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Revision 1

Light Water Reactor Sustainability Program

Flexible Plant Operation and Generation Probabilistic Risk Assessment of a Light-Water Reactor Coupled with a High-Temperature Electrolysis Hydrogen Production Plant

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U.S. Department of Energy

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EXECUTIVE SUMMARY

This report details an expansion of the original two generic probabilistic risk assessments (PRAs) for the addition of a heat extraction system (HES) to a light-water reactor, one for a pressurized-water reactor and one for a boiling-water reactor. The new material in this revision includes a new HES design, direct electrical coupling of the nuclear power plant to the High-Temperature Electrolysis Facility (HTEF), and a smaller 100-MWt HTEF analysis. The results investigate the applicability of the potential licensing approaches, which do not require a full United States Nuclear Regulatory Commission licensing review. The PRAs are generic and include some assumptions. We eliminated many conservative assumptions from the preliminary pressurized-water reactor PRA report using design data for both the HES and HTEF. The PRA results indicate that the 10 CFR 50.59 licensing approach is justified due to the minimal increase in initiating event frequencies for all design basis accidents, with none exceeding 5.6%. The PRA results for core damage frequency and large early release frequency support the use of RG 1.174 as further risk information that supports a change without a full licensing amendment review. Further insights provided through hazard analyses and sensitivity studies confirm with high confidence that the safety case for licensing an HES addition and an HTEF sited 1.0 km from the nuclear power plant is strong and that the placement of a HTEF at 0.5 km is also a viable case. Site-specific information can alter these conclusions.

ACKNOWLEDGEMENTS

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ACRONYMS

AFW	auxiliary feedwater
ATWS	anticipated transient without scram
BWR	boiling-water reactor
CCF	common cause failures
CCG	common cause group
CDF	core damage frequency
CST	condensate storage tanks
DBA	design basis accidents
FMEA	failure modes and effects analysis
HES	heat extraction system
HPI	high-pressure injection
HTEF	high-temperature electrolysis facility
HTF	heat-transfer fluids
HRA	Human reliability analysis
IE	initiating event
IPEEE	individual plant examination of external events
LAR	licensing amendment review
LERF	large early release frequency
LOOP	loss of switchyard components means a loss-of-offsite-power
LPI	low-pressure injection
LWR	light-water reactor
LWRS	Light Water Reactor Sustainability
MCA	maximum credible accident
MSIV	main steam isolation valves
NPP	nuclear power plants
NRC	Nuclear Regulatory Commission
P&ID	piping and instrumentation diagram
PCS	power conversion system
PRA	probabilistic risk assessment
PSF	performance shaping factors (used in SPAR-H)
PWR	pressurized-water reactor
RCP	reactor coolant pump
RPN	risk priority number

RPS	reactor protection system
RWST	refueling water storage tanks
SAPHIRE	Systems Analysis Programs for Hands-on Integrated Reliability Evaluations
SBO	station blackout
SME	subject matter experts
SNL	Sandia National Laboratories
SPAR-H	Standardized Plant Analysis Risk HRA
SSC	structures, systems, and components
TPD	thermal power delivery

Flexible Plant Operation and Generation

Probabilistic Risk Assessment of a Light-Water Reactor Coupled with a High-Temperature Electrolysis Hydrogen Production Plant

1. OVERVIEW

1.1 Purpose

Penetration of variable renewable power plants and low natural gas prices are threatening the profitability of already existing, paid-off, nuclear power plants (NPPs). The Nuclear Energy Institute [1] reported that the total generating cost of existing light water reactor (LWR) plants in 2017 was $33.50/MWh. This relatively low operating cost is quite competitive with other energy sources. However, there are other economic factors that need to be considered due to the intrinsic nature of the LWR power generation process. The LWR NPPs are typically run at full power during unfavorable over-supply electric market situations caused by fair weather and low electricity demands. This is driven by the need to avoid reactor shutdowns, which lead to time delays in restarting. On the other hand, NPPs generally have superior reliability, which allows operators to continue running them without frequent shutdowns. As a result, while the current LWR fleet consists of 10% of the operating capacity of electricity generation, it is consistently run at a much higher capacity than other technologies and provides 20% of the electricity sold in the United States (U.S.). This is one of the benefits NPPs provide to the electric grid, which is not adequately compensated, thereby disrupting their finances and sustainability by operating in such a baseload manner. During these times, Nuclear Energy Institute reports [1] that NPP operators only recoup the U.S. government subsidy of $23/MWh, essentially causing operators to pay for the electricity they create. No substantial governmental policy has been put into place to support the sustainable operation of NPPs as reliable baseload providers.

To increase the utility and profitability of the current fleet of LWRs, the Light Water Reactor Sustainability (LWRS) Program is evaluating the feasibility of using part of the heat from an NPP for use in other industrial applications. Steel manufacturing, chemical processing, desalination, and hydrogen production are industrial applications that could utilize heat from an LWR. The collocated industrial facility will benefit from lower cost process heat, and the NPP will benefit from a steadier income from its consistent production of energy. The feasibility of installing a modification of an LWR to export process heat to an industrial facility is broken into two parts: economic viability and the safety case. The economic benefit will determine if the modification is desired. The safety case will determine if the modification is allowed through licensing by the U.S. Nuclear Regulatory Commission (NRC). This report concentrates on the probabilistic safety case of the use of LWR-extracted heat in hydrogen production through water electrolysis. We chose hydrogen production because of the large demand for hydrogen across various markets and the added benefit of less carbon in the hydrogen production cycle. Currently, most of the commercial hydrogen production uses steam methane reforming, which utilizes natural gas as a source of hydrogen and produces CO_2 as waste. Electrolysis utilizes water as the source of hydrogen.

For the suggested change to the LWR design and operation to be approved, the NRC requires a demonstration that the NPP safety will not be adversely affected. A probabilistic risk assessment (PRA) is used to risk inform the decision for change acceptance by the NRC. PRA is a process by which risk is numerically estimated by computing the probabilities of what can go wrong and the consequences of those undesired events. The quantitative PRA results are compared to NRC guidelines, which determine if the design and operation are safe enough for approval or if changes need to be made to increase its safety.

1.2 Background

A LWR NPP PRA is broken into three levels. A Level 1 PRA estimates the frequency per year of accidents damaging the reactor core, referred to as core damage frequency (CDF). This is done using two types of logical structures—event trees (ETs) and fault trees (FTs). An ET represents the possible pathways that can occur due to an undesired outcome. The initial undesired event is called an initiating event (IE). After the IE, the ET uses FT model results representing responding systems that prevent core damage. These FTs are the top events of the ET. The ET sequence of events results in end states indicative of the reactor state. The end state of interest here is core damage. All basic events of component or human action failures have associated probabilities of failure that are used in relation to one another as defined by the logic trees. The sum of the probabilities associated with all the sequences leading to the core damage end state represent the CDF.

Top-down methods are typically used to define IE frequencies by using data of recorded events to calculate the event frequency.

The probability of failure for FT top events are calculated using a bottom-up method. Bottom-up methods rely on knowing the exact system componentry and controls that are then translated into an FT. Typically, this is accomplished by referencing a system piping and instrumentation diagram (P&ID) and a list of operator actions, then identifying how each of those components and actions could fail in a way that leads to a failure event in the ET. The FTs are created and integrated into ETs by identifying within which IE the system failure would be used, either as an initiator itself or as a modification to one of the responding systems.

2. OBJECTIVE

The objective of this PRA is to further refine and expand upon the initial release of this report. This PRA includes both boiling-water reactor (BWR) and pressurized-water reactor (PWR) generic models to provide an example for starting a site-specific PRA. These PRAs include the risk assessment of proposed design options for thermal transfer, direct electrical transfer, and two sizes of hydrogen electrolysis facilities. The resulting PRA can be used to risk inform a licensing pathway with the NRC using 10 CFR 50.59,"Changes, Tests, and Experiments," [3] supported by RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" [4].

3. PROJECT SCOPE

The scope of this report is a Level 1 PRA that models the risk of core damage by quantifying the CDF associated with removing heat from the process steam of an LWR. This result is then carried forward for use in adding a hydrogen production plant that uses high-temperature electrolysis. In addition, direct electrical coupling to the hydrogen plant is modeled enabling the use of lower temperature electrolysis or boosting the temperature of the steam delivered for high temperature electrolysis. Within the PRA, the high-temperature electrolysis facility (HTEF) and its electrical connection to the LWR is treated as both a potential internal and external event hazard upon the LWR. The IE frequencies associated with the addition of the proposed LWR heat extraction systems (HES) and the HTEF are compared against the guidelines set in 10 CFR 50.59 and the CDFs and large early release frequencies (LERF) calculated from the PRA are compared against the guidelines set in RG 1.174. Recommendations for the applicability of the results to this licensing path are given in this report.

The primary internal event concern for increased risk when heat removal is added to a standard LWR is the loss of steam inventory by a steam line break. Ultimately, the loss of steam results in the average temperature of the secondary system cooling down, thus causing a positive temperature coefficient that leads to reactivity insertion, which leads to a reactor power spike. The following increased temperature of the reactor core is what can lead to a reactor trip or core damage. Thus, large steam line break failures are considered the major risk added by the addition of the HES. Increases in the IE frequency of the large steam line break are quantified in this report. In addition to these events, the increase in transients caused by smaller steam line leaks, control system faults, overcurrent from the HTEF load etc., are also considered.

Hydrogen production poses a threat to the reactor core in large detonation accidents where the overpressure impulse (i.e., shock wave), fire, or shrapnel comes into contact with the reactor building or other critical structures on the site. While deflagration events have consequences local to the HTEF, those are not consequential outside of the facility.

The physical specifications of the proposed HES and HTEF are also detailed. These specifications are used to add on to the generic PRA models.

4. NUCLEAR POWER PLANT MODIFICATIONS FOR A HYDROGEN CUSTOMER

There are two NPP system modifications proposed. The first is adding the HES to extract thermal power and provide it to the HTEF. The second is adding the switchyard of components necessary to provide direct electrical coupling to the HTEF.

4.1 Nuclear Power Plant with Heat Extraction System and Collocated High-Temperature Electrolysis Facility System Description

There are three designs considered for the HES. One is a two-phase-to-two-phase transfer design where the heat-transfer medium in the thermal power delivery (TPD) loop enters a vapor phase when heated to operating temperatures. The other design is a two-phase-to-one-phase transfer where the heat-transfer medium stays in the liquid phase. Steam-to-steam heat transfer will always use the two-phase-to-two-phase design. Heat-transfer fluids (HTF), many times incorrectly referred to as "heating oil," can be used in two-phase or single-phase operating states, depending on their physical characteristics and the desired operating temperature (Section 5.1.4.5). The first two designs are conceptual designs based on those used in the LWRS report "Incorporation of Thermal Hydraulic Models for Thermal Power Dispatch into a PWR Power Plant Simulator" [5]. The two-phase-to-two-phase hybrid power design is proposed by Sargent and Lundy power engineers, with the consultation of the LWRS Hydrogen Regulatory Research Review Group.

4.1.1 Heat Extraction System Design 1: Two-phase-to-two-phase

A P&ID diagram of the proposed HES line for steam in the TPD loop is shown in Figure 4-1 as adapted from Reference [5]. The nuclear plant's steam line (main steam header) taps steam from the main steam line downstream from the main steam isolation valves (MSIVs) and before entering the high-pressure turbine. The steam condition available for extraction at the main steam header is saturated steam with a total mass flow rate of 5.8×10^6 kg/hr (1.3×10^7 lb/hr) at 6.95 MPa (1,008.5 psia). HES-1 is the main control valve for the HES line and therefore has the largest effect on reactivity control. During steady-state operations, the steam in the HES line is condensed to avoid sending high-pressure steam to the condenser, which would decrease plant operating efficiency. The extraction heat exchangers required for heat transfer to the hydrogen production plant are located at the NPP site. The HES is also near the turbine system, but not necessarily within the turbine building, to reduce losses and minimize the amount of additional steam inventory cycled through the NPP. Two HES isolation valves are modeled in series (IV-1 and IV-2), mimicking the configuration of a typical MSIV arrangement. For the option using superheated steam or a vapor-phase HTF in the TPD loop, the extraction heat exchangers comprise a two-stage system because there is a phase change in both the hot and cold fluids.

The first heat exchanger HES-EHX-1 is a once-through steam generator. The saturated steam is on the tube side of the heat exchanger, and the delivery steam is evaporated completely and superheated on the shell side. The reason for this design choice is that the once-through steam generator provides slightly superheated steam from a subcooled liquid inlet in a single heat exchanger. This, combined with the vertical nature of the heat exchanger, makes it reasonable for providing the desired heat transfer and fluid conditions. The TPD loop is superheated by about 45°F if steam is used as the heat-transfer medium (vapor-phase HTF superheated temperatures would vary) to assist thermal delivery to the hydrogen plant approximately a kilometer away with minimal condensation.

TPD-EHX-2 has a design like a feedwater heater. The wet steam from the NPP enters the heat exchanger on the shell side to be condensed and subcooled by the condensate from the TPD loop. The condensate in the TPD loop is preheated in the tube side of the heat exchanger before being fully evaporated and superheated in HES-EHX-1. The subcooled liquid is designed to exit HES-EHX-2 at 193.3°C (380°F) at a high pressure of 68.3 bar (980 psi). This liquid is throttled to condenser pressures through an orifice. There is a check valve prior to the orifice that requires a high differential pressure to open. This helps to ensure that the HES line remains pressurized in the event of a system malfunction to protect the chemistry of the nuclear steam in the case of a substantial tube leak in either of the extraction heat exchangers.

As the steam in the hydrogen production plant is pumped through the HES-EHX-2 tubes, it is preheated to saturation, then boils and superheats as it passes through the shell side of HES-EHX-1. The maximum flow rate of steam exiting the extraction heat exchangers and moving toward the hydrogen plant is 2.715×10^5 kg/hr (5.986×10^5 lb/hr) and the temperature is 252°C (485°F). This steam travels approximately 1 km to the hydrogen plant via a pipe equipped with steam traps to ensure dry steam is sent to the hydrogen plant's steam generator. The condensate is then pumped back to the HES heat exchangers, where it is boiled into steam again. Several valves in Figure 4-1 are highlighted in blue. This highlight indicates they are design options. A sensitivity analysis is conducted in Section 6.5 to analyze the safety benefits of these options, and to select the optimal option in terms of safety and costs.

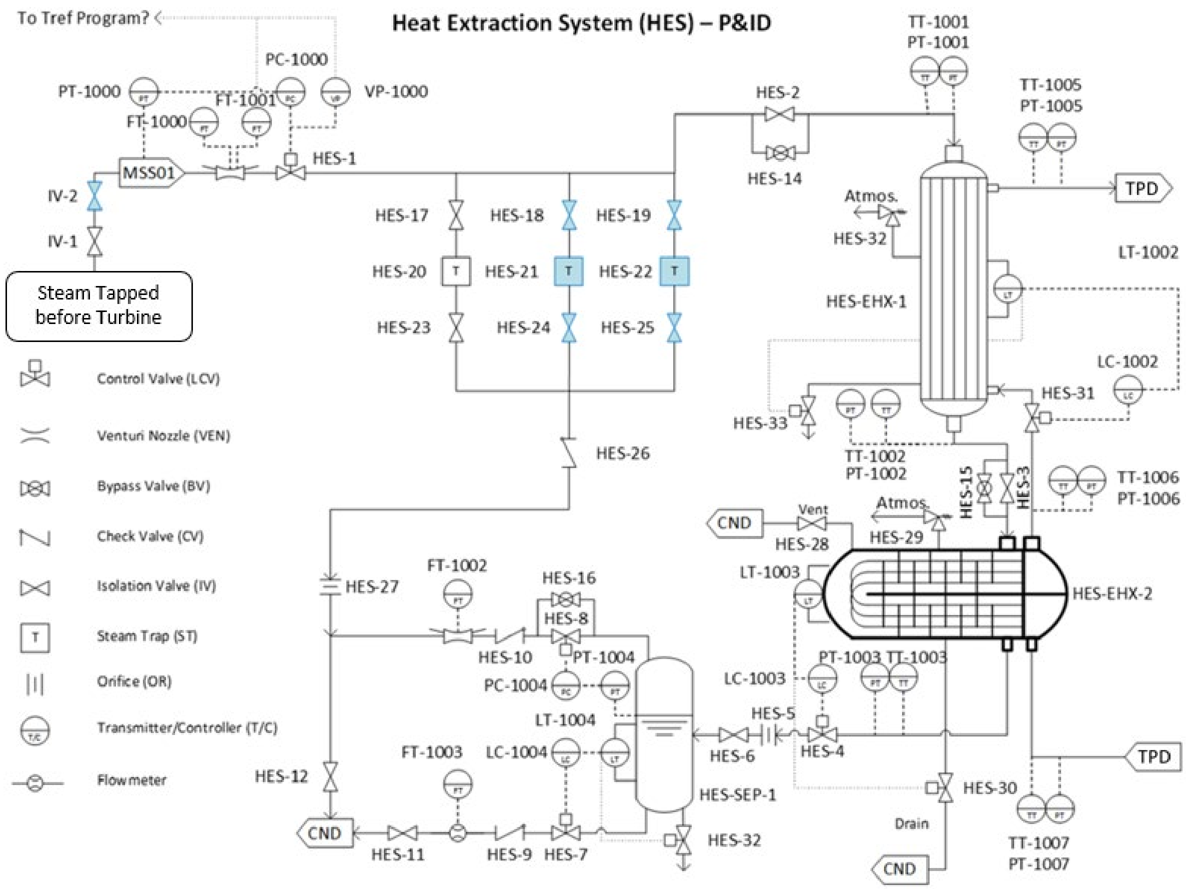

Figure 4-1. P&ID of two-phase-to-two-phase HES.

4.1.2 Heat Extraction System Design 2: Two-phase-to-one-phase

The P&ID for the HES for a constant liquid phase in the TPD loop is shown Figure 4-2 [5]. The design shown is the same as described in Section 4.1.1 with the following exceptions:

Steam traps are not used as a bypass configuration. Instead, HES-7 in the main extraction line downstream from HES-1 removes condensate that forms while saturated steam travels to the extraction heat exchangers. HES-EHX-1 condenses the steam in the HES steam line and is equipped with a hotwell (HES-HW-1). HES-HW-1 is a reservoir equipped with valves to control the condensate level in HES-EHX-1. At a specified condensate level, a valve opens to allow condensate to flow to the HES-EHX-2. This design ensures that only liquid water can flow to HES-EHX-2 when using a fluid-to-fluid heat transfer. HES-EHX-1 has a vent to the condenser for use while the water level is building to the desired level. HES-HW-1 also has a drain to the condenser to allow for extra draining, if necessary. The steam is in the shell side of HES-EHX-1. HES-EHX-2 is a normal shell-and-tube heat exchanger with the water in the tubes and HTF in the shell. This heat exchanger serves to sub-cool the water to allow for maximum heat dispatch. After the condensate exits HES-EHX-2, it flows to the condenser.

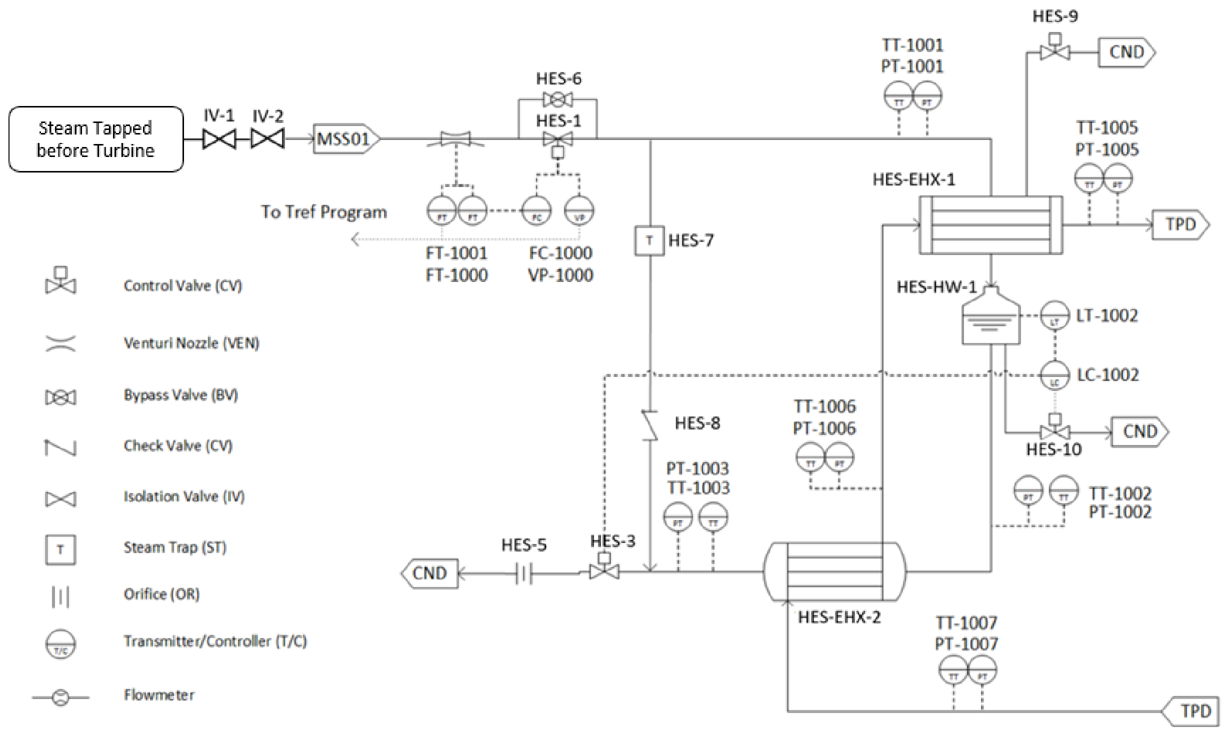

Figure 4-2. P&ID of two-phase-to-one-phase HES.

