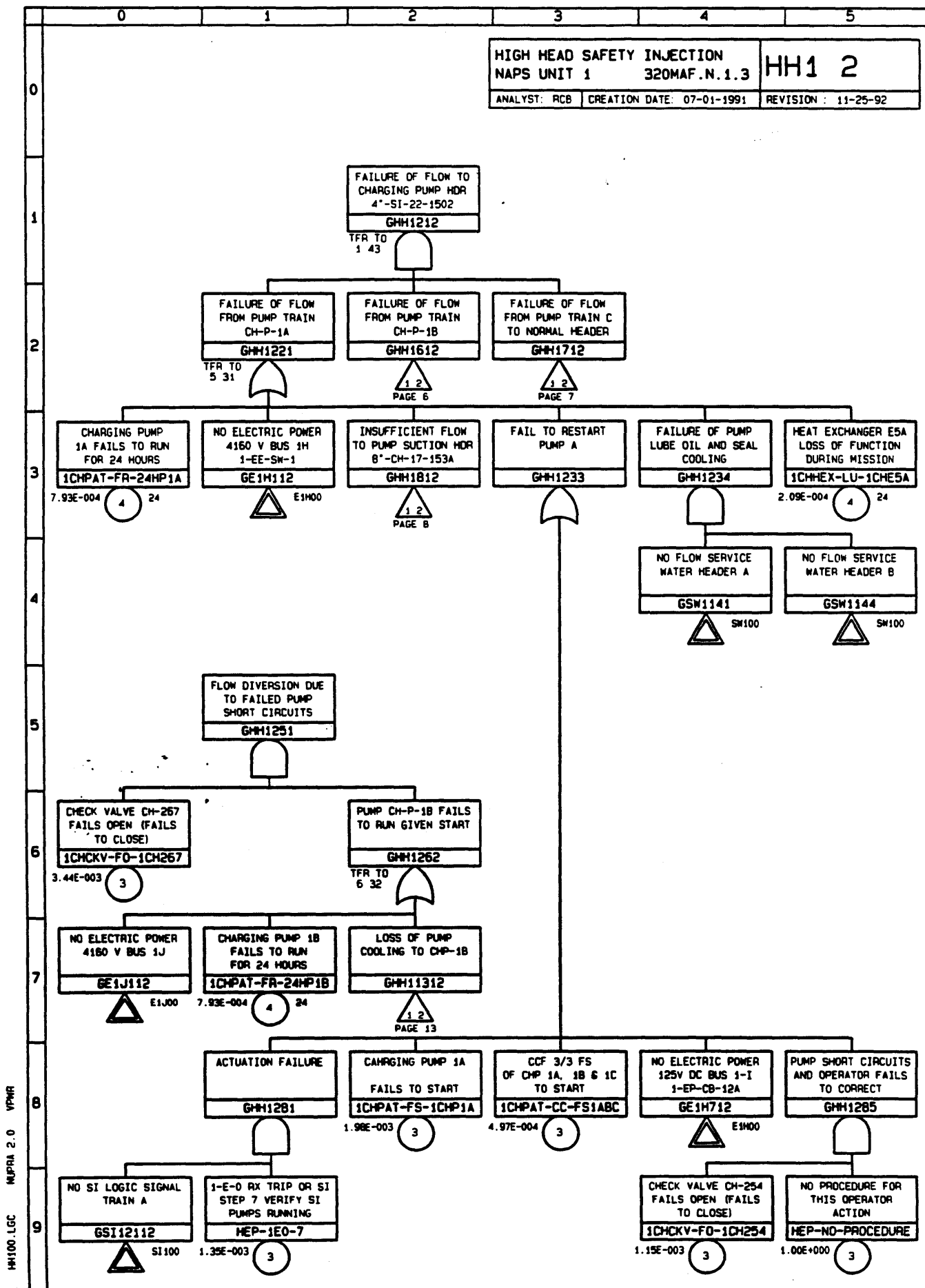


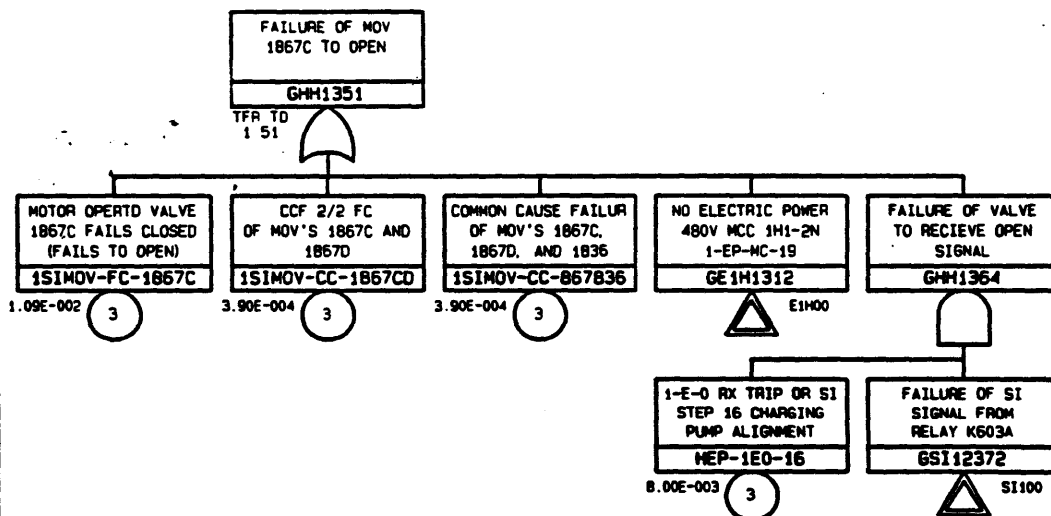




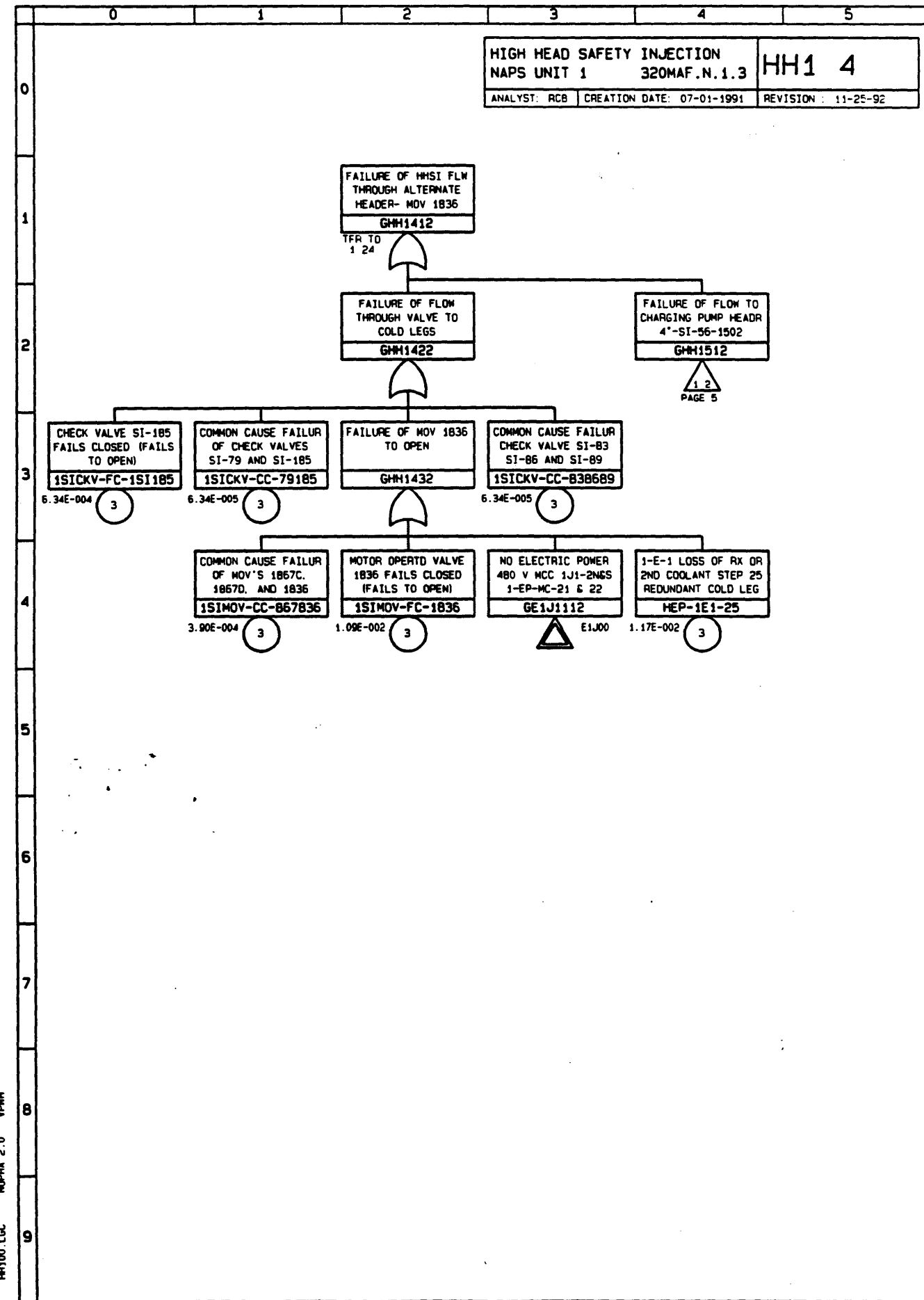




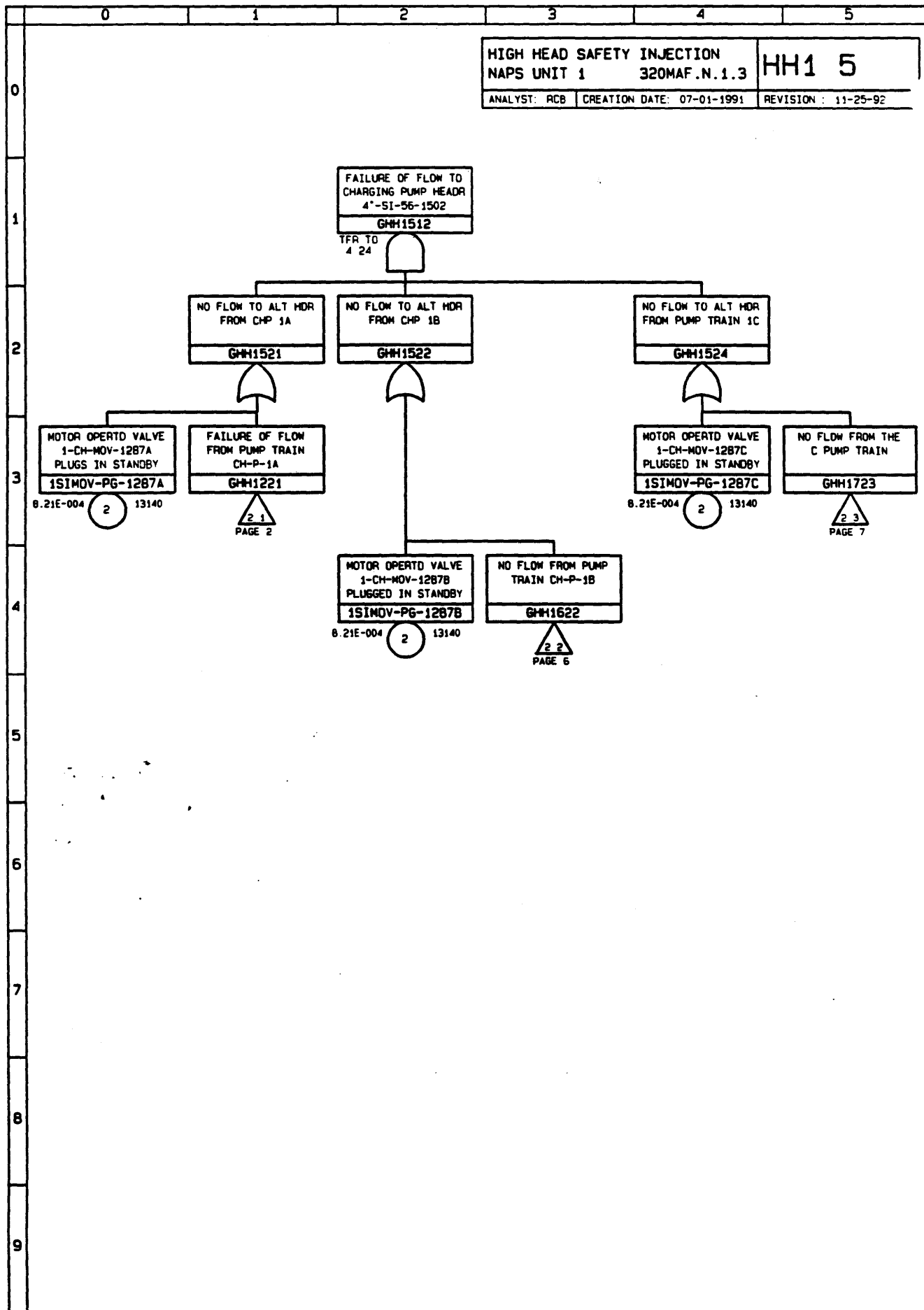




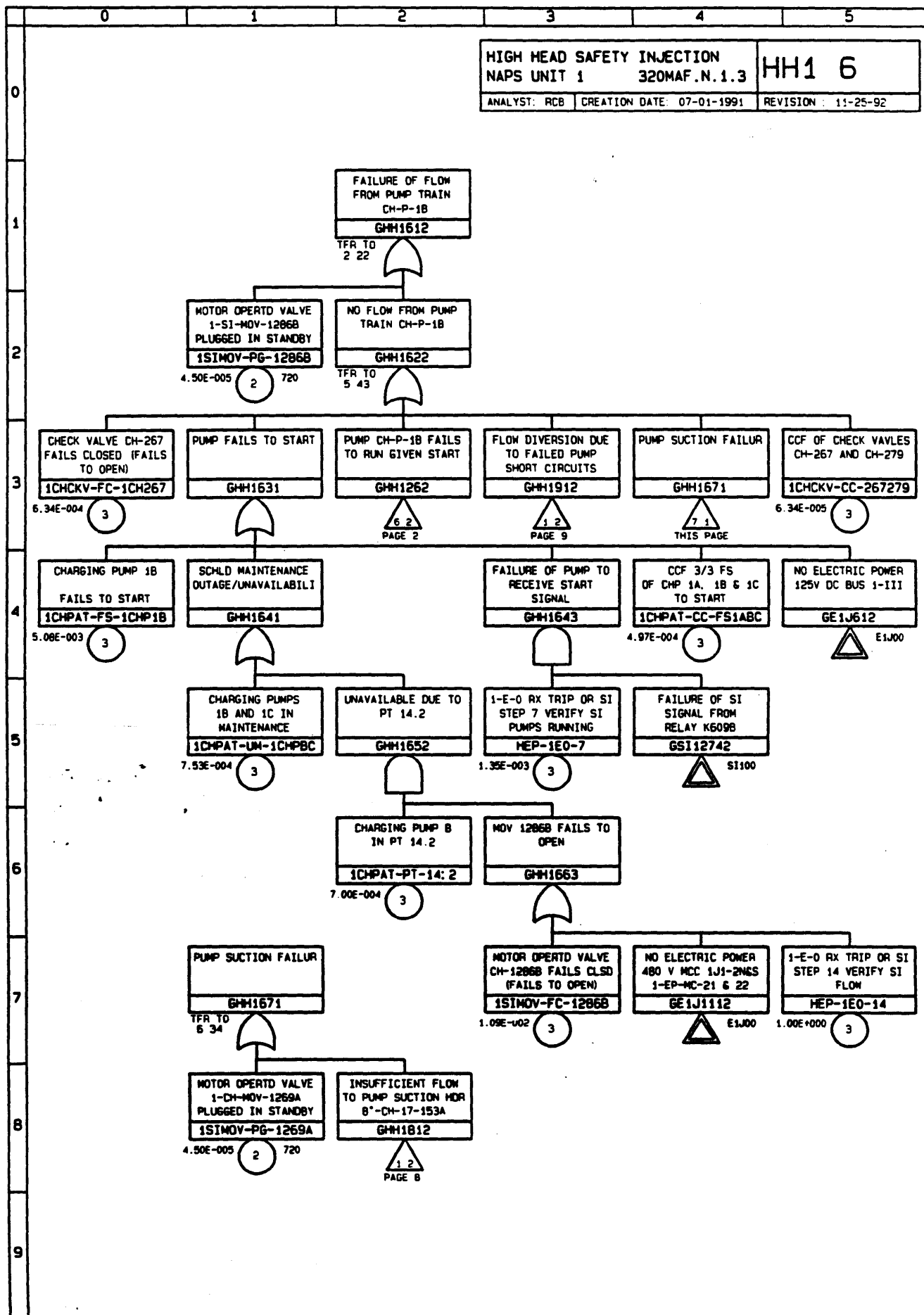
HH100 LGC NUPRA 2.0 VPMR

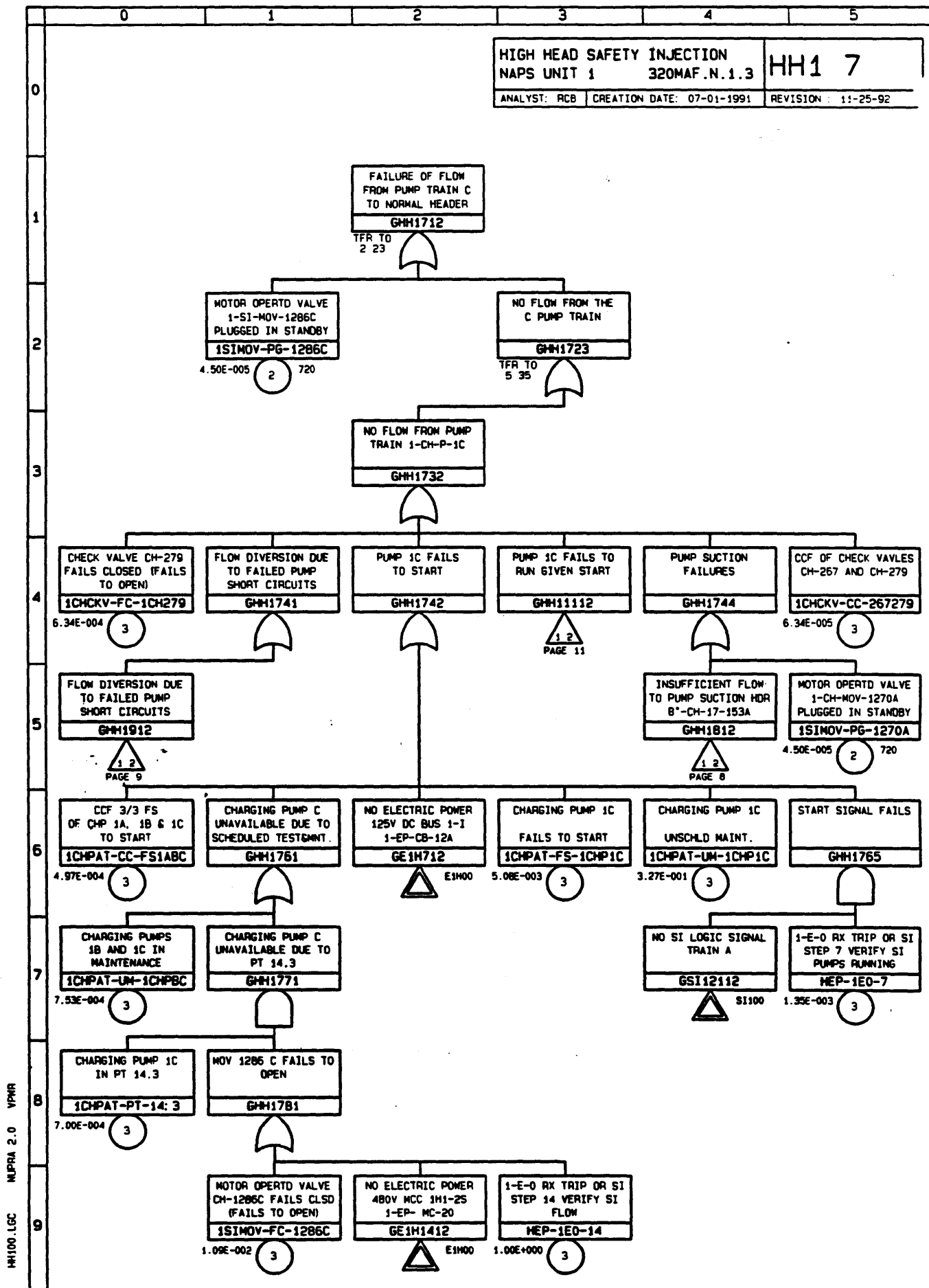


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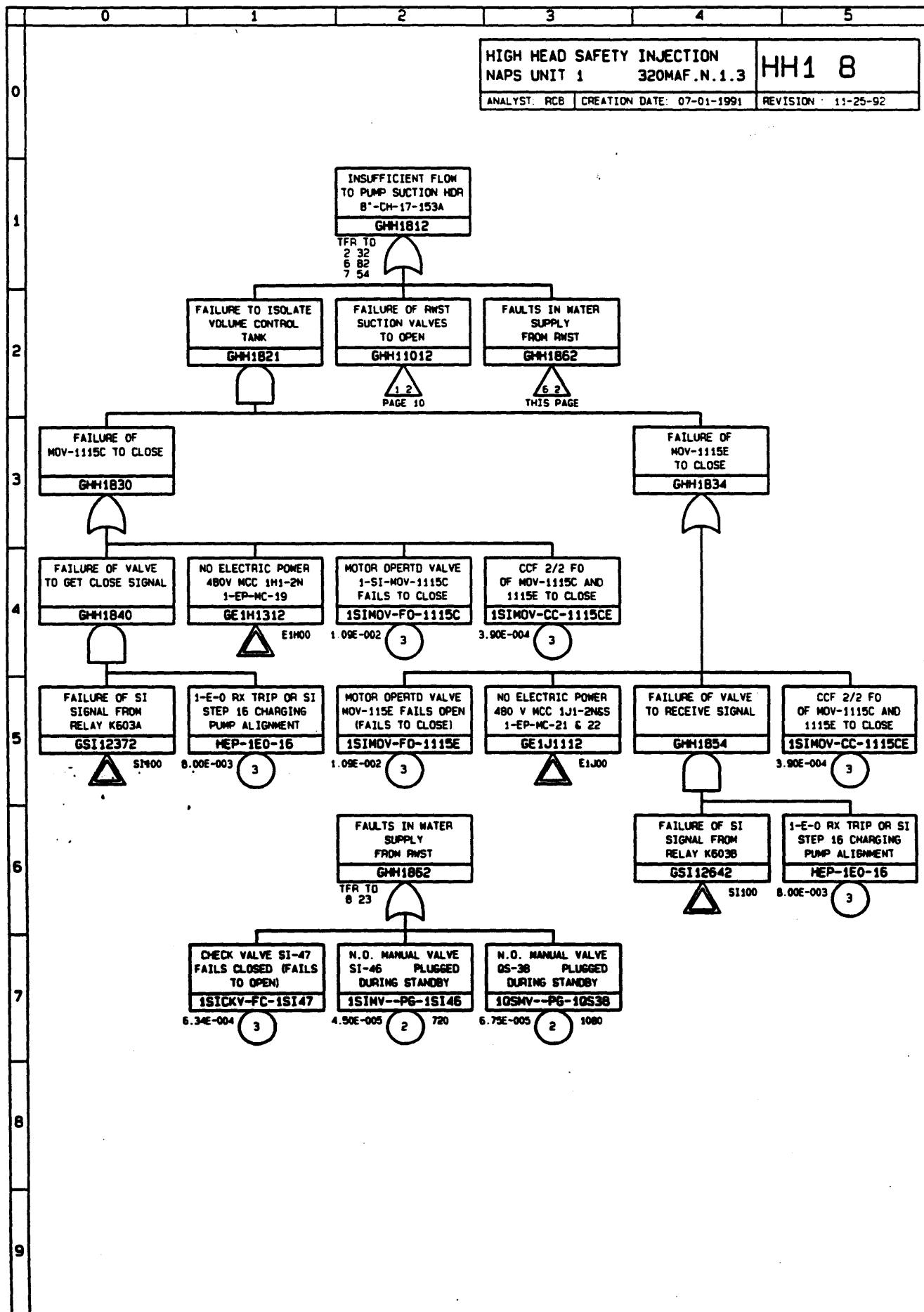


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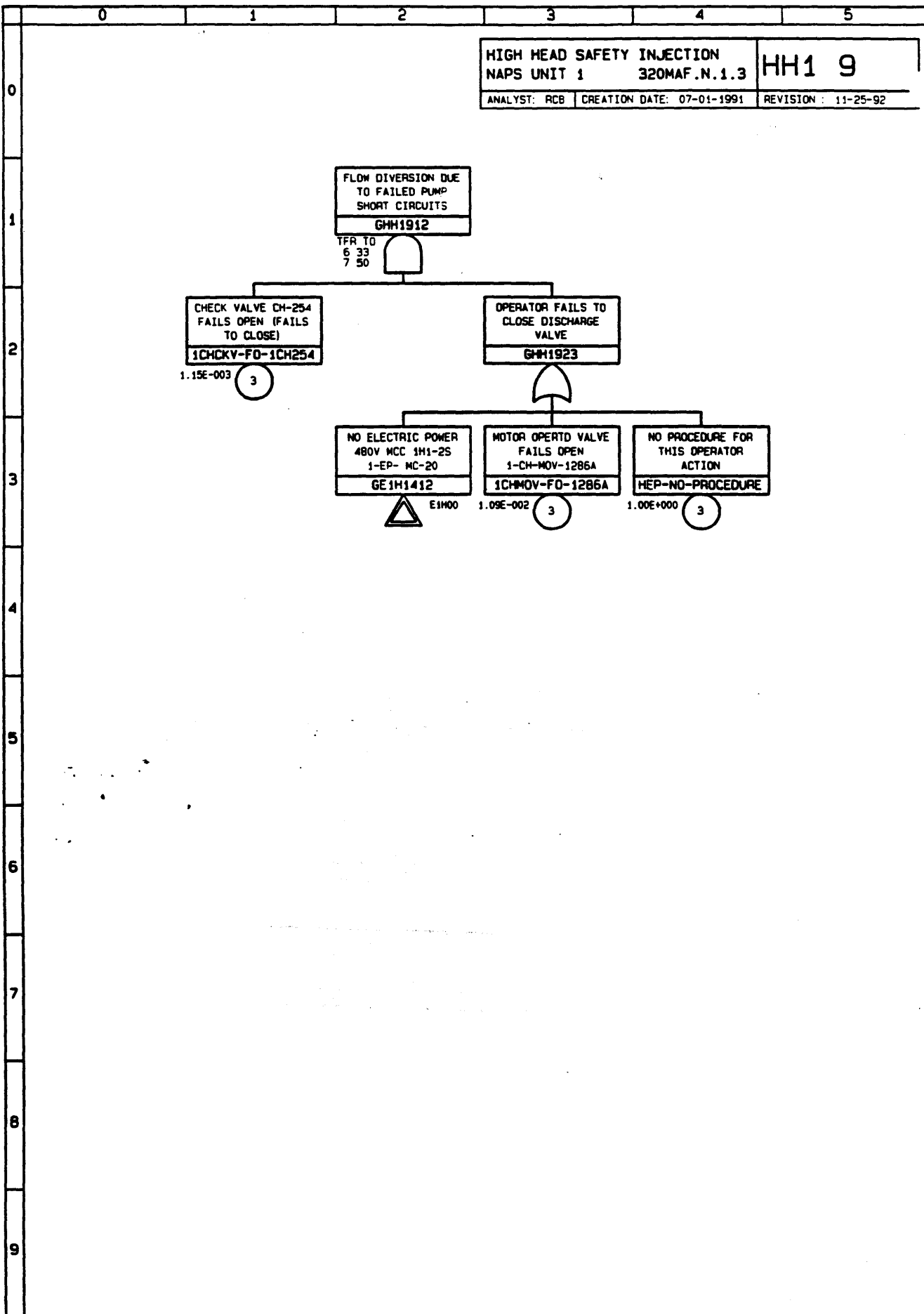




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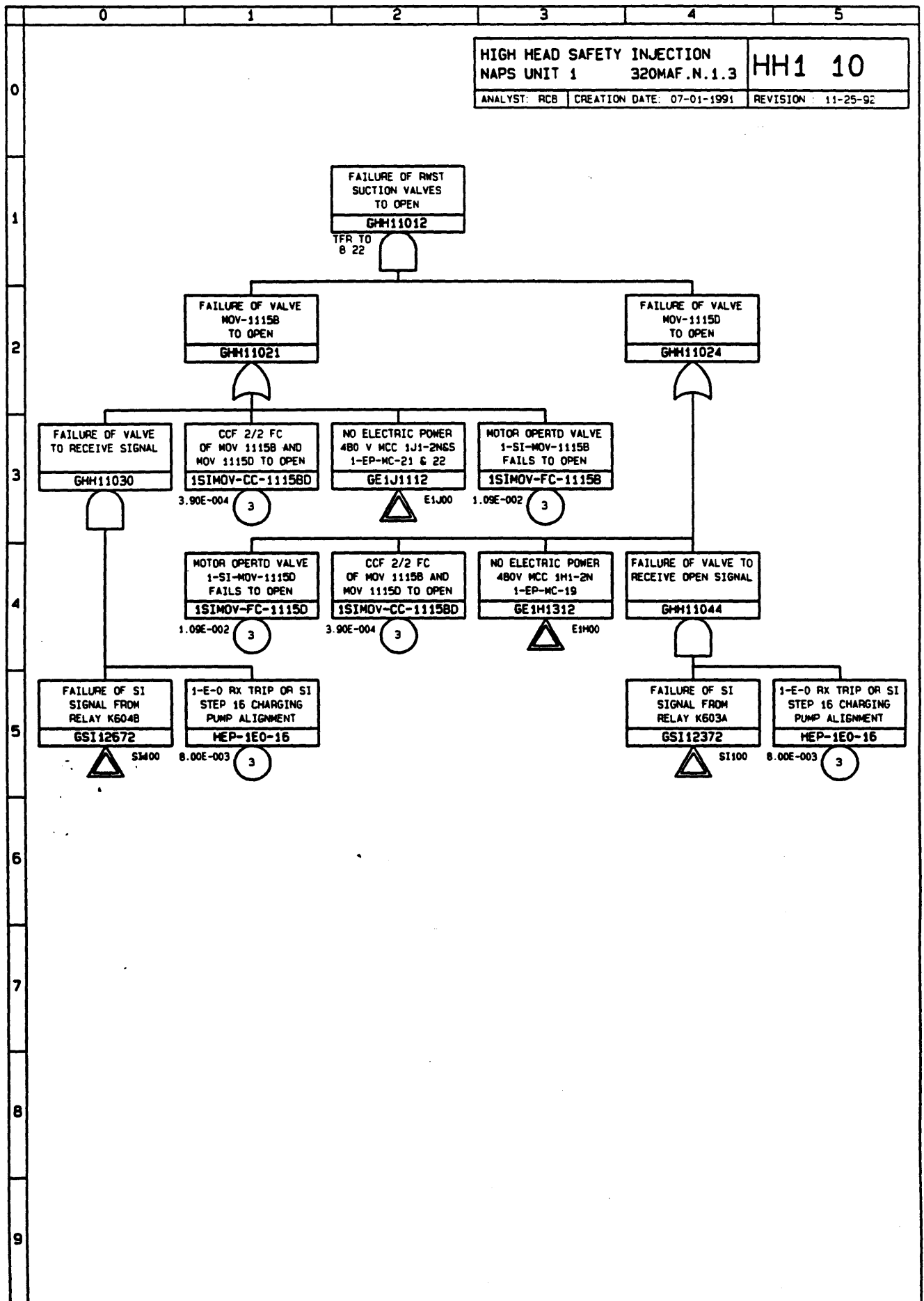


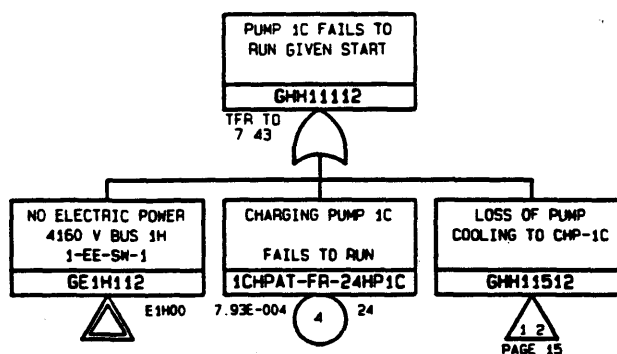
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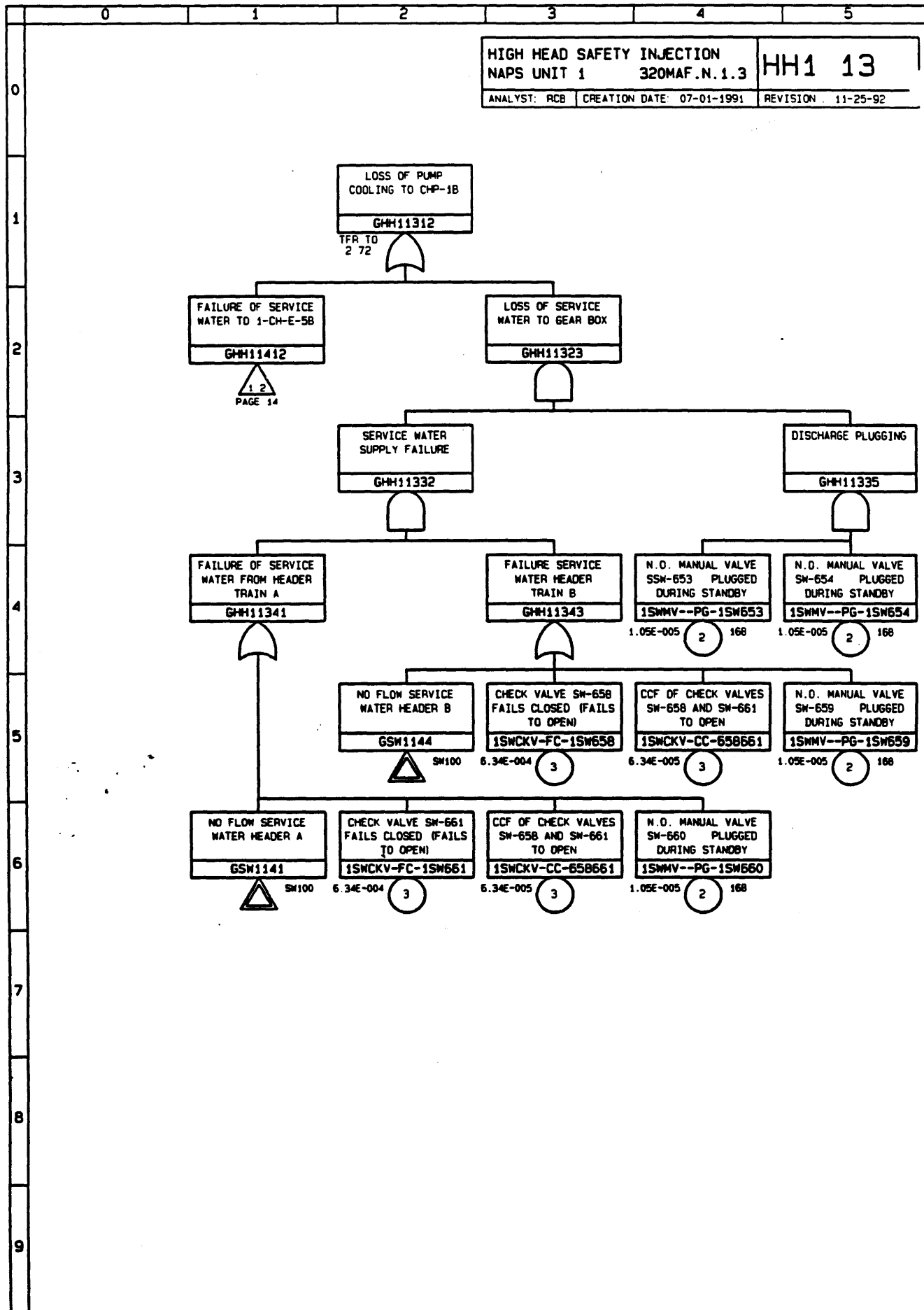
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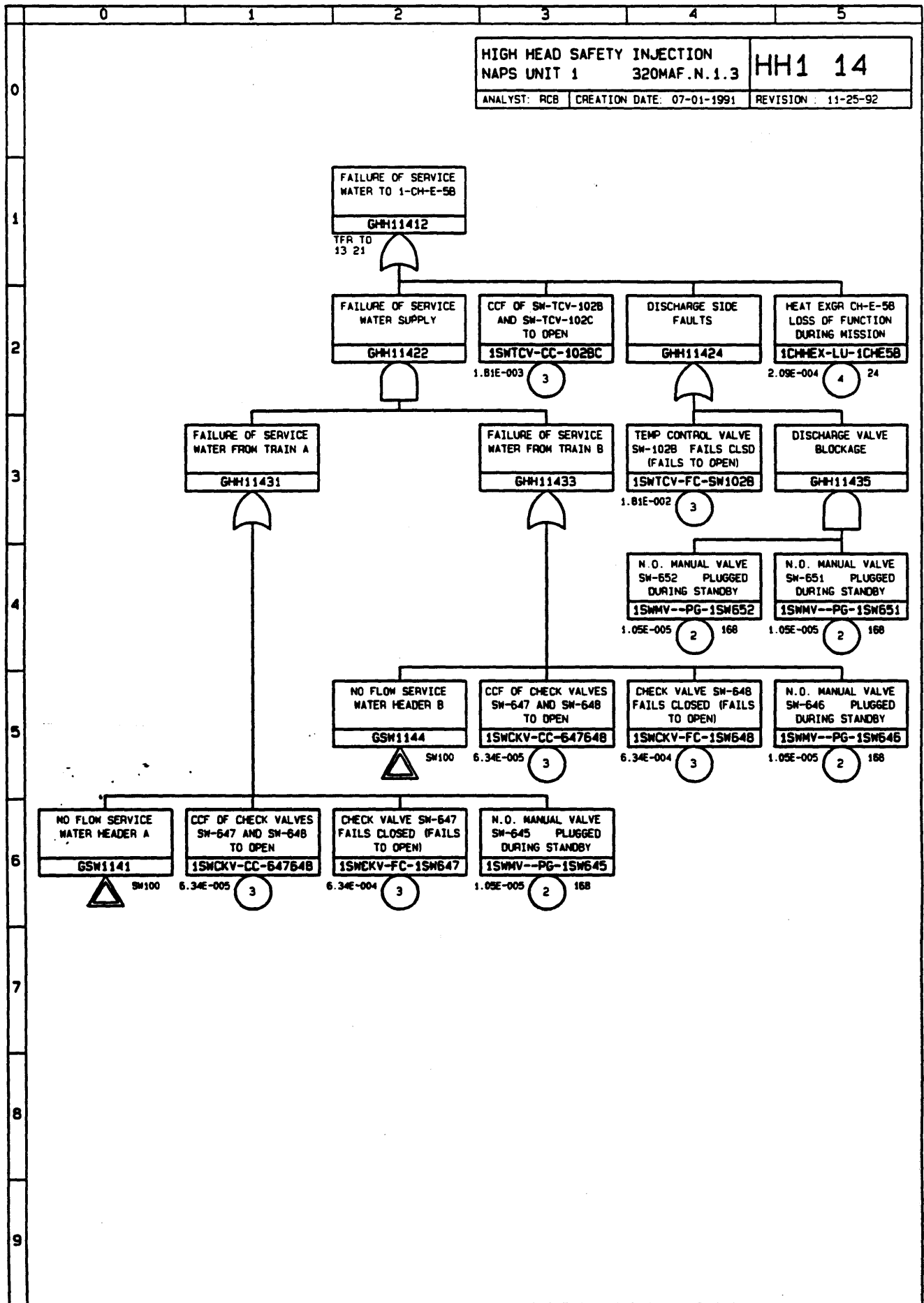


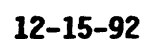
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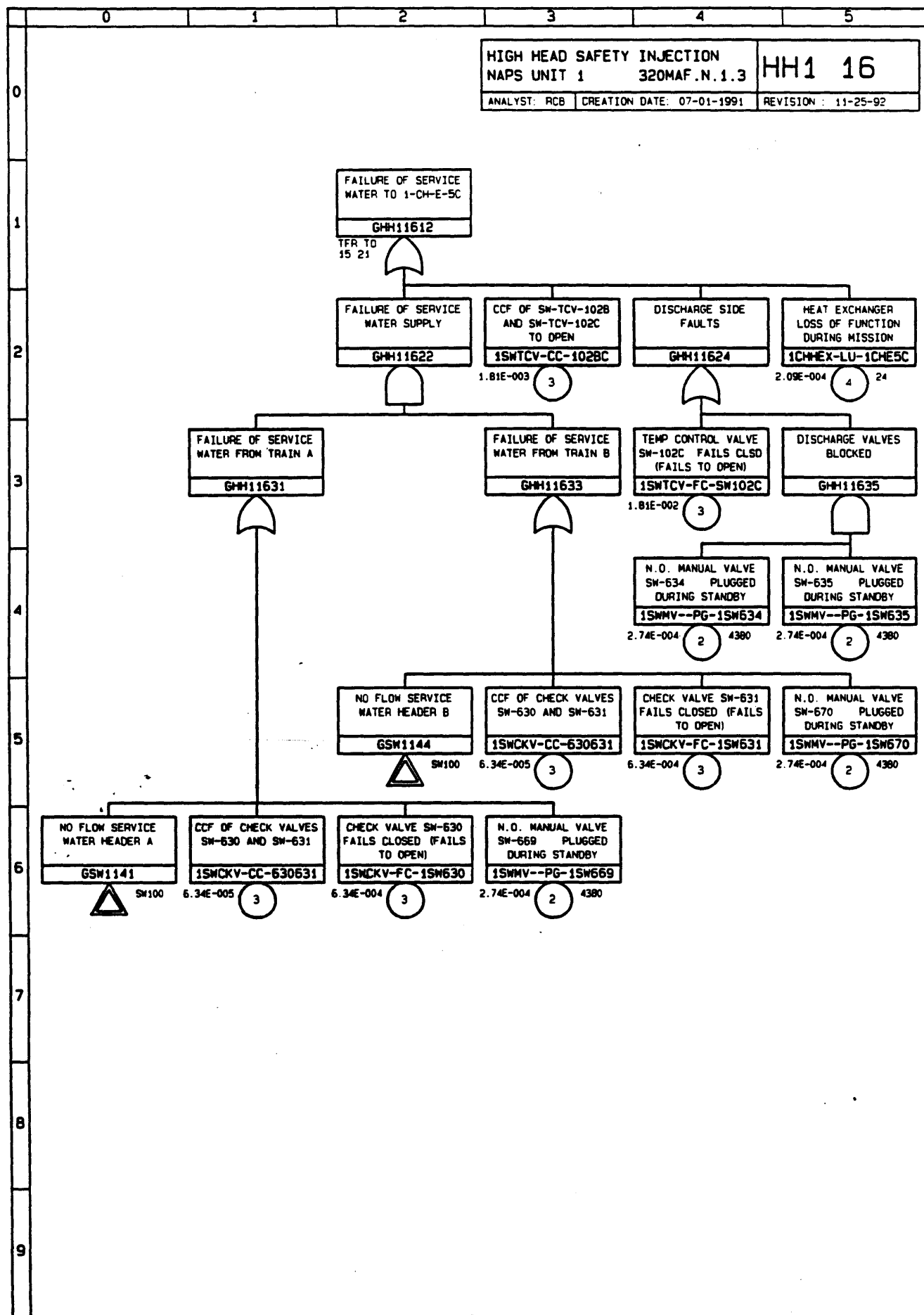


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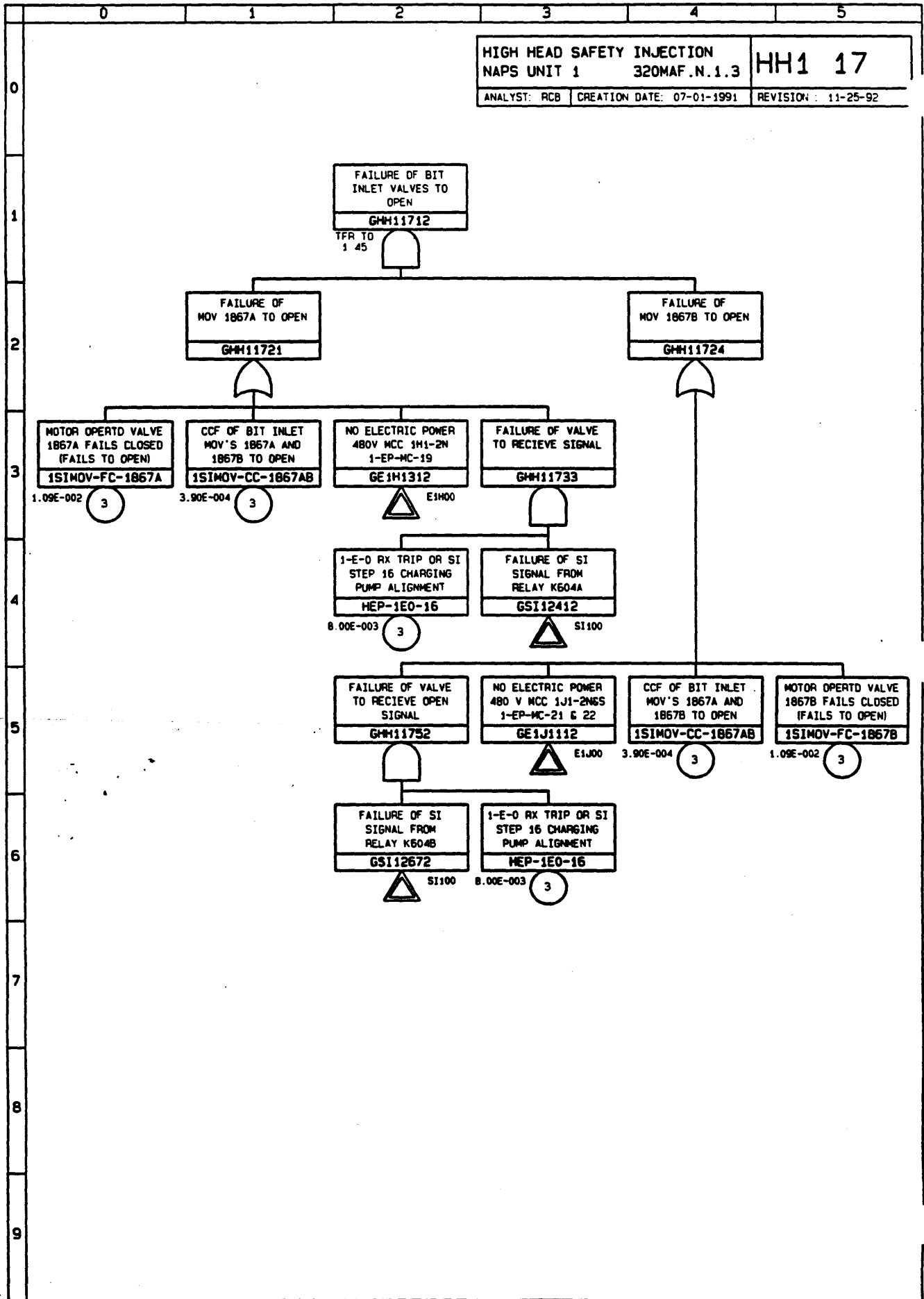




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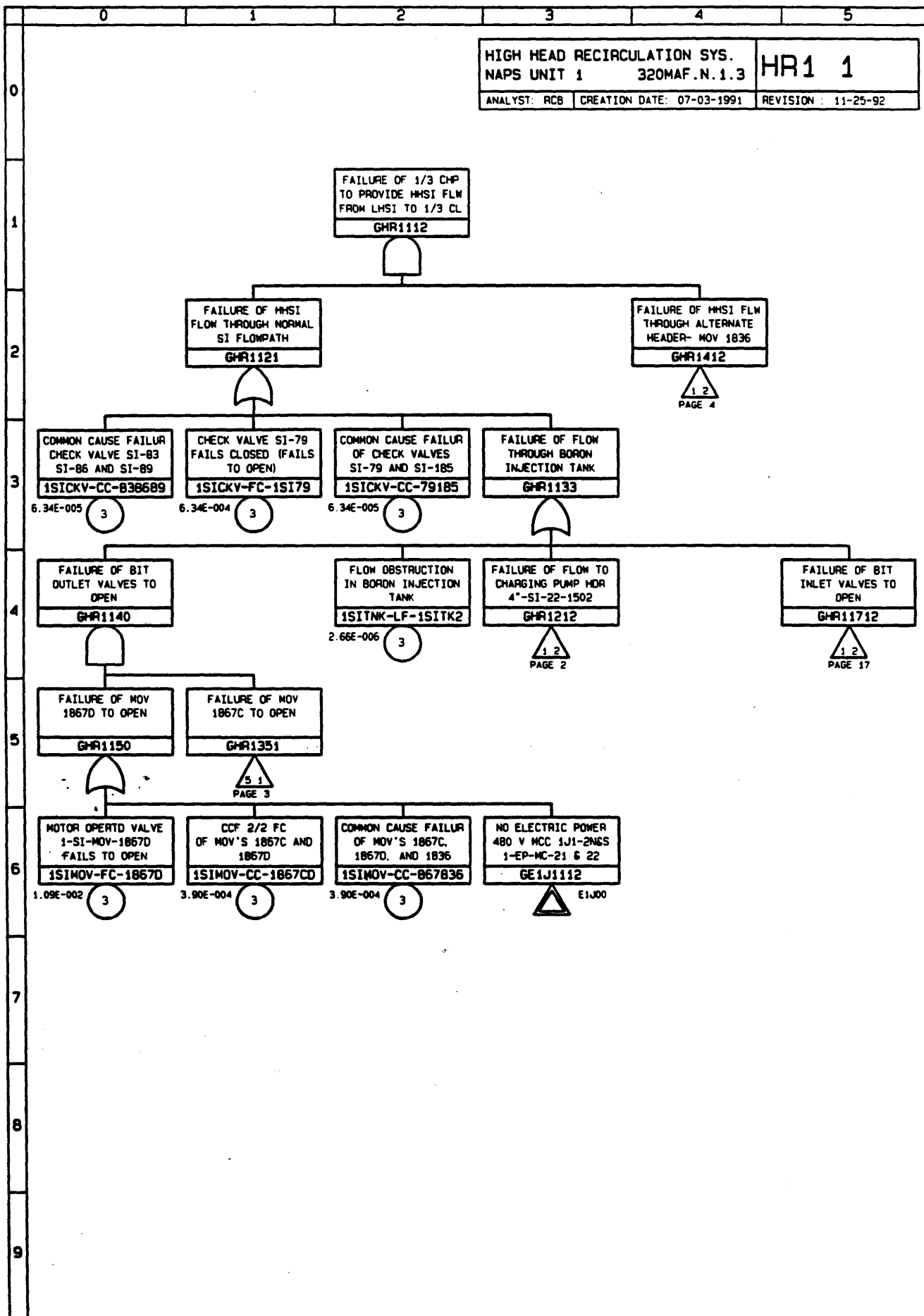


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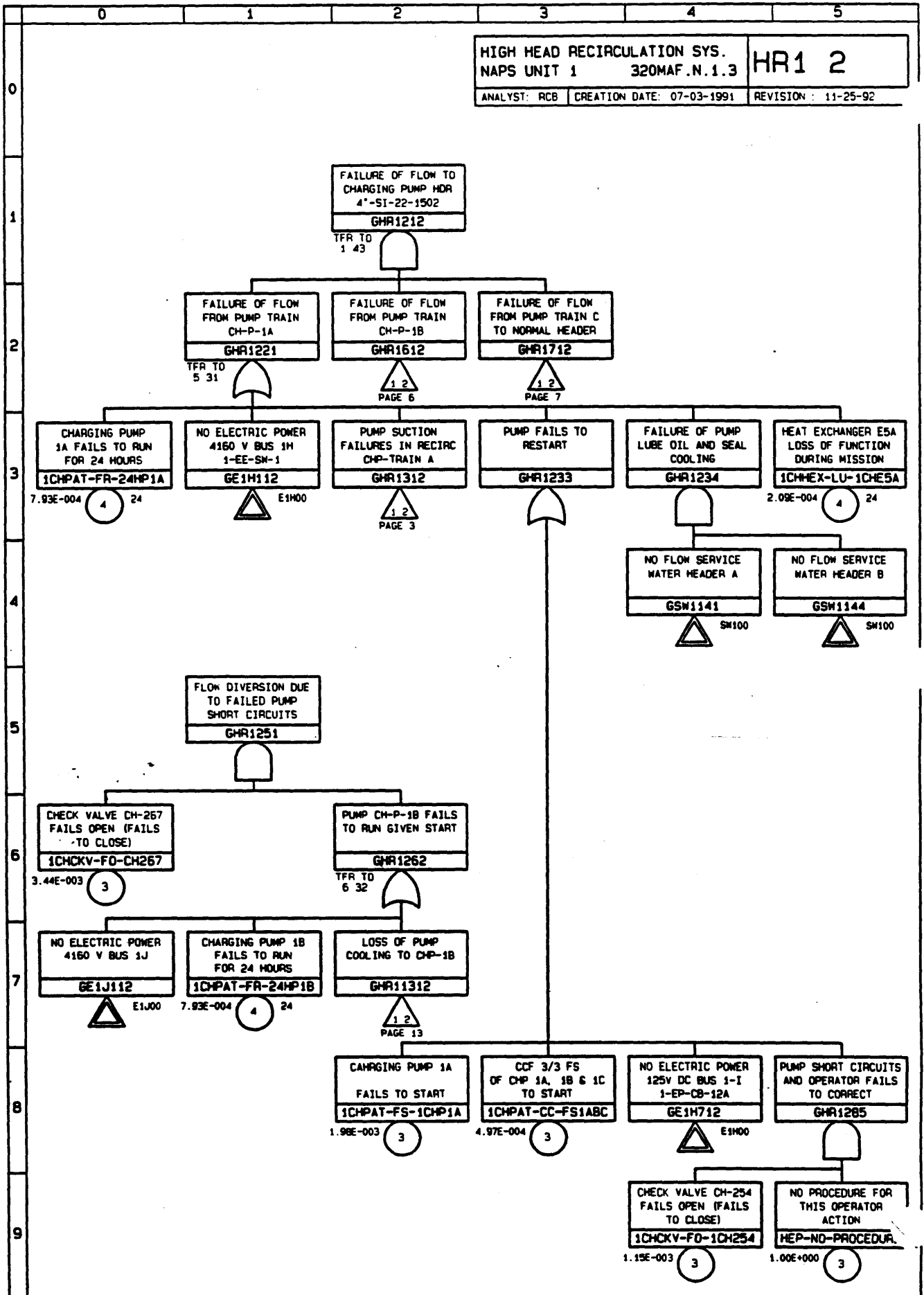




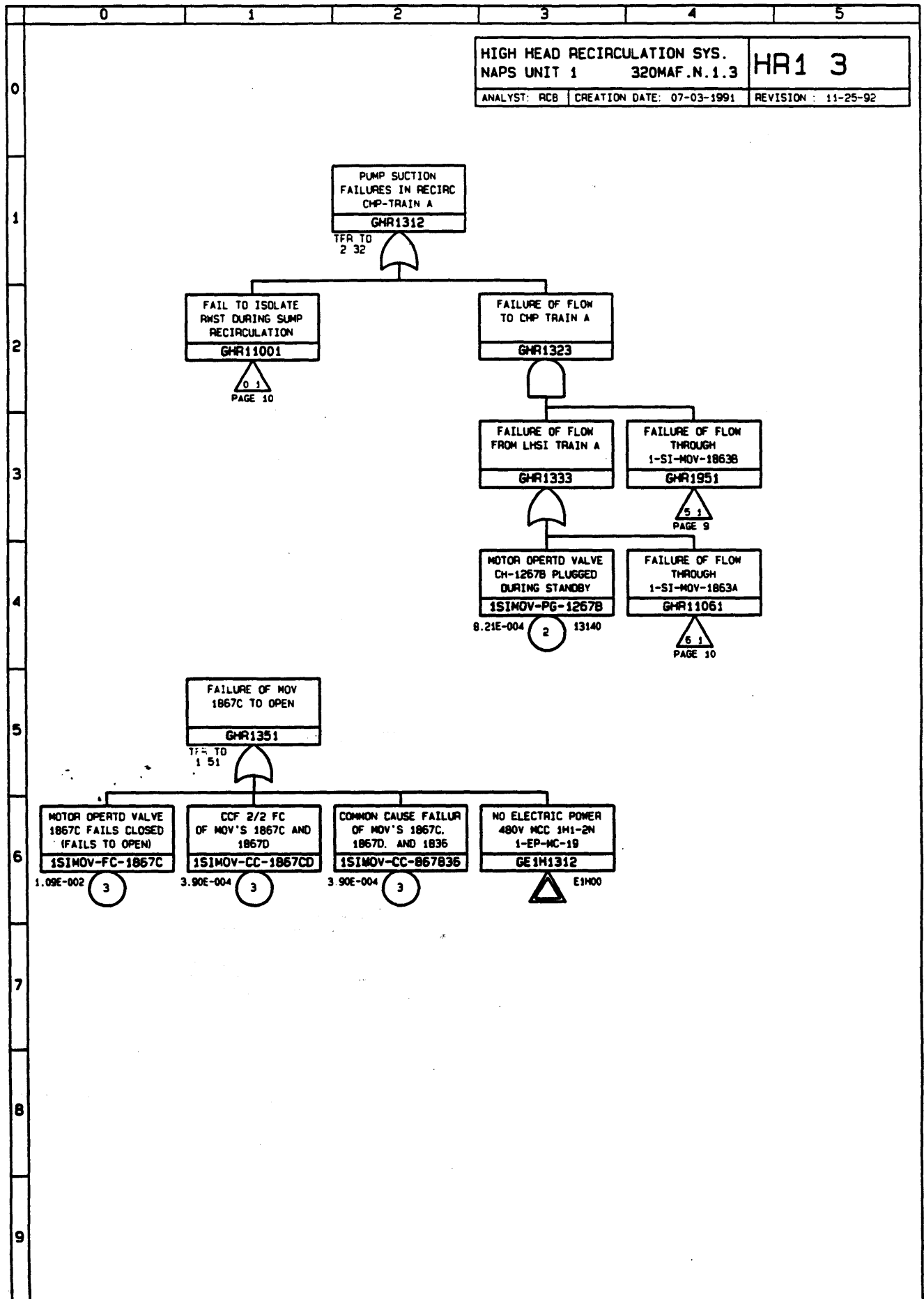
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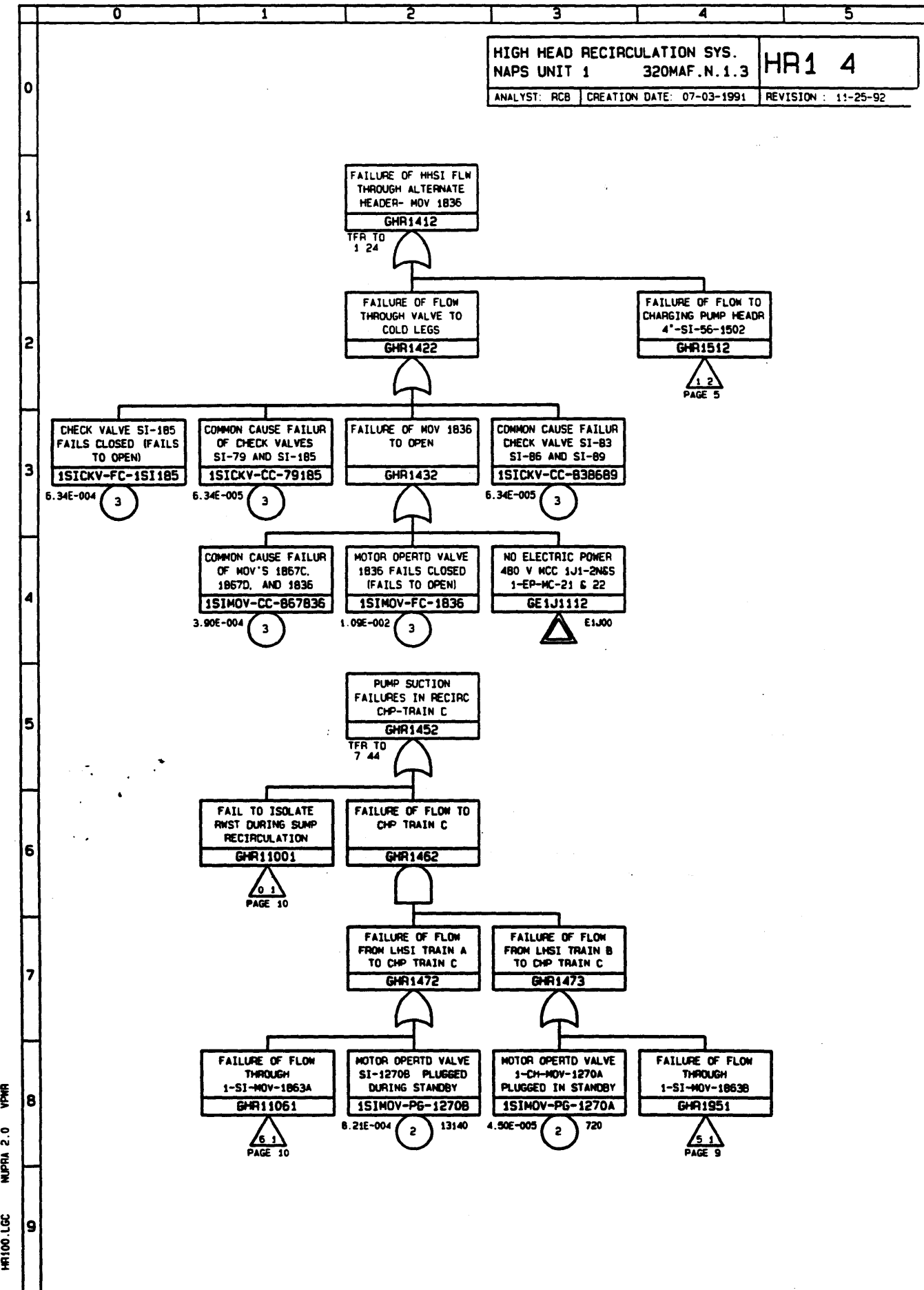
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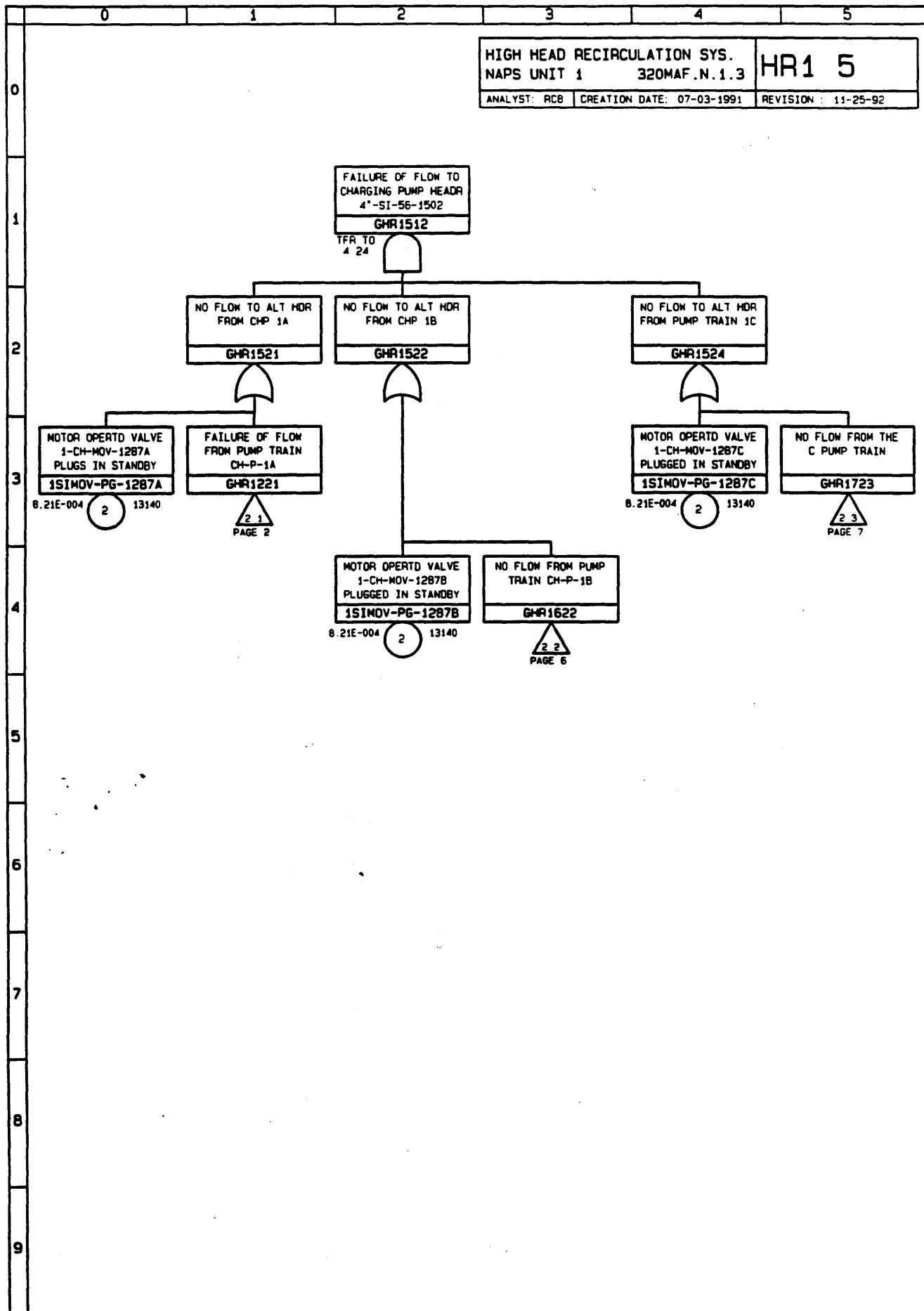


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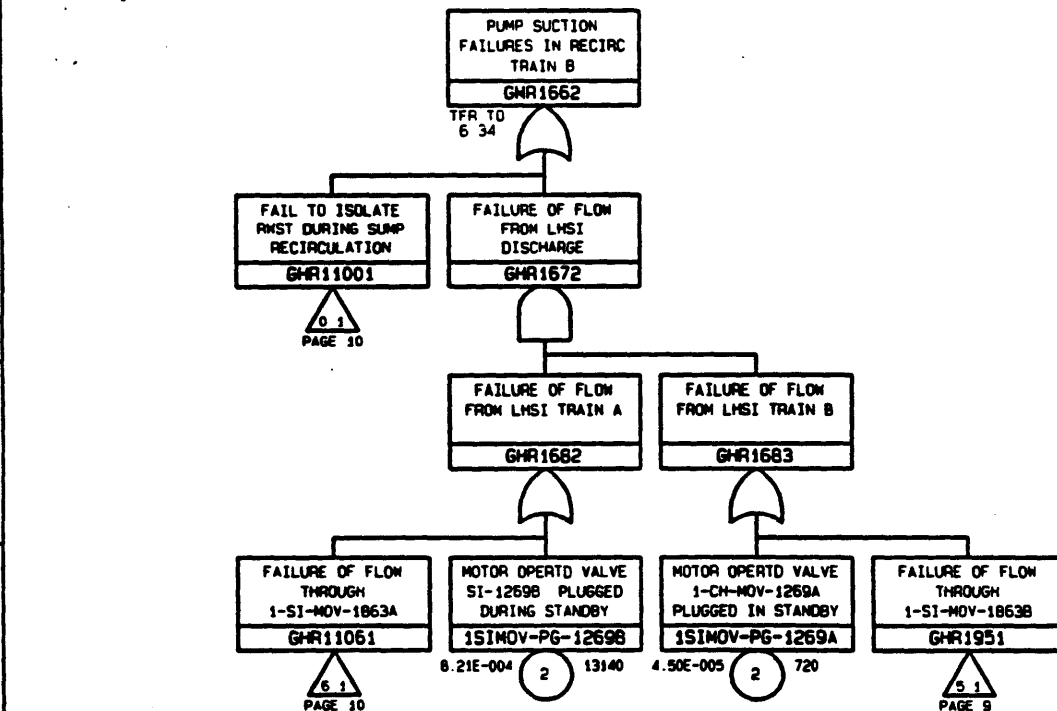


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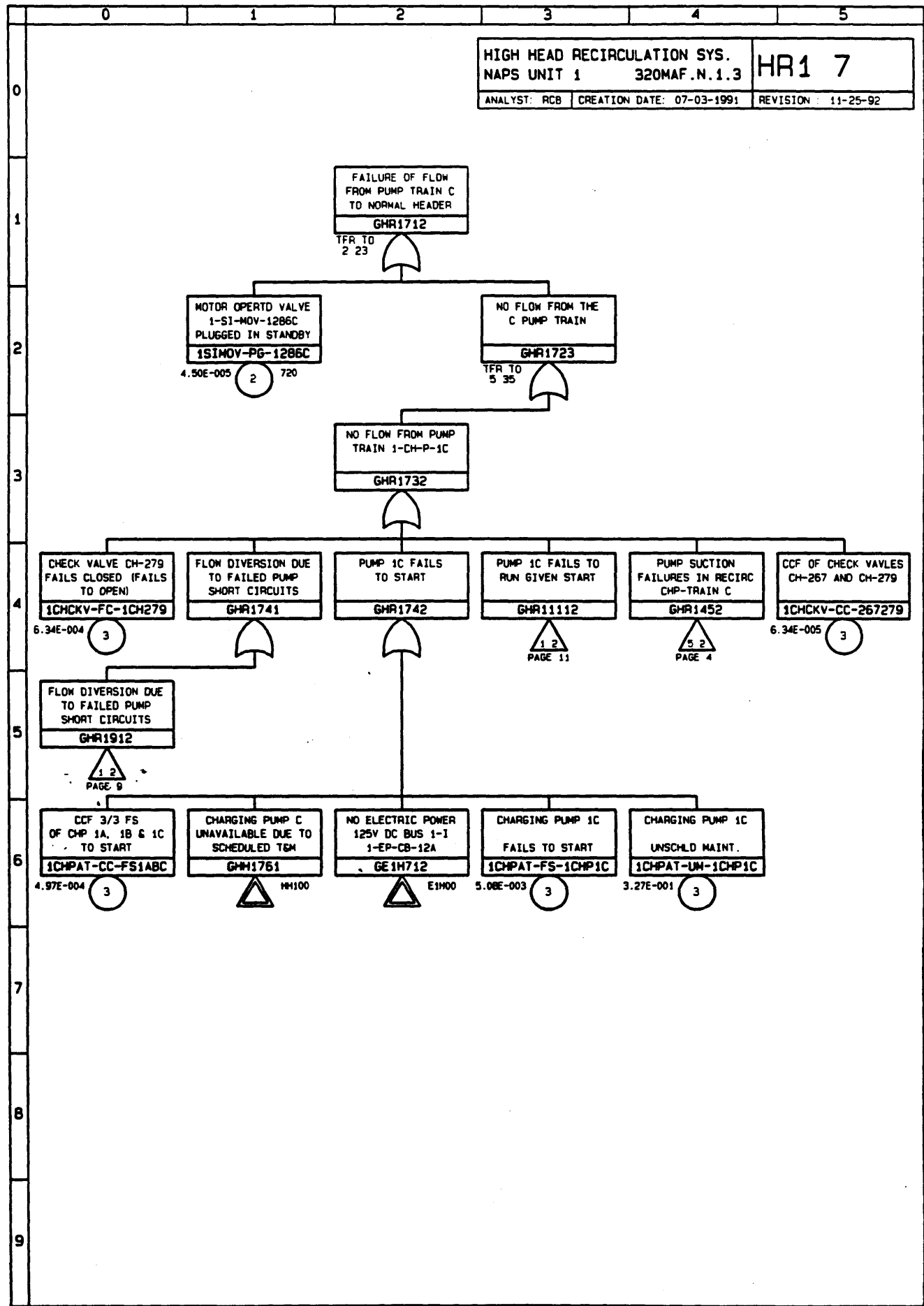




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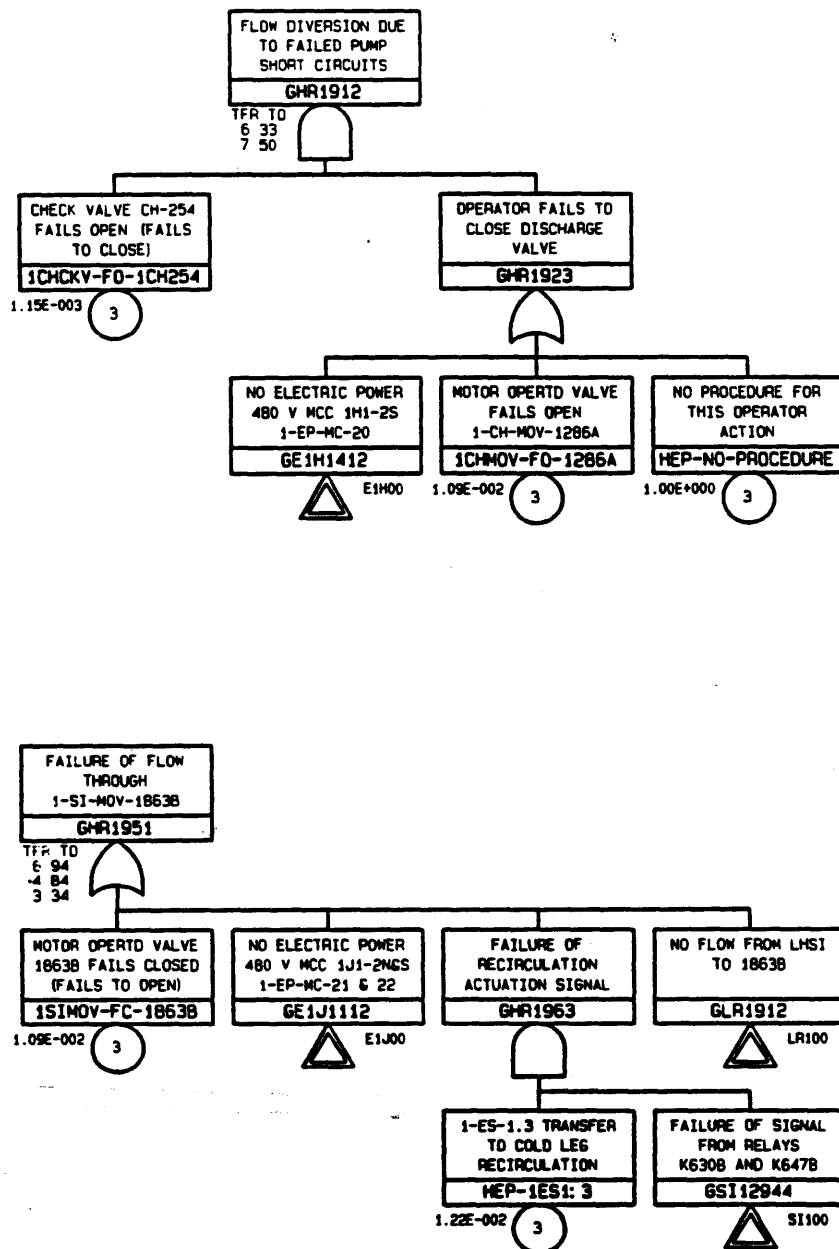
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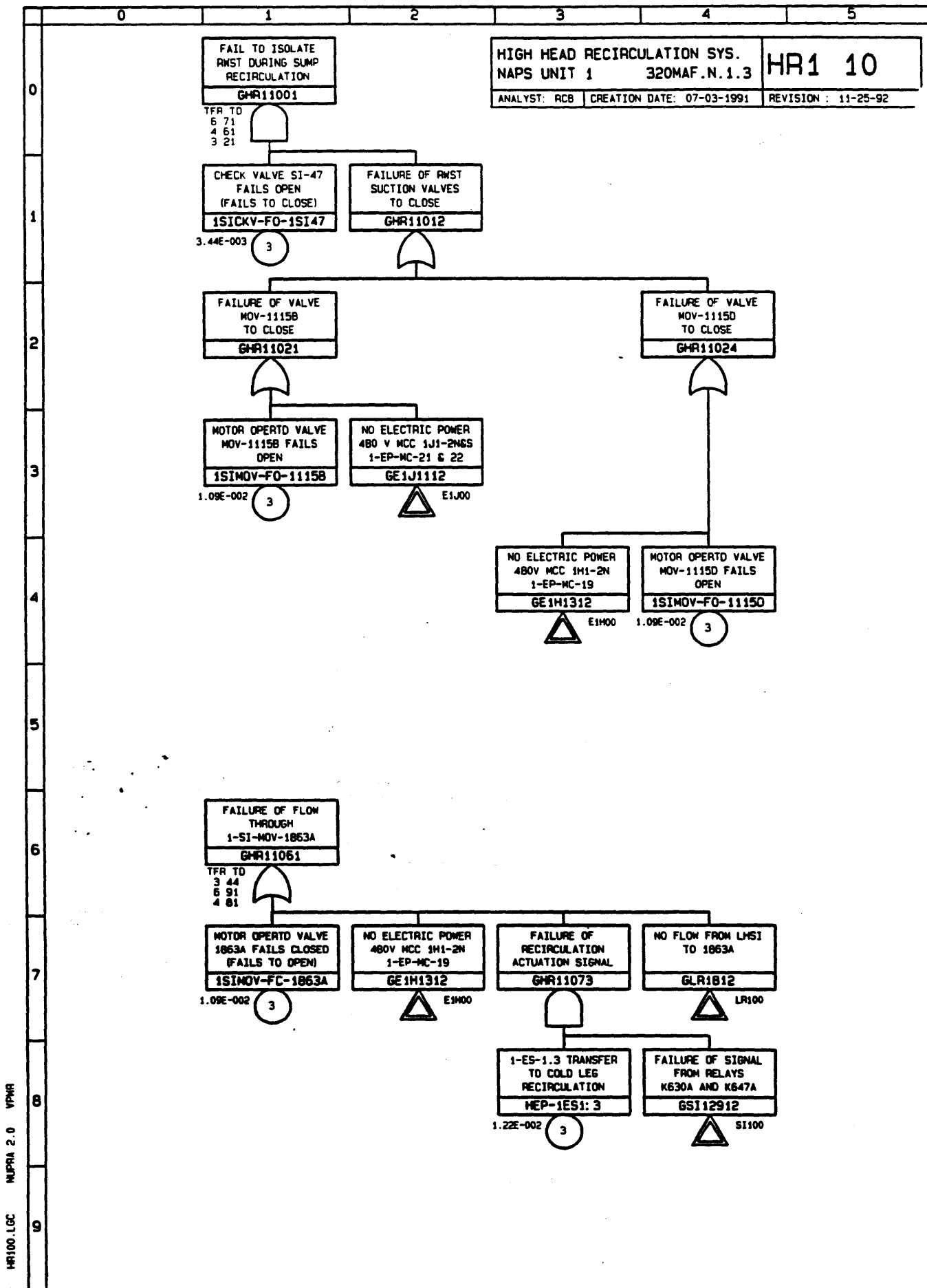
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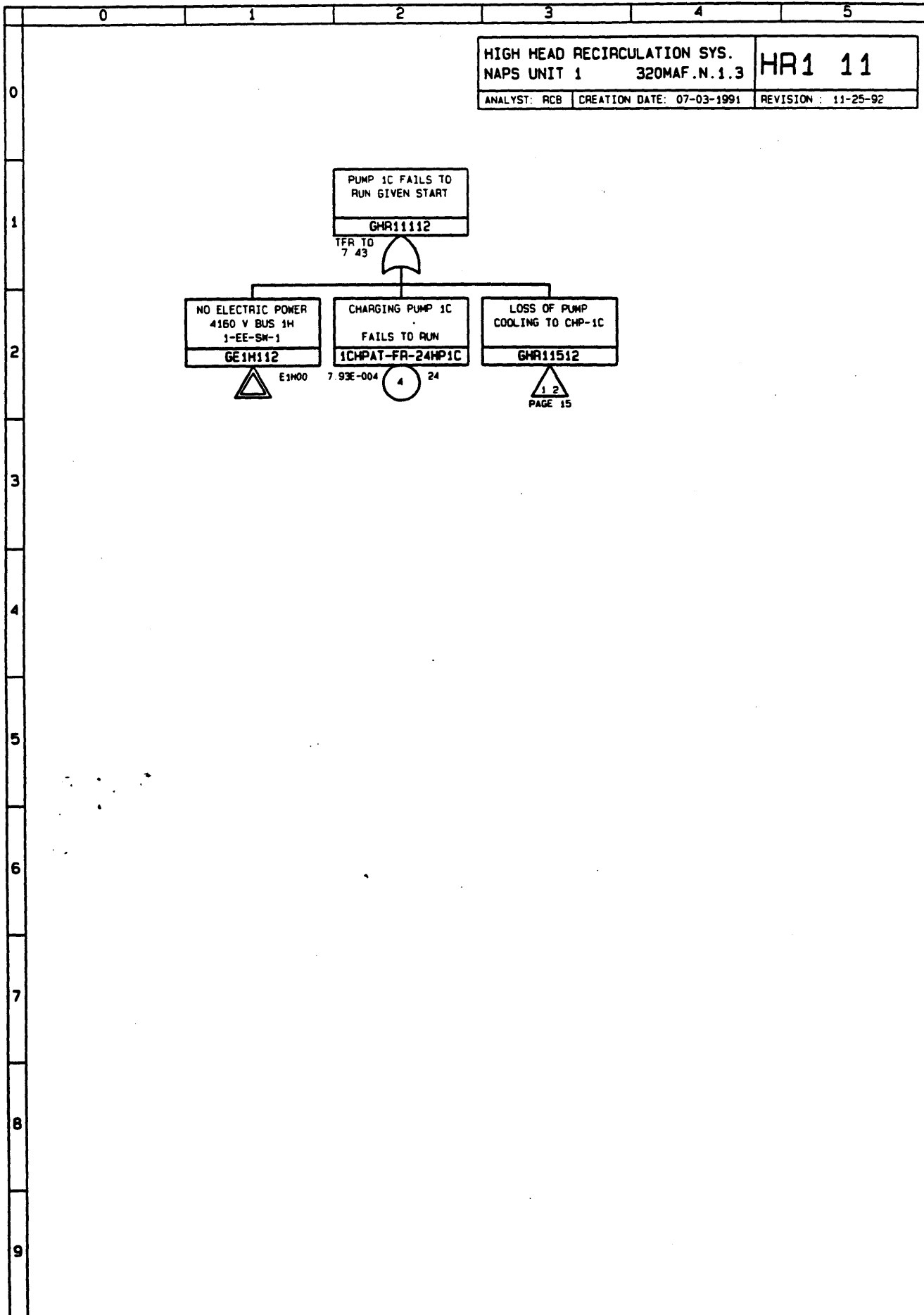
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HIGH HEAD RECIRCULATION SYS.		HR1 9
NAPS UNIT 1	320MAF.N.1.3	
ANALYST: RCB	CREATION DATE: 07-03-1991	REVISION: 11-25-92





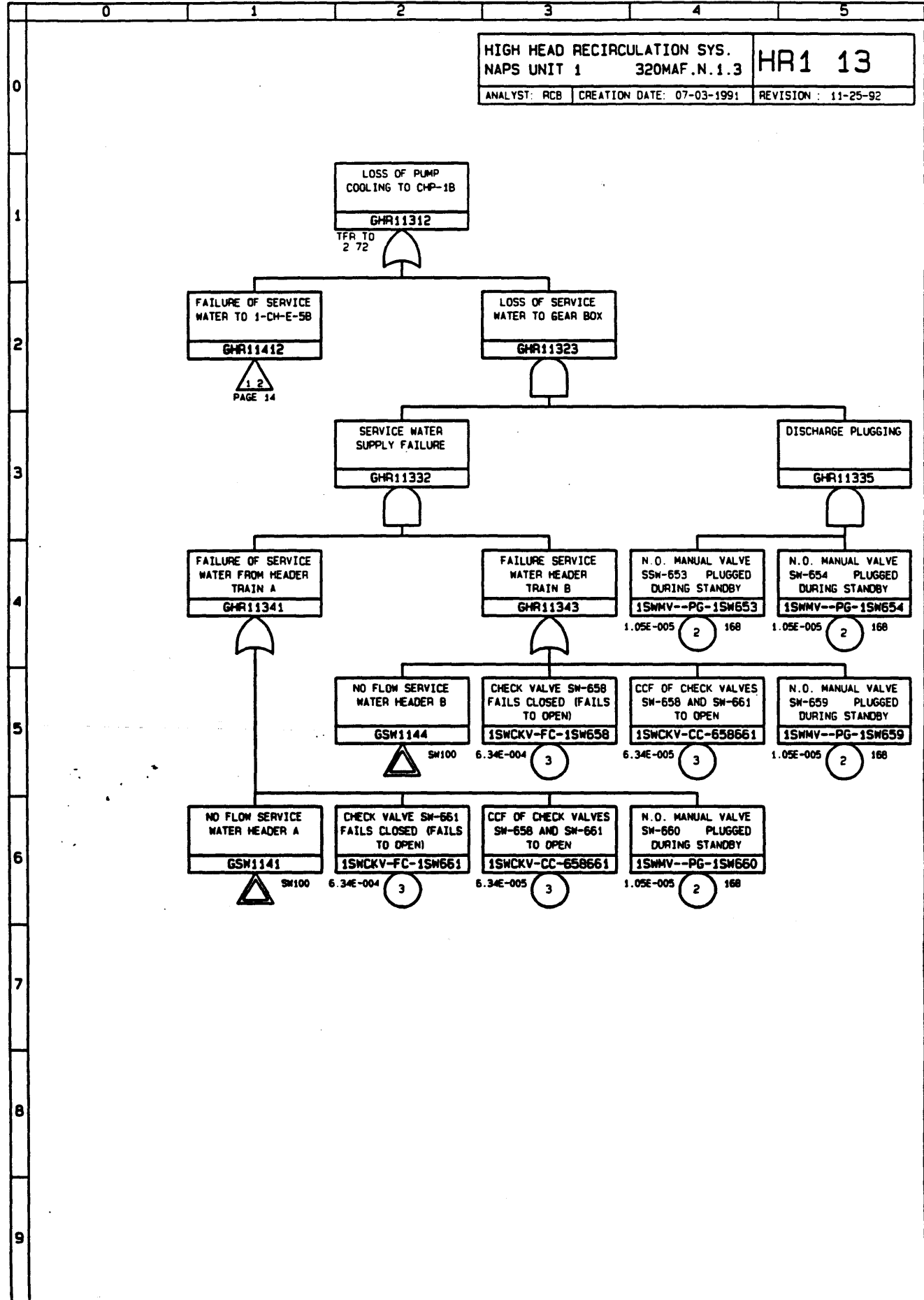
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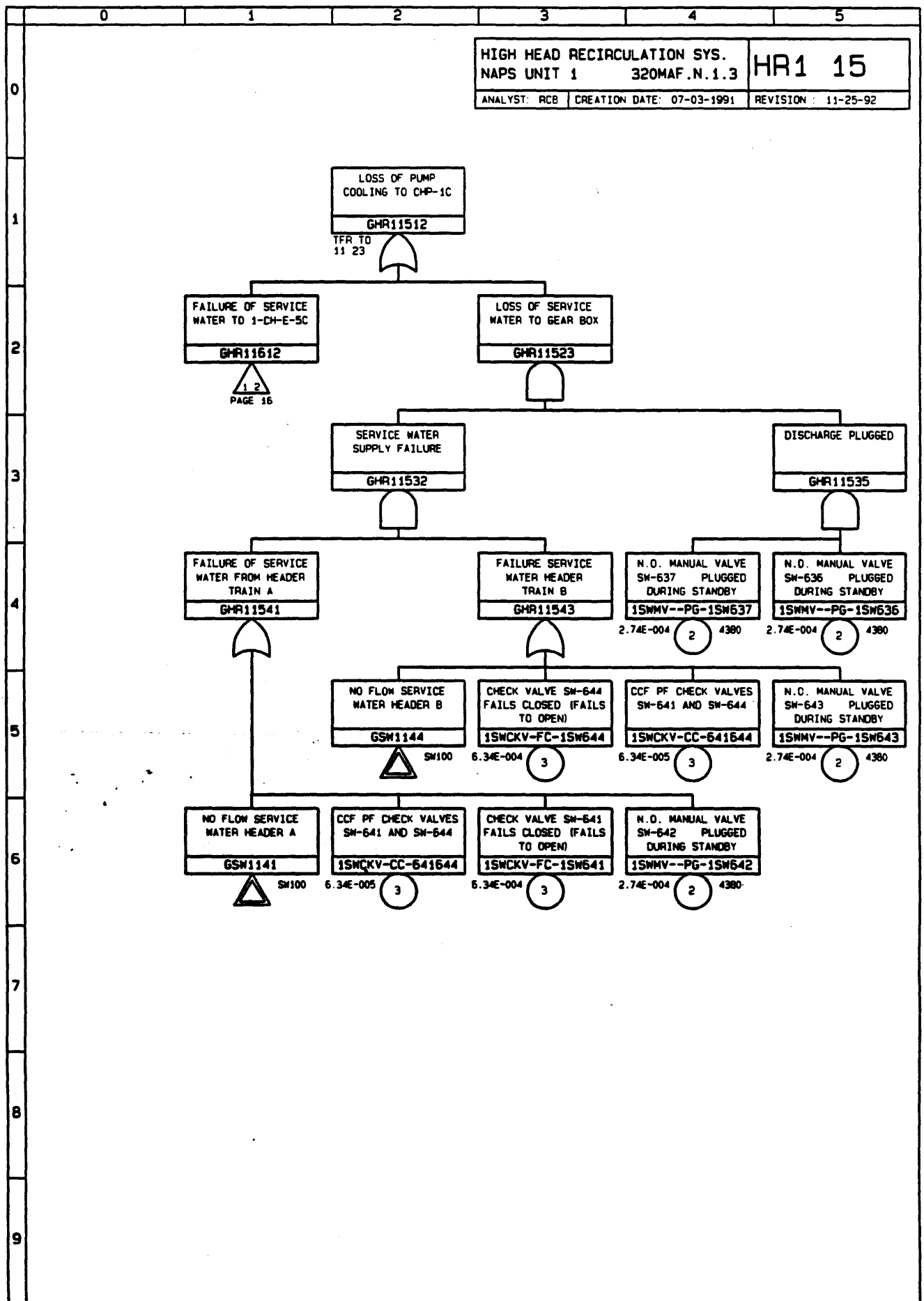
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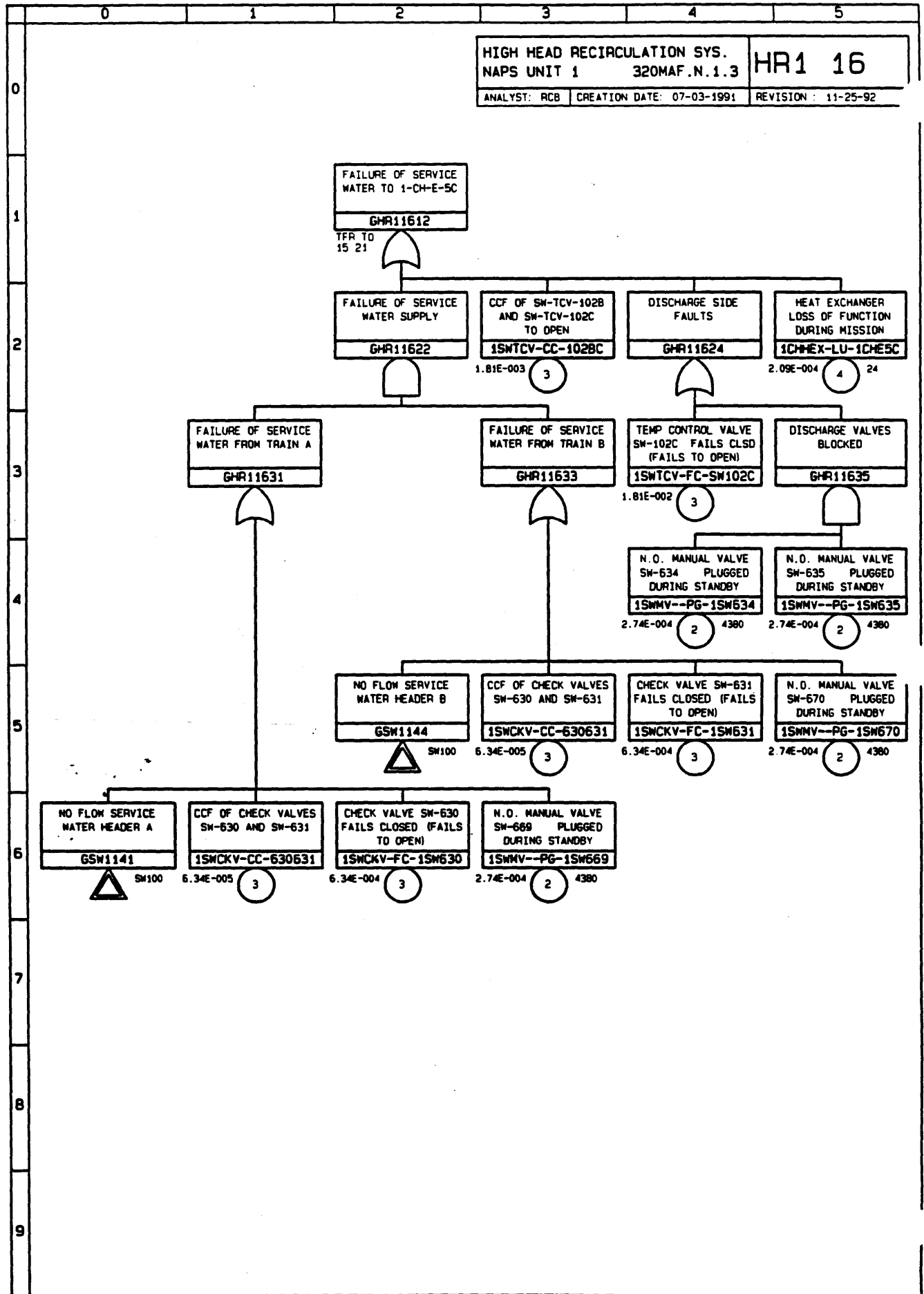




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MUPRA 2.0  
VPMR

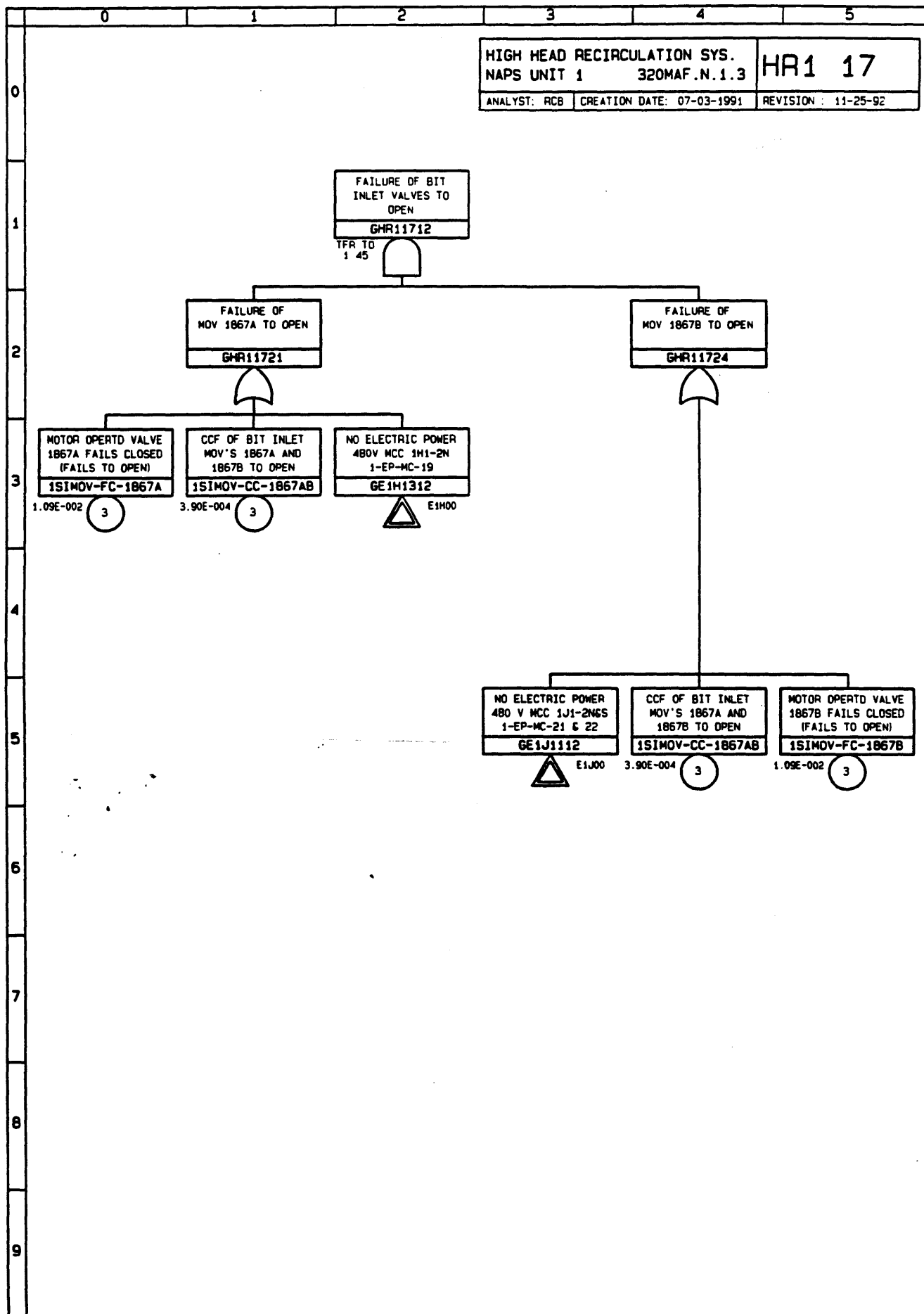


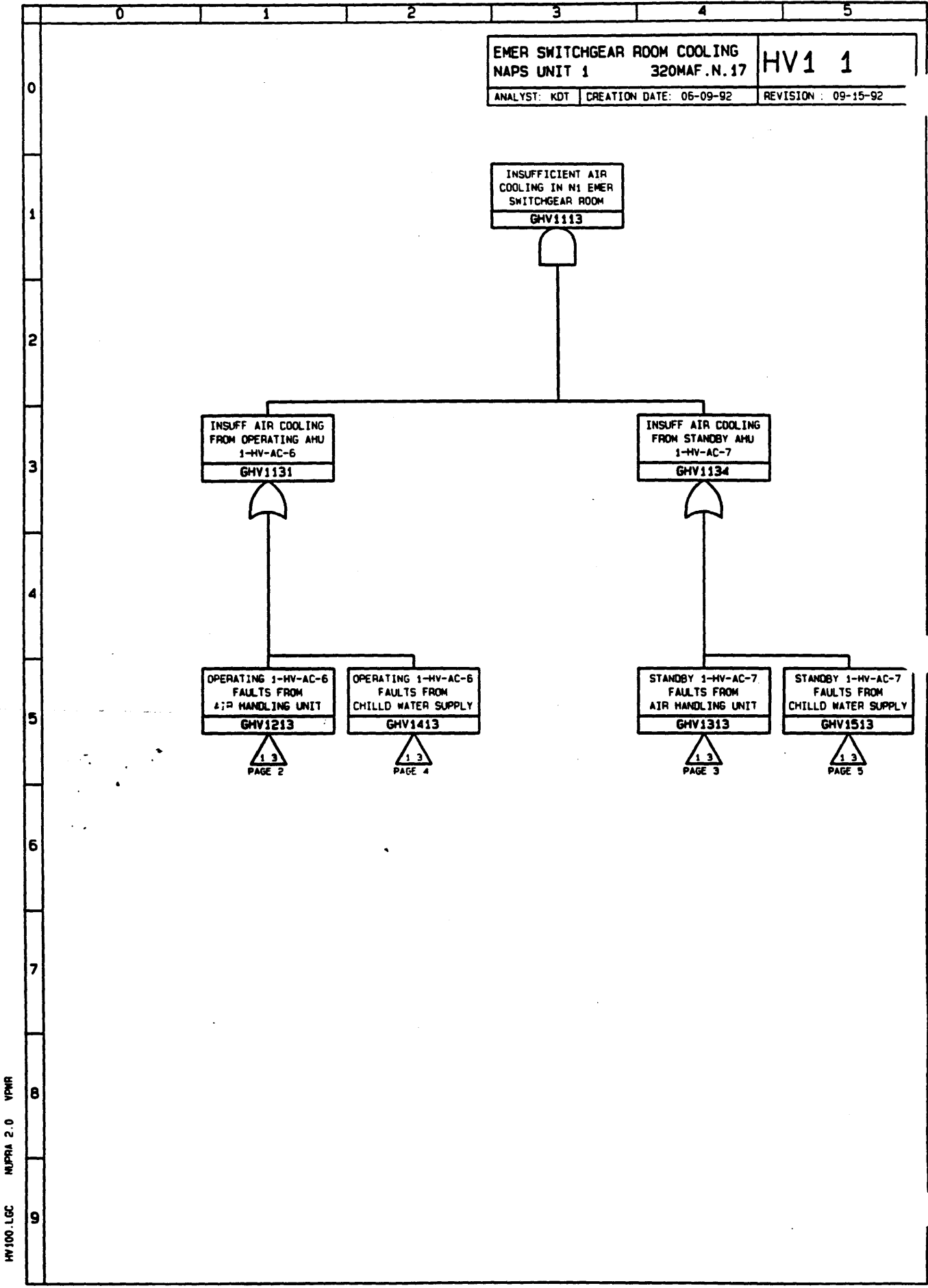
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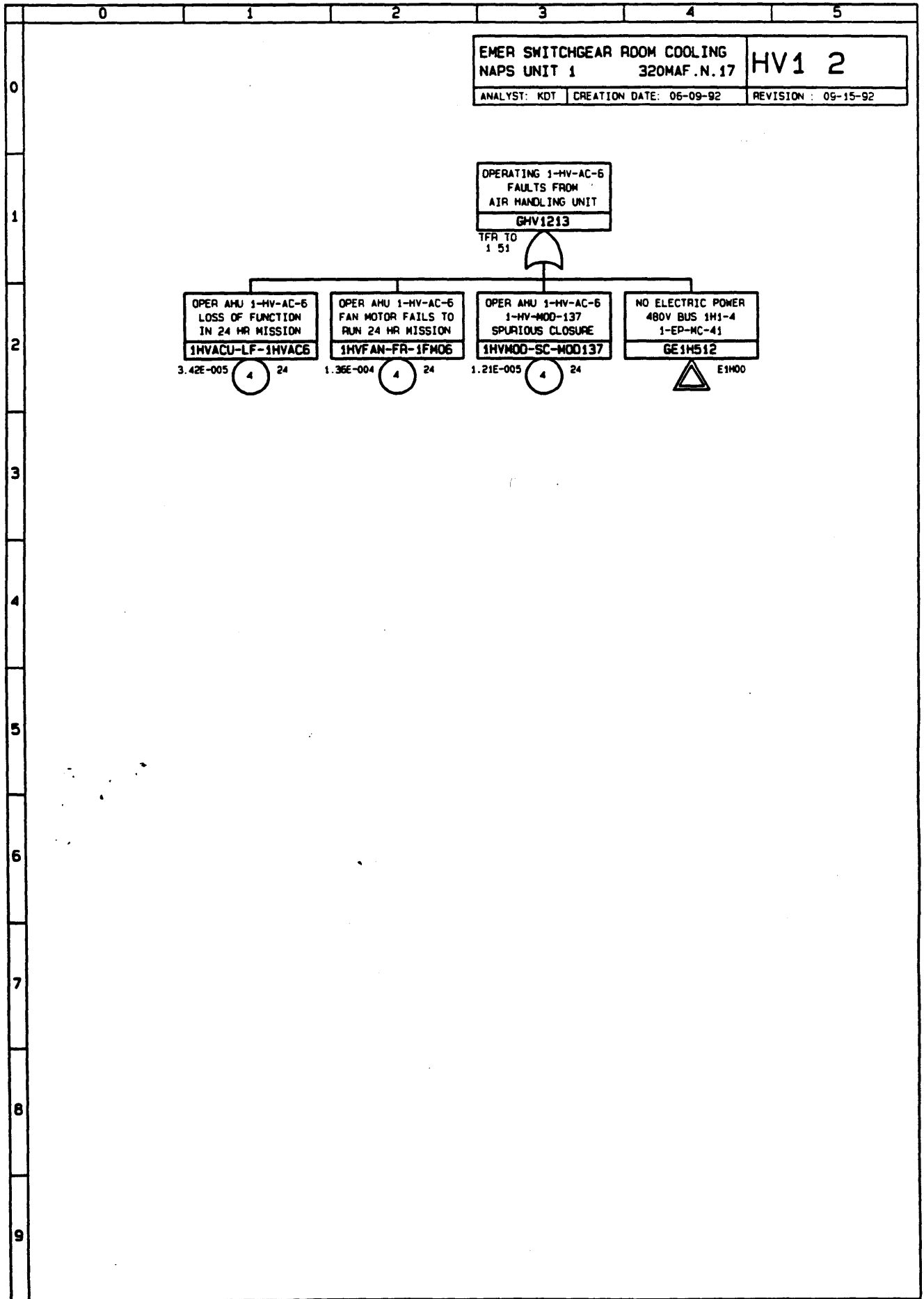


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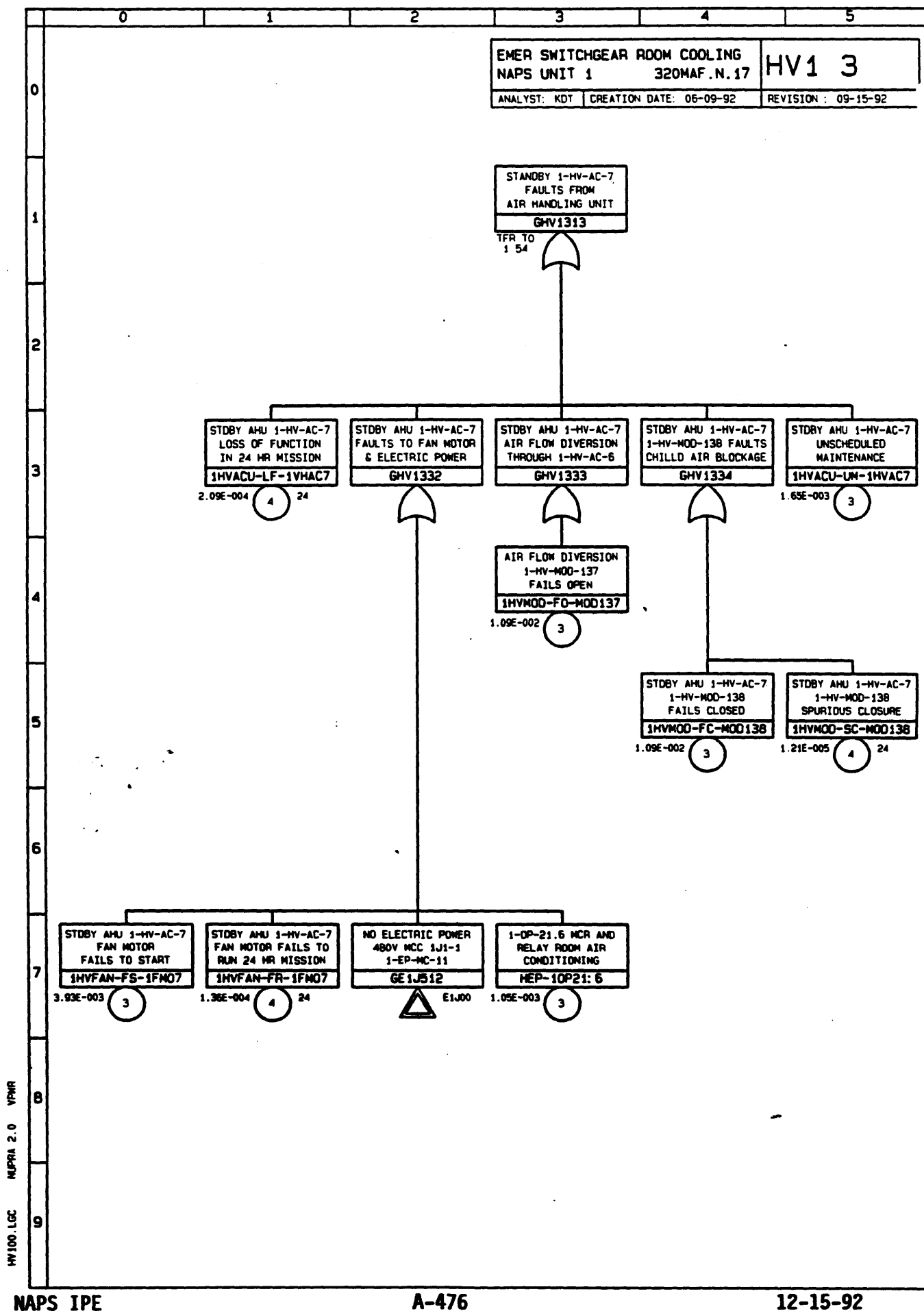


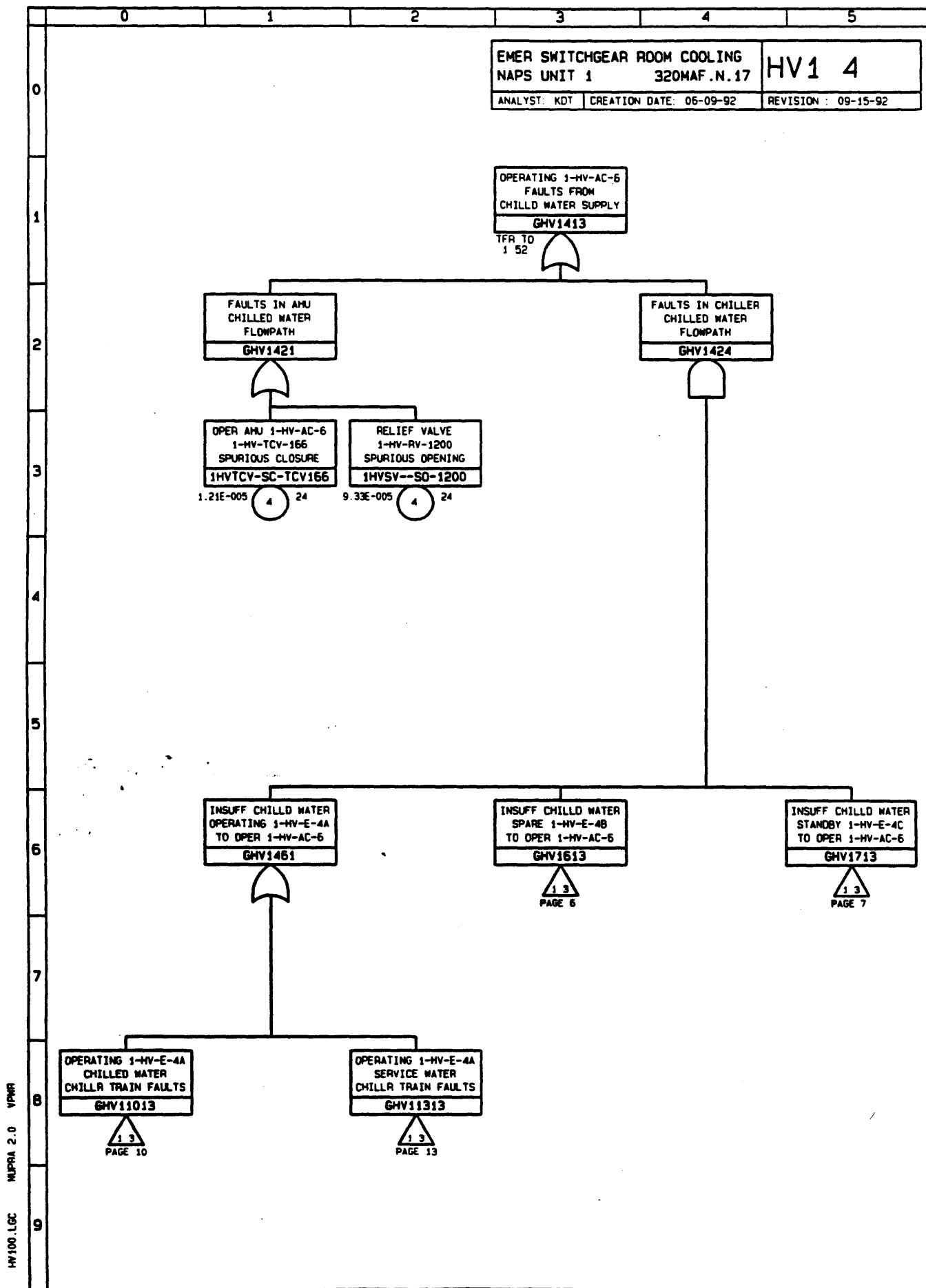


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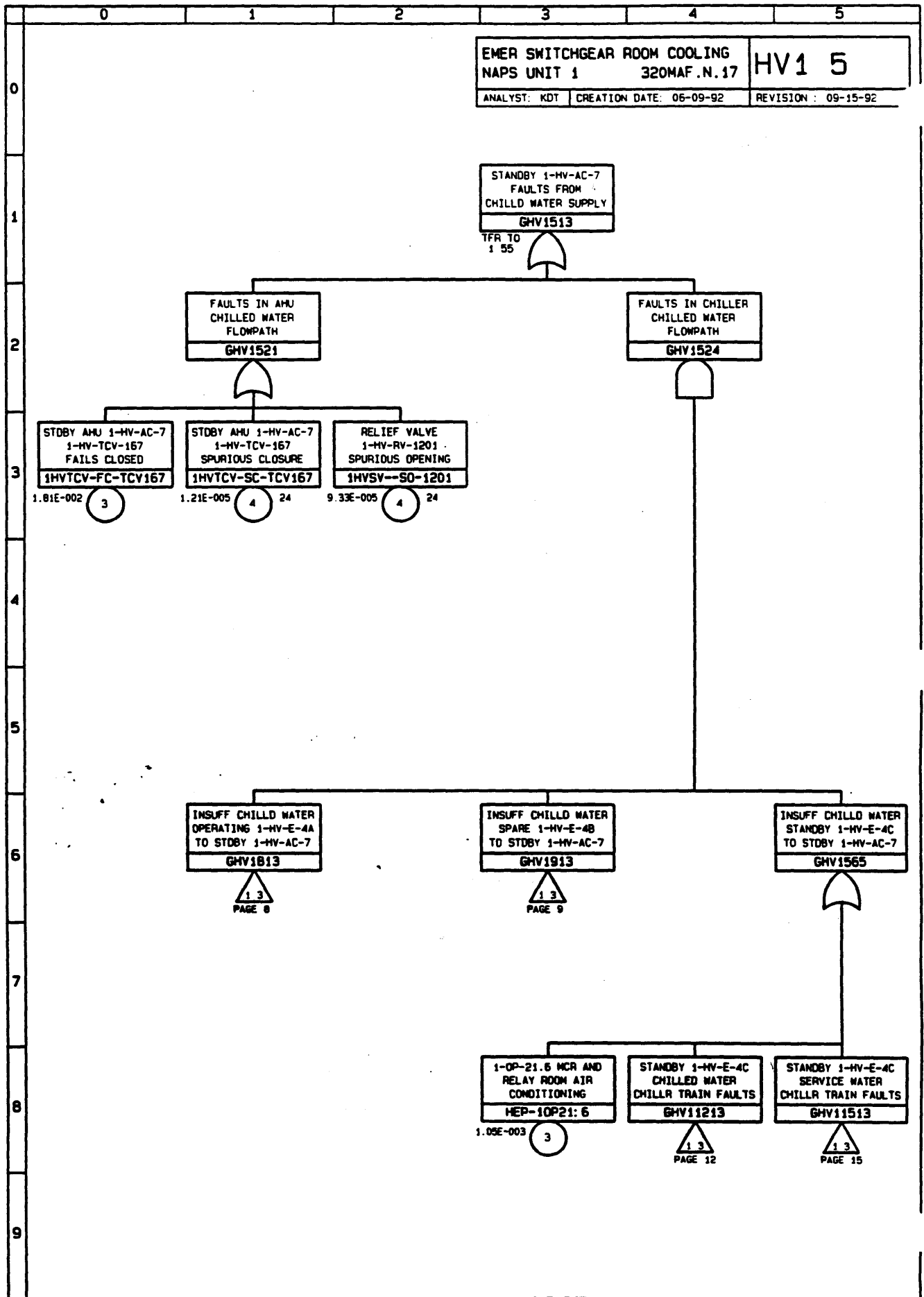


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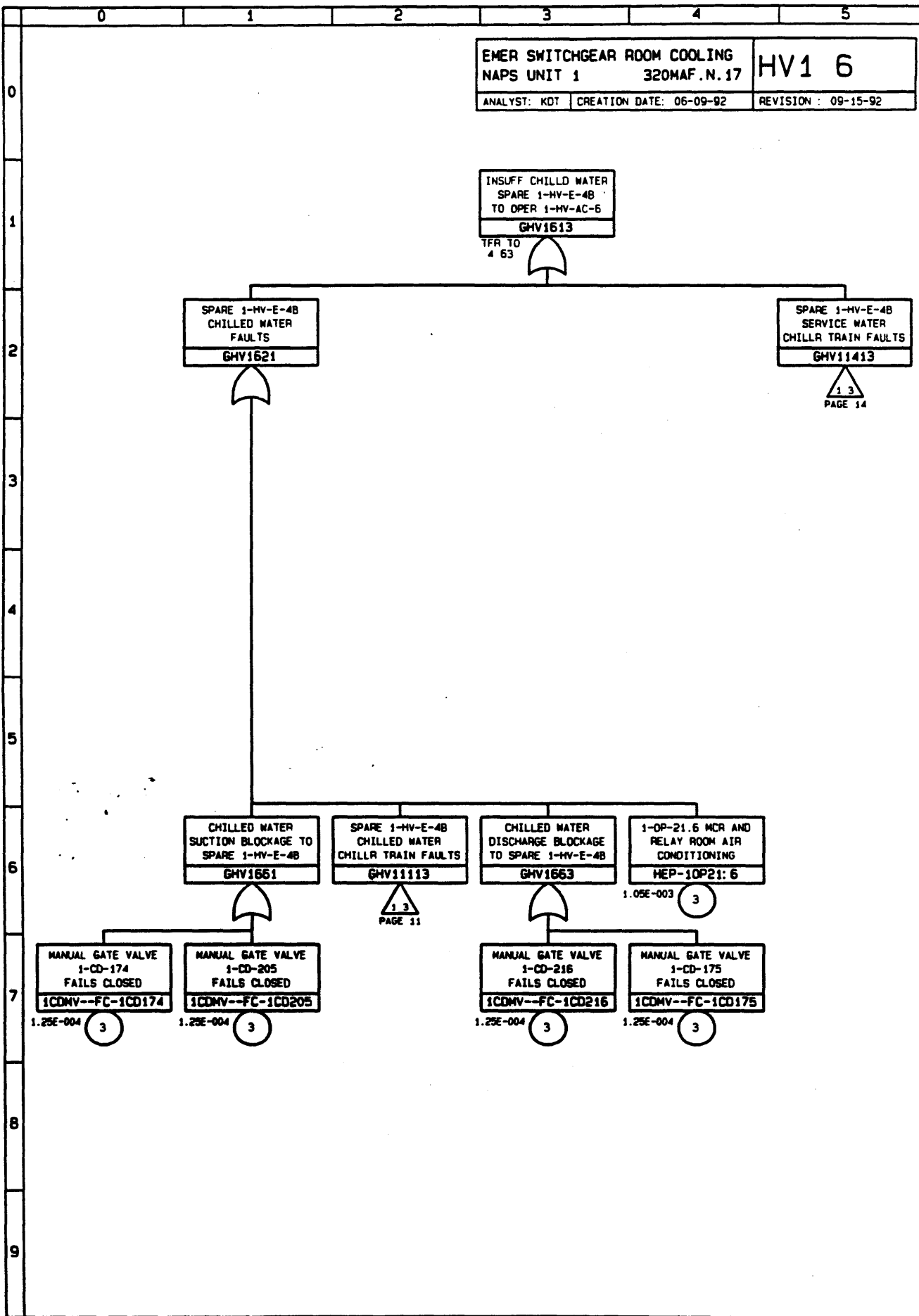




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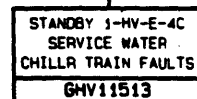


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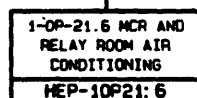


**GHV 1713**

TFR TO  
4 65

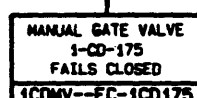


13  
PAGE 15



1.05E-003

3



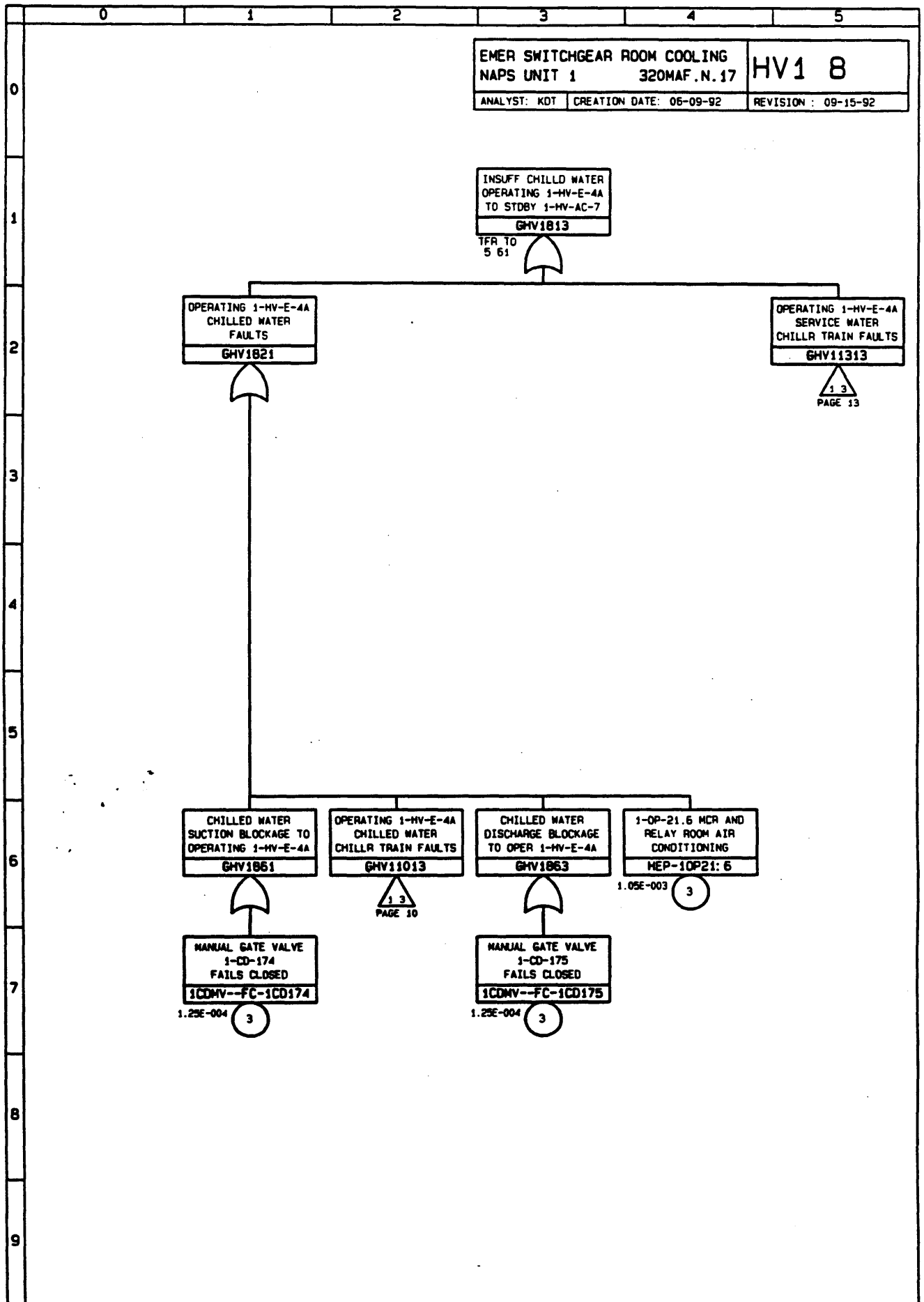
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1.25E-004

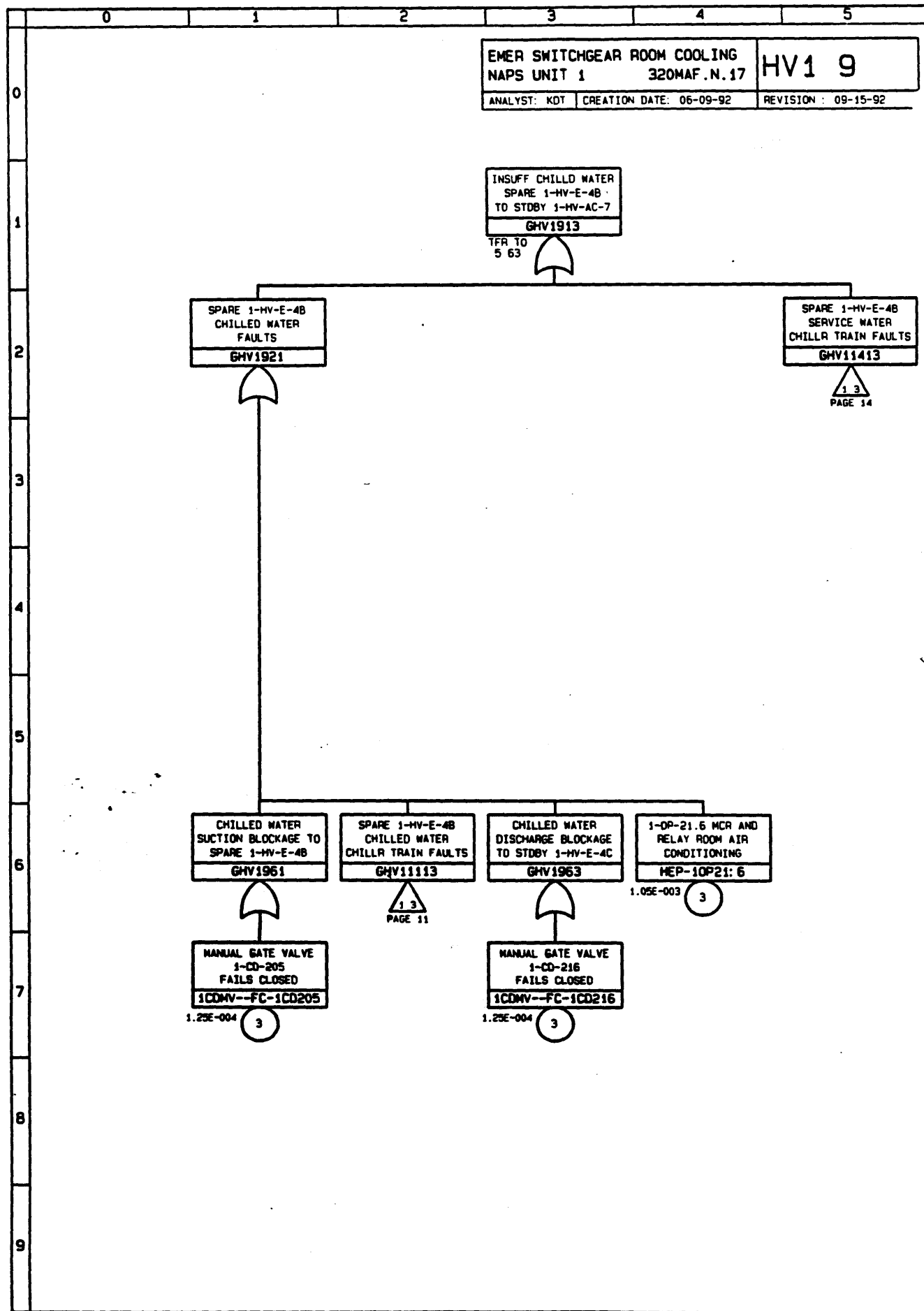
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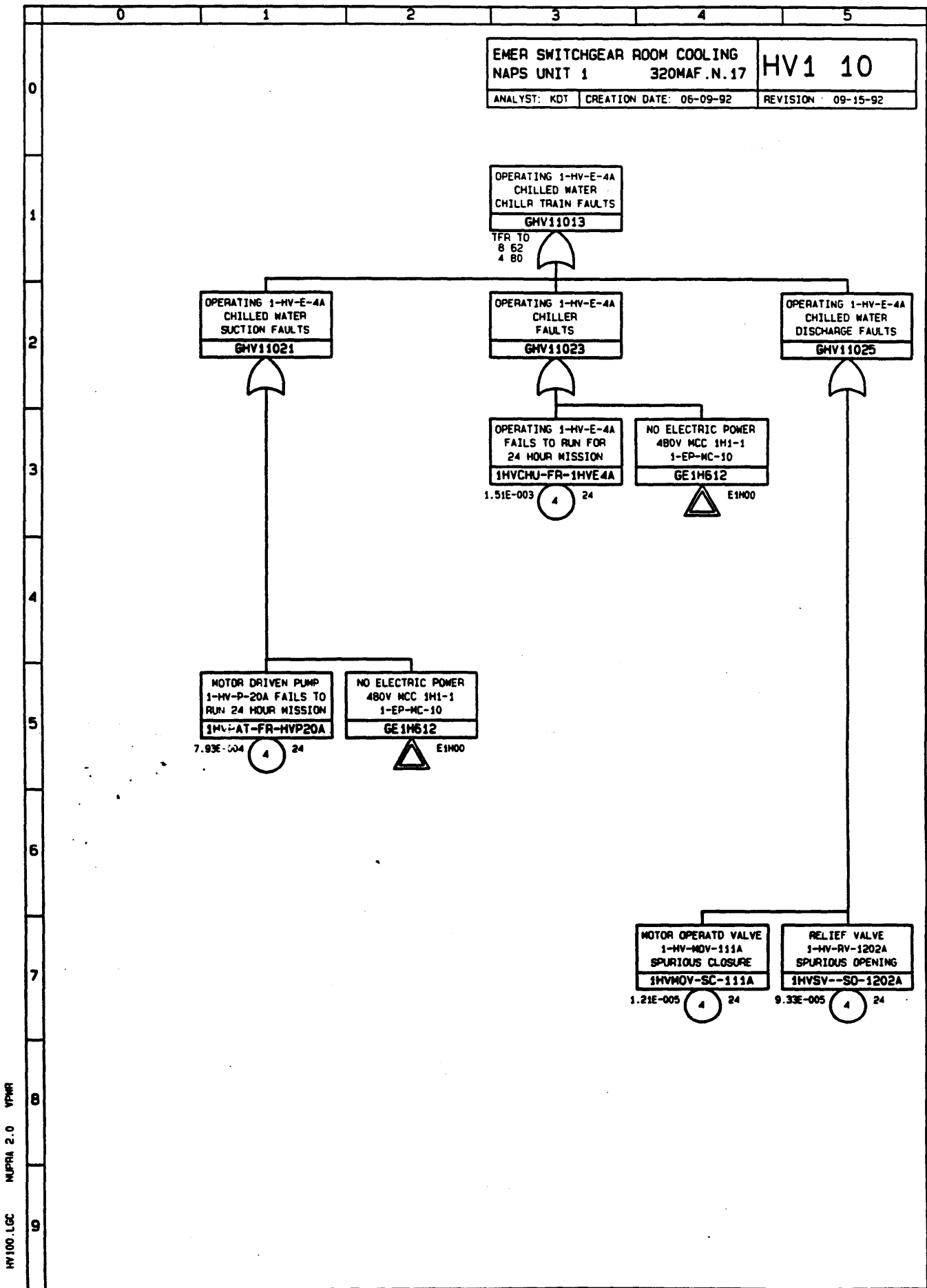


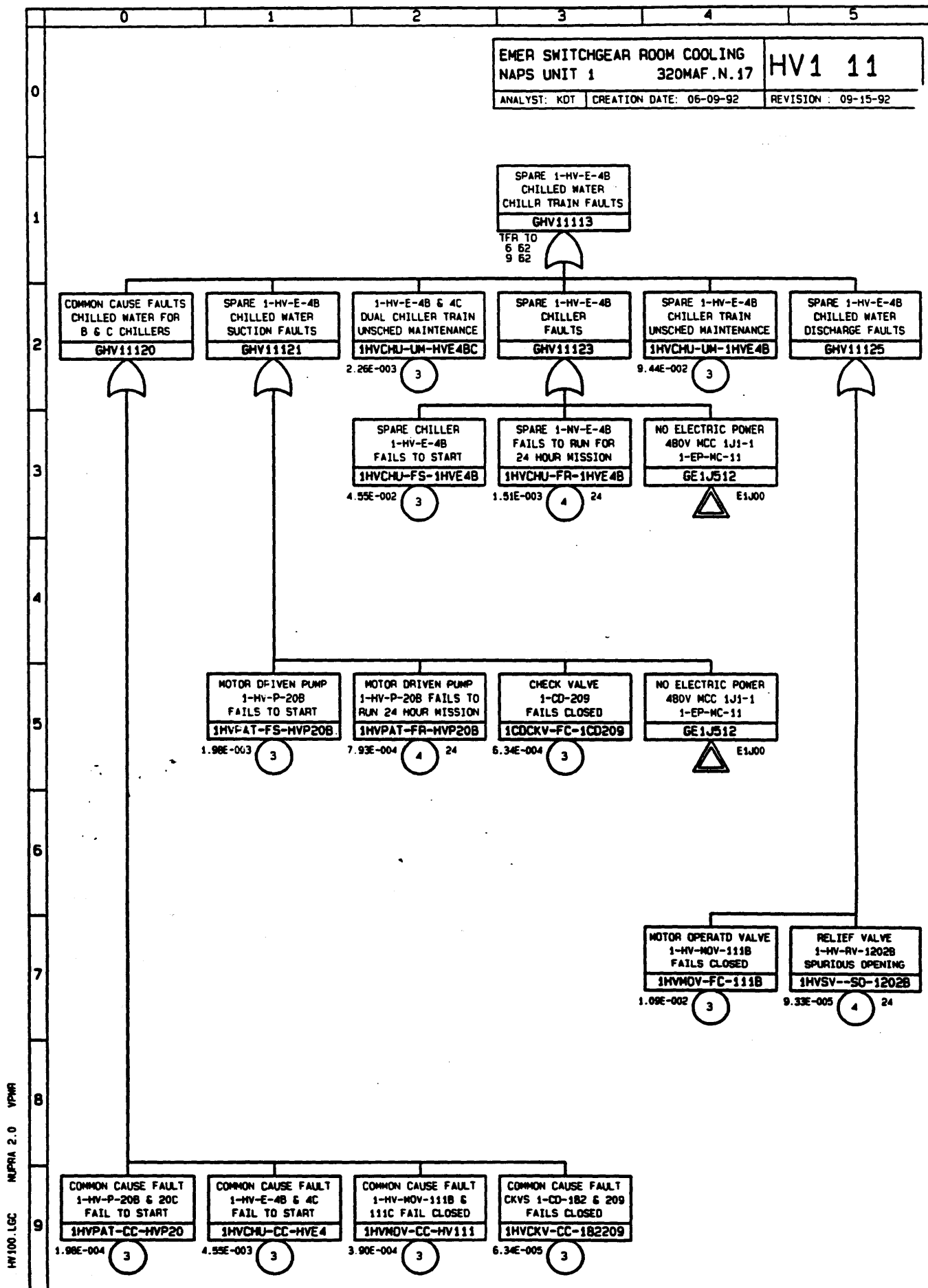
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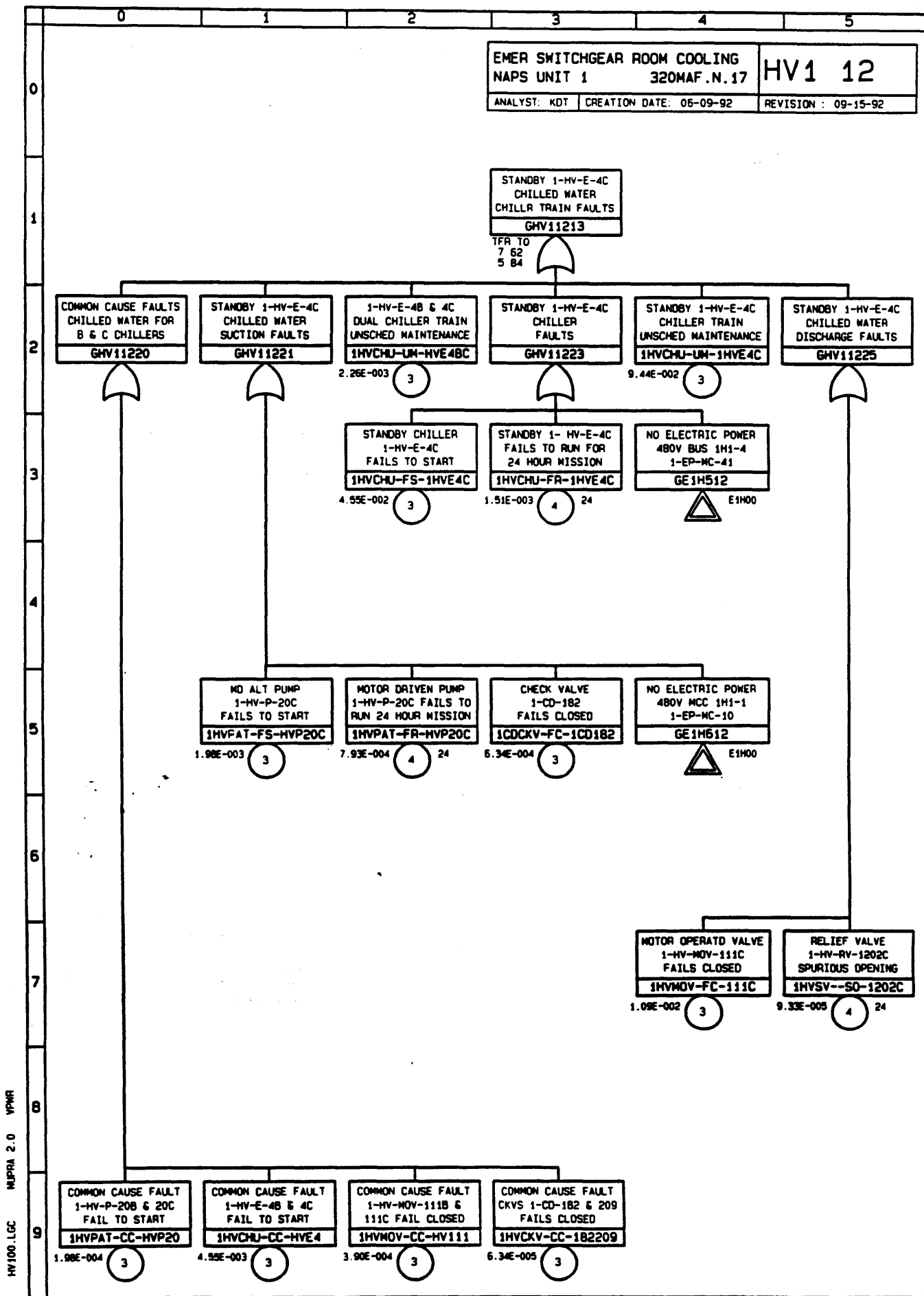


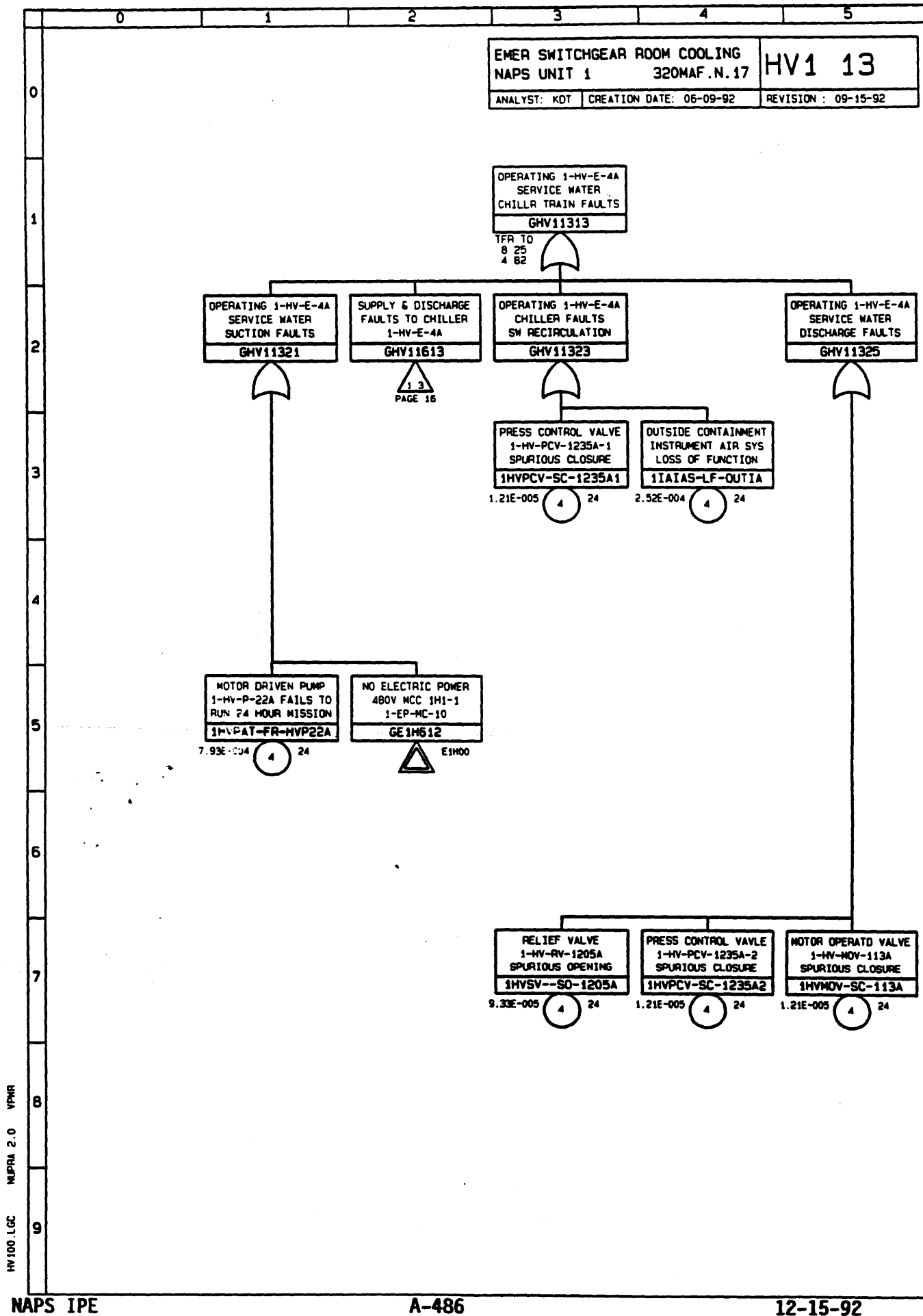
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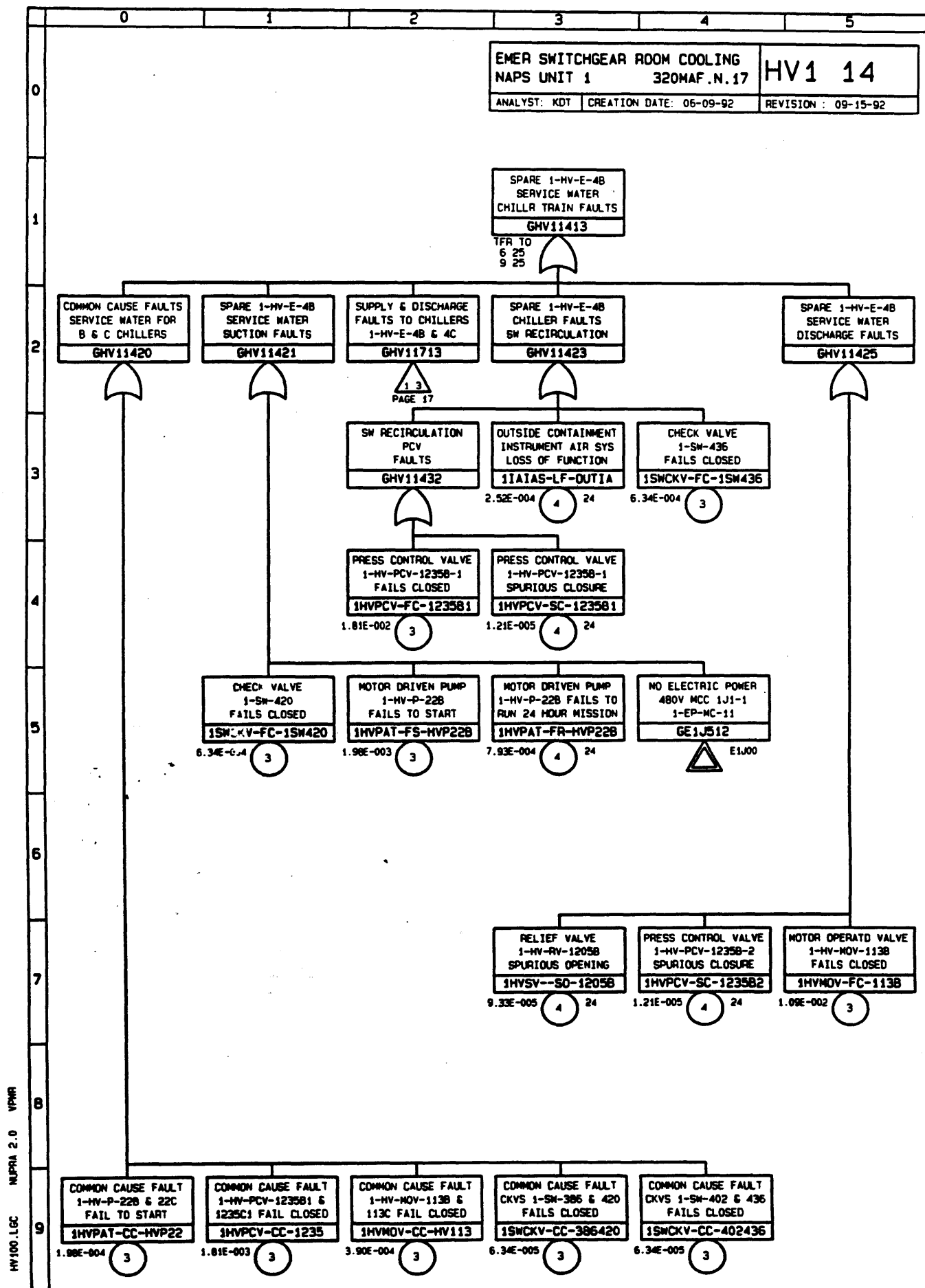


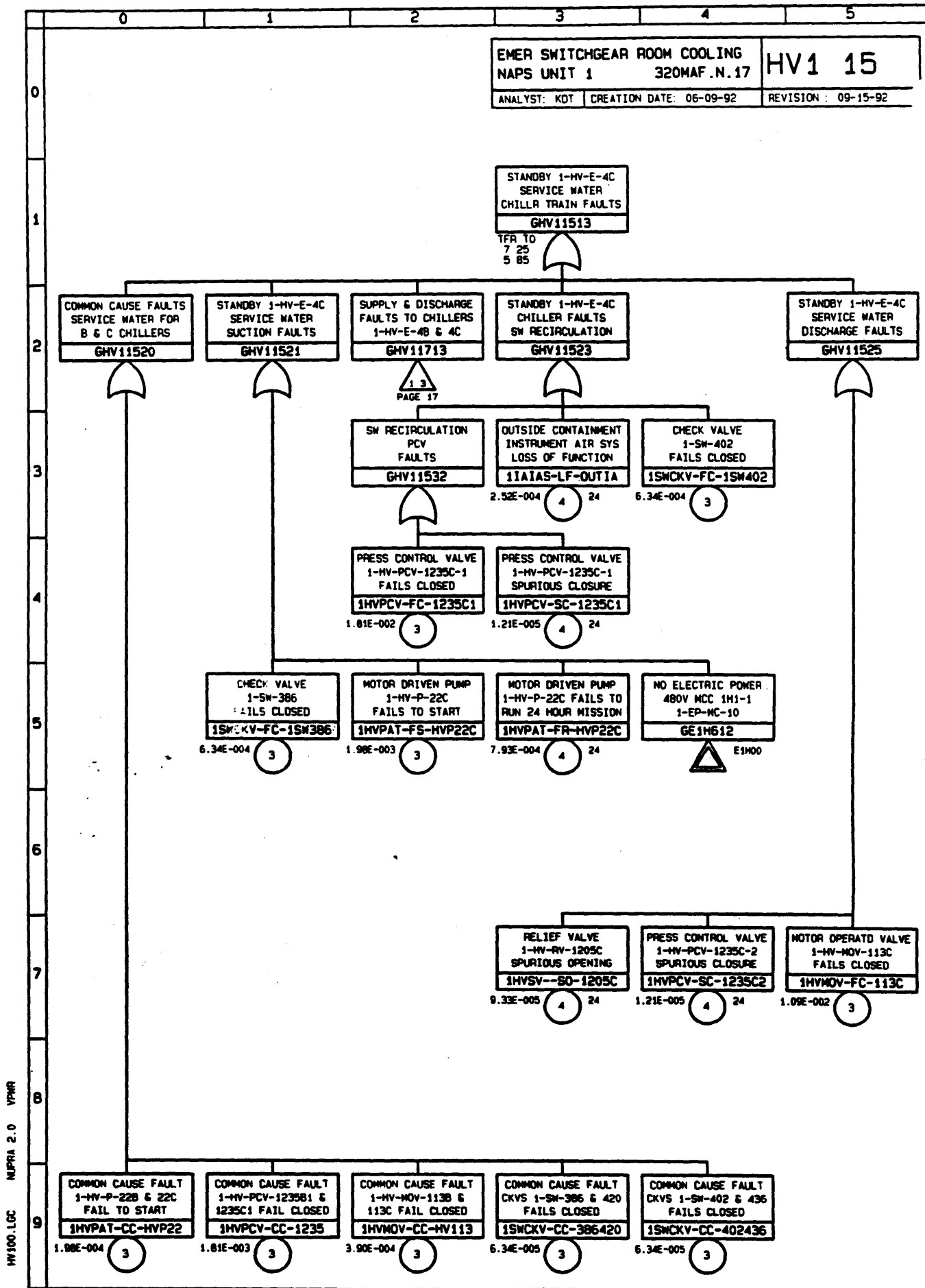




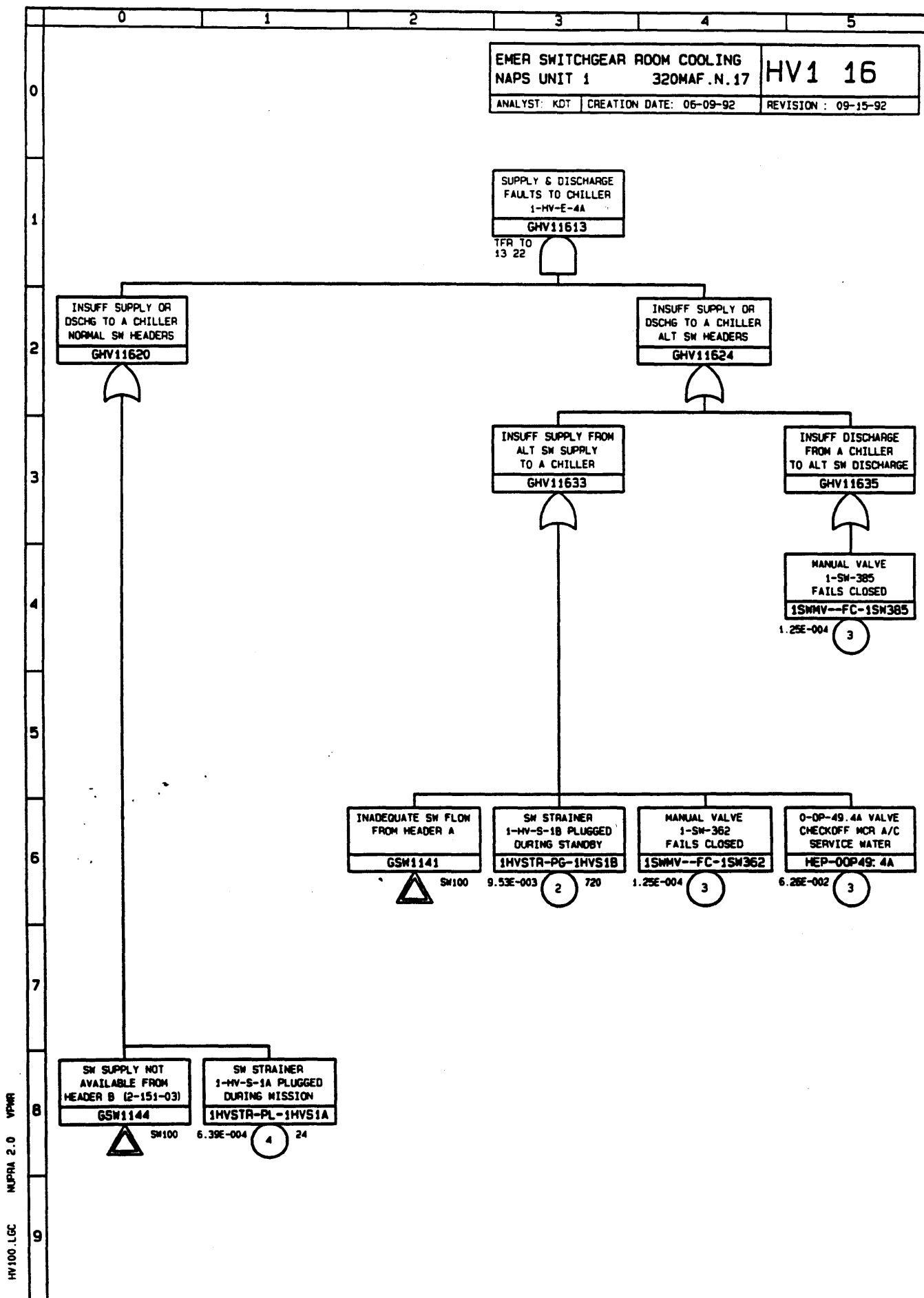


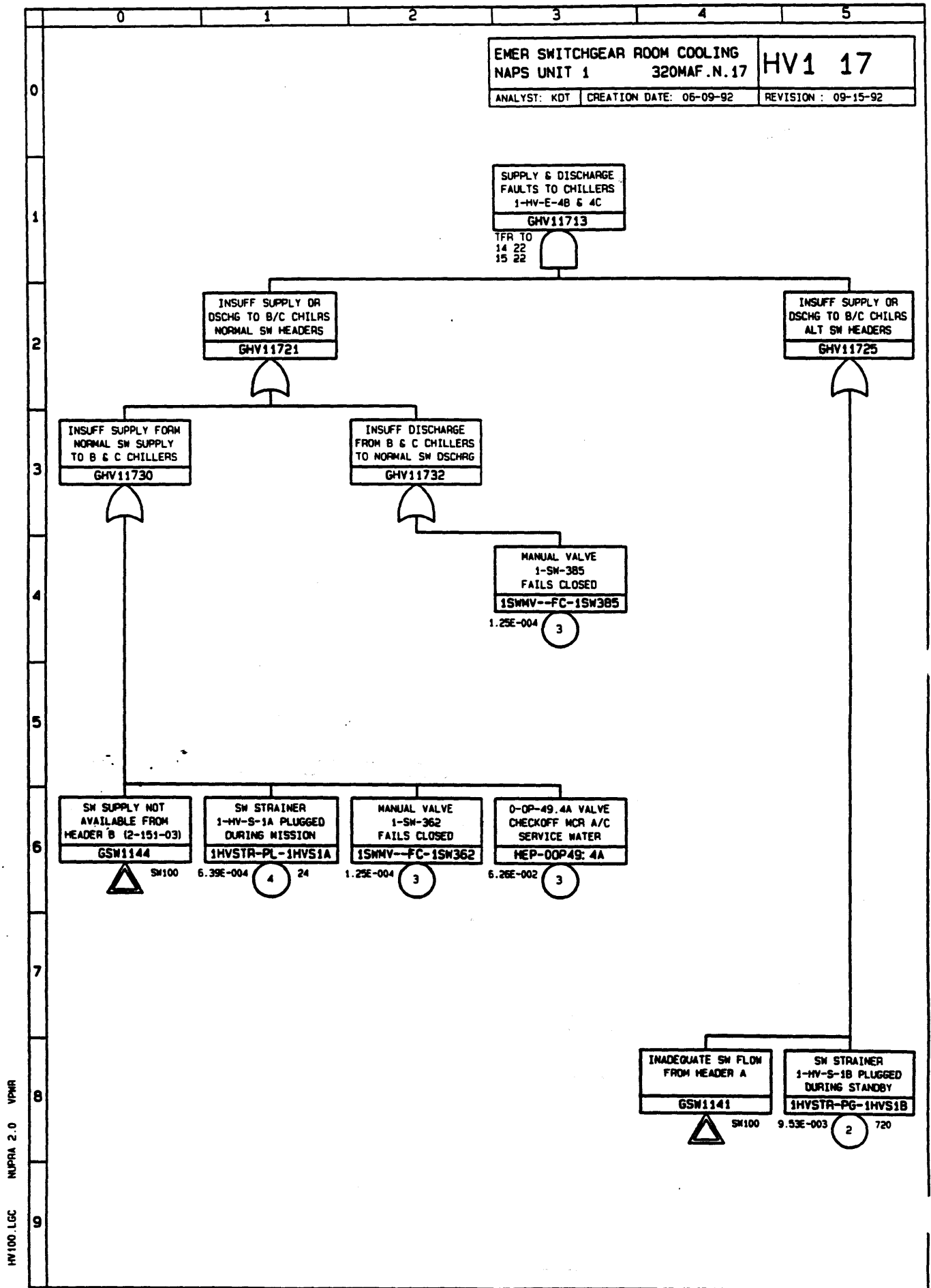


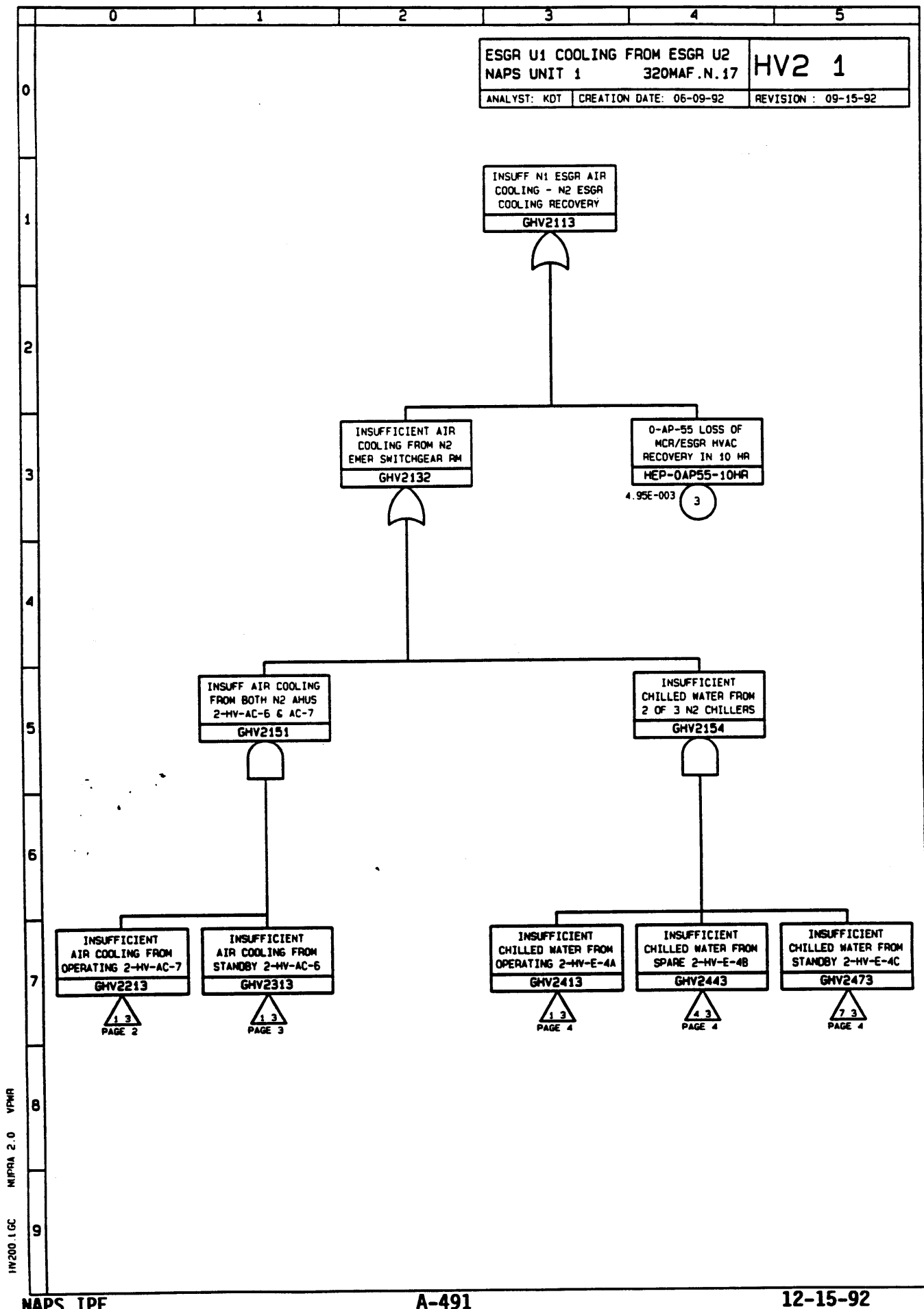




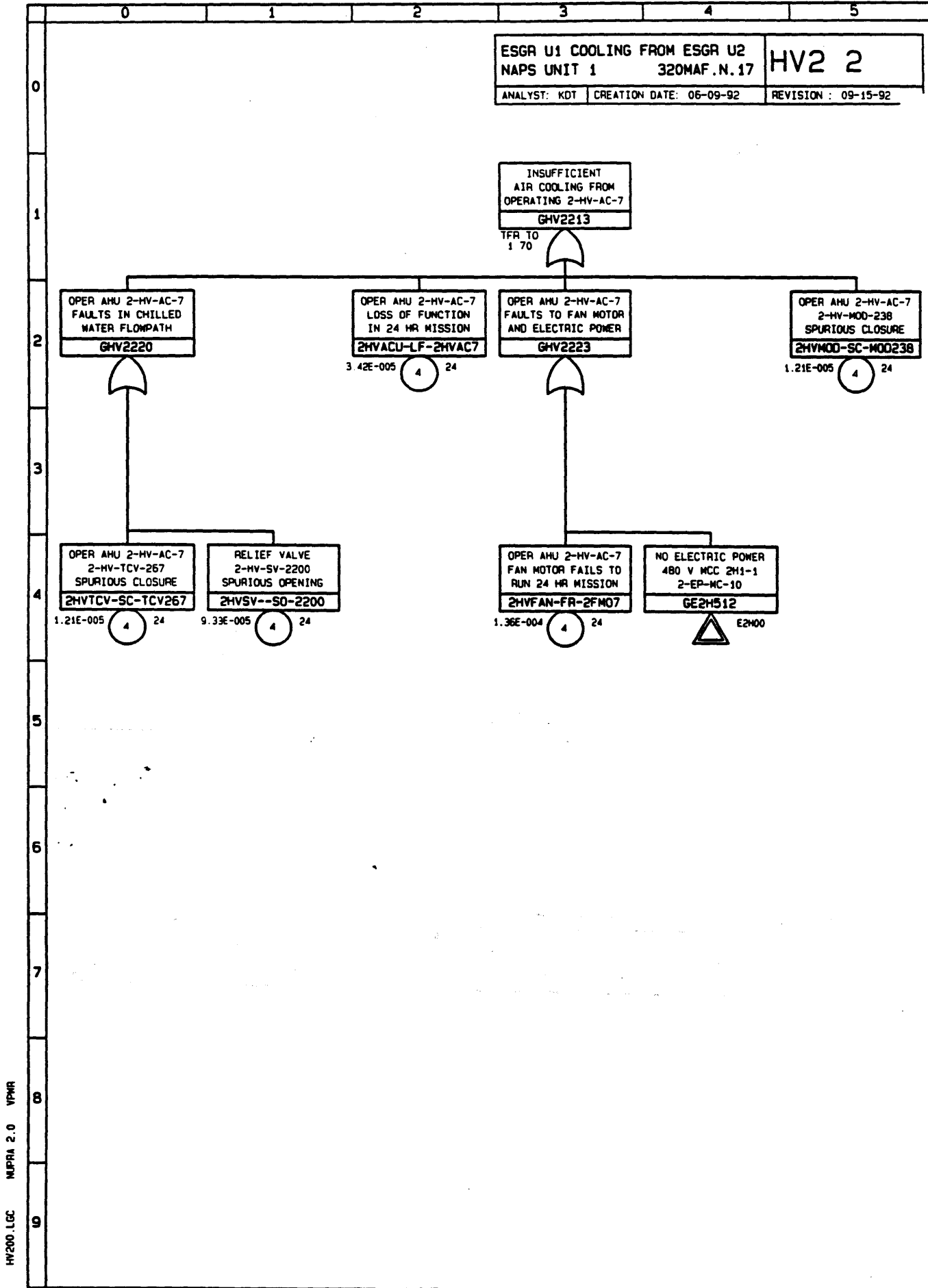




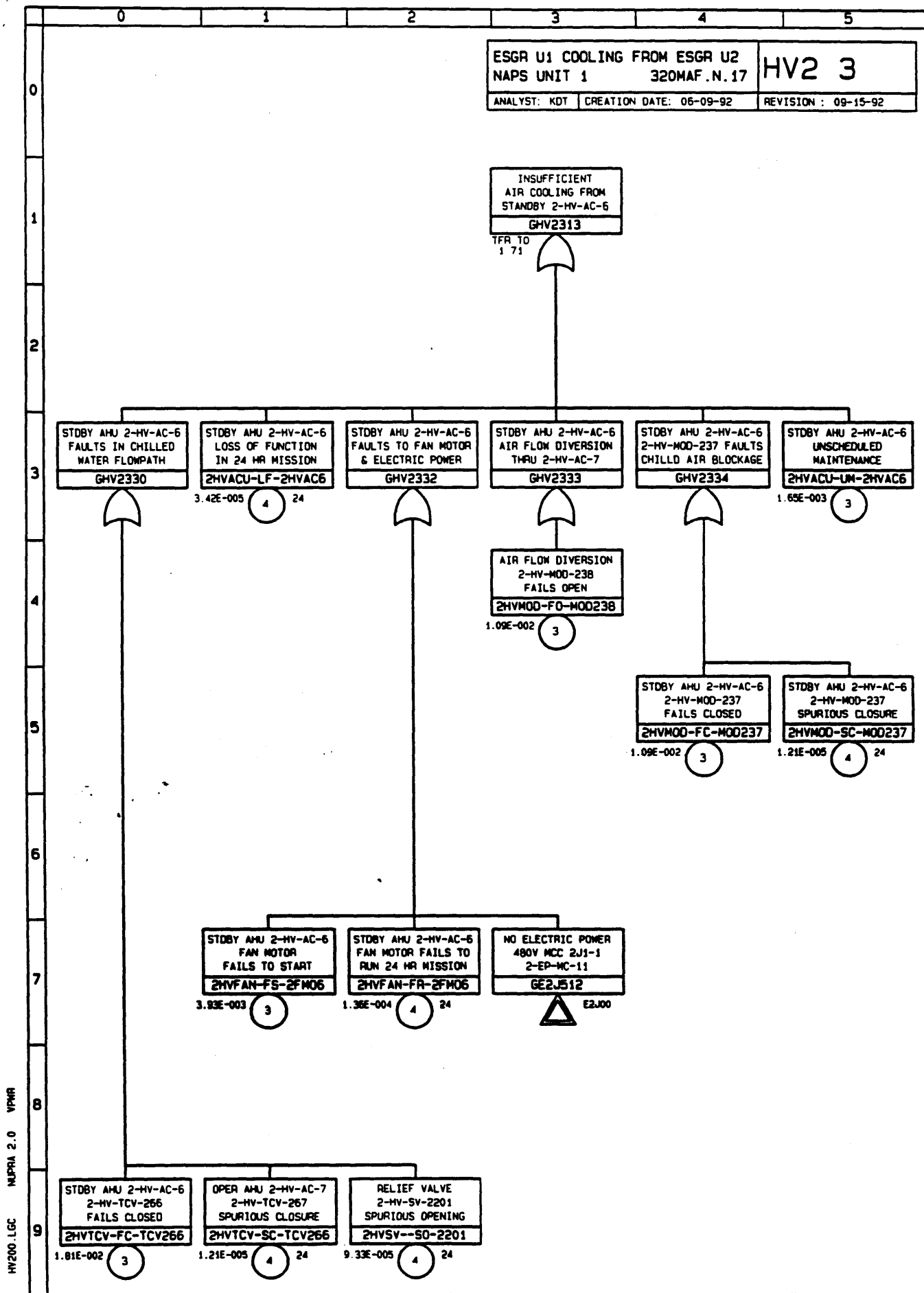


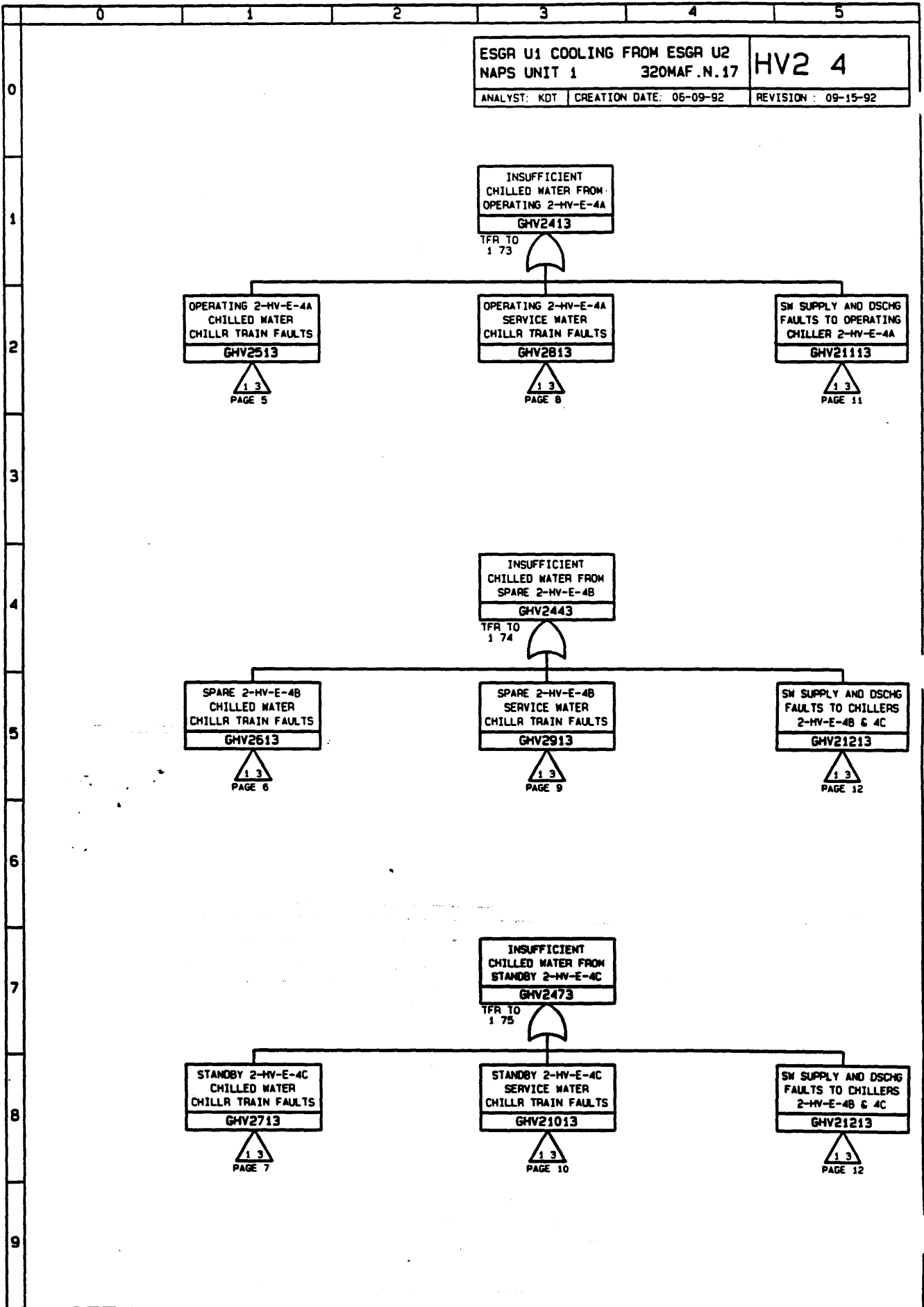


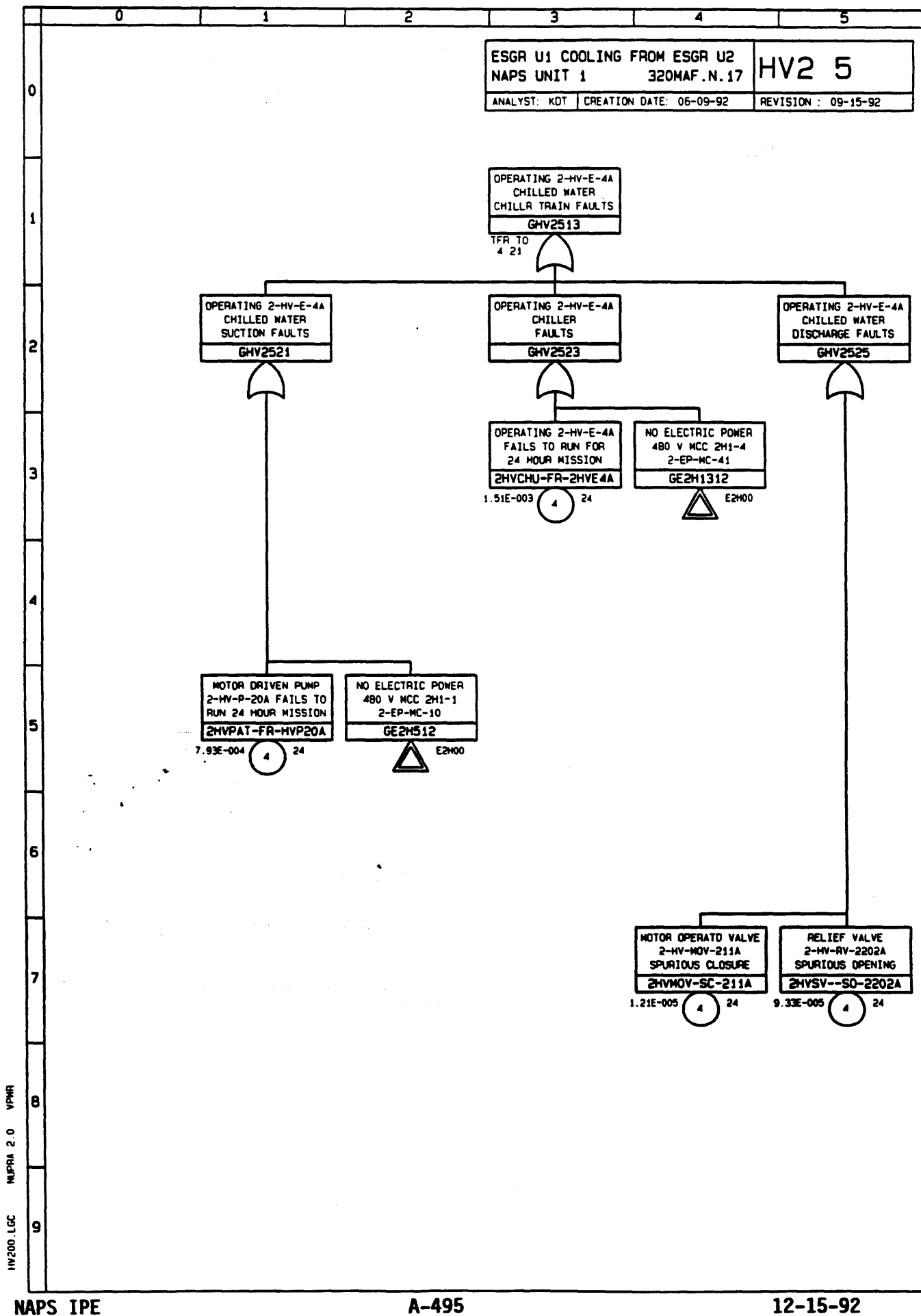
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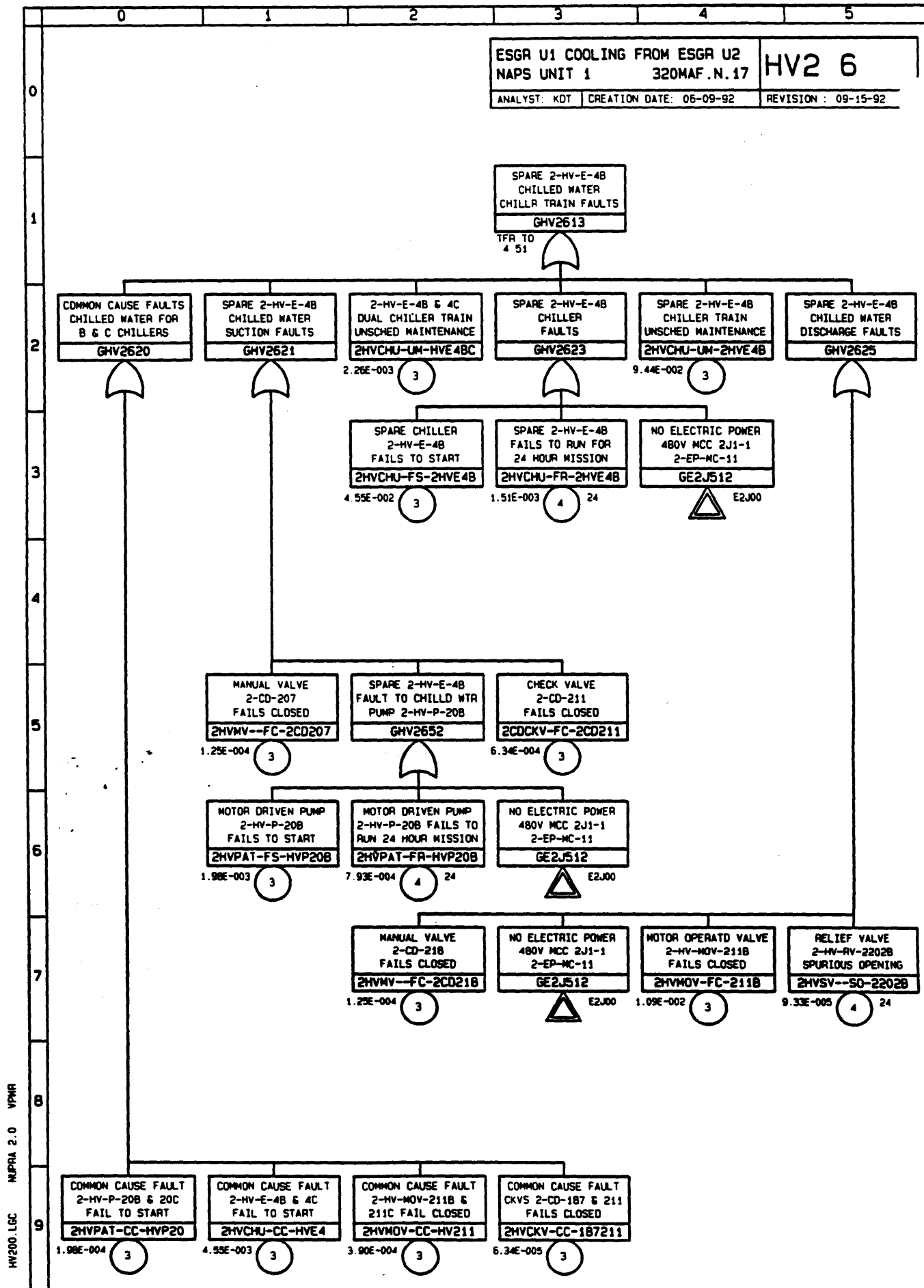