4.1.3 Heat Extraction System Design 3: Two-phase-to-two-phase Hybrid Power Design

A conceptual diagram of a newer HES line for steam in the TPD loop is shown in Figure 4-3 [6]. The NPP's steam line (main steam header) taps steam from the cold reheat line downstream from the high-pressure turbine exhaust. The steam condition available for extraction at the main steam header is a low-quality steam with a total mass flow rate of 38,663 kg/hr (85,237 lb/hr) at 1.15 MPa (166.8 psi) and 186 ºC (367 ºF). This amount of steam reduces approximately 0.67% of the total cold reheat flow going to the main steam reheater (MSR), and about 0.76% of hot reheat flow going into the low-pressure turbines. The tap design does not affect the main steam flow and turbine control valve position. The slight mass flow rate reduction to the low-pressure turbines reduces the total generator output by 5.3 MWe, or 0.4%. The steam is fed to an electric heater boosted heat exchanger (reboiler) to generate steam from deionized water. The reboiler is in its own enclosure to protect the turbine room and potential missile damage from a reboiler accident. The feedwater steam is sent to feedwater reheaters, while the deionized steam is sent to the hydrogen production plant. The failure modes and effects analysis (FMEA) analysis of this system design is given in Appendix C: FMEA Results. The FMEA analysis shows that risk to the NPP may originate from a failure in the steam extraction line or from the hydrogen production plant itself.

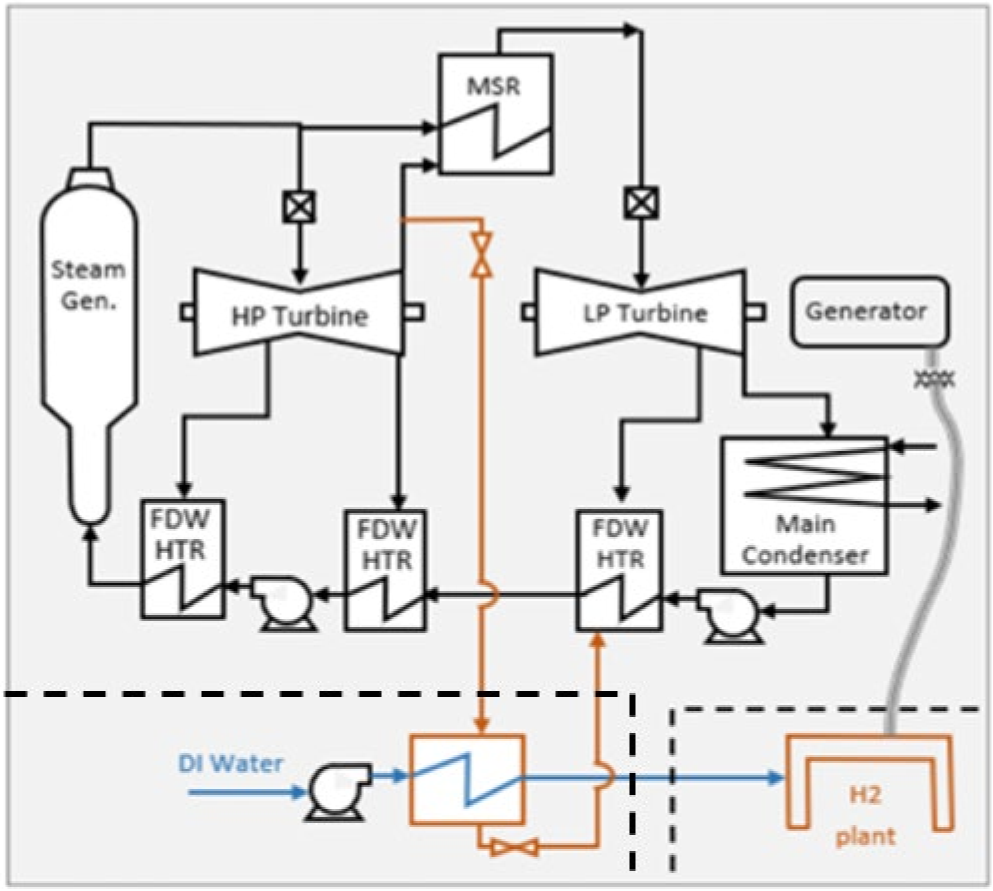

Figure 4-3. Conceptual drawing of two-phase-to-two-phase HES

The diagram of steam extraction line downstream the HP turbines leading to the reboiler is shown in Figure 4-4. J1, J2, J5 and J6 are gate valves that are normally open in HES operation. J3 is a flow control valve with a constant pressure drop of 20 psig, assumed to have no flow stopping capability. J4 is a stop check 90 degrees globe valve. The pipe's insulation is assumed 4.5 in. thick Calcium Silicate. The piping is located inside the turbine building, with an assumed indoor temperature of 70 ºF and air velocity of 0.1 ft/sec. Since a failure in this line may lead to an increased risk to the NPP, a FT for the line is developed as shown in Figure 6-16.

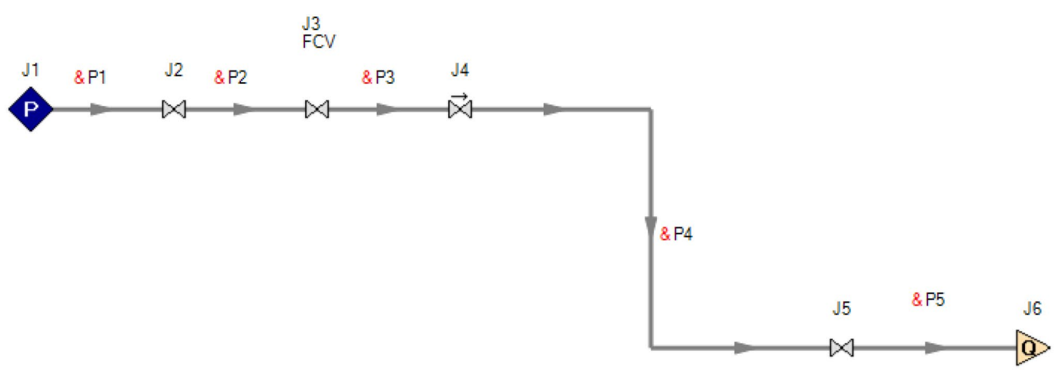

Figure 4-4. Diagram of steam extraction piping to the H2 plant steam generator

The extraction heat exchangers required for heat transfer to the hydrogen production plant are located within the NPP site. The steam extraction operation described above is similar to a low-turbine bypass. Since the amount of extracted steam (0.67%) is much lower than the typical capacity of most NPP designs (25% or more), this extraction process is not expected to affect normal plant operation. This design is for extracting of 25 MWt of steam. Out of this 25 MWt power, 20 MWt is used to generate hydrogen while the remaining 5 MWt is a margin to cover various thermal losses. Other designs are considered for the extraction of 80 and 100 MWt steam. Key plant parameters for the different steam extraction levels are summarized in Table 4-1 [6].

Table 4-1. Technical parameters for the different steam extraction levels [6].

Parameter	Steam Extraction Level (MWt)			
	0	25	80	100
Reactor thermal power (MWt)	3659	3659	3659	3659
Main steam flow (Mlb/hr)	16.28	16.28	16.28	16.28
Cold reheat flow (Mlb/hr)	12.73	12.72 (-0.05%)	12.71 (-0.15%)	12.70 (-0.19%)
Remaining steam to MSRs (Mlb/hr)	12.73	12.64 (-0.67%)	12.44 (-2.27%)	12.36 (-2.85%)
Hot reheat flow (Mlb/hr)	11.26	11.17 (-0.76%)	10.99 (-2.41%)	10.92 (-3.04%)
High-pressure feedwater heater cascading drain flow (Mlb/hr)	1.39	1.39 (-0.23%)	1.38 (-0.7%)	1.38 (-0.88%)
High-pressure feedwater heater cascading drain temperature (ºF)	423.0	422.9 (-0.1%)	422.7 (-0.3%)	422.6 (-0.4%)
Low-pressure feedwater heater cascading drain flow (Mlb/hr)	2.42	2.41 (-0.41%)	2.38 (-1.31%)	2.38 (-1.66%)
Low-pressure feedwater heater cascading drain temperature (ºF)	131.6	131.6 (-0%)	131.6 (-0%)	131.6 (-0%)

4.2 Direct Electrical Connection

Refer to Figure 4-5. The electrical connection to the HTEF goes from a tap just outside of the NPP main generator step-up (GSU) transformer to the switchgear at the HTEF. The transmission line is a 0.5 km, 345 kV high-voltage line with protection at each end, a circuit breaker with manual disconnect switches on each side, and primary and backup relays. The first circuit breaker downstream of the tap point also electrically separates the transmission from the NPP switchyard breaker alignment. As stated in Section 4.3.5 of Reference [6], "The new H2 power line has no effect on the switchyard voltage, breaker alignment, generator AVR loading, or the status of offsite power voltage regulating devices." This eliminates the impact of the transmission line on NPP safety systems that rely on offsite power.

A three winding step-down transformer steps the line voltage down to the 13.8-kV medium voltage required at the switchgear for the HTEF. The switchgear at the HTEF is interpreted as drawn, a circuit breaker protected bus with four inputs on each winding. The transformers and generator circuit breaker

(GCB) also have primary and backup relays. Control panels and power for the relays before the 0.5-km transmission line are within the NPP boundary and after the 0.5 km transmission line are at the HTEF, labeled "H2 Island" in Figure 4-5. Should these protections fail in an overcurrent event due to loads at the medium voltage switchgear or either of the transformers, the resulting overcurrent felt at the generator could cause a transient event at the NPP. This failure model is detailed in Section 6.2.

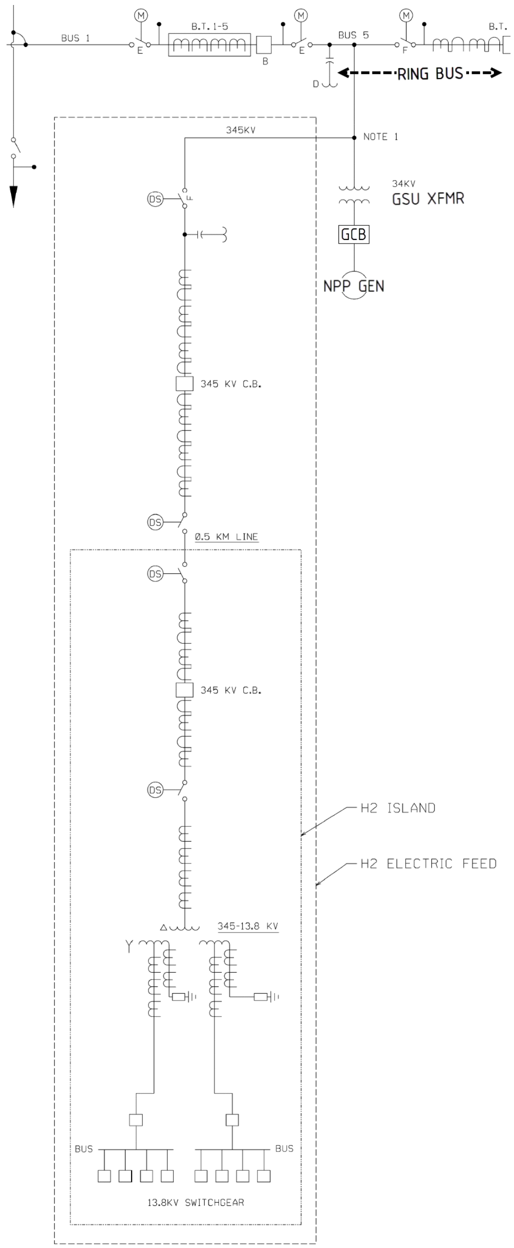

Figure 4-5. Transmission line and portion of ring bus switchyard arrangement at NPP [7].

5. HAZARD ANALYSIS

The hazards considered potentially affect the frequency of internal and external NPP events. To define internal events in an NPP connected through a thermal loop to an HTEF, the jurisdictional boundary must be defined where the NRC's regulation of the nuclear facility ends. A report issued to address facility collocation at advanced nuclear reactor sites, INL/EXT-20-57762, “Establishing Jurisdictional Boundaries at Collocated Advanced-Reactor Facilities” [8], summarizes the following points applicable to jurisdiction:

- The NRC would retain full oversight authority over structures, systems, and components (SSCs) needing protection under physical-security regulations. These security elements would be part of the nuclear facility.

- All SSCs that perform nuclear-safety-related or risk-significant functions would be included within the nuclear facility boundary and under NRC jurisdiction.

- Energy-conversion system(s) located within the nuclear protected-area boundary are integral to the nuclear facility, operated by the nuclear facility control room, and should be considered part of the nuclear facility. Energy-conversion system(s) located outside the protected-area boundary and separated from the nuclear facility by a transfer system with appropriate interface criteria could be excluded from nuclear facility scope. Interface criteria must ensure the nuclear facility is not dependent upon or adversely affected by industrial facility events.

- A nuclear safety analysis would be required of all nuclear and industrial systems with respect to potential missiles, security issues, flooding issues, or any other impacts that may influence SSCs that perform a nuclear safety function.

- The regulatory boundary between the nuclear and industrial facilities can be defined by describing the boundary in the nuclear facility system design, transfer-system(s) design, and interface descriptions with appropriate interface requirements, and pertinent downstream conceptual-design information. Interface requirements must address industrial facility systems transients and failures. Requirements must ensure that no portion of the industrial energy-transfer system performs or adversely affects a nuclear safety function. Appropriate monitoring and detection systems are to be employed. Radioactive material releases from energy-transfer system(s) must meet applicable limits.

    - Interface requirements would demonstrate a robust ability to maintain safe nuclear operation. Site-related requirements and assumptions associated with the standard design would be shown as met along with all criteria-pertinent standard design safety. These requirements are also focused on preserving SSC nuclear safety functions.

These principles hold true for existing LWR facilities as well. A generalized NRC regulatory jurisdiction boundary is summarized in [8].

Most events that can interfere with the operation and safety of the NPP affected by the location of the HTEF outside of the regulatory jurisdiction (shown in Figure 5-1) are treated as external events. The exception is the reactivity feedback that would occur if there were a sudden large leak in the TPD that services the HTEF. External events are added to the NPP site by the potential for industrial interrupts and accidents at the HTEF. Other external events specific to the site are assumed to already be covered adequately by the existing NPP Level 1 PRA.

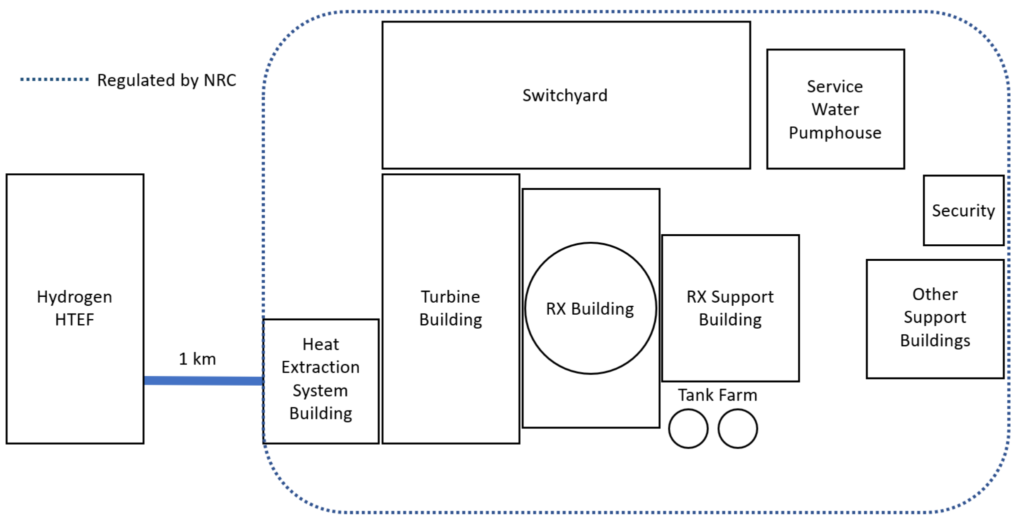

Figure 5-1. NRC jurisdictional boundary for LWR servicing an HTEF.

Hazard analyses were performed for both the NPP and the HTEF. The NPP hazard analysis included the envelope beyond that postulated in Reference [8] by considering the heating loop provided by the NPP to the HTEF and the temperature drop negative reactivity feedback that would occur if the loop were to experience a sudden break in the piping. The HTEF hazard analysis started on the secondary side of the heat exchanger after the delivery of thermal energy to the HTEF.

5.1 Nuclear Power Plant with HES Hazard Analysis

The hazards associated with the addition of the HES to the existing NPP were considered through interviews with subject matter experts (SMEs) and available design drawings and options of the proposed HES.

5.1.1 Design Options and Assumptions

The HES design options and assumptions considered for the representative NPP, HES, and HTEF are listed in Table 5-1. HES design options reference the P&ID. Other assumptions are made based on physical properties and a generic geographic region.

Hydrogen detonation overpressure is a fraction-of-a-second impulse. Multiple detonations provide follow-on impulses. While it is reasonable to assume that a first impulse may weaken a structure and that a following impulse might damage it, the fragility curves we use in this report are evaluated at the point of zero fragility to the impulse-equivalent psi. For multiple high-pressure jet detonations, it is possible that the first detonation would break another line, providing the opportunity for another high-pressure jet detonation of the same overpressure. An accumulated hydrogen cloud detonation would not cause another hydrogen cloud detonation because the facility is assumed to not have hydrogen storage.

Table 5-1. HES design options and assumptions.

Component/Parameter	Identification (Figure 4-1)	Options	Assumptions
Isolation valve	IV-1, IV-2	One or two valves in series	Isolation valves will follow design of NPP MSIVs
Bypass valve trains	HES-17 through HES-25	One, two, or three trains	None

Component/Parameter	Identification (Figure 4-1)	Options	Assumptions
Heating medium	TPD loop out and in	Steam or heating fluid	Steam is the standard
HES placement	Not Applicable (NA)	House the HES in the turbine building or in a dedicated building	HES is placed in a dedicated building (FMEA recommended)
Hydrogen Storage and Transfer Facility	NA		HTEF will pipe the production hydrogen to a storage and transfer facility 5 km distant from the NPP's critical structures
Electrical Power Linkage from NPP to HTEF	NA	Direct linkage, load following or connection to the grid then to the HTEF	1,150 MWt HTEF: The NPP is connected to the grid to buffer upsets from HTEF 100 MWt HTEF: The NPP is connected directly to the HTEF
HTEF ventilation	NA	Is there an HTEF industrial building ceiling ventilation of the hydrogen leak	A dedicated industrial building ceiling ventilation is not considered in base PRA case
Loss-of-offsite-power (LOOP) frequency	NA		LOOP frequency is the same for the generic BWR and PWR model, assuming the same geographical region
Multiple detonations at HTEF	NA		Bounding accident is assumed for the first detonation overpressure Ensuing detonations will not exceed bounding accident Structures will not be weakened in the first detonation overpressure
Temperature of the thermal delivery loop	NA		$\leq 600^{o}$F

5.1.2 Nuclear Power Plant Safety-Critical Structures

The reactor building is the primary critical structure at an NPP. It is also the most well-protected from any external forces, such as blast impulse shock waves. Nuclear-grade concrete walls encase the containment and provide significant protection to the reactor internal structures in addition to providing significant protection from accidental release of ionizing radiation. Critical structures external to the reactor building are typically designed to withstand postulated local wind and seismic loads. These include refueling water storage tanks (RWST) and condensate storage tanks (CST).