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HV200 LGC



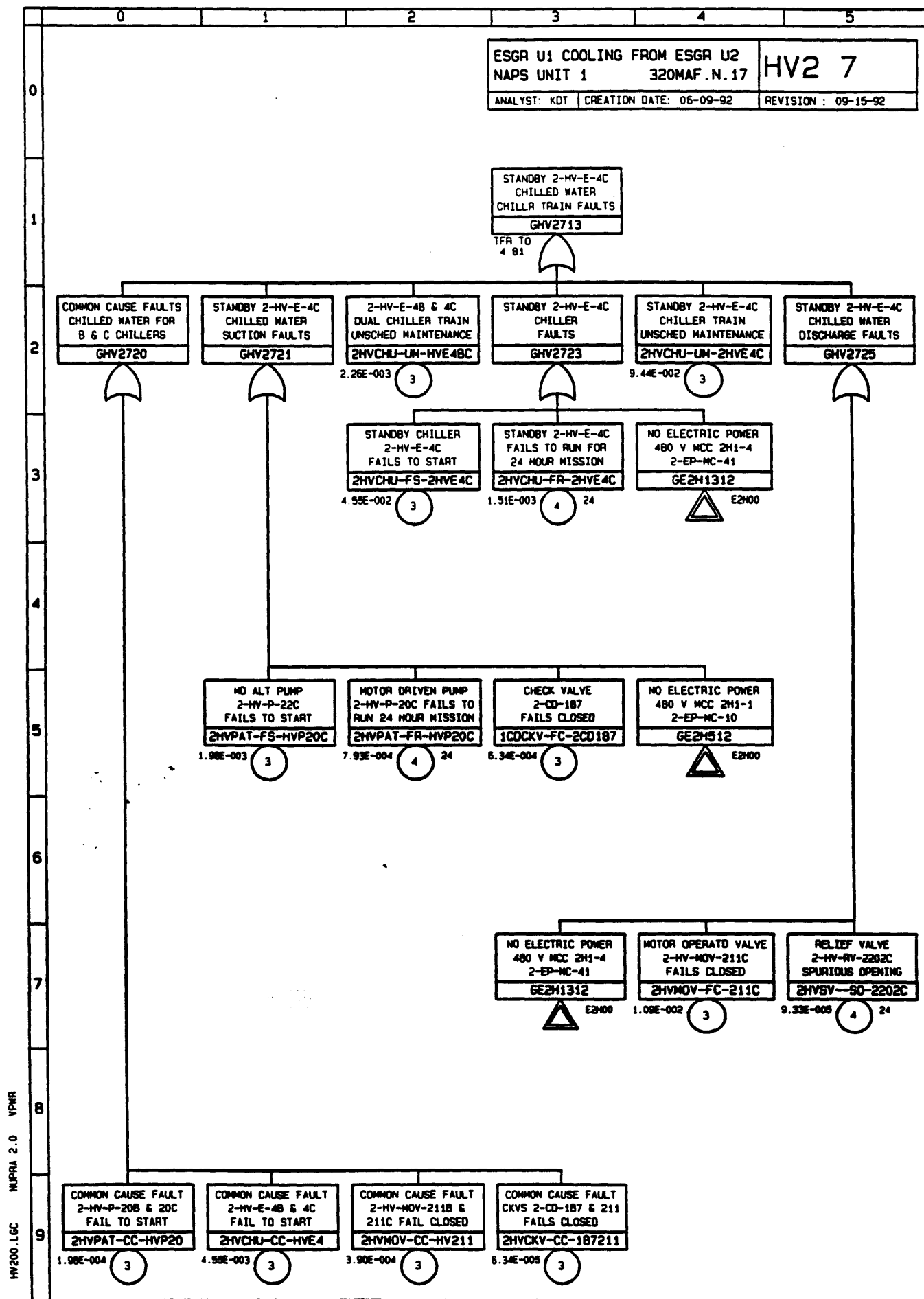


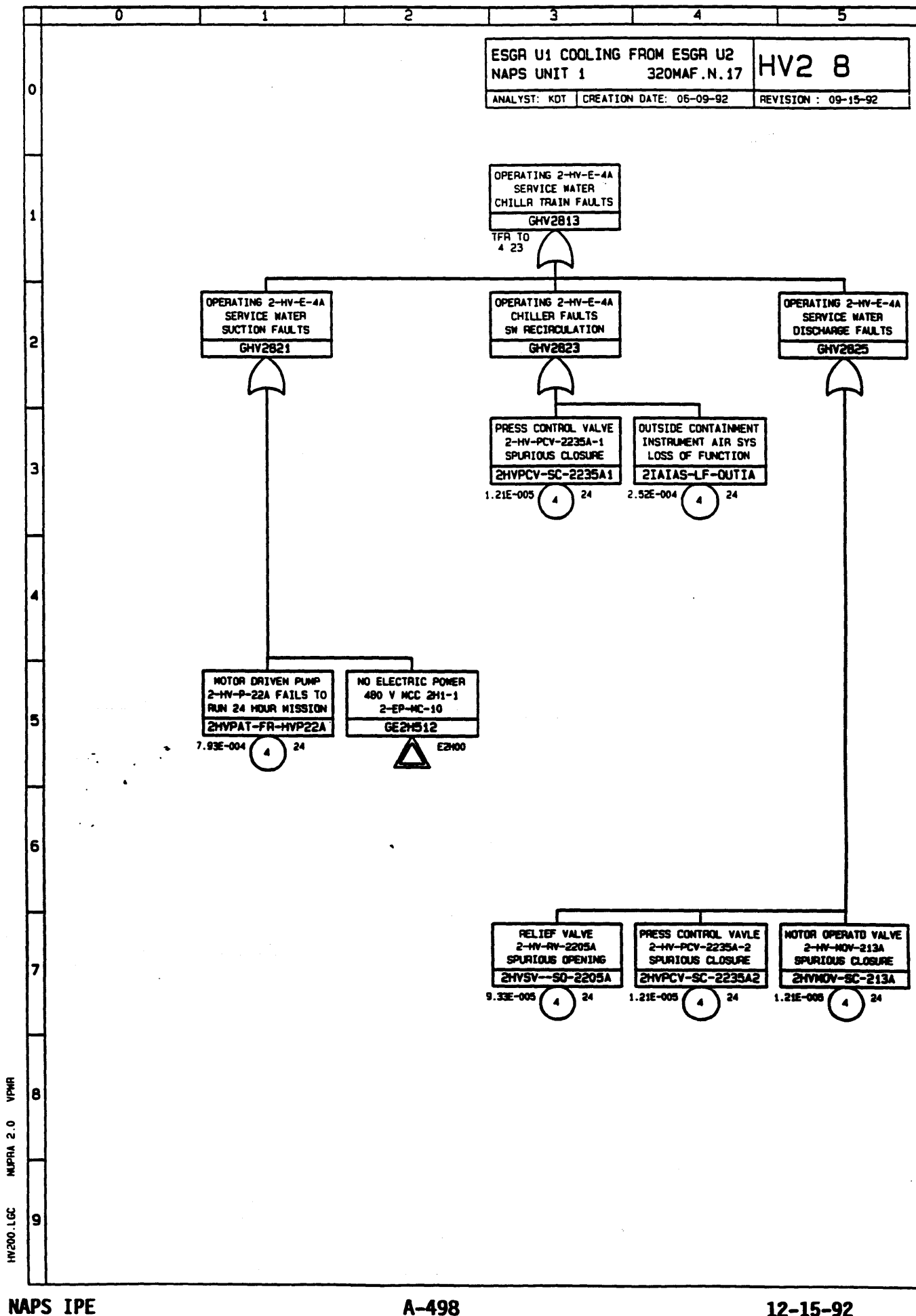


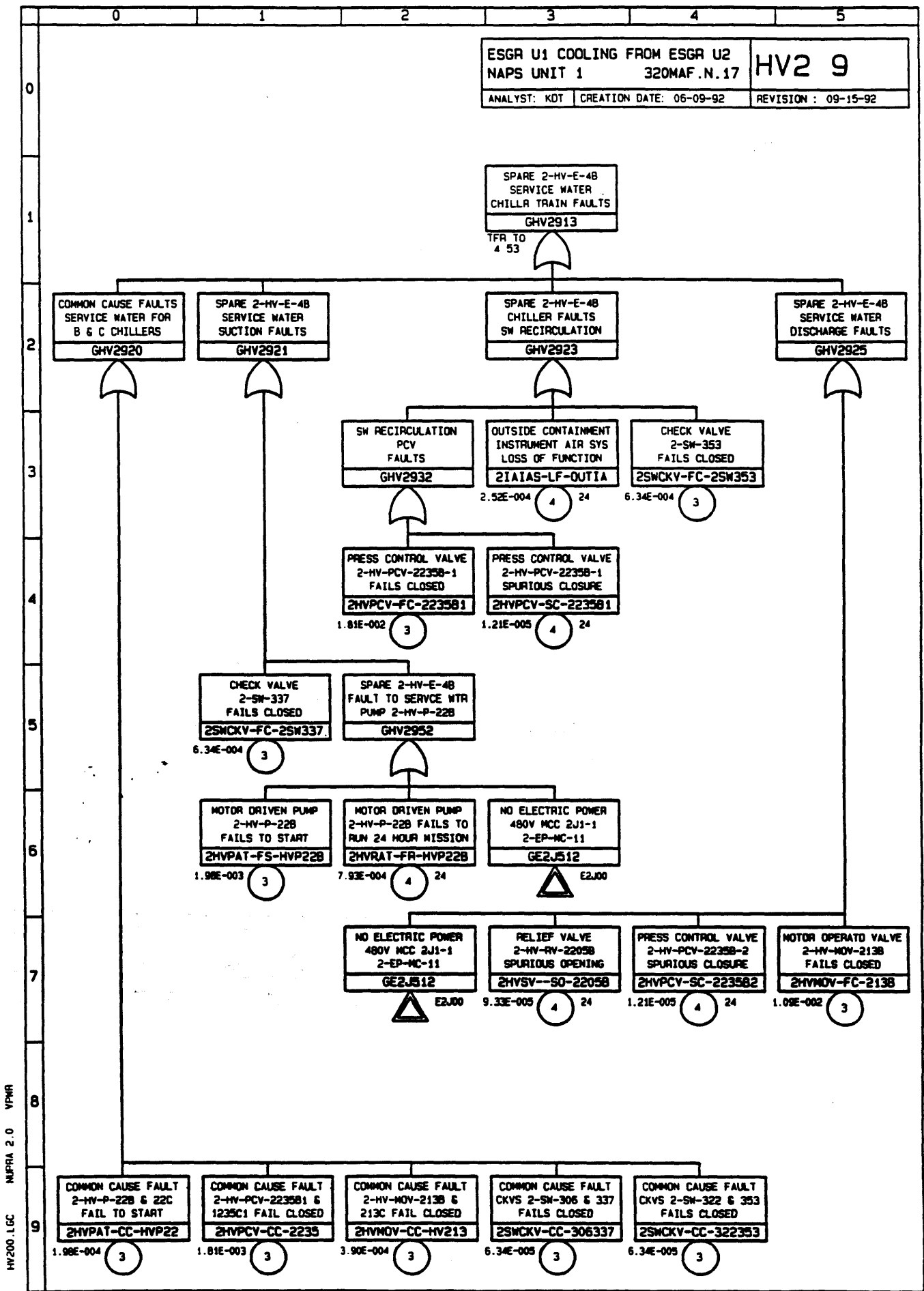


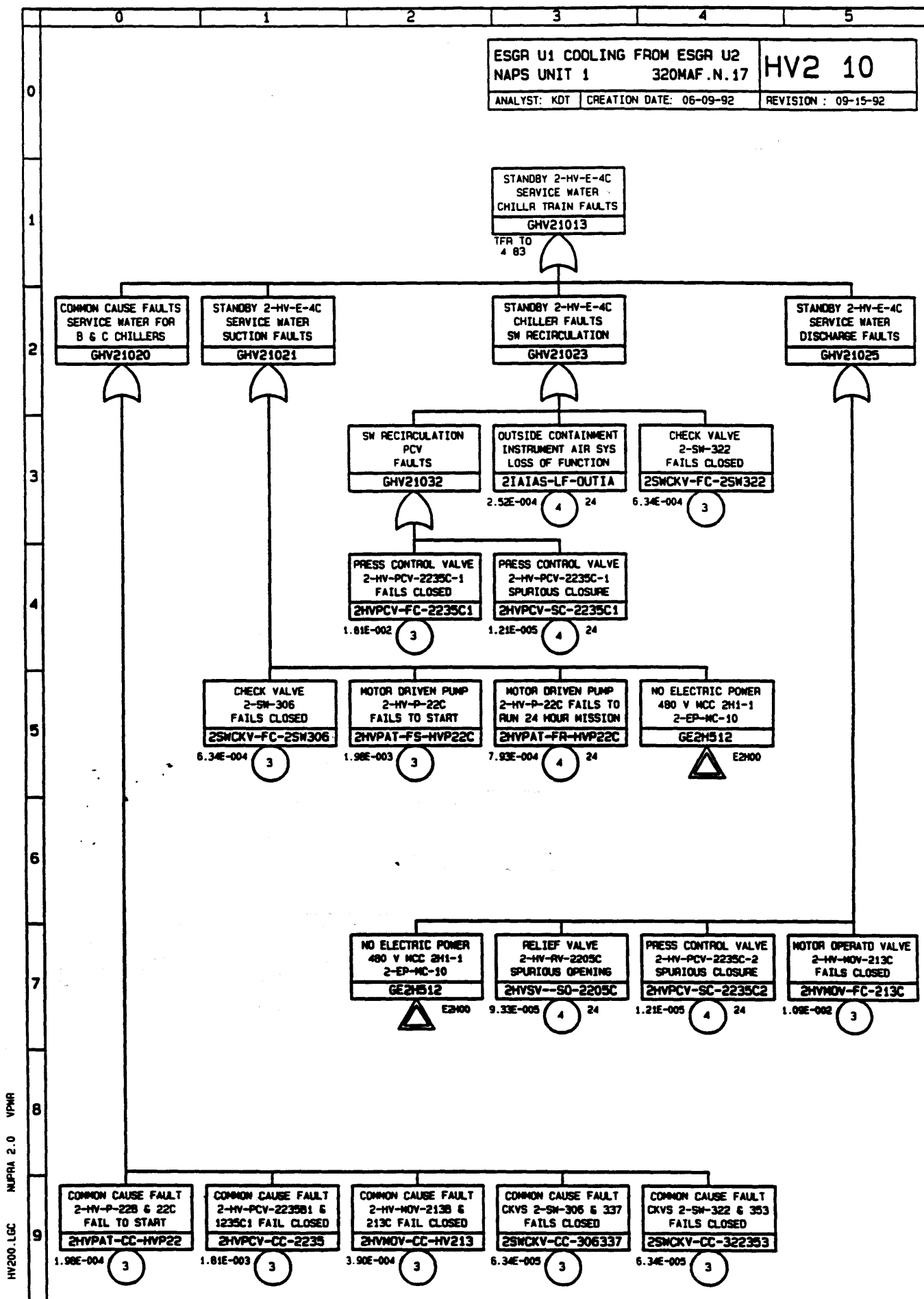
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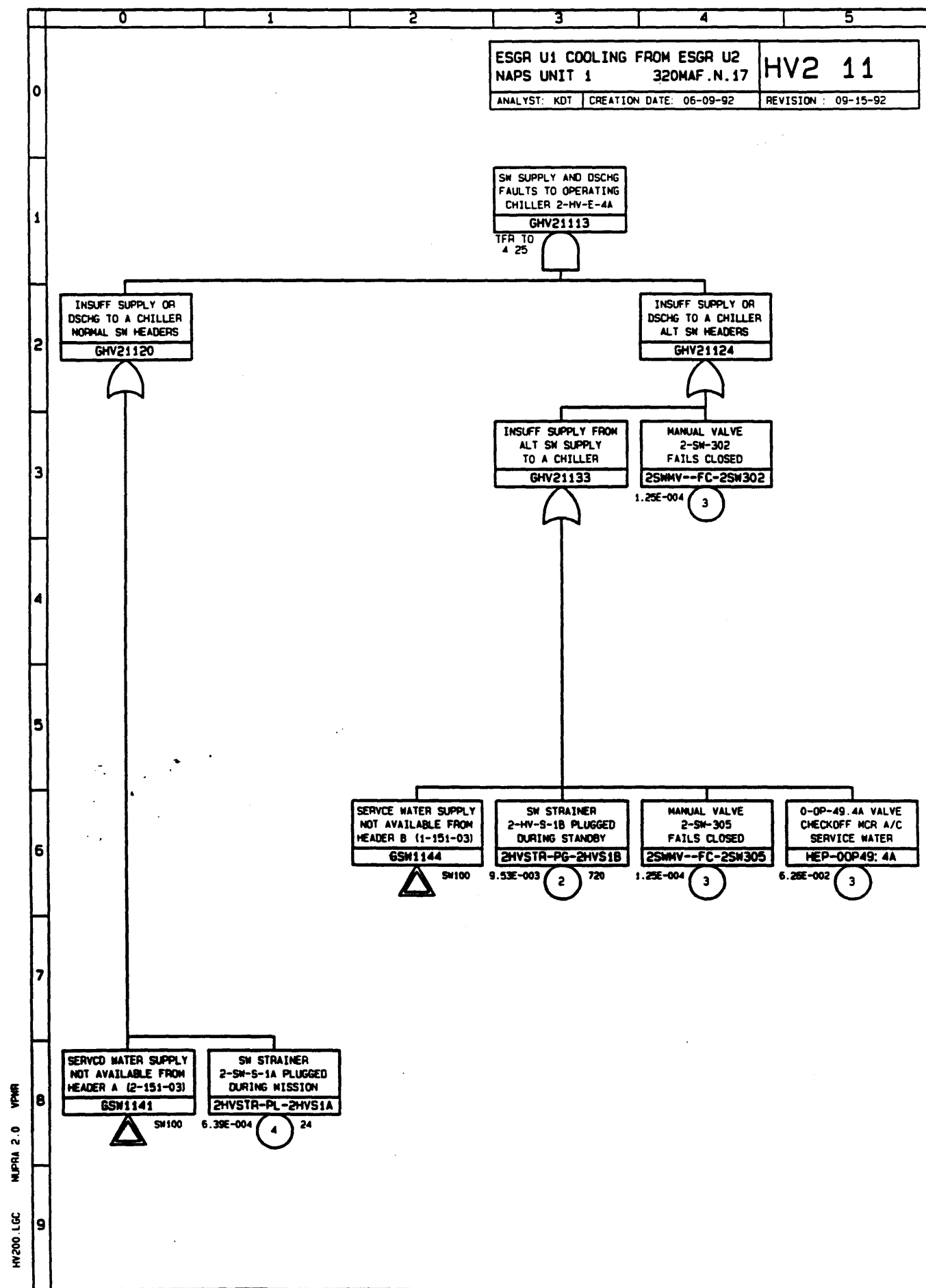




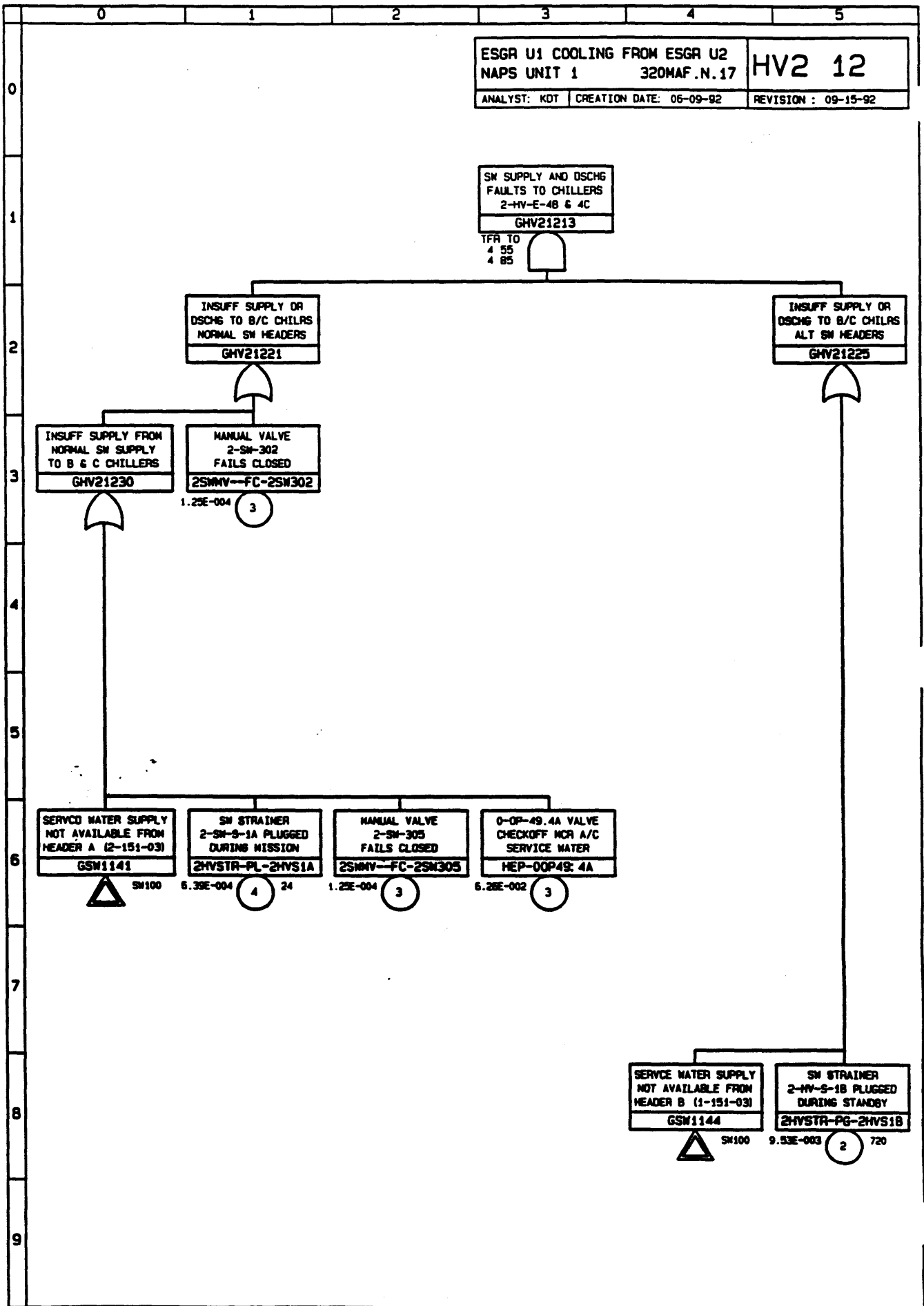




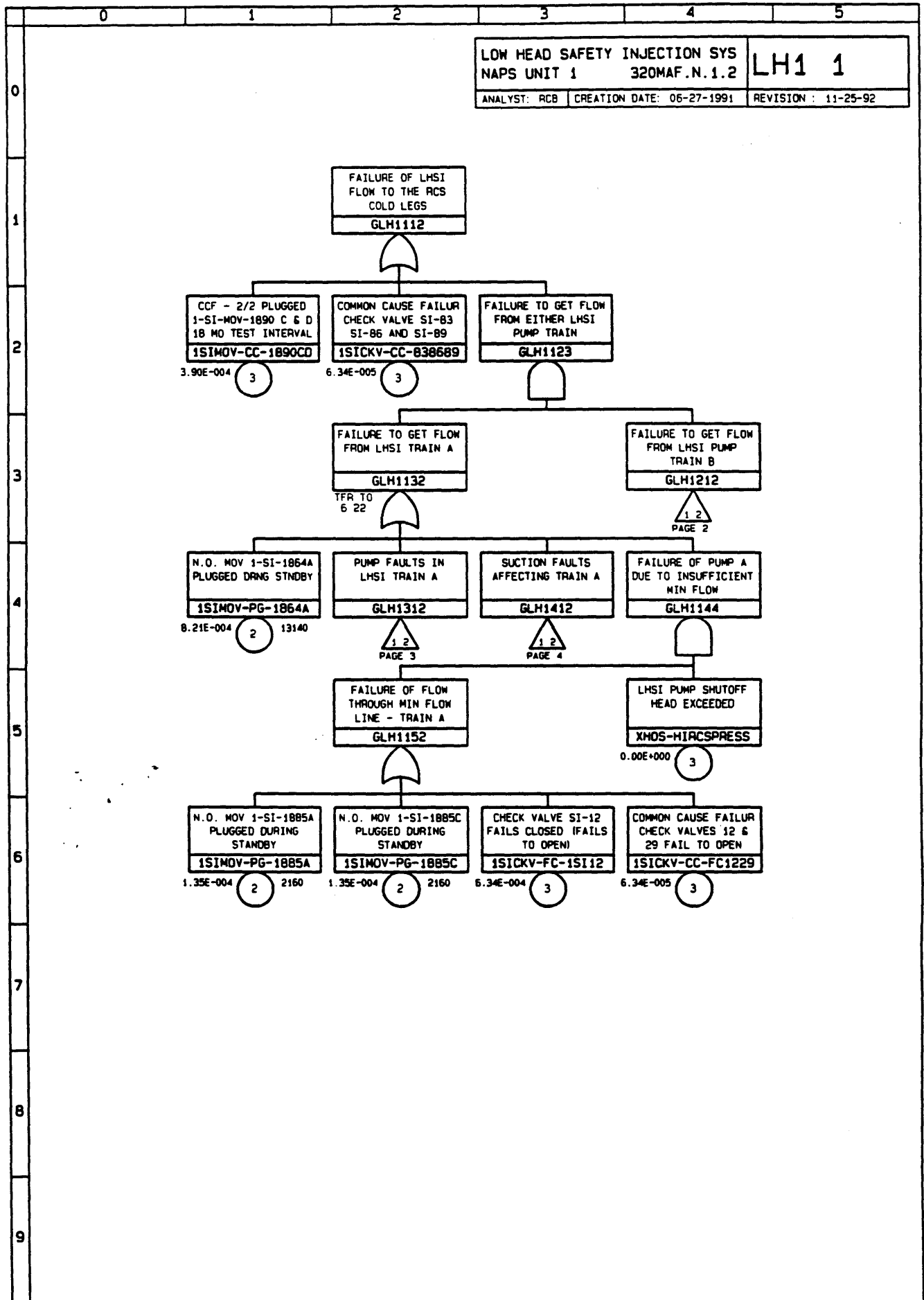
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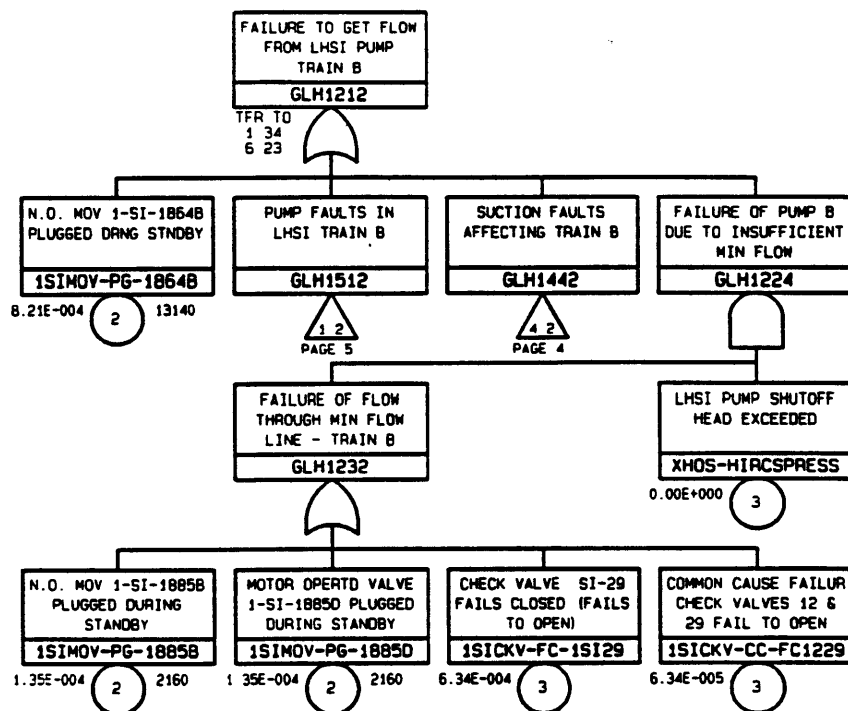


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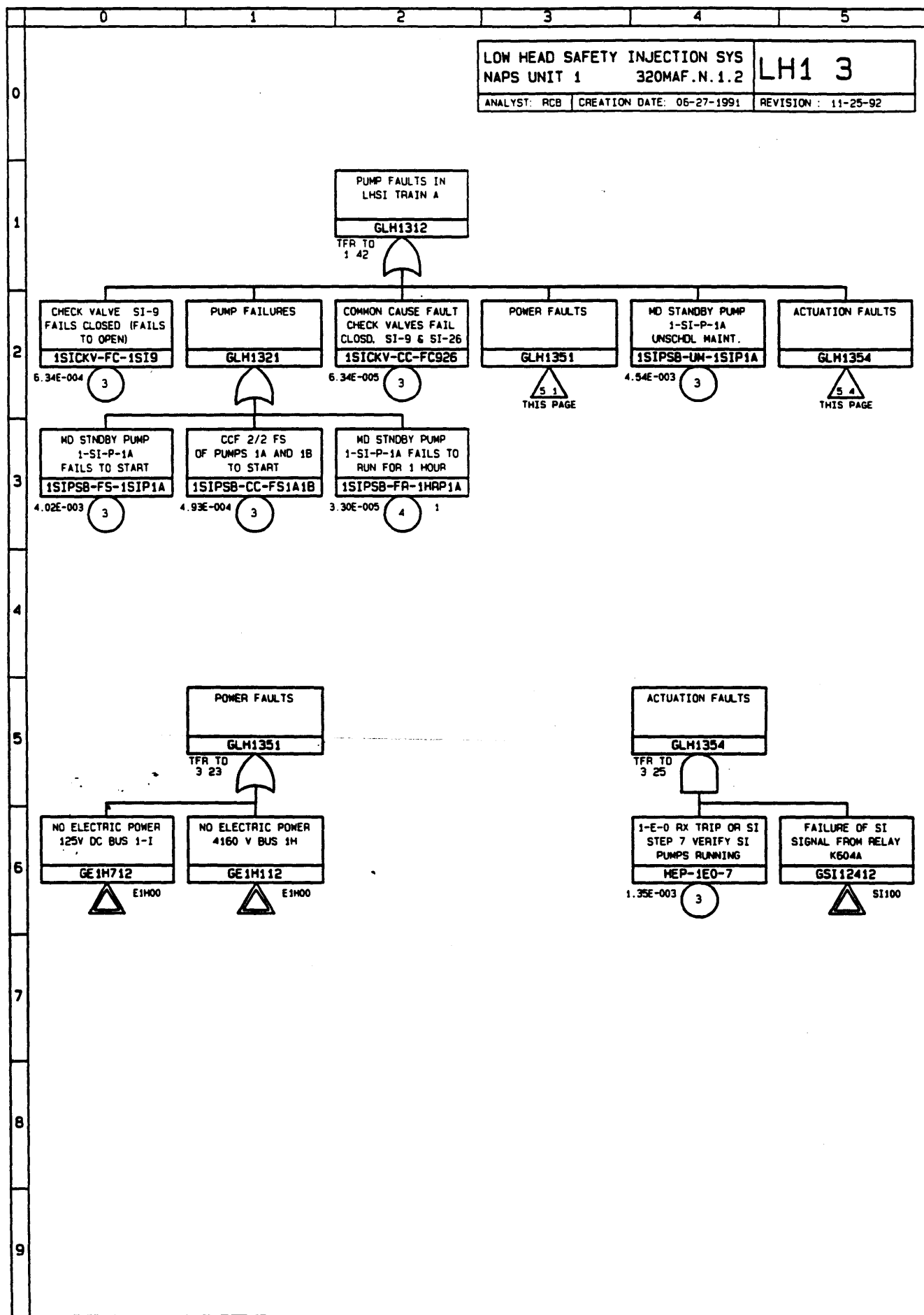
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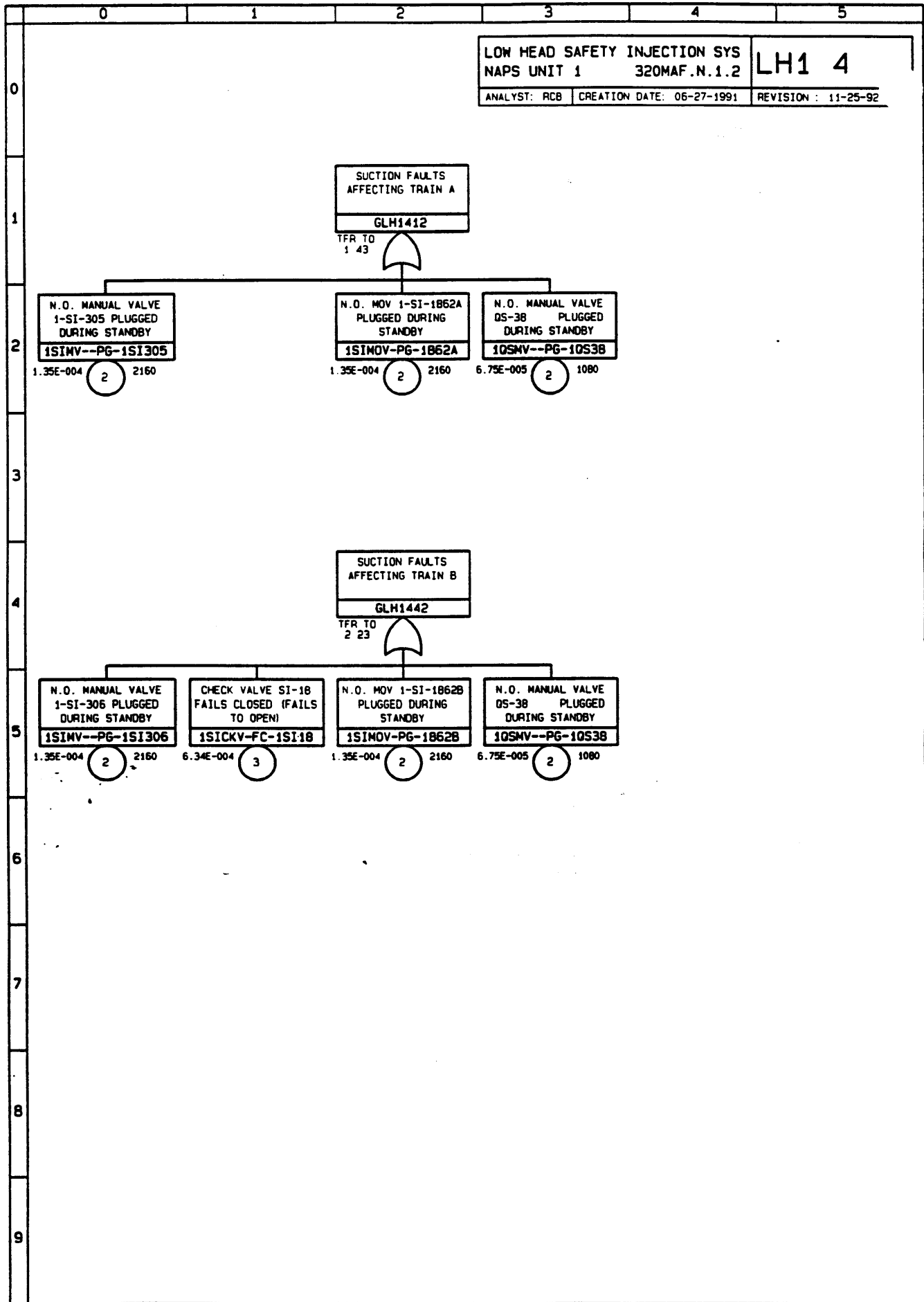
LOW HEAD SAFETY INJECTION SYS		LH1 2
NAPS UNIT 1	320MAF.N.1.2	
ANALYST: RCB	CREATION DATE: 06-27-1991	REVISION : 11-25-92



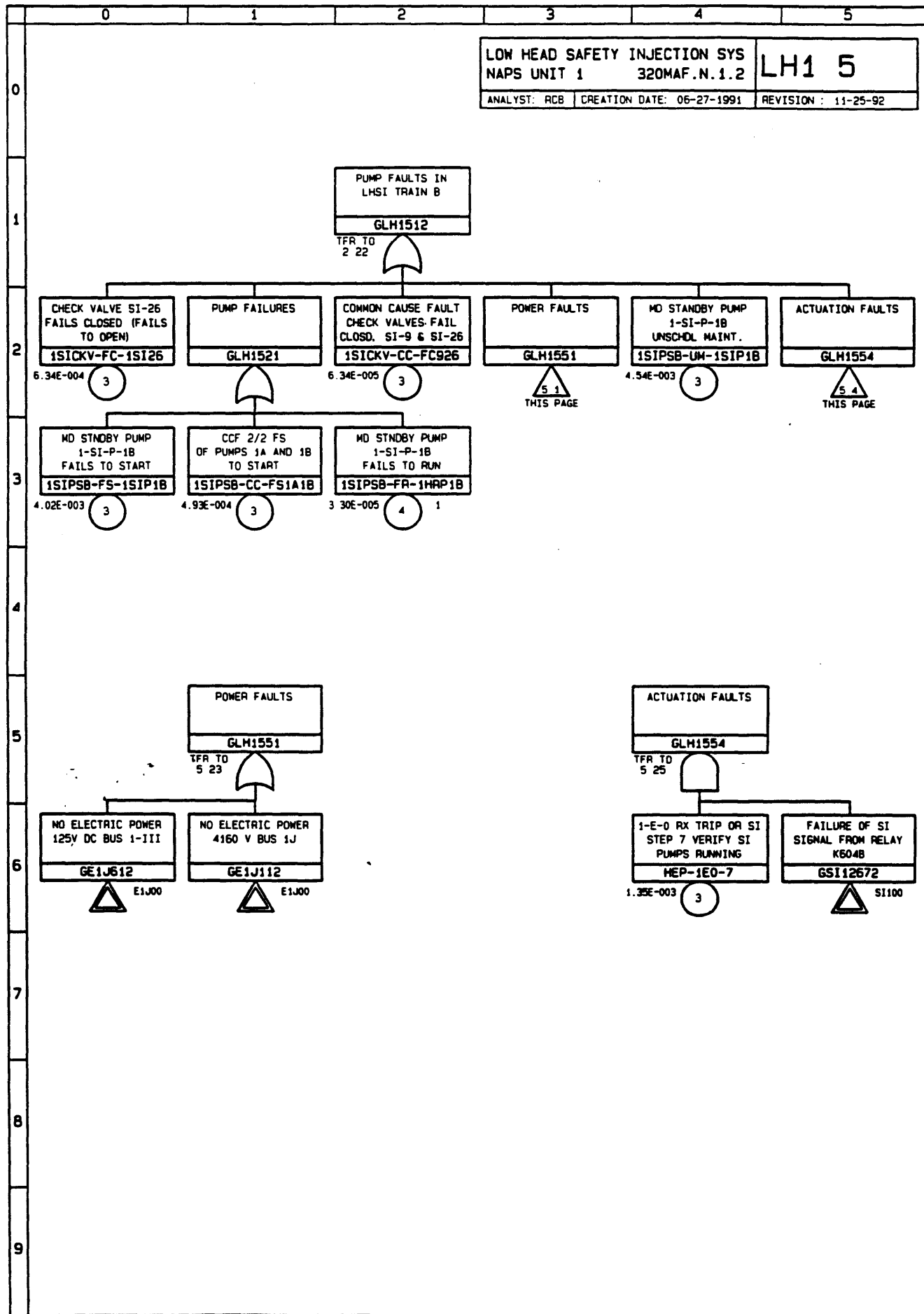


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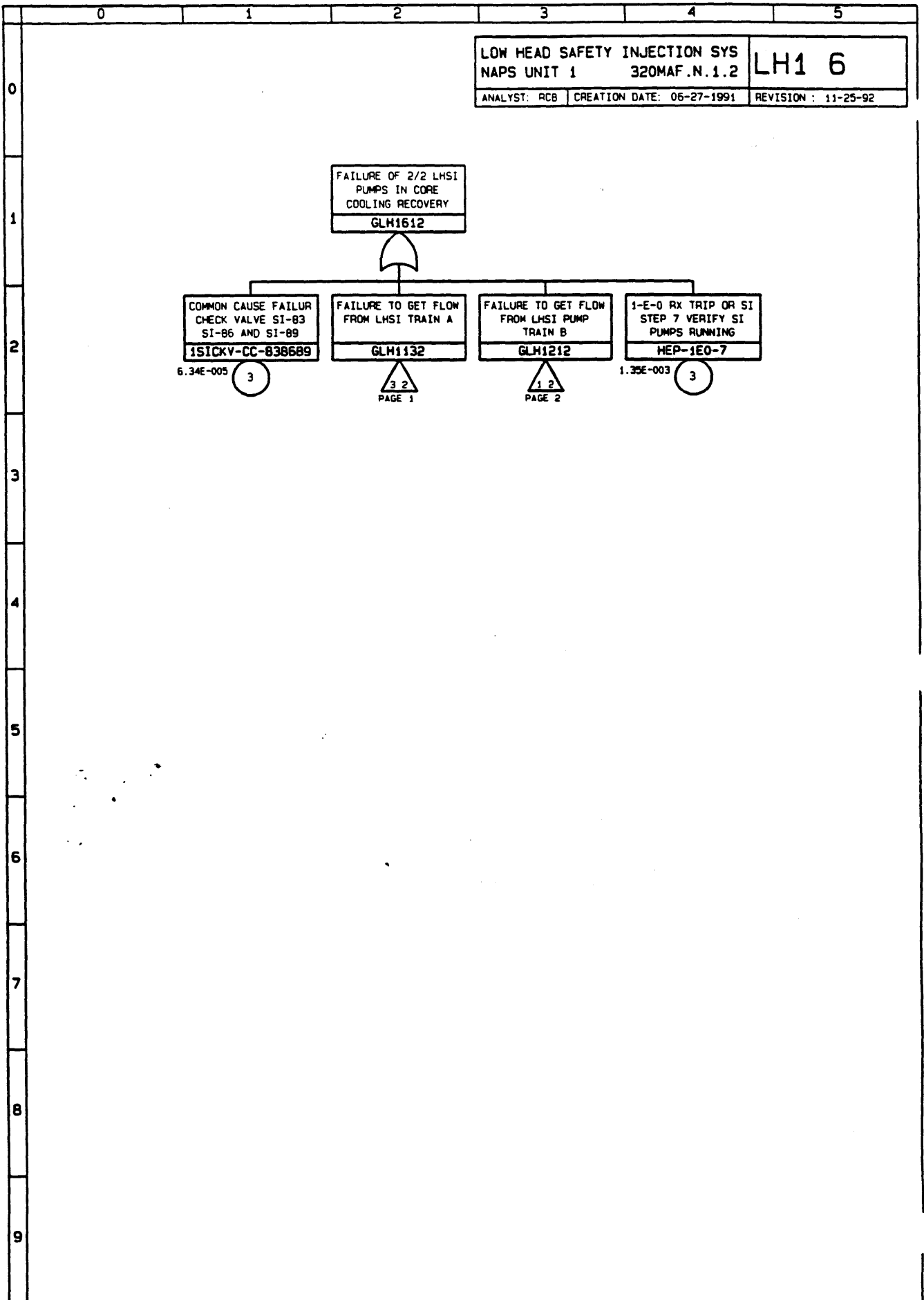


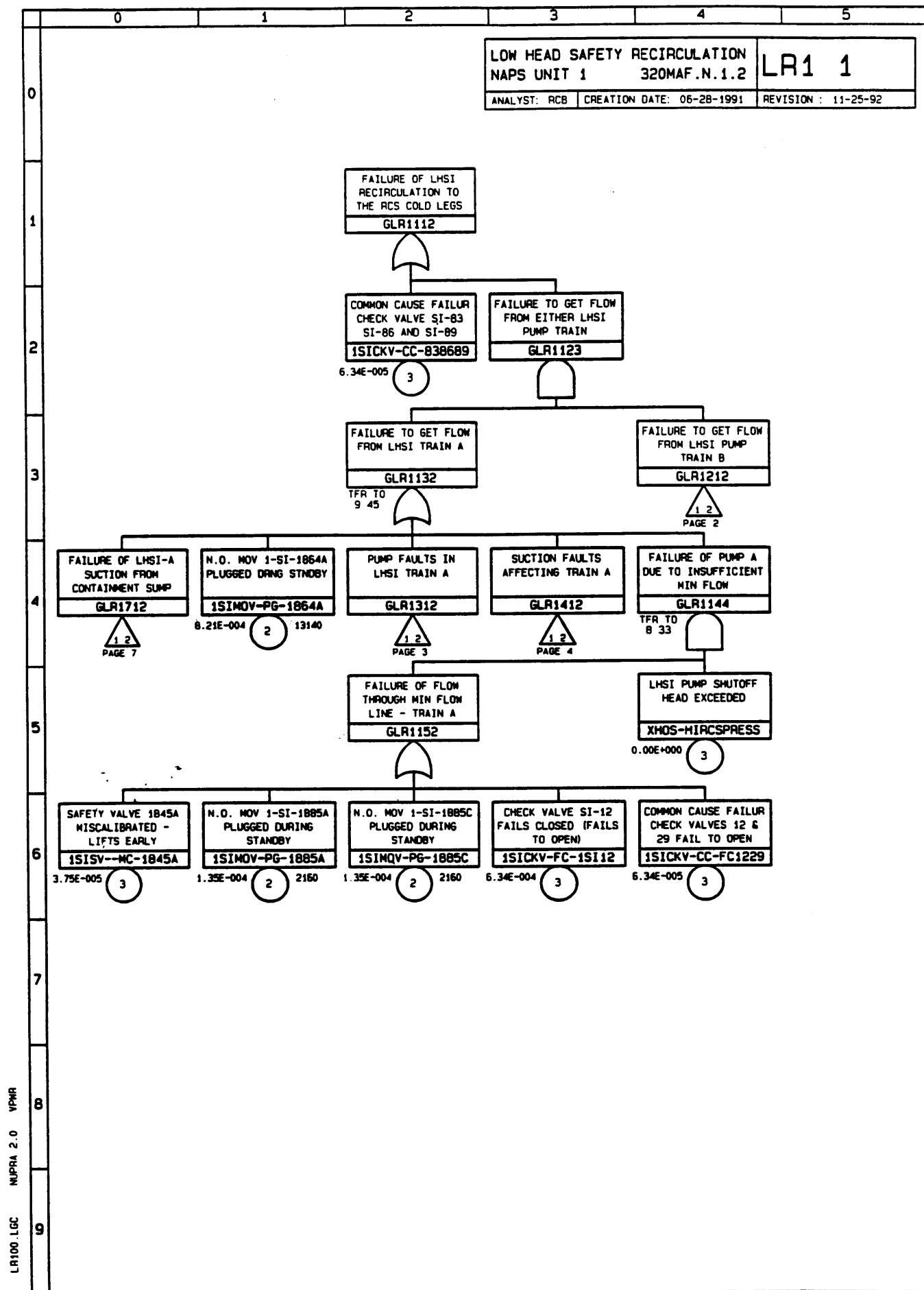


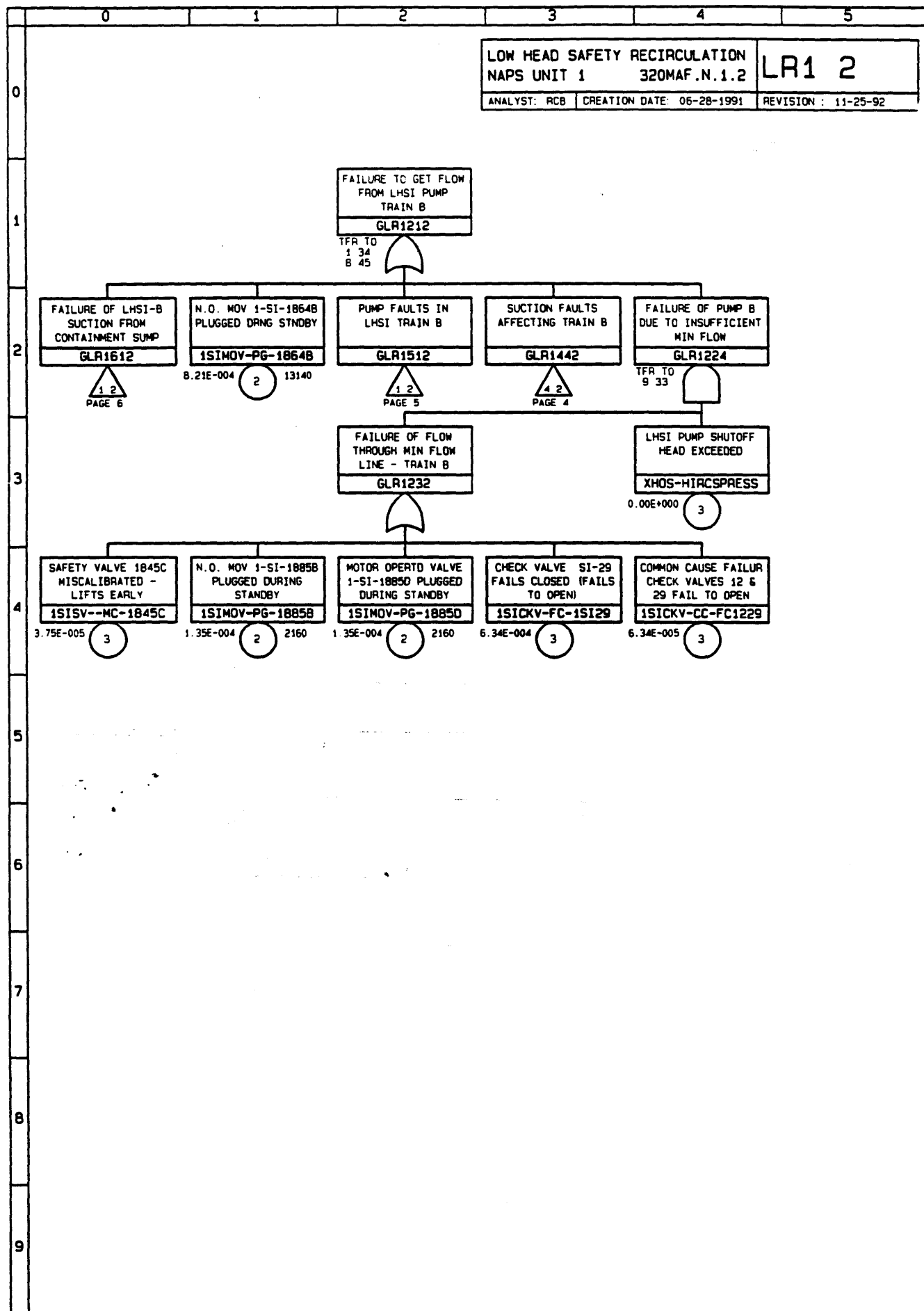
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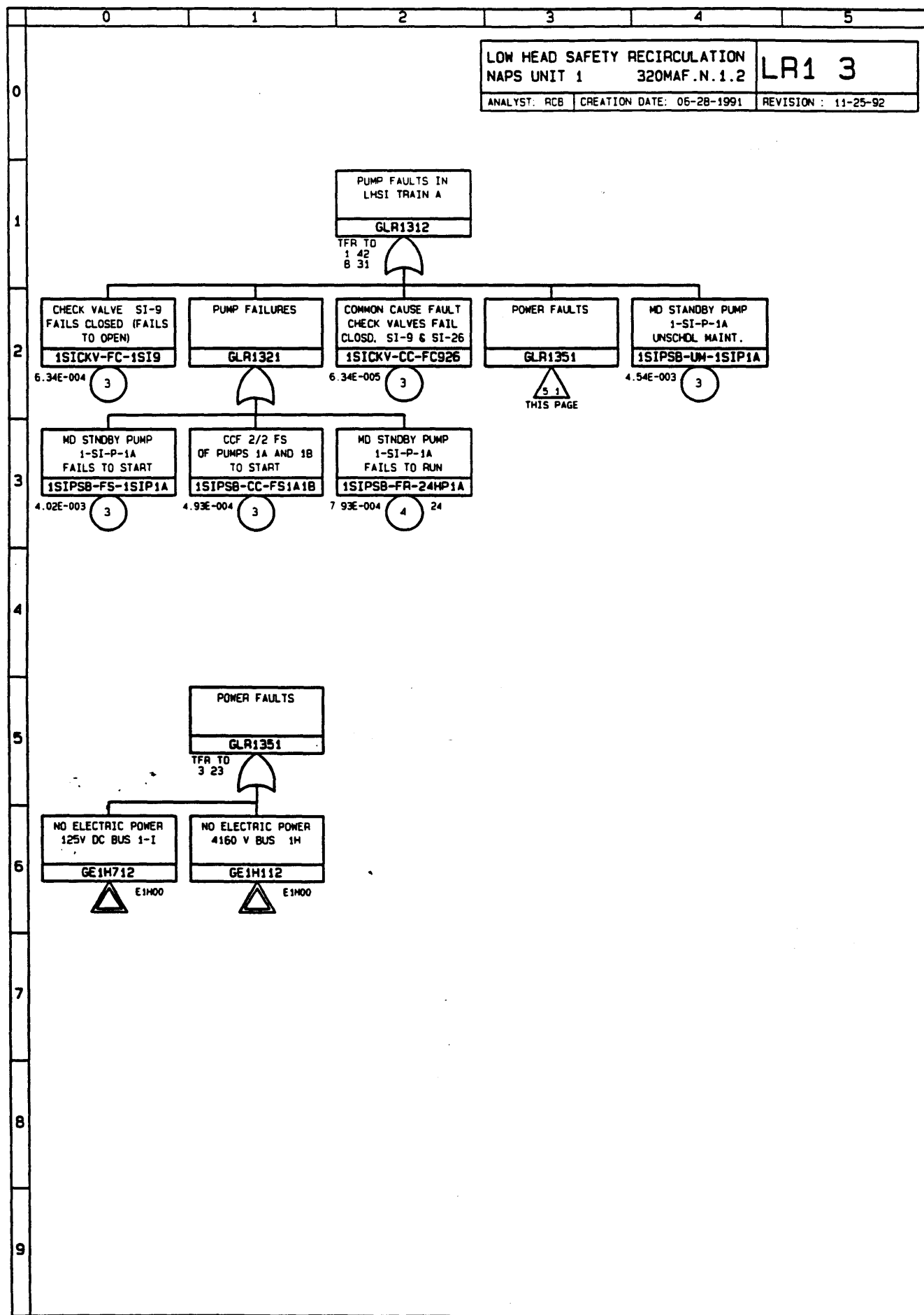
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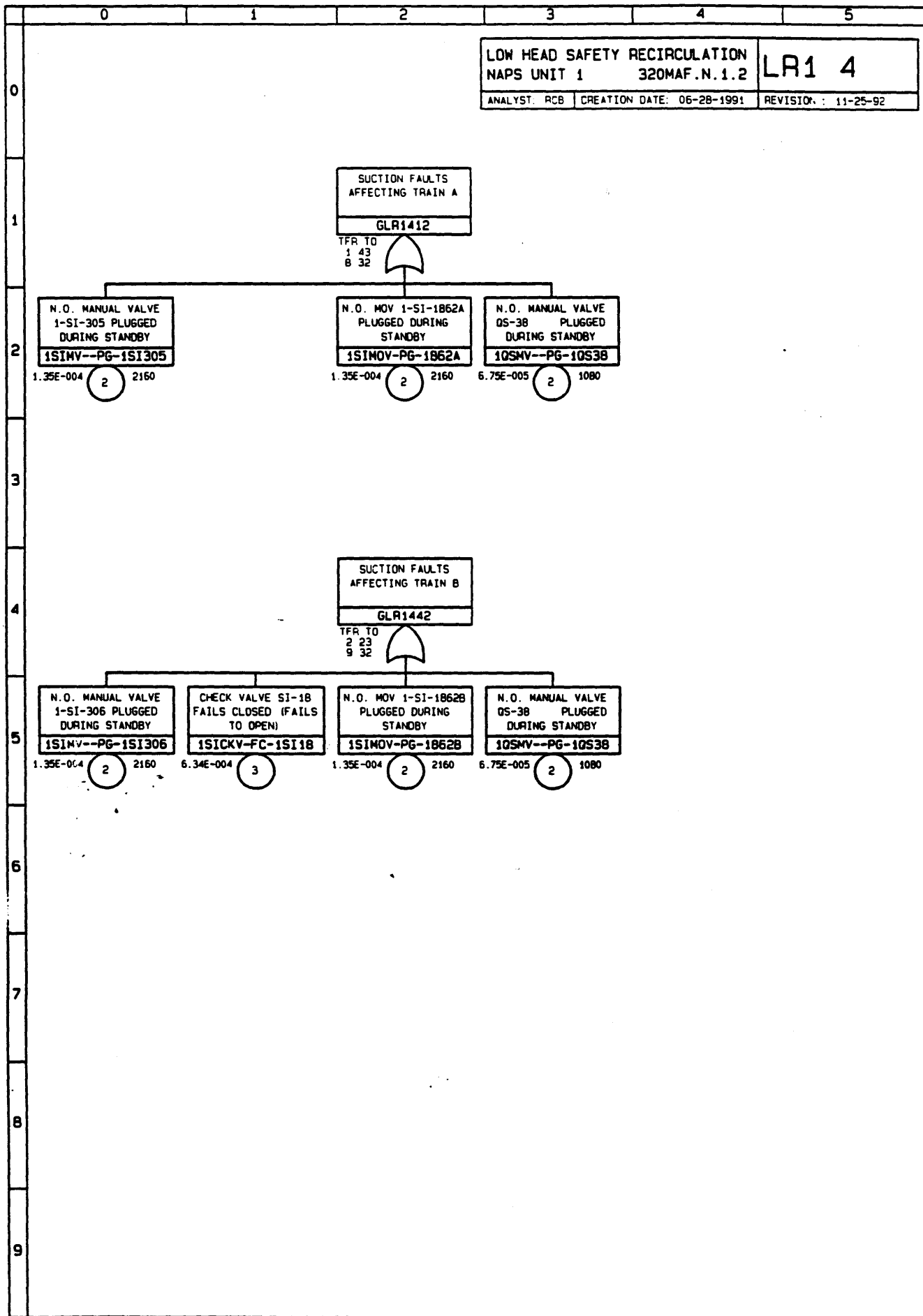




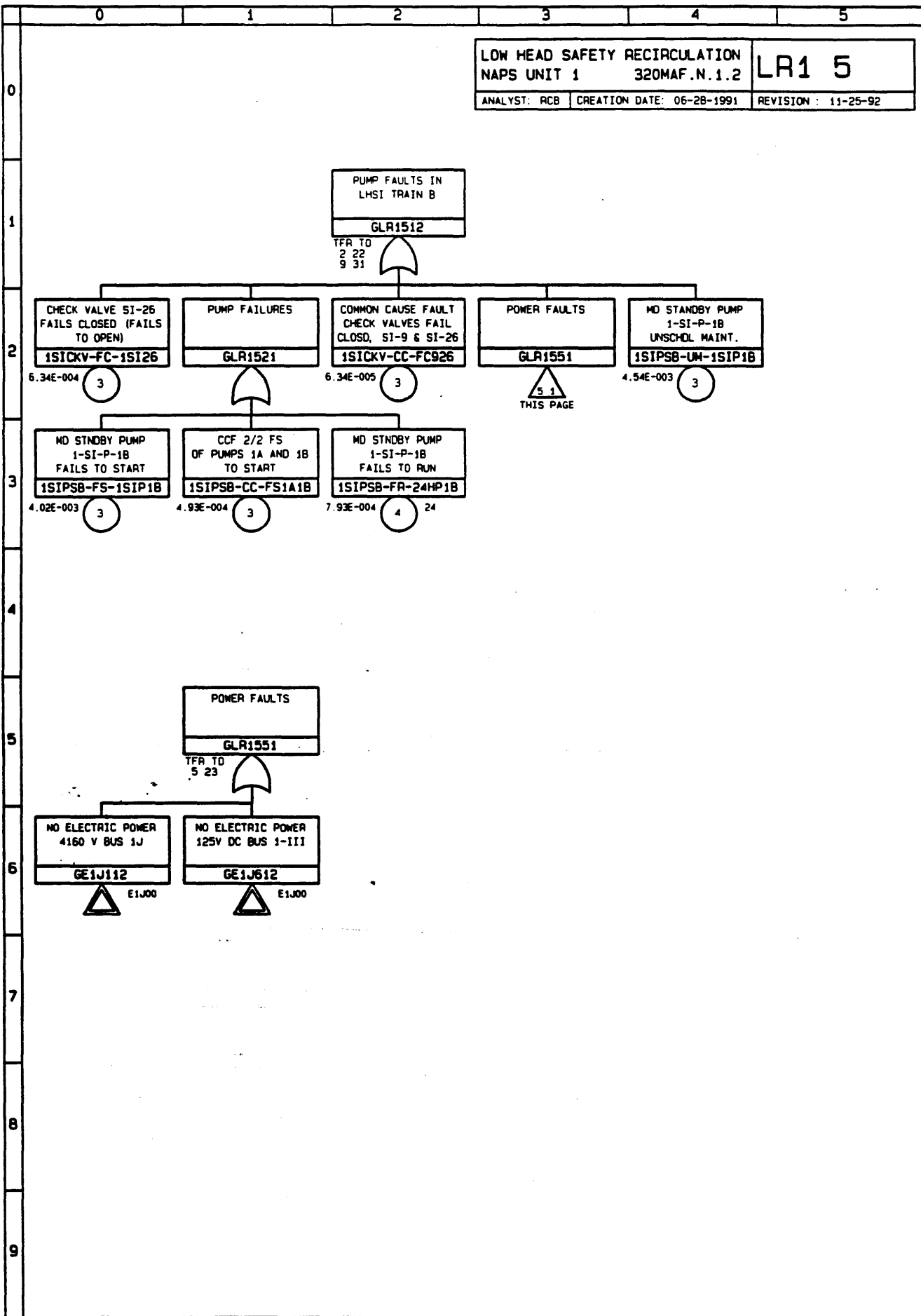
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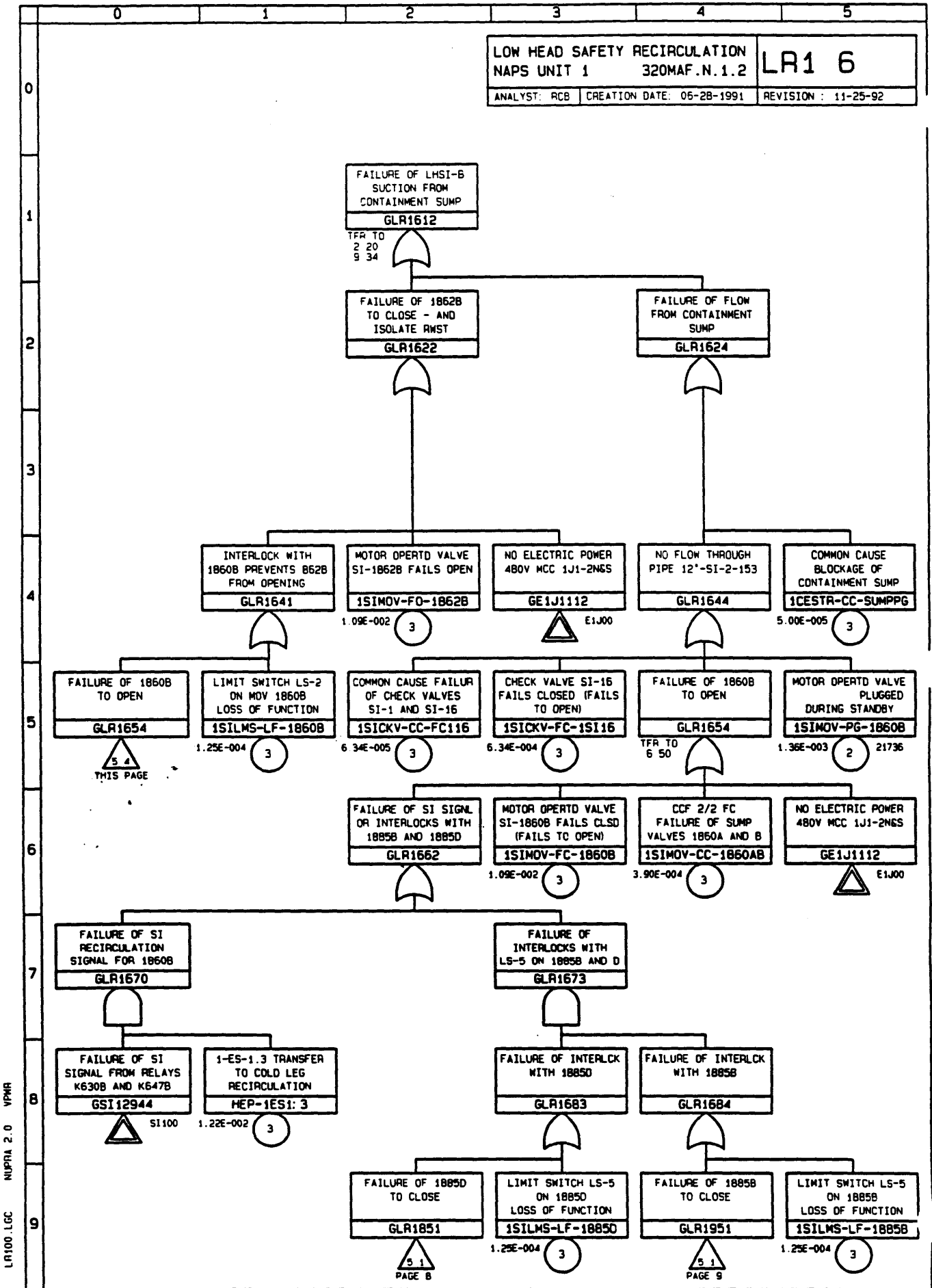


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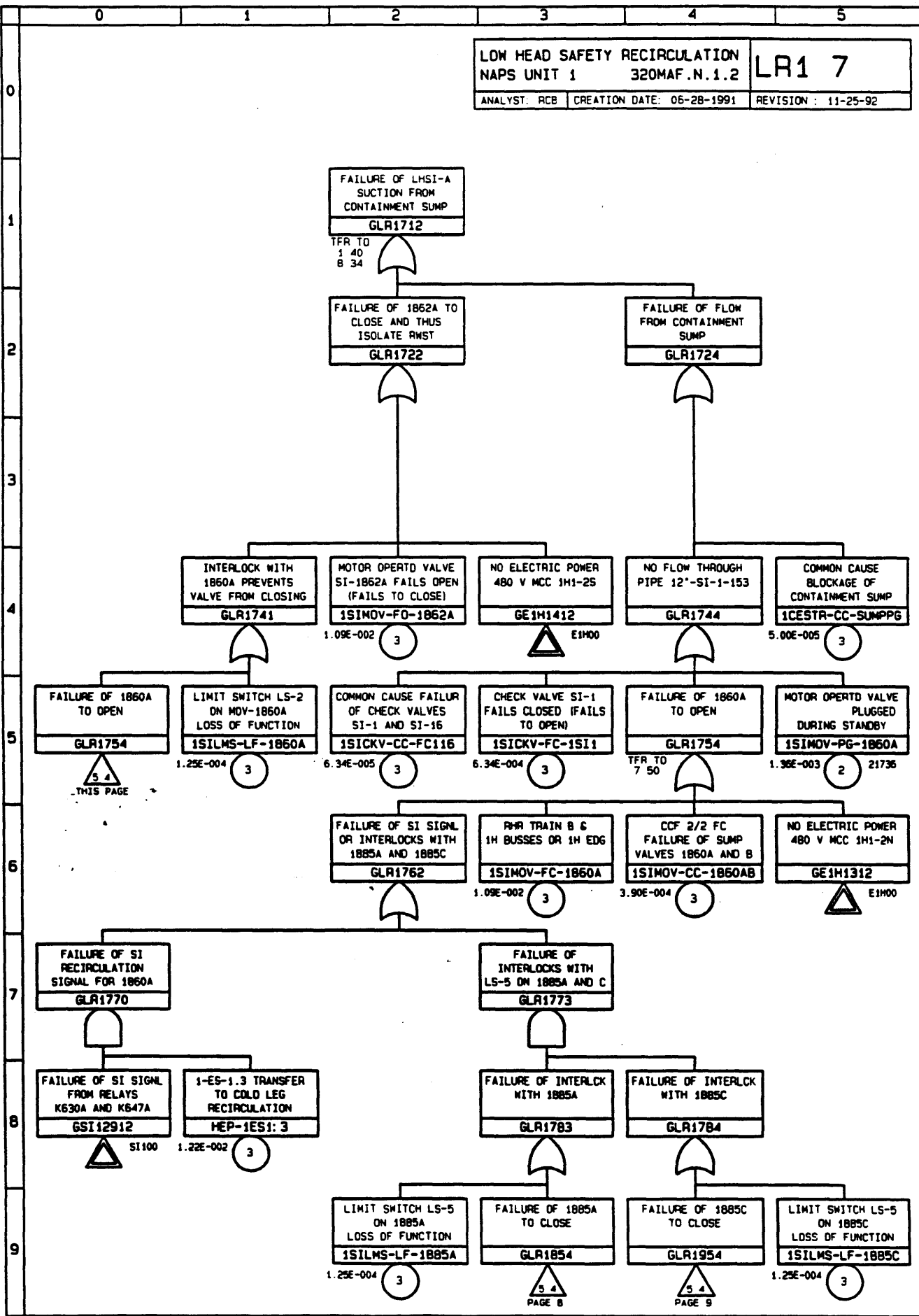


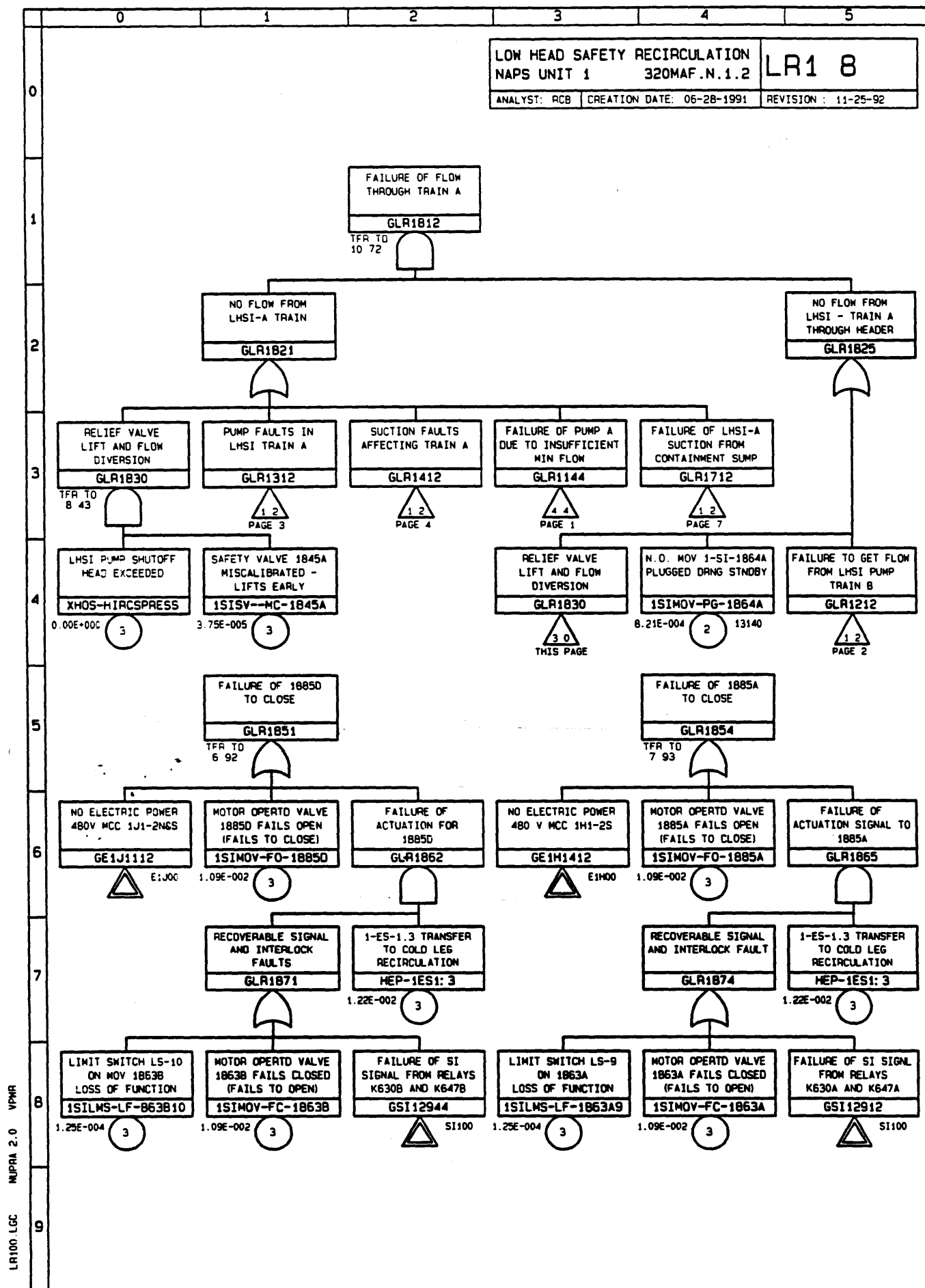


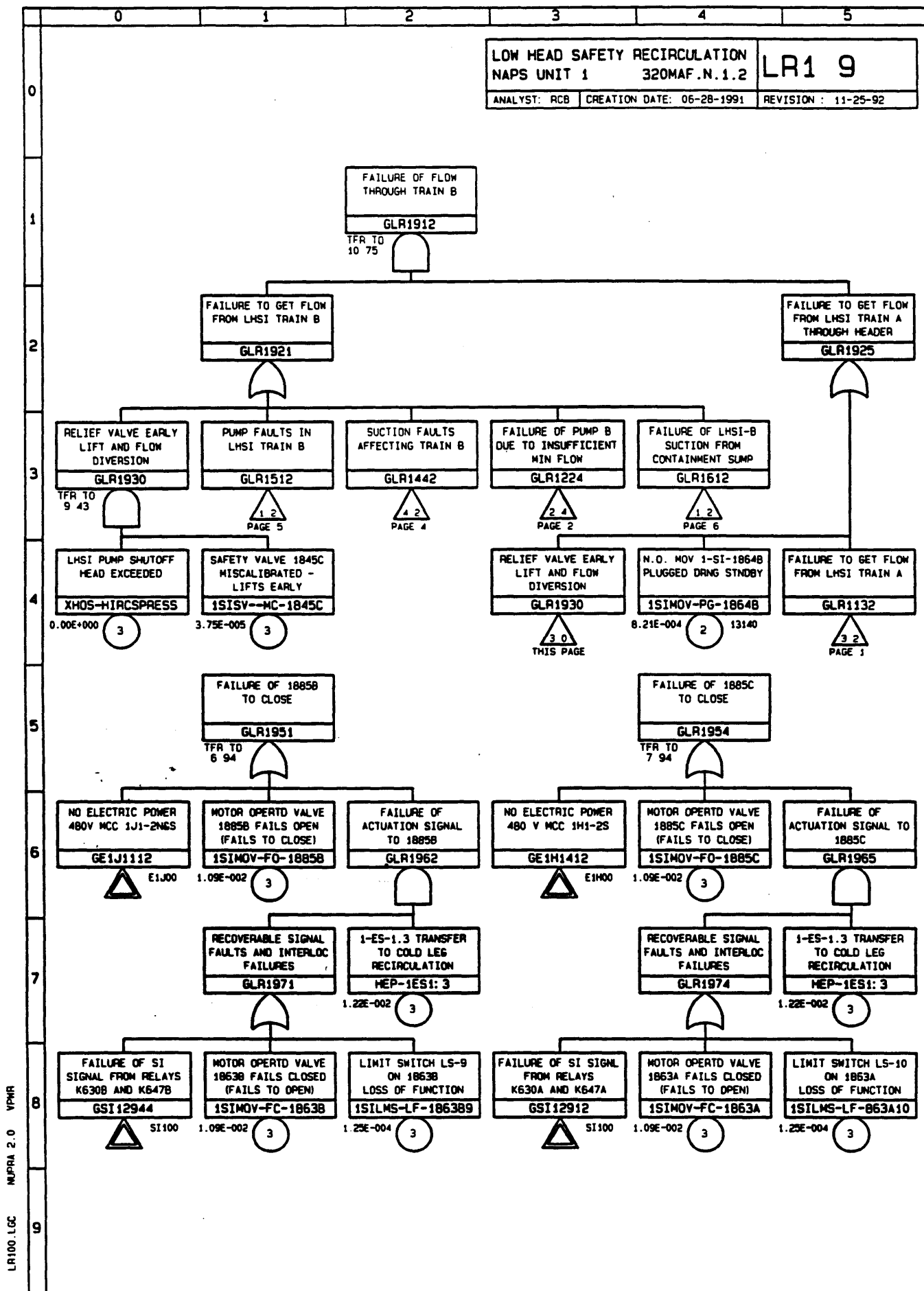




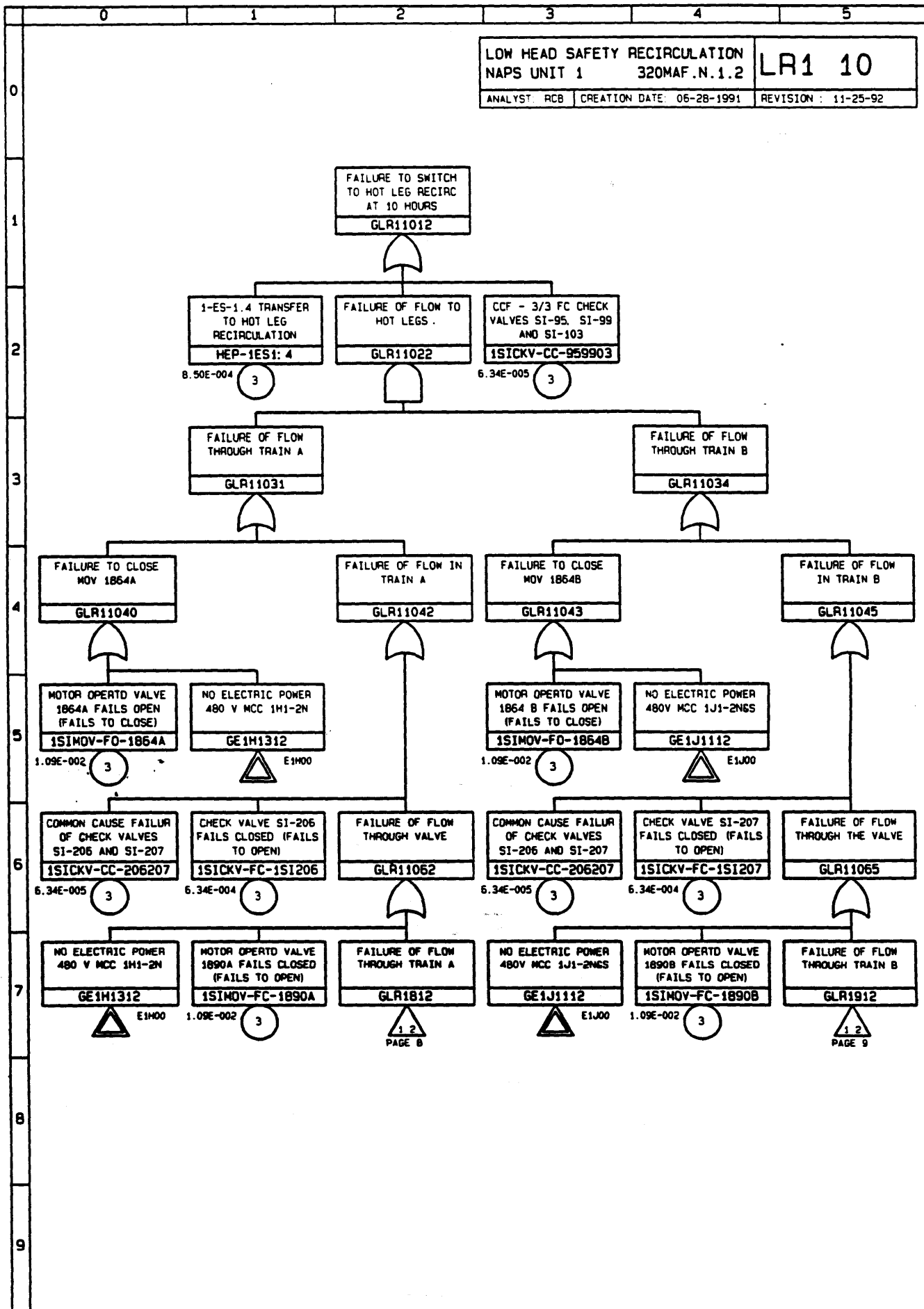
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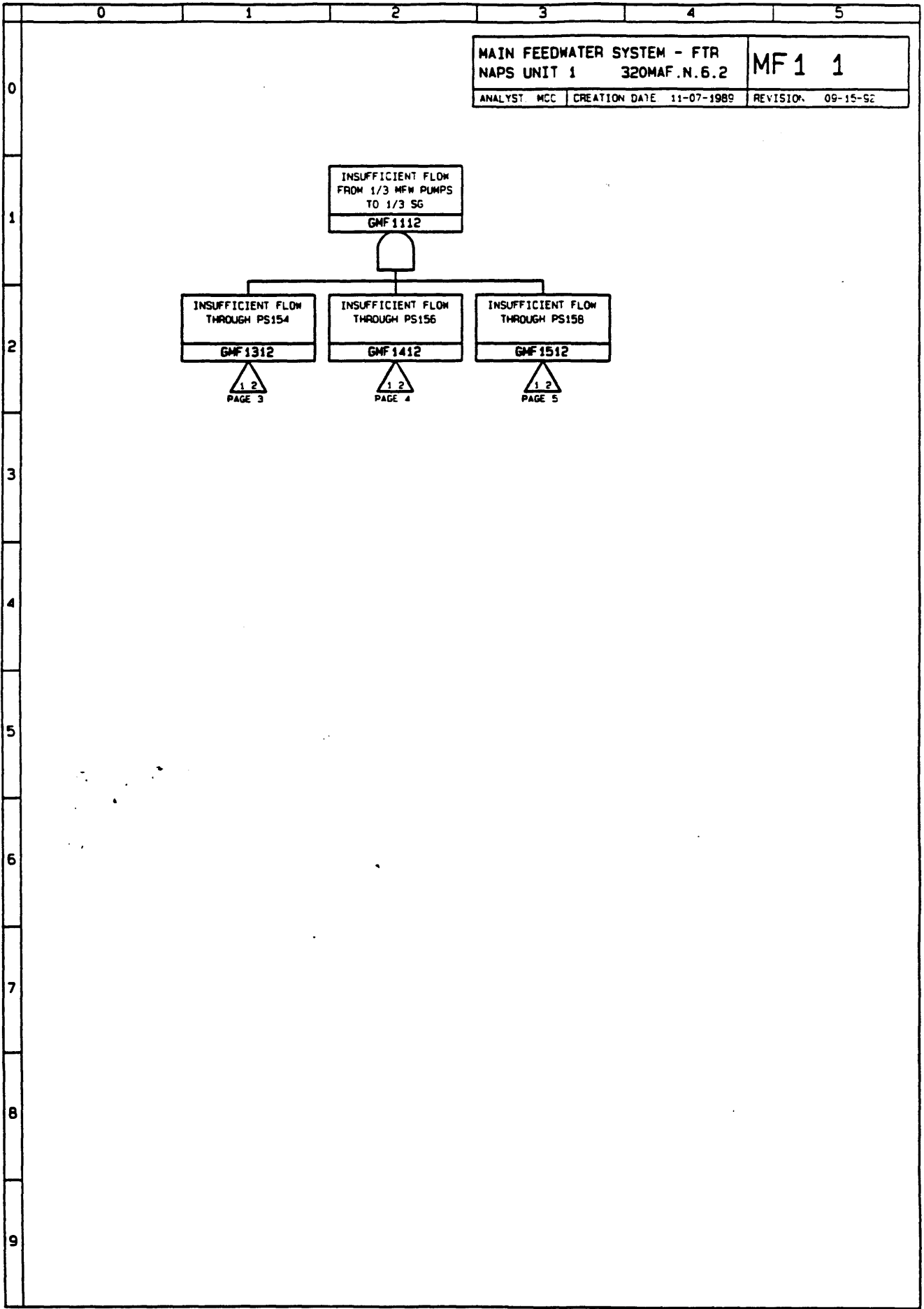






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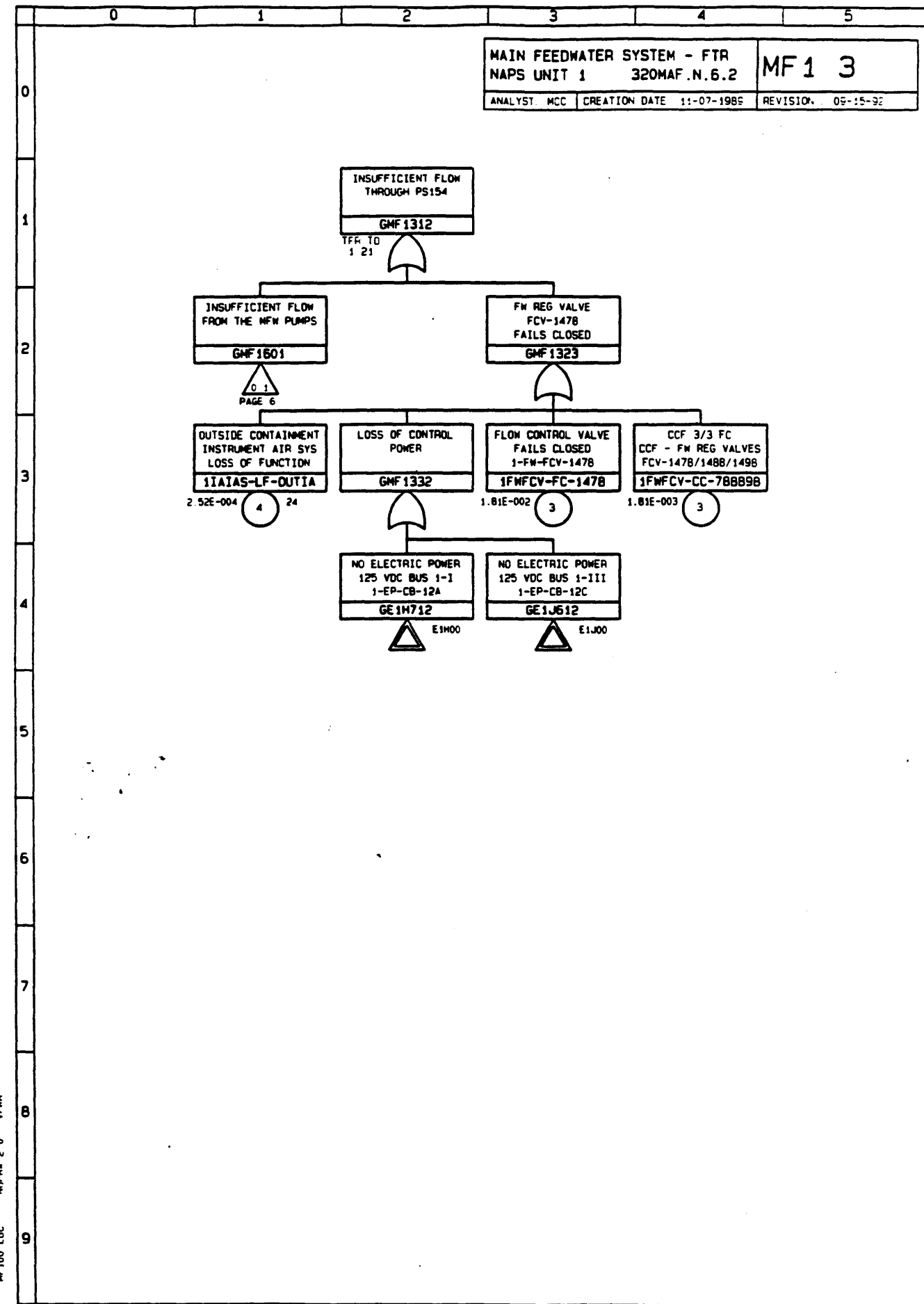


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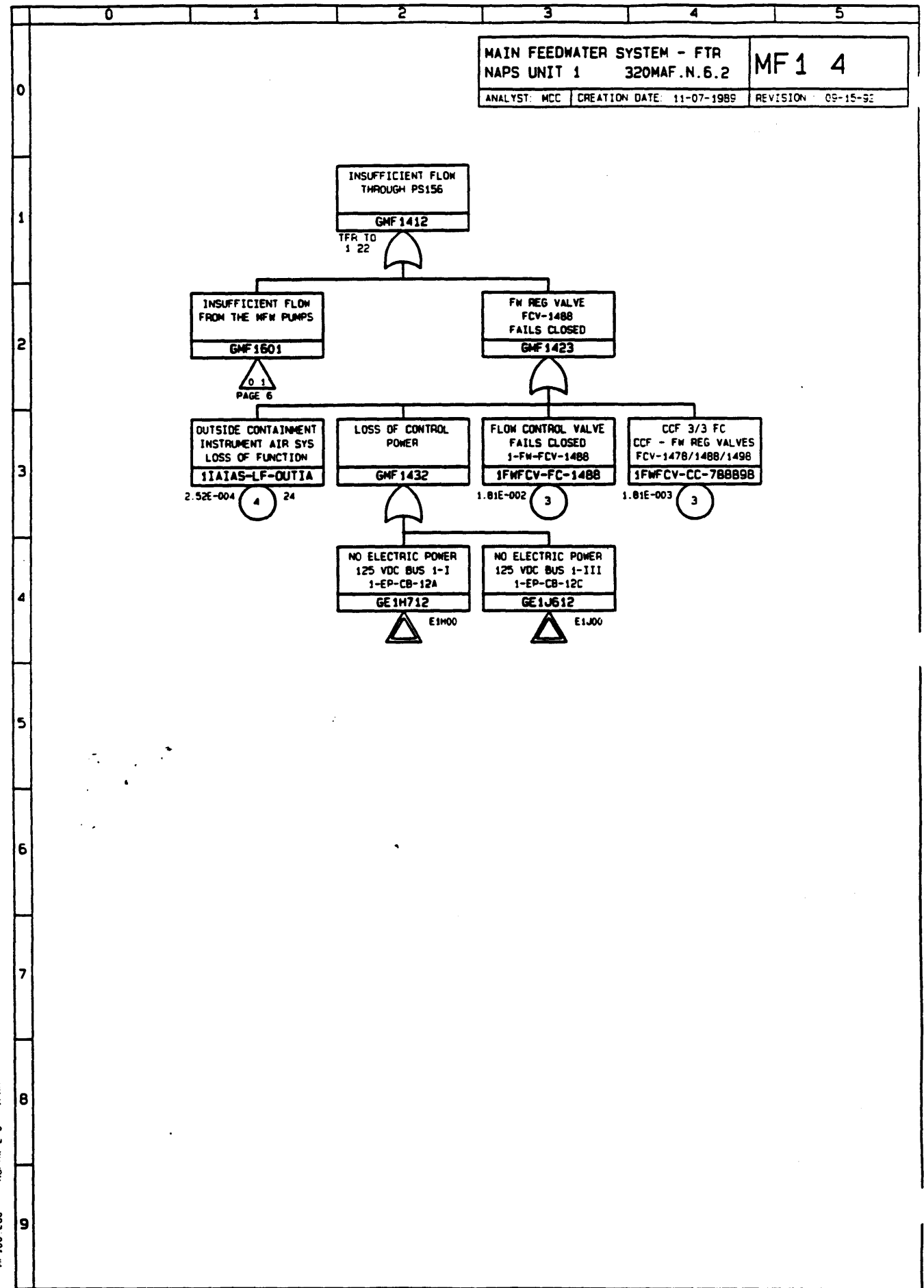
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Fault Tree MF100**



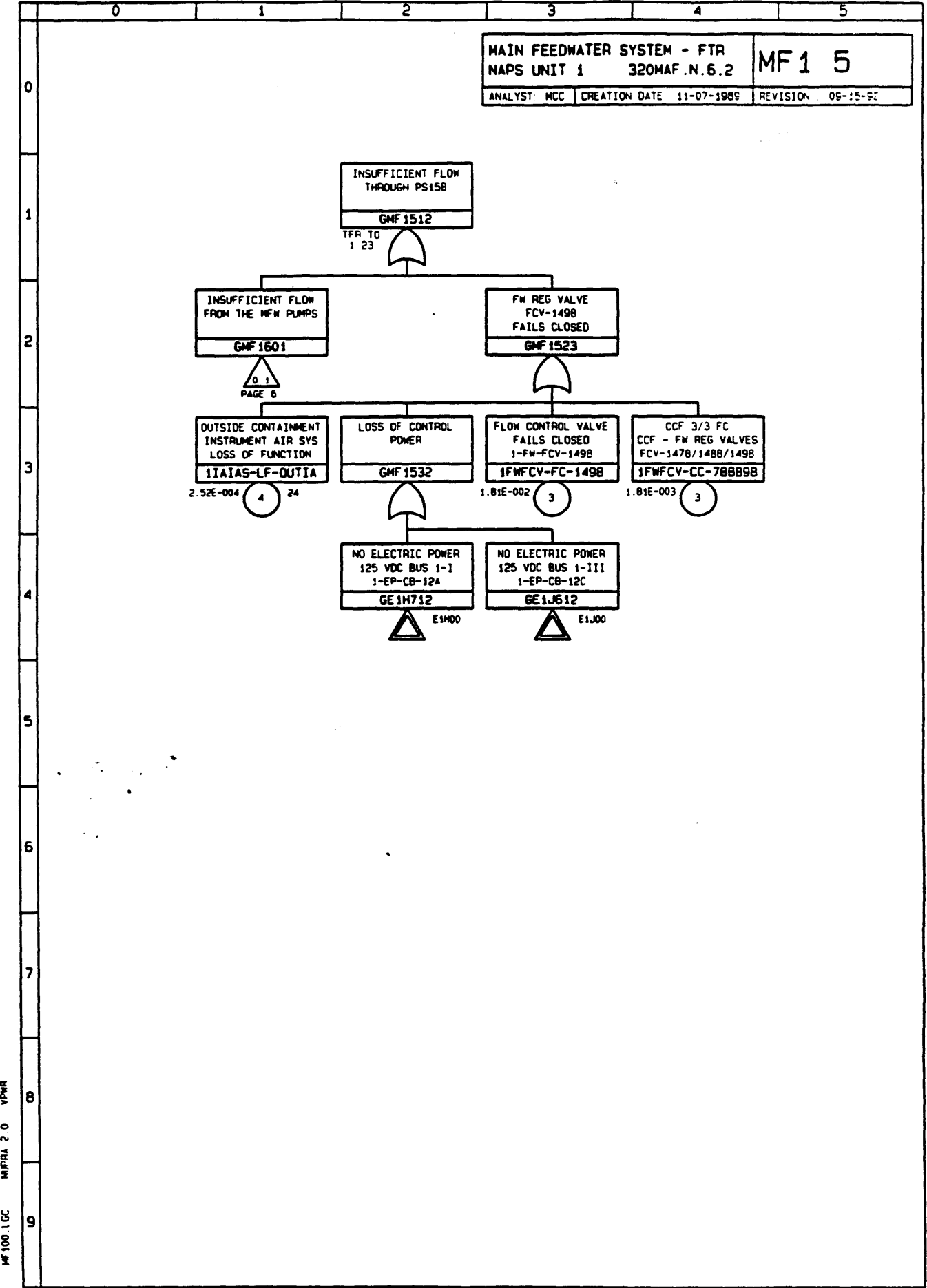
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NAPS 2 0  
VPMR



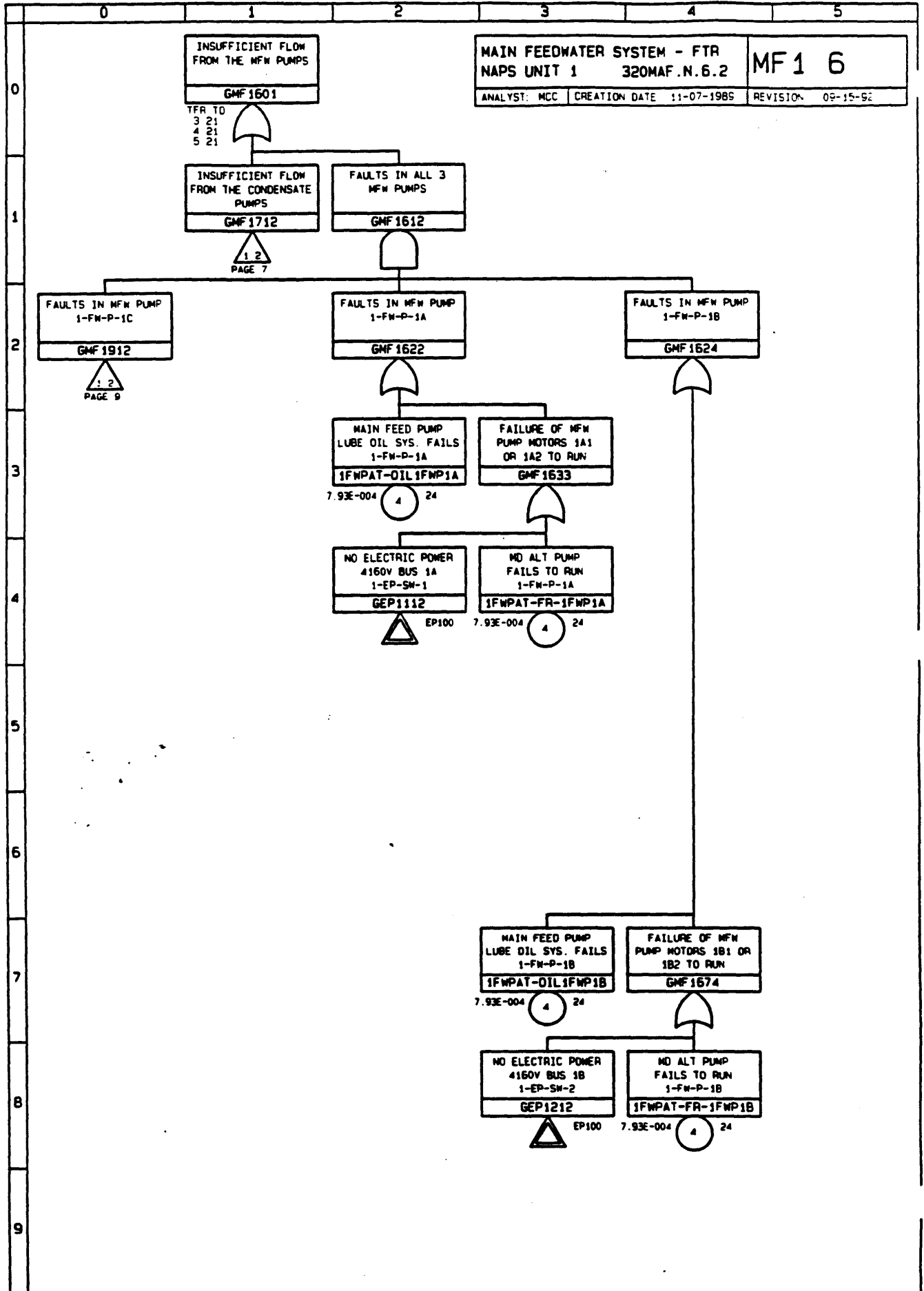
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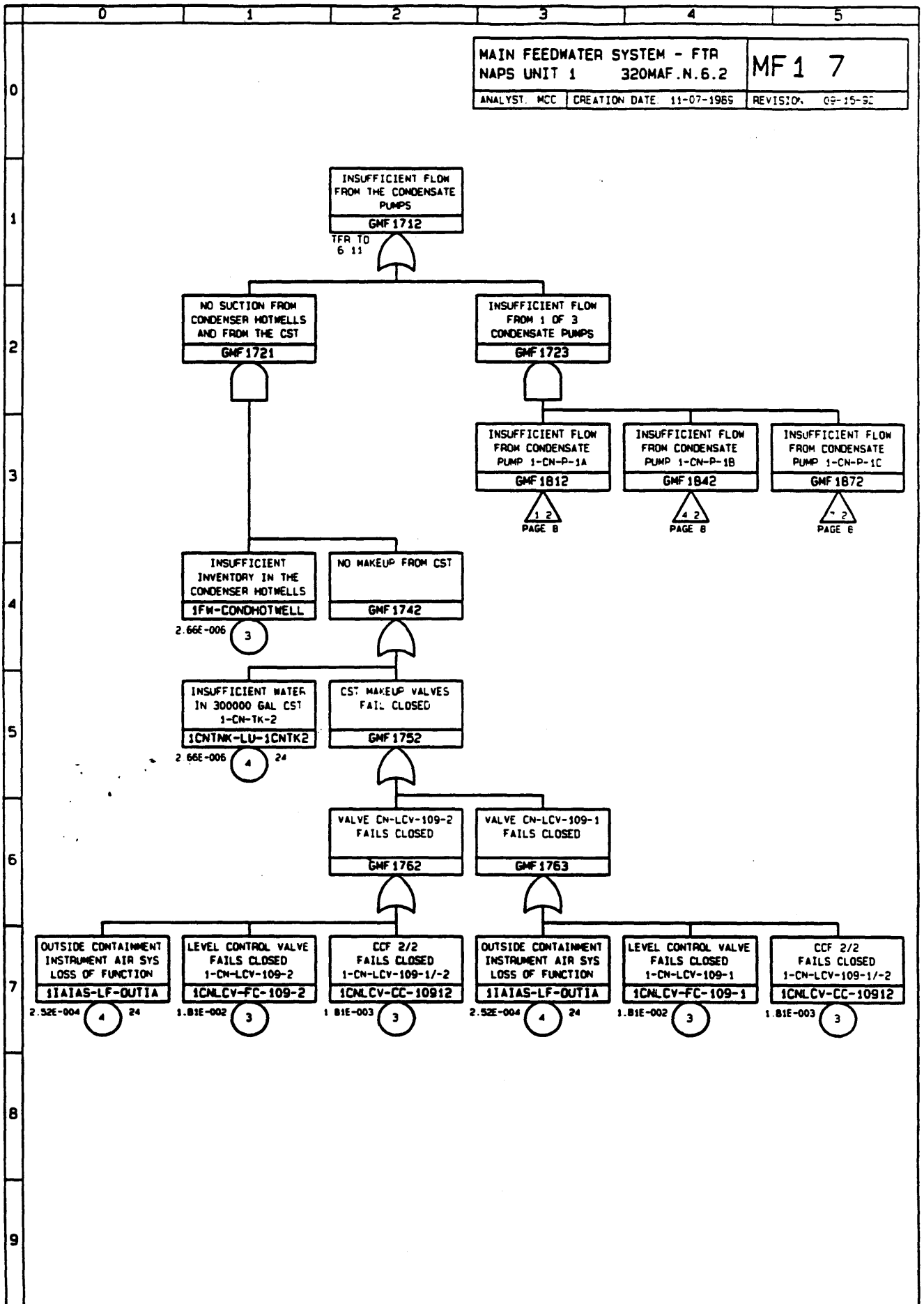
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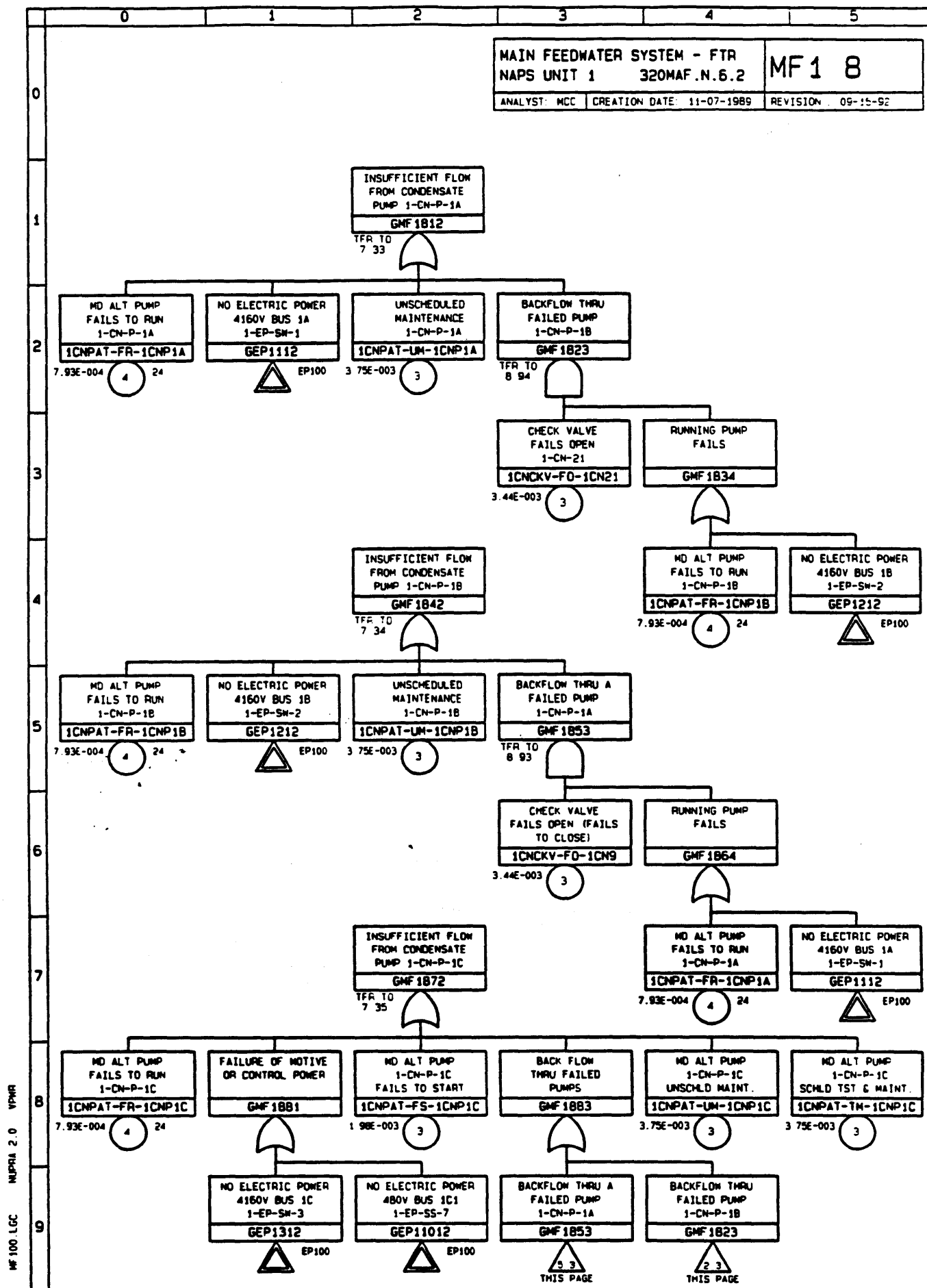


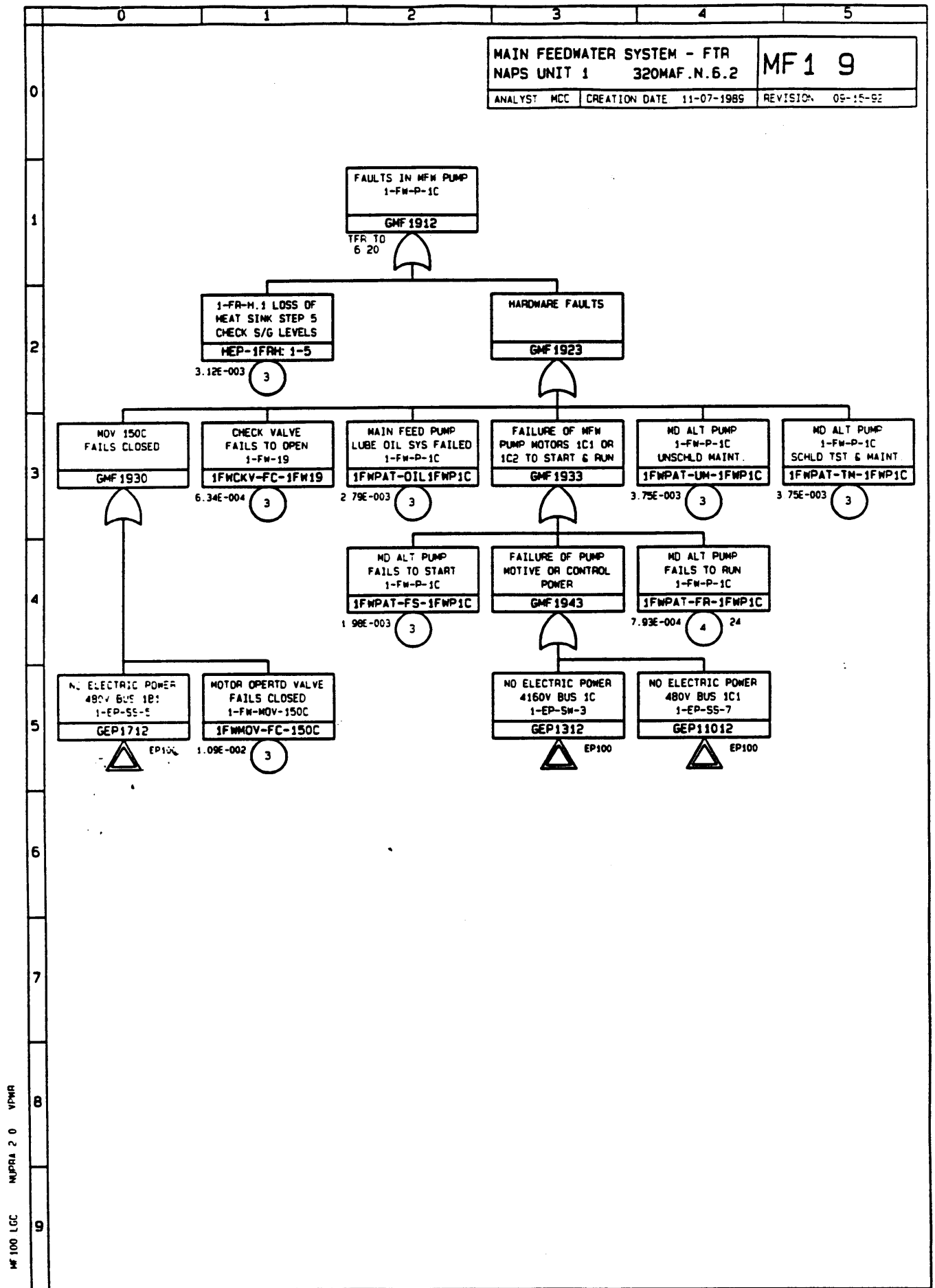
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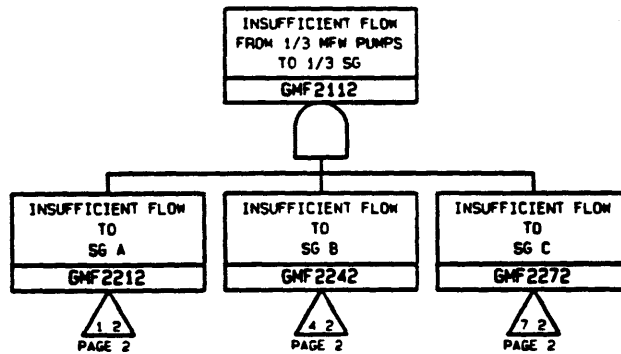


MF 200 LGC NAPS 2 0 VPMR

MAIN FEEDWATER SYSTEM -FTS&R  
NAPS UNIT 1 320MAF.N.6.2

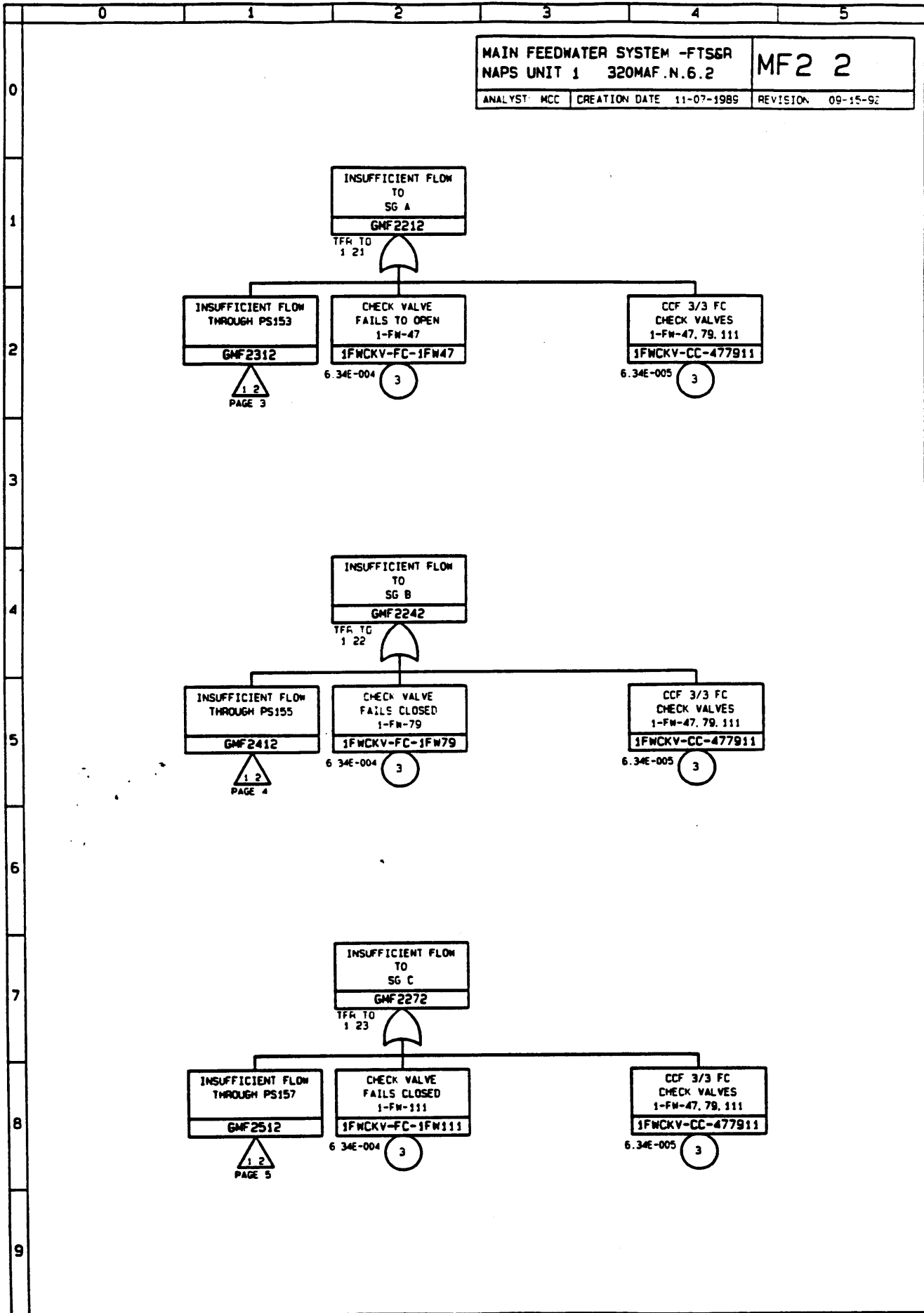
MF2 1

ANALYST: MCC CREATION DATE: 11-07-1989 REVISION: 09-15-92

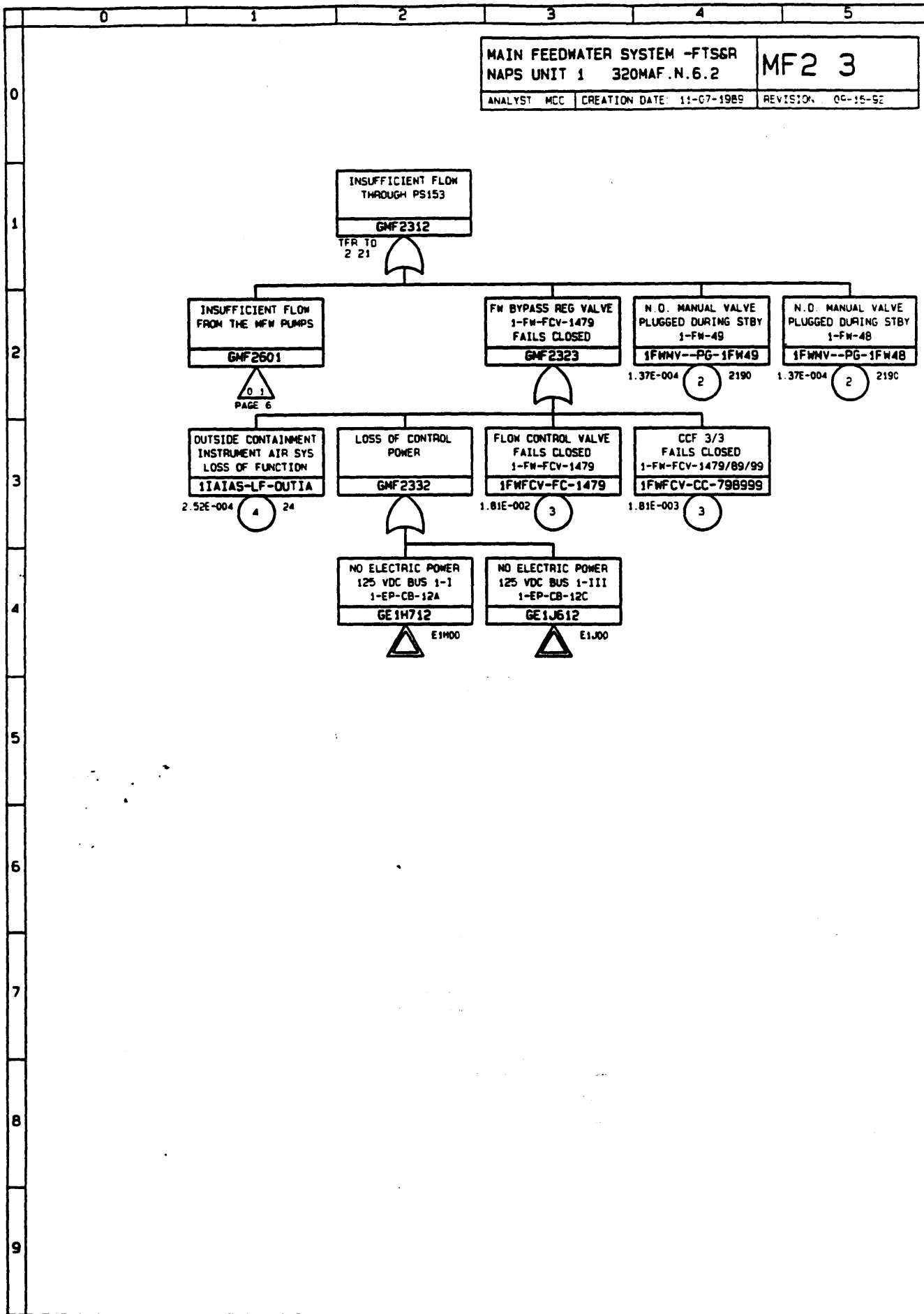




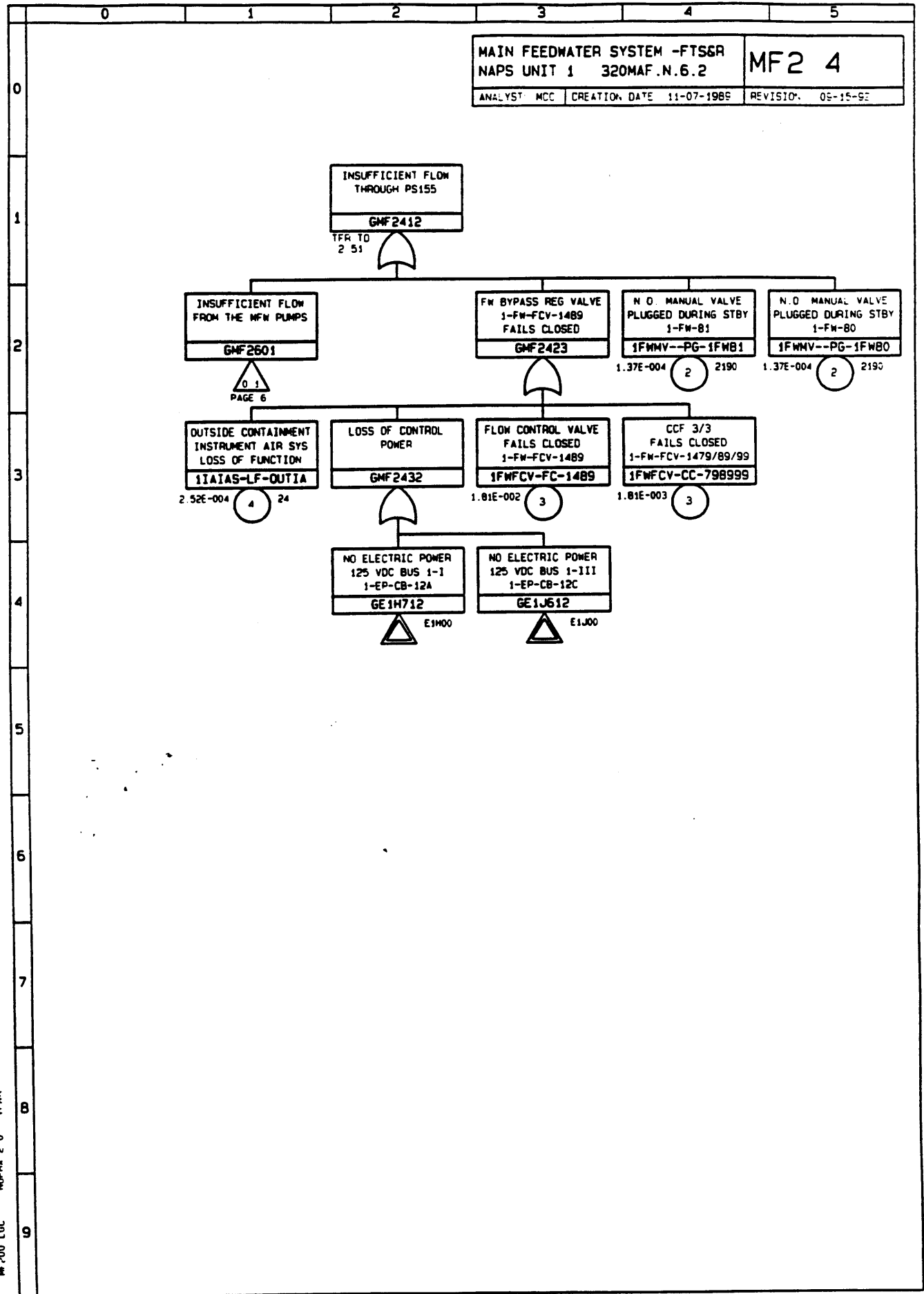
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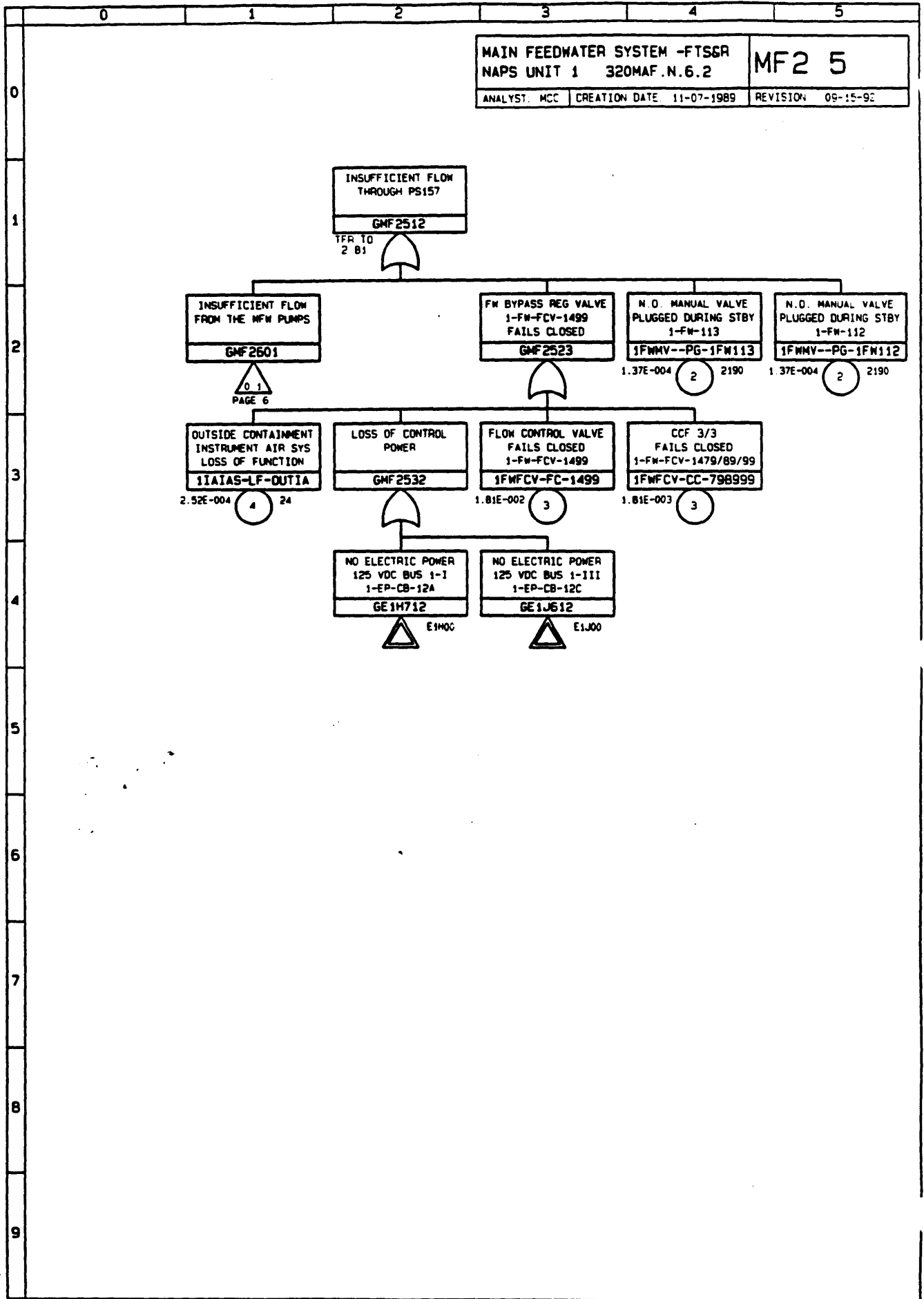
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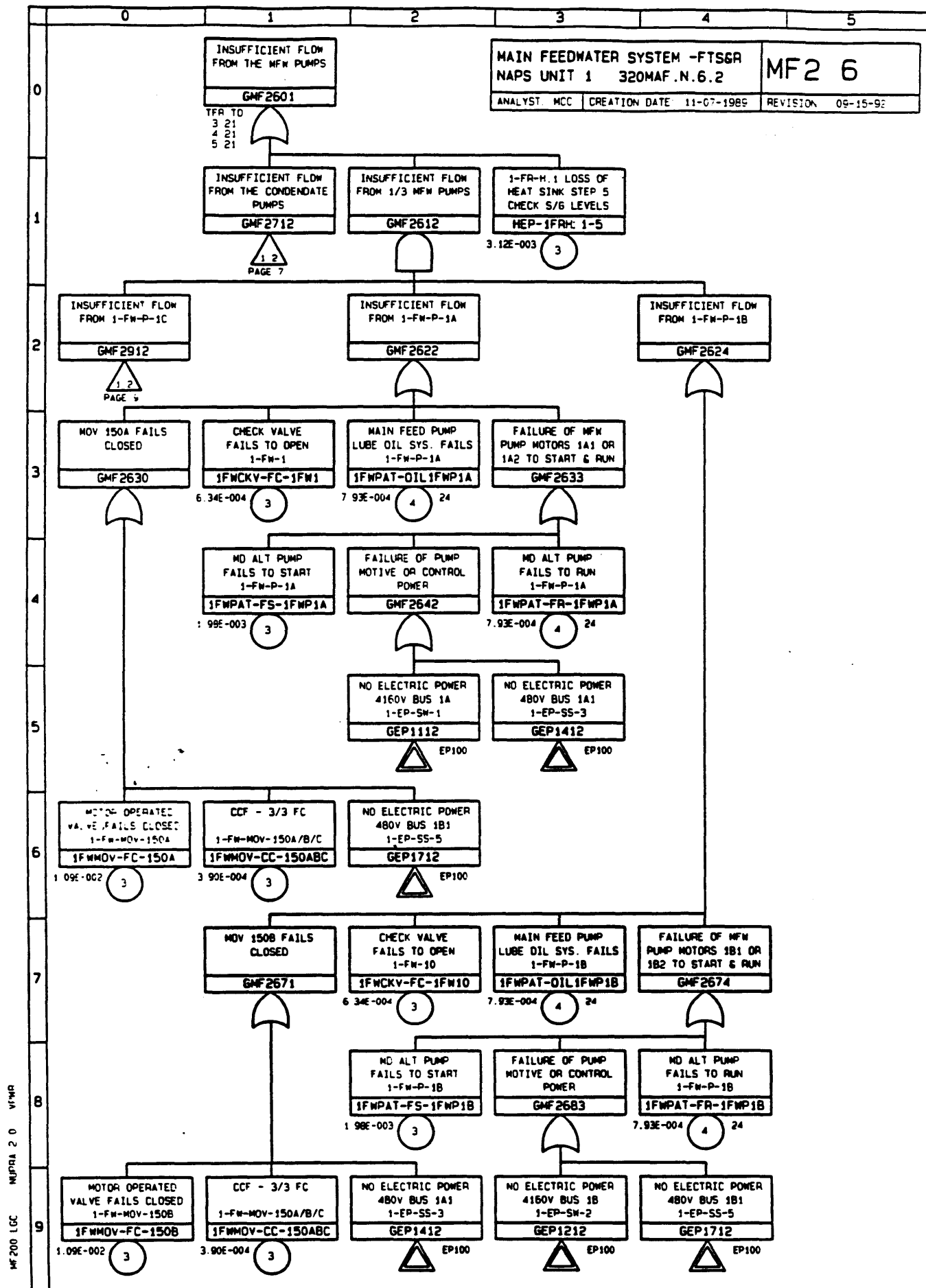


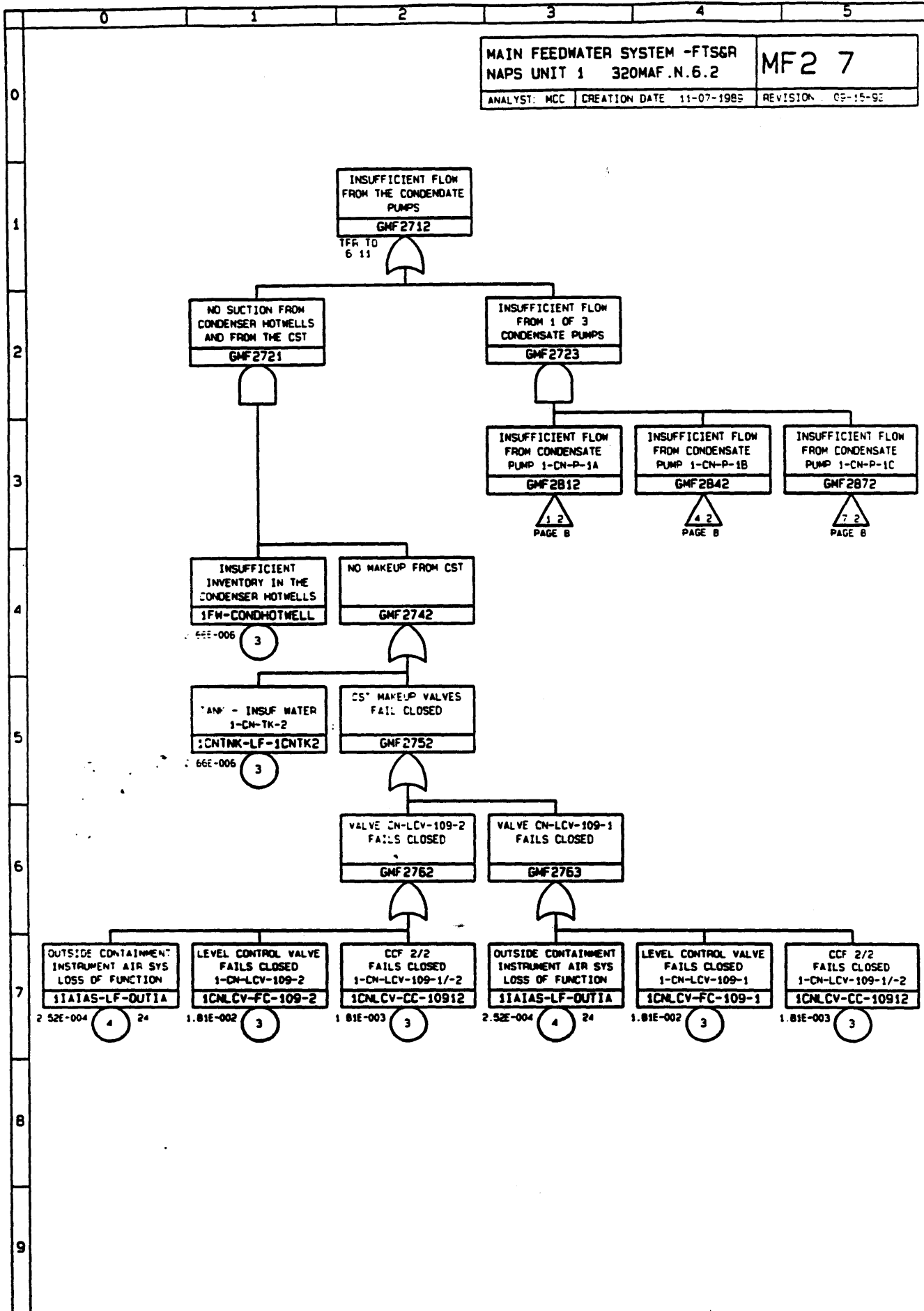
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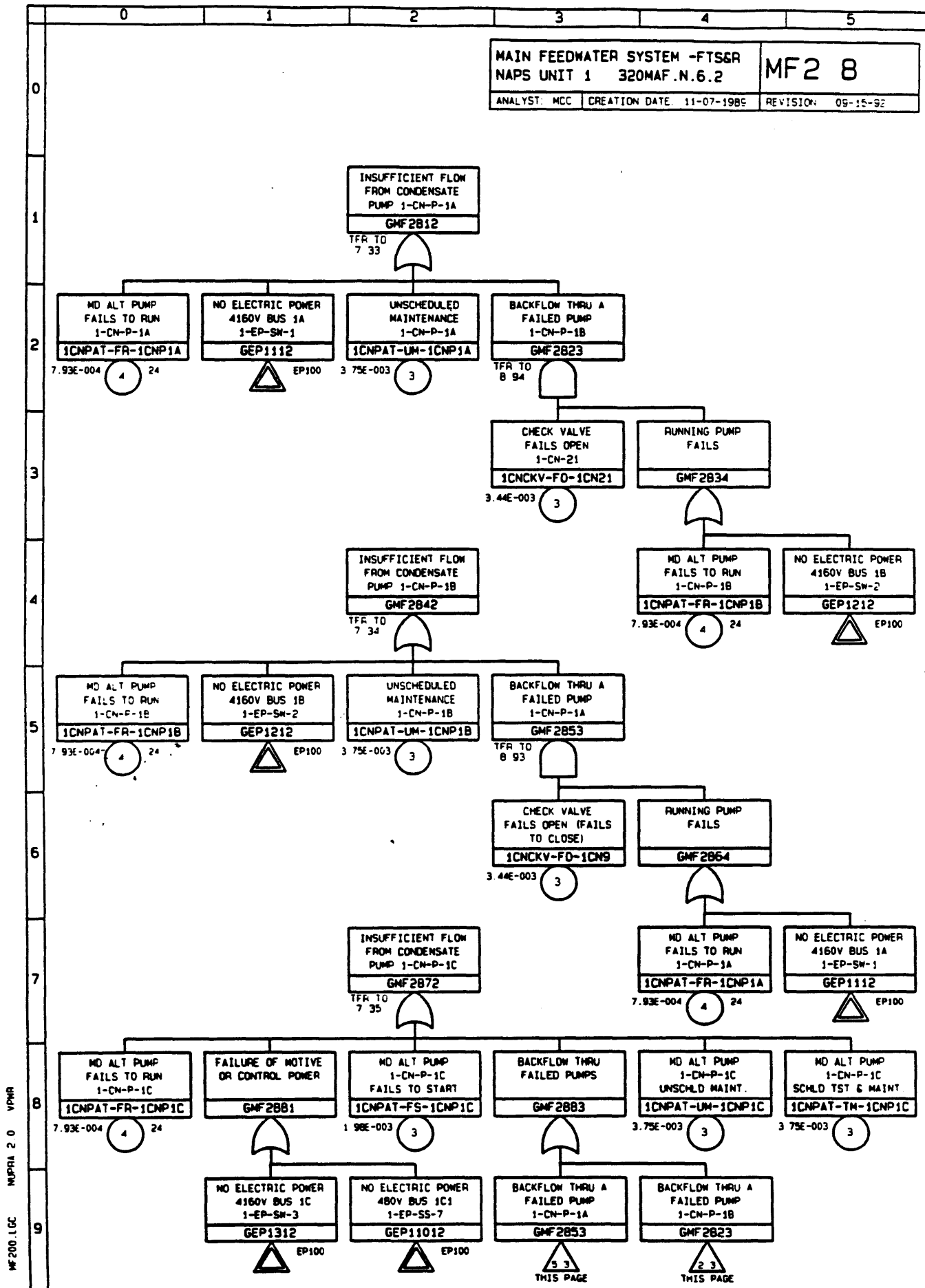


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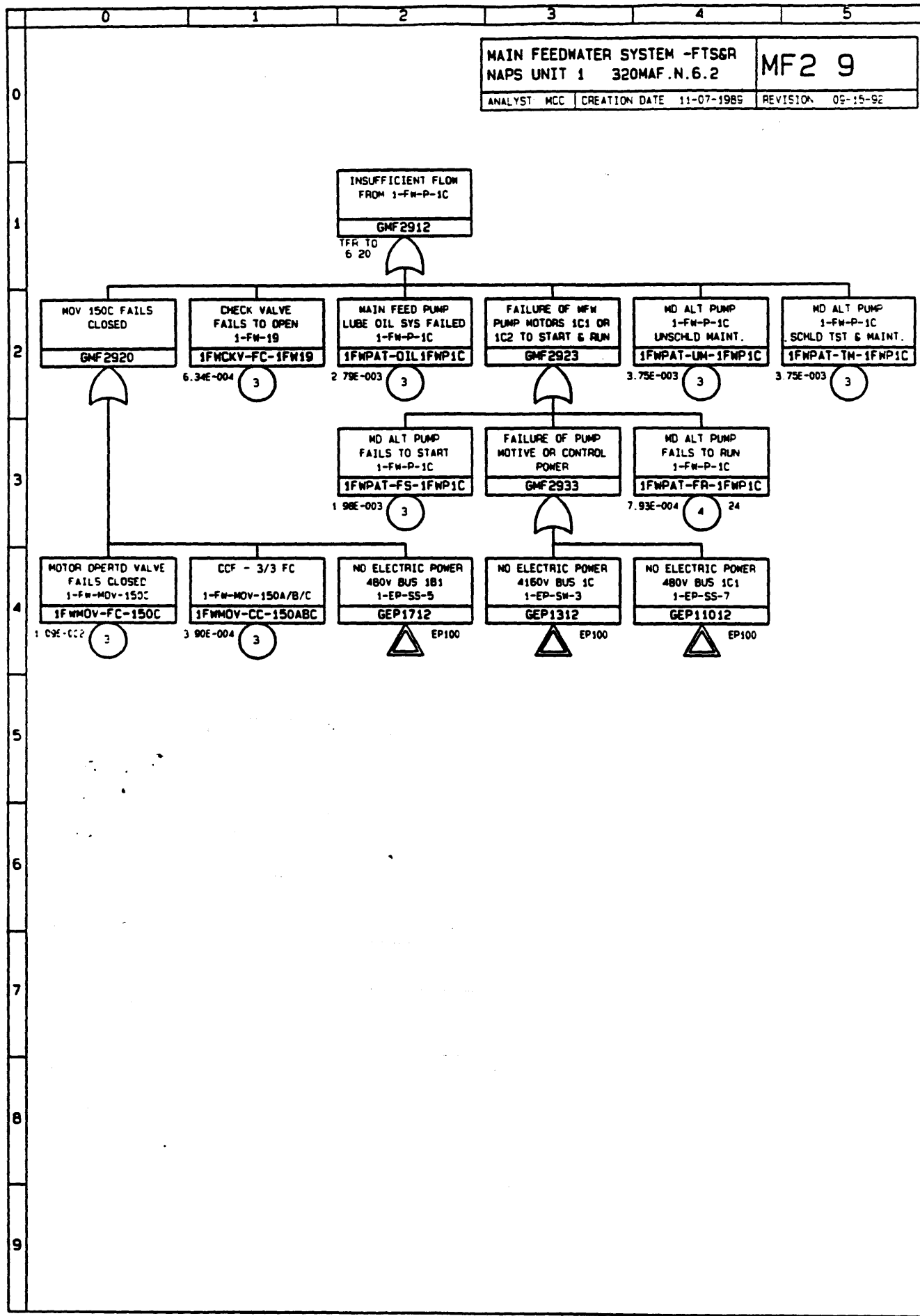






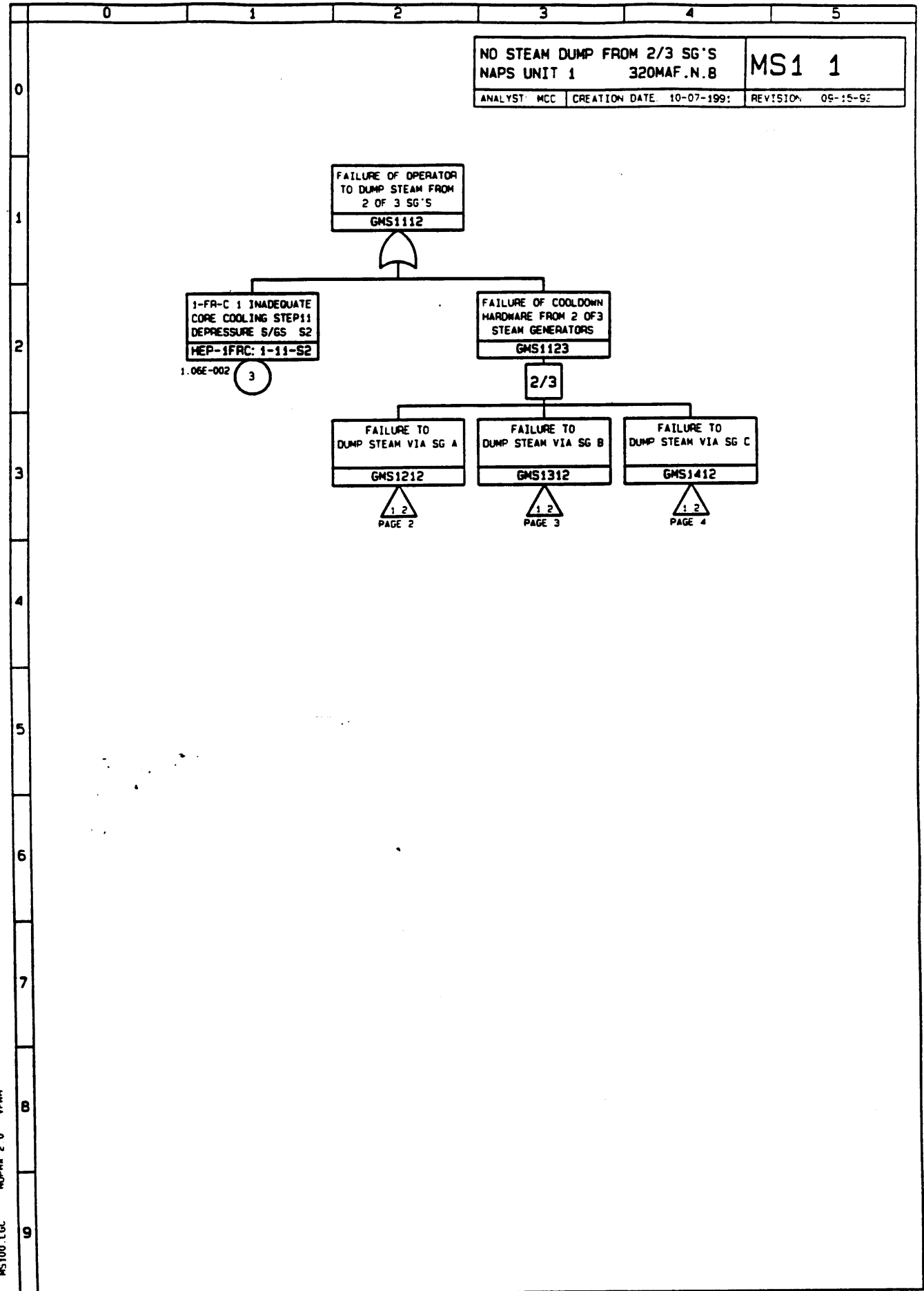


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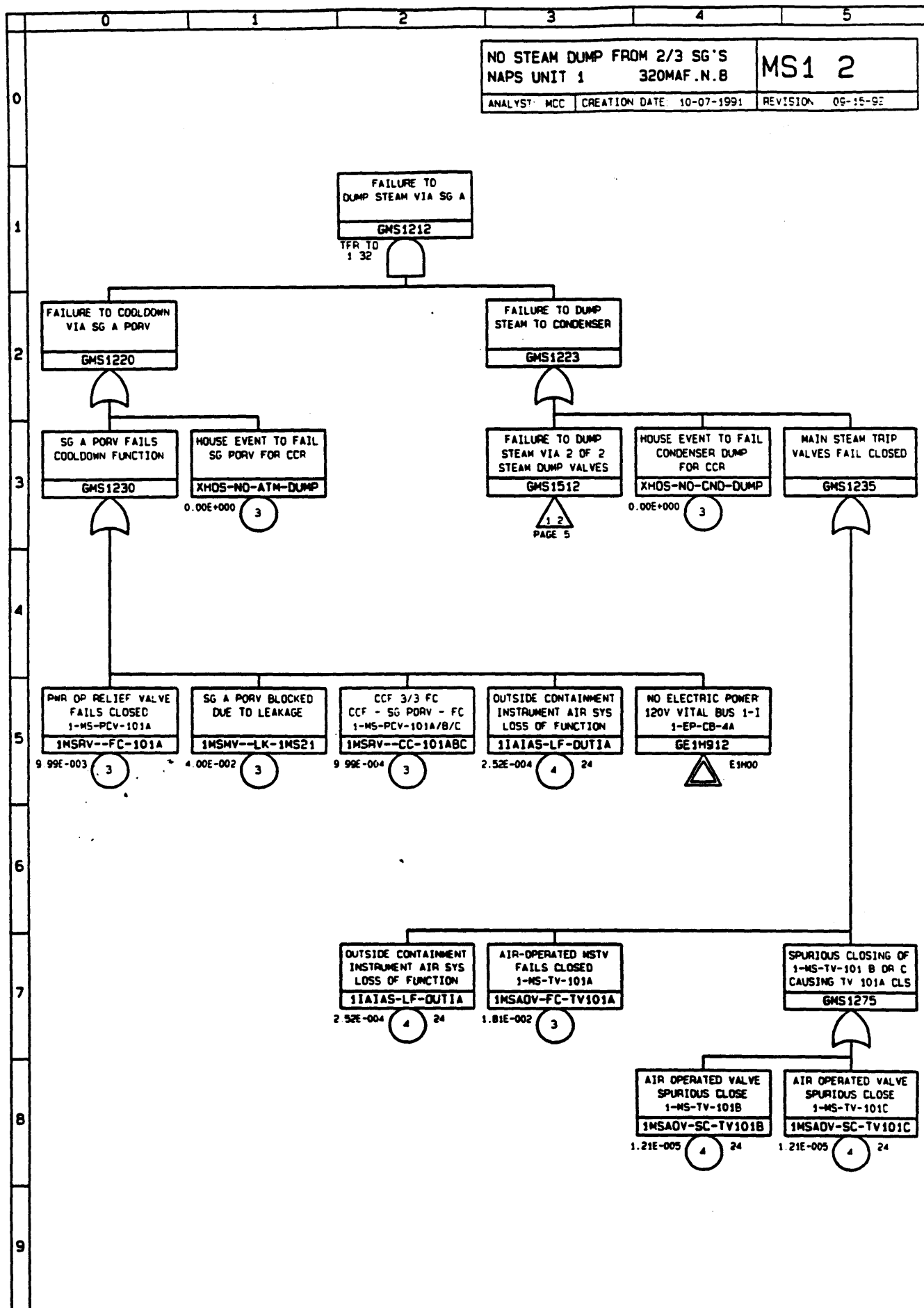




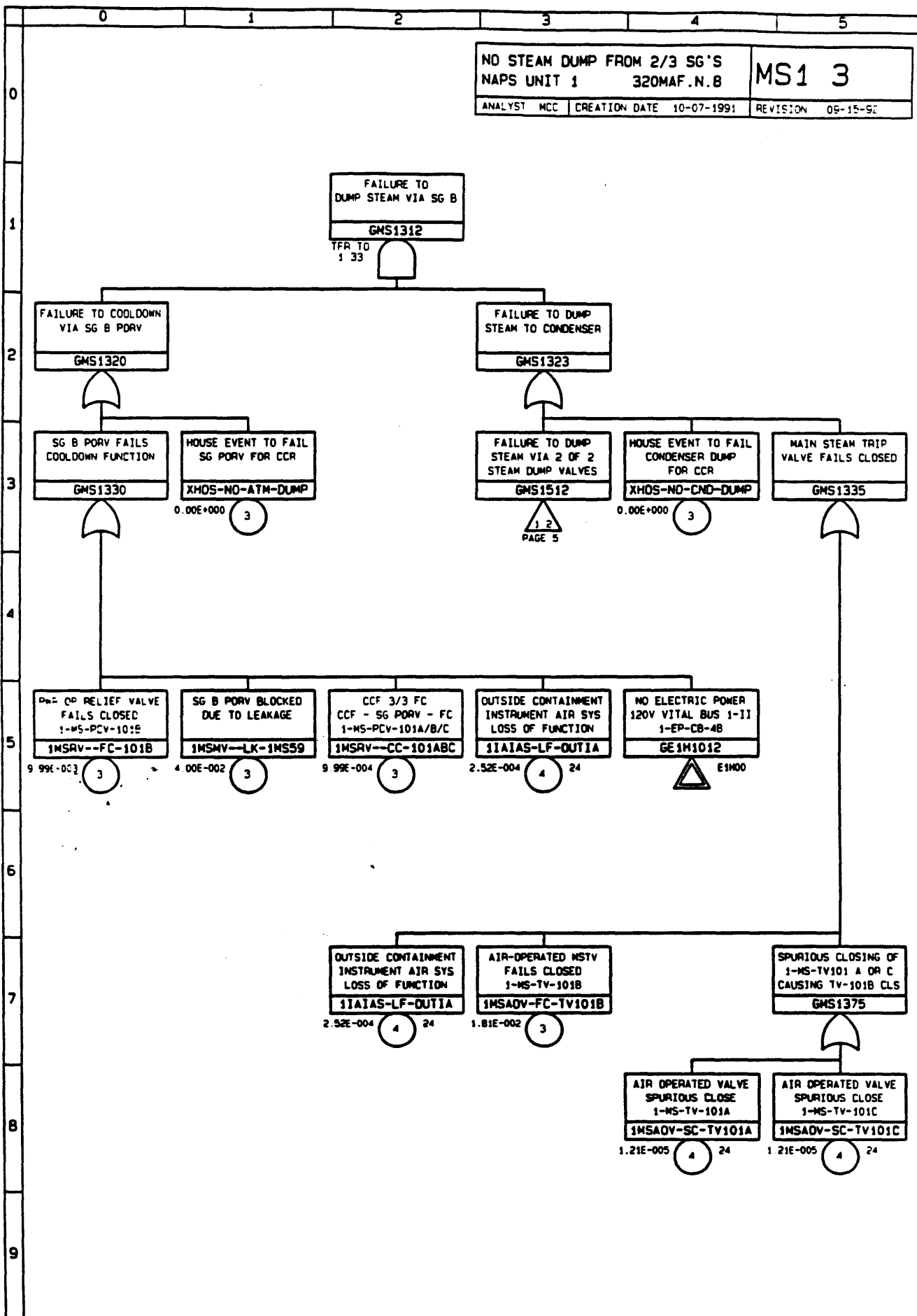
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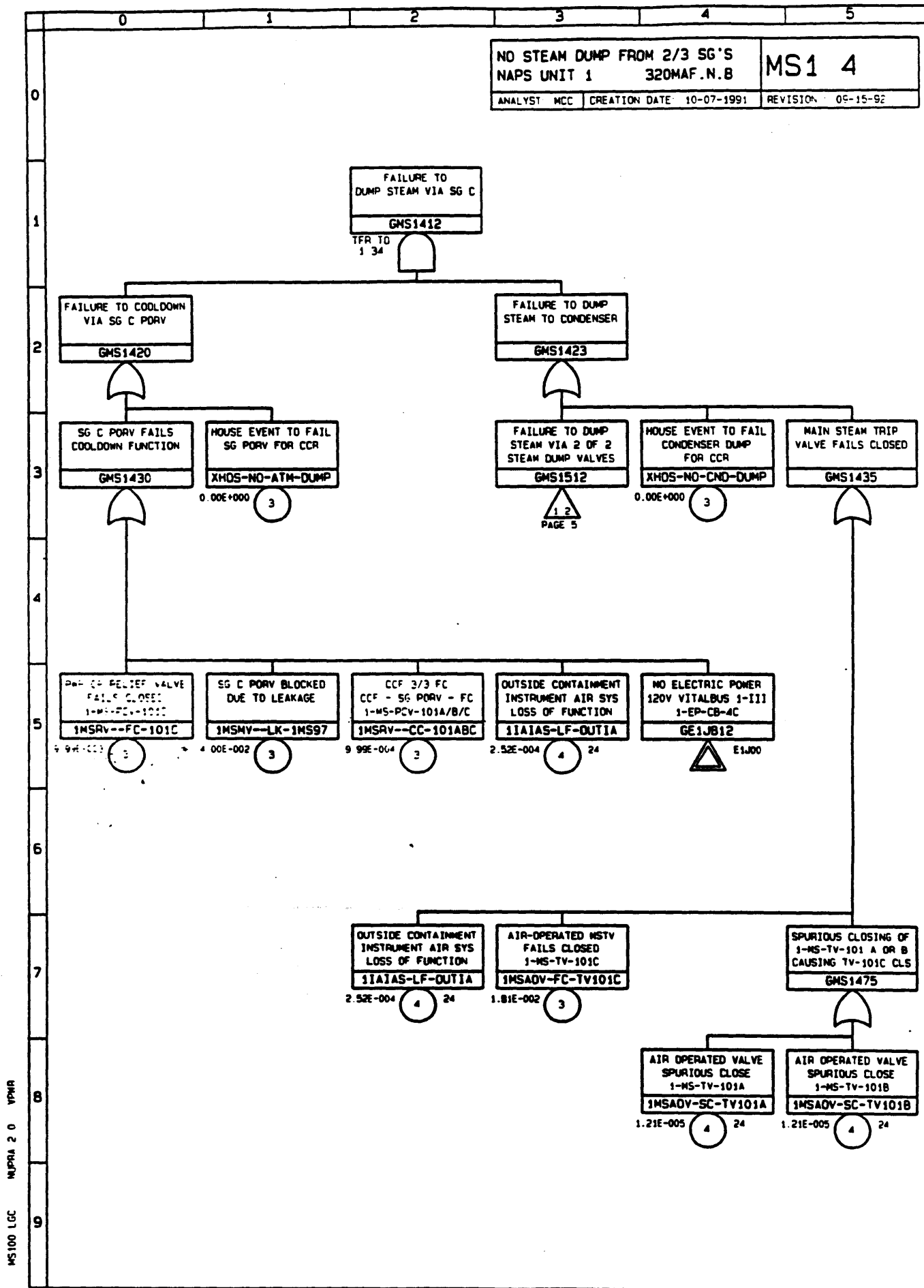


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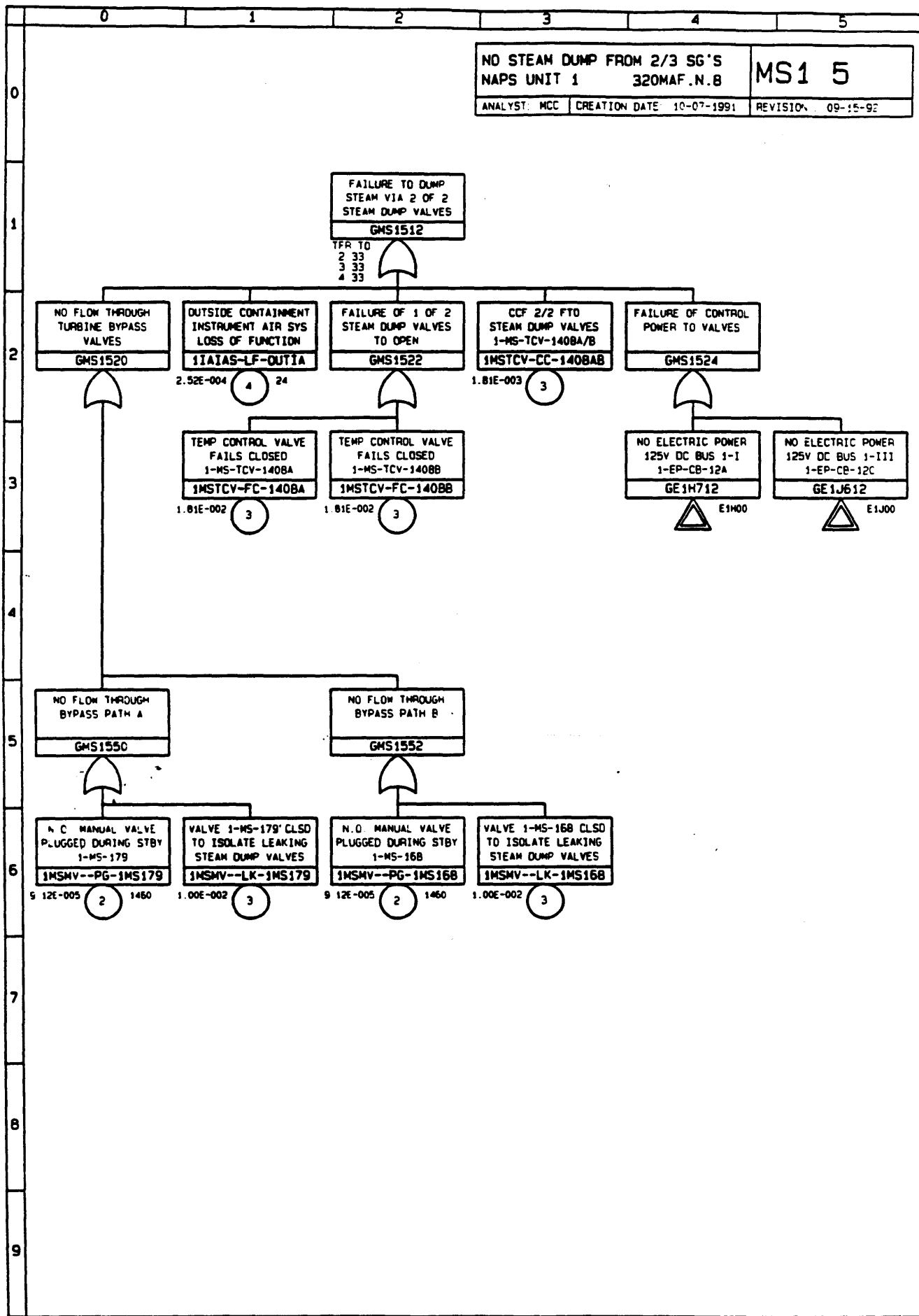
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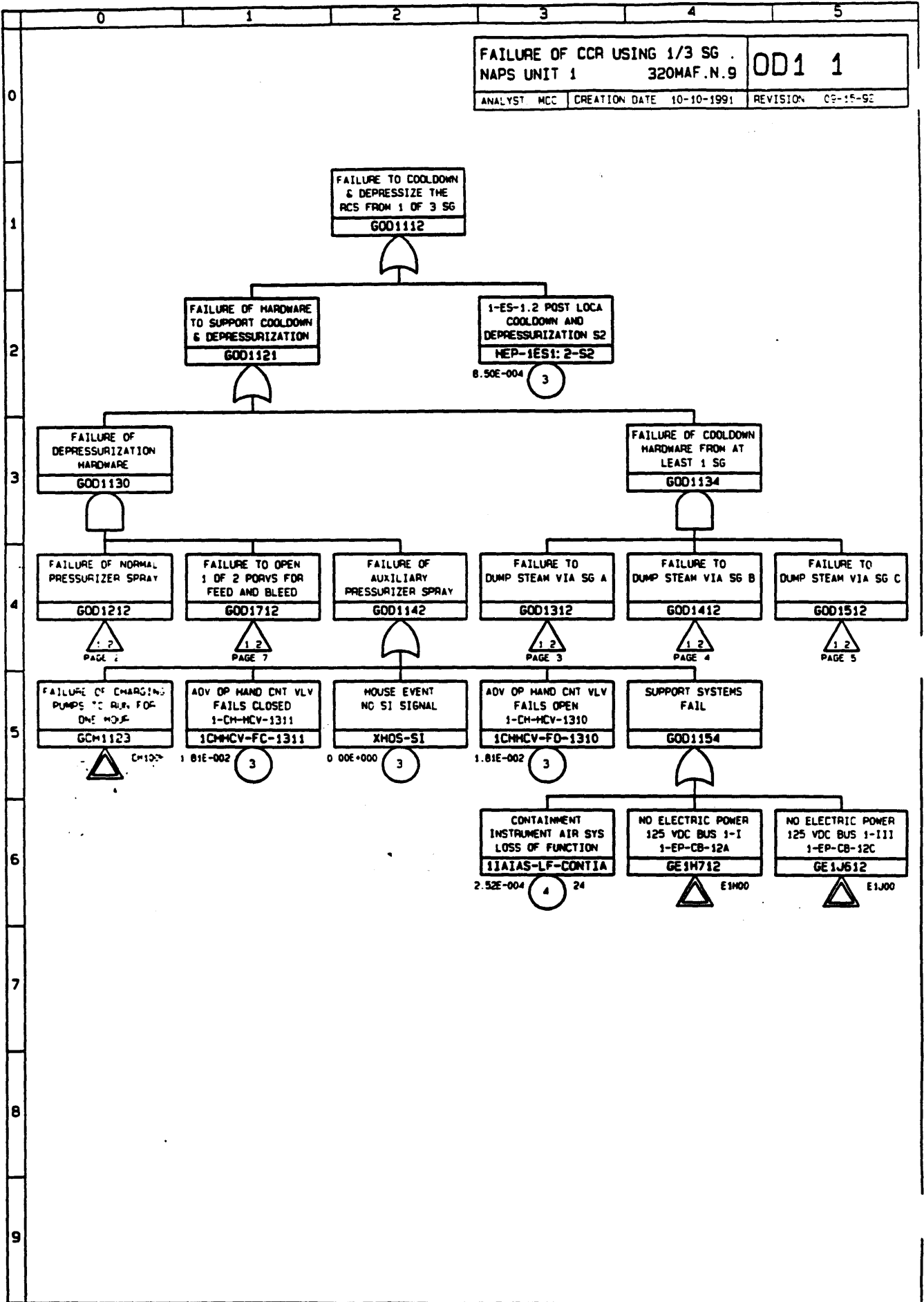


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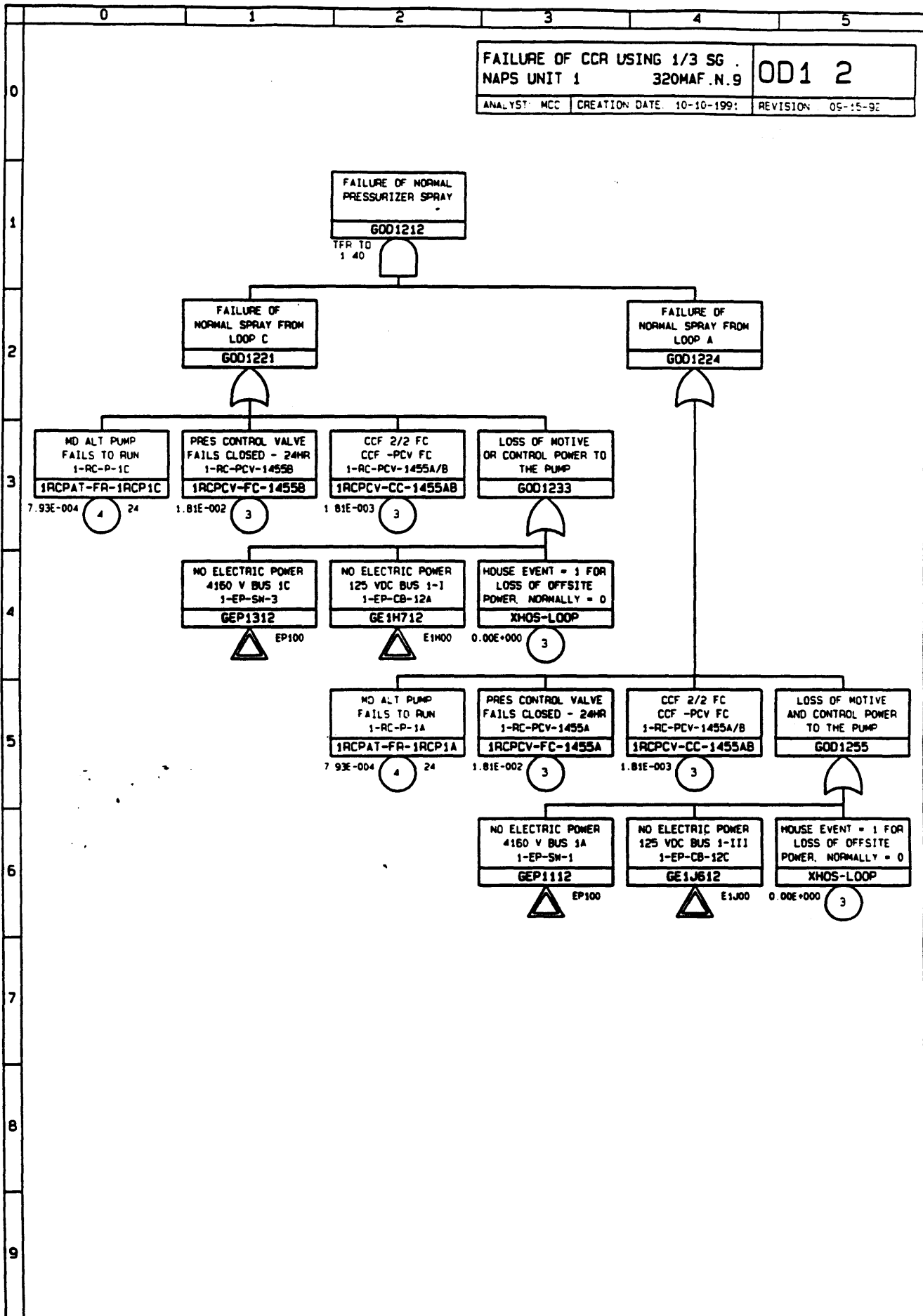
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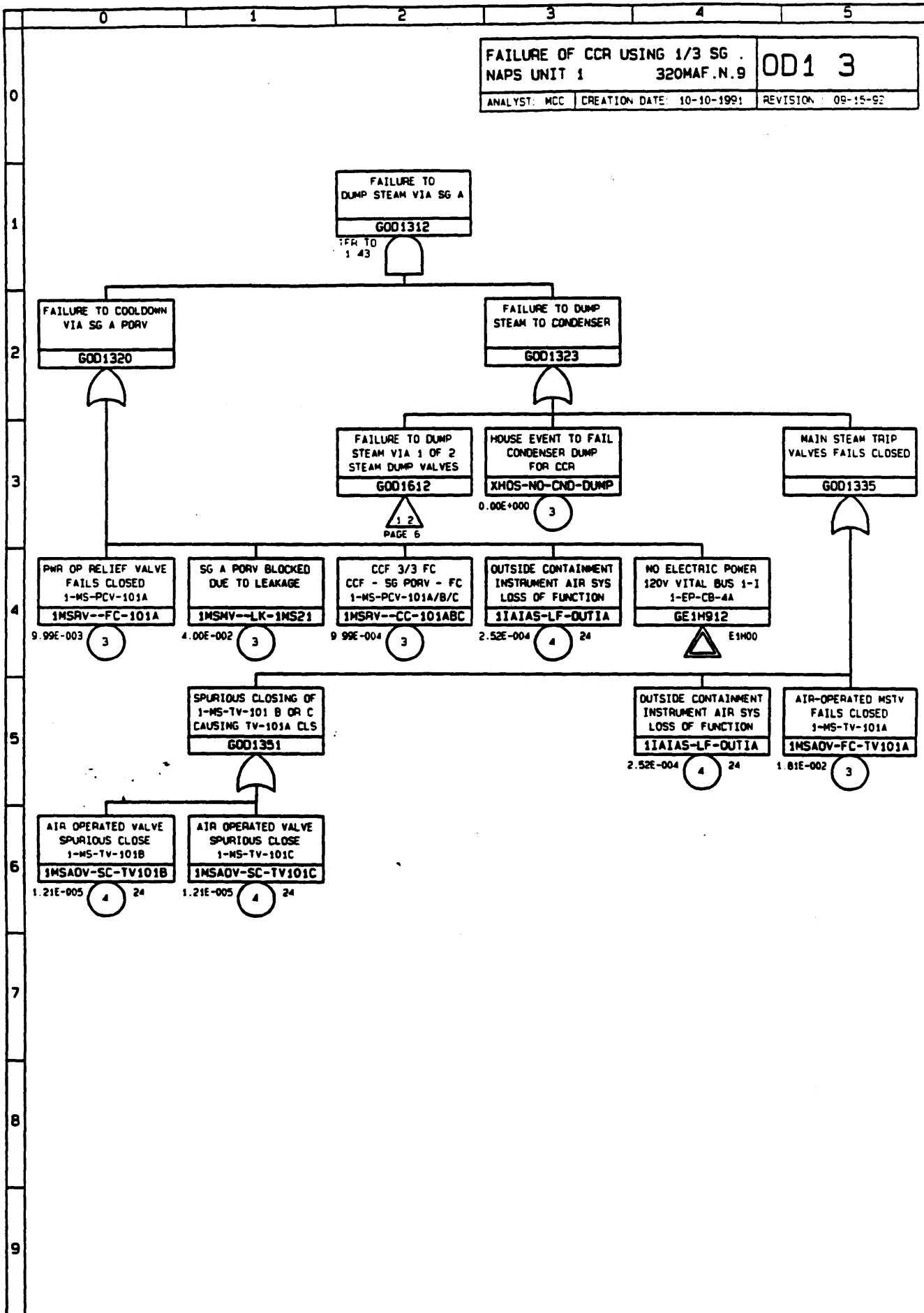
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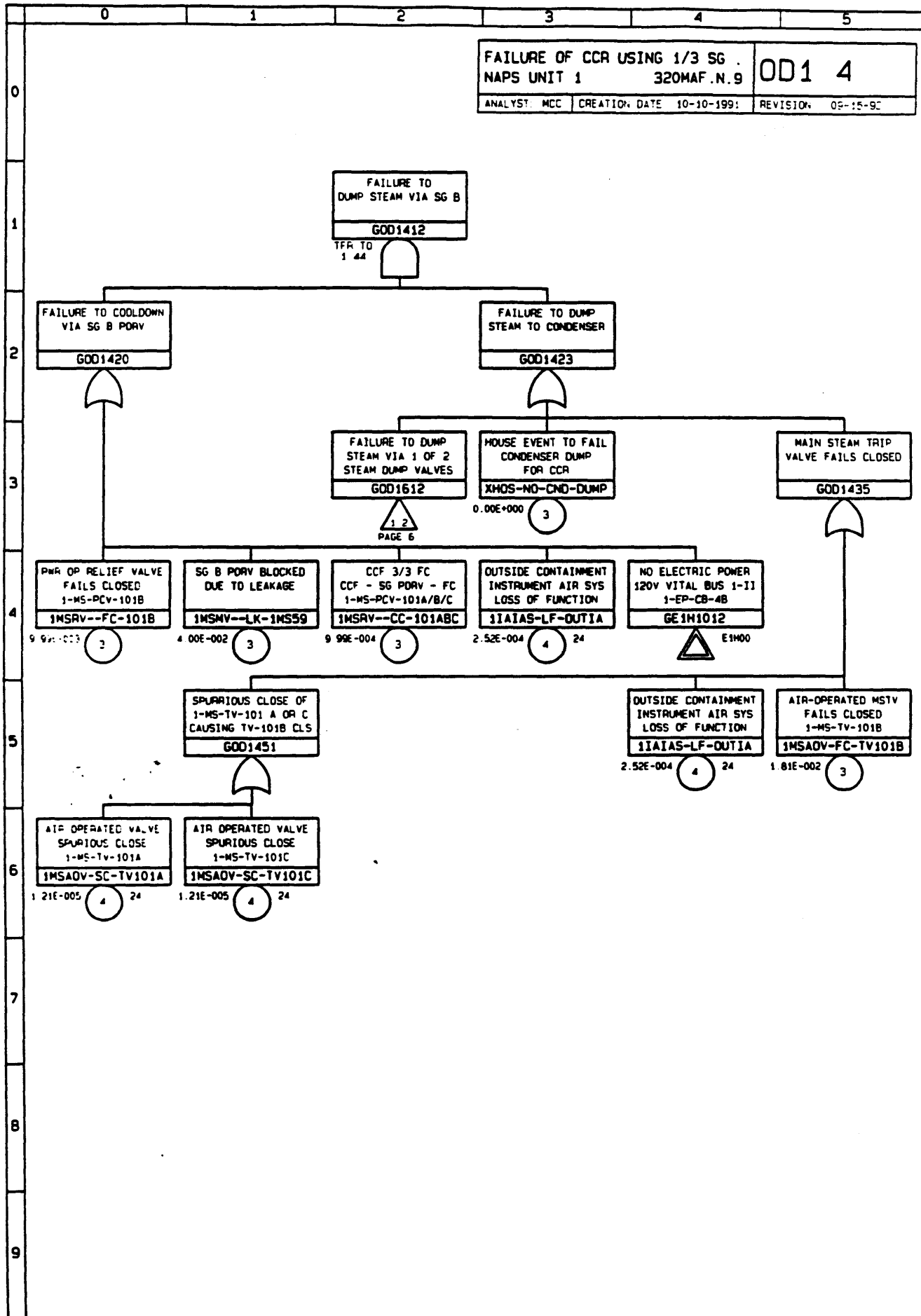


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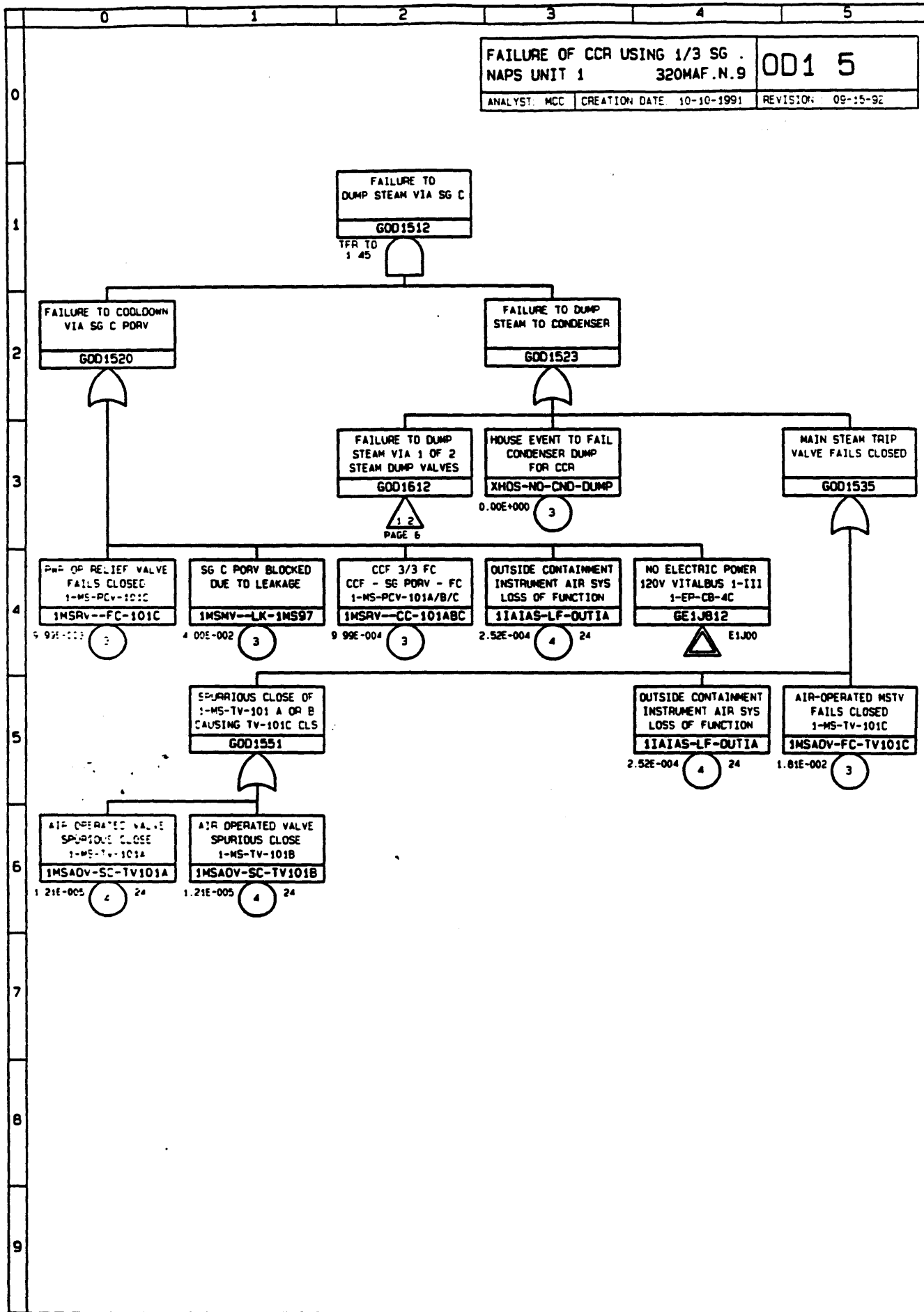