5.1.2.1 Reactor Containment Structure Fragility to Overpressure Events

Reactor building concrete walls were characterized in EGG-SSRE-9747, "Improved Estimates of Separation Distances to Prevent Unacceptable Damage to Nuclear Power Plant Structures from Hydrogen Detonation for Gaseous Hydrogen Storage" [9]. The lowest static pressure capacity of nuclear concrete identified is 1.5 psi. This conservative estimate was used for the blast analyses performed in the separation study INL/EXT-05-00137, "Separation Requirements for a Hydrogen Production Plant and High-Temperature Nuclear Reactor" [10] and INL/EXT-19-55884, "Preliminary Probabilistic Risk Assessment of a Light Water Reactor Supplying Process Heat to a Hydrogen Production Plant," [2] and is adopted as the static pressure capability of nuclear concrete walls in this study as well.

5.1.2.2 Safety-Critical External Structures Fragility to Overpressure Events

Critical structures outside of the reactor building have been identified when assessing high-wind fragility for PRA. For most BWRs, these include at least one CST. Many times, there is an auxiliary (sometimes called emergency) feedwater tank, service water pump house(s) and intakes, and the electrical switchyard. For PWRs, there is typically an RWST, an auxiliary or emergency feedwater tank, a CST, service water pump house(s) and their associated intakes, and a switchyard. Many wind-pressure and wind-missile fragility studies have been performed for NPPs. The individual plant examination of external events (IPEEE) studies in the 1990s produced a wealth of information on wind fragilities. The Duane Arnold IPEEE [11] was selected to act as a baseline for these fragilities. An updated high-wind fragility analysis performed by Applied Research Associates [12] determined the mean fragilities components commonly found in the switchyard. These wind pressure fragilities of 6-second gusts were transformed into blast overpressure impulse fragilities in SAND2020-7946, "Final Report on Hydrogen Plant Hazards and Risk Analysis Supporting Hydrogen Plant Siting near Nuclear Power Plants" [13].

External water tanks are located close to the reactor building to provide condensate storage and coolant for routine and emergency operations. In some cases, there are concrete walls placed around the external tanks for protection, but some NPPs choose not to include external protection other than the tank's own construction. These tanks are built to extreme standards. According to Reference [11] and other IPEEEs, they are equivalent in structural integrity against wind pressure to a Category I Structure. This means that the tanks are nearly as durable as the reactor building itself and nearly as durable as reactor containment when it comes to handling pressure. The CST and other storage tanks are assumed to be Category II structures when considering susceptibility to wind missiles. The probability of failure per instance of overpressure for storage tanks and Category I Structures are listed in Table 5-2. An overpressure event is a fraction-of-a-second impulse, so the correlation between wind speed pressure fragility to overpressure requires proper scaling.

Service water intakes are solid structures, and their failure modes typically involve the buildup of debris on the screens instead of physical damage; however, the pump house is not typically built to withstand tornadic or hurricane winds. In some NPP PRAs, a loss of service water is itself an initiator that challenges the NPP to shut down safely. The probability of failure per instance of wind speed for a typical pump house is listed in Table 5-2.

Loss of switchyard components means a loss-of-offsite-power (LOOP) event that challenges the NPP to shut down safely. Switchyard components are fragile to wind pressure, and therefore also fragile to an overpressure event. The resulting overpressure fragilities for the switchyard are shown in Table 5-2.

Table 5-2. Blast overpressure fragilities of switchyard components.

SSC	Effective Pressure (psi)	Equivalent Windspeed (mph)	Total Fragility (Wind and Missiles)
All Category I Structures	0.59	182	0
	0.97	234	4.00E-04
	1.49	290	4.60E-03
	2.16	349	4.00E-02
Storage Tanks (CST, RWST, etc…)	0.59	182	2.10E-03
	0.97	234	2.80E-03
	1.49	290	1.60E-02
	2.16	349	5.40E-02
Circulating Water/Service Water Pump Area in Pump House	0.10	75	8.00E-04
	0.20	105	5.80E-02
	0.28	125	1.50E-01
	0.59	182	5.20E-01
	0.97	234	9.40E-01
	1.49	290	1.0
	2.16	349	1.0
Switchyard, General	0.32	135	3.78E-01
	0.48	165	9.74E-01
	0.71	200	1.0
Transmission Tower	0.10*	75*	0.0*
	0.16*	95*	0.0*
	0.20*	105*	0.8*
	0.32	135	9.18E-01
	0.48	165	1.0
	0.71	200	1.0
Standby Auxiliary Transformer	0.32	135	1.99E-01
	0.48	165	2.68E-01
	0.71	200	3.11E-01
Note: * Updated and lower wind speed and pressure values taken from "Fragility Analysis and Estimation of Collapse Status for Transmission Tower Subjected to Wind and Rain Loads" [14].			

5.1.2.3 Non-Safety-Critical External Structures

In addition to critical structures, some other structures that affect operations, but not typically the ability to safely shut down the reactor, are located in the plant yard as well: circulating water and standby service water pump houses, demineralized water storage tank(s), cooling towers, well water pump houses, a liquid nitrogen tank, and hydrogen and nitrogen gas cylinders, which present stored energy in the form of chilled and pressurized gas.

Further, the day-to-day NPP operations would be affected by damage to the turbine building, administrative building, and maintenance support buildings located throughout the site.

5.1.2.4 Example Site Plans with External Structures for Pressurized-Water Reactor and Boiling-Water Reactor

Several NPPs were reviewed for external safety-critical and non-safety-critical structures. Calvert Cliffs NPP was chosen as a representative PWR site and Columbia NPP was chosen as a representative BWR site.

Calvert Cliffs NPP was chosen because it is a good example of a shoreline NPP where the placement of an industrial complex is limited to 180 degrees around the NPP due to the water source. It also has many natural obstructions due to the woods in the area. The overhead view of the Calvert Cliffs NPP (Figure 5-2) shows the possible location at a 1-km distance denoted by the red circle where a co-located industrial plant may be placed. Once a site is selected, the origination and direction of an overpressure event can be determined along with attenuating obstructions. The analysis performed for this report did not consider attenuating obstructions to remain a generic model, but this feature is something to consider for an actual site if conservatism is not desired or warranted. Figure 5-2 shows an aerial view of Calvert Cliffs NPP with the critical structures labeled. This gives a good perception of the sizes of the tanks and the geography of the surrounding area. Figure 5-3 and Figure 5-4 show the Calvert Cliffs site plan with the critical structures labeled. Other structures of interest are the water storage tanks alongside the CSTs and the liquid nitrogen storage in the northeast corner of the tank farm where the CSTs are located.

Figure 5-2. Calvert Cliffs NPP 1 km from reactor building overhead view, © listed in image.

Figure 5-3. Calvert Cliffs NPP critical structures labeled on aerial view, image from the NRC.

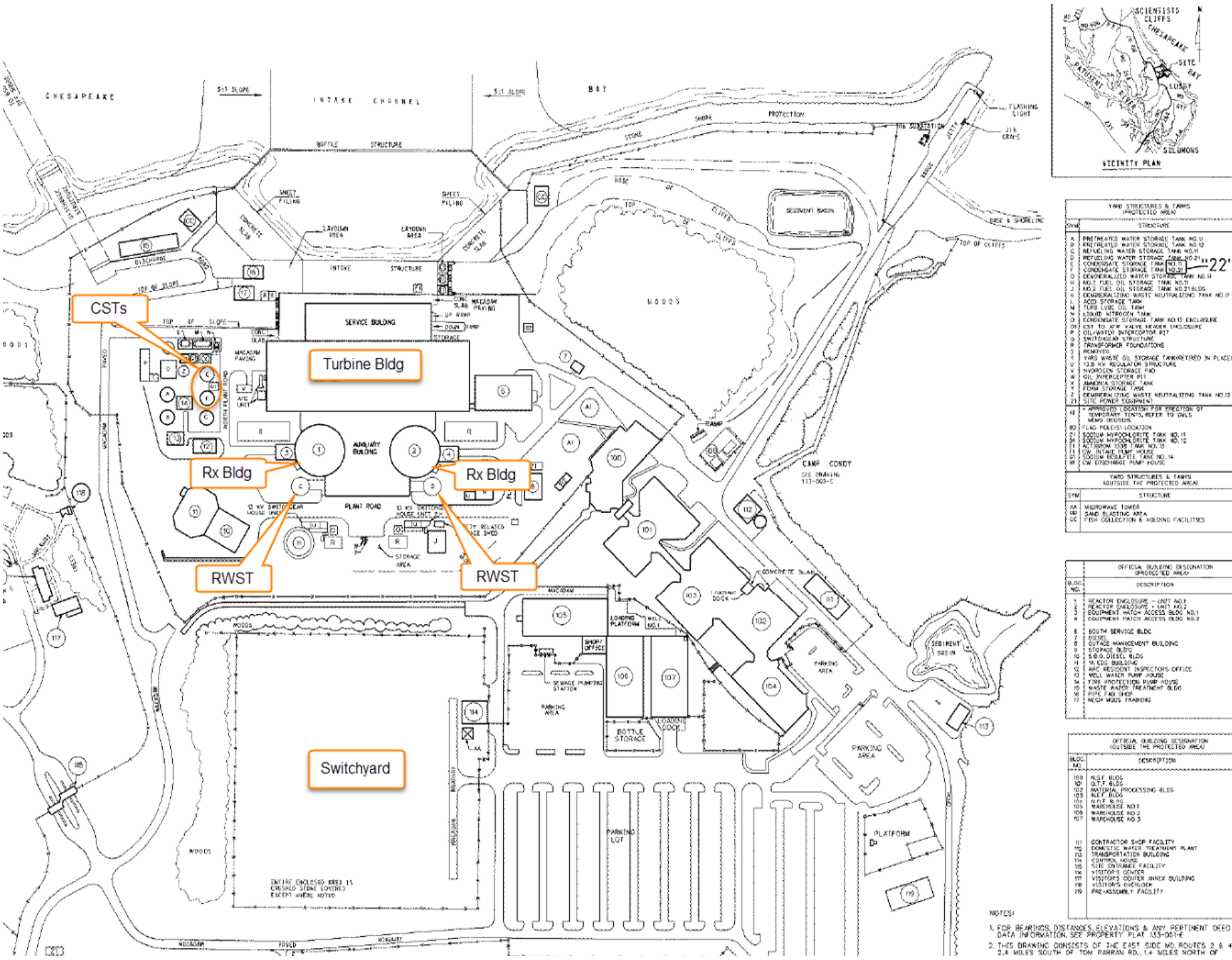

Figure 5-4. Calvert Cliffs NPP Site layout from IPE.

Columbia Generating Station NPP was chosen as an example BWR for several reasons. Even though the Columbia River is in close proximity, the Columbia NPP is a good example of an inland NPP site using man-made ponds. The site has no natural obstructions within the 1-km area specified for a co-located industrial site. There are two abandoned NPP projects immediately to the east which could potentially be an industrial site location. The overhead view of Columbia NPP (Figure 5-5) shows the possible orientation within 1 km where a co-located industrial plant may be placed. Once a choice of siting is made, the origination and direction of an overpressure event can be determined along with attenuating obstructions. As stated previously, attenuation of an overpressure event was not considered in the analysis, but attenuation should be considered for an actual site if conservatism is not desired or warranted. Figure 5-6 shows an aerial view with the critical structures labeled. Figure 5-7 shows the Columbia NPP site plan with the structures labeled. The CSTs, transformer yard, and switchyard are critical structures. Other structures of interest are the standby service water pumphouses.

Figure 5-5. Columbia NPP 1-km boundary from reactor building overhead view, © listed in image.

Figure 5-6. Columbia NPP site overhead view © Google Maps, Maxar Technologies, USDA.

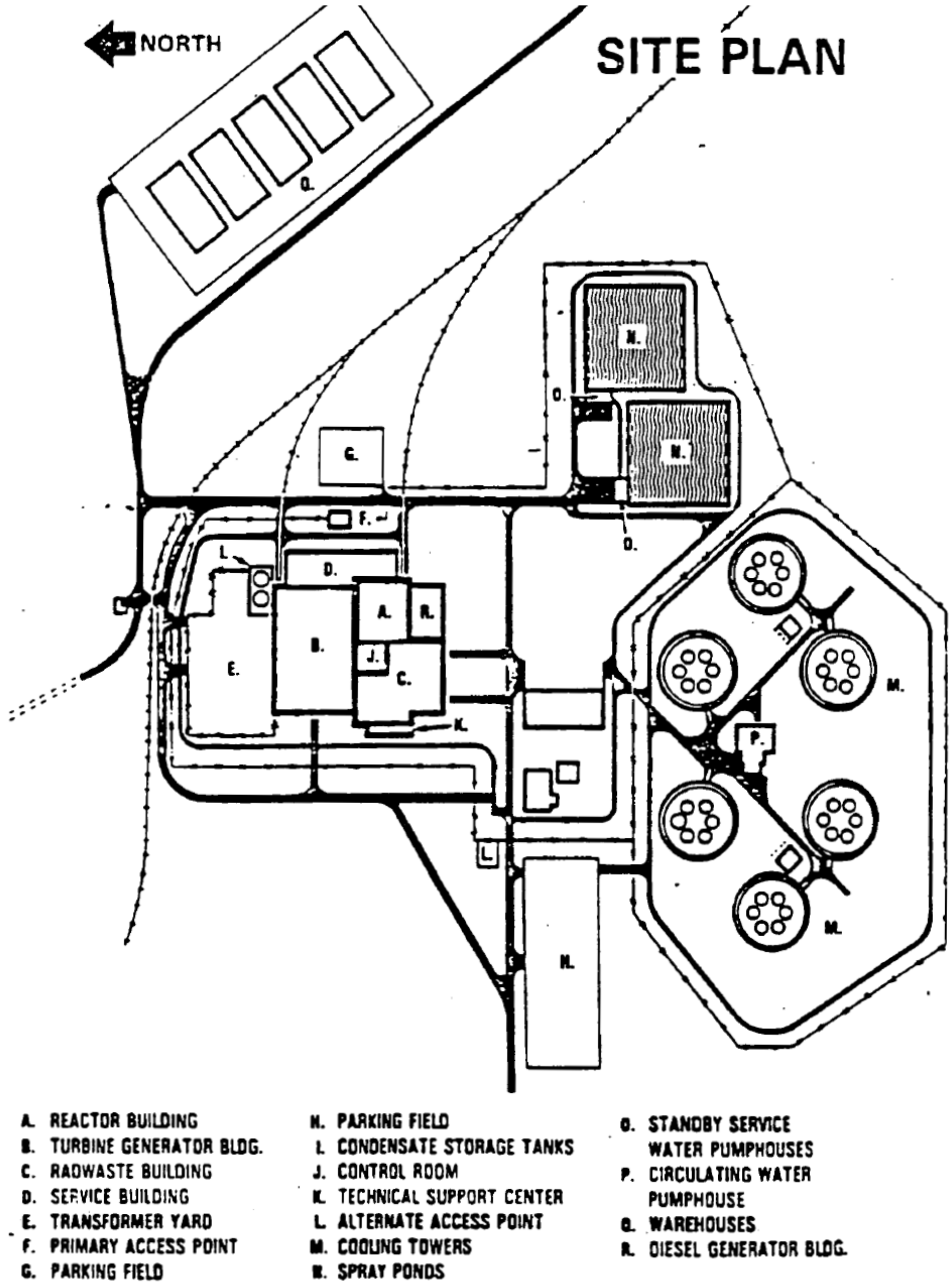

Figure 5-7. Columbia NPP site plan from IPE.

5.1.3 NPP Hazard Analysis

A group of SMEs were gathered for a FMEA. The team included SMEs with experience in PRA and reliability engineering, PWR operations, BWR operations, detailed design knowledge of the hydrogen HTEF proposed for this study, chemical, and controls experts. Information gathered from the SNL report [13] was used to determine the external events that could possibly affect the NPP. These included external overpressure events, heating medium (steam or HTF) leakage at the HTEF, and electrical power load loss from the HTEF.

An outline of the topics considered for the FMEA included:

- External overpressure event effects on NPP
- Thermal and electrical load effects on NPP
    - Thermal and Electrical load power profiles supplied by the NPP to the HTEF
- Hot standby mode
- Steam vs. HTF
- A list of the HTFs under consideration
- Placement of the HES
- Unique risks of BWR
- Unique risks of PWR
- Production hydrogen routing options and effects on risk.

Possible external overpressure events effects on the NPP were summarized to include the damage to the containment, damage to external coolant storage tanks, LOOP, damage to above water spray mechanisms in spray ponds, debris in spray pond or cooling tower pond, and service water pump house damage. The results of the SNL report on Maximum Credible Accident (MCA) at 1 km distance were known prior to this FMEA. The team was therefore able to quantify a risk priority number (RPN) for each of the components considered based on the overpressure created from the MCA.

Possible thermal and electrical load effects on the NPP were summarized as a load-drop feeding back negative reactivity into the NPP, possibly causing a reactor trip.

Hot standby mode discussion was centered around the thermal and electrical load effects.

Differences were considered between steam and HTF as the heat transfer fluid in the secondary HES loop providing thermal energy to the HTEF. Steam is the preferred heat-transfer medium from anecdotal evidence and a discussion with Electrical Power Research Institute (EPRI) BWR and PWR experts in January 2020. This preference is far and away due to the familiarity of working with steam. There are benefits to using HTF compared to steam. The HTF maintains heat for a longer period of time, and it can operate in a steady state or from a liquid to a vapor, with a much less chance of pump cavitation, if used. Finally, the heat exchanger for a steam system would be larger and therefore more expensive than the heat exchangers for HTF.

The HES was considered for placement within the turbine building or in a building separate from the turbine building. The benefit of placement in the turbine building (if room in the existing NPP is available) is lower cost. The benefit of having its own structure is increased safety, as the FMEA results (Appendix C) identify.

Unique risks were considered for BWR and PWRs for each of the hazards identified.

Hydrogen production and storage was discussed as a potential hazard. The current model consists of piping the hydrogen to a transfer facility at least 5 km away from the NPP. This facility would consist of truck transfer and other pipeline transfer, including the possibility of mixing with natural gas.

5.1.4 List of Nuclear Power Plant Hazards Identified

The NPP FMEA results are listed in Appendix C: FMEA Results. The RPN for each identified hazard was calculated and ranked. RPNs for this exercise are used as risk information. There is no RPN cutoff at which the hazard will not be modeled in the PRA. All risks identified are evaluated in the sections that follow. Those not screened by an engineering evaluation are mapped into the respective ETs, and the IE frequency for these ETs are re-quantified for the respective BWR and PWR models based on the increased frequency of occurrence caused by the addition of the HES and 1-km distance of the HTEF.

The hazards either affected or added to the PRA by the addition of the HES and the HTEF are listed in Table 5-3. Also listed in the table is the event tree that the hazard would map to and the status (include or screen from the PRA) from the FMEA panel. There are five potential hazards considered in adding the HES and locating the HTEF at 1-km distance: hydrogen detonation at the HTEF causing an overpressure event at the NPP site, an unisolable steam pipe leak in the HES outside of the NPP MSIVs, a heat exchanger leak in the HES, ignition of the heating medium, and the prompt loss of thermal load to the HES.

Table 5-3. FMEA potential failures from hazards and PRA ET assignment.

Hazards	Potential NPP Process Functions Affected	Potential PRA ET Assignment	FMEA Hazard Status
H2 detonation at HTEF (high-pressure jet detonation, cloud accumulation detonation)	Loss of Offsite Power	Switchyard-centered LOOP (LOOPSW)	Included
	Loss of Service Water (Spray Pond damage or debris, Cooling Tower Pond debris, Service Water Pump House, Forced Air Cooling)	Loss of Service Water System (LOSWS) (BWR) No generic PWR tree affected	Included
	Critical Structure Damage (Reactor Containment, CST, or other coolant supply tanks)	HTEF-H2-DETONATION[1]	Included
HES steam pipe rupture outside of NPP MSIVs	Missile damage in turbine building (if HES located in turbine building)	Main (Large) Steam Line Break in HES (MSLB-HES), TRANSIENT (MSLB-HES bounding)	Included (screened if HES is not in the turbine building)
	Main (large) steam line rupture, unisolable steam leak	MSLB-HES	Included
HES heat exchanger leak	Large Leak/Rupture: Main steam line unisolable steam leak	MSLB-HES	Included
	Small Leak: Contamination of the HTEF heating loop (steam or HTF)	Not a design basis event. Economic risk. BWR is a higher risk to contaminate the HTEF heating loop.	Screened for Level-1 PRA. There is an economic and environmental concern

[1] Potential new ET if evaluated overpressure damages critical structures.

Hazards	Potential NPP Process Functions Affected	Potential PRA ET Assignment	FMEA Hazard Status
Ignition of heating medium	Steam, non-flammable HTFs: flammable	None	Screened for steam Not considered for HTFs
Prompt steam diversion loss, feedback	5% thermal diversion	None. NPP can handle 30% prompt load loss. Screened out.	Screened
HES steam rupture in the turbine building	Turbine building SSC damage, possible safety bus damage, depending on plant configuration	TRANSIENT, emergency power capability	Screened out by recommendation to not place HES in turbine building

5.1.4.1 Hydrogen Leakage at the HTEF

The hydrogen detonation at an 1,150 MWt HTEF is the focus of the study performed by SNL [13]. SNL provided direct input to this revision of the report for a 100 MWt facility using the same processes described in Reference [13].