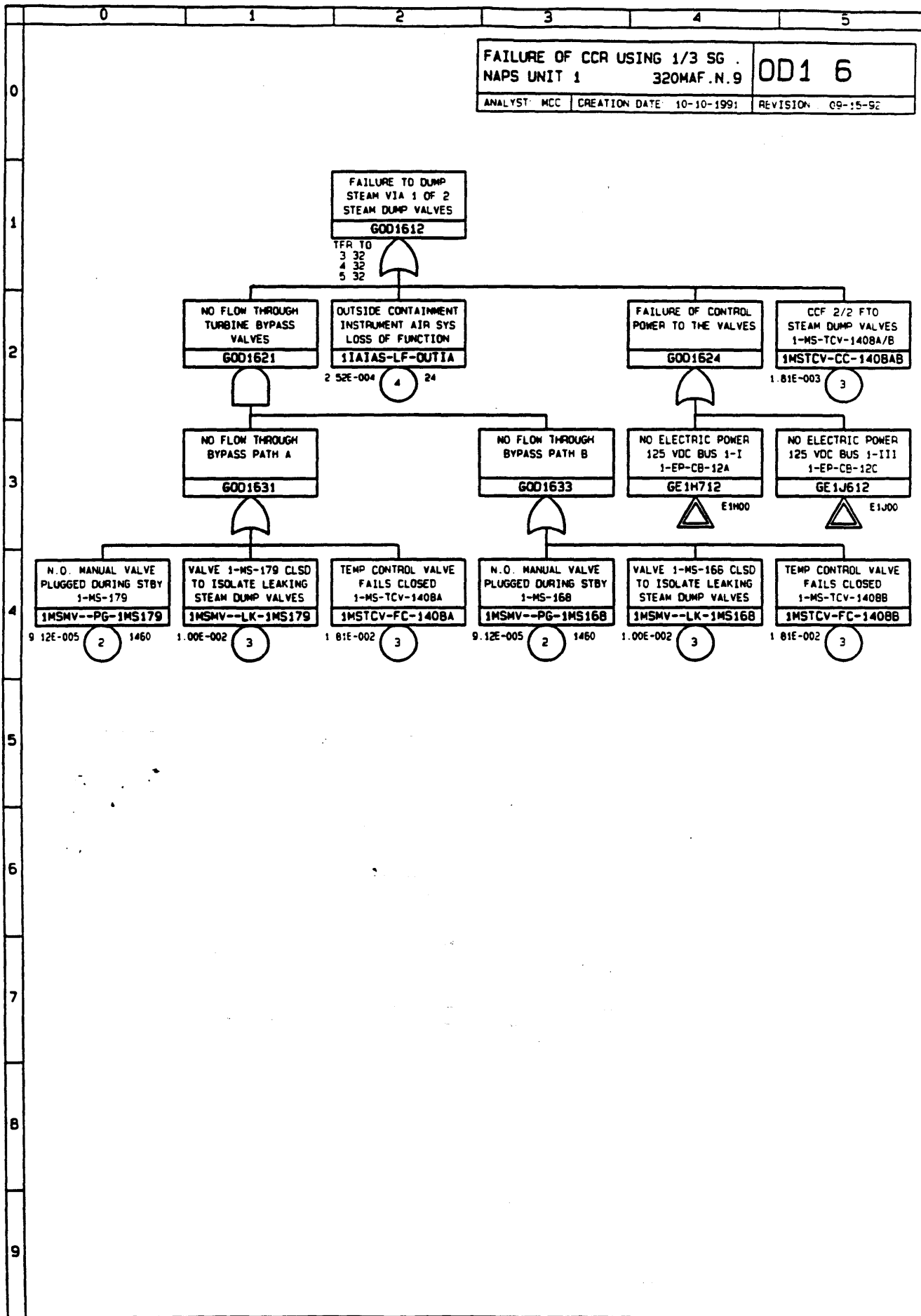
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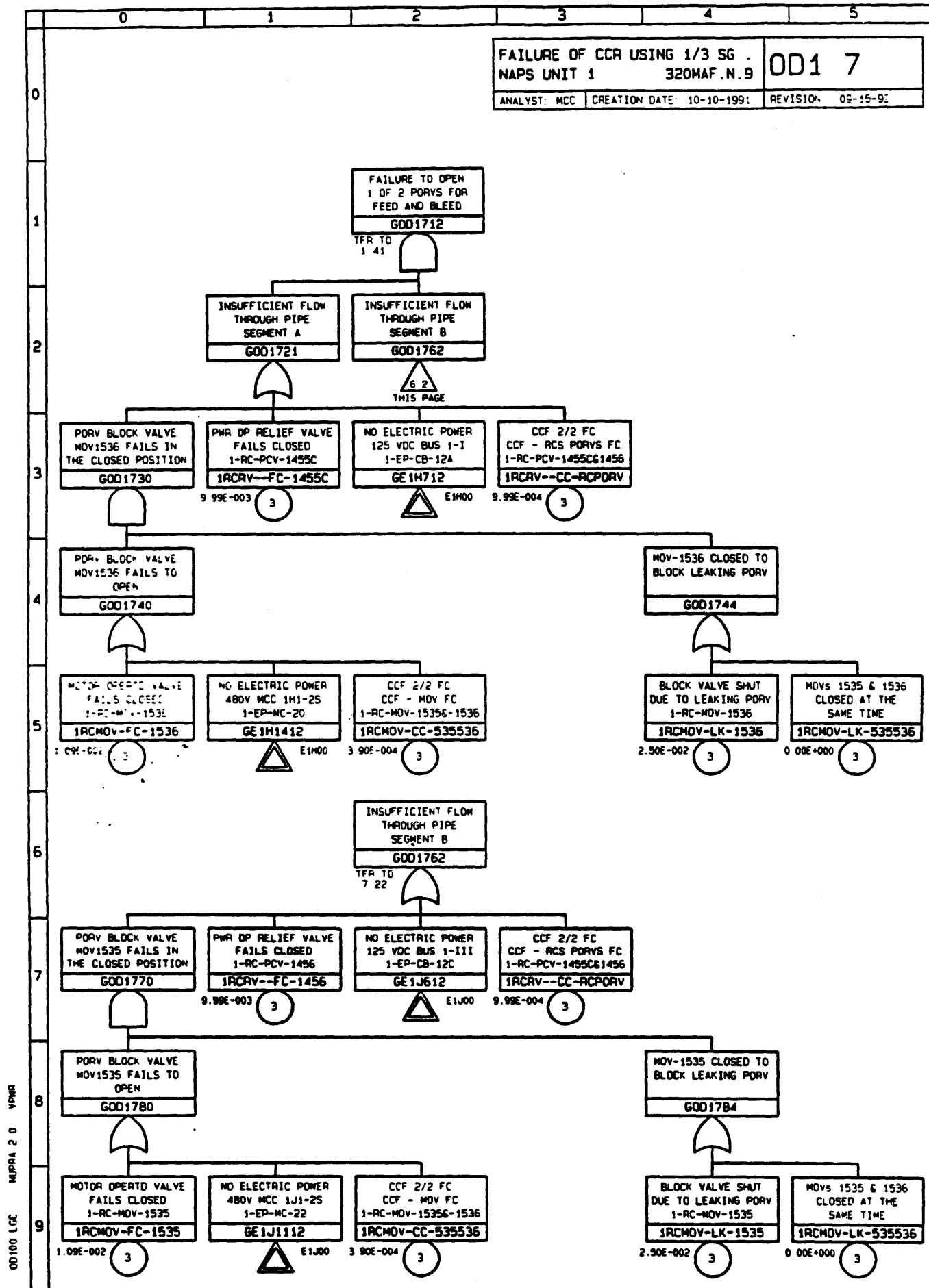


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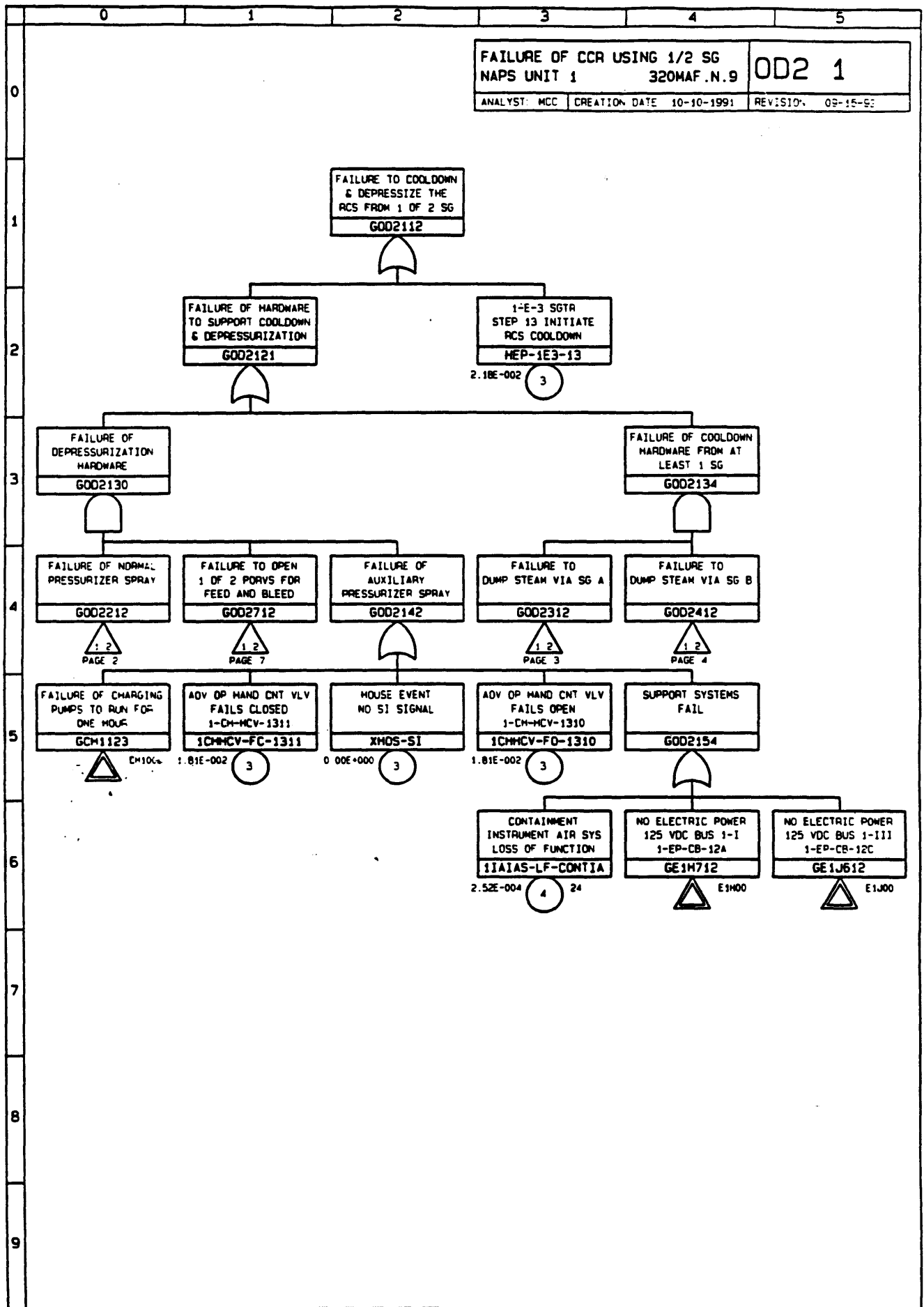


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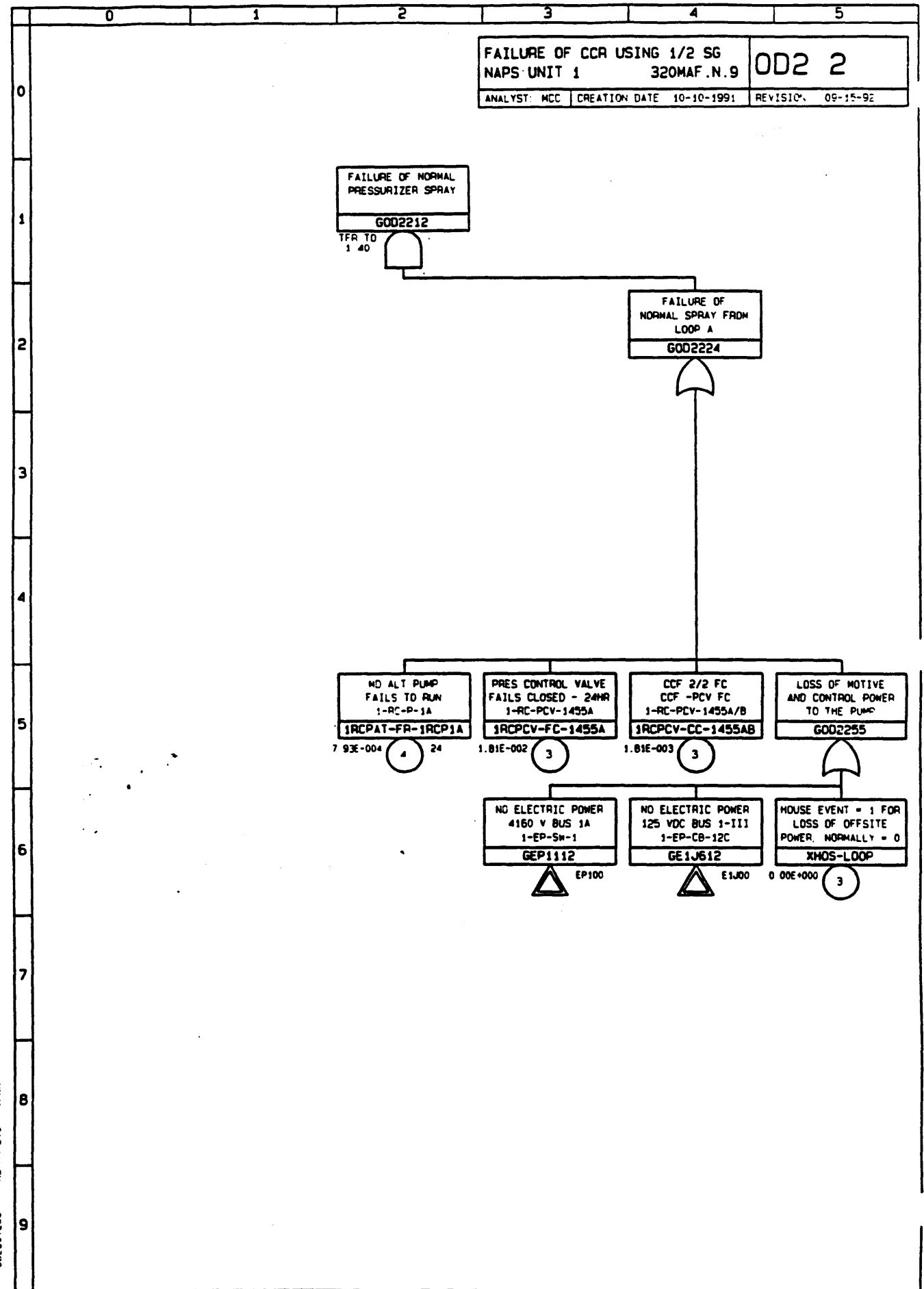


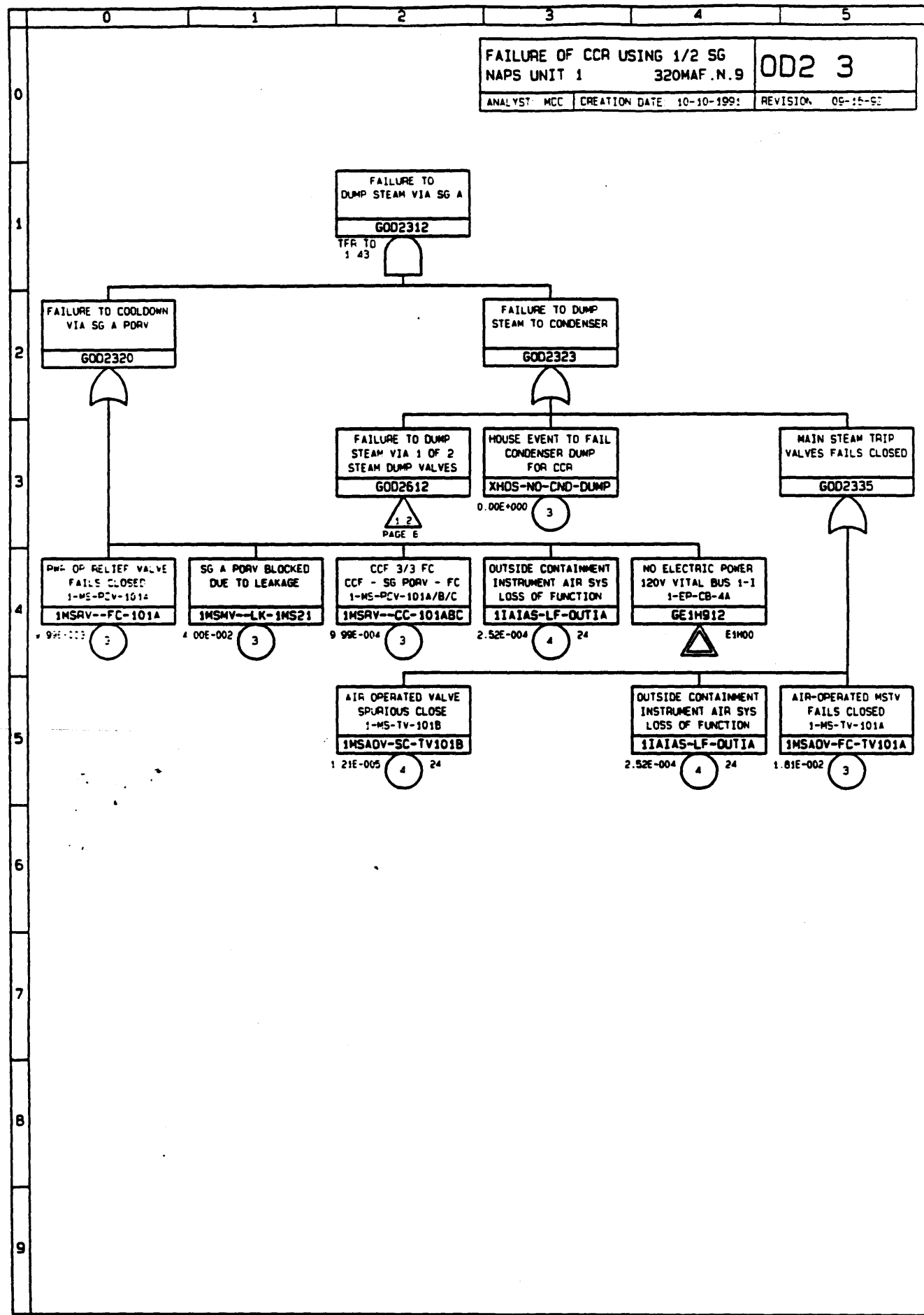


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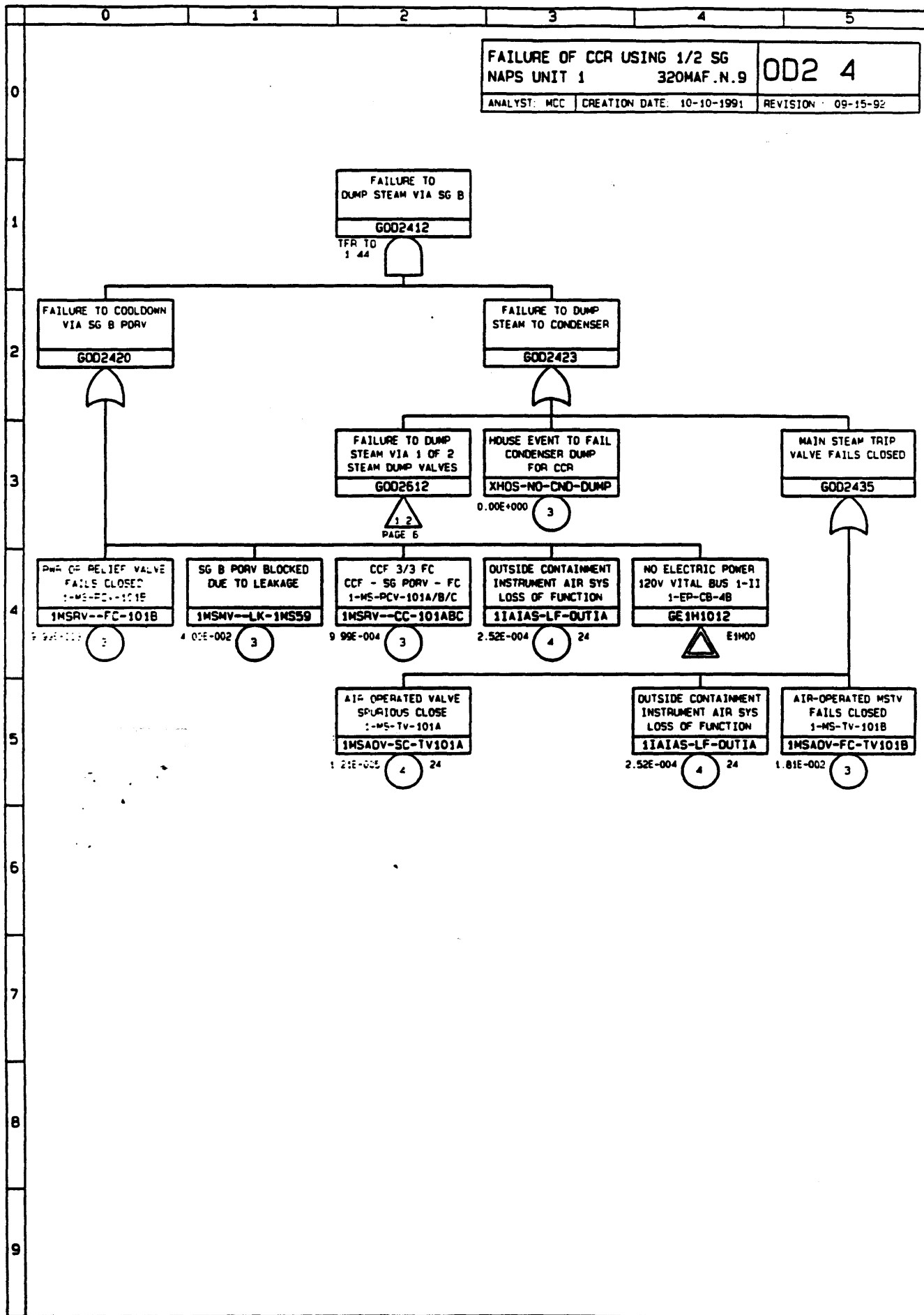
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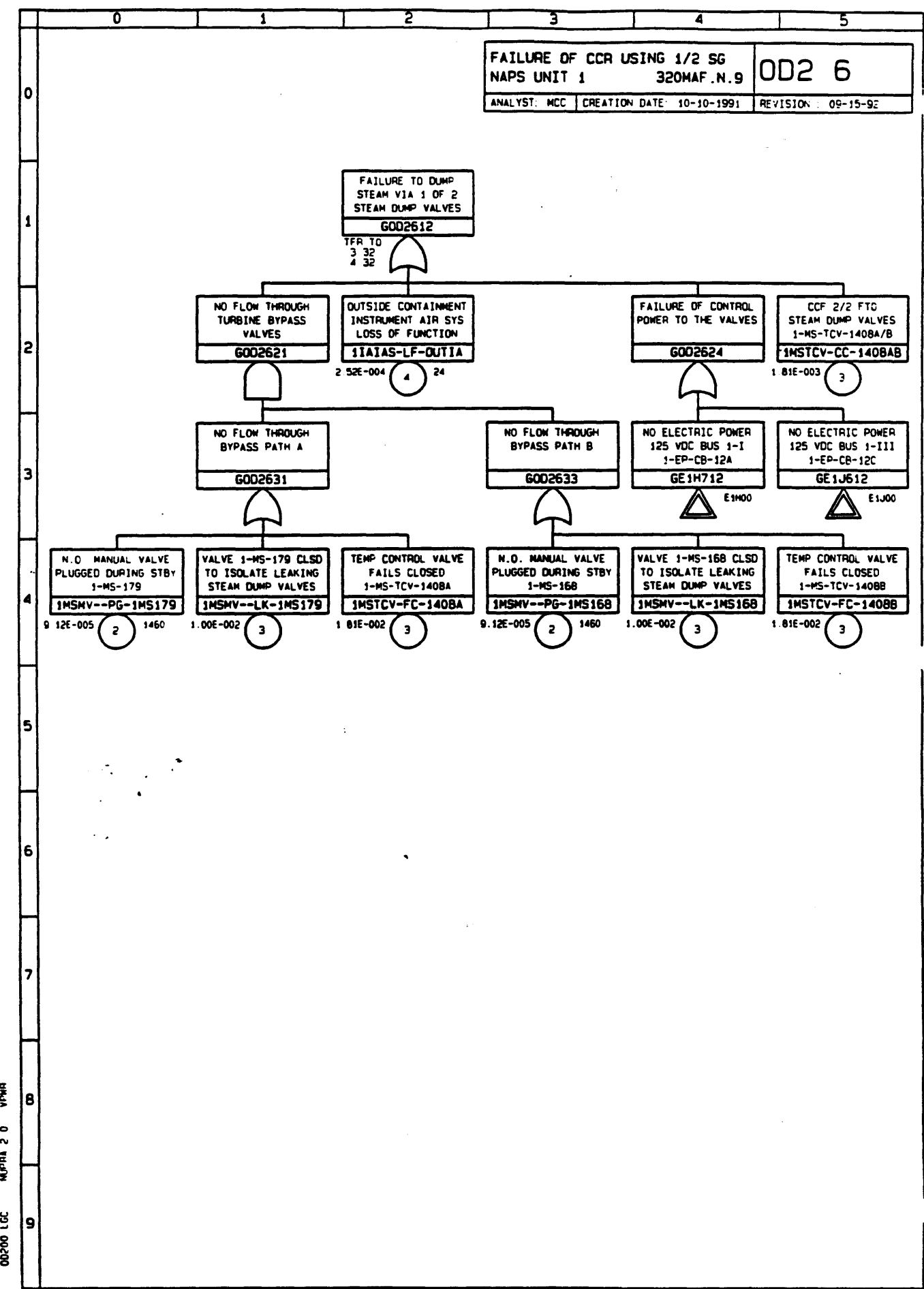


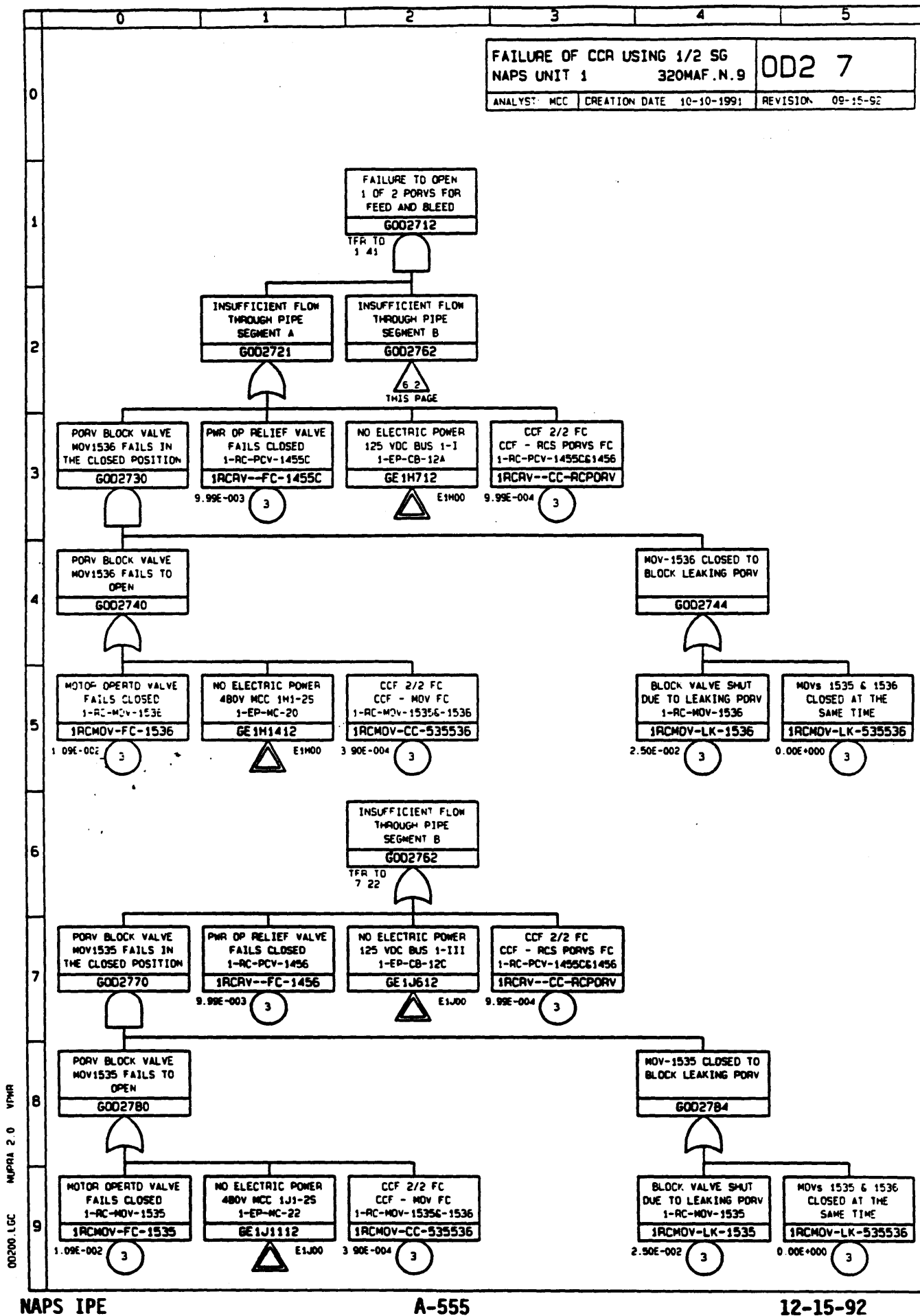


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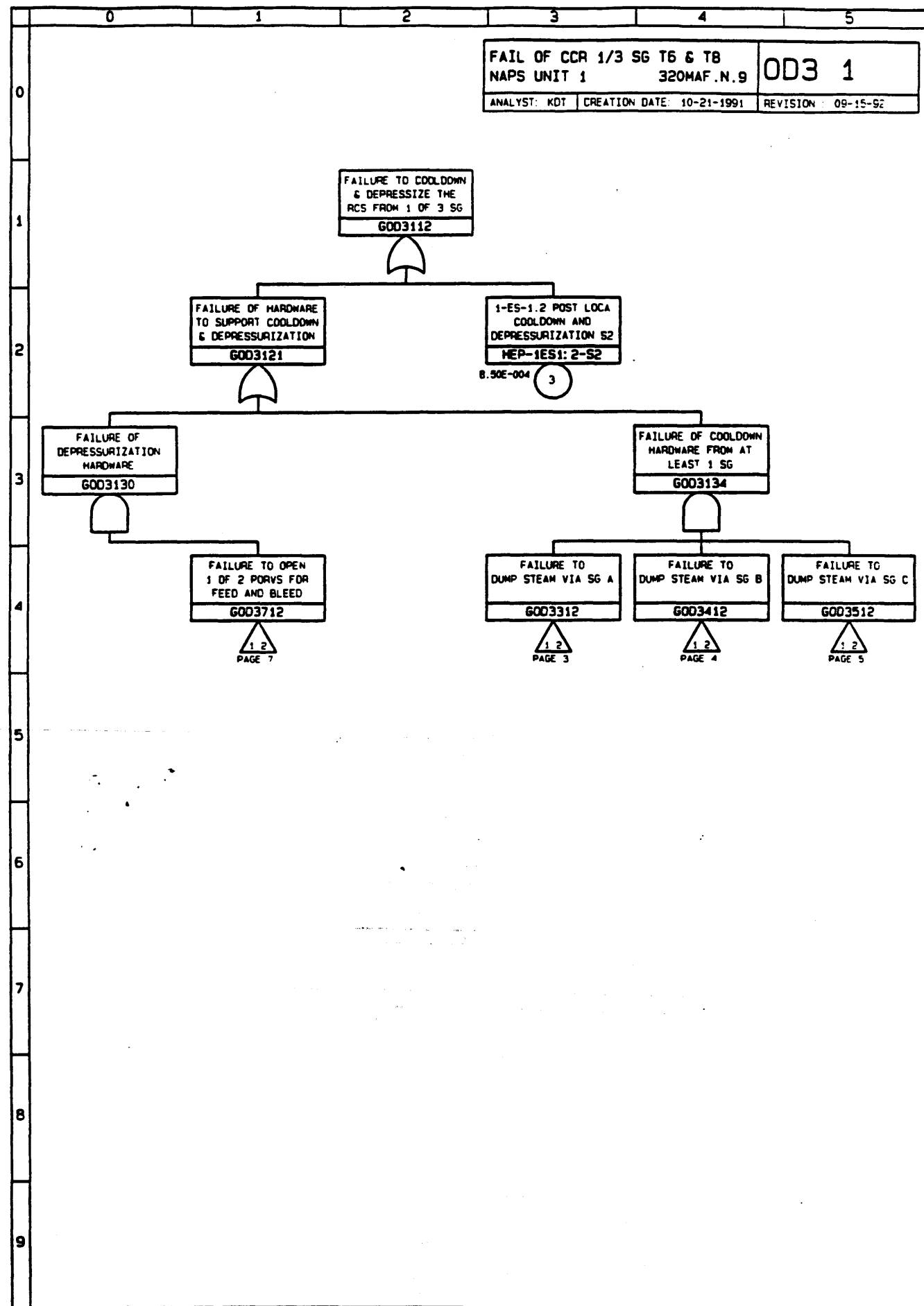
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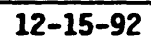




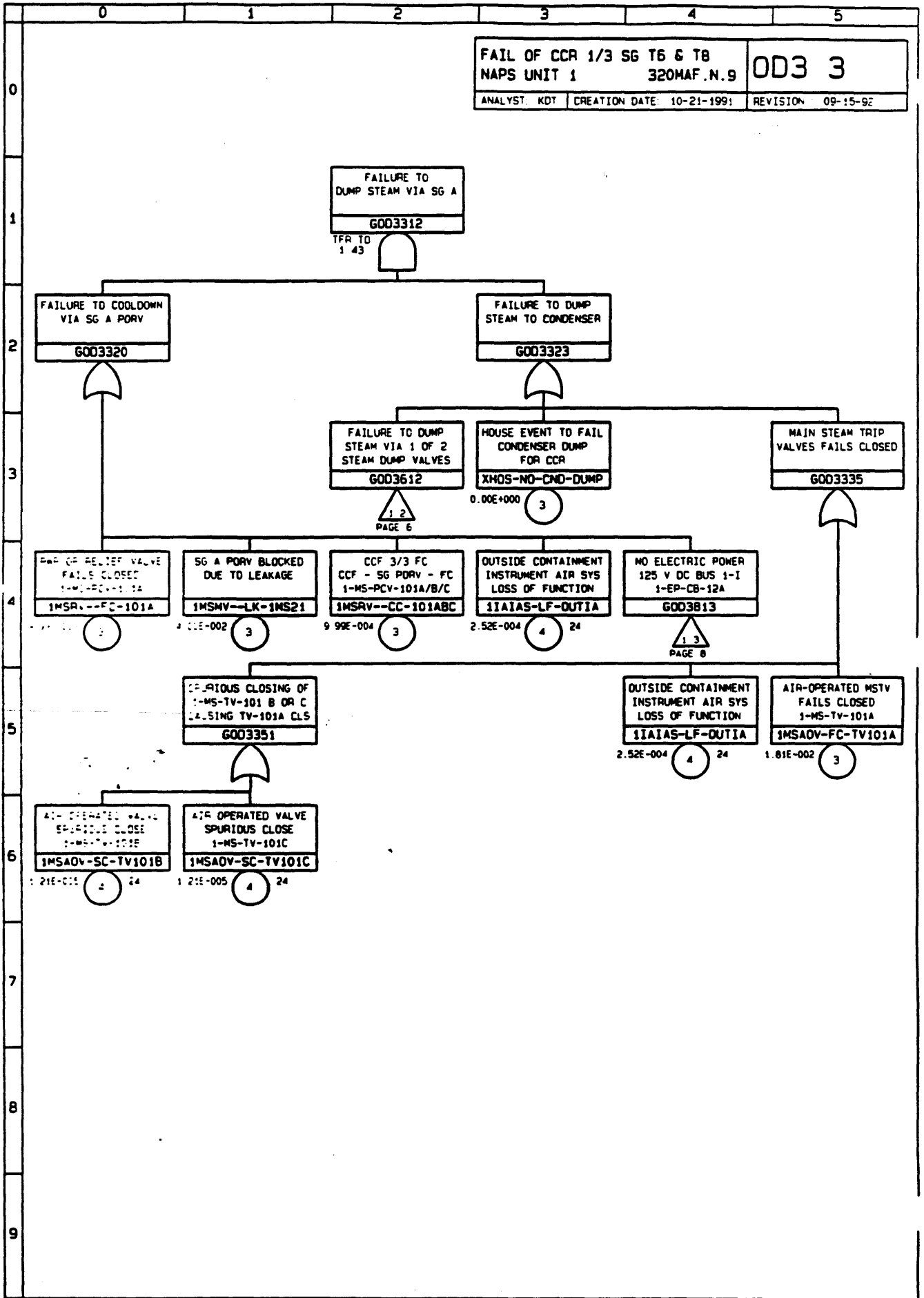
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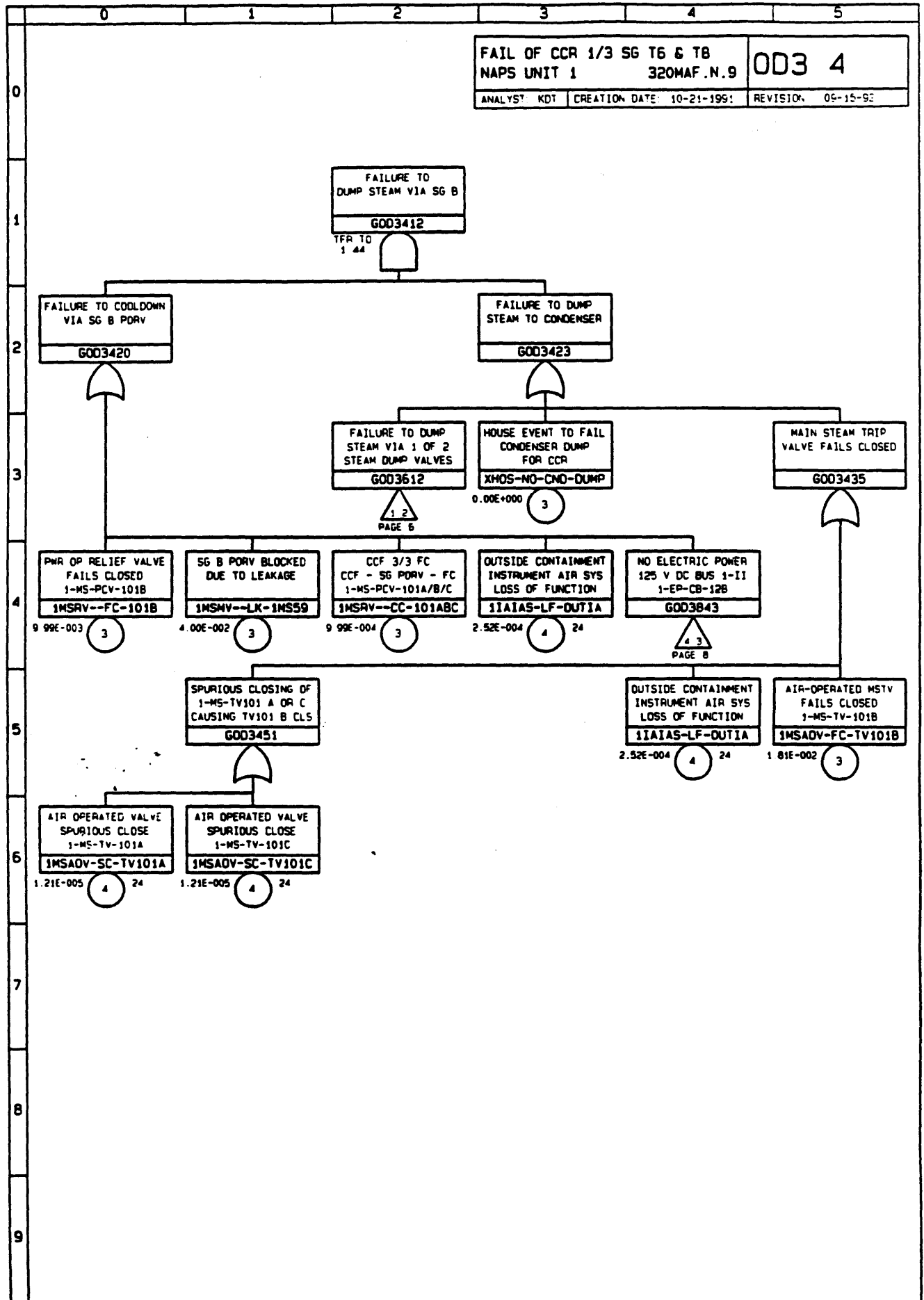
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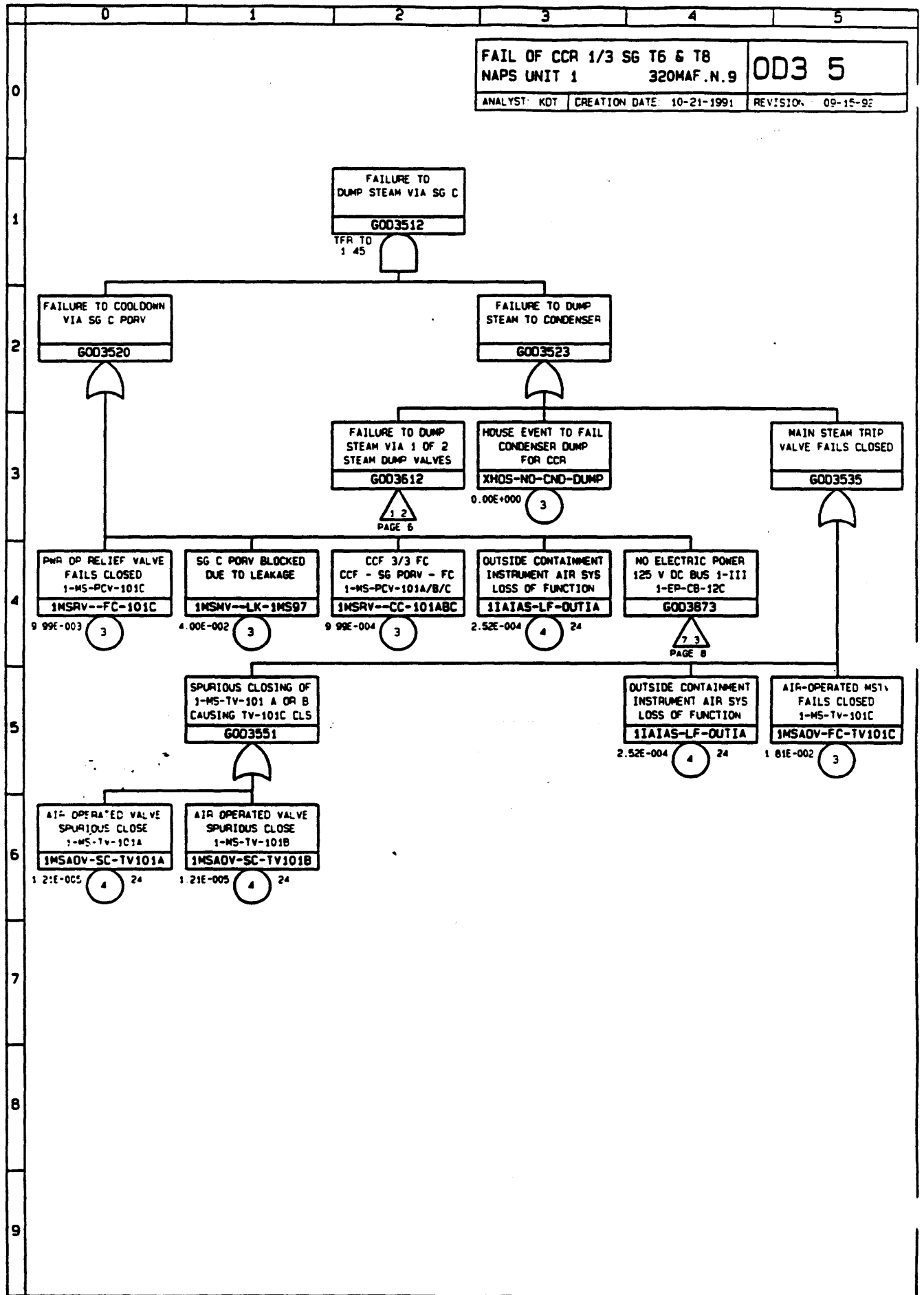
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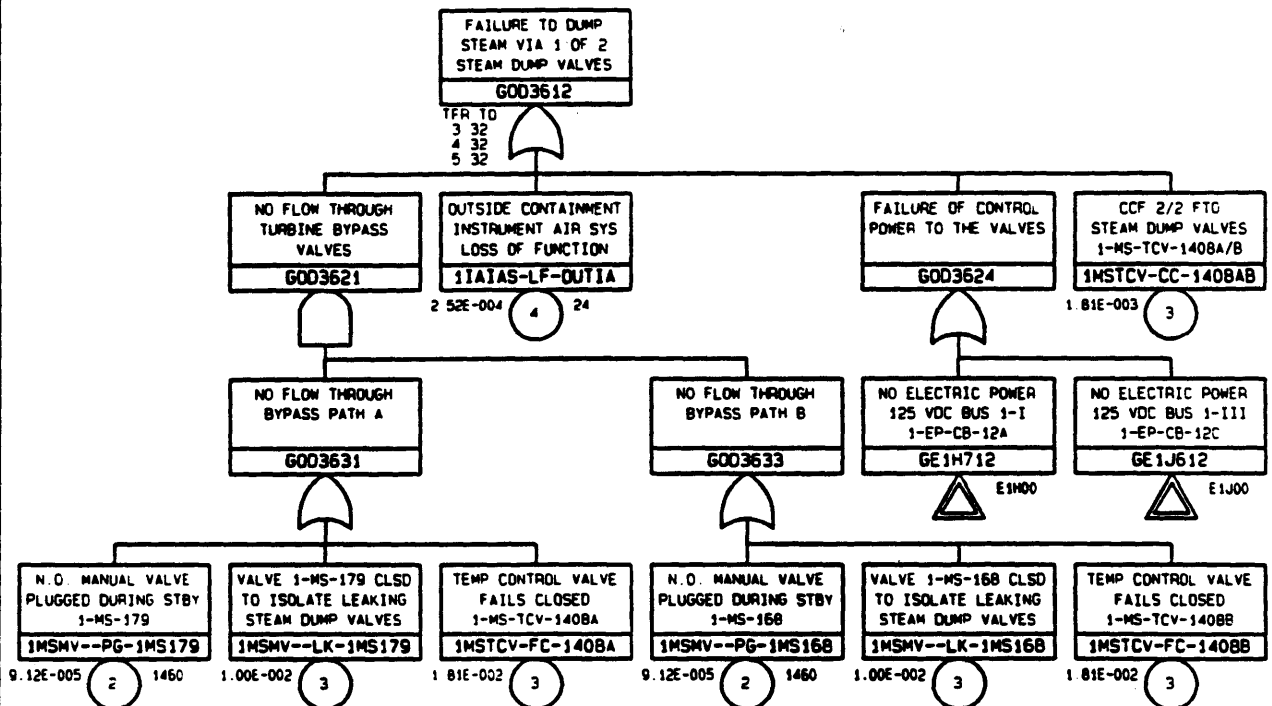
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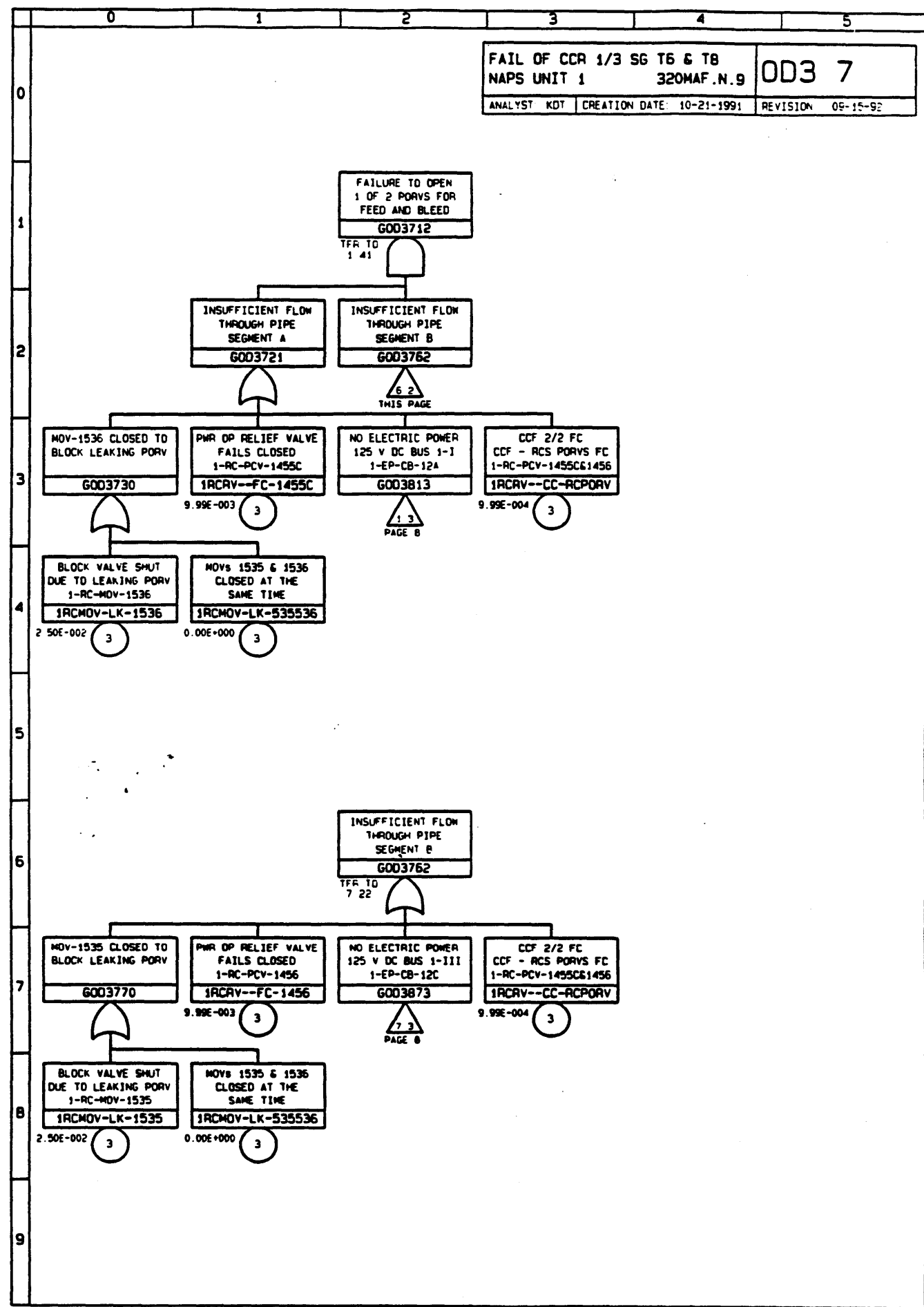


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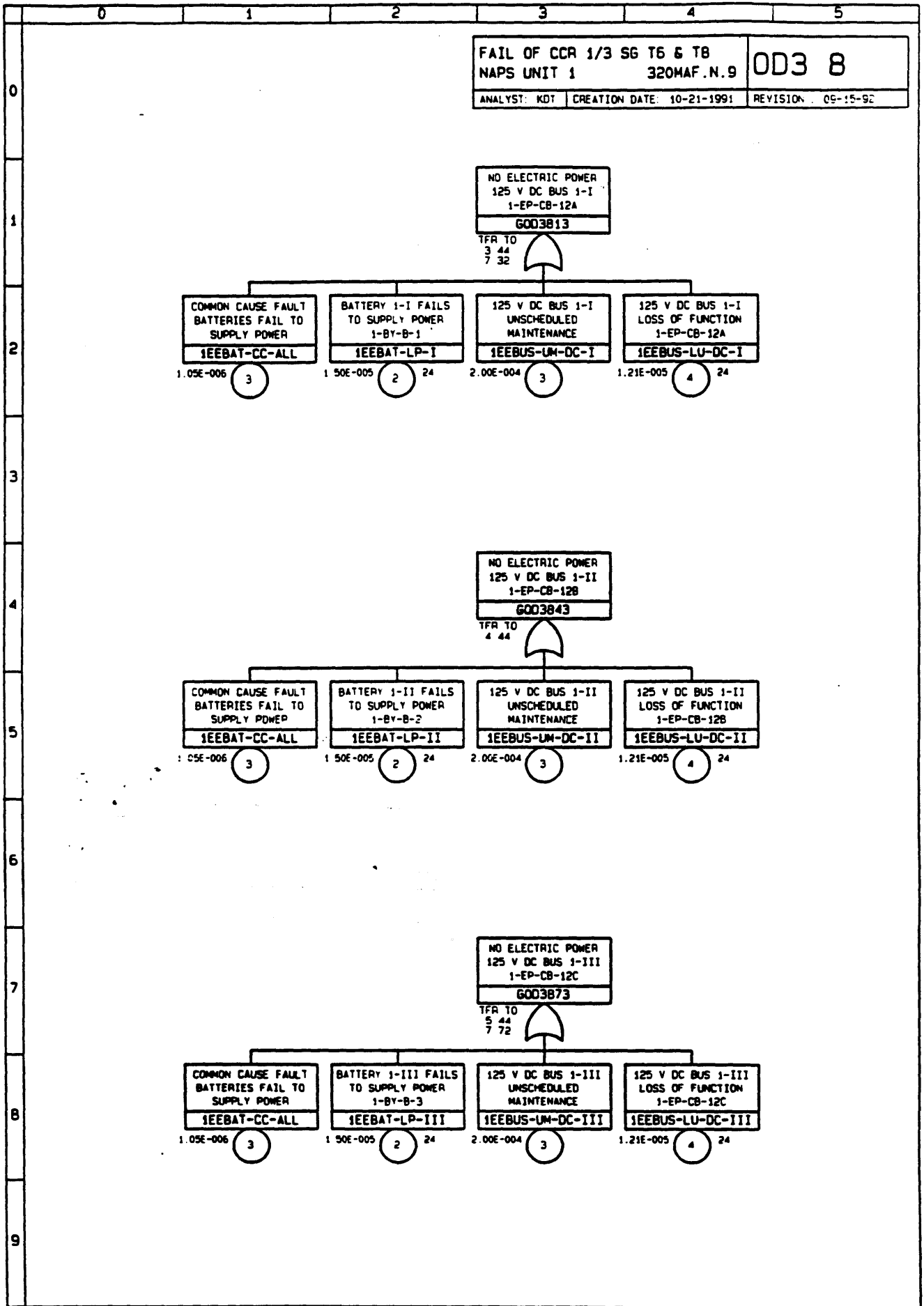
ANALYST KDT	CREATION DATE 10-21-1991	REVISION 09-15-92
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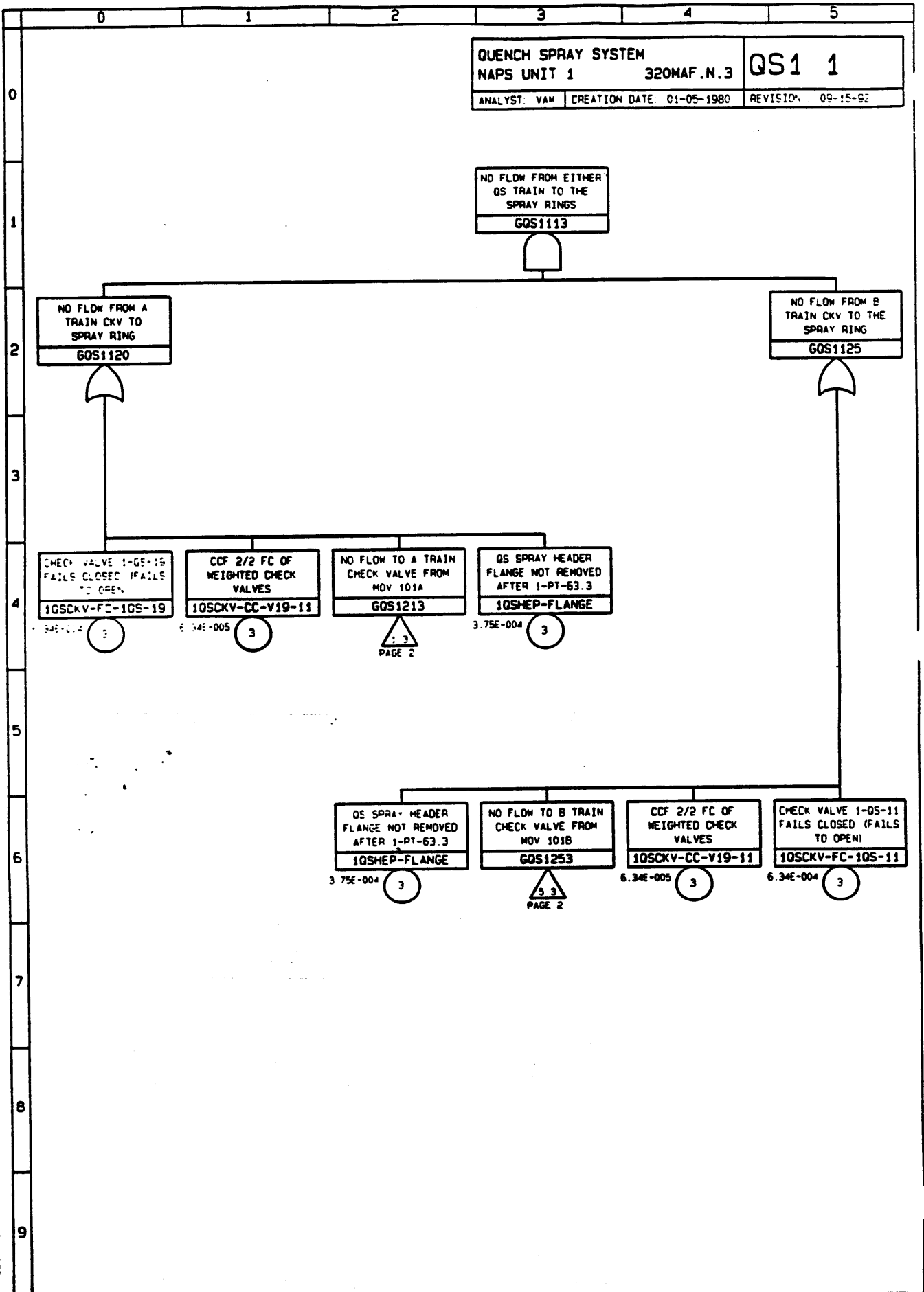
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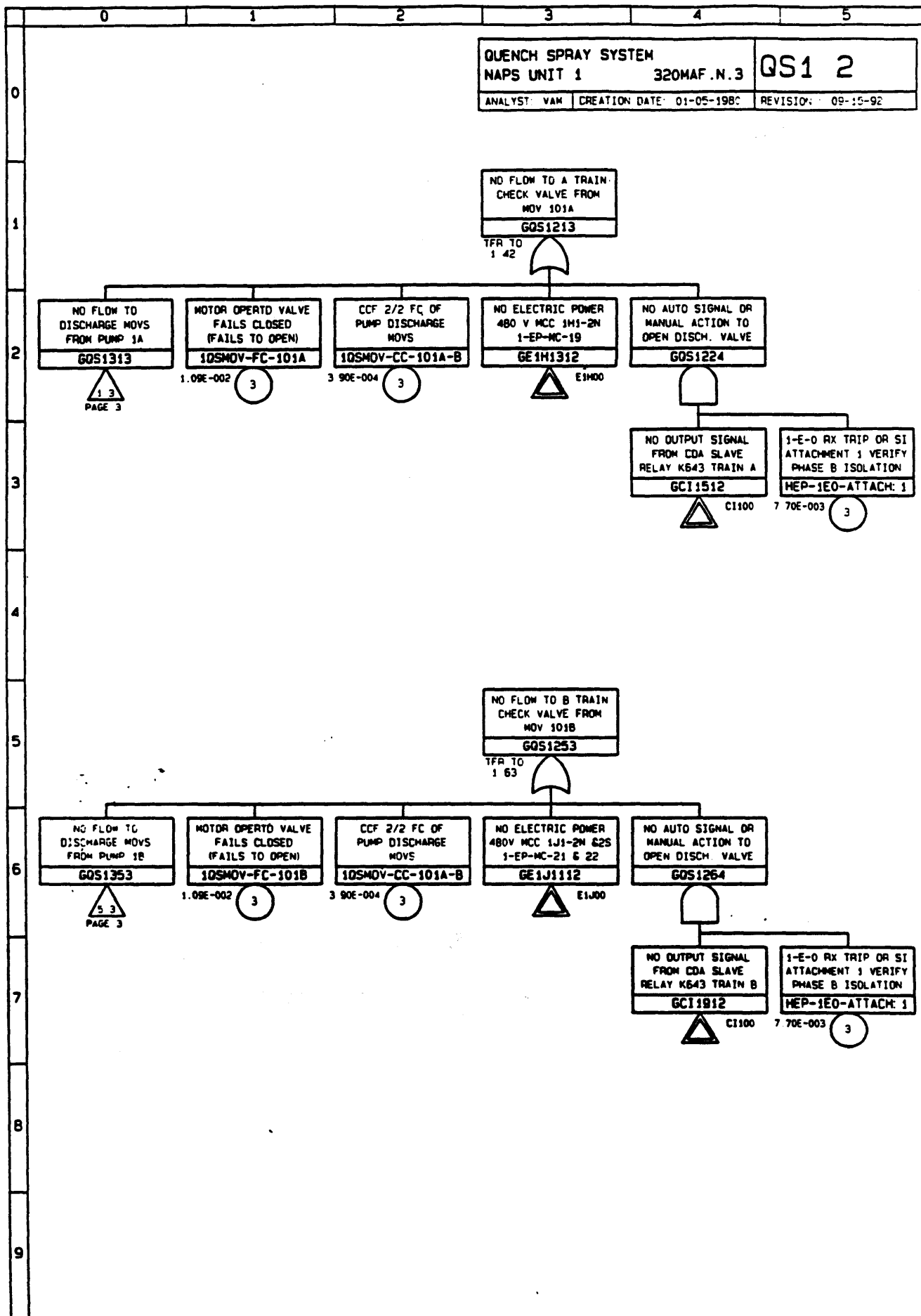
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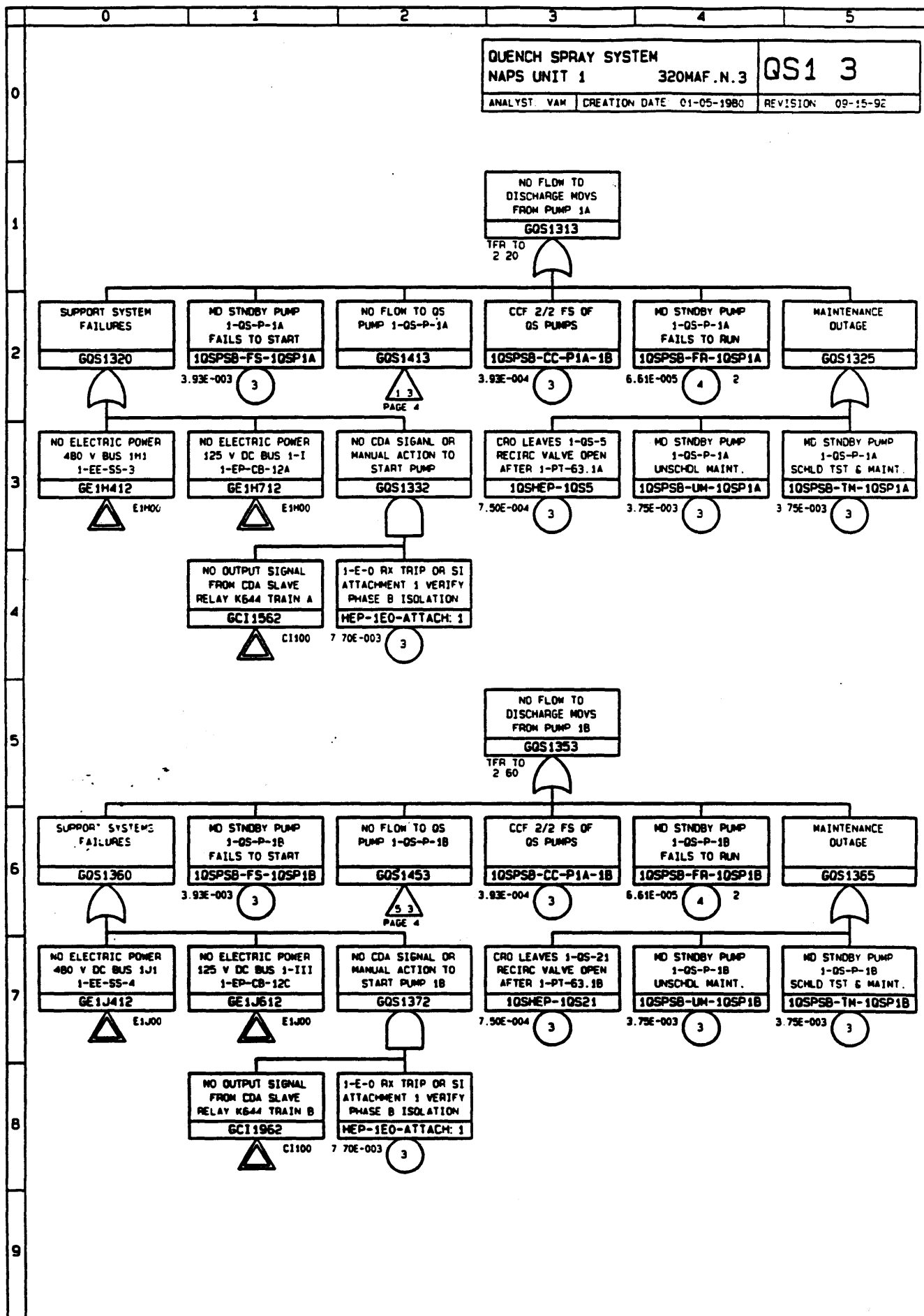
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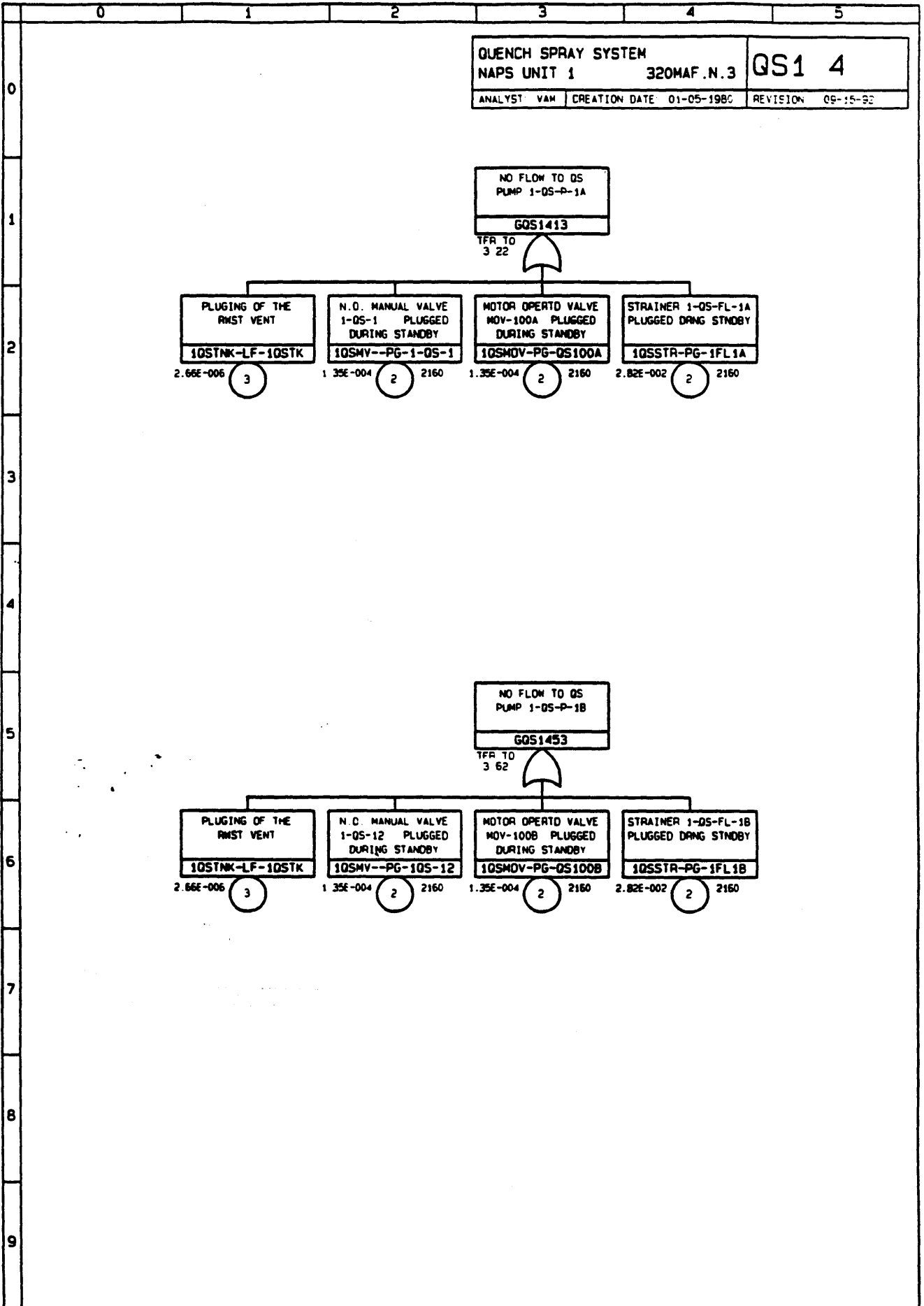
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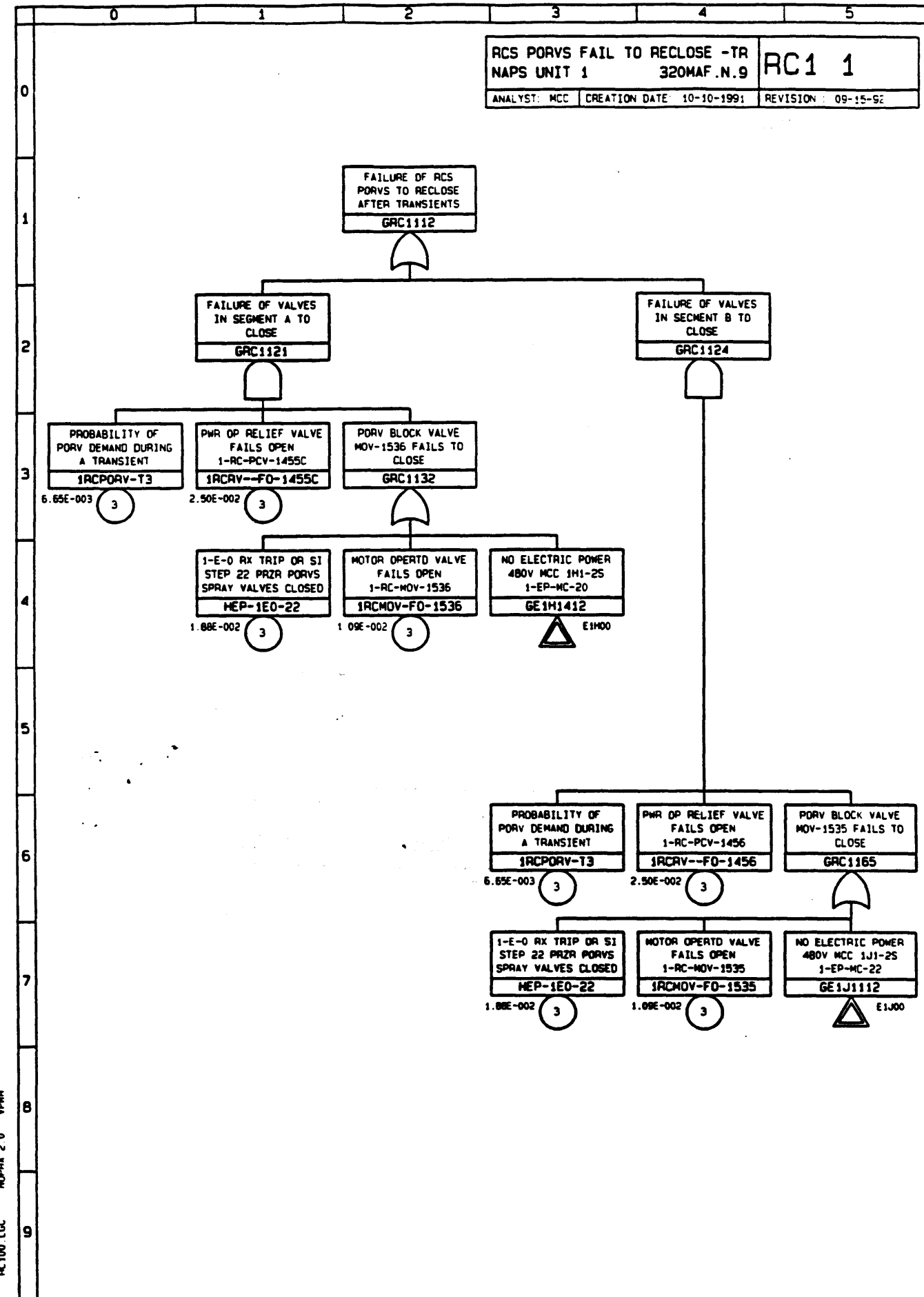
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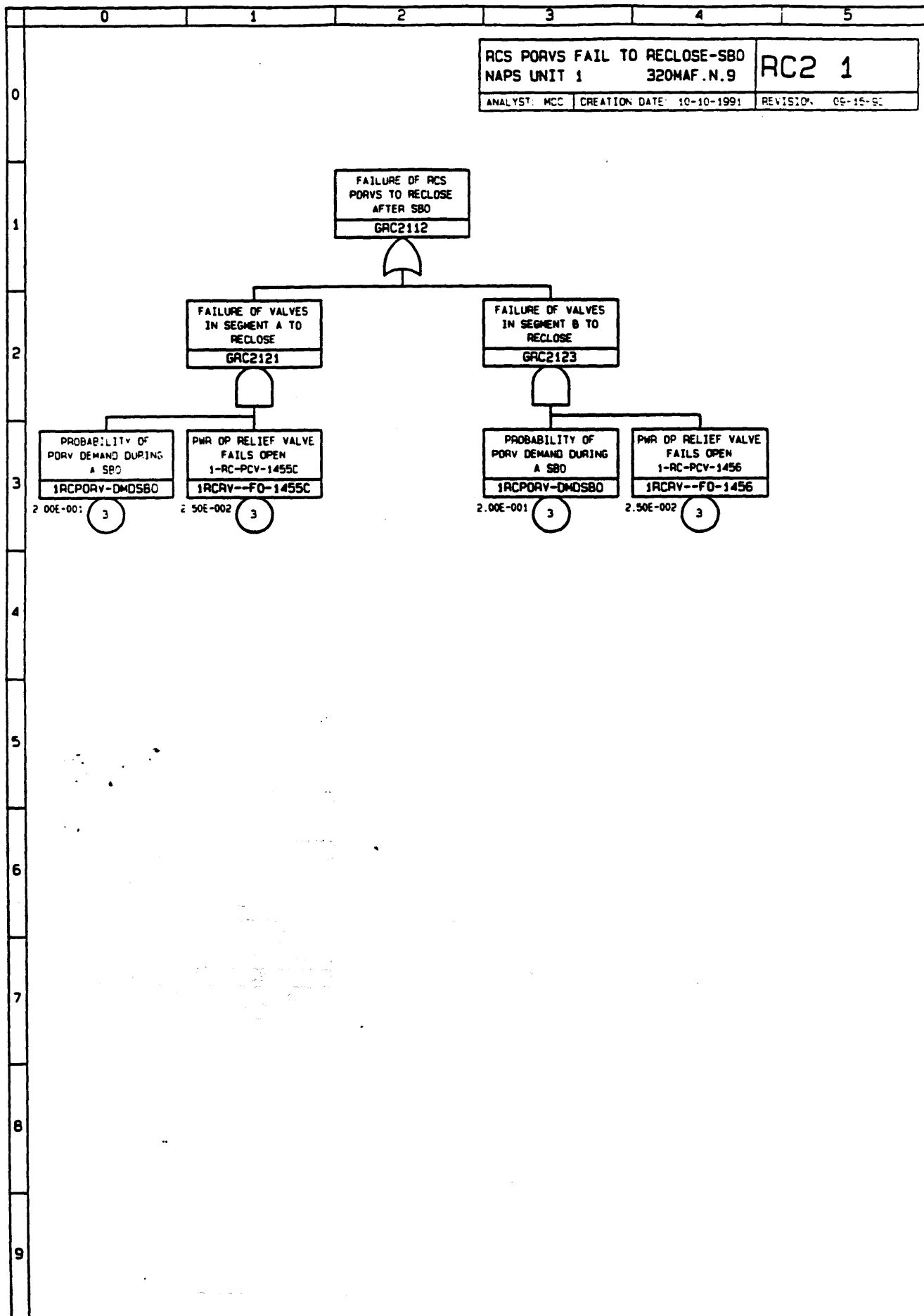
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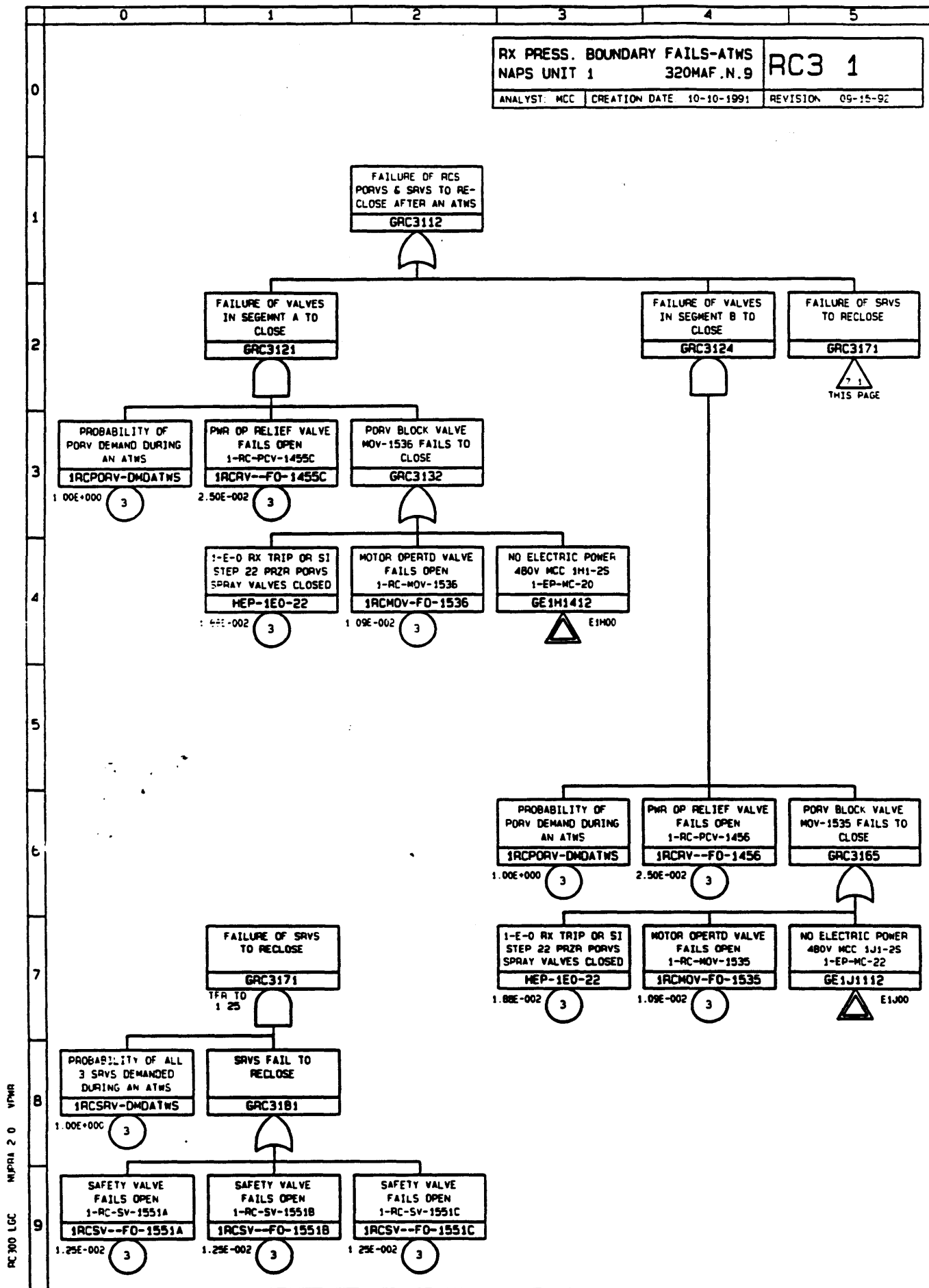
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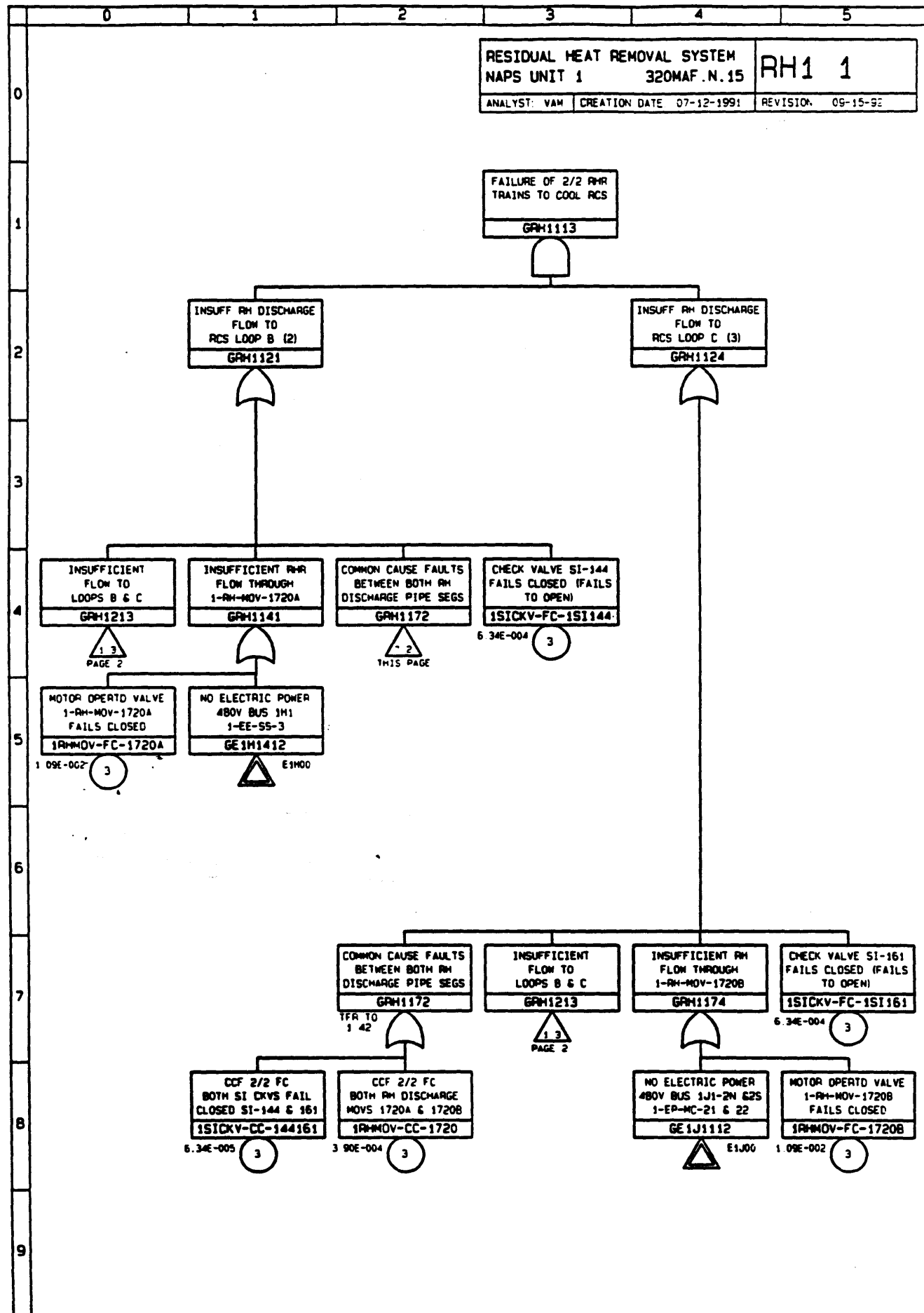






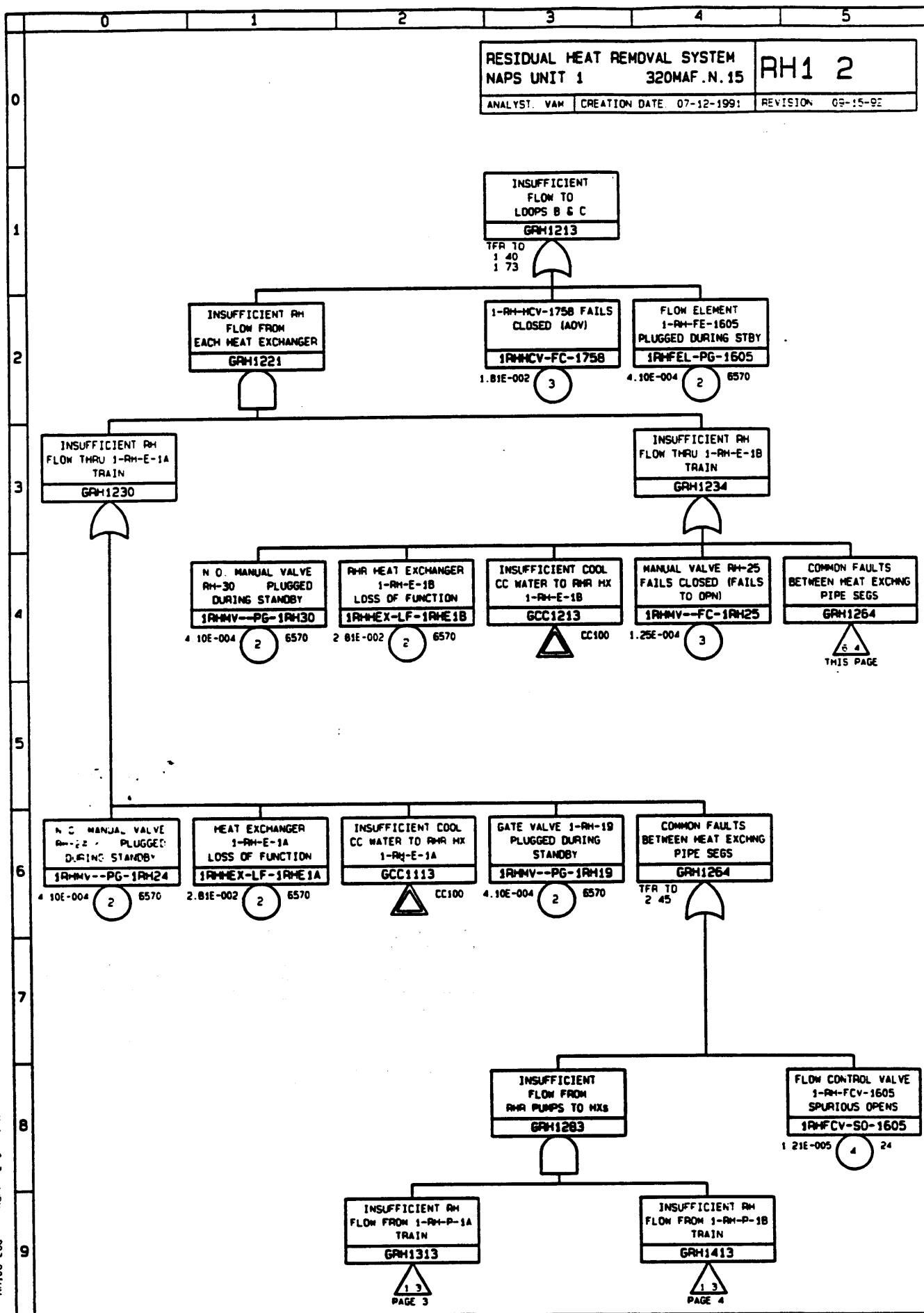
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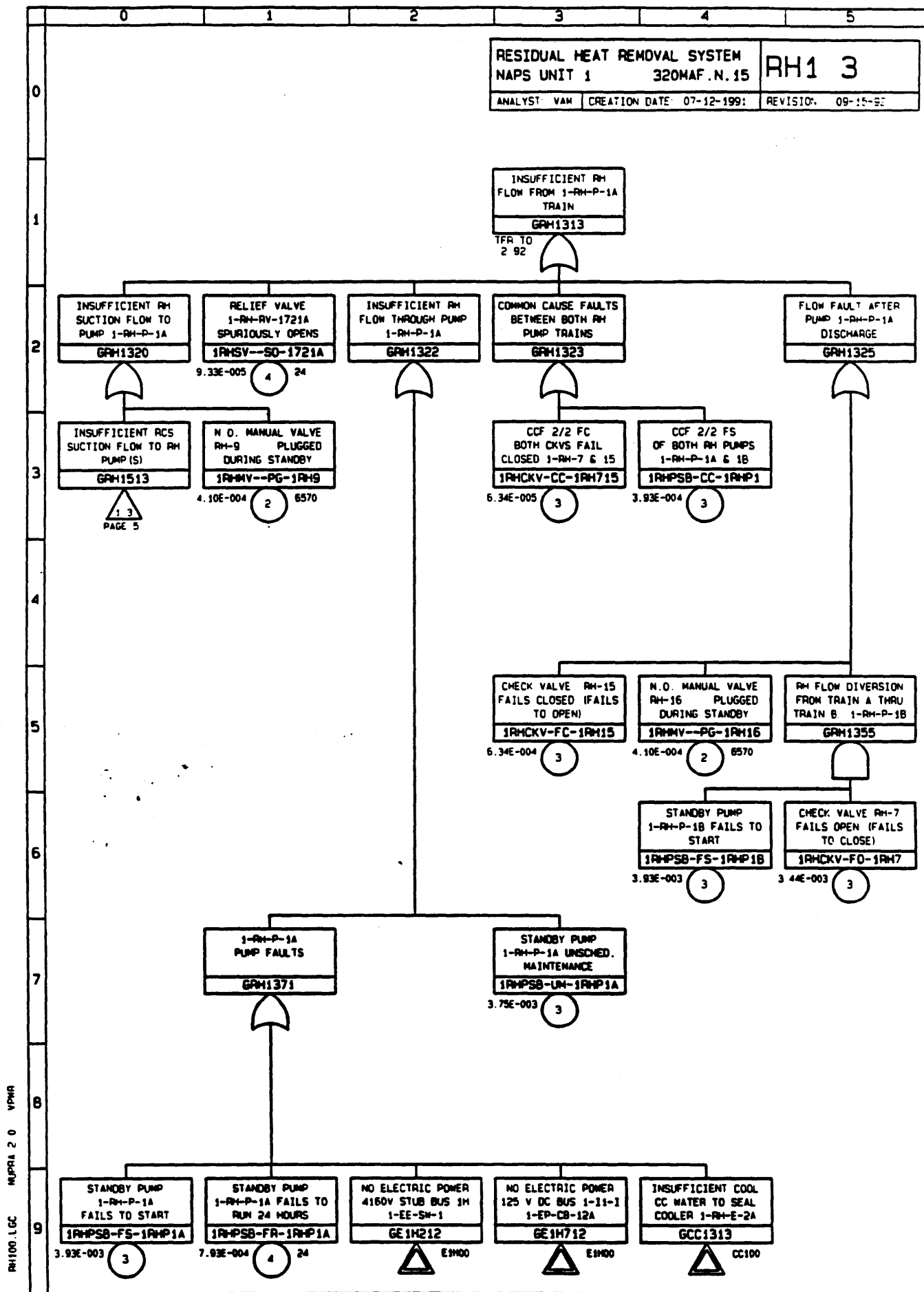




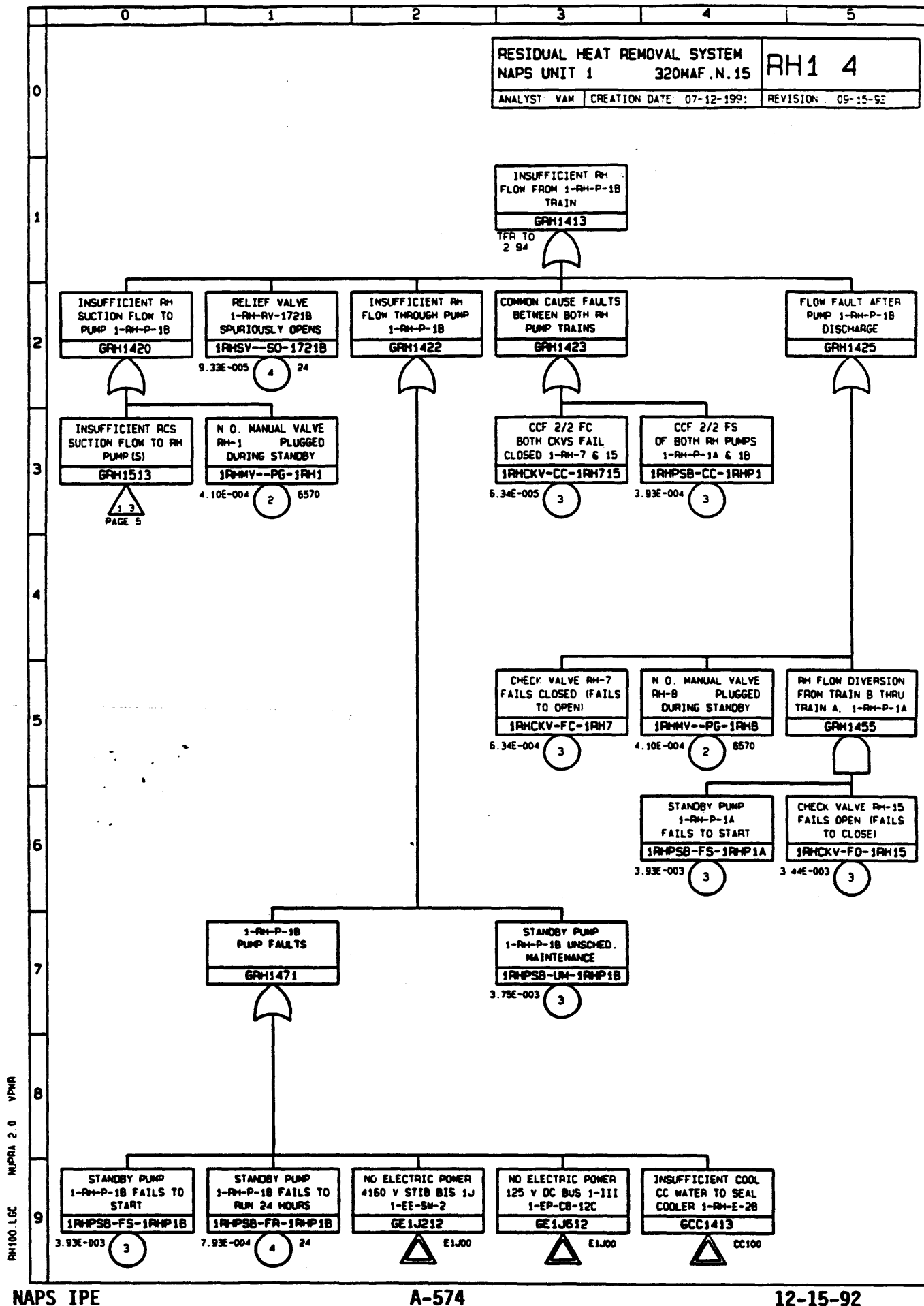
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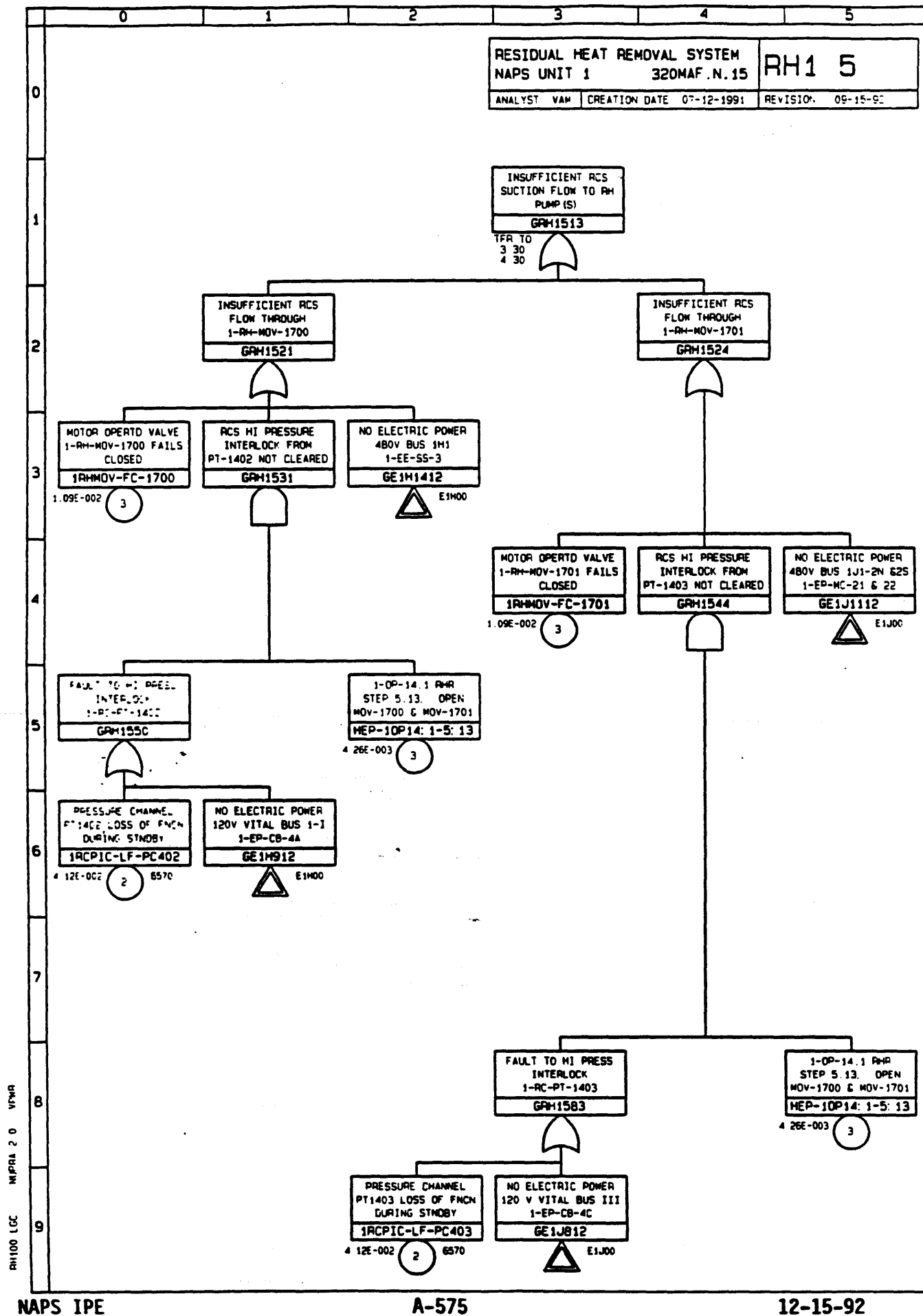
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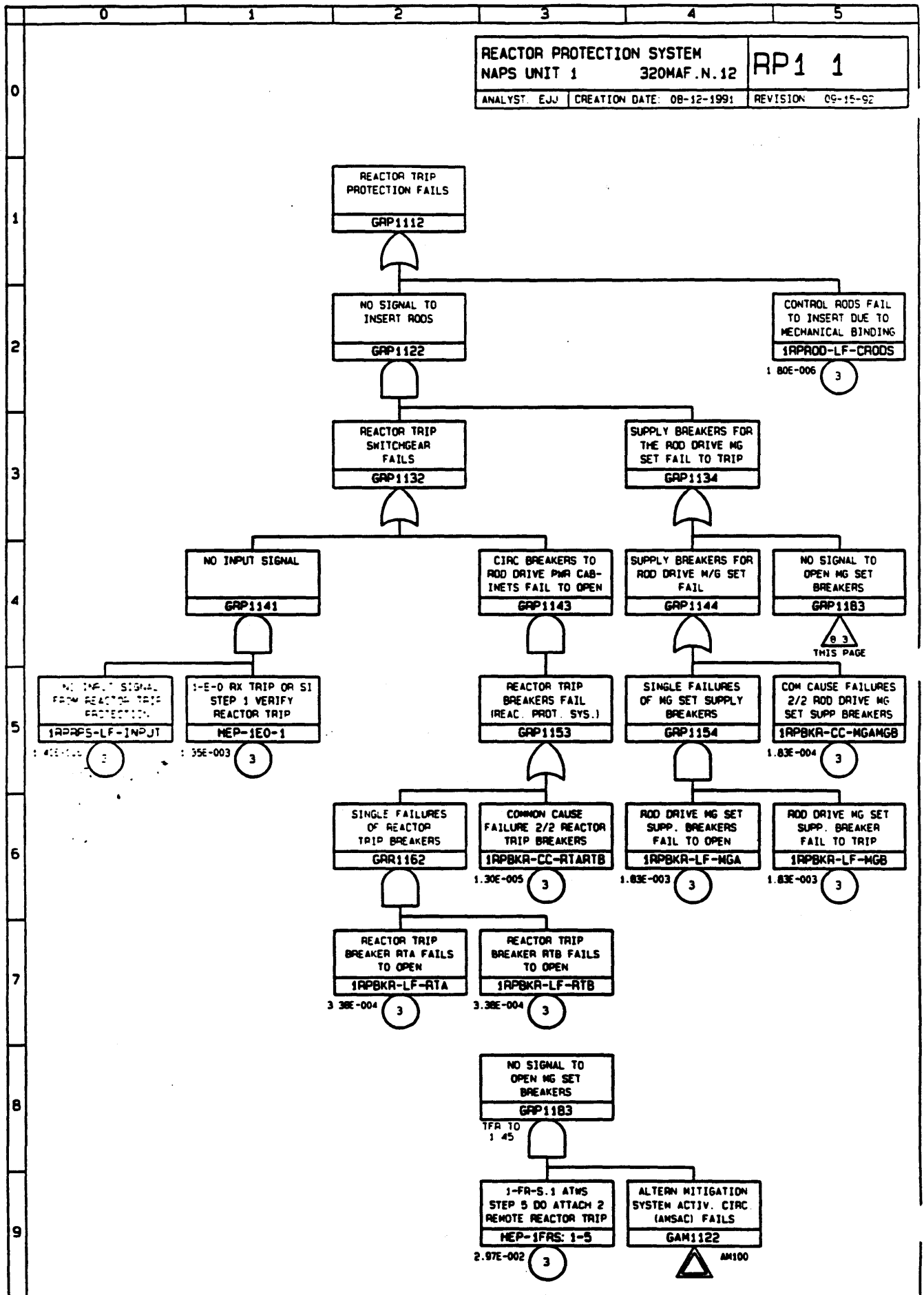
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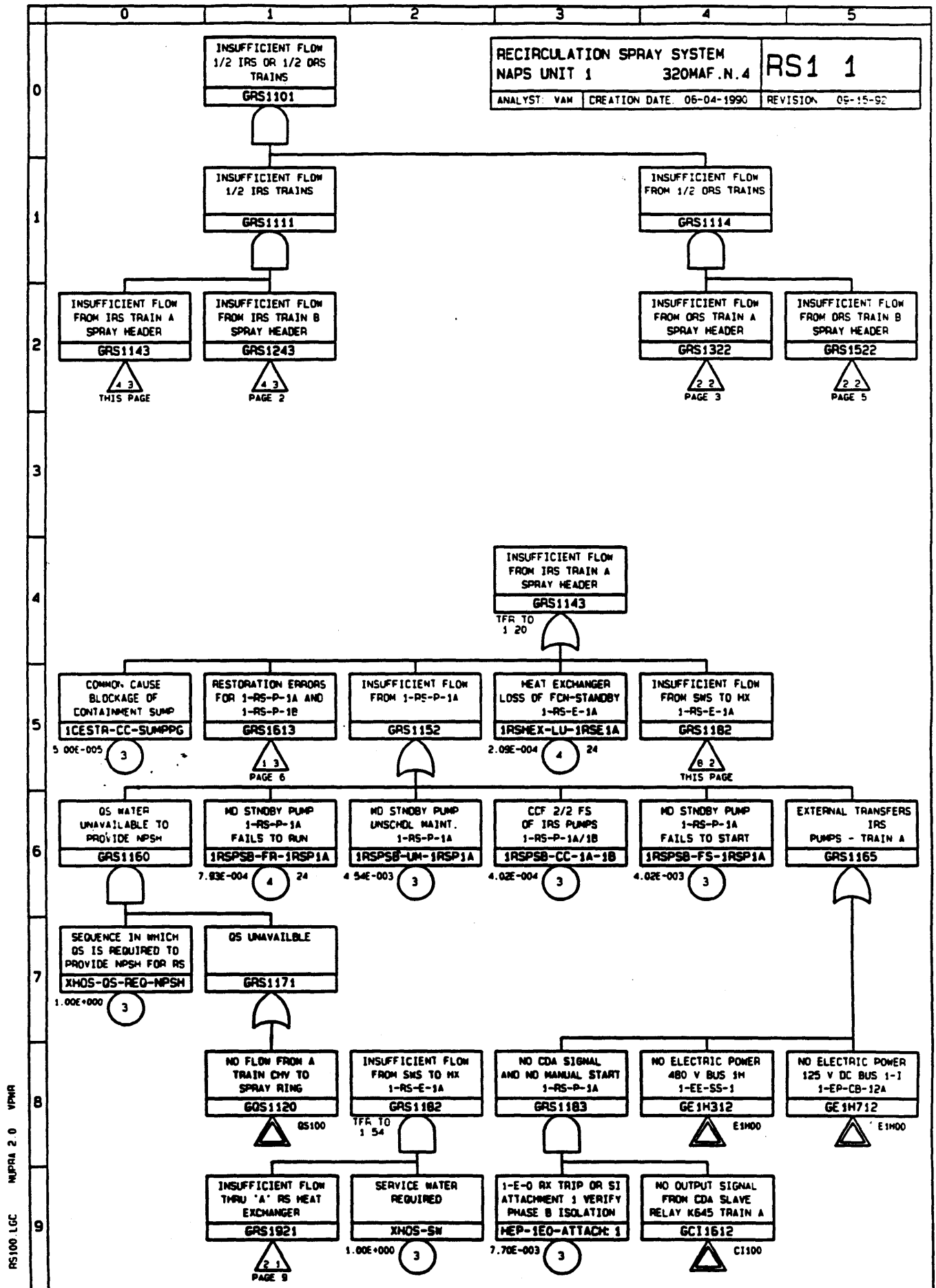


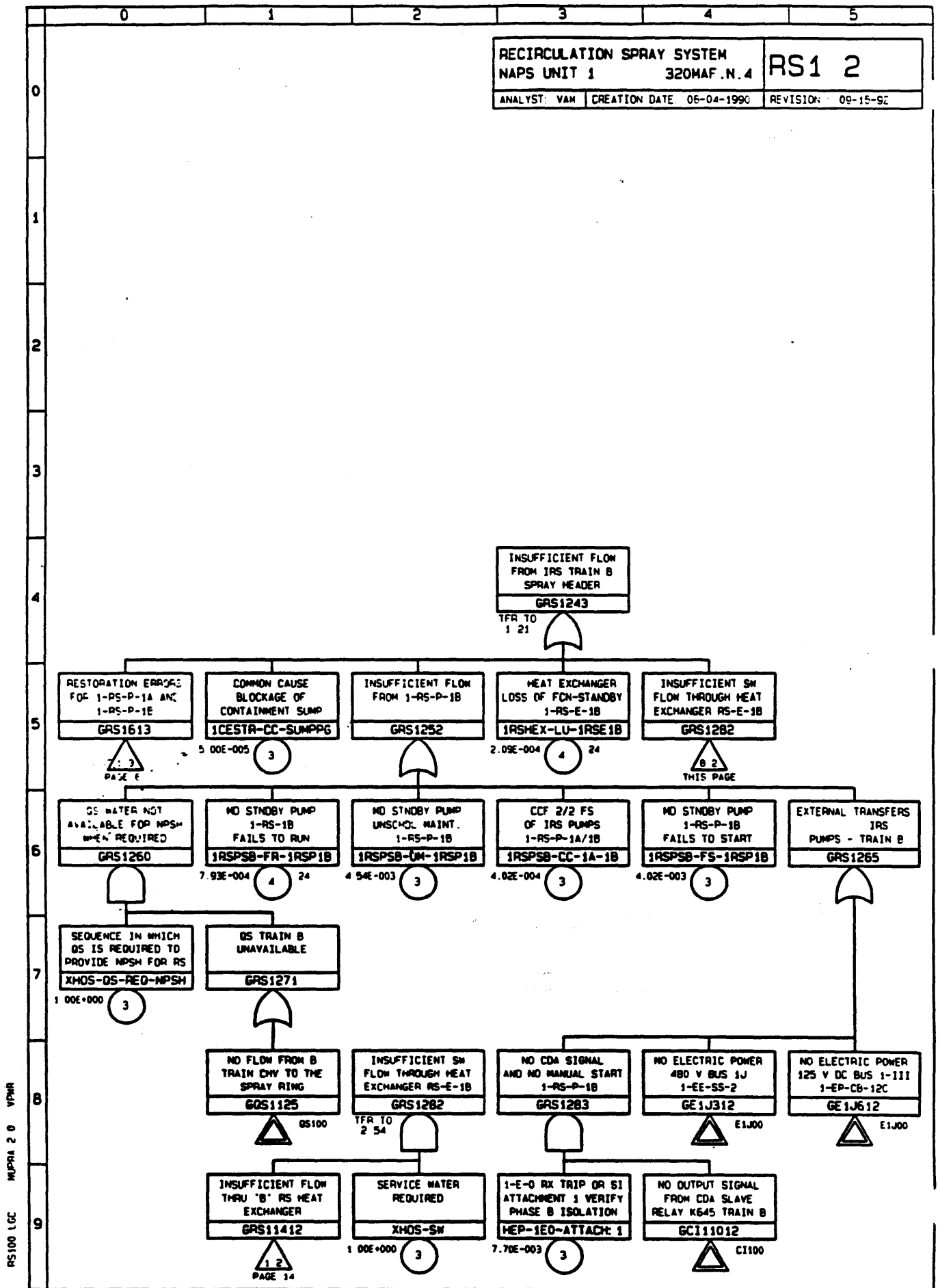
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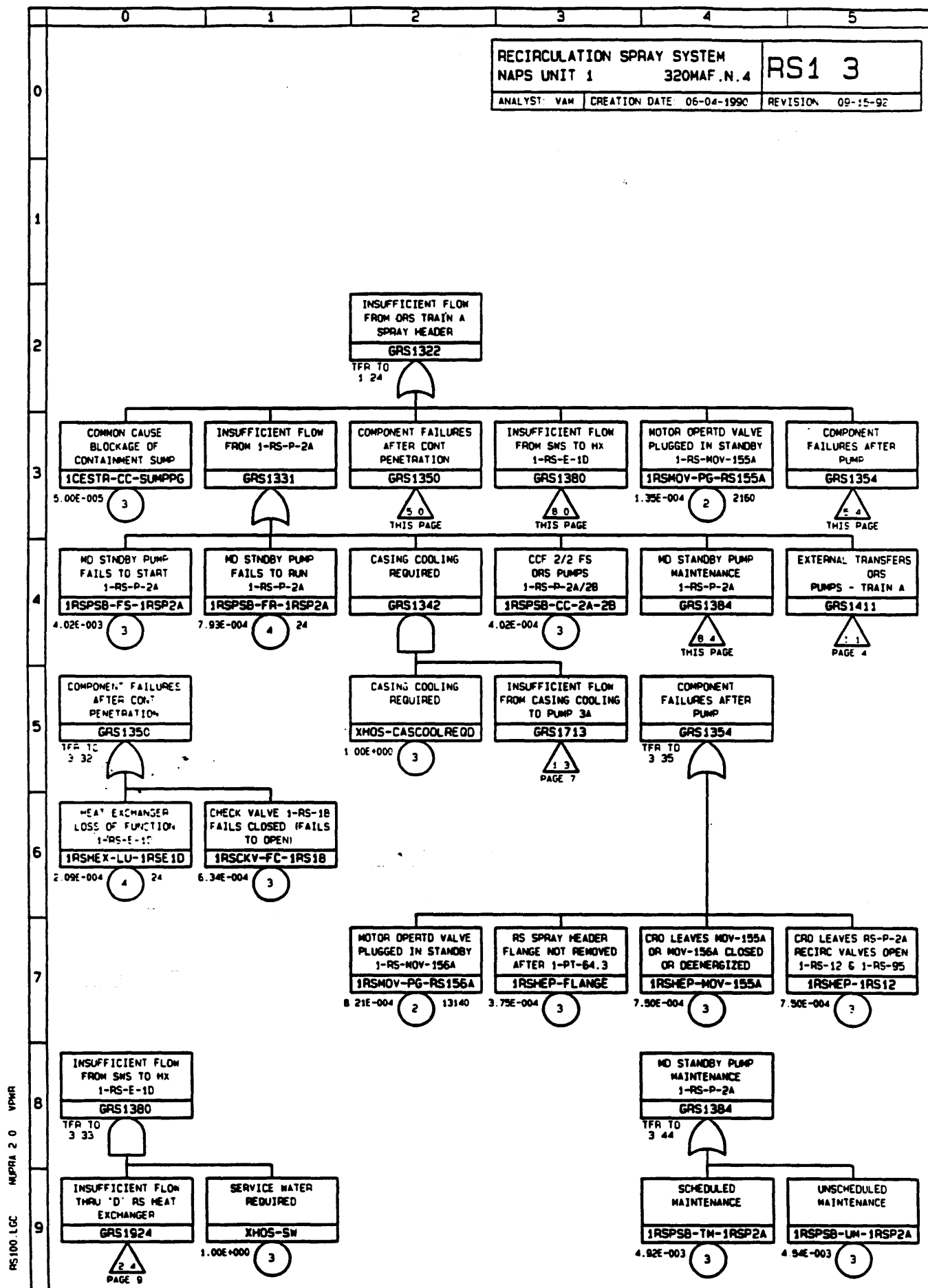
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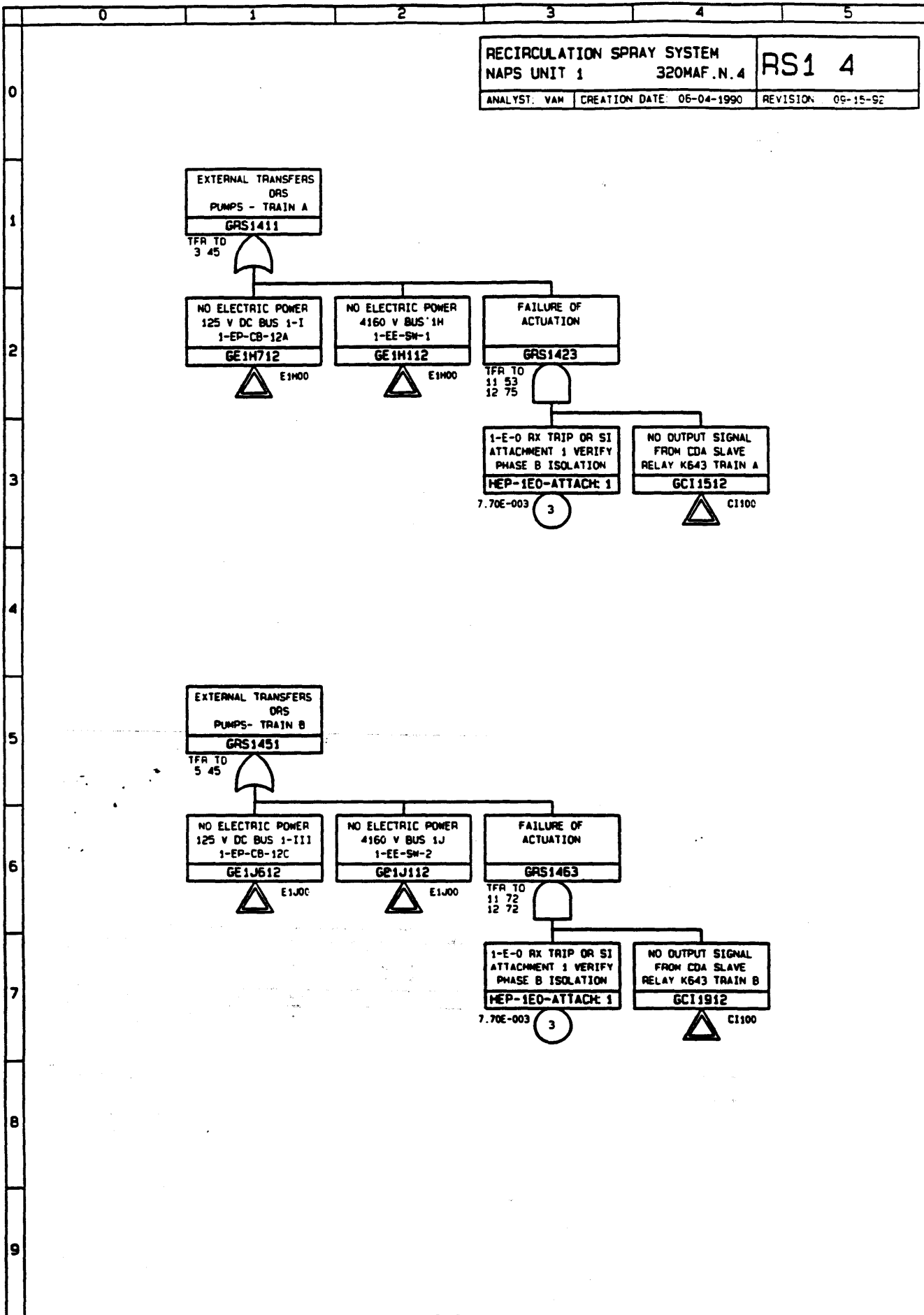


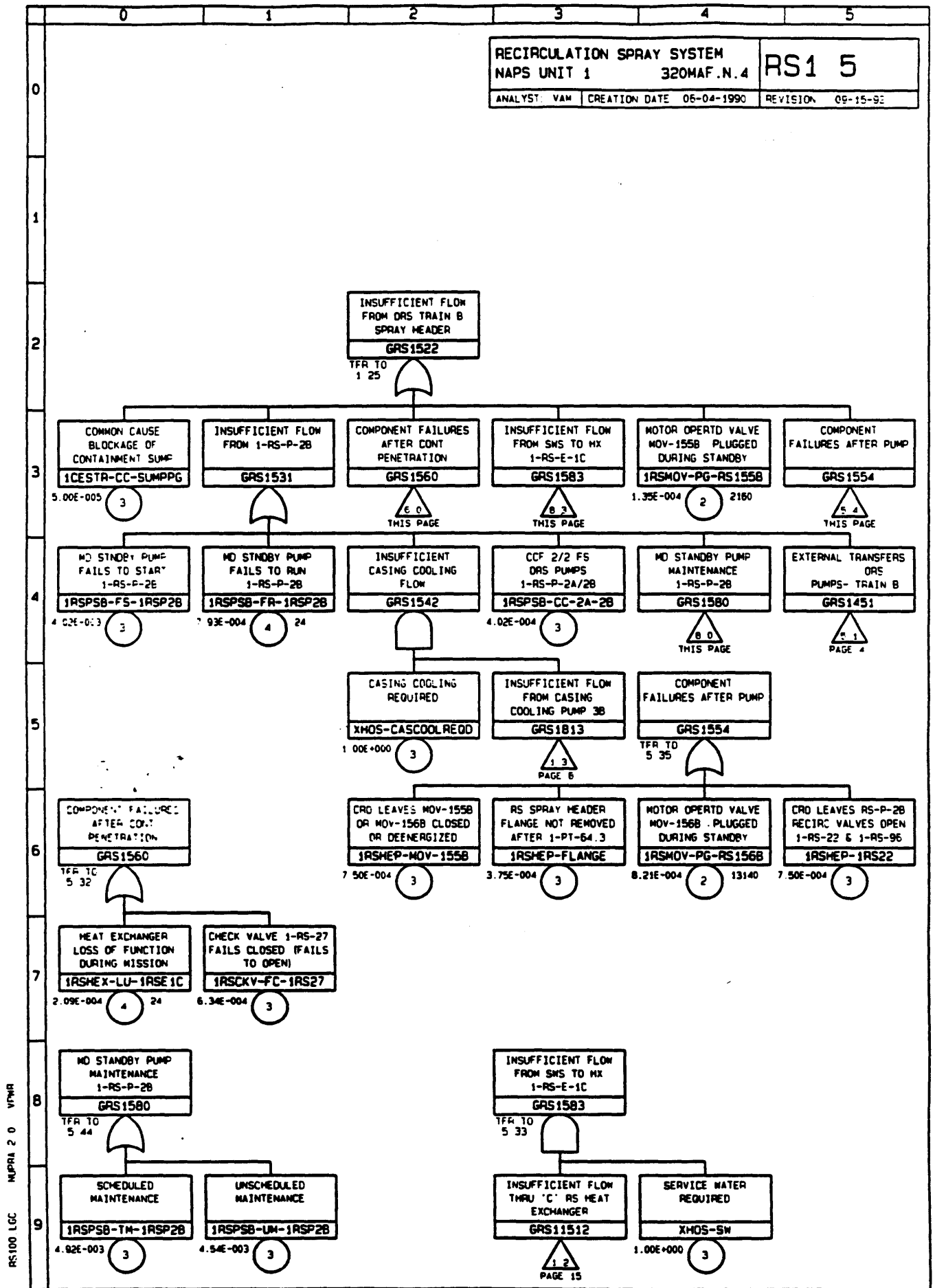


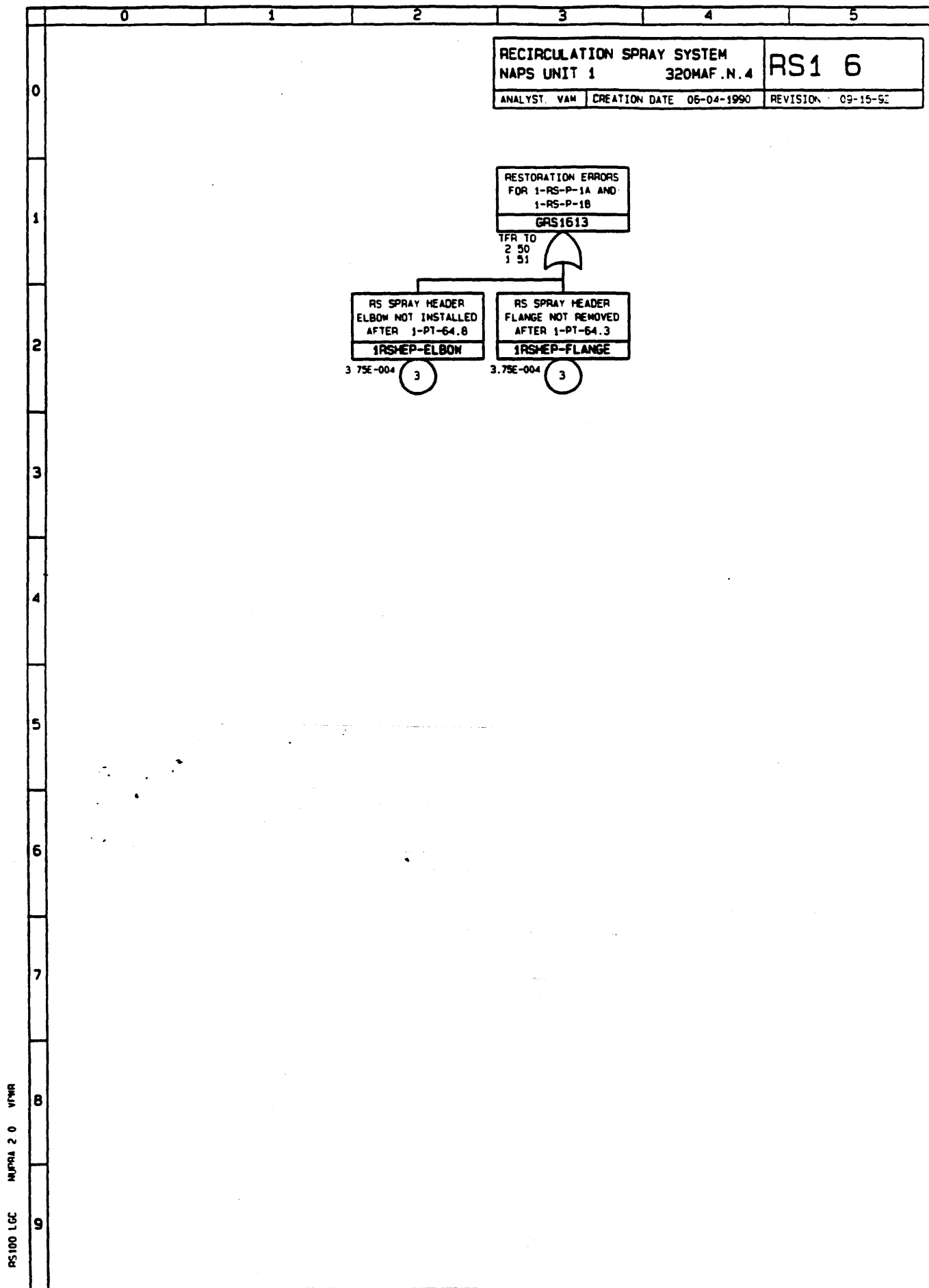




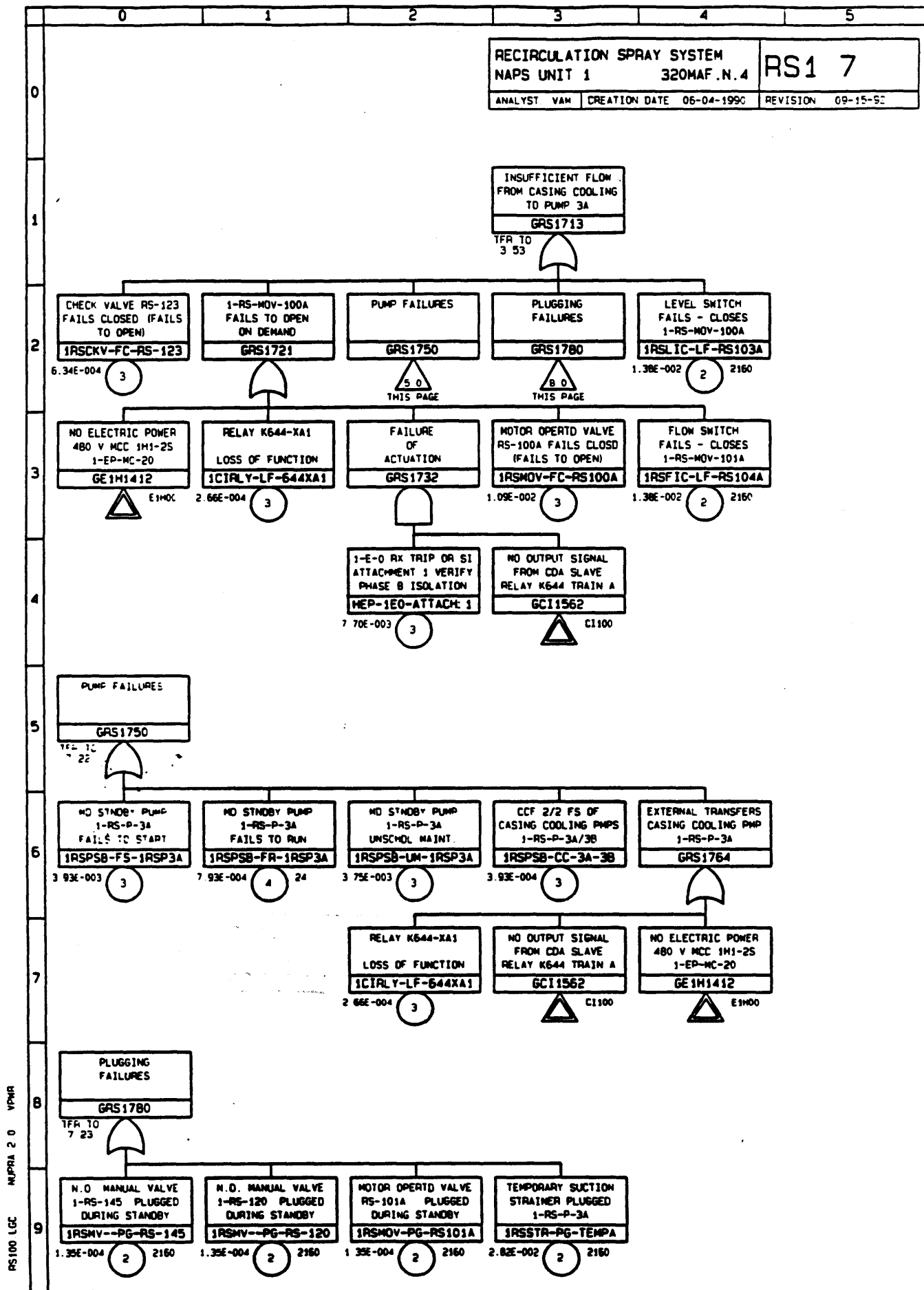


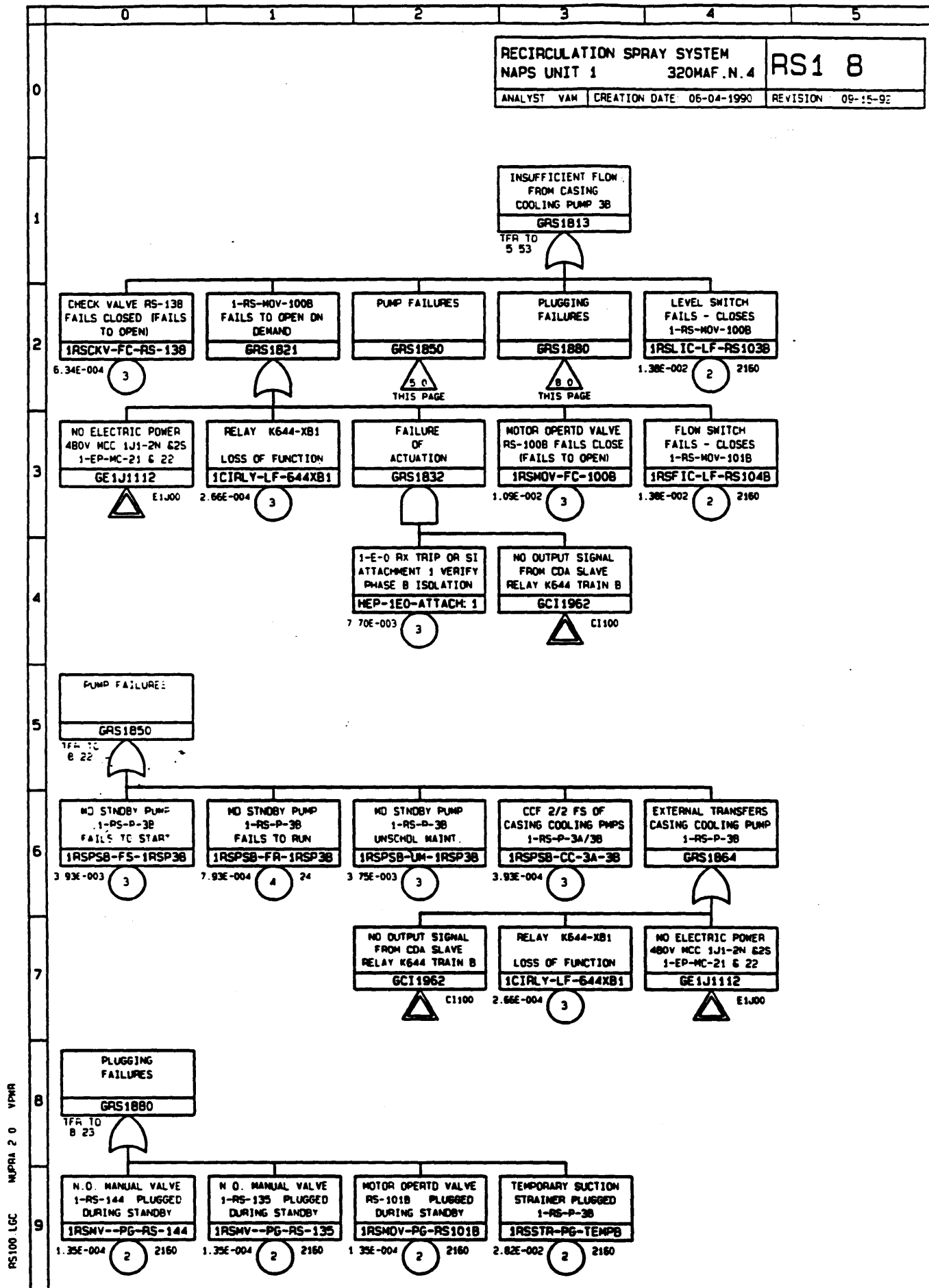




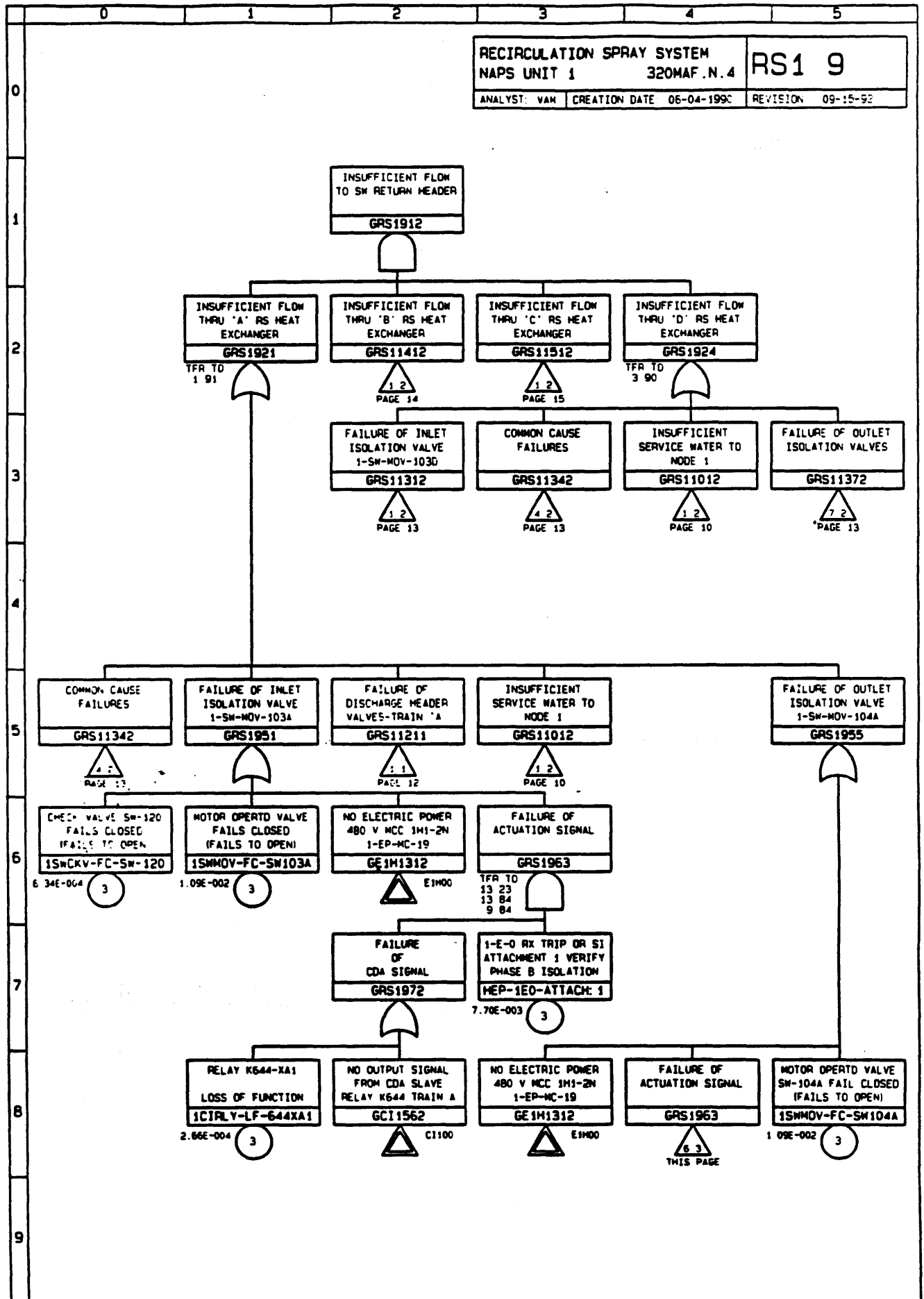


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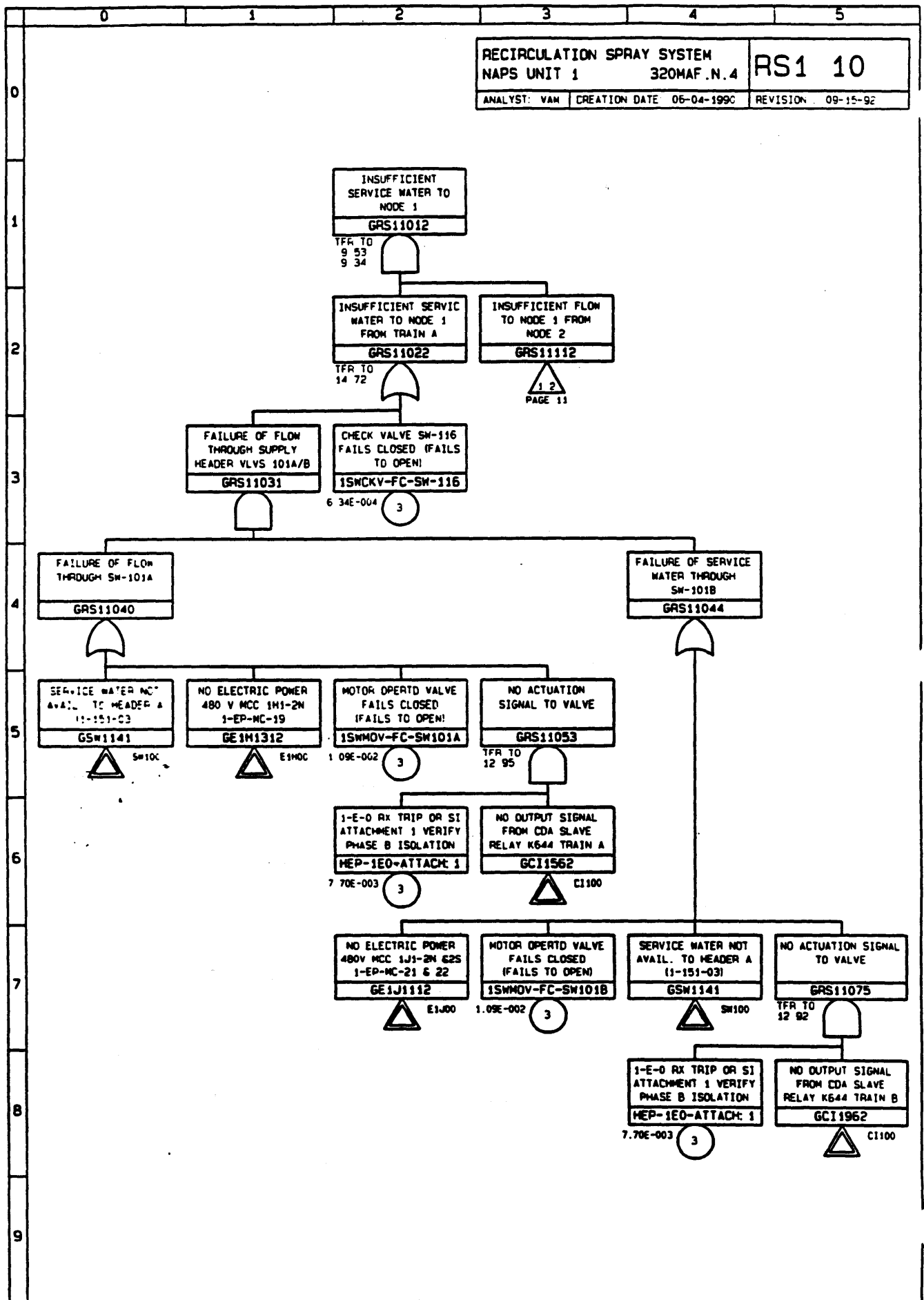


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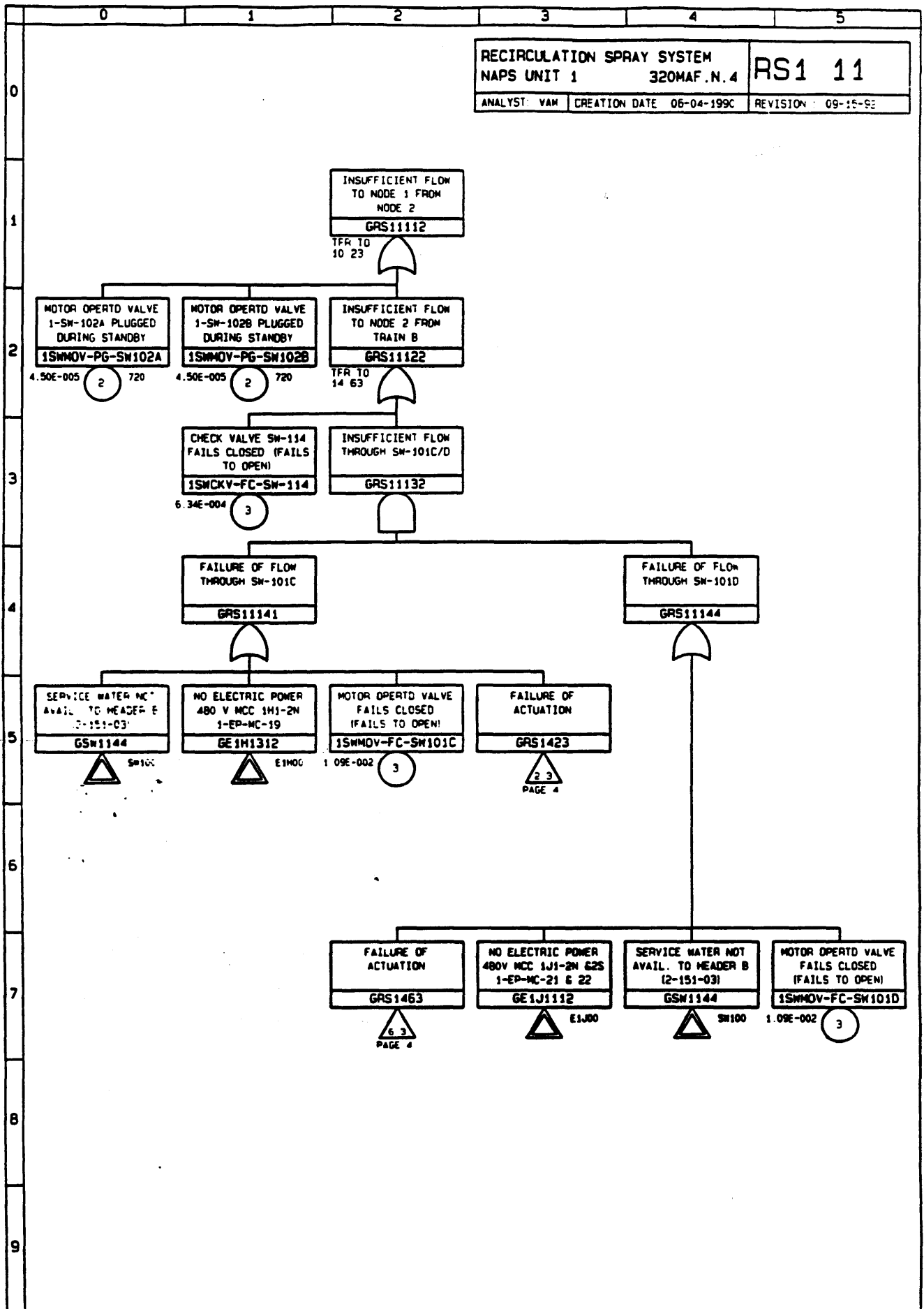
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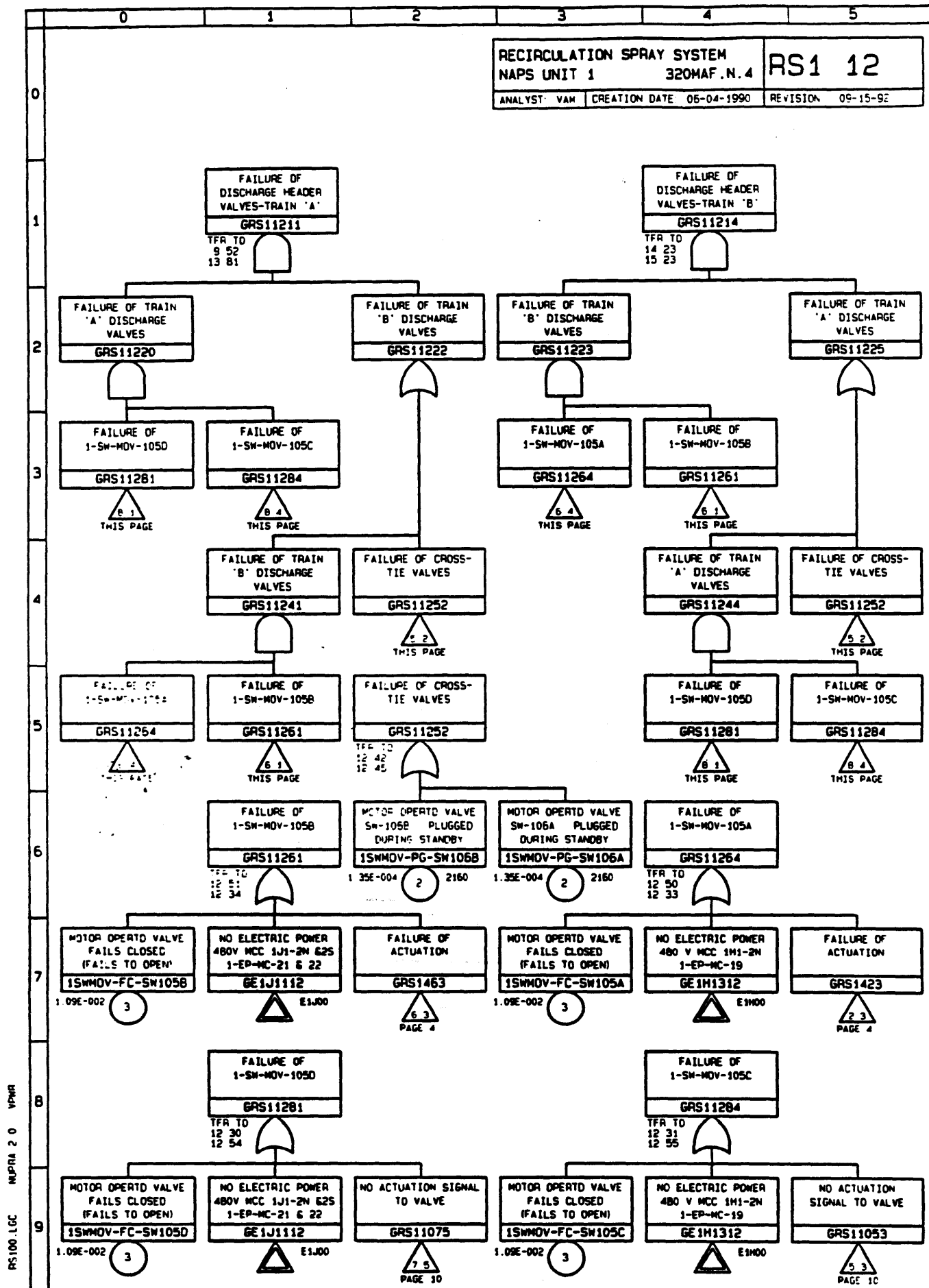
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12-15-92

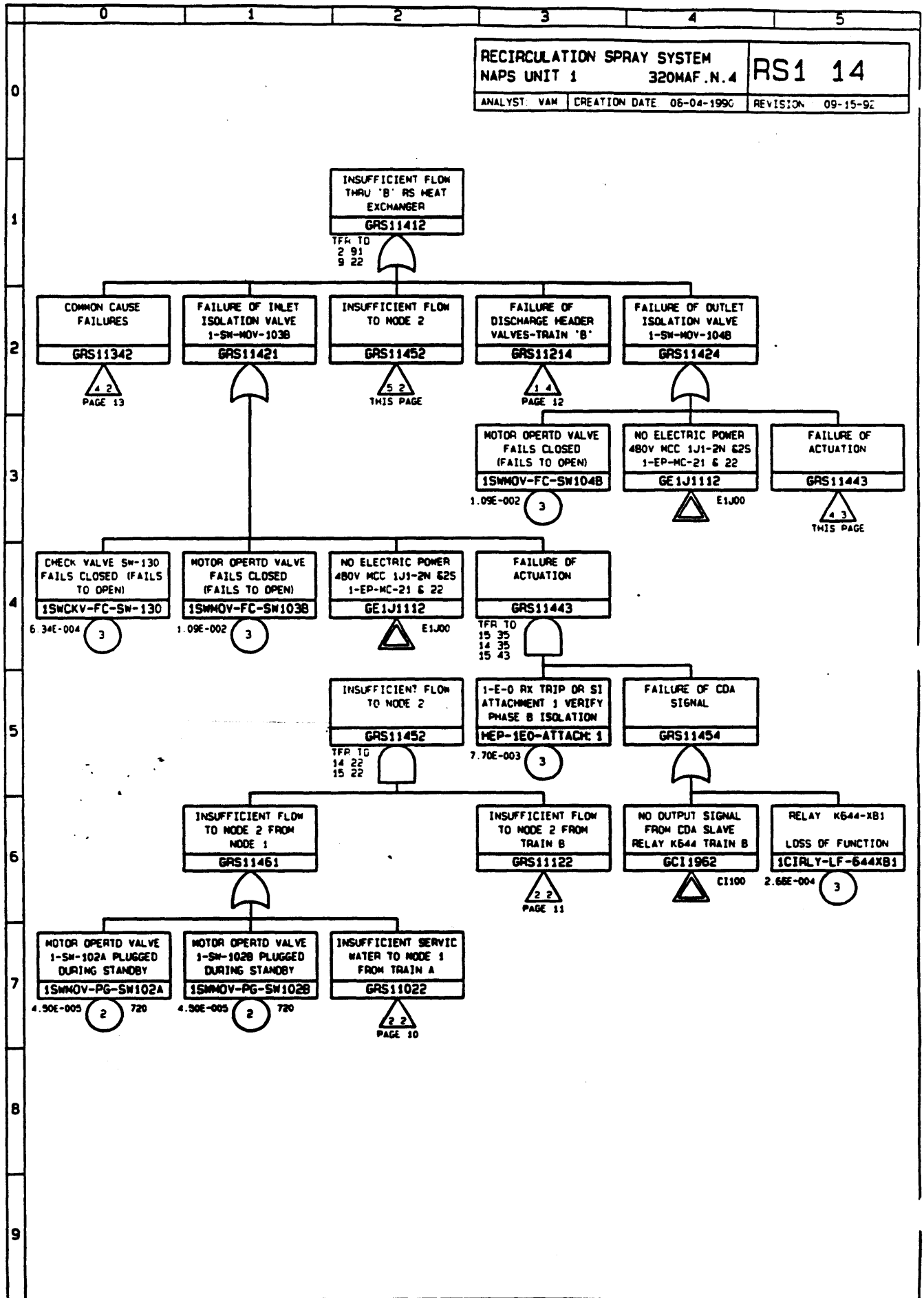


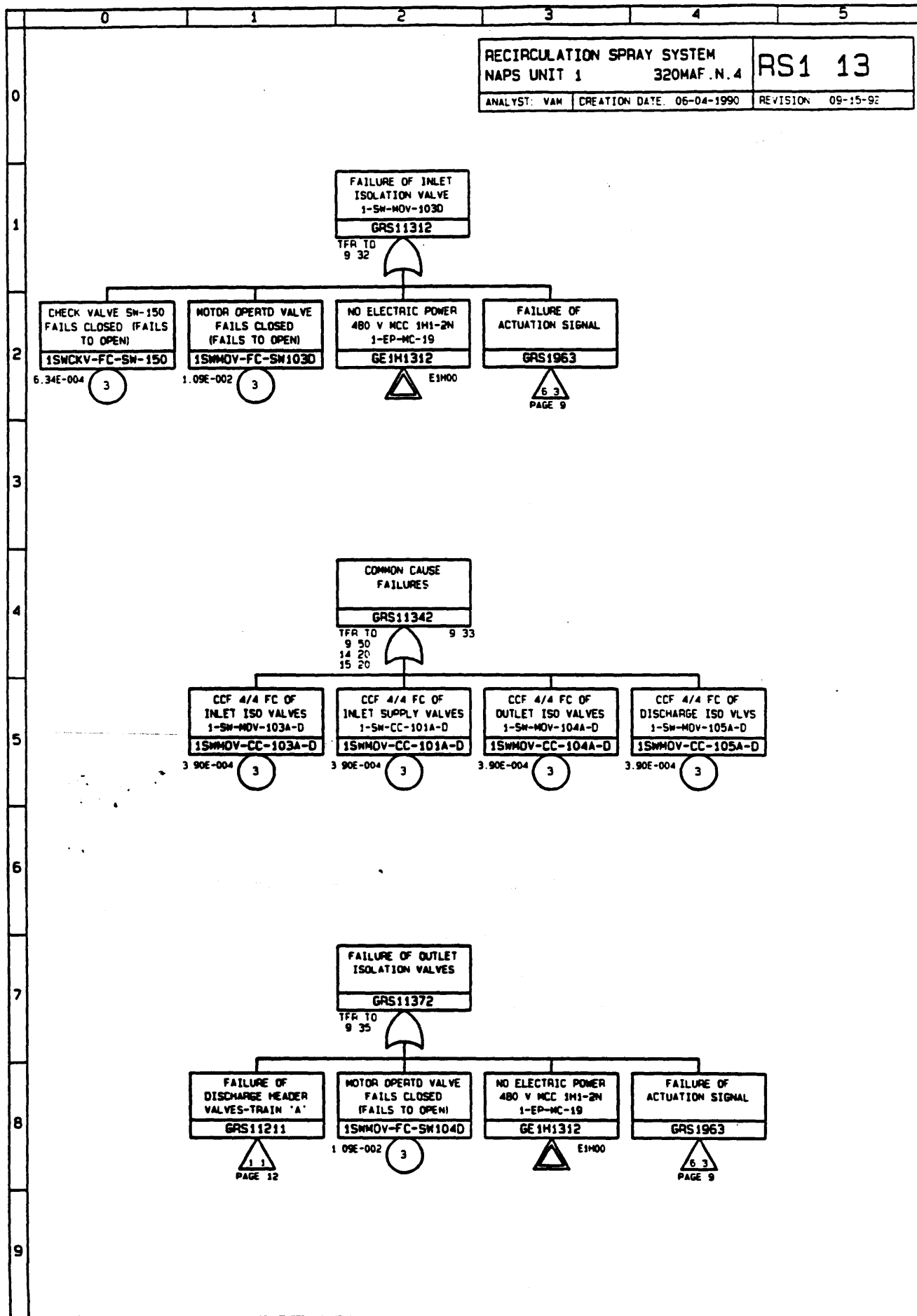
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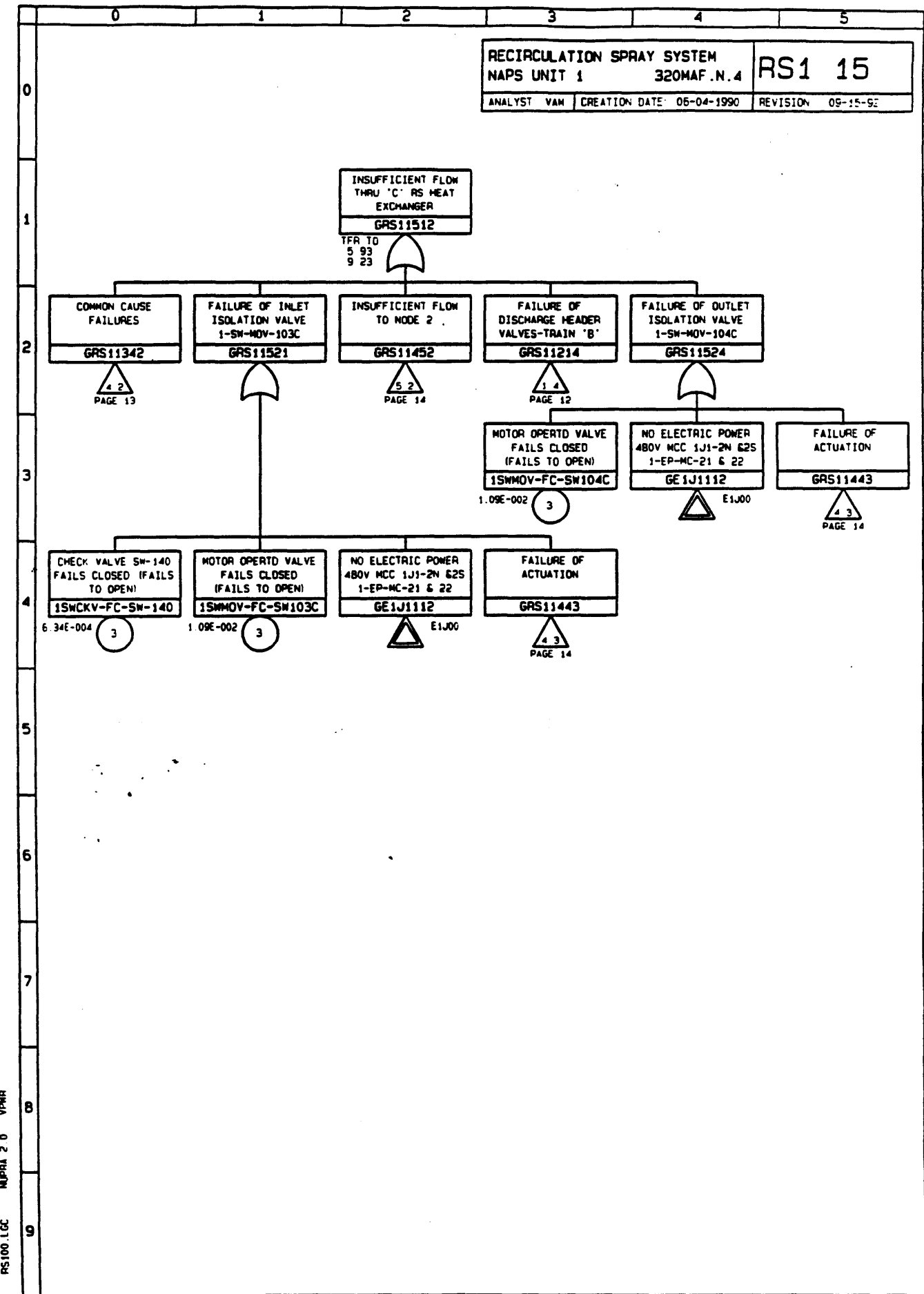
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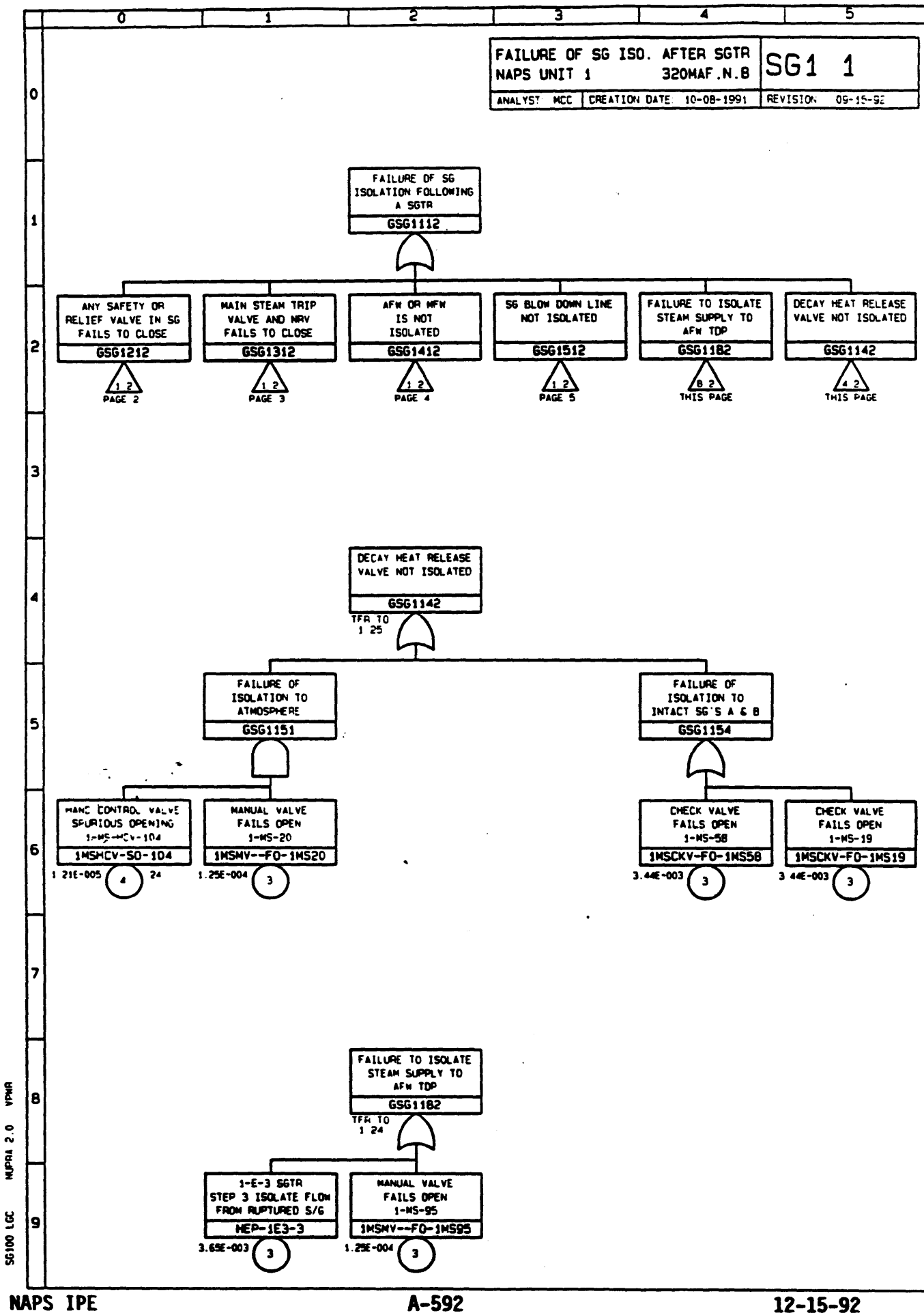




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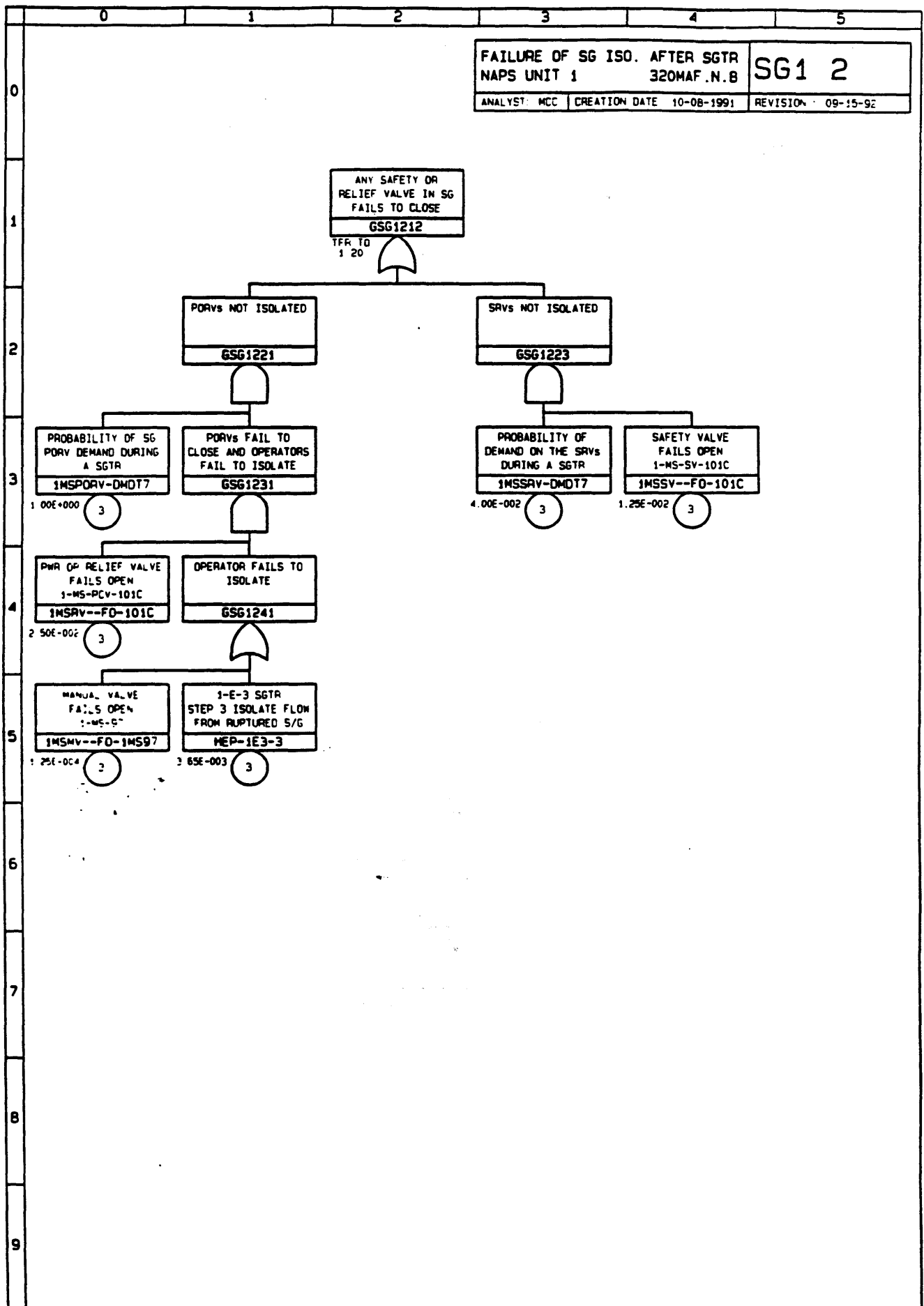


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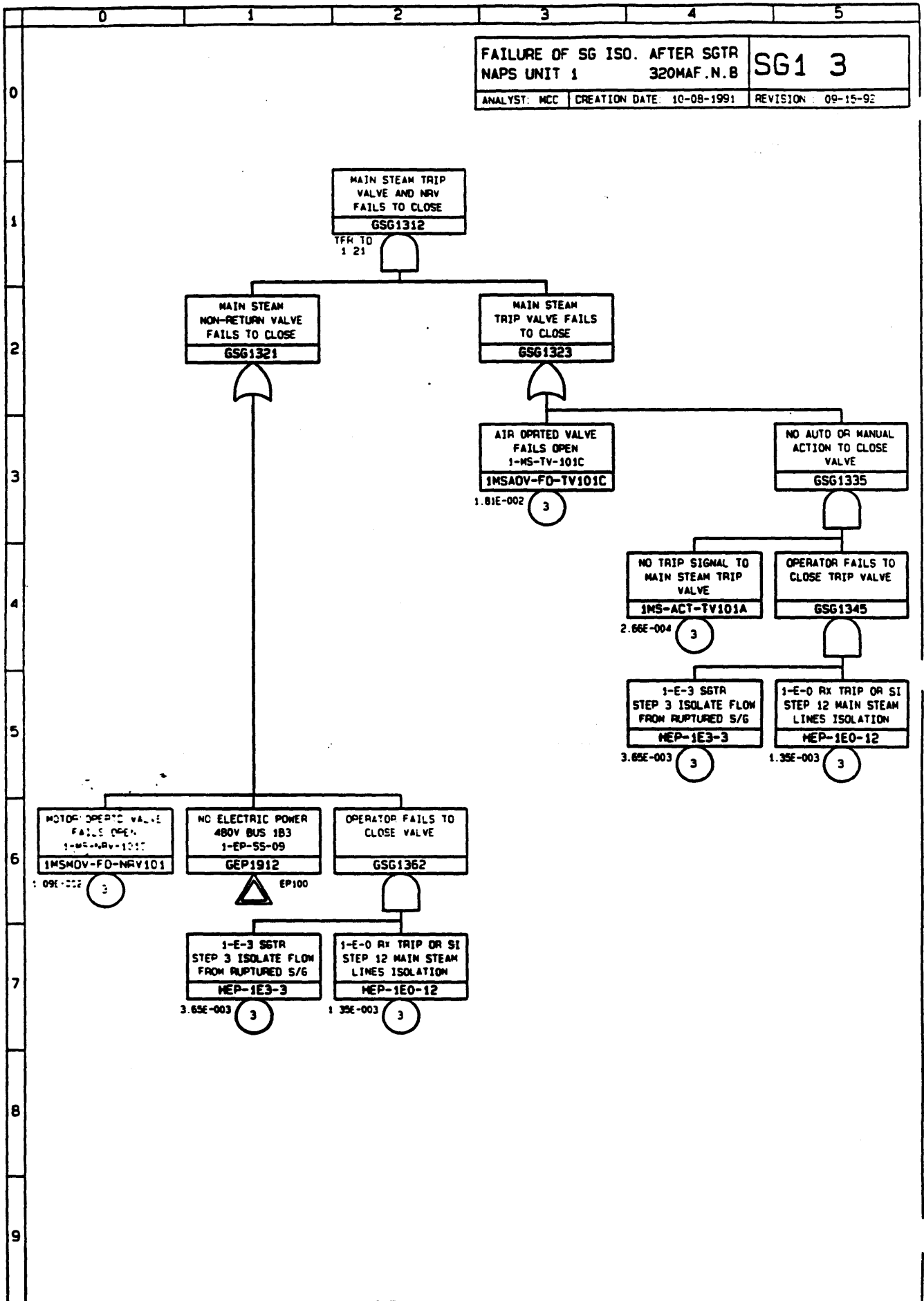
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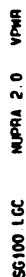


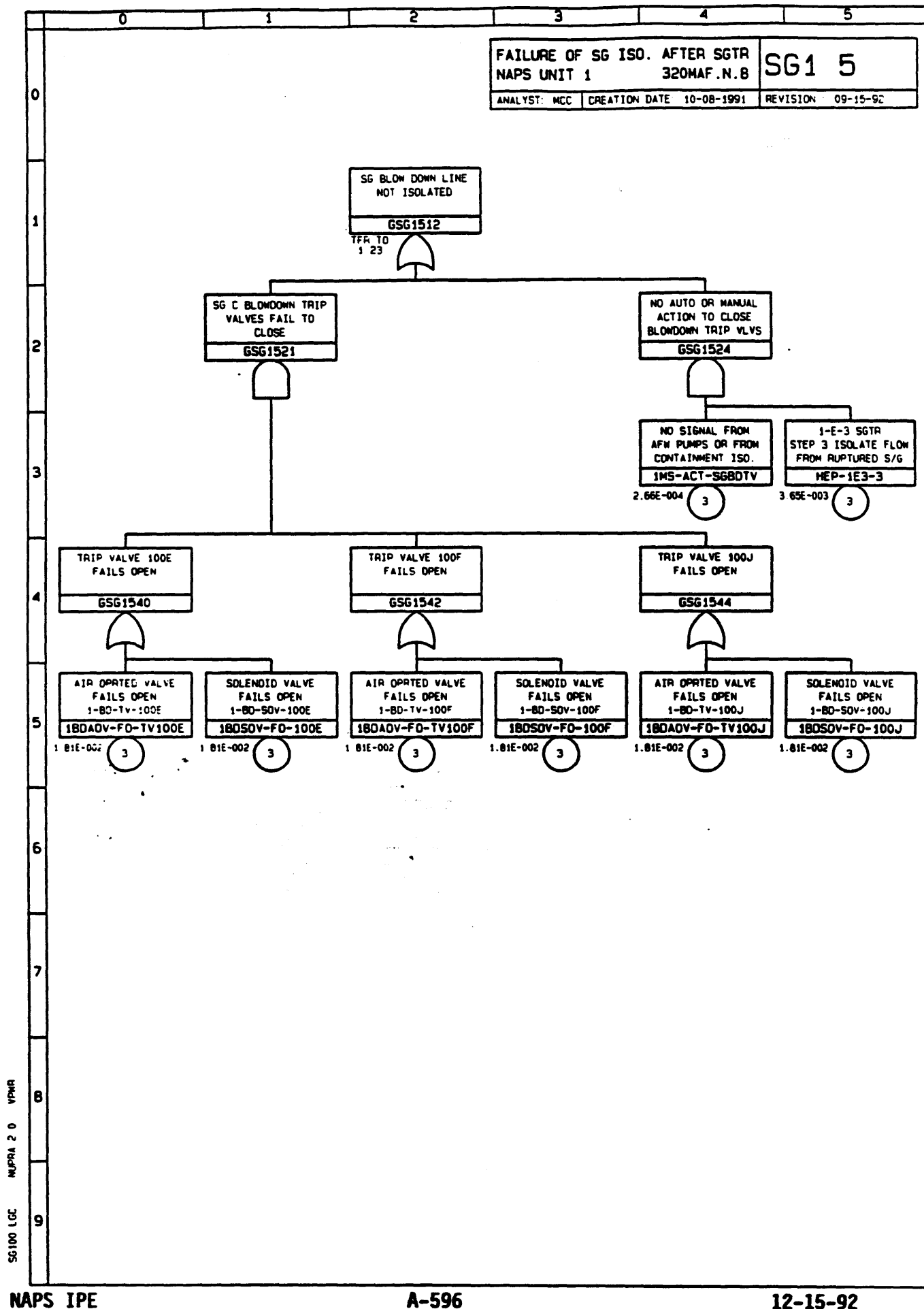
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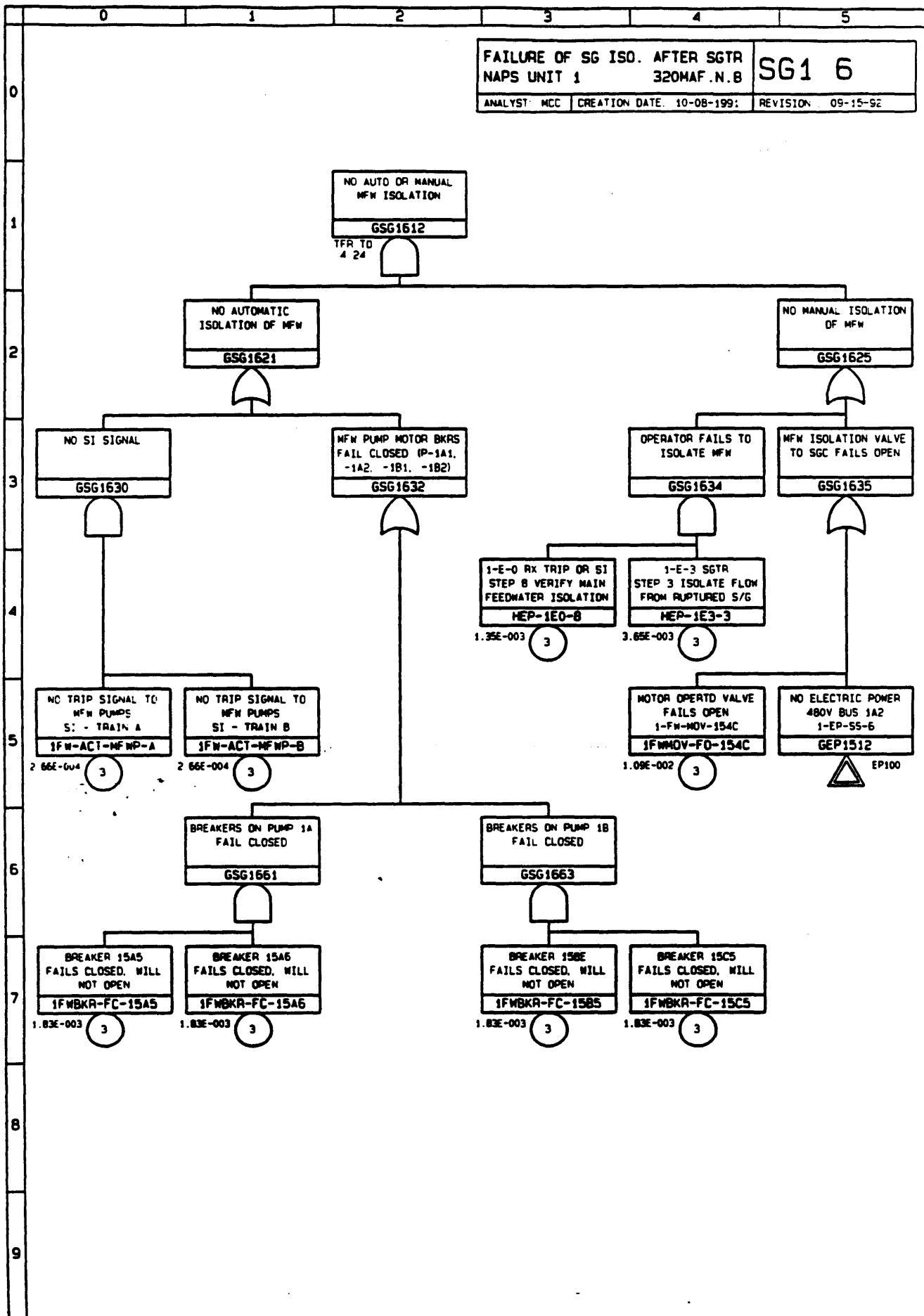
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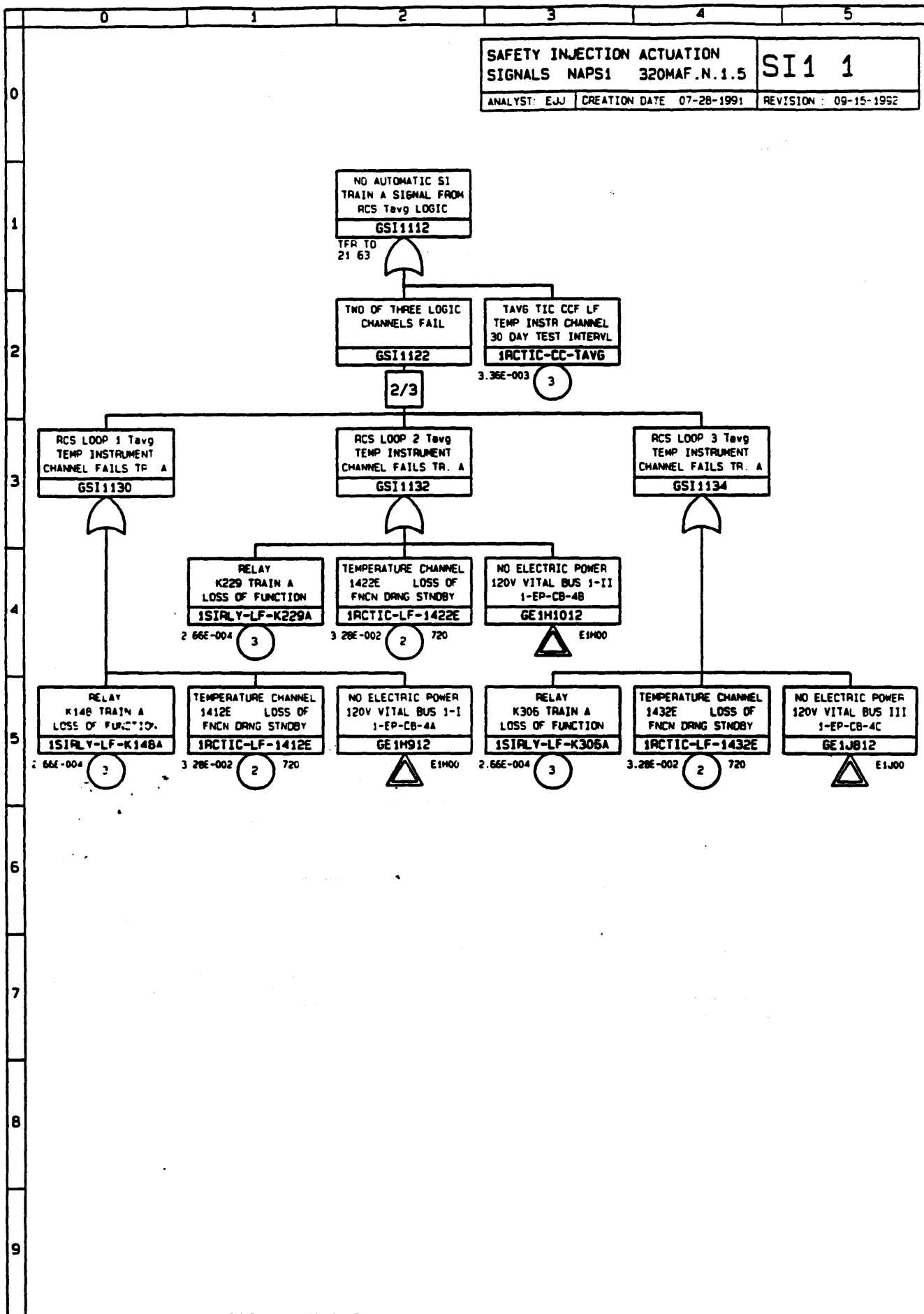