Leak rates determine the frequency of the overpressure event. The event consequences remain the same as in the prior analysis because the assumed MCA is the hydrogen produced by one electrolysis module. The number of modules increase with the size of the HTEF, but the module sizes remain the same. The 1,150 MWt HTEF consists of 46 25-MW modular units. Only four 24-MW modules are required for the 100-MWt HTEF.

The leak frequency of the facility was calculated from the bottom-up component leak frequencies. A Bayesian statistical analysis was used to combine leak events from non-hydrogen sources that are representative of hydrogen components with the limited data for leak events from hydrogen-specific components. The overall leak rate for leak sizes scaled from 1 = full line break of a 1,150 MWt HTEF is reproduced from Reference [13] in Table 5-4. SNL analyzed a smaller 100 MWt plant for revision 1 of this report. The overall leak rates for leak sizes scaled from 1 = full line break of a 100 MWt HTEF is shown in Table 5-5.

Table 5-4. 1150 MWt HTEF System Leak Frequency (/y) from [13].

Leak Size	1150 MWt HTEF Module System Leak Frequency			
	Mean	5th	Median	95th
0.0001	2.28E+01	7.95E+00	1.70E+01	5.48E+01
0.001	4.19E+00	1.13E+00	3.32E+00	9.89E+00
0.01	1.37E+00	1.45E-01	7.47E-01	4.16E+00
0.1	1.33E-01	3.34E-02	1.01E-01	3.20E-01
1	5.19E-02	2.51E-03	2.18E-02	1.83E-01

Table 5-5. 100 MWt HTEF System Leak Frequency (/y).

Leak Size	100 MWt HTEF Module System Leak Frequency			
	Mean	5th	Median	95th
0.0001	1.99E+00	6.91E-01	1.48E+00	4.77E+00

Leak Size	100 MWt HTEF Module System Leak Frequency			
	Mean	5th	Median	95th
0.001	3.64E-01	9.82E-02	2.89E-01	8.60E-01
0.01	1.19E-01	1.27E-02	6.50E-02	3.62E-01
0.1	1.16E-02	2.93E-03	8.85E-03	2.80E-02
1	4.59E-03	2.38E-04	1.97E-03	1.60E-02

5.1.4.2 Hydrogen Detonation at the HTEF

The consequences calculated in the previous report utilized system parameters (flowrate, pressure, temperature, etc.) from hydrogen production components within a single module. Therefore, these consequences are still applicable to the reduced 100 MW facility introduced in this revision. Therefore, no reduction in consequence can be calculated based on the smaller facility.

The overpressure felt at the NPP from a high-pressure jet leak detonation or a hydrogen cloud accumulation detonation were determined based on 15 leakage scenarios. No credit was given for attenuation of the shock wave made by buildings, wooded areas, or other topography. The bounding case presented in Reference [13] used the largest leak size and therefore this frequency (5.19E-02 /y) was used in the PRA IE development. Calculations were made for the next largest leak size, denoted 0.1, and the most fragile components of the NPP were not affected by the overpressures created from either the high-pressure jet or hydrogen cloud detonation. According to “Methodology for Assessing the Safety of Hydrogen Systems: HyRAM 1.1 Technical Reference Manual” [15], the highest probability of detonation of a hydrogen leak, given an ignition source, is 0.35. This conservative value was used for the determination of detonation frequency, given a leak, in the PRA model.

High-Pressure Jet Detonation: The high-pressure jet detonation frequency is not determinant on the human action to isolate the leak. The hydrogen is immediately available for detonation at the strength calculated. The maximum overpressure from a credible accident felt at 1 km from a high-pressure jet detonation is 0.056 psi [13]. The total fragility of switchyard components resulting from wind pressure and tornado-generated missiles is listed in Table 5-2 from References [11] and [14]. This fragility data is used to determine the failure probability of these components when a hydrogen detonation event occurs. The fragility data points are shown in Figure 5-8. Fragility estimates between the known data points are interpolated linearly. The most fragile component in the switchyard is the transmission tower. The probability for damaging a transmission tower goes to zero at approximately 0.16 psi [14]. For reference, windows will break at an incident overpressure between 0.15 and 0.22 psi (Federal Emergency Management Agency, citing Kinney and Graham, “Explosive Shocks in Air” [16]). We use this data to screen out the high-pressure jet detonation as a safety concern in the PRA.

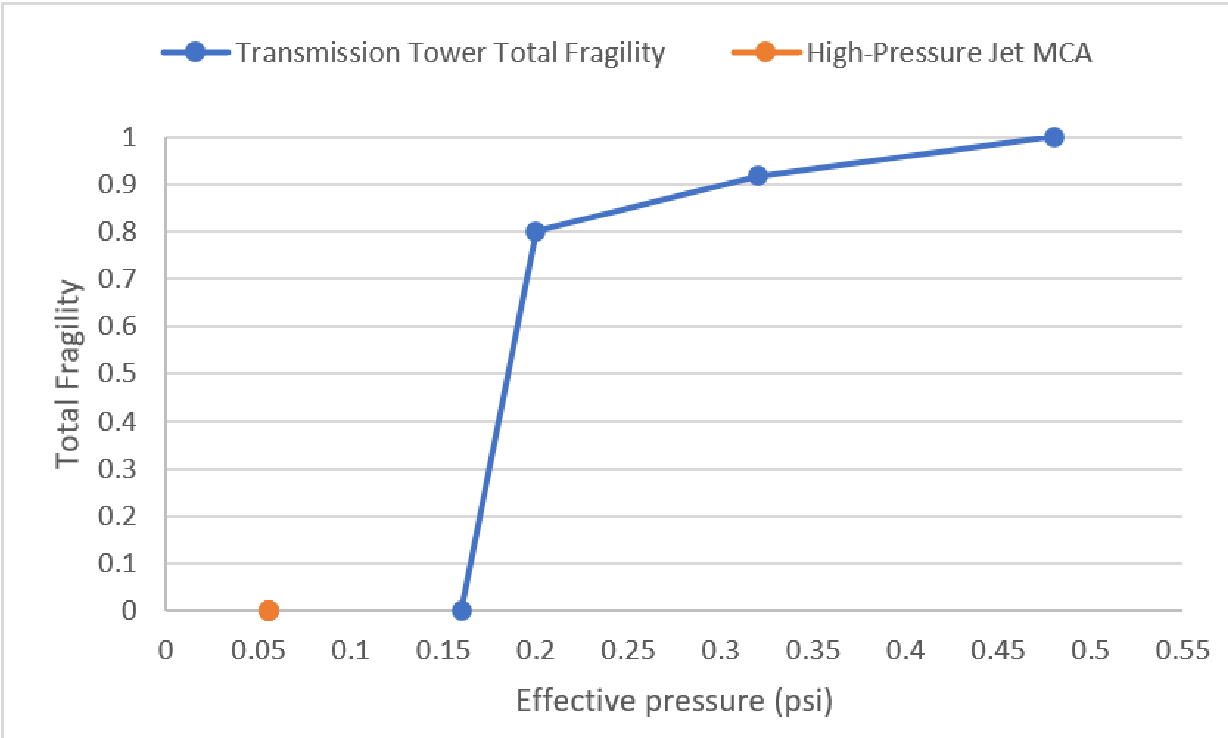

Figure 5-8. Switchyard components fragility as a function of wind pressure.

Hydrogen Cloud Detonation: The hydrogen cloud detonation frequency is determinant on the ability of hydrogen to accumulate within the building. This is determined by the failure of the building ventilation system to vent the leak to atmosphere and the failure of human action to isolate the leak within the specified time noted in Reference [13]. For the MCA, this time is 120 minutes. The human action probability of failure was determined using the standardized plant analysis risk human reliability analysis (SPAR-H) methodology within SAPHIRE to be conservatively 1.0E-2, given nominal time to perform the action and all other performance shaping factors (PSFs) listed as nominal. A less conservative approach, giving expansive time to perform the action was calculated as a probability of failure of 1.0E-04. The failure of all modes of an industrial building ventilation system was noted to be 2.4E-05/h in INEEL-EXT-99-001318, "Ventilation Systems Operating Review for Fusion Systems" [17]. The probability of detonation, given a leak is 0.35, as noted above. These probabilistic events, along with the yearly frequency of 5.19E-02/y for the full leak creating the MCA, were modeled in an FT to determine the frequency per year of the cloud detonation MCA event. This FT is the branch beginning with the AND logic gate IE_LOOPSC-HES-MCA in Figure 6-28. The resulting frequency is 4.15E-09/y. This is seven orders of magnitude below the loss-of-offsite-power switchyard-centered (LOOPSC) IE frequency of 1.34E-02/y (basic event IE-LOOP-SC) for both the BWR and PWR models described below and five orders of magnitude below the Initiating Event Fault Tree Loss of Service Water System (IEFT-LOSWS) IE result of 1.80E-04/y in the BWR model for service water failure. We used the results of this IE FT to screen out the hydrogen cloud detonation as a safety concern in the PRA.

5.1.4.3 Heat Extraction System Unisolable Steam Pipe Rupture

A large steam line break is the most common hazard introduced by adding the HES to the NPP. The HES P&ID (Figure 4-2) shows there are two isolation valves for the HES, set in a series. The success of these valves is the first line of defense of a steam line rupture within the HES after the NPP's MSIVs. Isolation valve ruptures are also a possibility that needed modeling. After the isolation valves, all of the other active components in the P&ID are evaluated in the HES FT (Section 6.1). The FT result was added to the IE for a large steam line break, as described in Section 6.3.1 for a PWR and Section 6.4.1 for a BWR.

5.1.4.4 Heat Extraction System Heat Exchanger Leak

Two types of heat exchanger leaks are considered for the PRA: a slow leak that is not a prompt safety concern to the NPP operation and a heat exchanger rupture.

Slow Leak of an HES Heat Exchanger: The heat-transfer loop to the HTEF will always be operating at lower pressure than the NPP steam loop through the HES. This prevents the contamination of the NPP steam loop. Small leaks in the heat exchanger may contaminate the heat-transfer loop to the HTEF. This can cause a cleanup problem if there is enough activity transferred to the heat-transfer loop. For most NPPs, this will not be a problem. BWR steam loops are more likely than PWR steam loops to have radioisotopes of any measure, but their steam loops are typically very clean as well. This a unique potential hazard to the LWR NPPs considering this modification. There are prevention, detection, and mitigation measures that obviously would need to be in place to monitor for and react to any small leaks. This hazard can cause economic issues for the cleanup, including reactor shutdown, and cause environmental concerns in the public. This study is concerned with reactor safety and did not consider the architecture of a representative system.

Rupture of an HES Heat Exchanger: There are two HES heat exchangers. See Figure 4-2. HES-EHX-1 heats the heating medium (steam or HTF) to its operating temperature. HES-EHX-2 pre-heats the returning heating medium and helps to chill NPP steam as after it exits HES-EHX-1. An HES heat exchanger rupture failure maps to the HES large steam line break event and is treated as an event within the IE FT for PWRs (Section 6.3.1) and BWRs (Section 6.4.1).

5.1.4.5 Ignition of Leaked Heat-Transfer Medium

The use of steam as the heat-transfer medium screens this hazard out from consideration. If HTF is used, it is dependent on the type of HTF. Four HTFs were provided by the designers of the proposed HES and are considered for this hazard: Therminol 66, Dowtherm A, Dowtherm G, and Therminol VP-1. As stated in Section 5.1.3, Dowtherm A and Therminol VP-1 operate in vapor states at their higher operating temperatures. HTF ignition would result from a leak with an ignition source at a temperature above the flash point or over-heating the HTF to the auto-ignition temperature in the presence of oxygen. HTF leakage was not determined for this study. Ignition probability was also not determined in this study; however, the flammability parameters and notes are listed in Table 5-6. The operating temperature of the HTEF thermal transfer loop is assumed to be ≤600°F.

A leak and fire within the HES building could damage the equipment and cause the NPP to isolate the HES. If the fire is severe enough, there is a possibility of damaging the ability to isolate the HES without closing the NPP's MSIVs.

Table 5-6. Heat-transfer fluid properties.

Heat-Transfer Fluid	Max Operating Temperature (°F)	Flash Point (°F)	Auto-ignition (°F)
Dowtherm A	494 (liquid) 495–750 (vapor)	236	1110
Dowtherm G	675 (liquid)	280	810
Therminol 66	650 (liquid)	338	705
Therminol VP-1	256 (liquid) 257–750 (vapor)	230	1114

5.1.4.6 Prompt Steam Diversion Loss Causes Feedback

The addition of the HES to the NPP provides a new steam loop that must be evaluated for safety. The design considered for this study assumes that the amount of steam diversion is limited to 5% of the total steam production. This screens out one of the postulated hazards (Table 5-3), that the prompt load drop was felt by the NPP and pushed to the turbines, even with the successful closing of the HES isolation valves. The FMEA team determined that LWR NPPs can withstand up to a 30% load drop without having to trip.

6. PROBABILISTIC RISK ASSESSMENT MODEL

Two generic PRAs were prepared for this report: one is a PWR and the other is a BWR. The difficulty in preparing a generic PRA for existing LWRs is that there are many differences in the existing LWR fleet and the geographical effects on both LOOP and external events. To remain generic, external events other than those created by the addition of an HTEF in close proximity to the NPP were not calculated. A Mark I containment BWR and a two-loop PWR were modeled. All mitigating FTs were left intact except where affected by the addition of the HES or the effects on internal events of the HTEF. The external event of the HTEF detonation was considered for licensing under 10 CFR 50.59 as causing an increase in the LOOPSC IE frequency. The hydrogen detonation was also analyzed for inclusion in the PRA on its own as potentially damaging to critical structures not related to causing a LOOP, as noted in Section 5.1.4.1.

The following sections detail the HES model and PRA modifications made to the generic models to assess the effects of the HES and HTEF on the NPP.

6.1 HES PRA Model

Since the HES is a separate, isolable steam system on the secondary side of the NPP, a steam line break in this system may not require a reactor trip if it can be isolated from the main steam line. For that reason, the steam leakage events and the failure to isolate HES events are modeled together, and the resulting probabilistic failure events are linked to the existing PRA model.

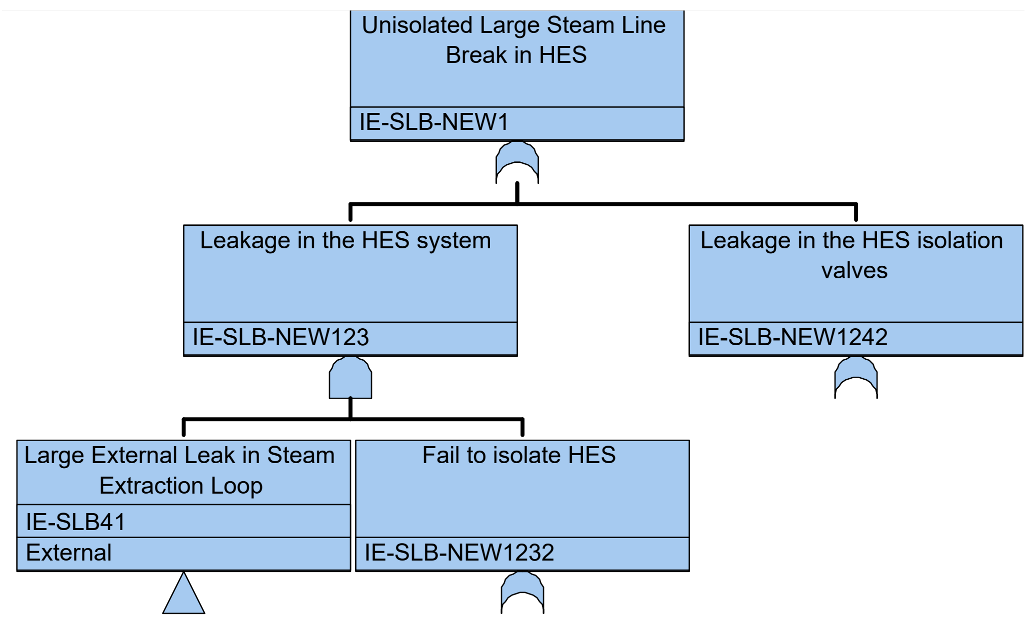

Figure 6-1. Unisolated large steam line break in HES FT (IE-SLB-NEW1).

The intermediate events that contribute to the unisolated large steam line break in HES are shown in Figure 6-1. Possible leakage events were categorized based on the leakage locations, either in the isolation valves themselves or in the HES. The latter consists of a large external leak coupled with the failure of isolation valves. The basic events in the former are shown in Figure 6-2. This tree consists of events in the different design options, whether the system uses an isolation valve or two in series. A House Flag event HES-ISOV-FLAG was paired in an AND logic gate with the basic events. The basic events when two valves are used in series include the event when IV-2 ruptures and IV-1 fails to stop the steam flow to the ruptured valve, or when IV-1 ruptures. Meanwhile with only one isolation valve, the possible rupture event exists for that valve only. The House Flag event is set as a complement in the one-valve subtree, such that only one configuration is active at a time, either the double- or single-valve configuration.

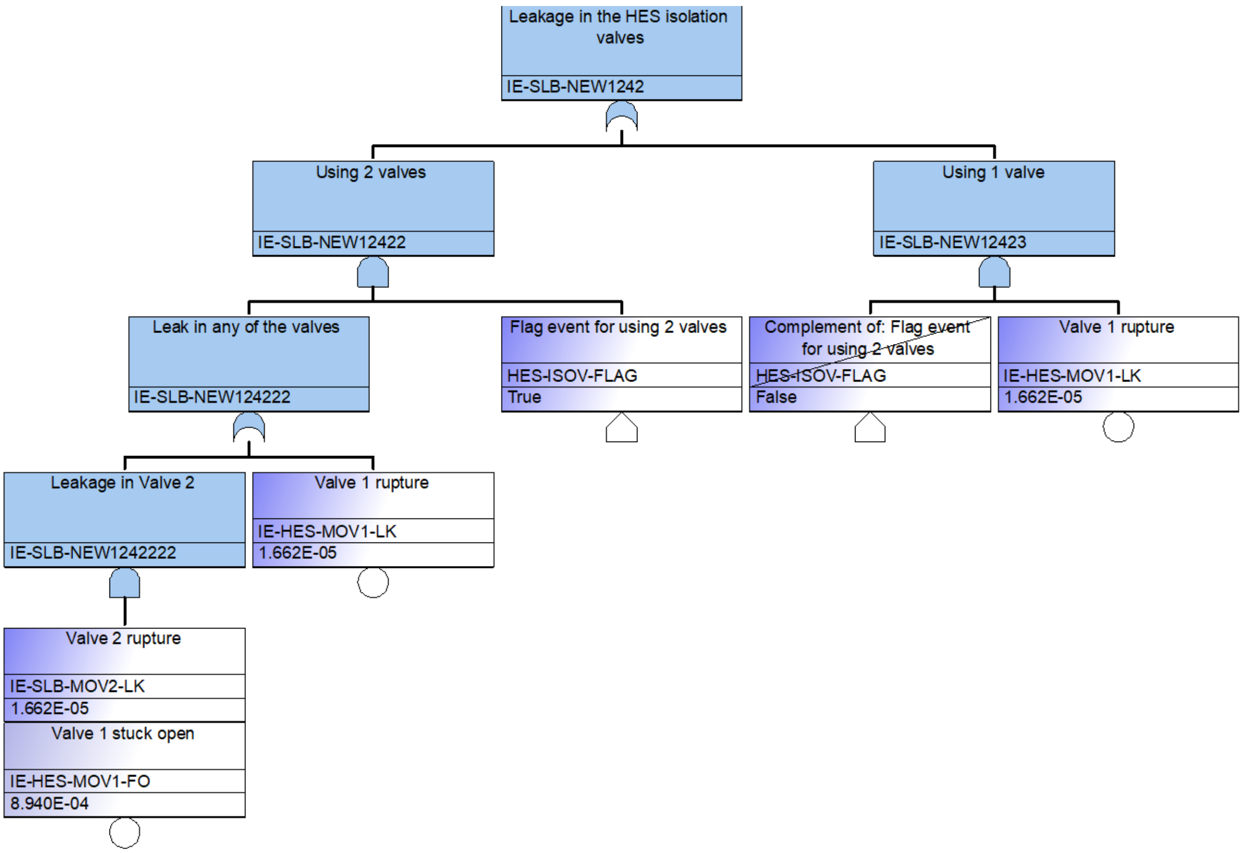

Figure 6-2. Leakage in HES isolation valves FT (IE-SLB-NEW1242).