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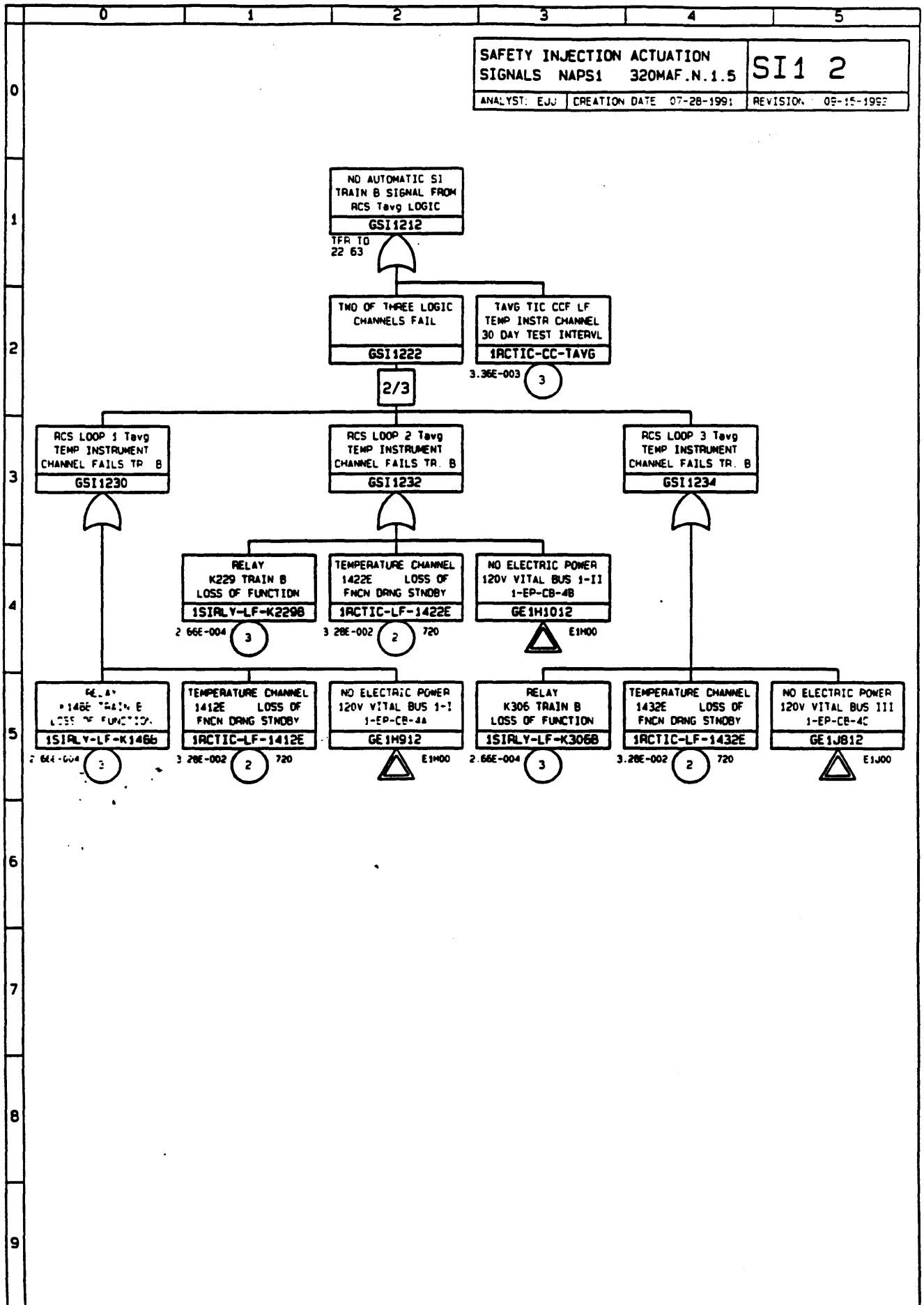
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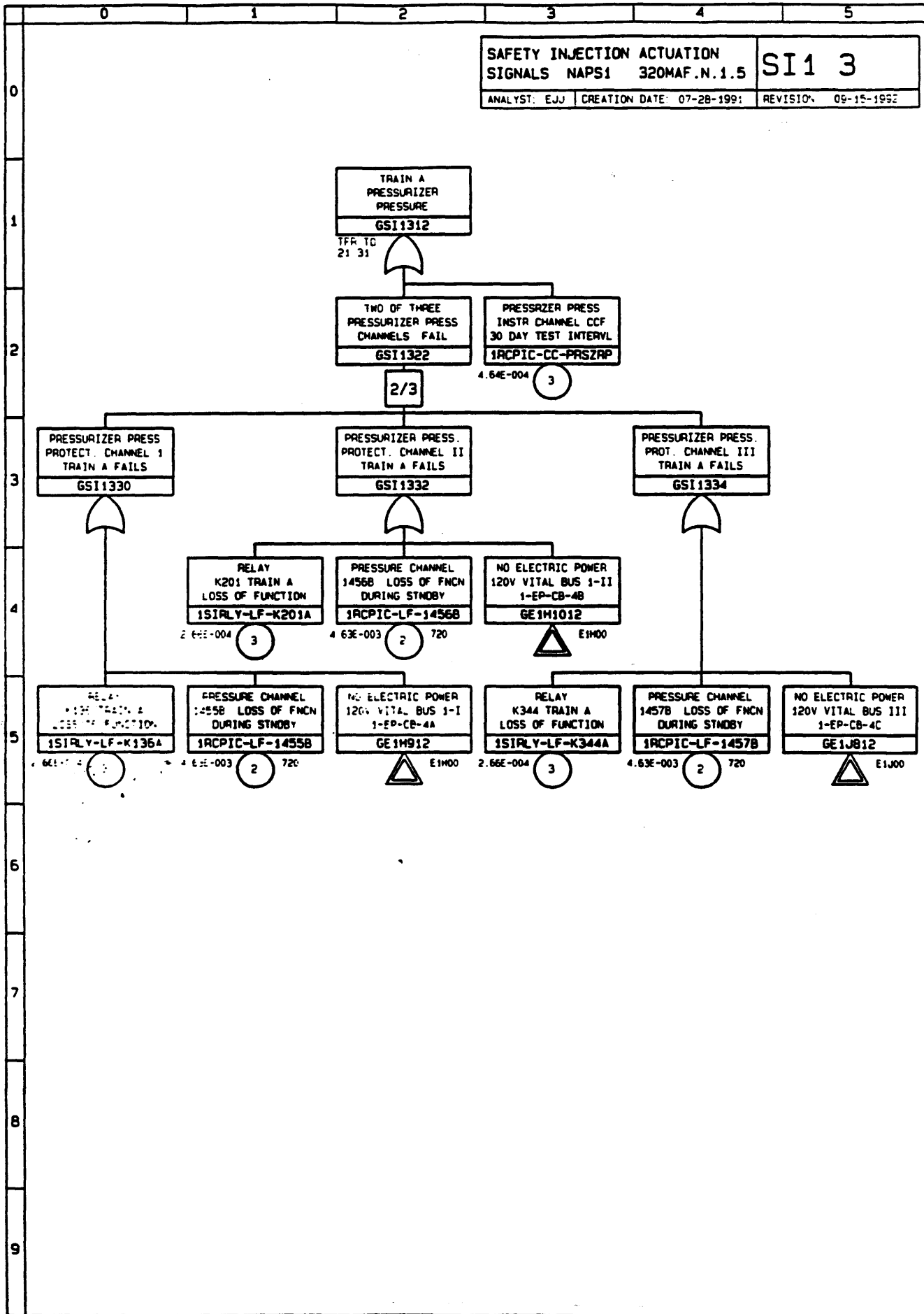
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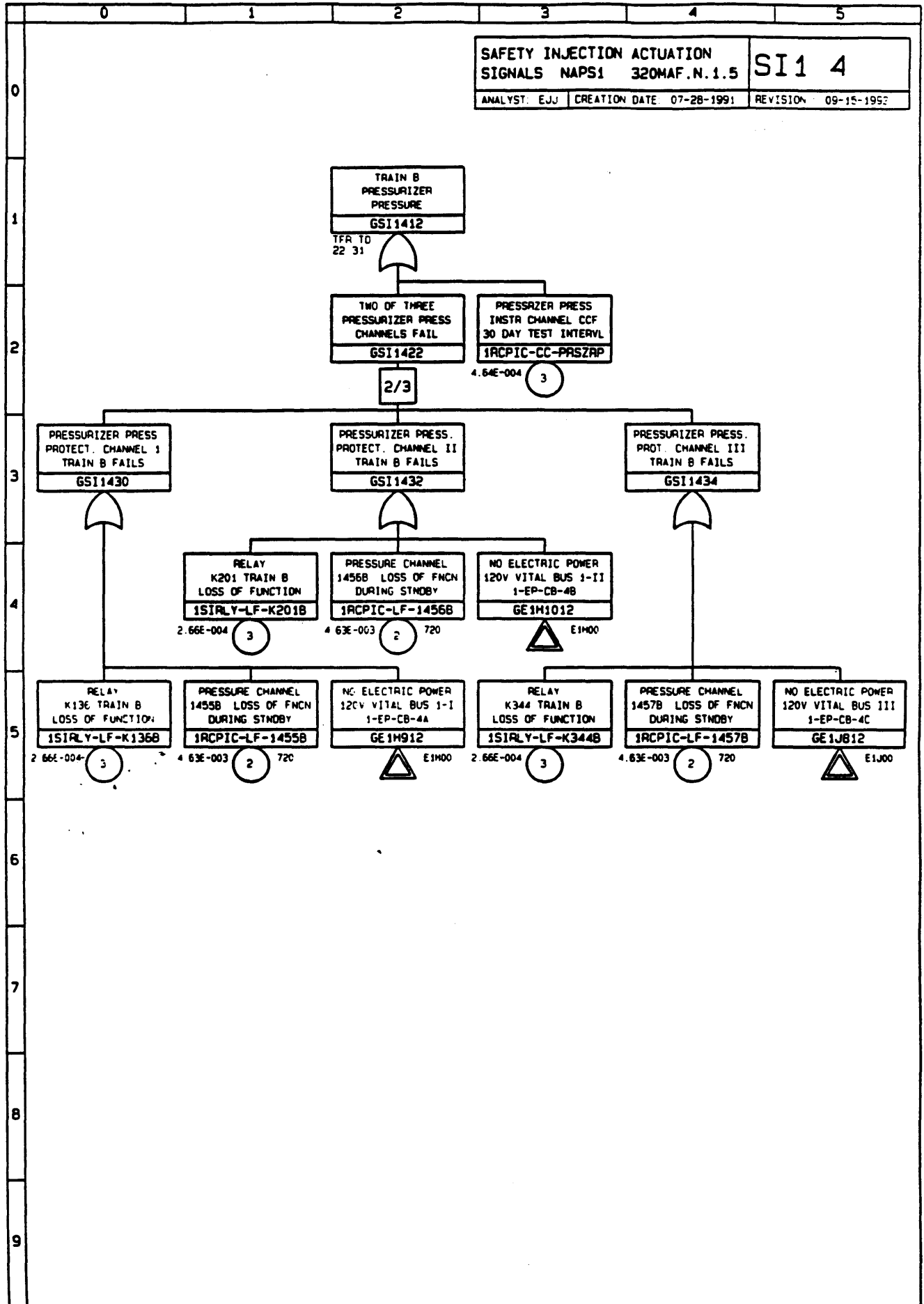


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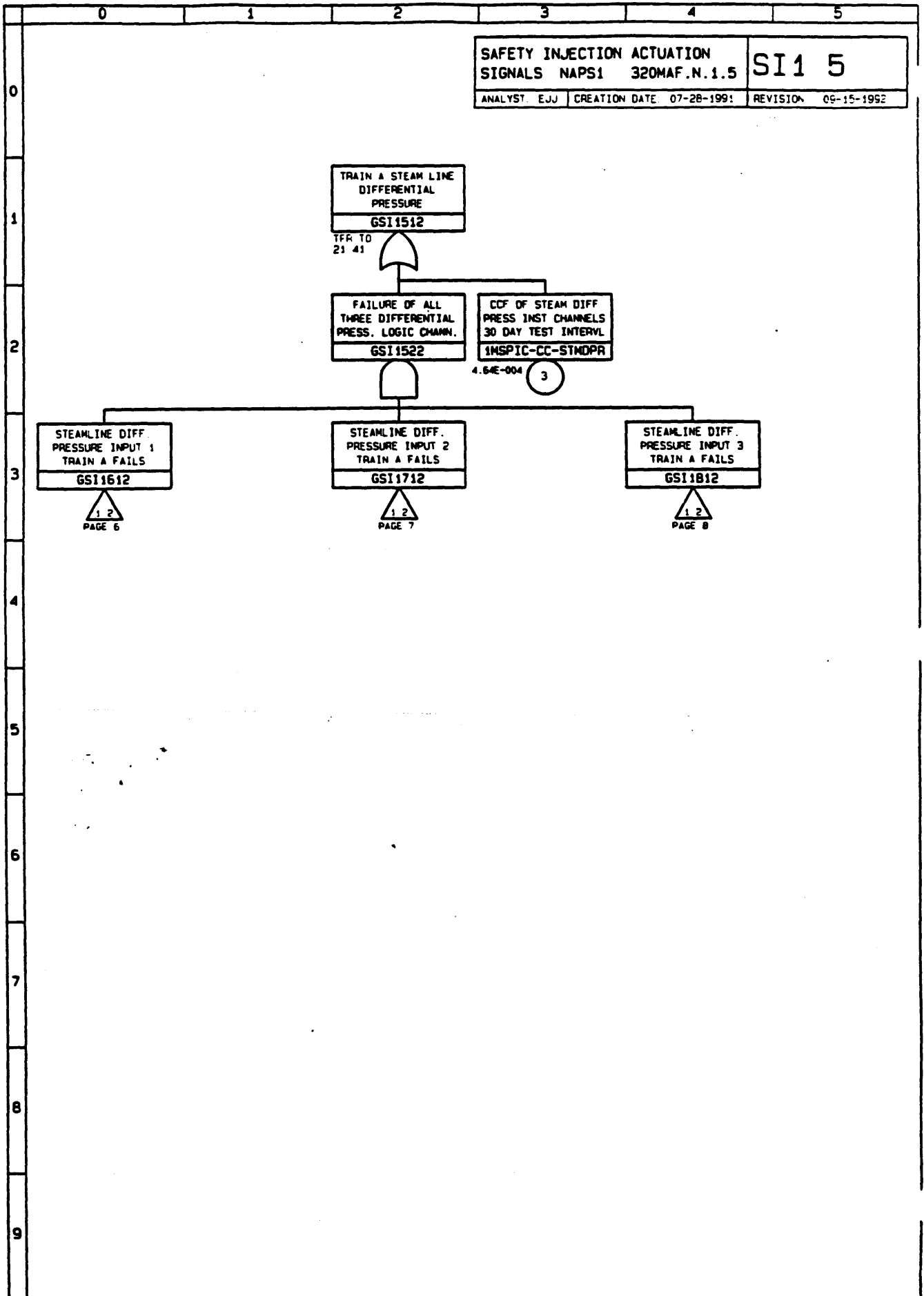


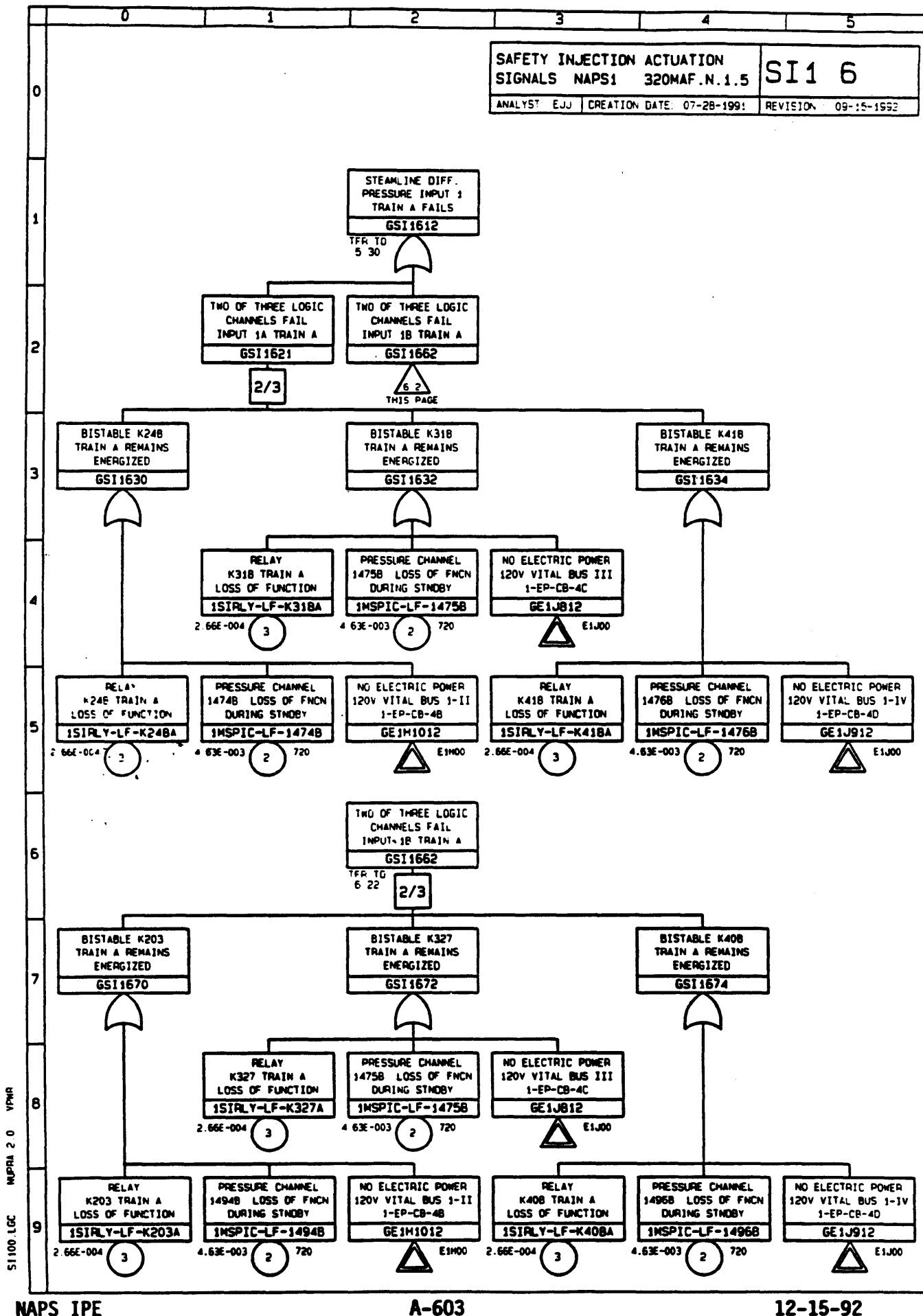


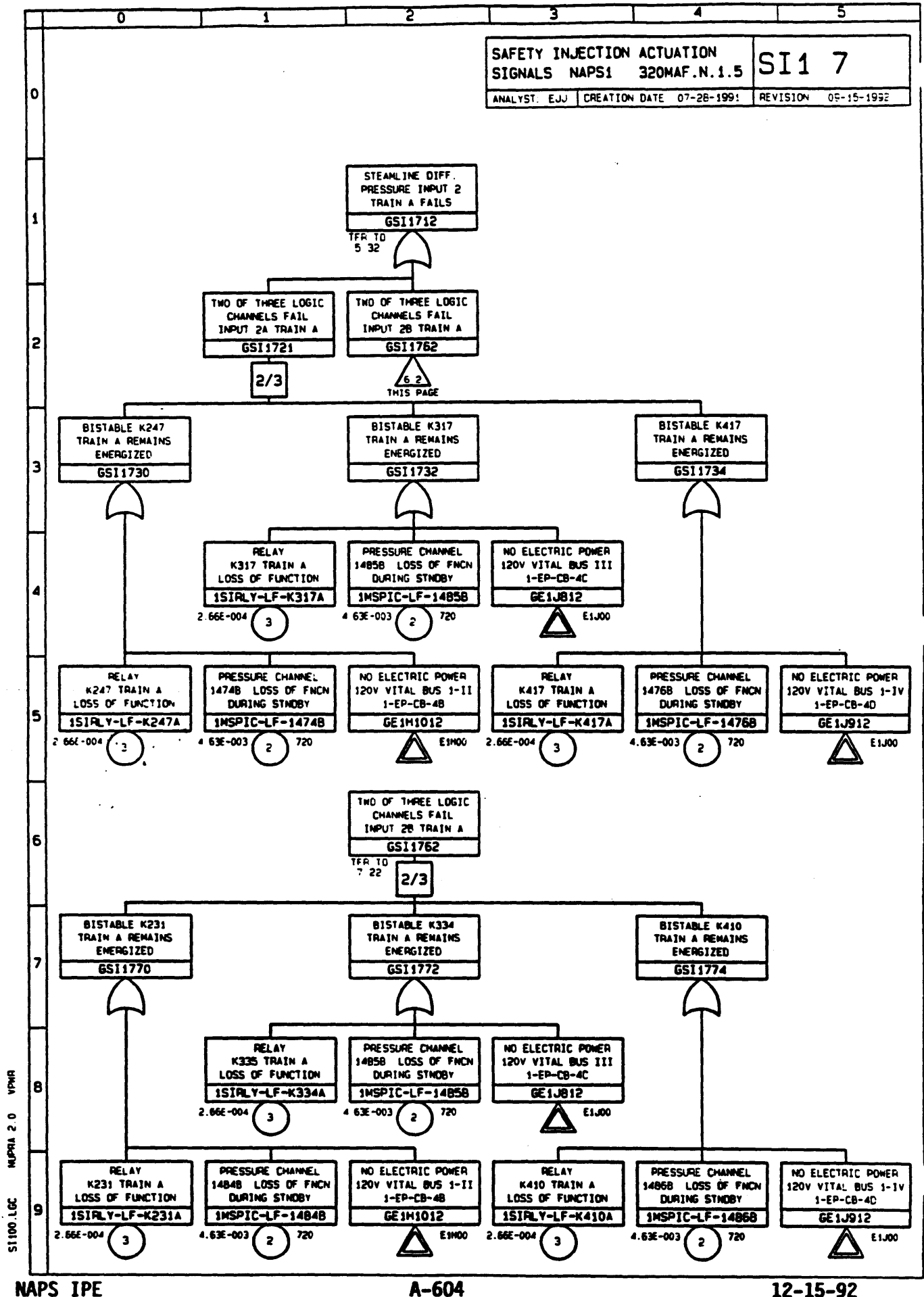
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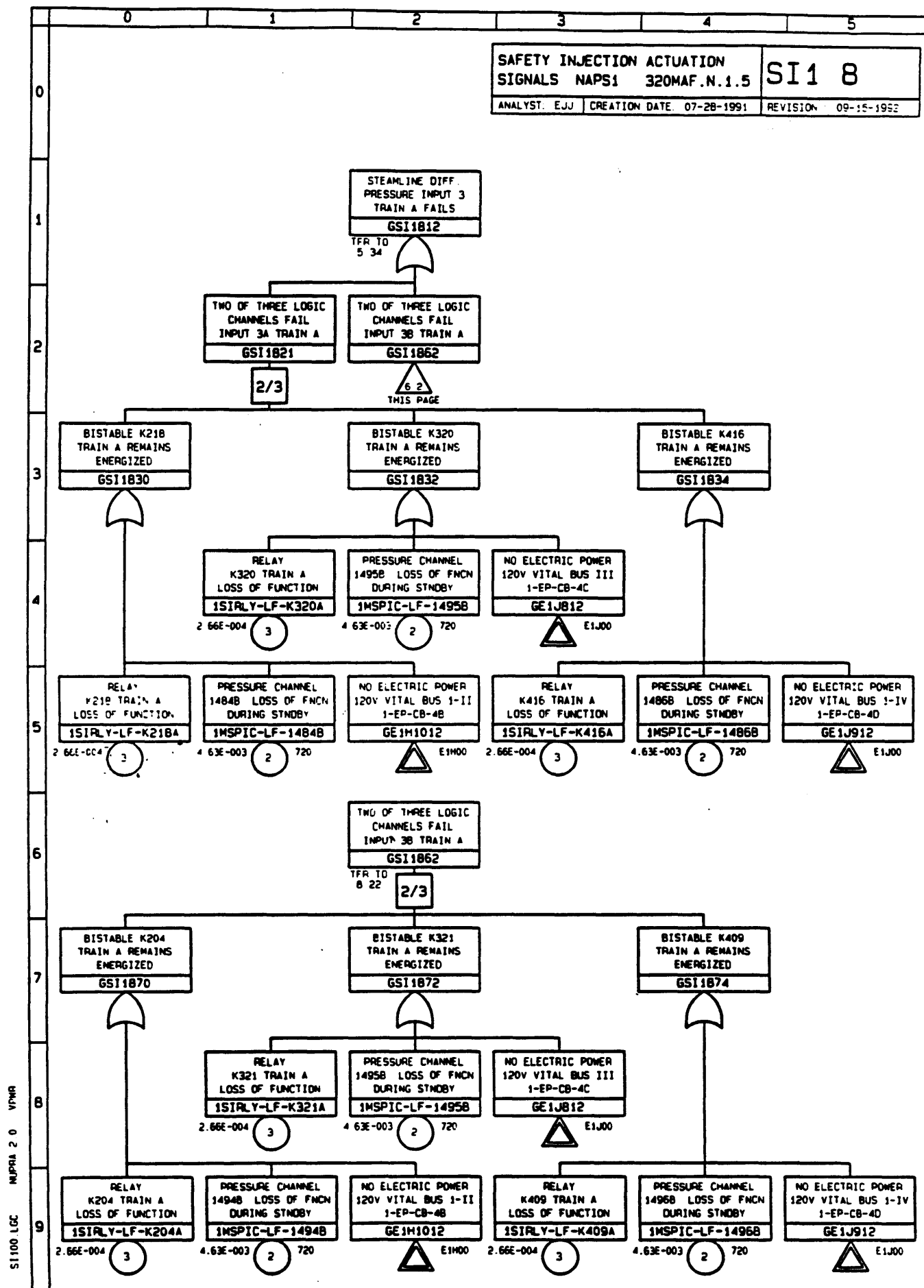


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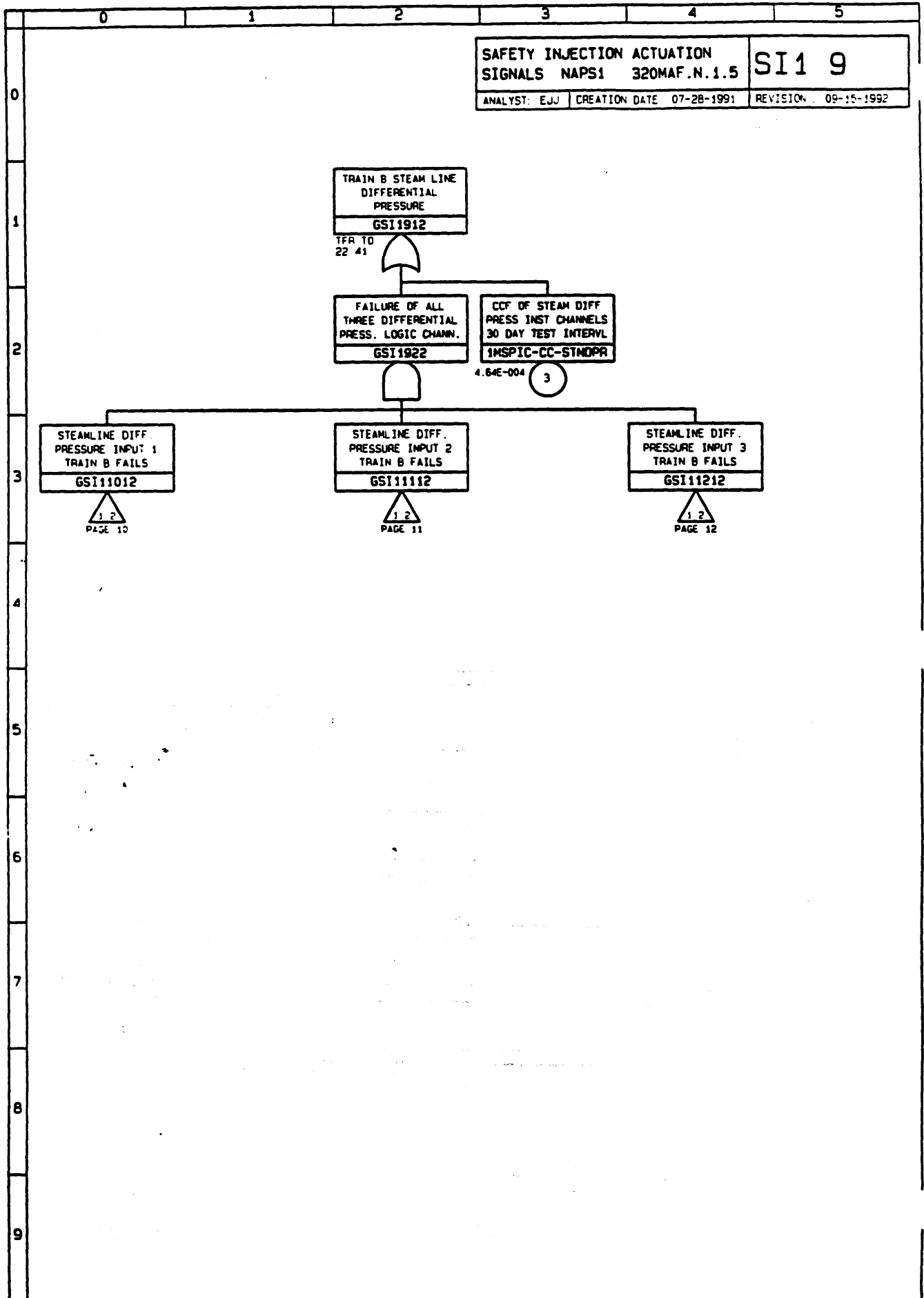


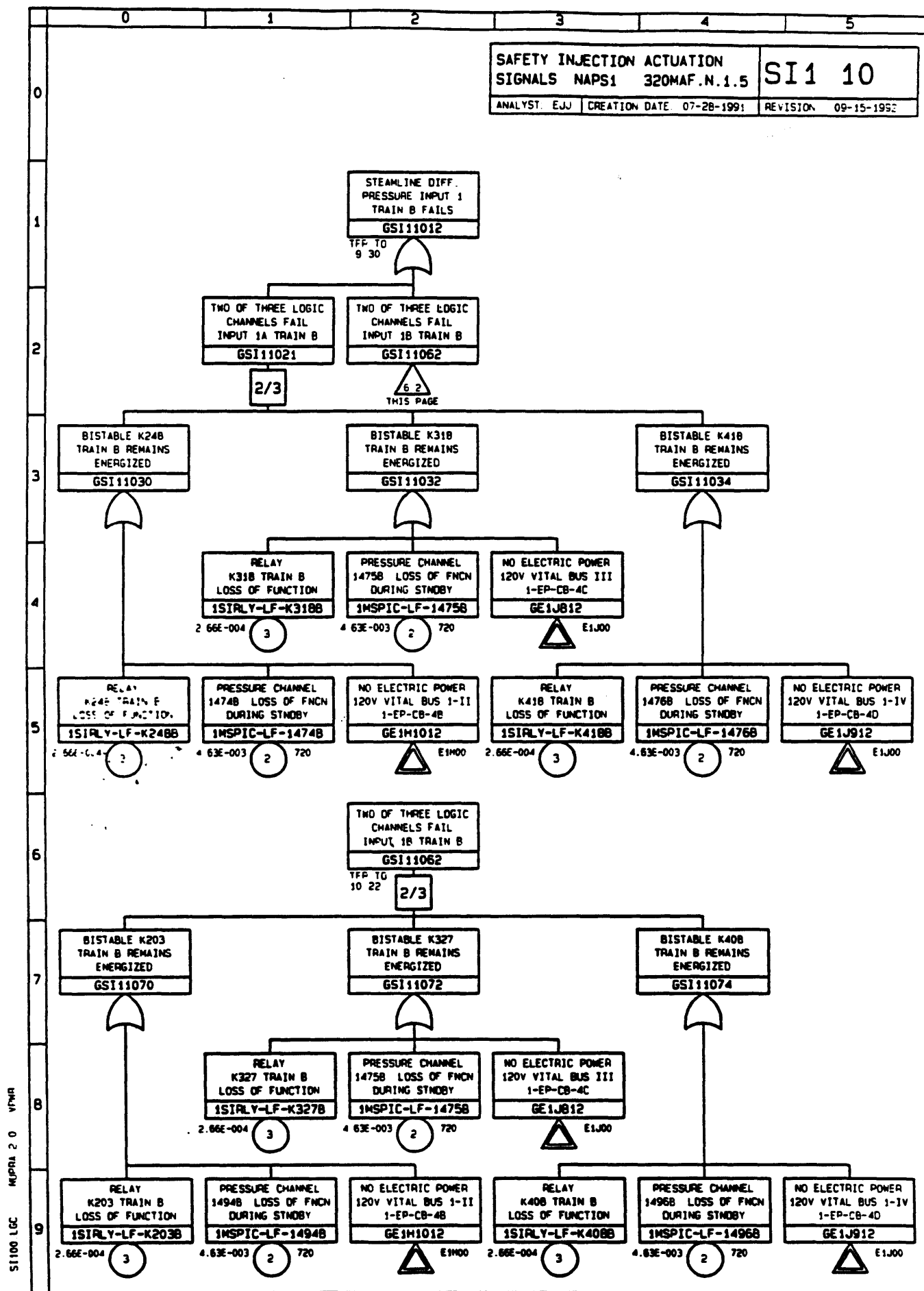






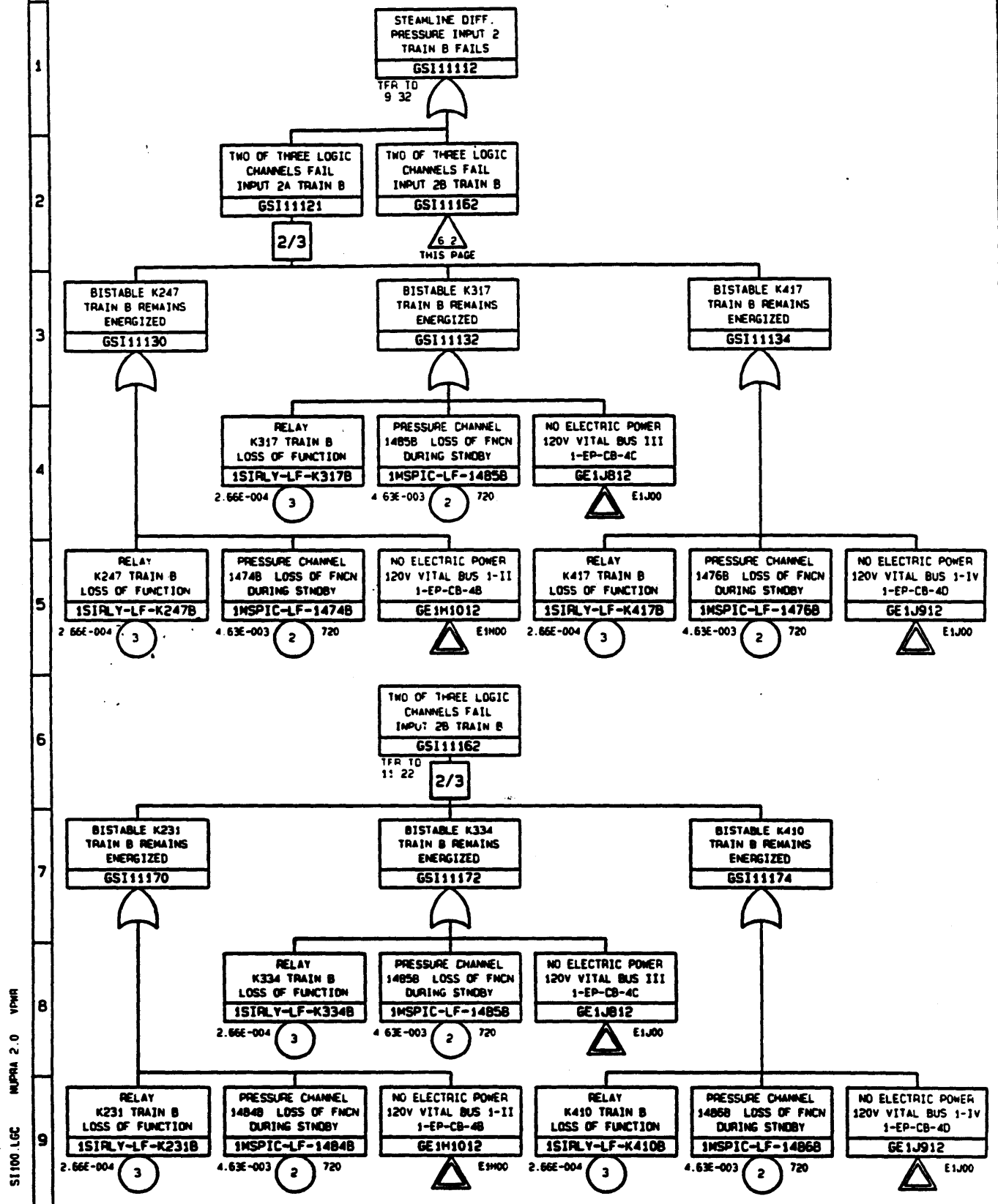
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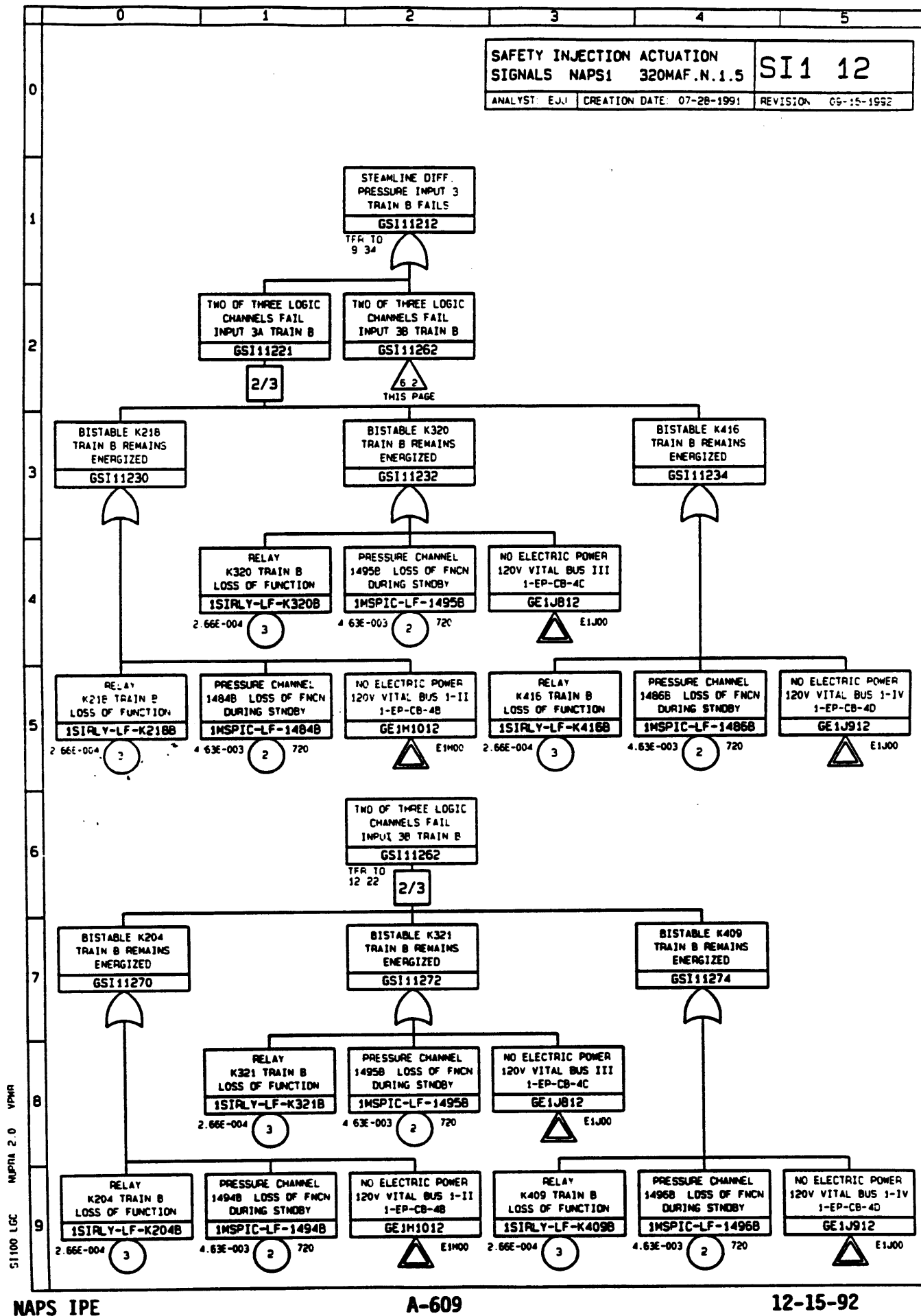


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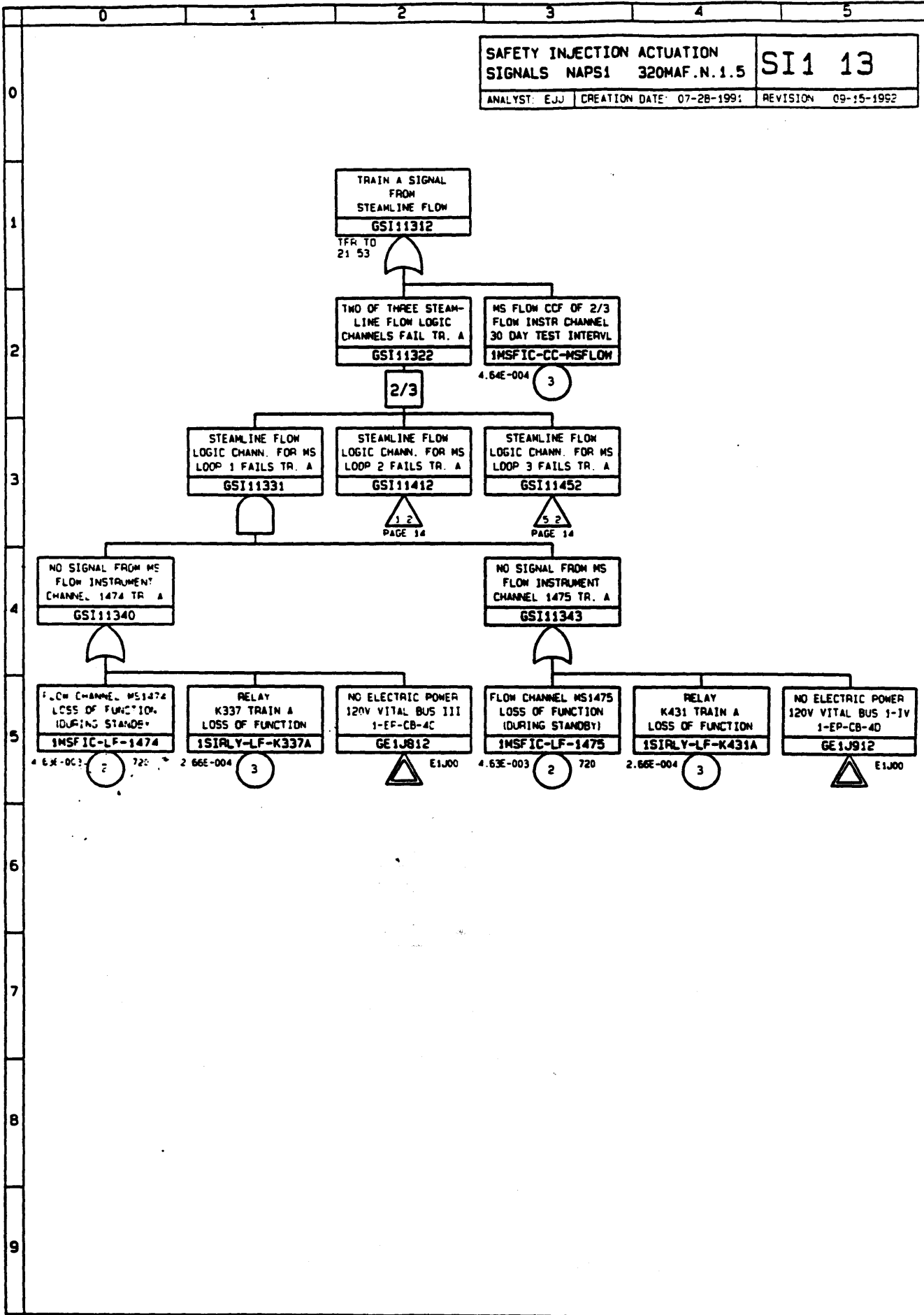
ANALYST: EJJ	CREATION DATE: 07-28-1991	REVISION: 09-15-1992
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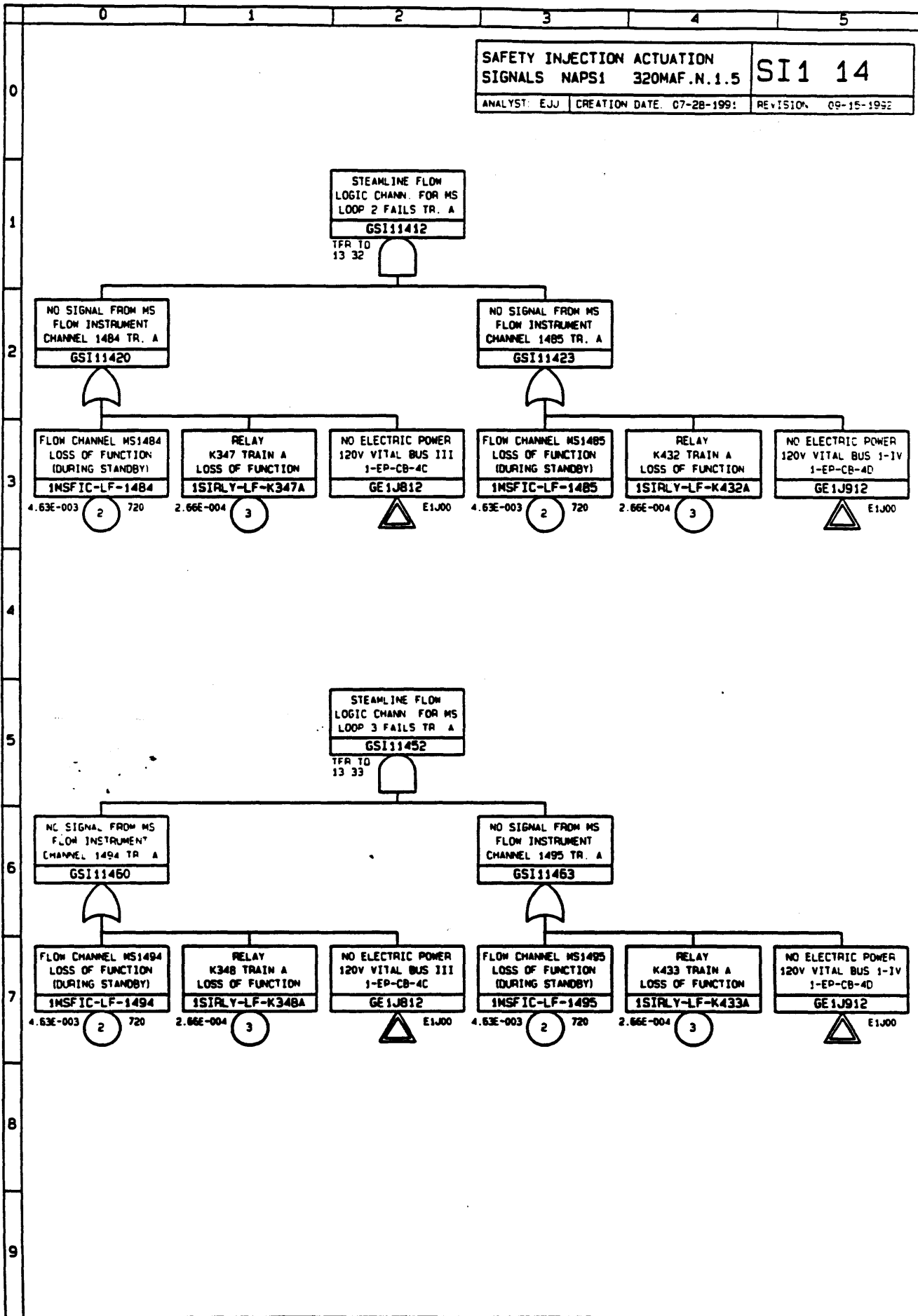




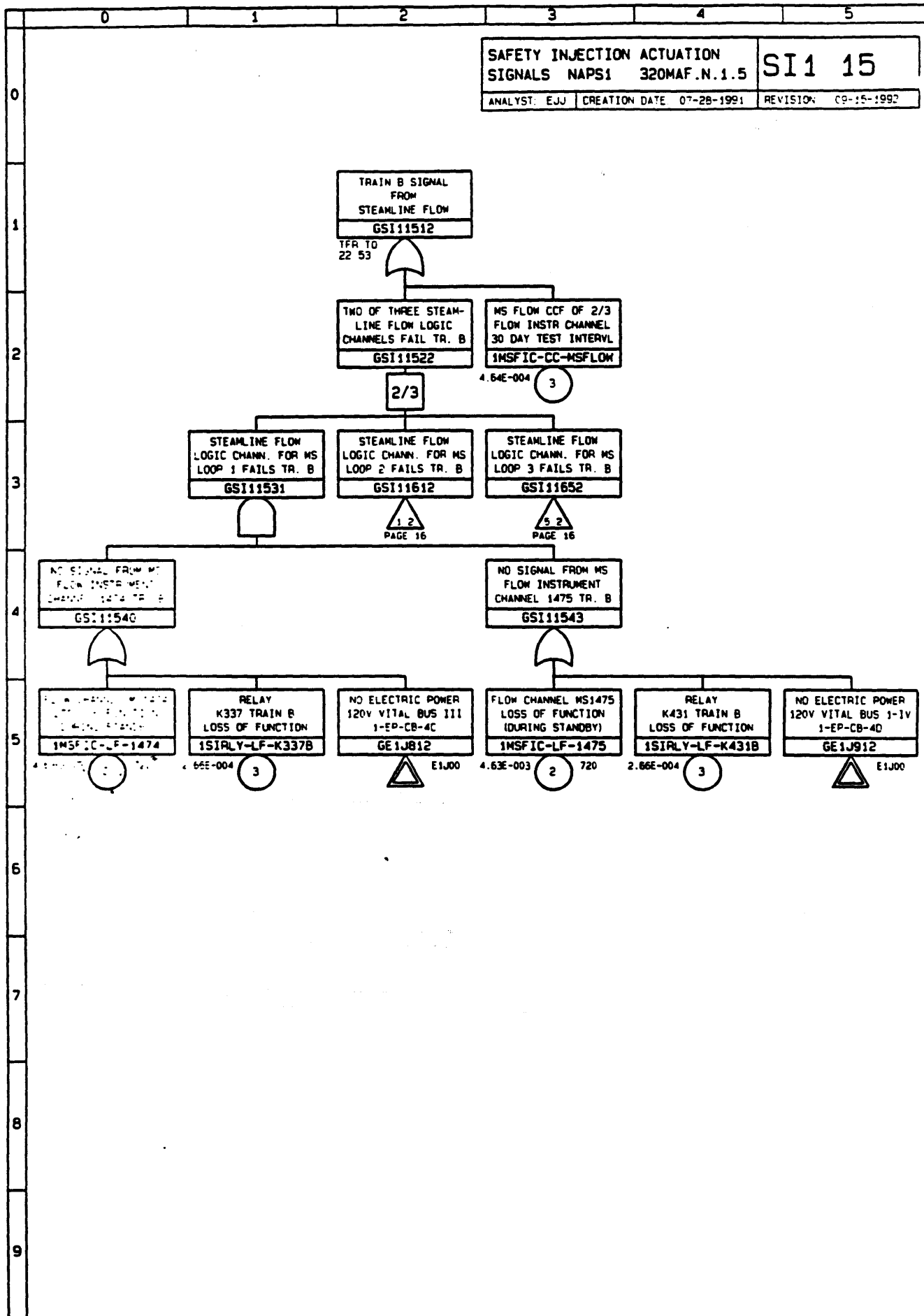
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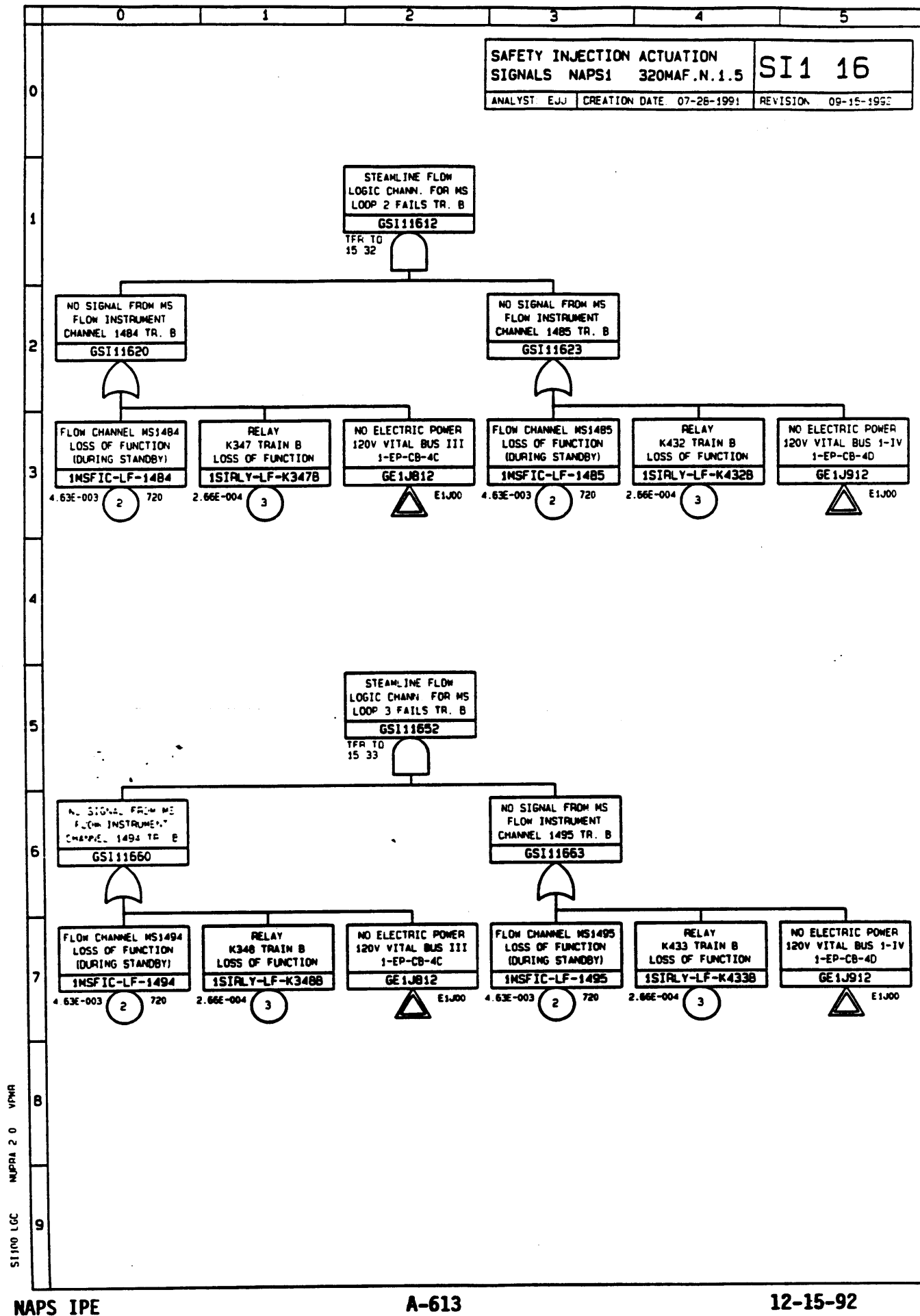


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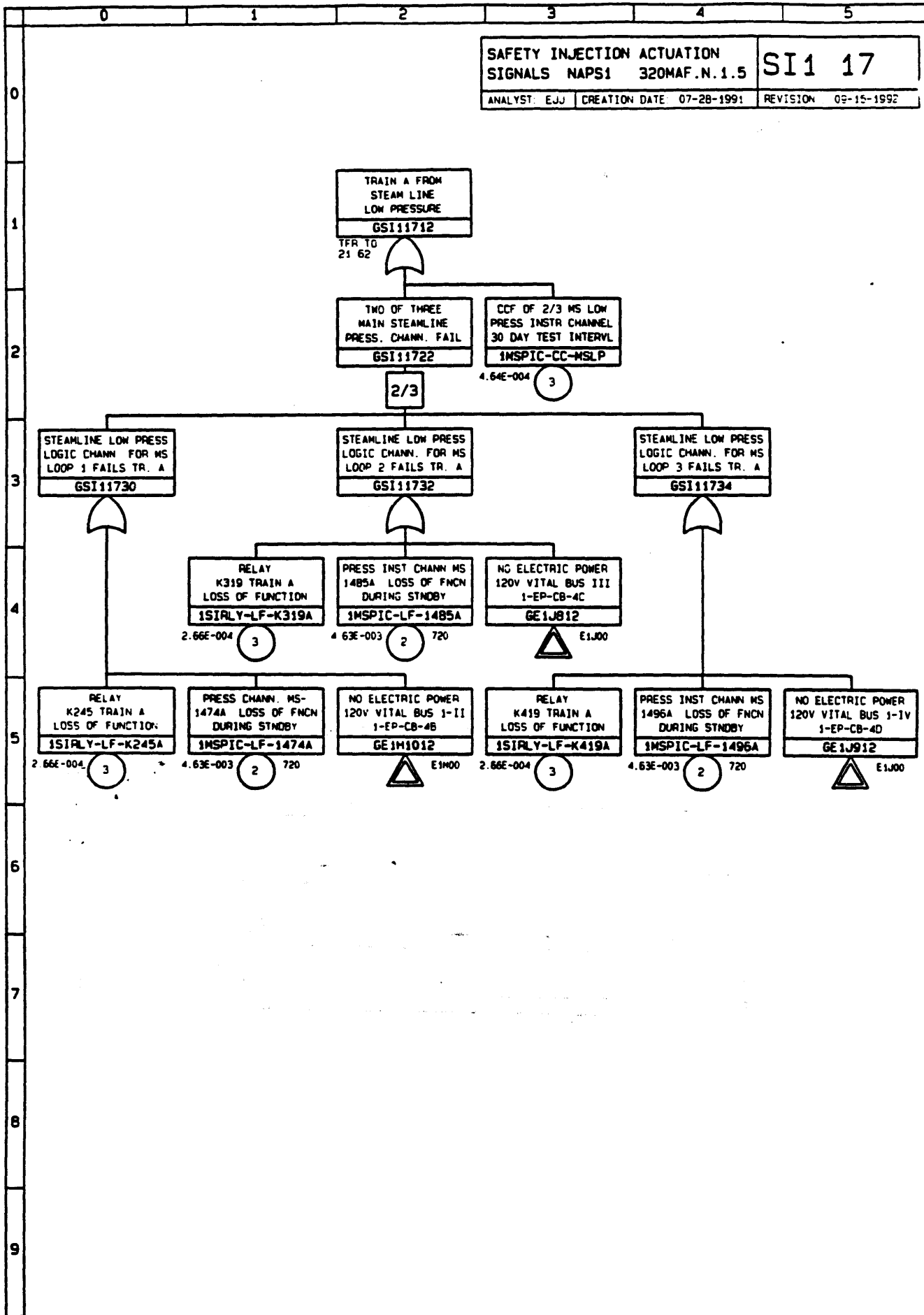


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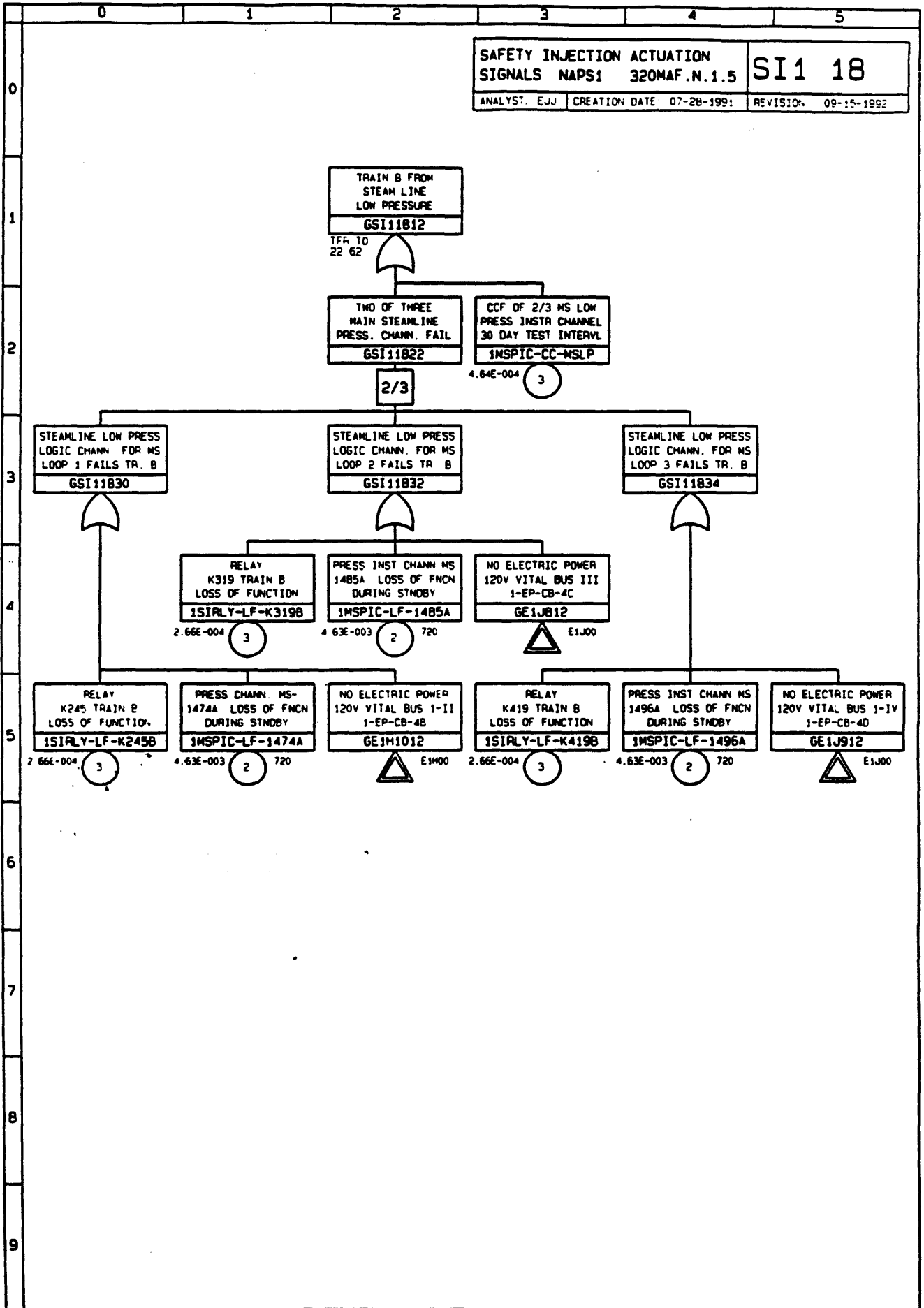


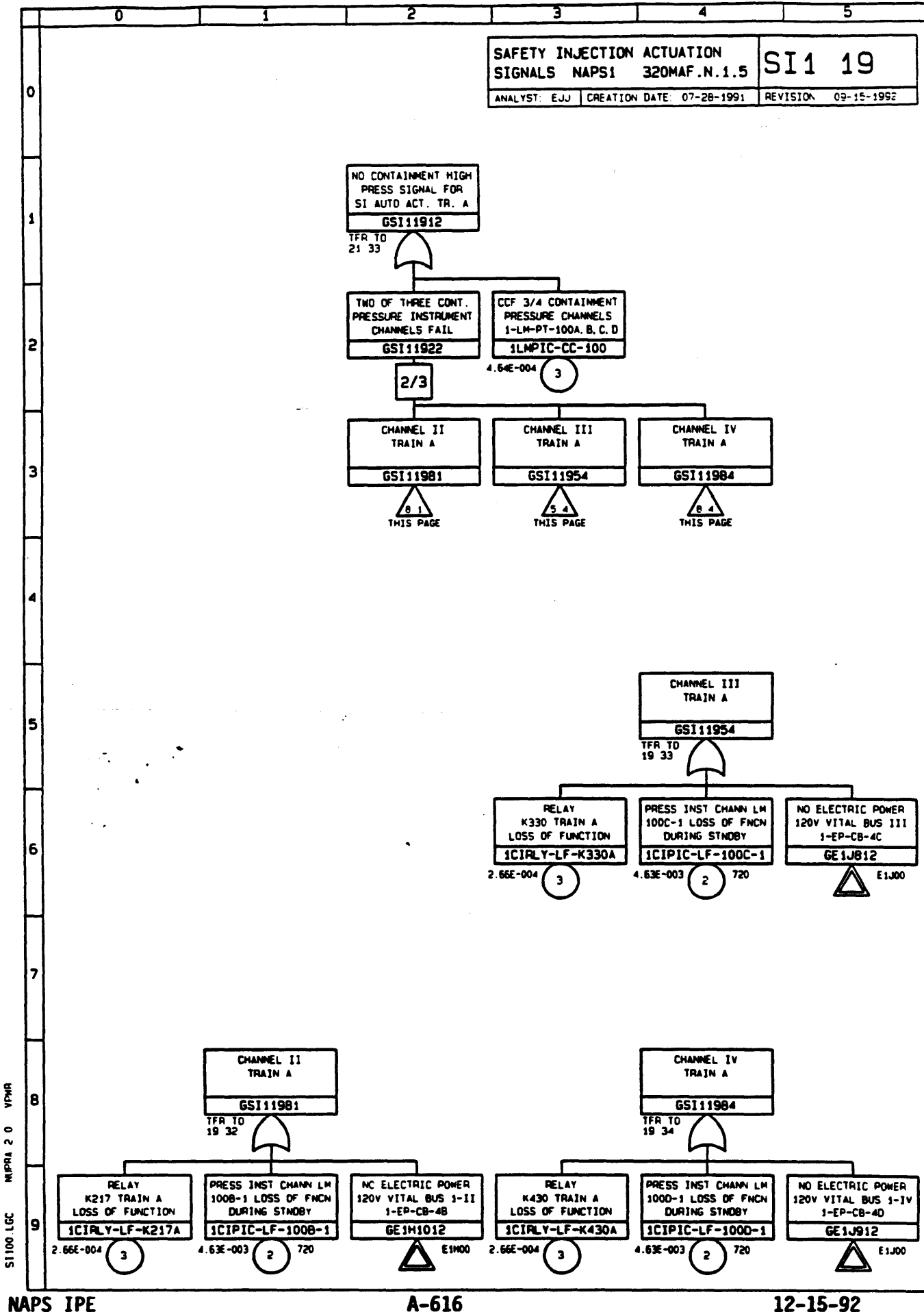


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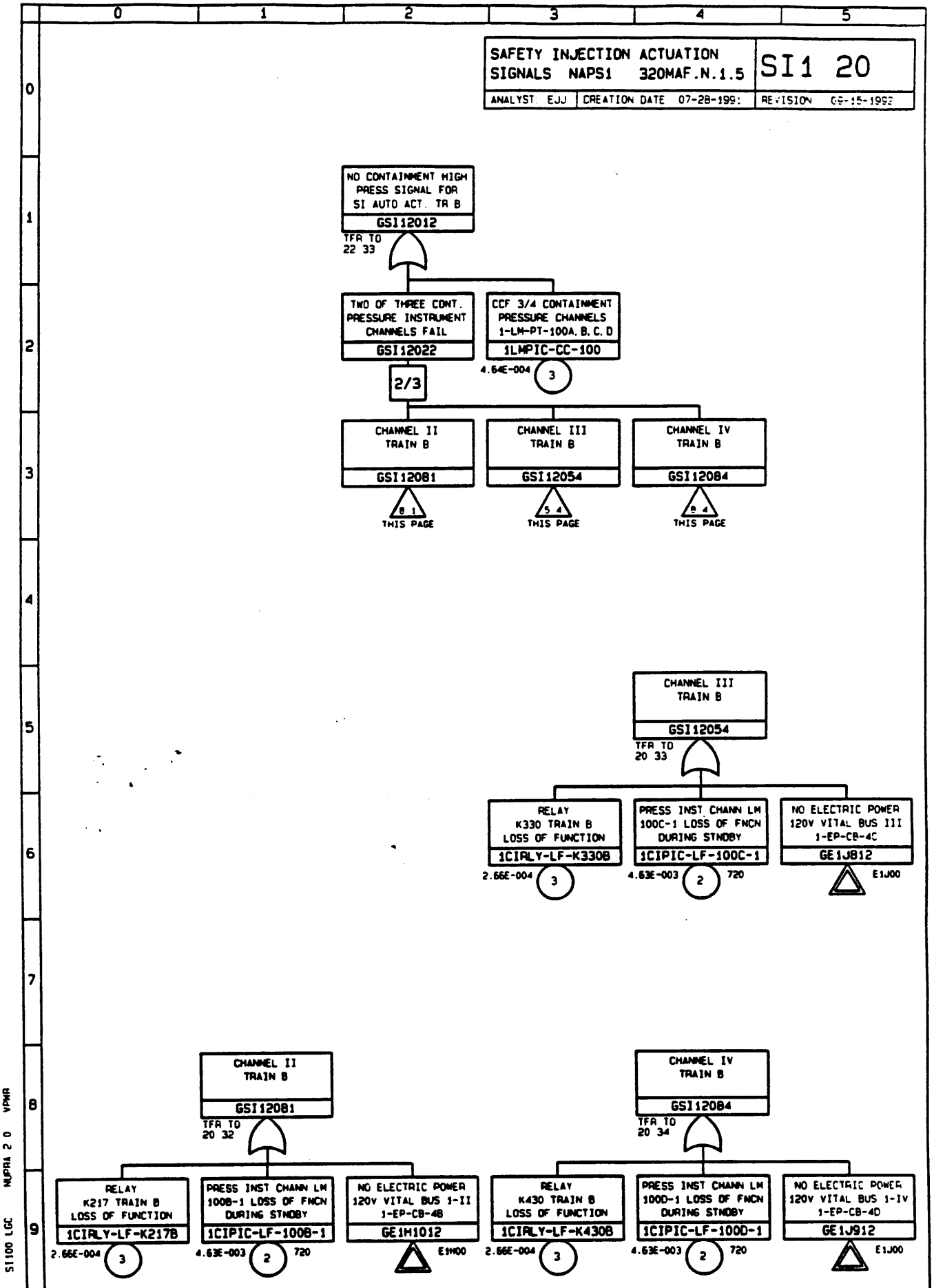
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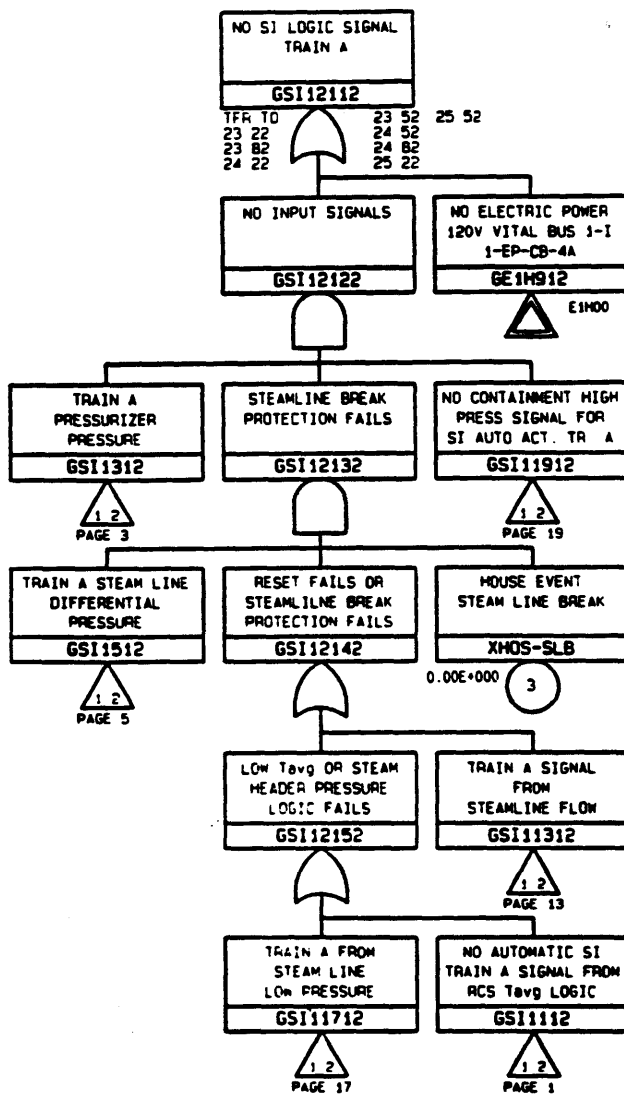


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SAFETY INJECTION ACTUATION  
SIGNALS NAPS1 320MAF.N.1.5

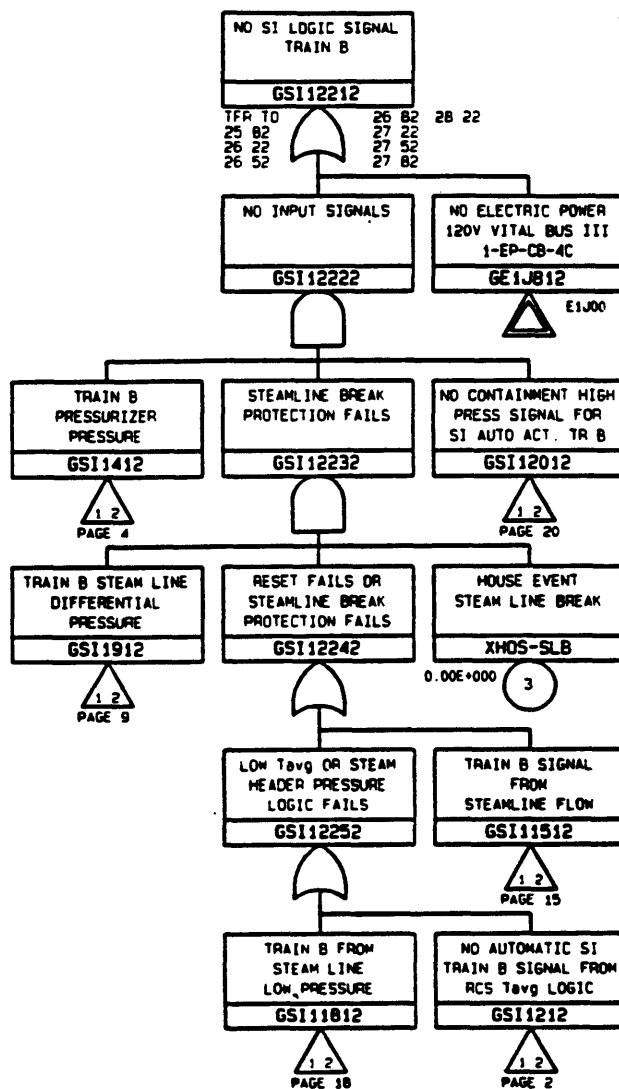
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ANALYST: EJJ CREATION DATE 07-28-1991 REVISION 09-15-1992

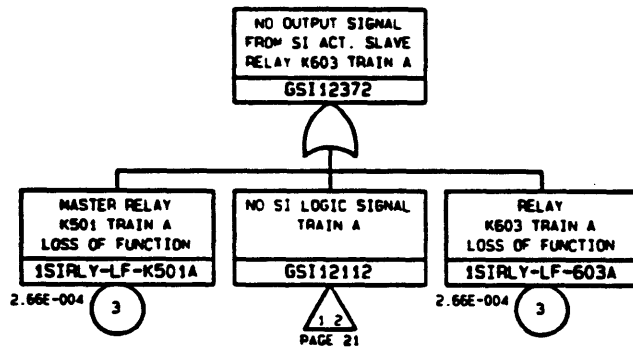
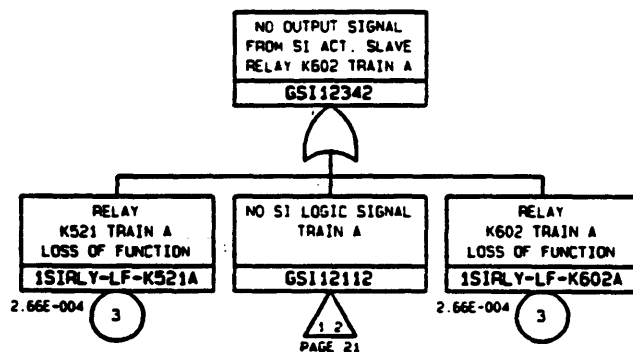
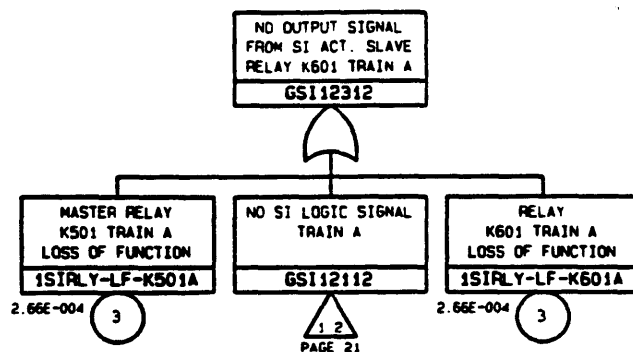


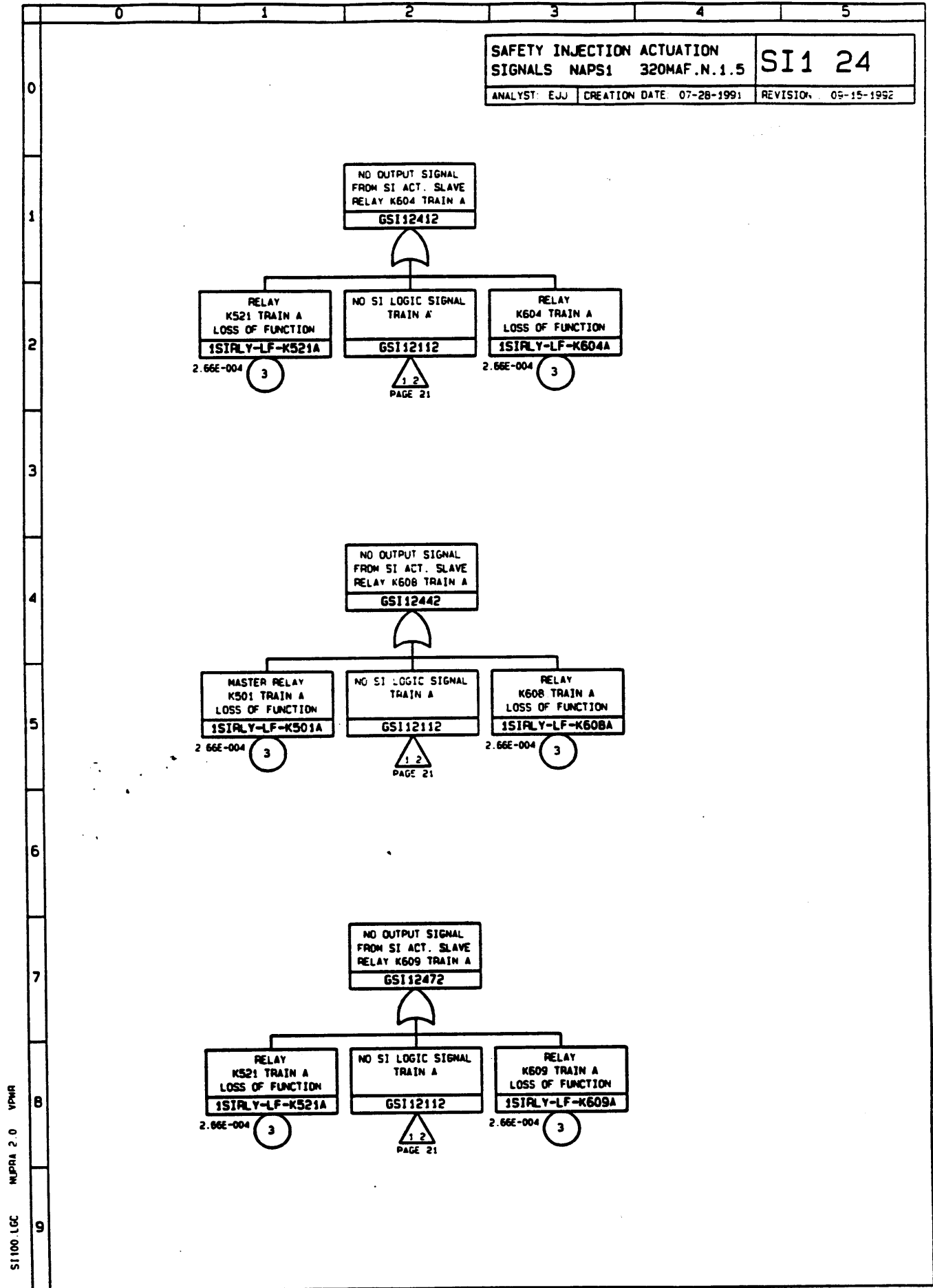
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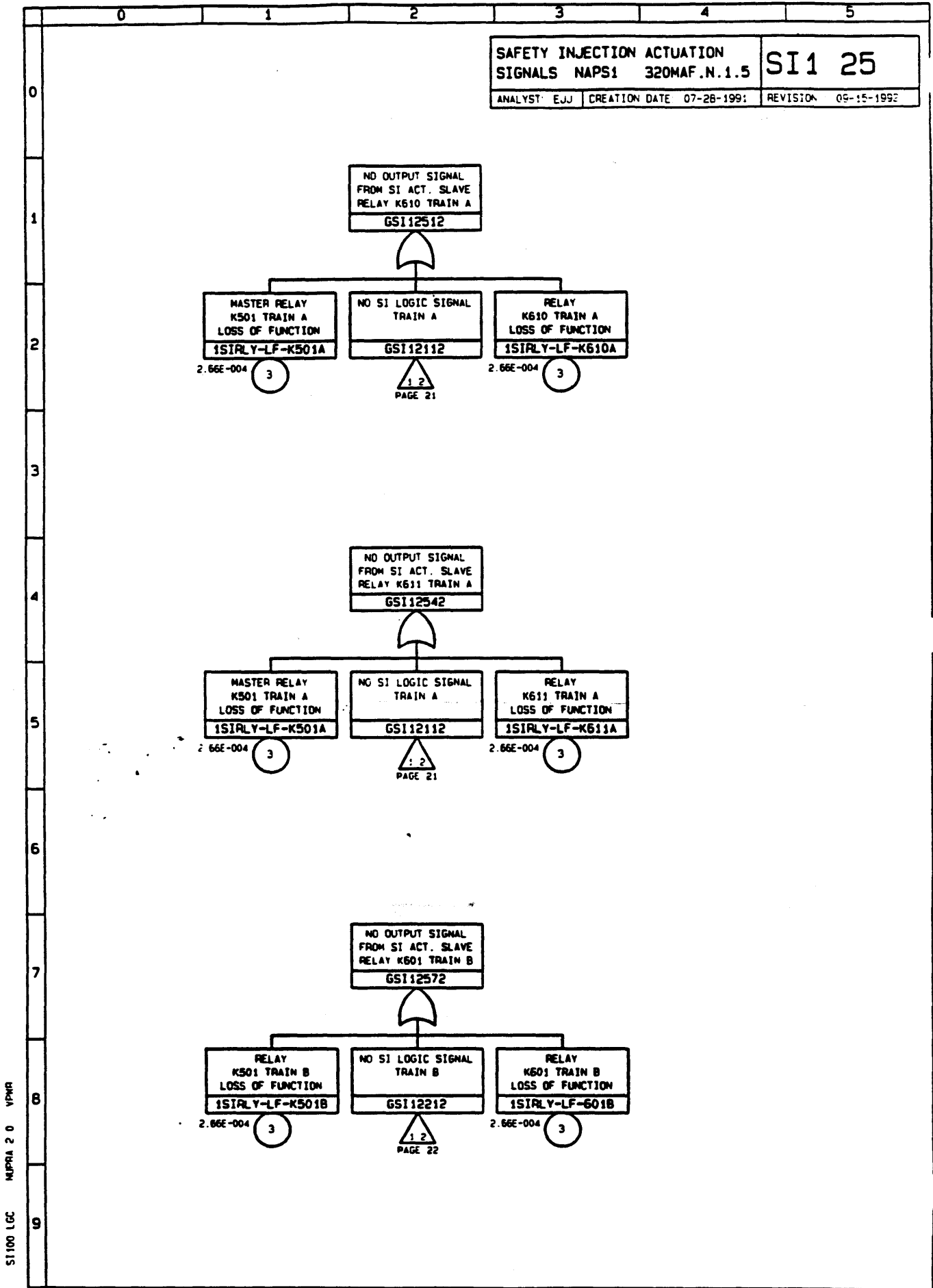
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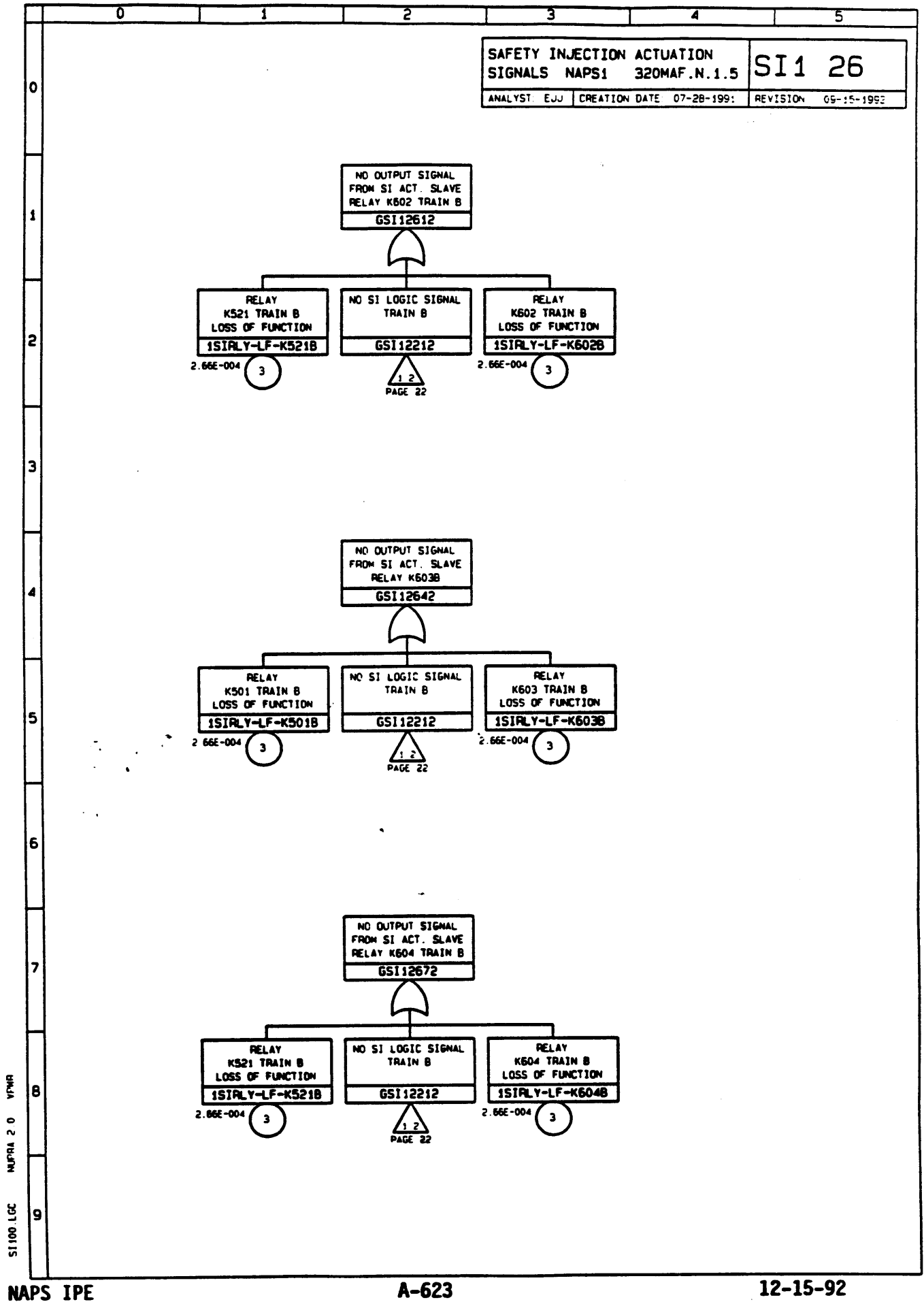




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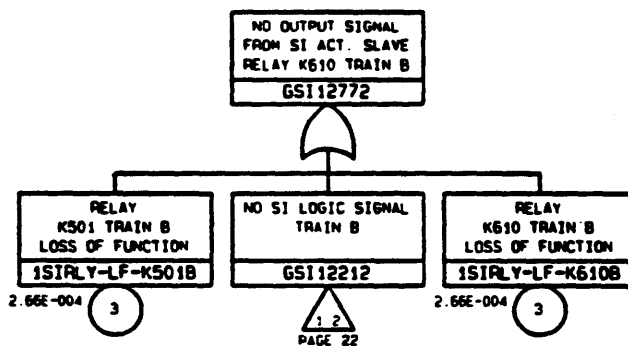
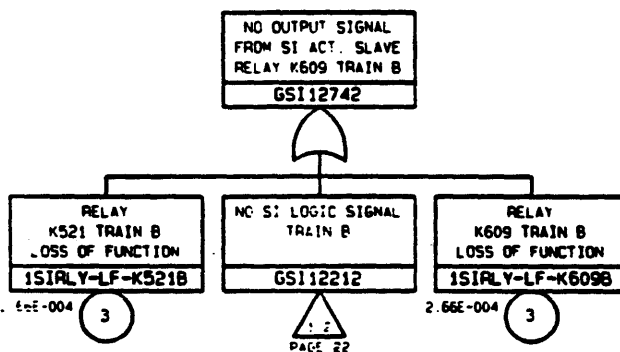
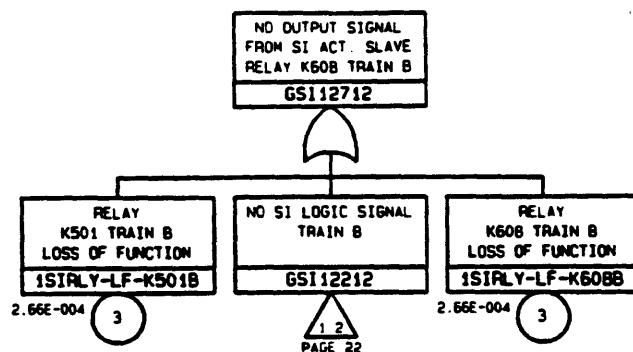