The IE-SLB-NEW1232 intermediate event in Figure 6-1 is expanded in Figure 6-3. The tree structure is similar to Figure 6-2, which considers the two design options of using double- and single-isolation valves and uses a House Flag event to select the design option for analysis. The failure to close in the double valve design consists of independent failures from both valves and Common Cause Failures (CCFs). The CCF event was constructed using the Alpha-factor method with a Staggered testing scheme. In this tree, it was assumed that the Common Cause Group (CCG) consists of only the two isolation valves.

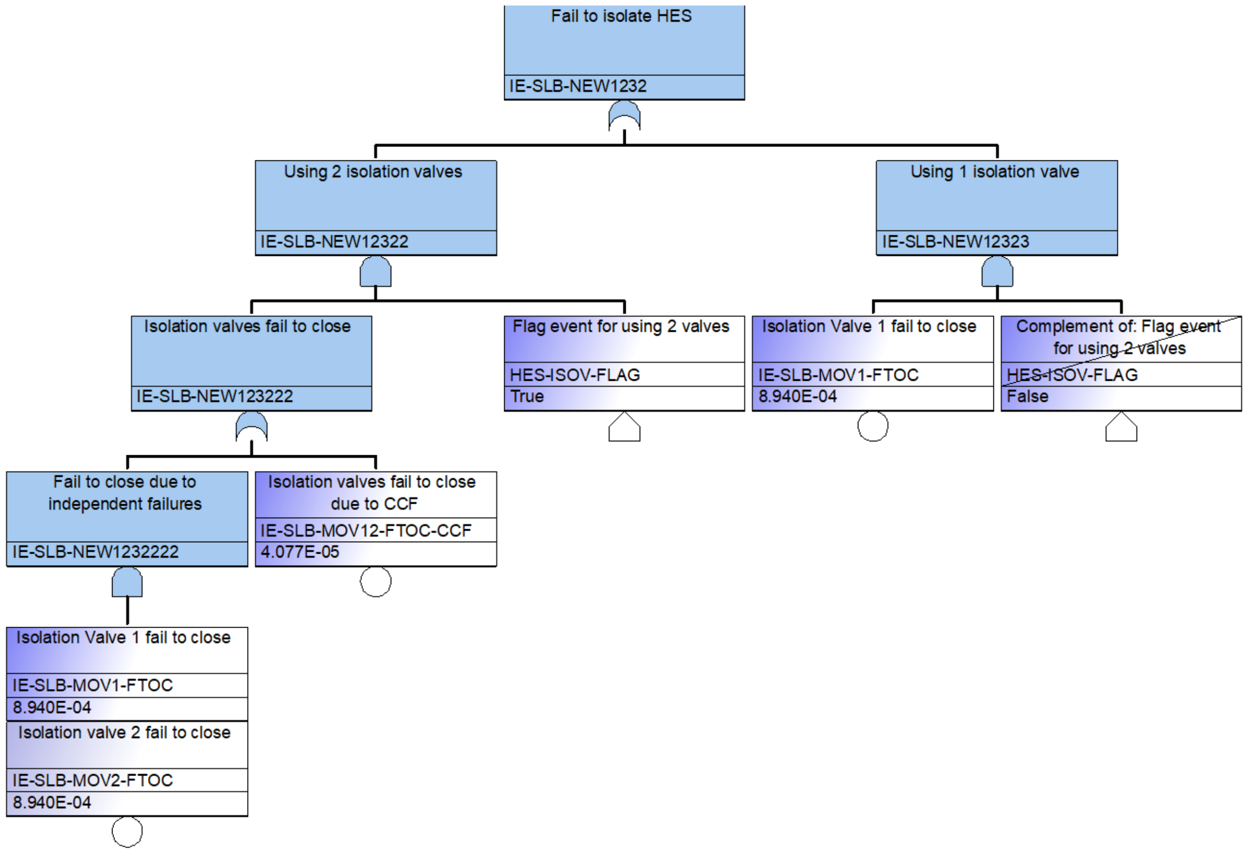

Figure 6-3. Failure to isolate HES FT (IE-SLB-NEW1232).

The IE-SLB41 intermediate event in Figure 6-1 is shown in Figure 6-4. In this tree, the HES-1 control valve was assumed to function as an isolation valve for the system. This valve is normally set to allow 5% of the main steam to be diverted to the heat extraction loop. It may close upon demand in case the isolation valve IV-1 and IV-2 fail to function. Therefore, the leak events in this tree may occur when HES-1 valve ruptures or when there is a leakage downstream of HES-1 and HES-1 fails to close.

The leakage in the HES intermediate event (i.e., IE-SLB4132), is shown in Figure 6-5. The leakage in HES downstream of the HES-1 control valve is categorized into sections based on the leak location. These sections include the three bypass trains, the components downstream of the bypass trains, the EHX-1 heat exchanger subsystem, the EHX-2 heat exchanger subsystem, and the SEP-1 tank subsystem. It was assumed there were no CCGs across these subsystems.

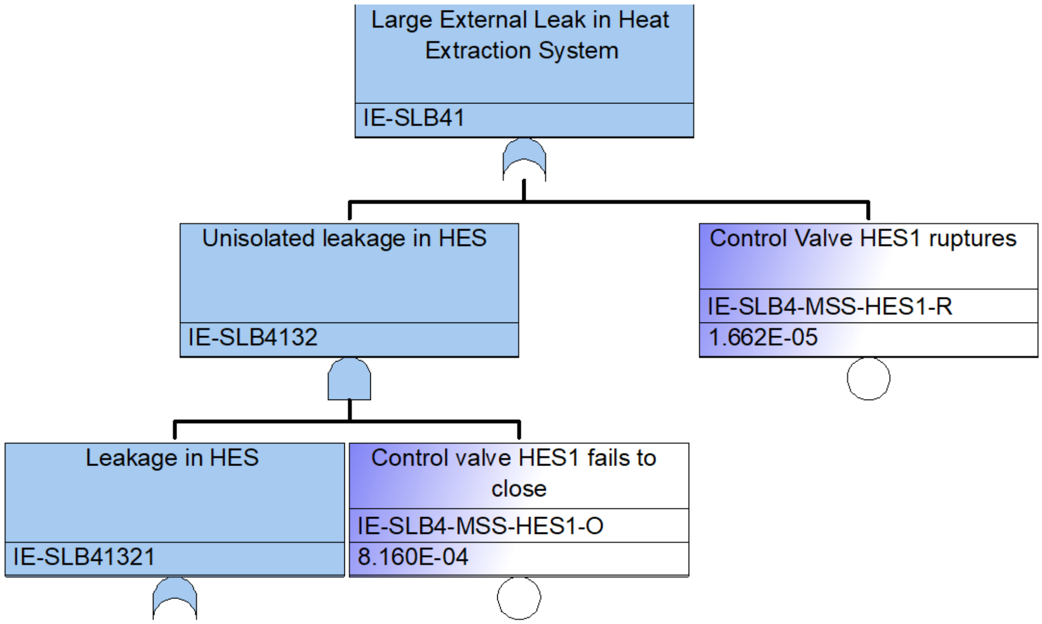

Figure 6-4. Large external leak in HES FT (IE-SLB41).

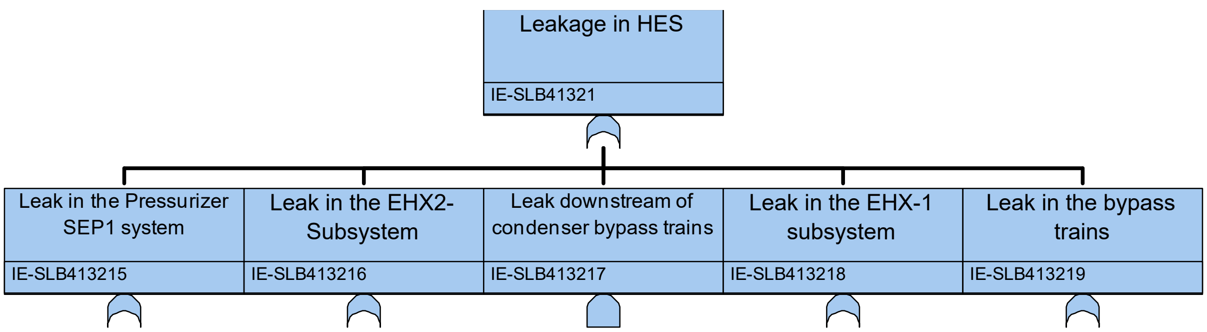

Figure 6-5. Leakage in HES FT (IE-SLB41321).

Steam leakage in the bypass trains may happen at any of the three trains, as shown in Figure 6-6. The subtree for the first train is shown in Figure 6-7. The leakage events in this train may occur when the upstream HES-17 valve ruptures, or when the downstream components rupture and the upstream valves fail to close. This logic applies likewise to the other trains as shown in Figure 6-8 and Figure 6-9. However, in these two trees, the logic structure was coupled to the House Flag event for that train in an AND gate. This modeling approach allows the analyst to evaluate risks by using single-to-triple redundant bypass trains in the HES.

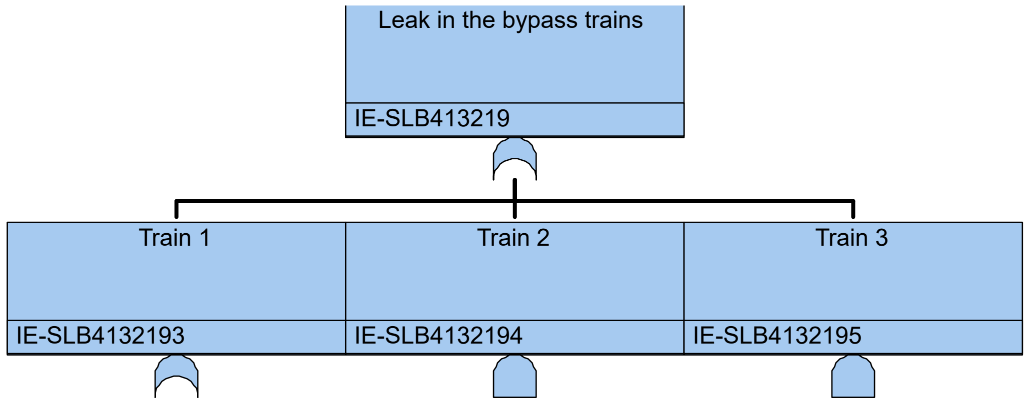

Figure 6-6. Leakage in the bypass trains FT (IE-SLB413219).

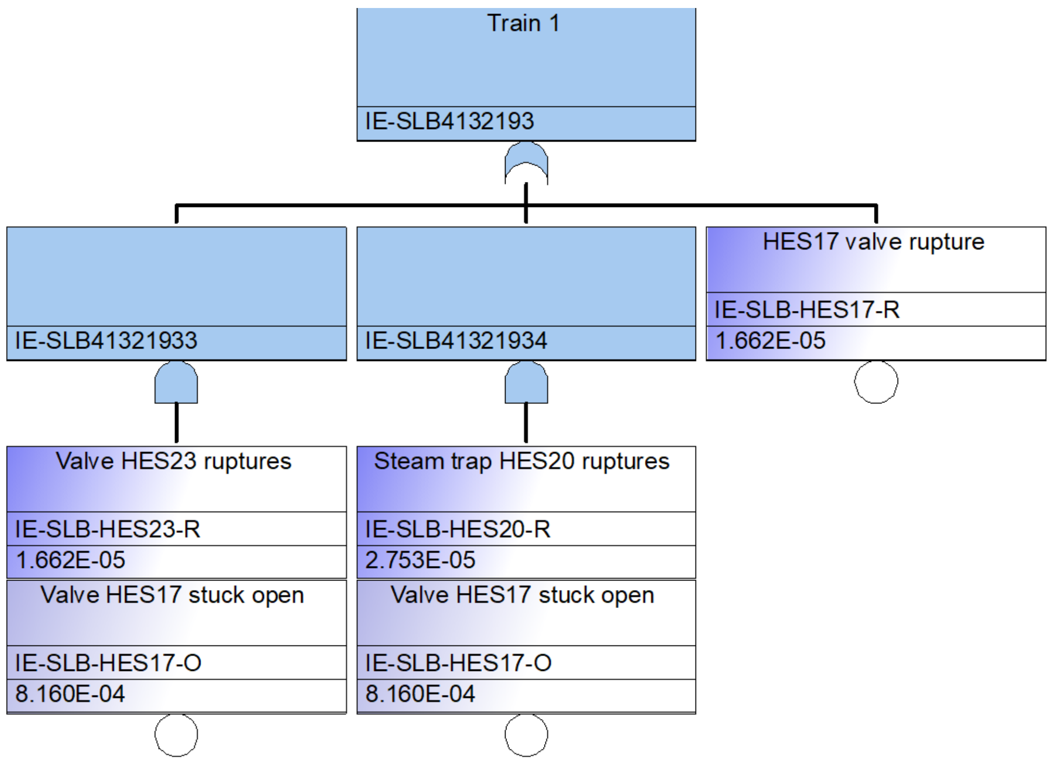

Figure 6-7. Leakage in the bypass train number 1 FT (IE-SLB4132193).

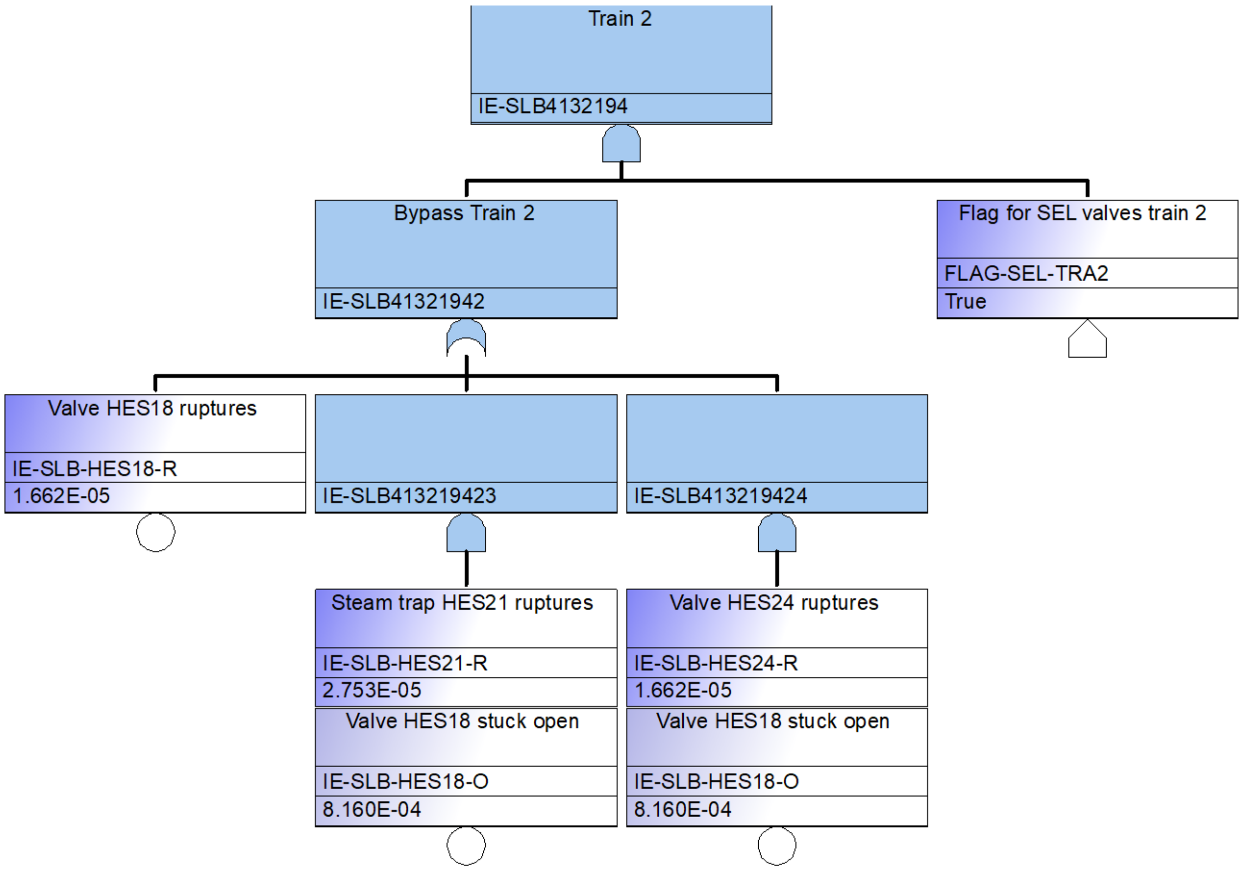

Figure 6-8. Leakage in the bypass train number 2 FT (IE-SLB4132194).

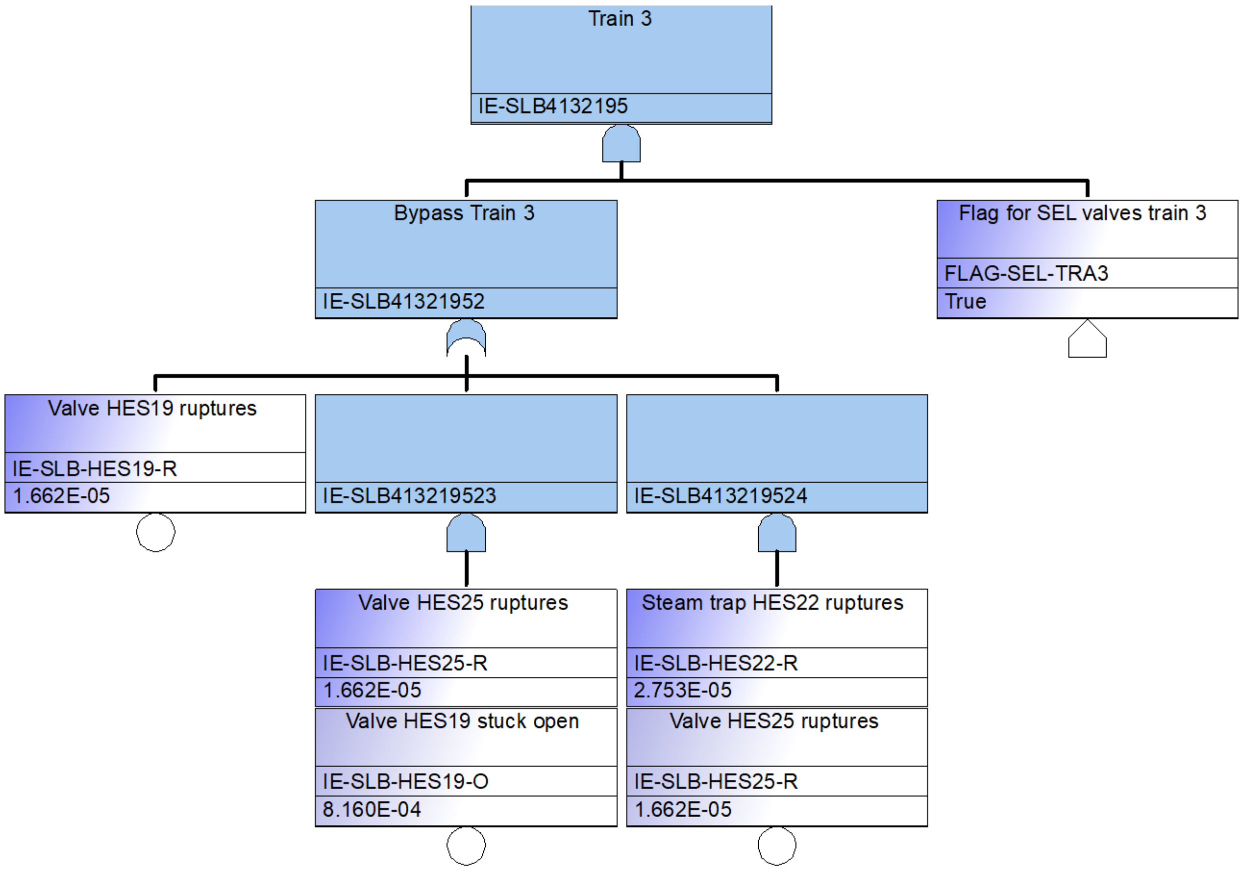

Figure 6-9. Leakage in the bypass train number 3 FT (IE-SLB4132195).

The FT showing leakage events in the EHX-1 heat exchanger subsystem is shown in Figure 6-10. Leakage may occur at the upstream valves (i.e., HES-2 and HES-14), or at the heat exchanger and is not isolated. Because HES-2 and HES-14 are installed in parallel, their failures are set in an OR gate. As can be inferred from the figure, although the probabilities for leakage events in the heat exchanger are relatively higher, they are coupled in an AND gate to the isolation failure events so the resulting probability for an unisolated leak is less significant than the valves' leakage probabilities.

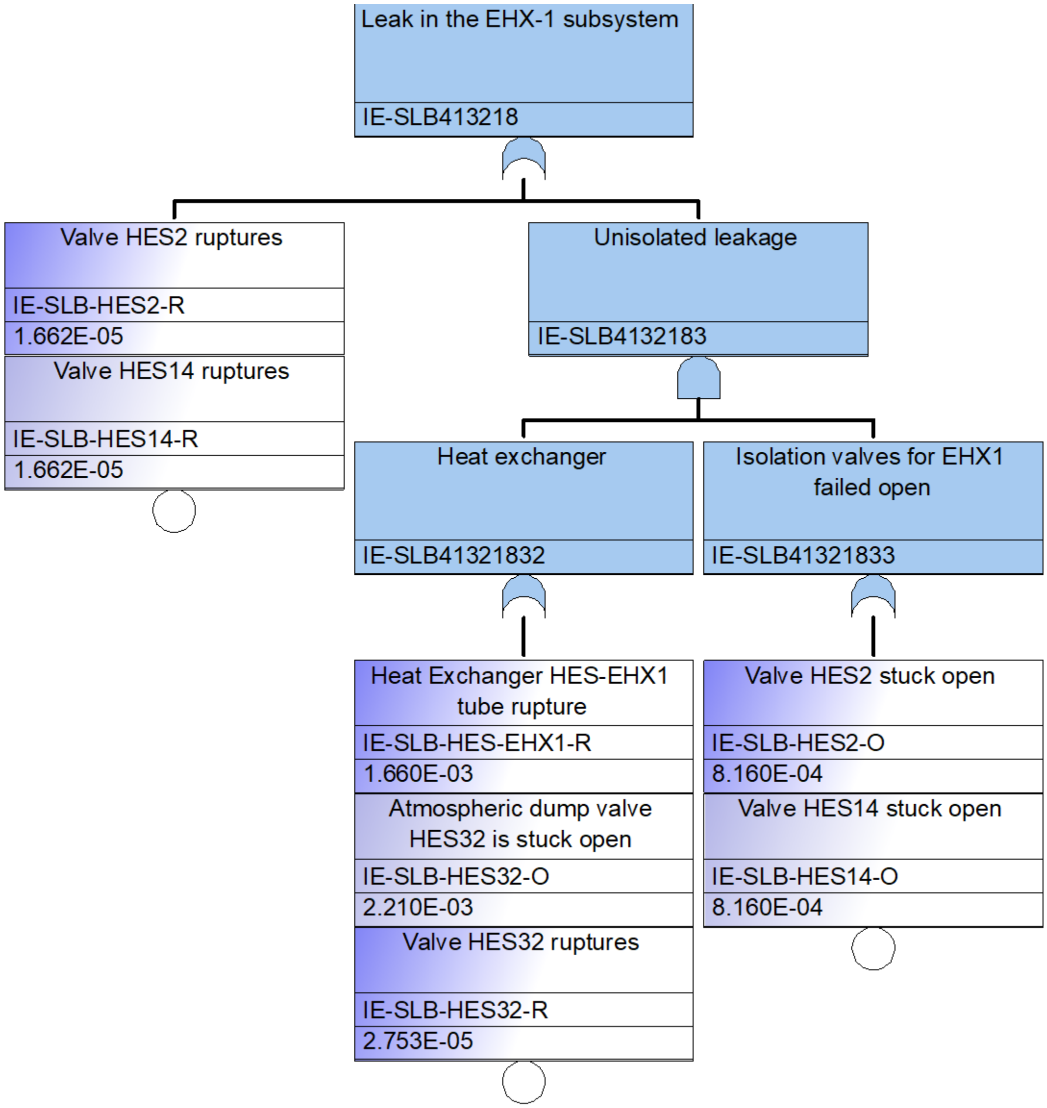

Figure 6-10. Leak in the first heat exchanger FT (IE-SLB413218).

The FT describing the leakage events at the downstream of condenser bypass trains is shown in Figure 6-11. The leak events may be caused by the rupture of components alongside the failure of all bypass trains to close. Because the bypass trains are designed in a parallel manner, the failure of a single train allows steam from the main steam line to flow to the break location. In such a case, up to 5% of main steam flowrate may leak out from the secondary coolant inventory.

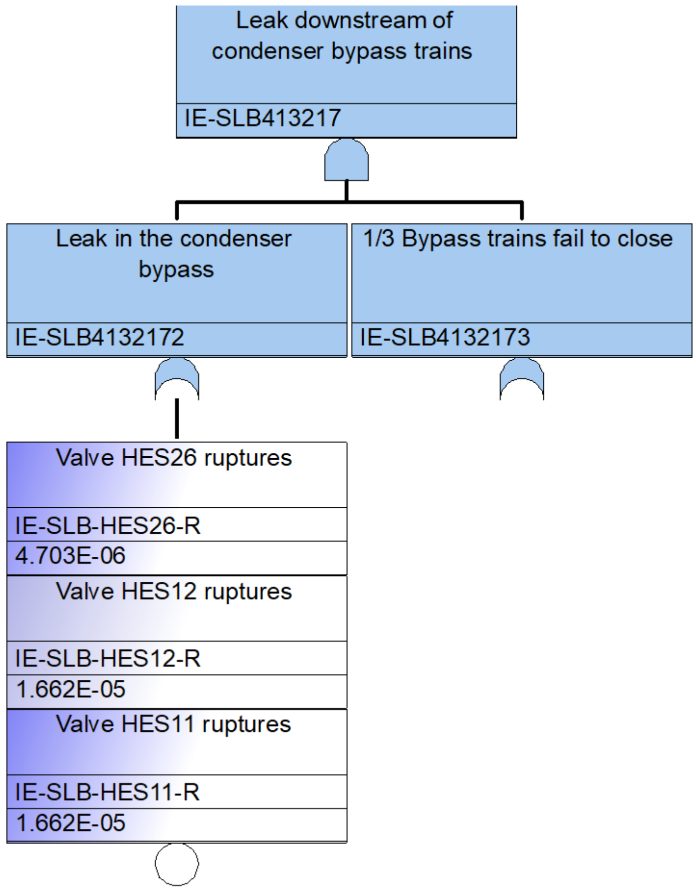

Figure 6-11. Leak downstream of condenser bypass trains FT (IE-SLB413217).

The FT describing the failure of bypass trains to close and isolate the downstream leakage is shown in Figure 6-12. The structure of this tree is straightforward where each train is represented by an AND gate of individual valve rupture events. The second and third trains are additionally coupled with their respective House Flag events to activate or deactivate the trains during the sensitivity analysis phase. An intermediate CCF event is included in the tree, which is shown in detail in Figure 6-13. The common cause events are constructed using the staggered Alpha-factor method. A combination of Flag events and their complements are added to select the active design configuration for the purpose of sensitivity analysis. A CCF for one, two, and three trains have a CCG of size 2, 4, and 6, respectively.

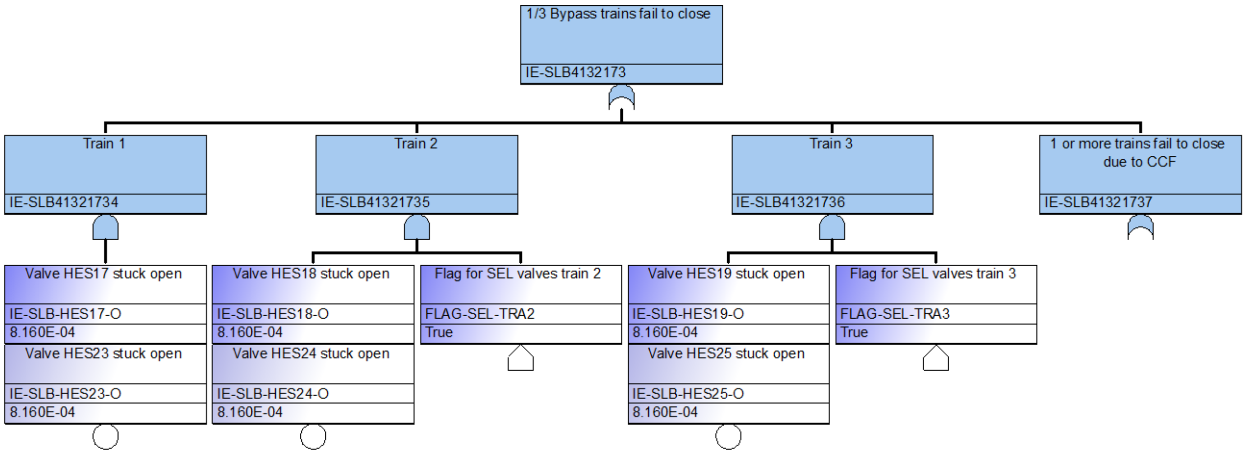

Figure 6-12. FT of 1-out-of-3 bypass train fail to close (IE-SLB4132173).

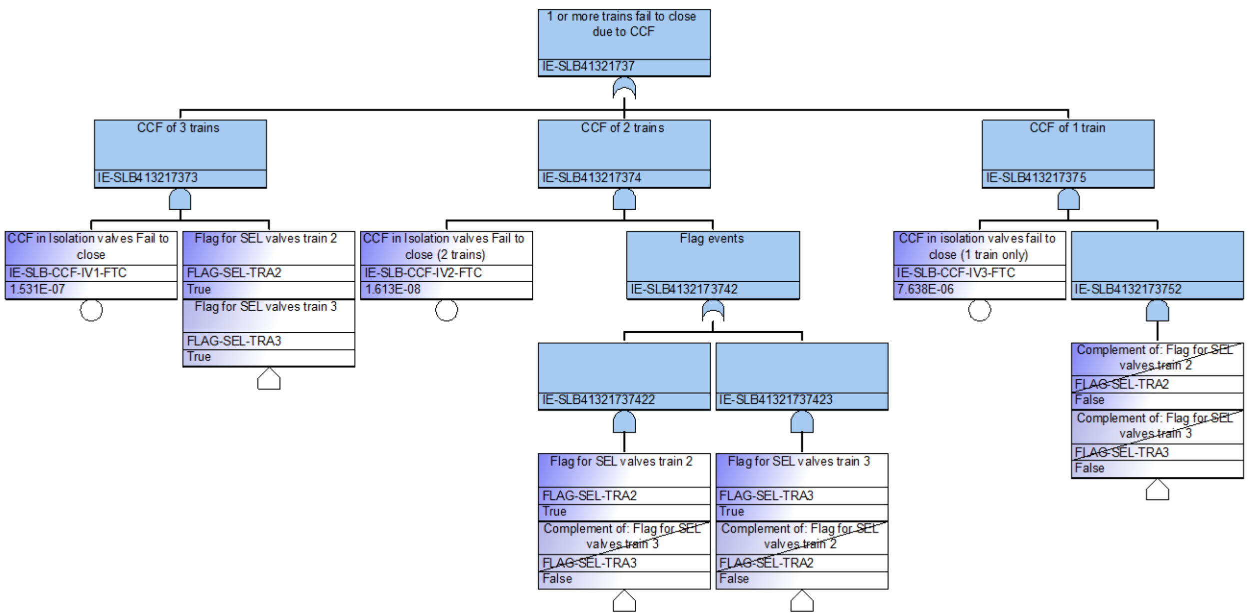

Figure 6-13. FT of fail-to-close events due to CCF in the HES bypass trains (IE-SLB41321737).

Leakage events in the second heat exchanger (EHX-2) subsystem are shown in Figure 6-14. The steam loss may originate from the rupture of the isolation valves (i.e., HES-3 and HES-15), or an unisolated leakage as a combination of leak events downstream from the isolation valves and the failure of those valves to close and terminate the steam flow. The most probable leakage event in this tree is the HES-29 atmospheric relief valve's failure to close, releasing steam from EHX-2. However, this event is coupled with the isolation failures from the HES-3 and HES-15 valves in an AND gate. Therefore, the resulting risk contribution from this event is reduced.

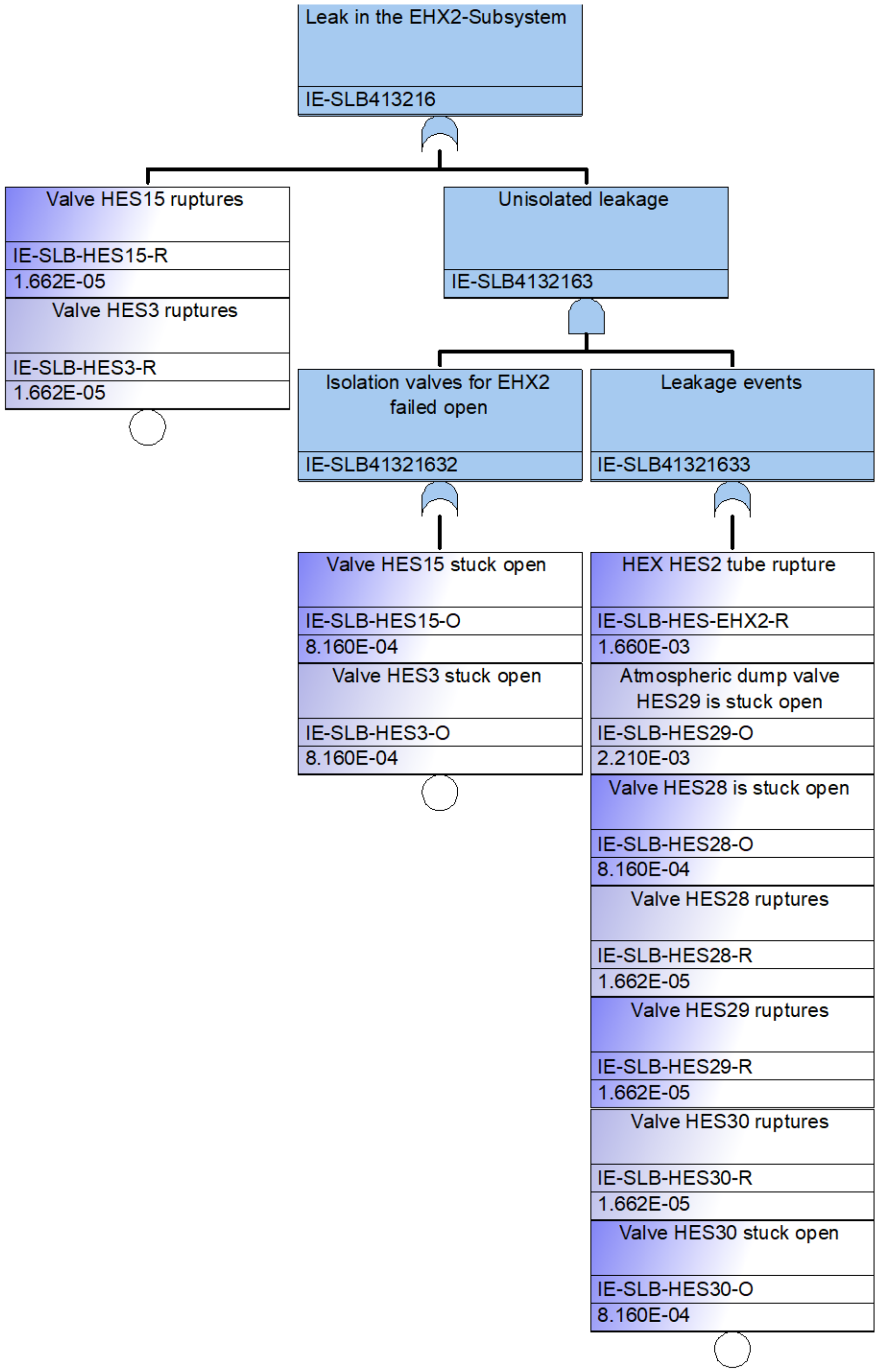

Figure 6-14. Leakage in the secondary heat exchanger FT (IE-SLB413216).

The FT describing leakage events in the SEP-1 tank subsystem is shown in Figure 6-15. The logic in this tree is quite similar to the leakage tree in the EHX-2 subsystem described earlier. The events consist of isolation valves ruptures (i.e., rupture of HES-4 or HES-6) and unisolated leakage in the tank and subsequent components downstream from those valves. Looking at the tree structure, the latter leakage events have negligible statistical probability less than 1E-8 due to the AND logical gate connecting the basic events. Therefore, the significant contributor of a steam-loss event in this tree comes from the isolation valves themselves.

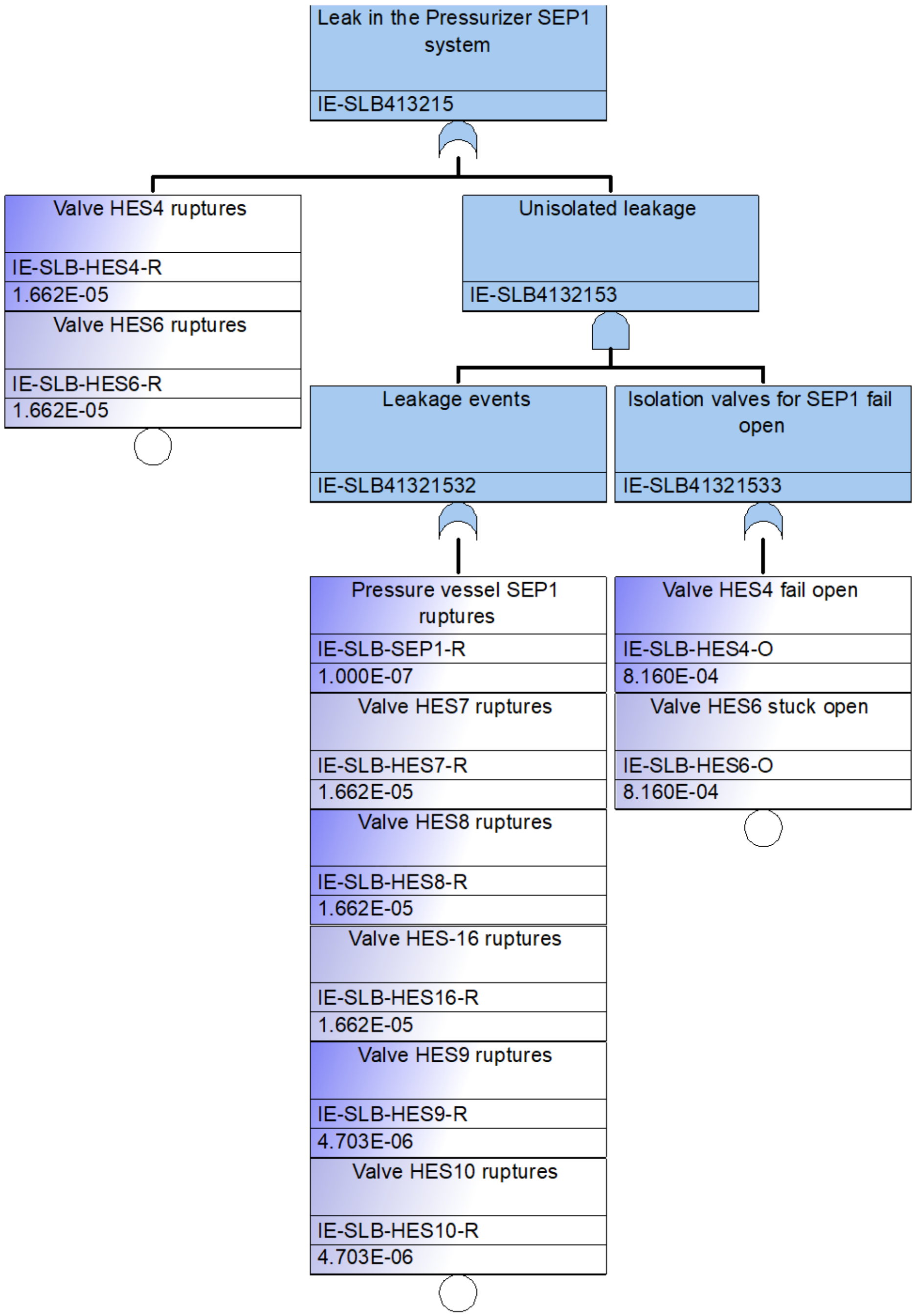

Figure 6-15. Leakage in the SEP1 subsystem FT (IE-SLB413215).

Meanwhile, the FT for an unisolated steam leakage event in the HES Design 3 module is shown in Figure 6-16. The tree is structured to model leakage in each of the pipe sections shown in Figure 4-4, which include the possible leakage source and the failure to seal the leakage upstream of the source.