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**SAFETY INJECTION ACTUATION  
SIGNALS NAPS1 320MAF.N.1.5**

**SI1 27**

ANALYST: EJJ CREATION DATE 07-28-1991 REVISION 09-15-1992





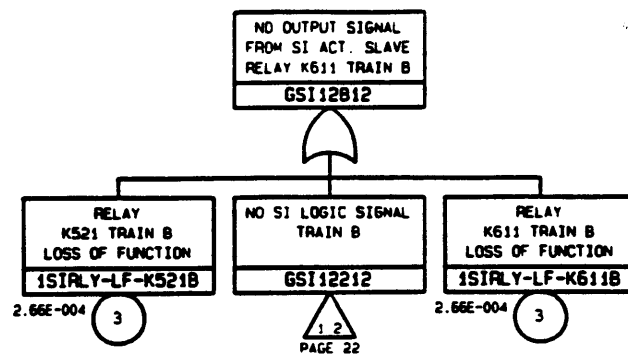
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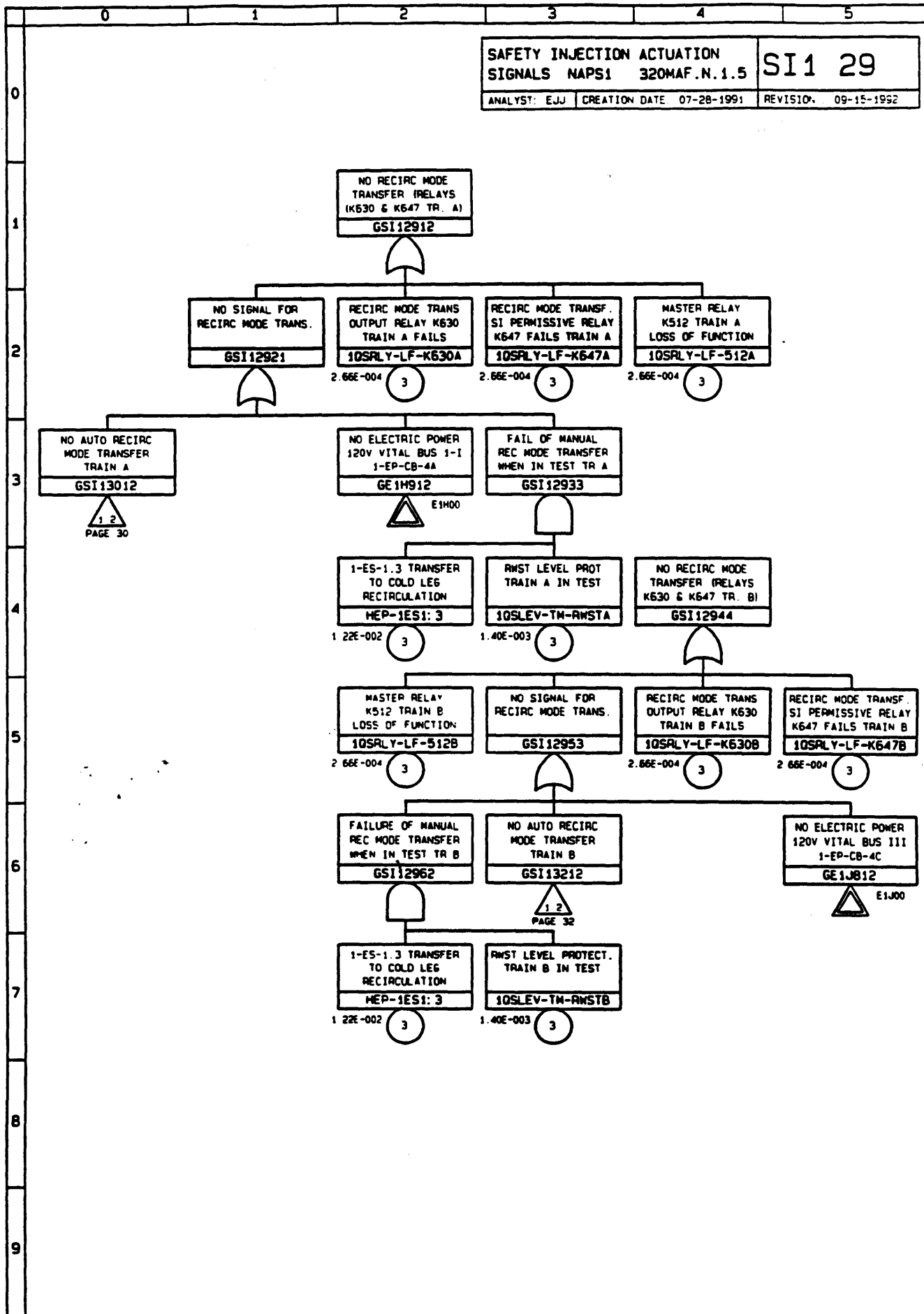
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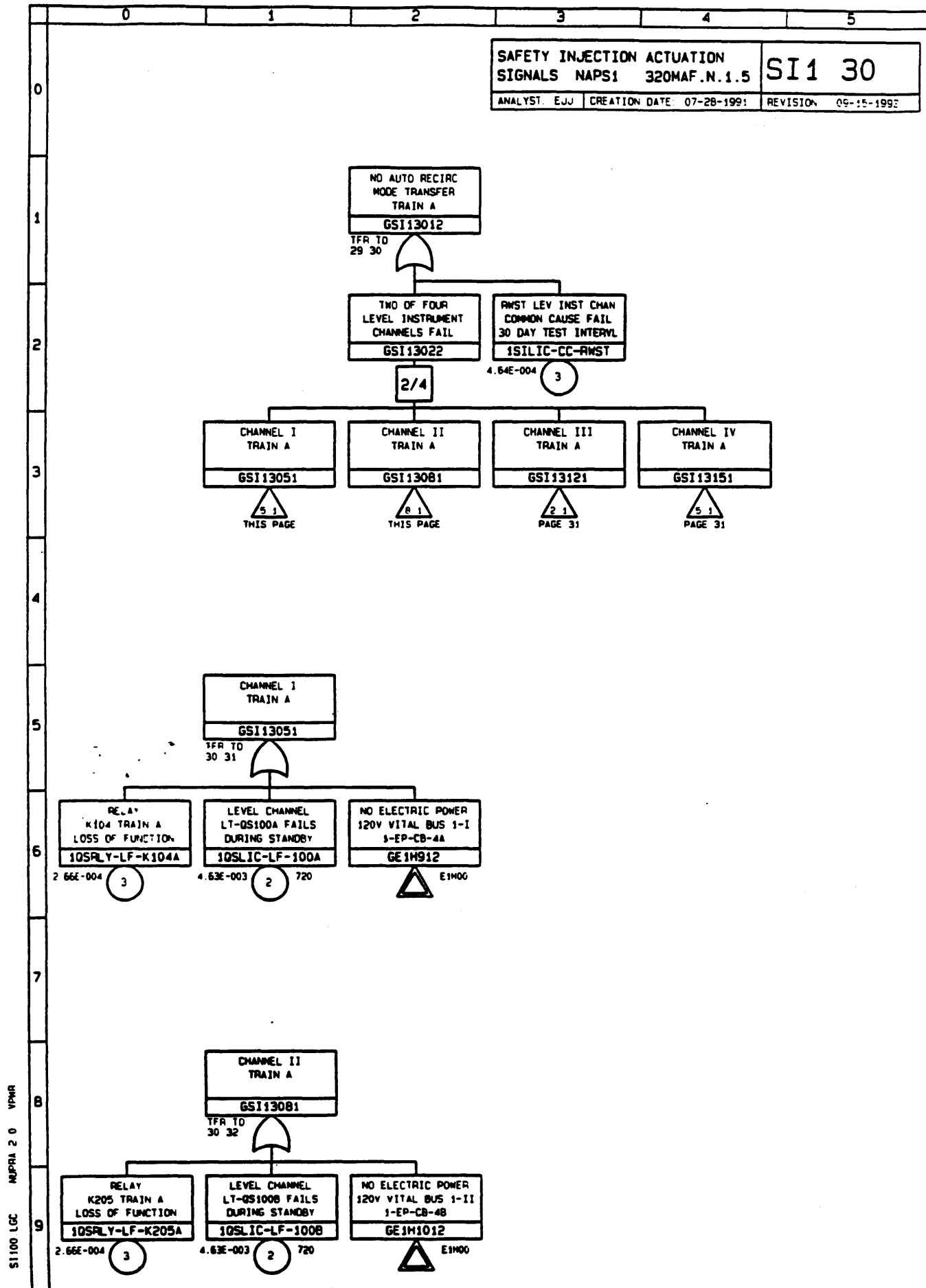
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ANALYST EJJ CREATION DATE 07-28-1991

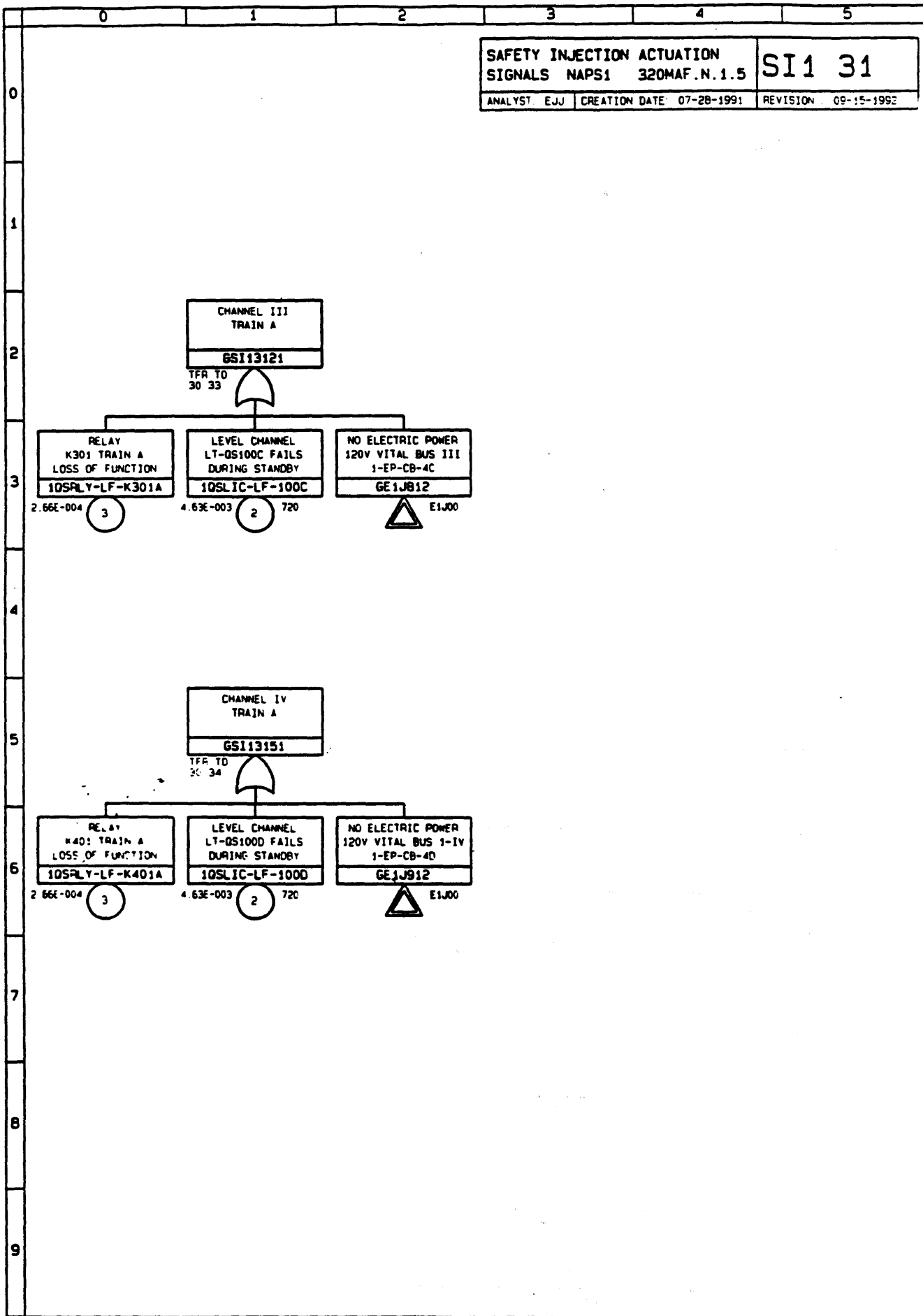
REVISION 09-15-1992

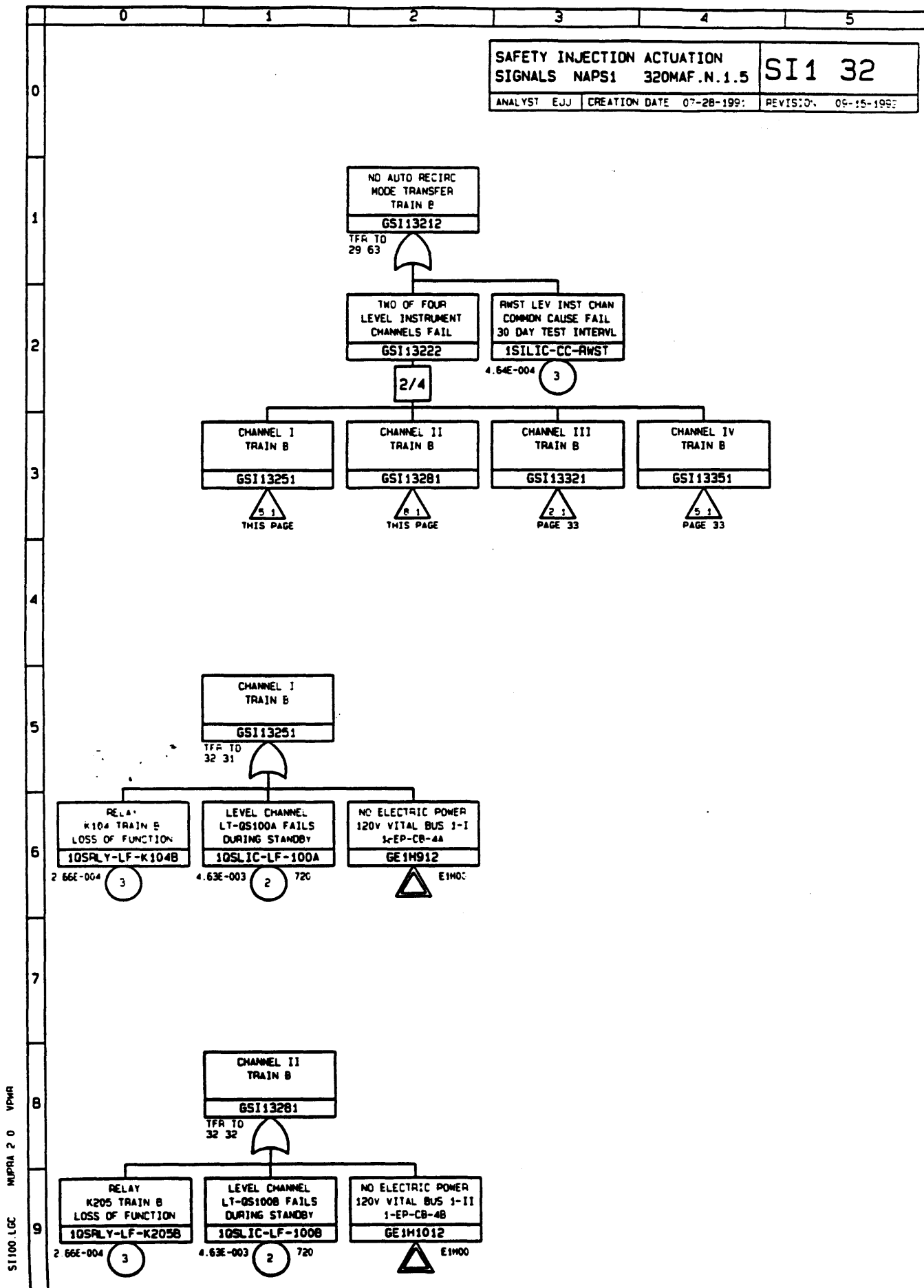






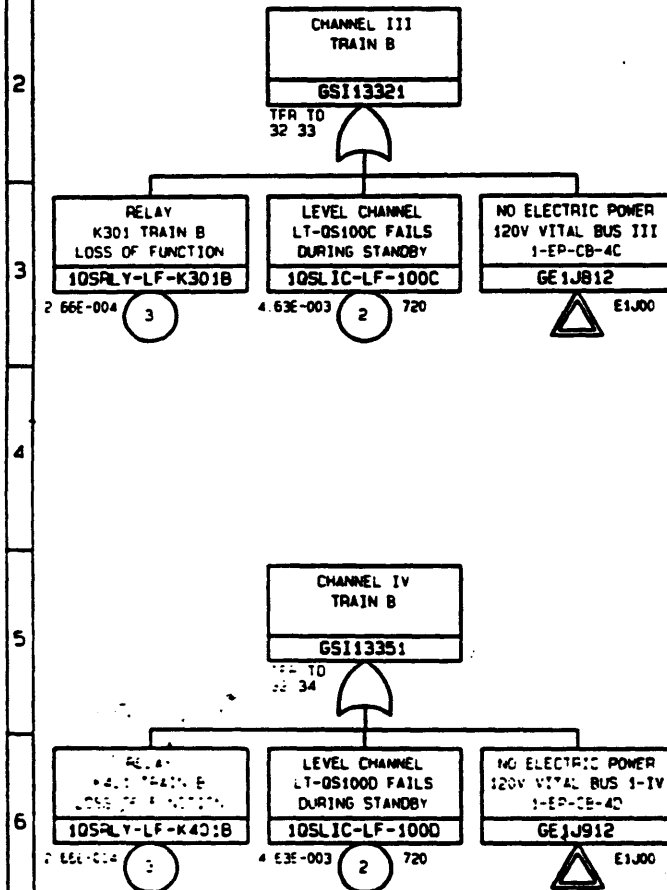
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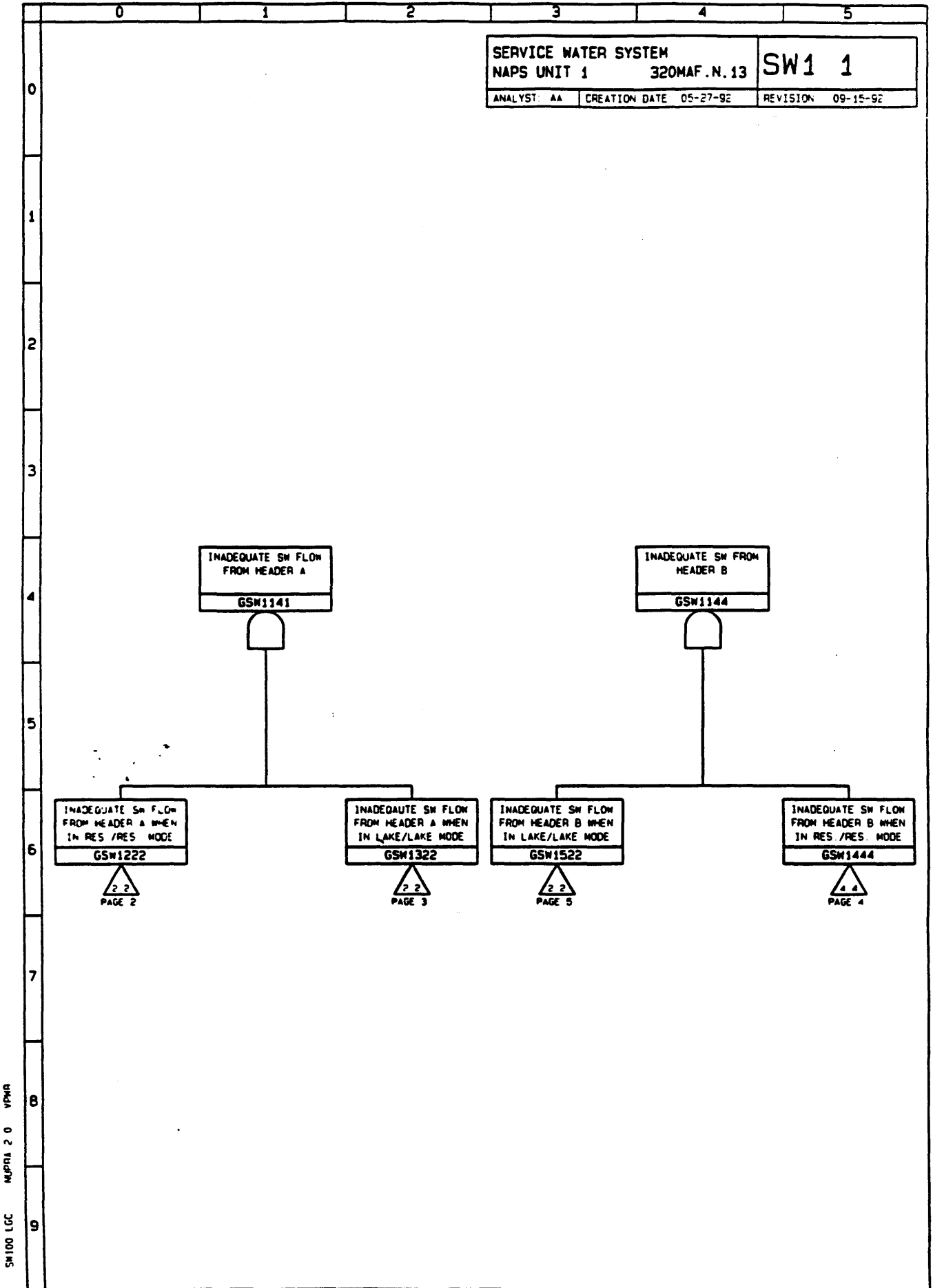




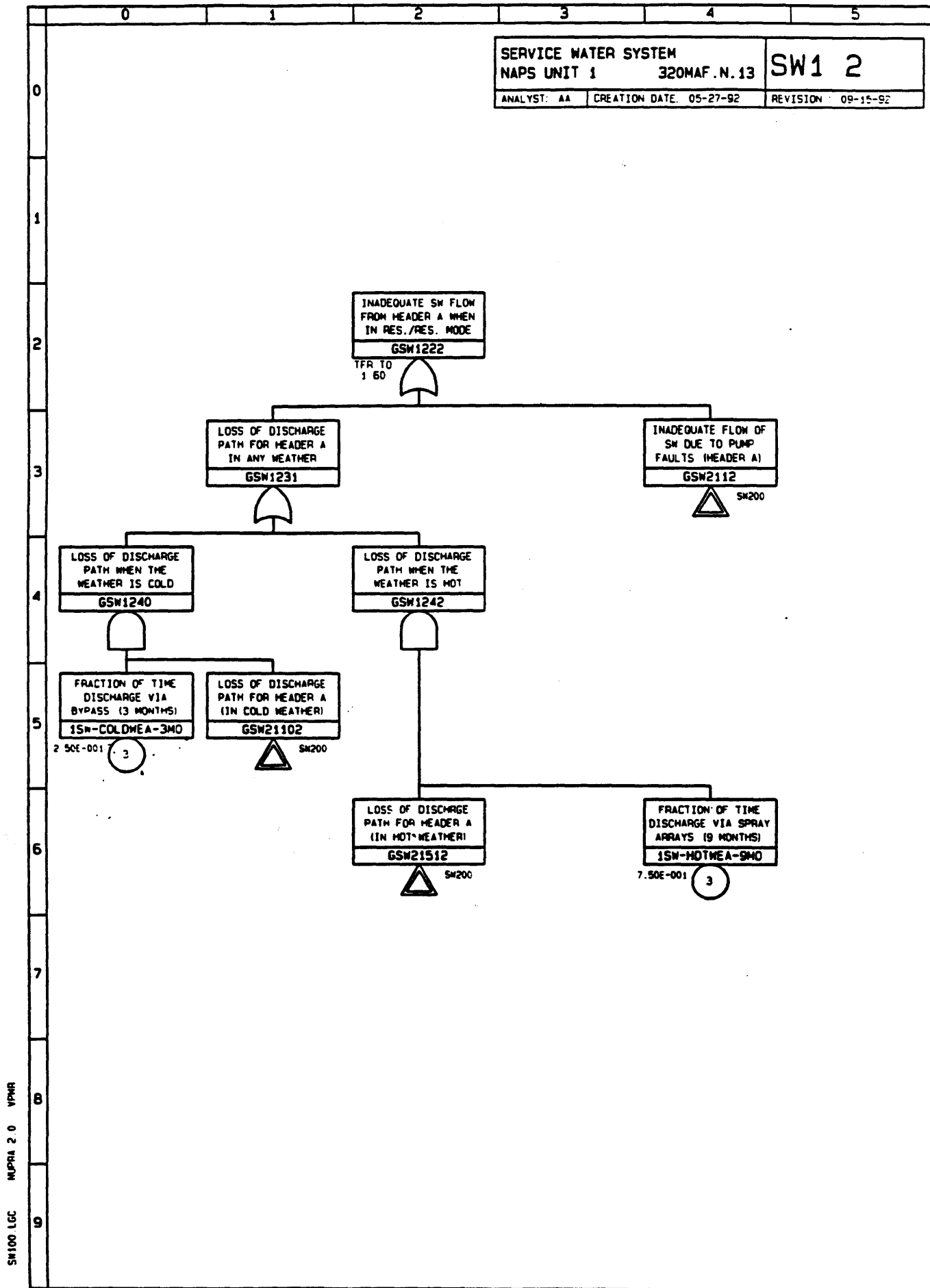
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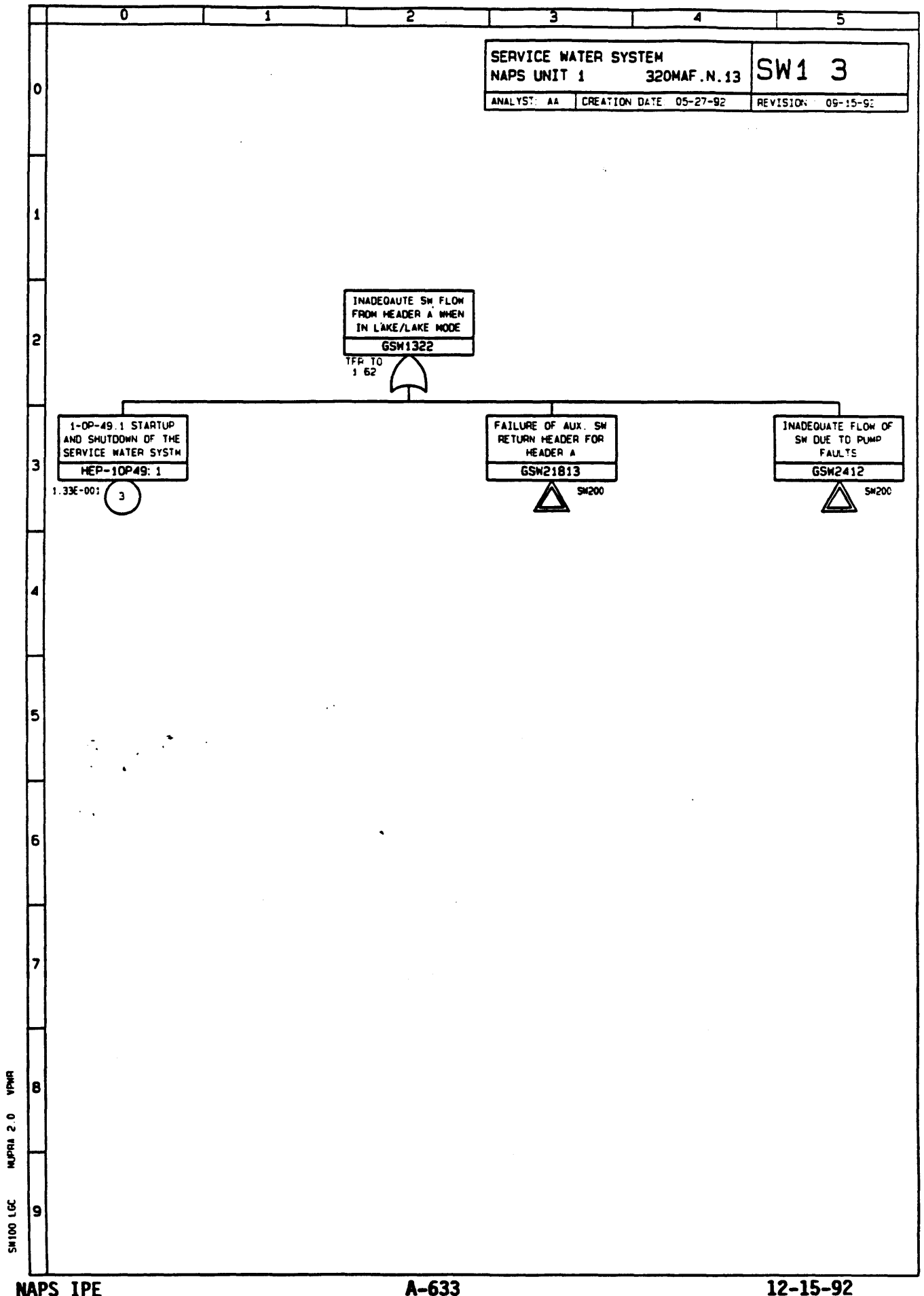




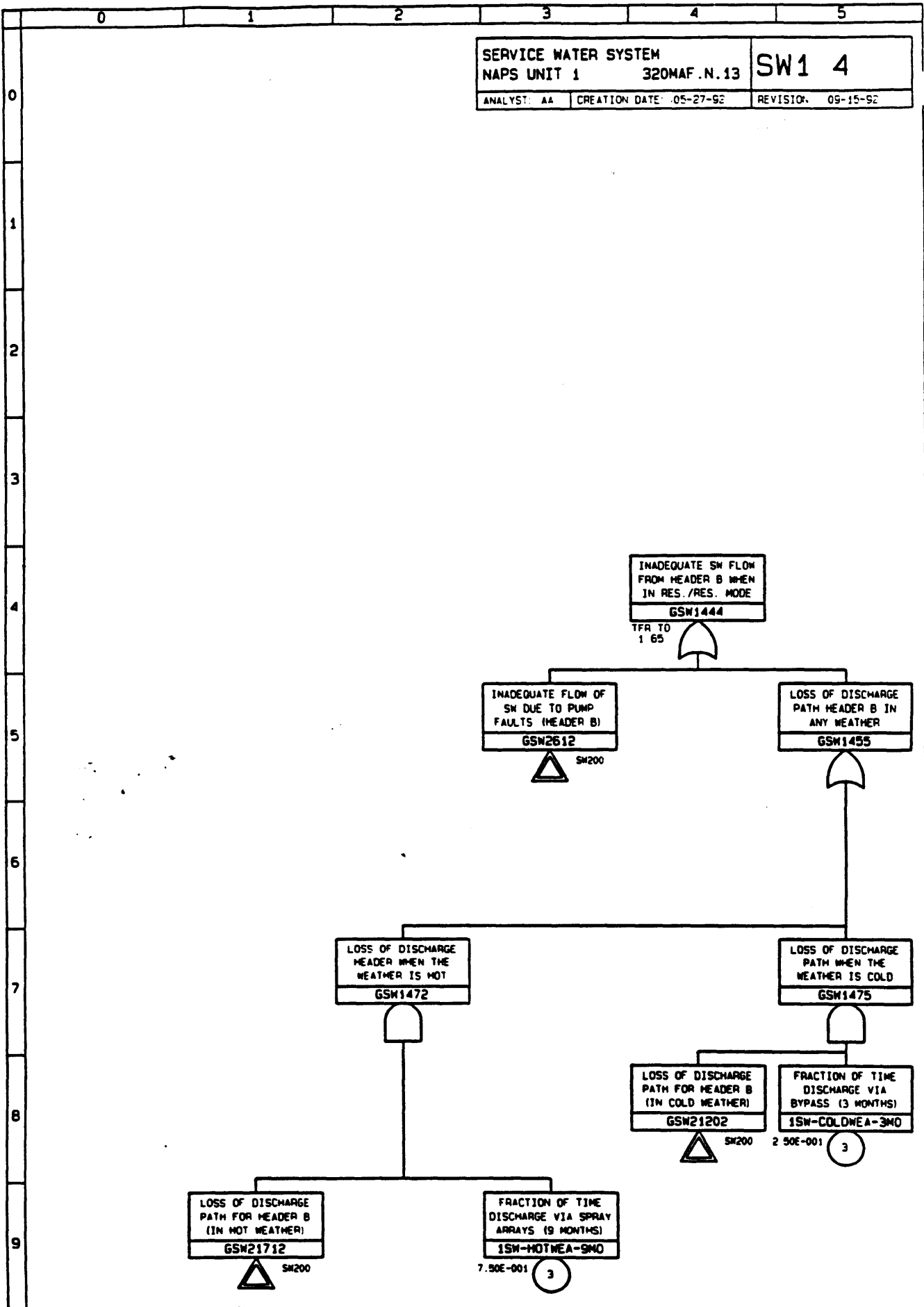
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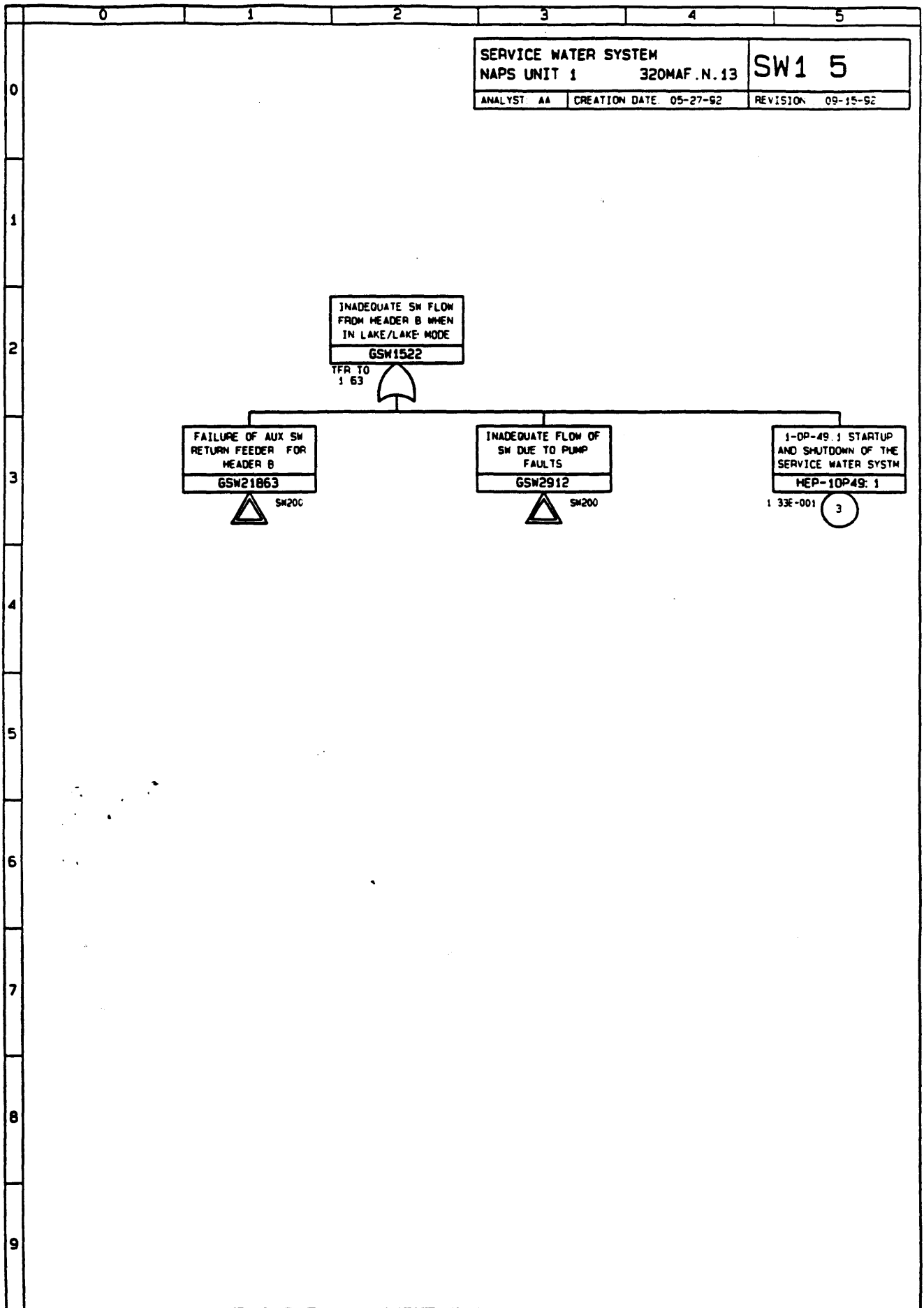


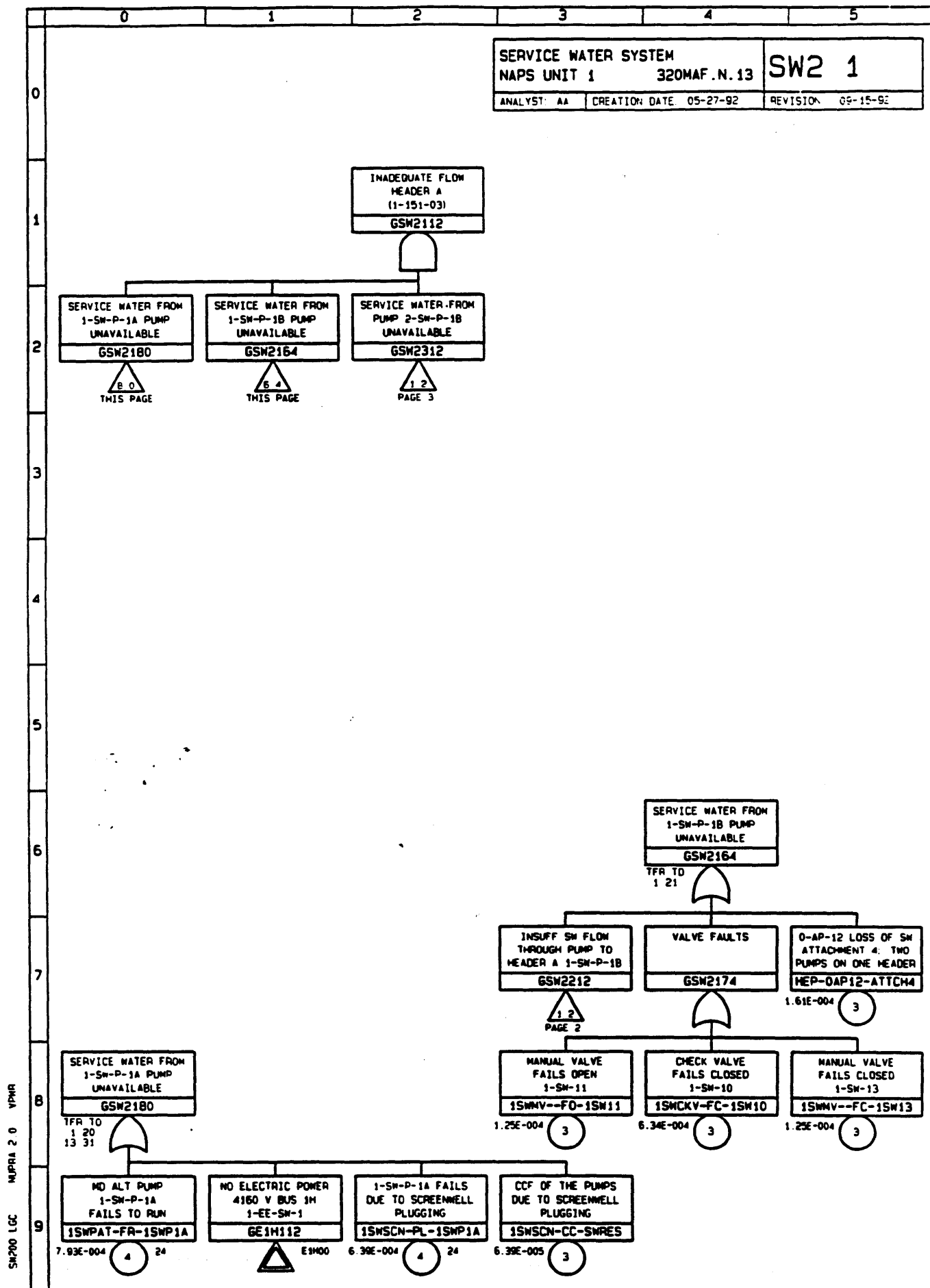
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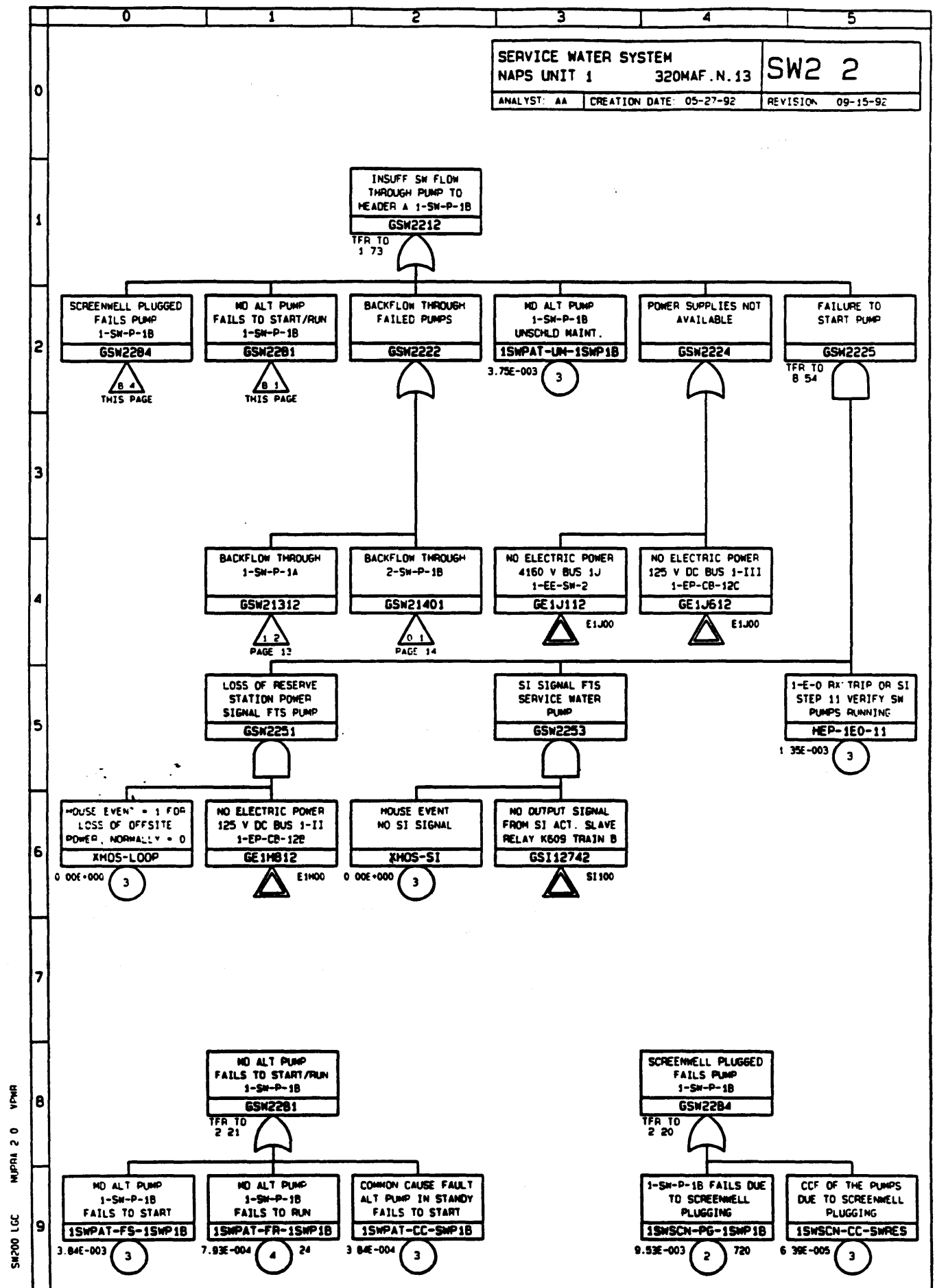
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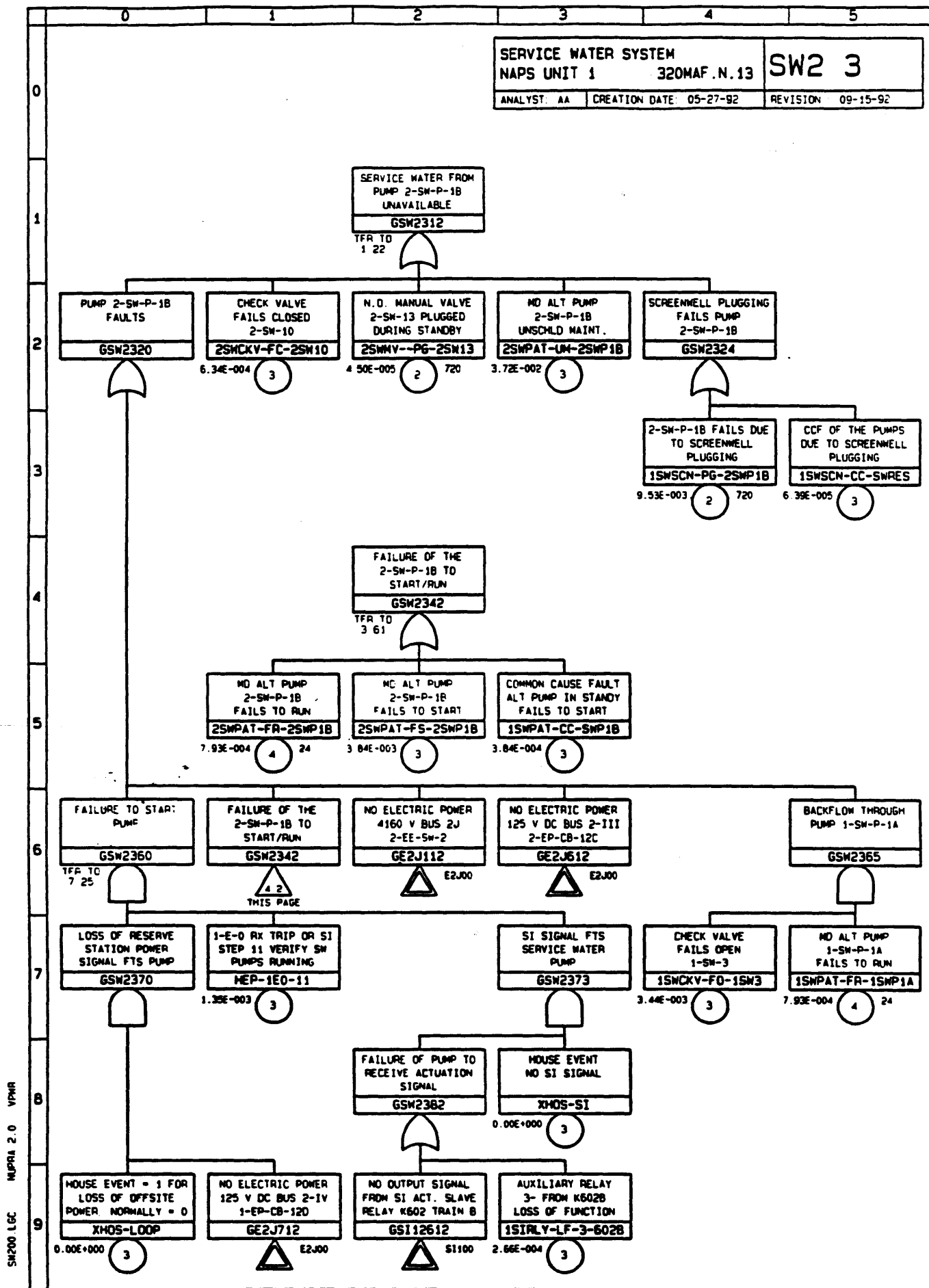
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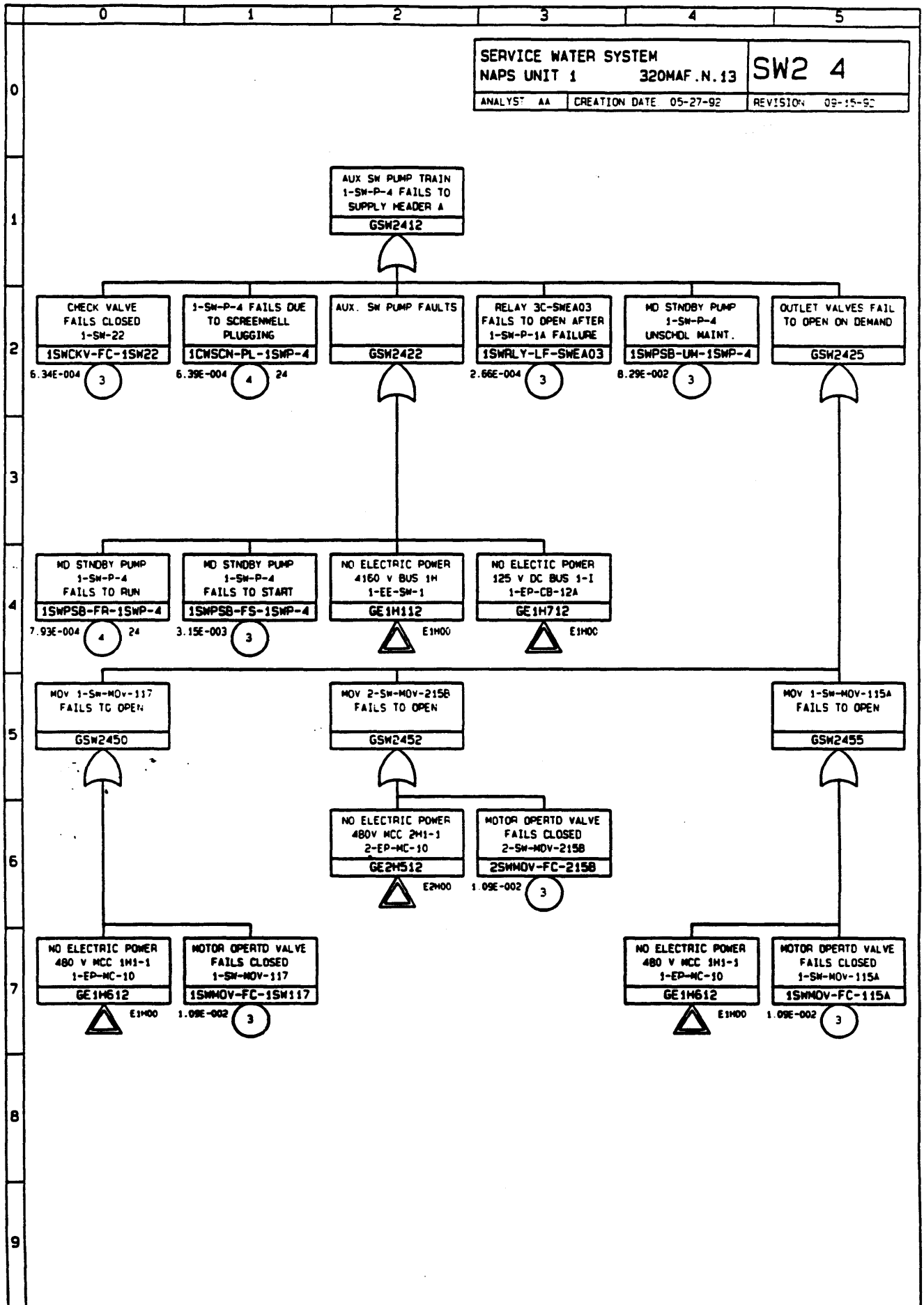


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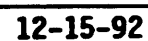


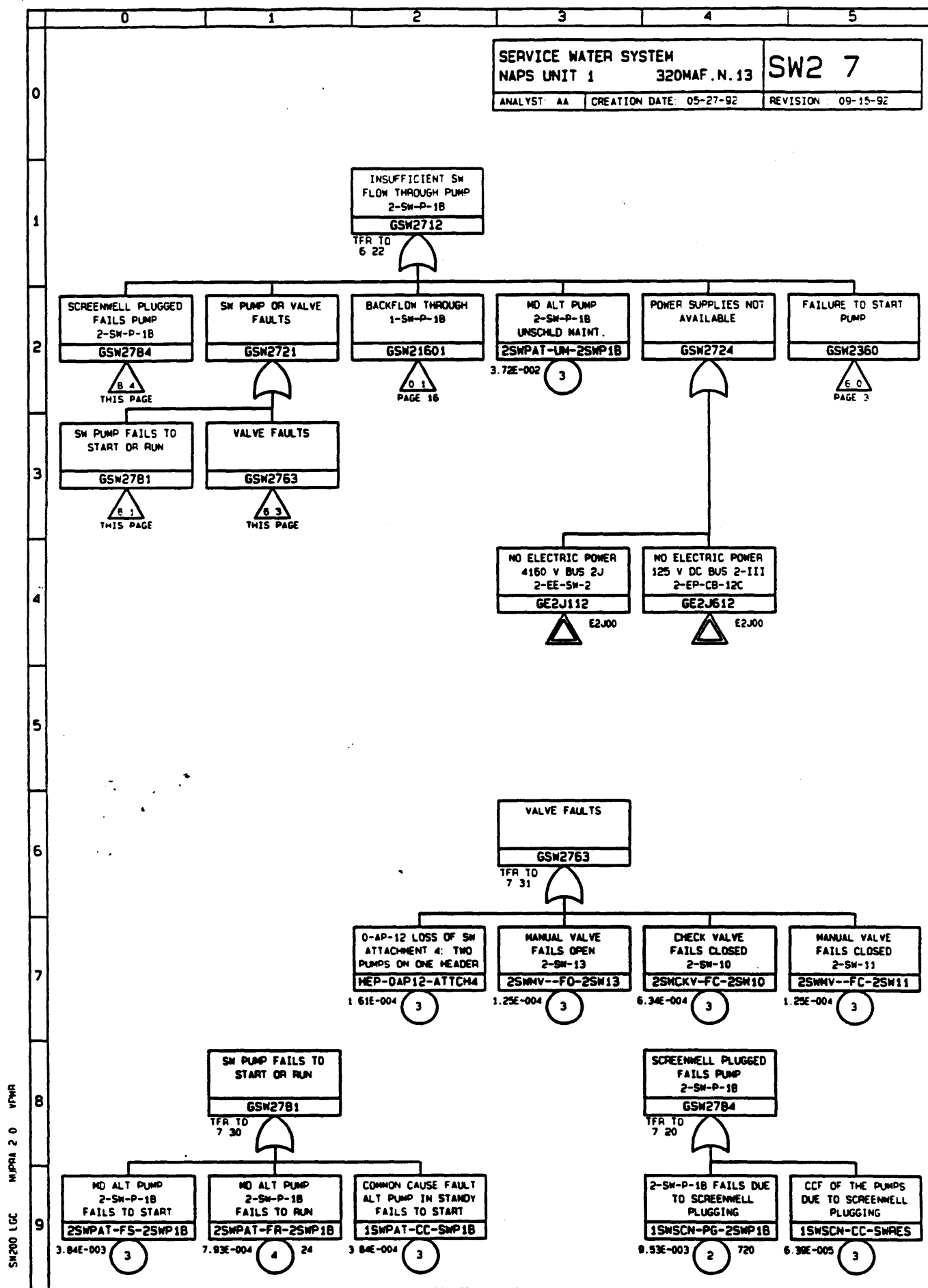
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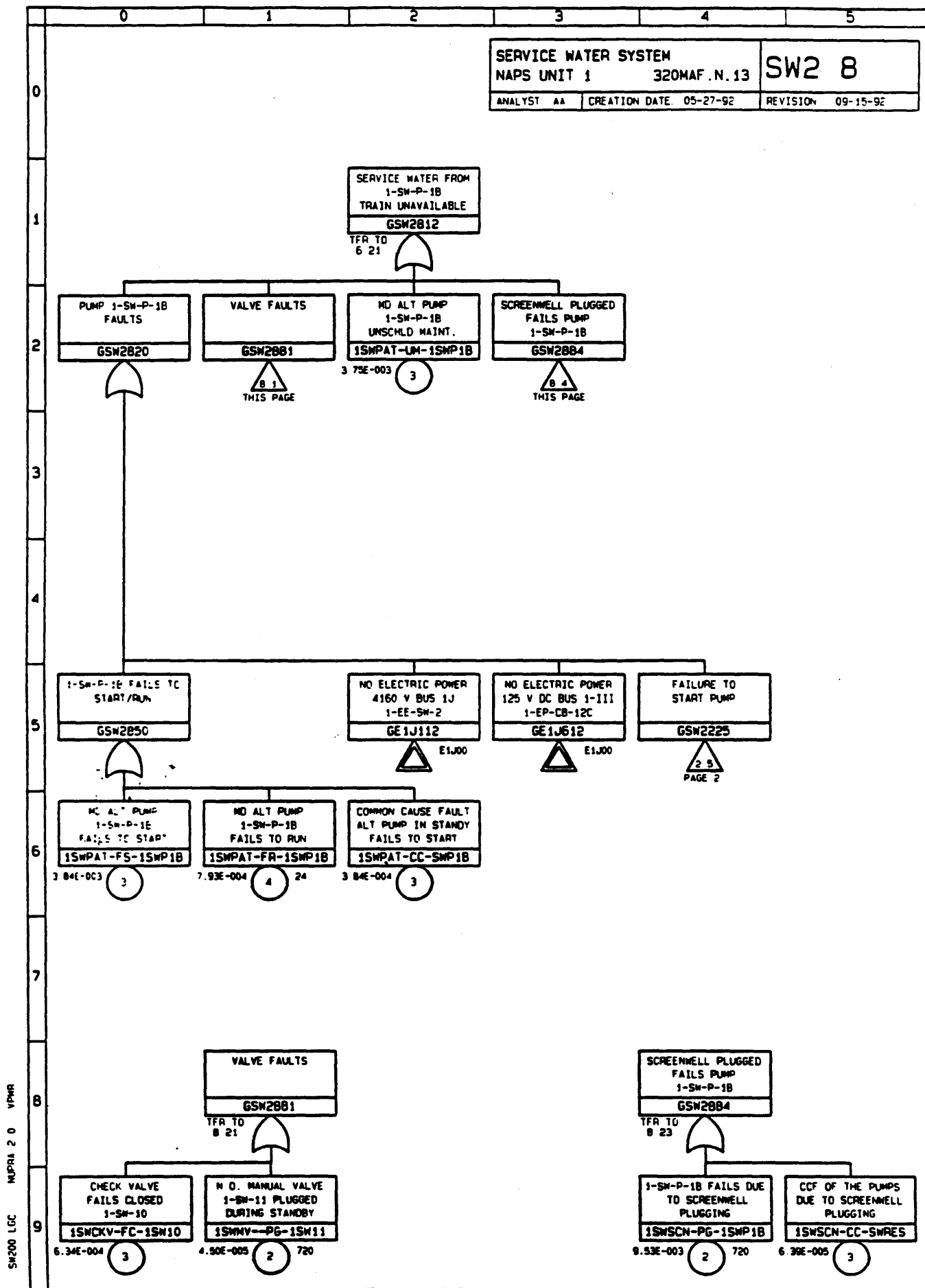
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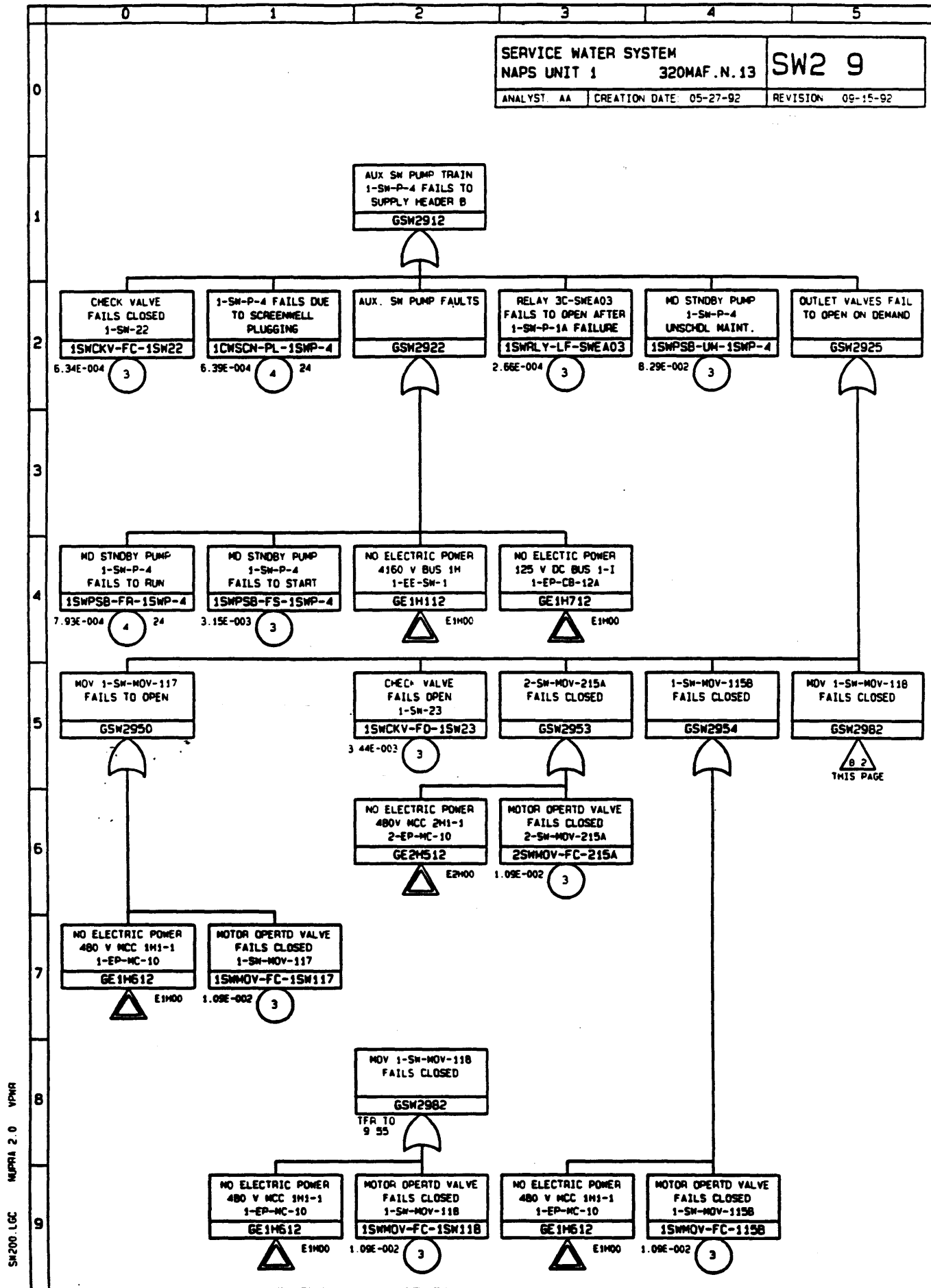


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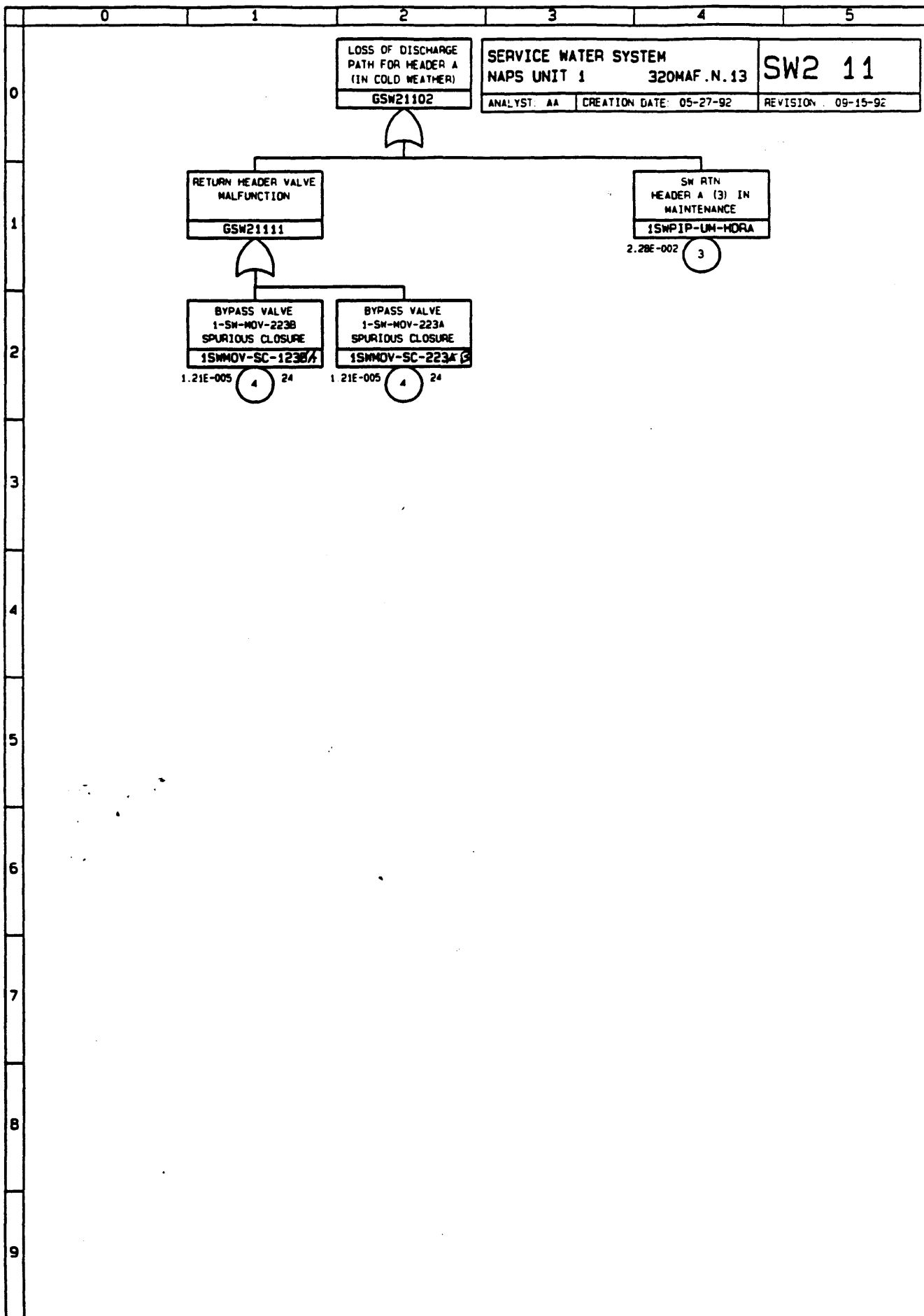


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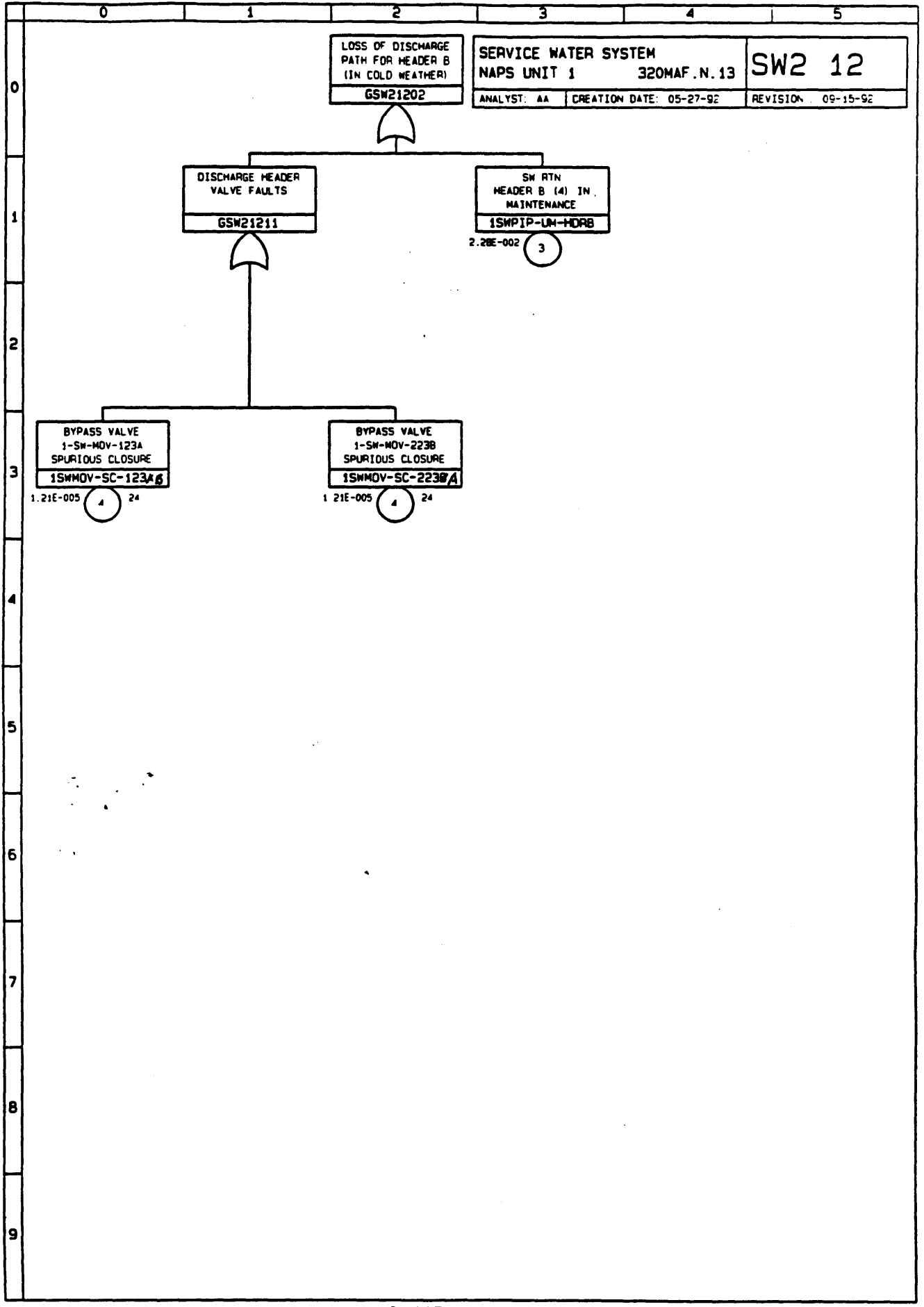
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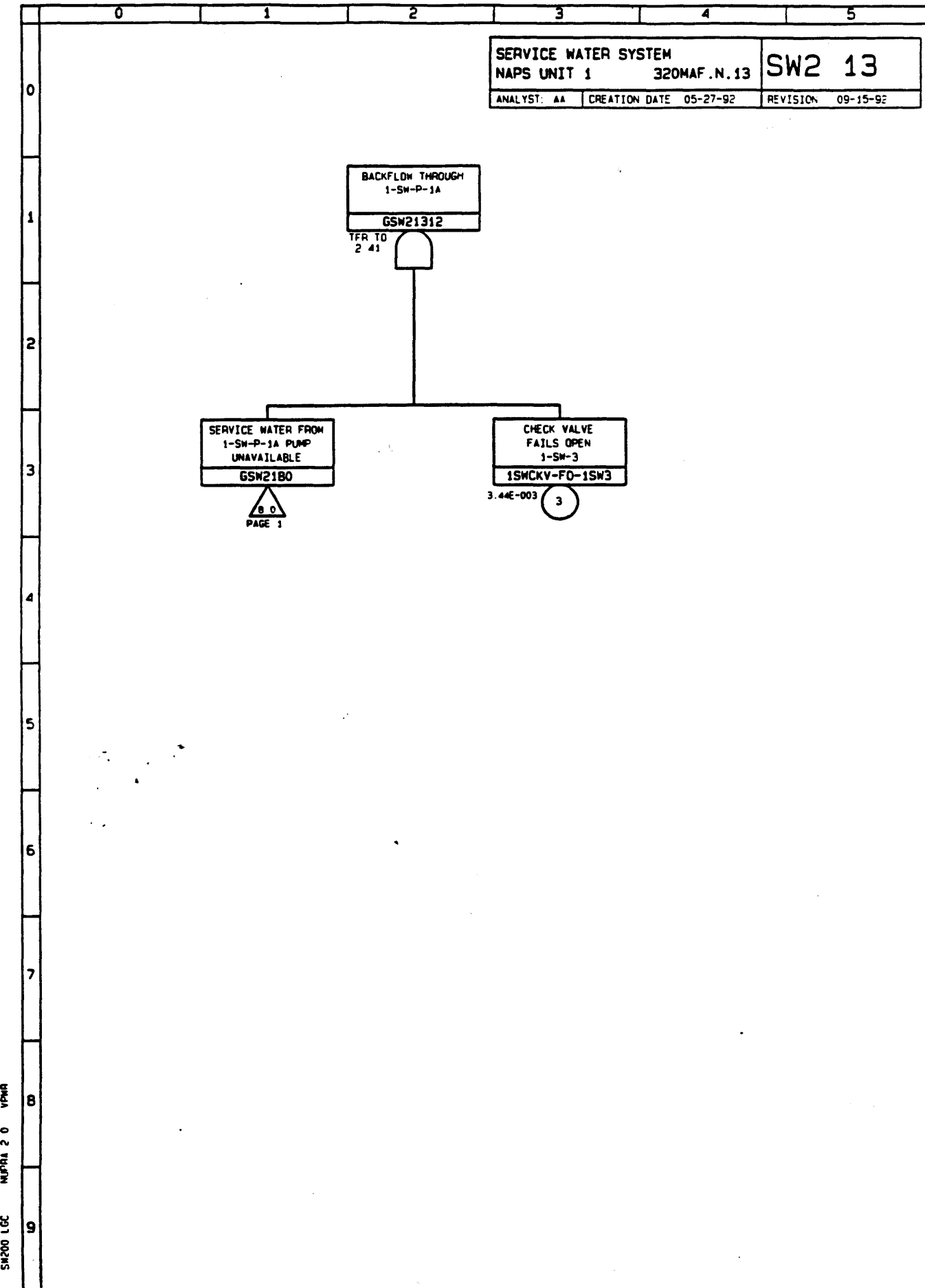
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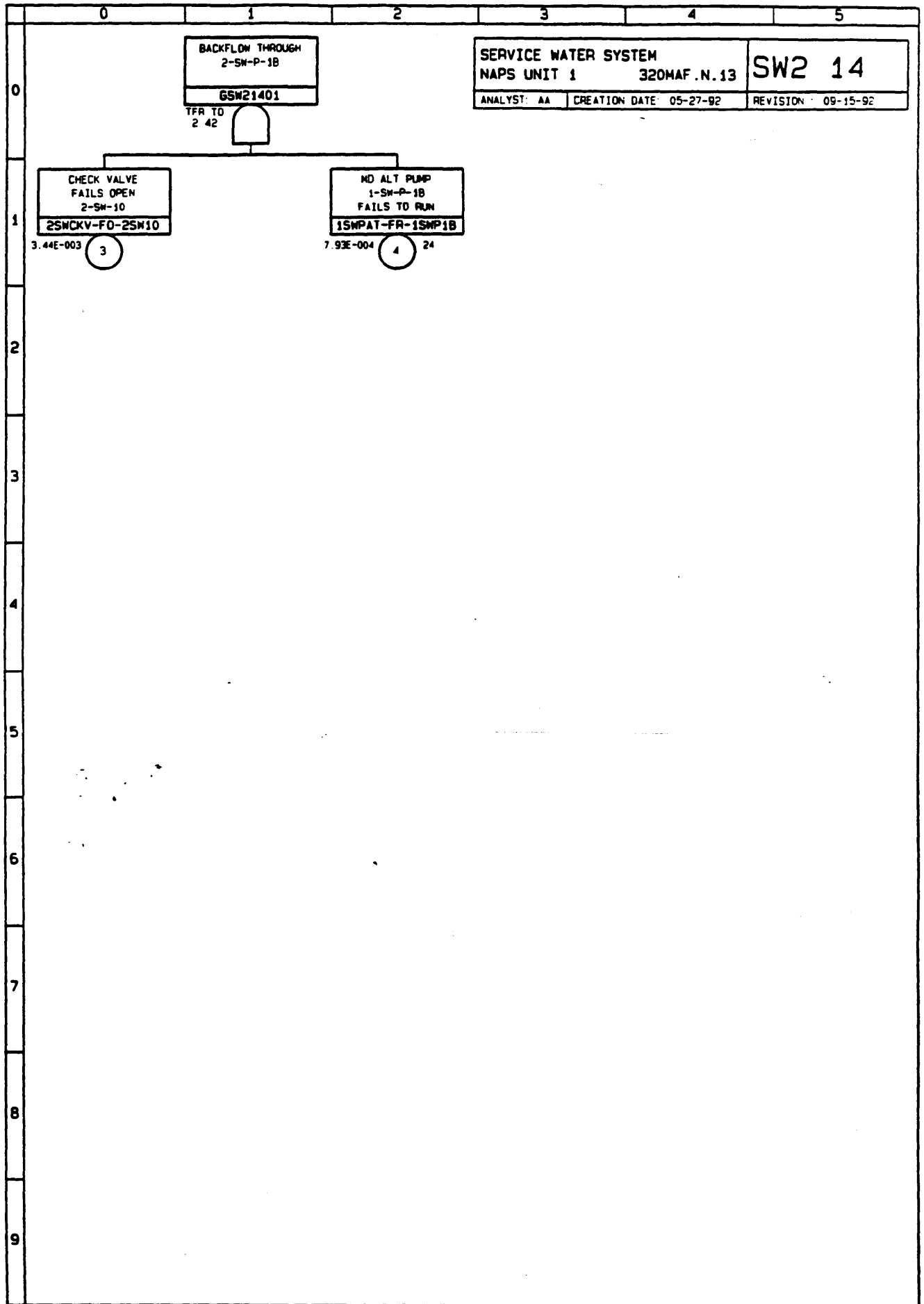


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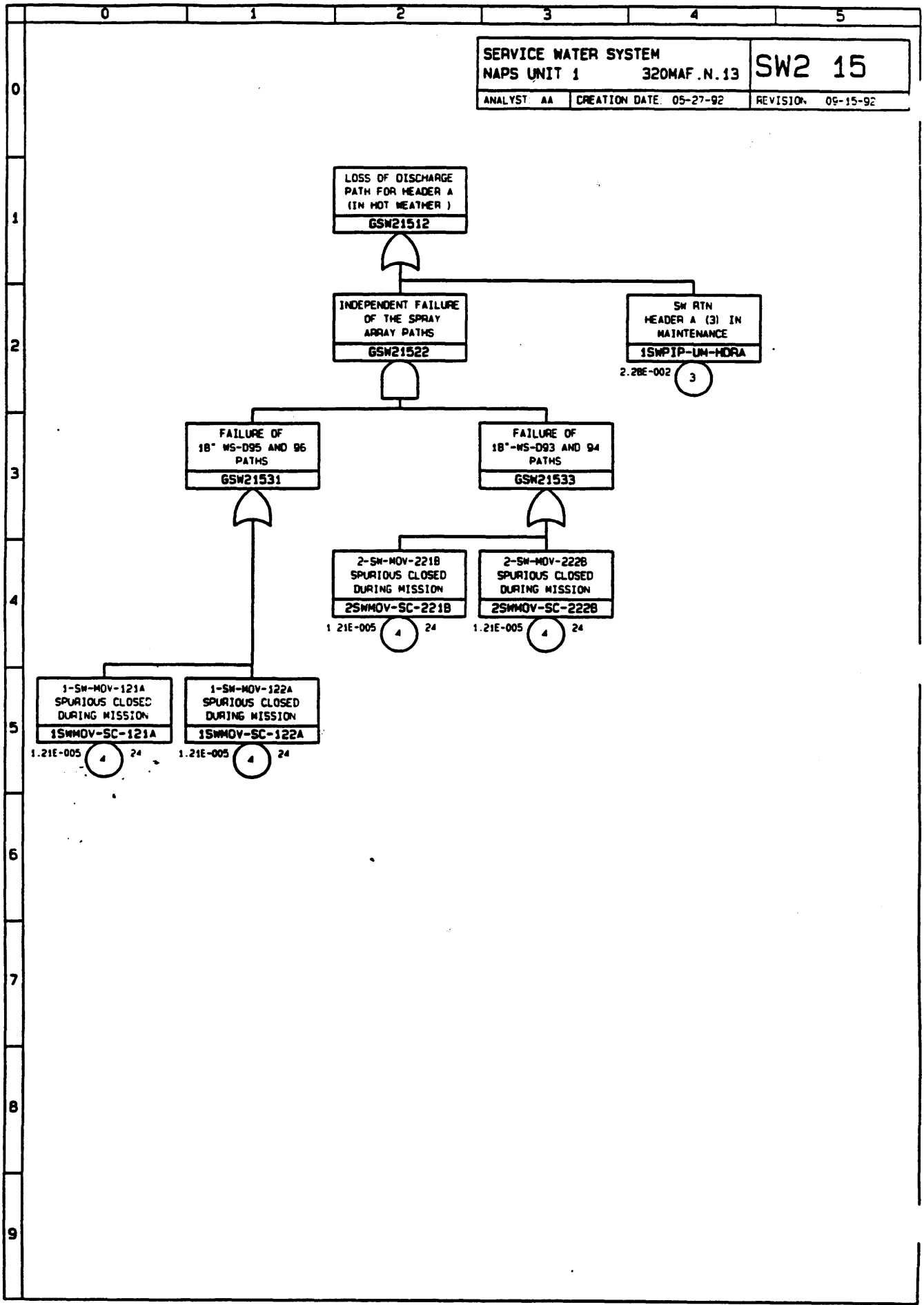


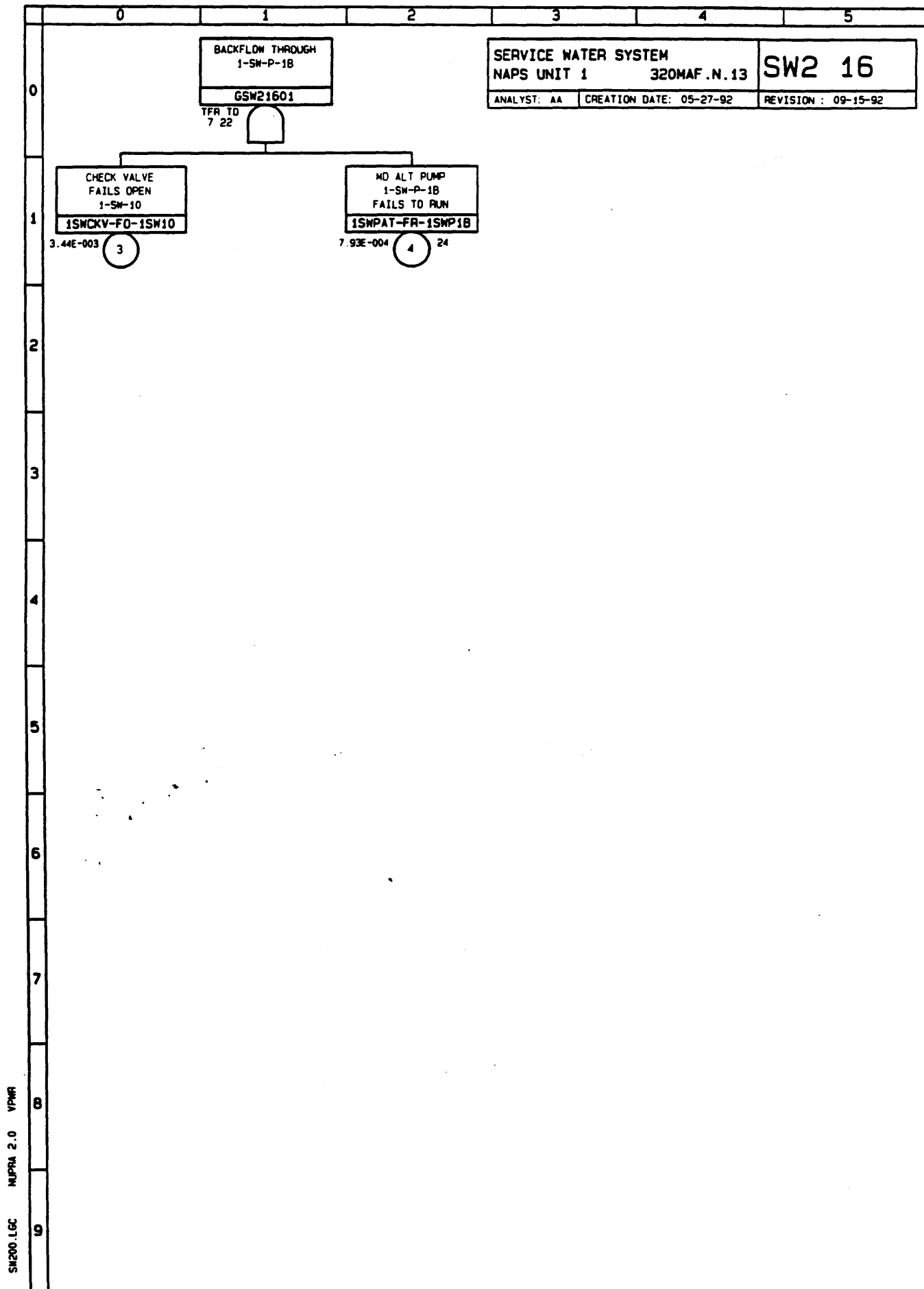


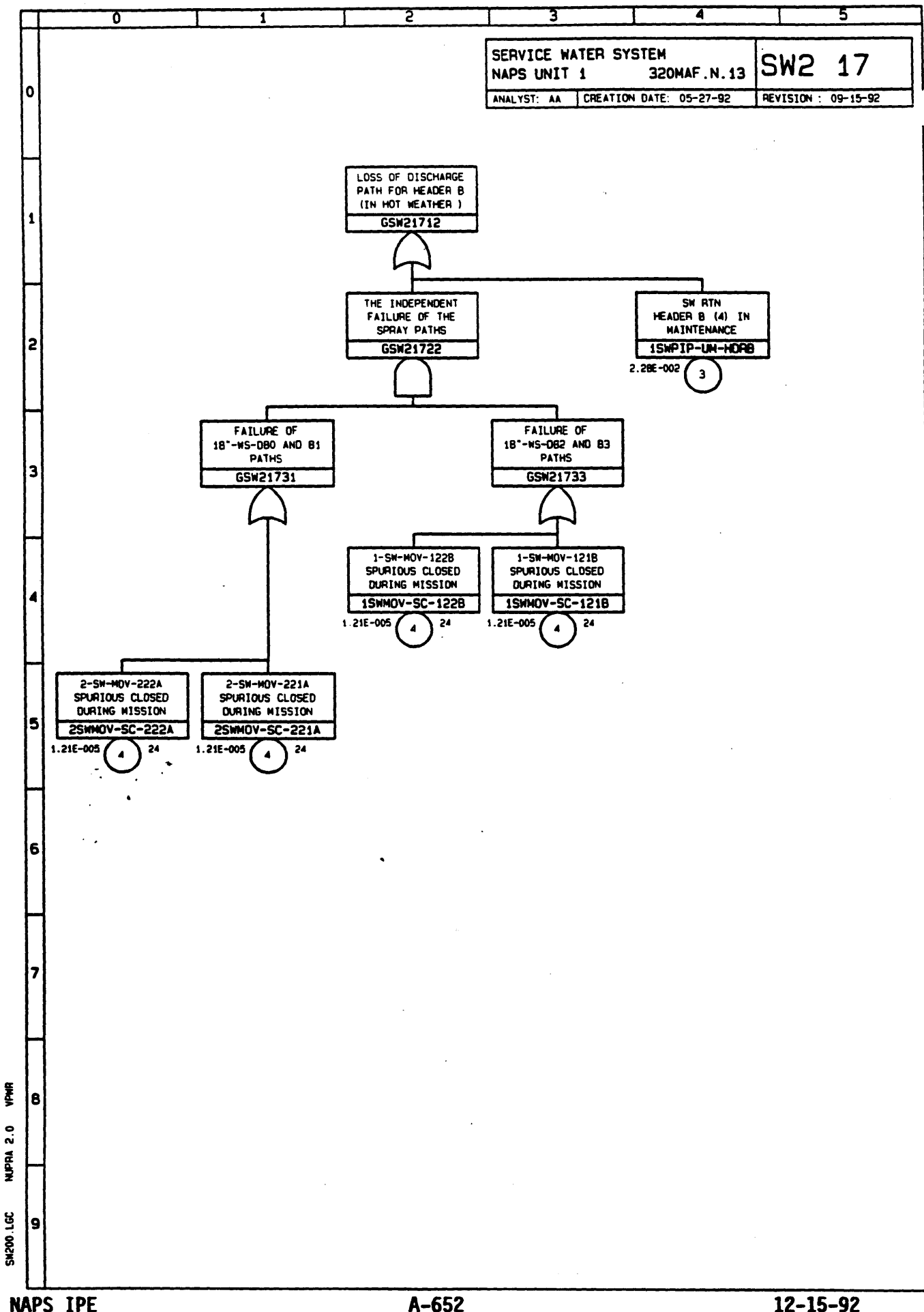
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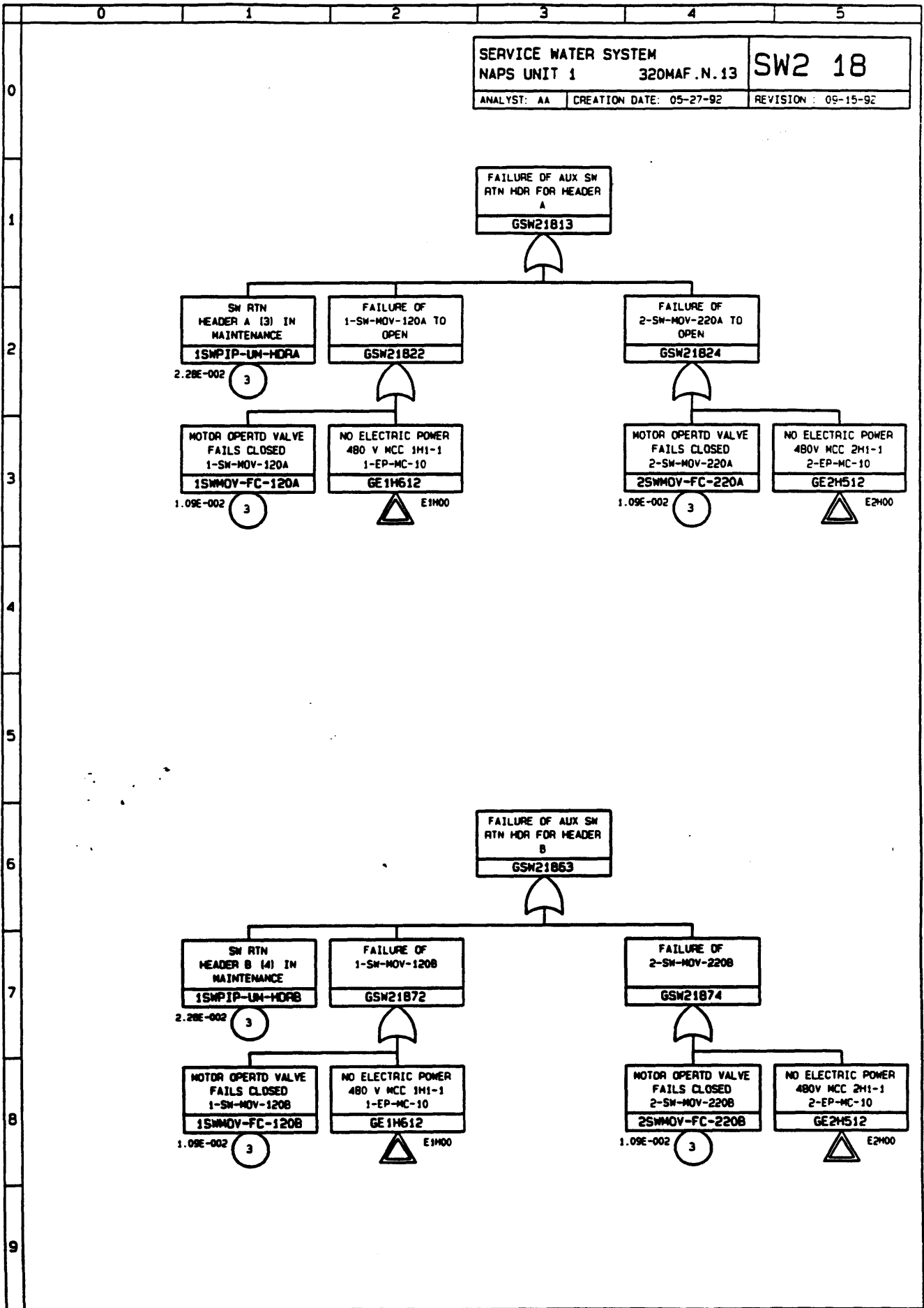


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