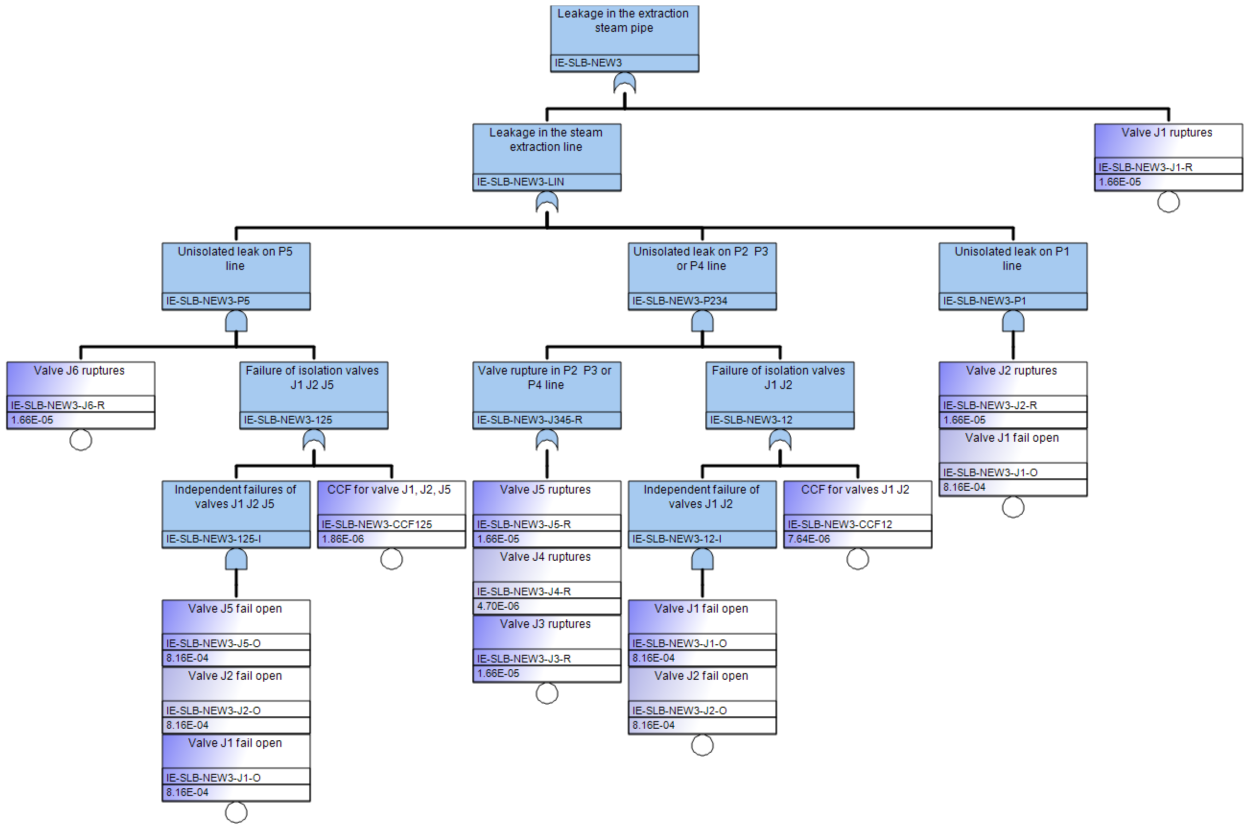

Figure 6-16. FT for a leakage in the HES Design 3 of the steam extraction line

6.2 Electrical Transmission PRA Model

A PRA model was created to evaluate the probability of a general plant transient occurring due to an overcurrent event damaging the turbine generator as seen at a high level in Figure 6-17. This could occur three different ways according to the one-line diagram in Figure 4-5: the three-winding transformer at the H2 plant experiences an overcurrent and all circuit breakers fail to trip, the load at the 13.8-kV switchgear pulls too much current and all circuit breakers fail to trip, and the generator transformer experiences an overcurrent and then the generator circuit breaker fails to open and isolate the generator. For the transformers and circuit breakers between the transformers, the relay protection diagram was utilized, and the primary and backup relay were individually accounted for each breaker and transformer as their protection system. The failure data used for the relays came from the 2020 Industry Average Parameter Estimates by the NRC and INL which analyzed reactor protection system (RPS) system studies data [18]. While this likely refers to low-voltage relays (125 VDC) utilized in RPSs, not high-voltage transmission, this was the best available data. For the switchgear for the H2 Island load, a failure for switchgear rated for over 5 kV was utilized. All other data used was sourced from the Institute of Electrical and Electronics Engineers Gold Book [19].

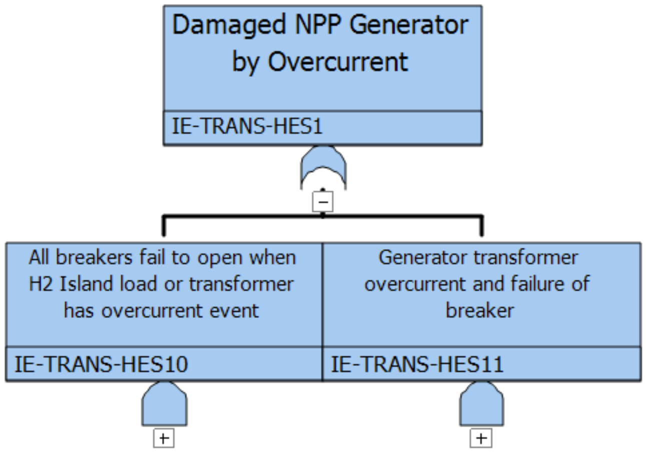

Figure 6-17. Overall FT (IE-TRANS-HES1).

The first two scenarios were modeled in a mutual AND gate with the circuit breakers between the transformers that need to trip to protect the generator from overcurrent in either the transformer or the loads as seen in Figure 6-18. The two scenarios were considered under an OR gate, Figure 6-19, indicating either scenarios' occurrence and the circuit breakers failure will lead to overcurrent at the generator. An application of a primary and backup relay for each breaker and transformer decreases the likelihood of failure along with the presence of the three breakers in series. As long as one of the breakers trips, the generator will be protected.

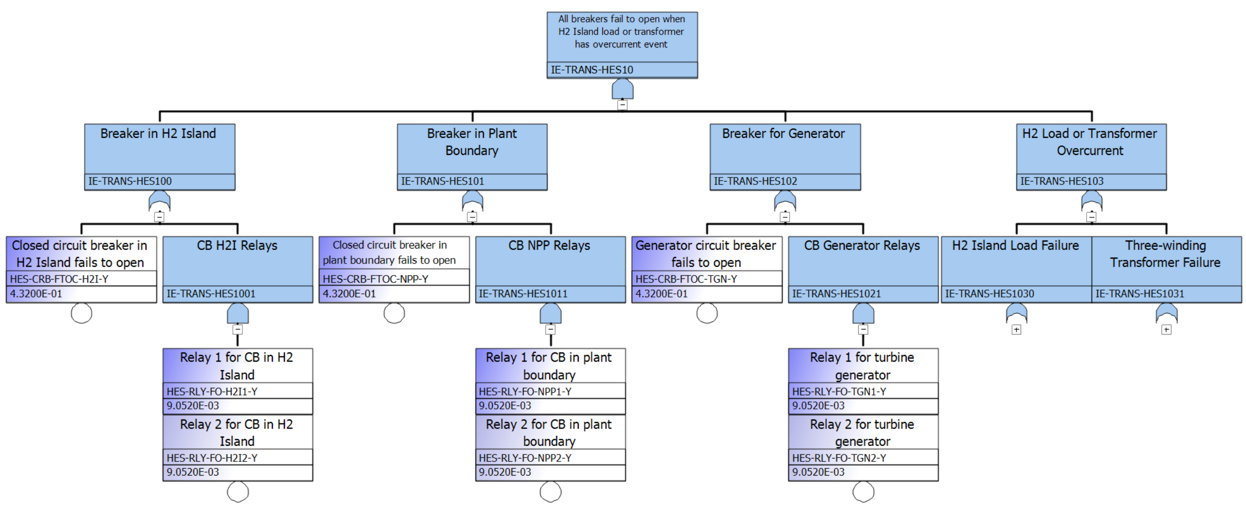

Figure 6-18. Overcurrent by H2 plant transformer or load with failure of circuit breakers (IE-TRANS-HES10).

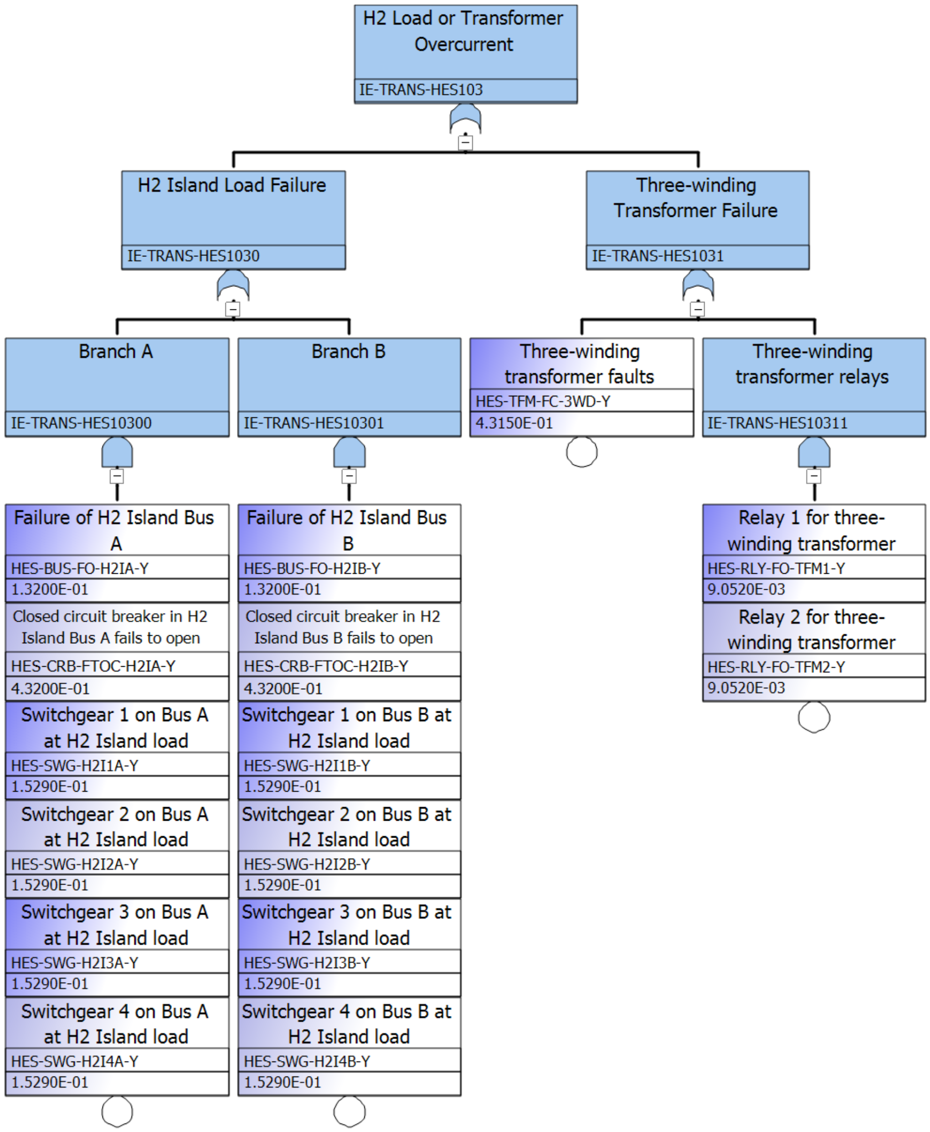

Figure 6-19. Overcurrent by H2 plant transformer or load expanded trees (IE-TRANS-HES103).

The third scenario models the occurrence of overcurrent at the generator step-up transformer and failure of the breaker to trip as seen in Figure 6-20. Since only one circuit breaker separates the transformer from the generator, it is more likely that the generator will be damaged by this scenario. Although, just like the other breakers and transformer, the application of a primary and backup relay for each breaker and transformer decreases the likelihood of failure.

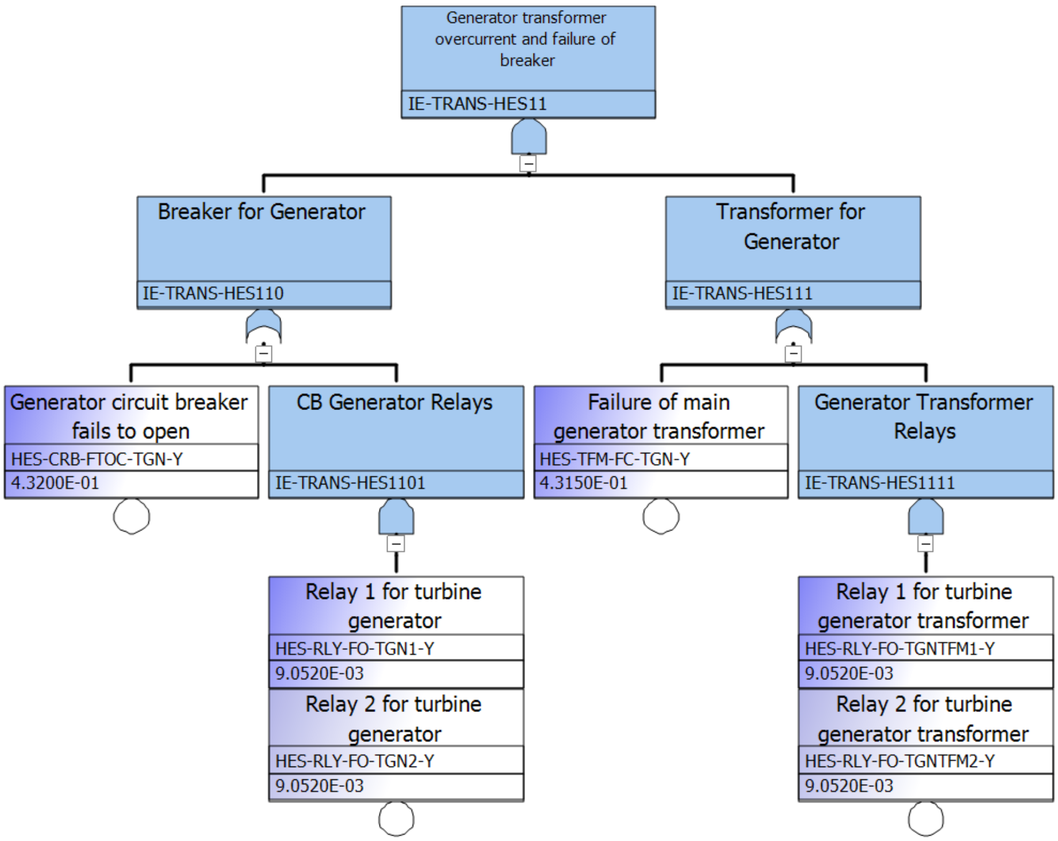

Figure 6-20. Overcurrent by generator step-up transformer.

No other scenarios needed to be considered as the report describing the pre-conceptual design states in Section 4.3.5 that "The H2 production facility is physically and electrically separated from the offsite power circuits. Therefore, there is no impact to offsite power sources or plant safety loads, which normally are powered from offsite power sources." [6] The single line diagram (Figure 4-5) illustrates this further by showing that the offsite power sources are on a different bus than the turbine generator and line to the H2 production facility in a ring bus arrangement.

6.3 Generic PWR Model

The addition of an HES into the steam line creates more venues for the steam to leak out either through pipe breaks or component ruptures. Therefore, one of the possible hazards considered in this study is an increased probability for steam leakage through the new system. In this study, a two-loop generic PWR model is used as a reference. The ET for the Main Steam Line Break initiator is shown in Figure 6-21. A break in the main steam line causes the loss of the ultimate heat sink and therefore the reactor must be tripped. The removal of reactor decay heat depends on whether steam generators are ruptured because of the steam line break. If steam generators are functioning, the Auxiliary Feedwater (AFW) system supplies feedwater to the steam generators while the main steam/feedwater line is isolated. If the main steam line cannot be isolated, the AFW system cannot inject water due to the high pressure in the line and the High Pressure Injection (HPI) is used in its place. In case the AFW system fails, the reactor heat is removed using the feed and bleed mechanism on the primary cooling line. The failure event of steam generators requires mitigation actions as prescribed in the Steam Generator Tube Rupture ET. Meanwhile, the failure of the reactor trip requires mitigation procedures laid out in the Anticipated Transient Without Scram (ATWS) Event Tree. These ETs are provided in Appendix A: Generic PWR PRA Model.

Additionally, the existence of a hydrogen production plant near the NPP may create another hazard (i.e., hydrogen explosion). This explosion may cause significant blast pressure and missiles that may damage surrounding structures including the plant's switchyard components. The loss of switchyard components may trigger a LOOP event that may cause a transient to the reactor. This event has been taken into consideration in the PRA model as shown in Figure 6-23. The LOOP IE trips the reactor and brings the emergency power online. The auxiliary feedwater system is then activated to maintain cooling on the secondary coolant loop. If the pressure-operated safety relief valves are closed and Reactor Coolant Pump (RCP) seal cooling is maintained, this mitigation action is sufficient to safely shut down the reactor. If RCP seal cooling fails, the mitigation procedure switches to the LOOP-1 Event Tree, shown in Figure 6-25. This procedure involves activating a controlled bleed-off in the primary cooling system while maintaining the reactor coolant subcooling. This action should prevent the RCP seal from failing due to overpressure and shuts down the reactor safely. If the RCP seal fails, the operator has 1 hour to recover power before the situation can be declared as a Medium-Size-Loss-of-Coolant-Accident. If power is recovered within that timeline, the operator can proceed with the HPI to make up the inventory of the primary cooling system until the reactor is brought to a safe shutdown state.

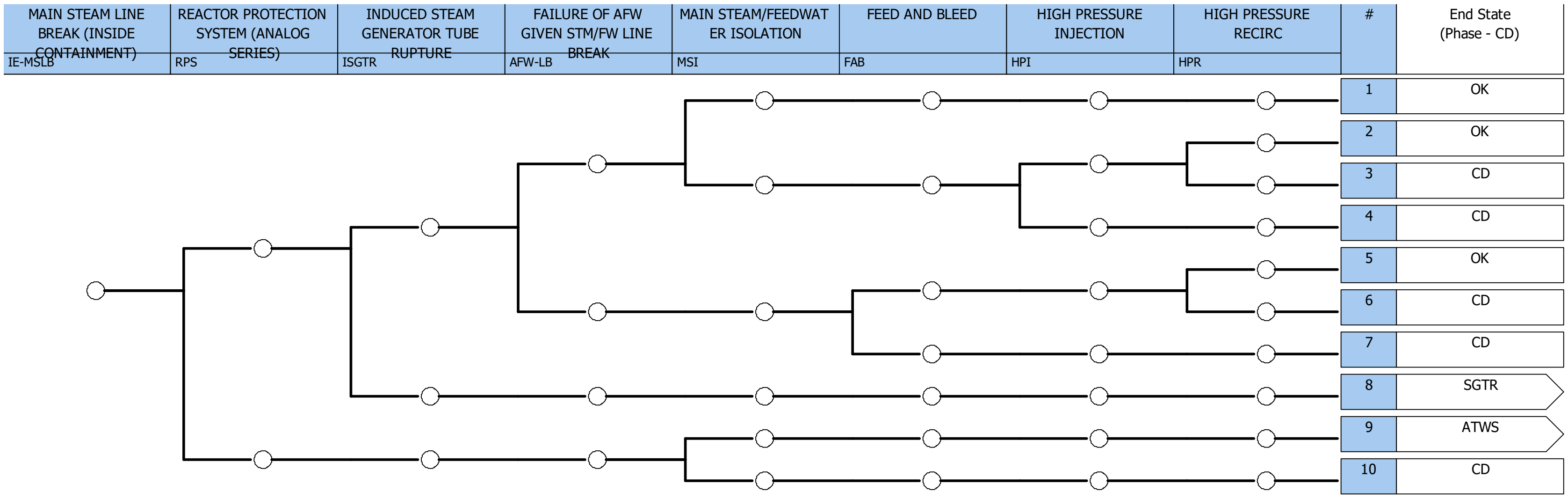

Figure 6-21. MSLB ET (IE-MSLB).

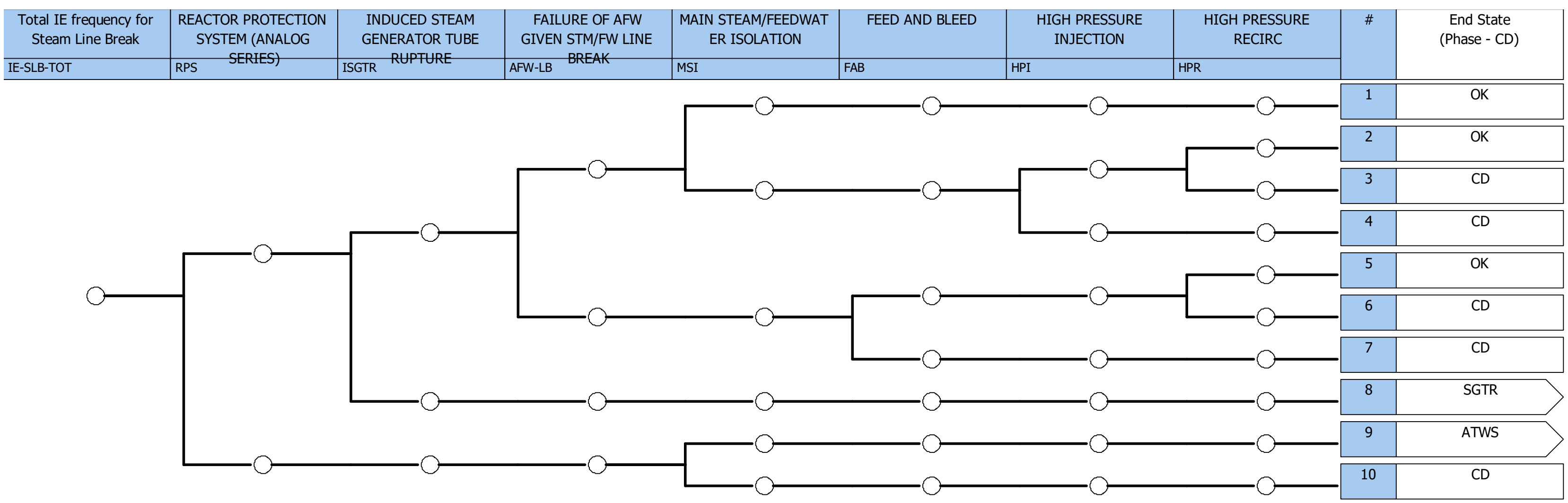

Figure 6-22. MSLB ET with HES (IE-SLB-TOT).

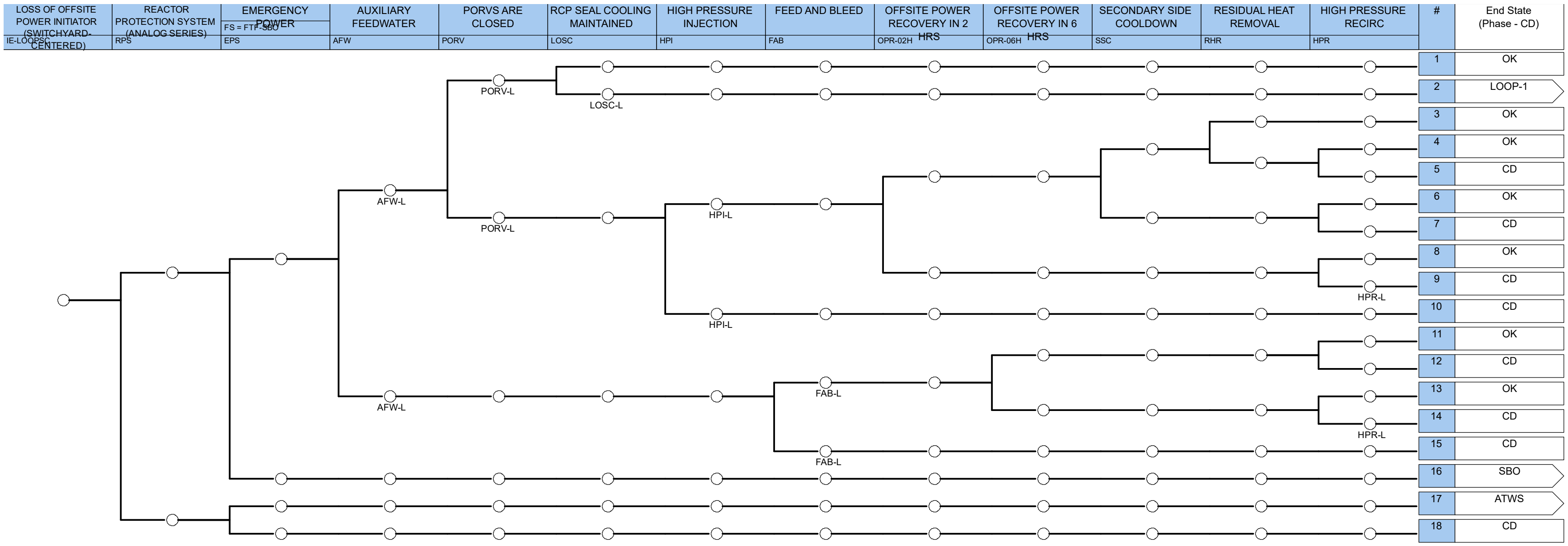

Figure 6-23. LOOPSC ET (IE-LOOPSC).

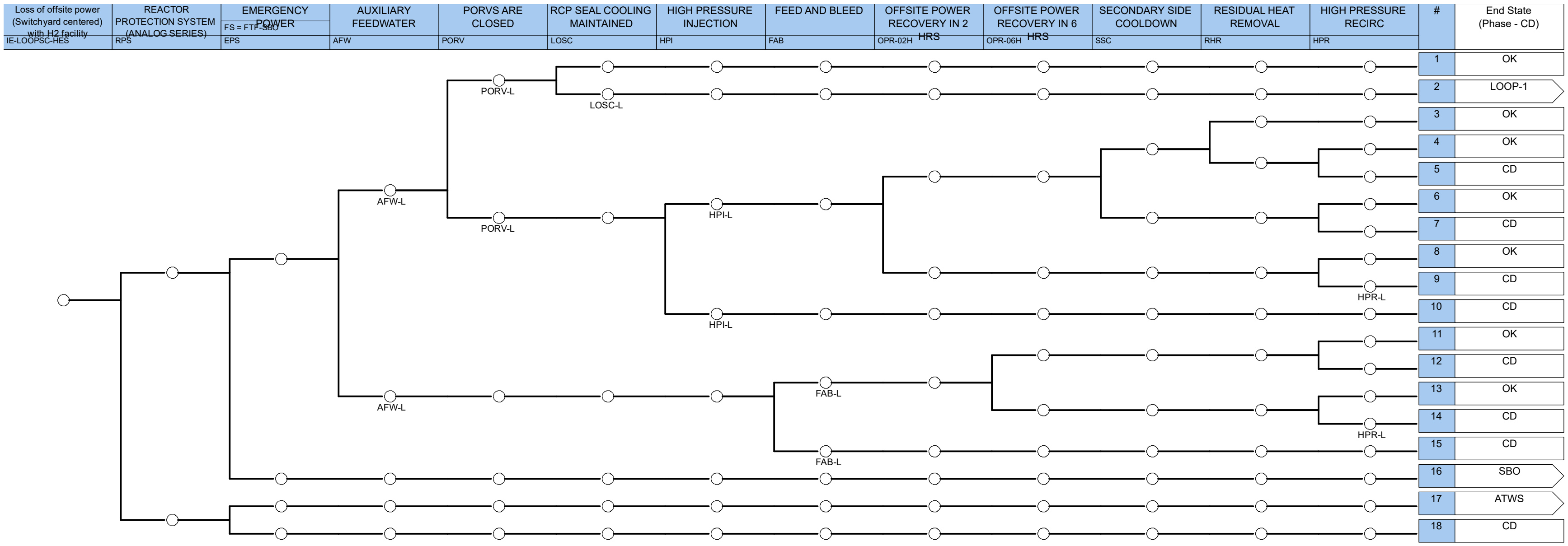

Figure 6-24. LOOPSC with HES ET (IE-LOOPSC-HES).

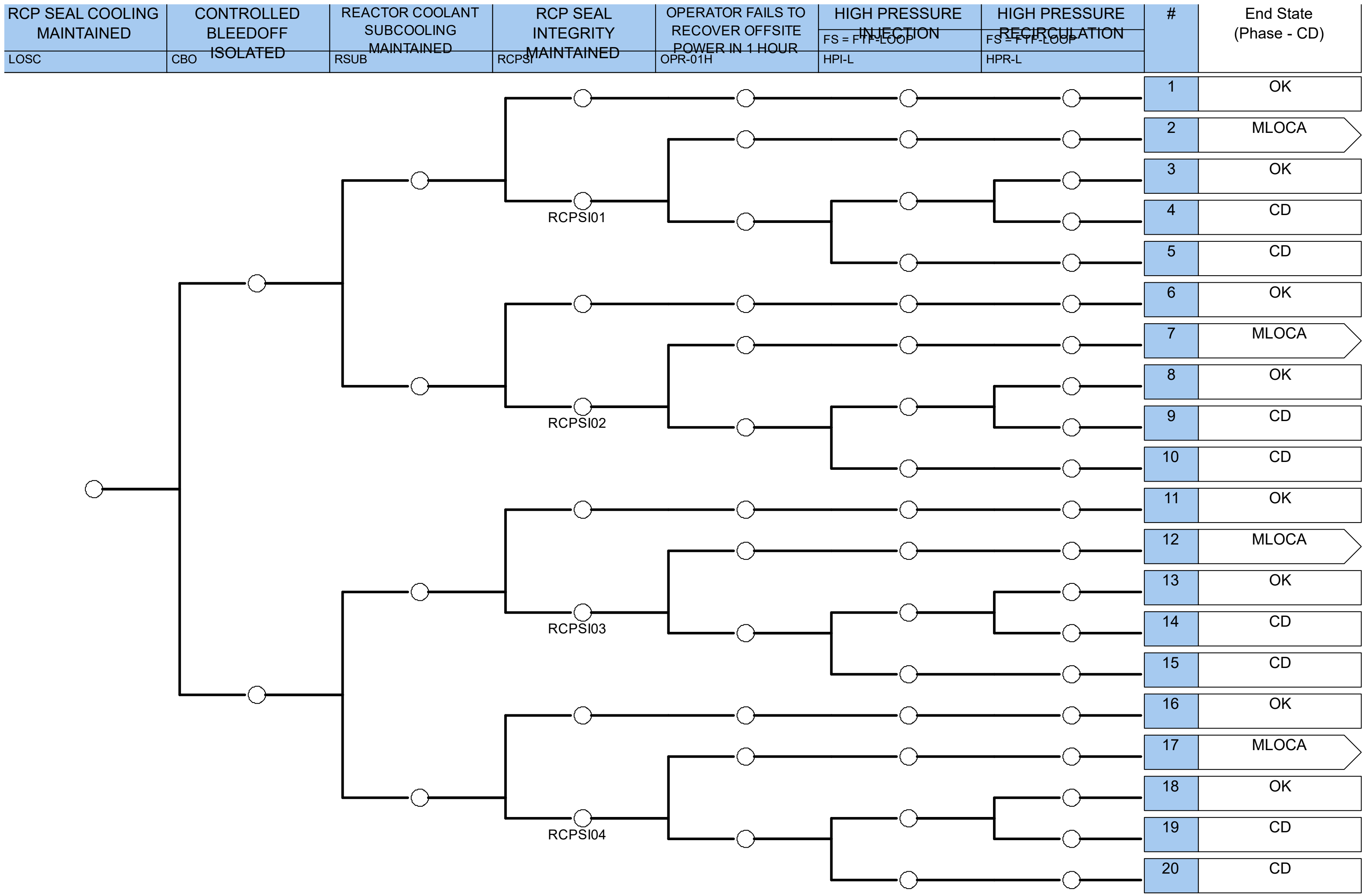

Figure 6-25. LOOP-1 ET (LOSC).

6.3.1 HES linkage into the PWR Model

The addition of the HES that taps into the main steam line of a NPP creates additional points where steam may leak out of the secondary cooling loop. The frequency of steam leak in the HES is estimated using the fault trees described in the previous section (Figure 6-1 through Figure 6-16.for HES Design 1 and Figure 6-17 for HES Design 3). The additional frequency from HES is added to the existing base IE frequency of the steam line break ET using a FT, as shown in Figure 6-26. The top event of this tree becomes the total steam line break IE frequency, which is used as the initiator for the new steam line break ET as shown in Figure 6-22.

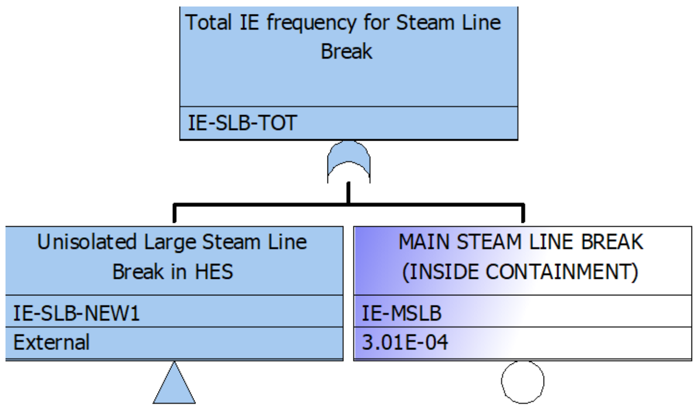

Figure 6-26. FT for Total Initiating Event frequency for MSLB (IE-SLB-TOT).

Another possible hazard identified in the previous section is the switchyard failure event due to hydrogen leakage and explosion. This switchyard failure may cause a LOOP event. The severity of hydrogen explosion and its annual frequency was calculated in a reference report [13]. The conservative leak frequency estimate from that reference is adopted in this work. An FT is constructed for each HES design, as shown in Figure 6-28, to model this additional risk. The switchyard component may fail when a hydrogen leak occurs with frequencies listed in Table 5-4 and Table 5-5, plant operator fails to isolate the leakage within 2 hours, the building ventilation fails to disperse the hydrogen to the atmosphere, and a spark occurs igniting the accumulated hydrogen cloud. This is the MCA scenario highlighted in Figure 6-26, which is assumed to be the bounding accident to damage the switchyard components. The hydrogen ignition probability is a function of hydrogen leakage rate [15]; however, in this FT, a conservative probability value of 0.35 is selected for the event. This scenario ignites a total of 13.2 kilograms of hydrogen and creating an overpressure of 0.39 psi to the nuclear plant structures located 1 km from the hydrogen plant. This overpressure may fail the switchyard components with a statistical probability of 0.95 and create a LOOP event. As with the steam line break hazard, the top event of this FT is set as the total initiator frequency for the new LOOP ET as shown in Figure 6-24.

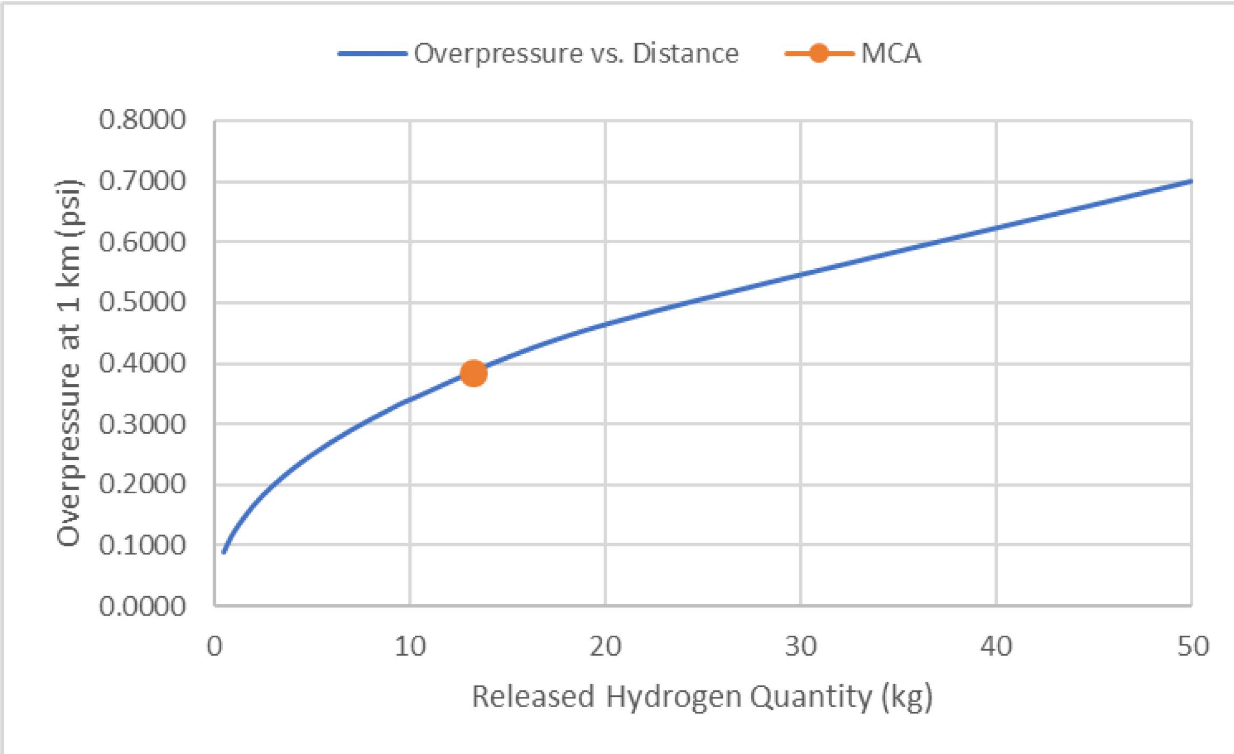

Figure 6-27. Overpressure at a distance of 1 km due to hydrogen detonation.

It is conservatively assumed that the hydrogen cloud detonation scenario always leads to the MCA scenario. With this assumption, the probability for an MCA scenario is 1 whenever there is an unmitigated hydrogen leakage. This conservative assumption is because of the absence of data available on the time distribution of uncertainty sources affecting the hydrogen leakage time (i.e., operator's timing to isolate the leakage, timing of spark occurrences, and actuation timing of building ventilation). These uncertainties may lower the probability for an MCA event. For example, if the leakage time is assumed to occur uniformly between 5 and 120 minutes, the total fragility may be calculated by uniformly sampling the quantity of released hydrogen in Figure 6-27 up to the MCA scenario and performing a look-up conversion of the detonation's overpressure to the switchyard fragility using Figure 5-8. The total switchyard fragility estimated using a Monte Carlo simulation of 10,000 samples is 0.76, which is less than the fragility for the MCA event (IE-LOOPSC-HES2144A). For that reason, it is reasonable to accept that the MCA detonation assumption is conservative.

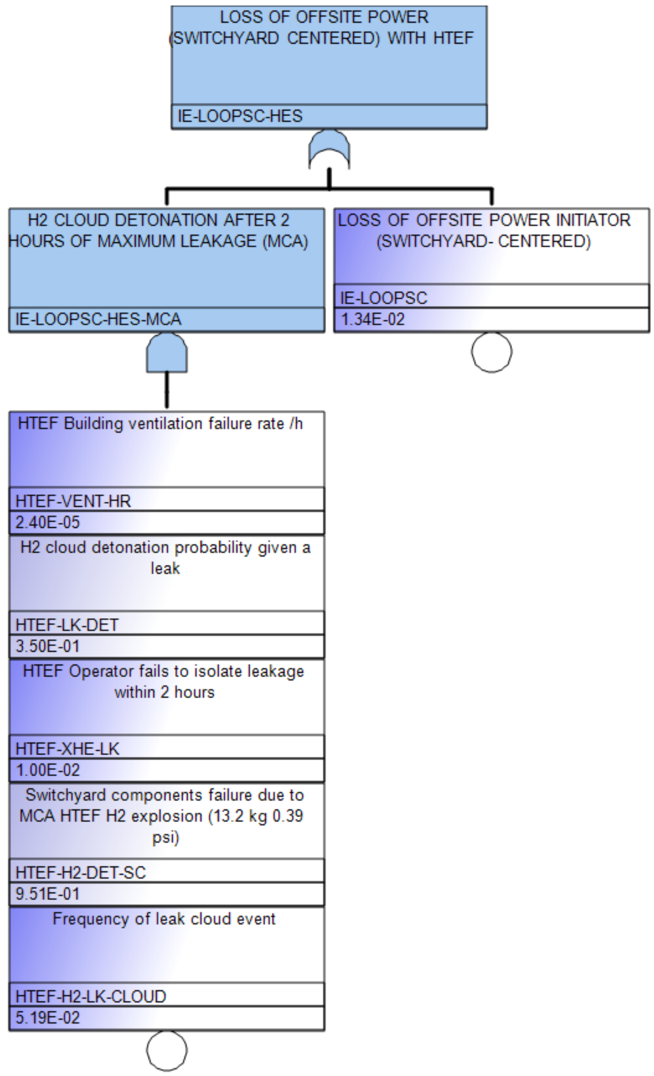

Figure 6-28. Total frequency of LOOP with Hydrogen Production Facility (IE-LOOPSC-HES).

6.4 Generic BWR Model

Similar to the PWR, the HES in the BWR taps steam from the main steam line after the MSIVs. A loss of up to 5% of the steam flow rate due to a leakage event in the HES may lead to a general transient event. The mitigation procedure for this event is shown in Figure 6-29. The transient can be mitigated safely if reactor power generation is shut down, the offsite power is available, the safety relief valves remain closed to preserve coolant inventory, and the power conversion system is running. If this power conversion system fails, the HPI system is activated followed by suppression pool cooling. Without the automatic suppression pool cooling, operators need to depressurize the reactor manually and perform the control rod drive injection. Further mitigation sequences can be deducted from the figure, in which various redundant measures are available including a low-pressure injection (LPI) system, shutdown cooling, containment spray, and containment venting.

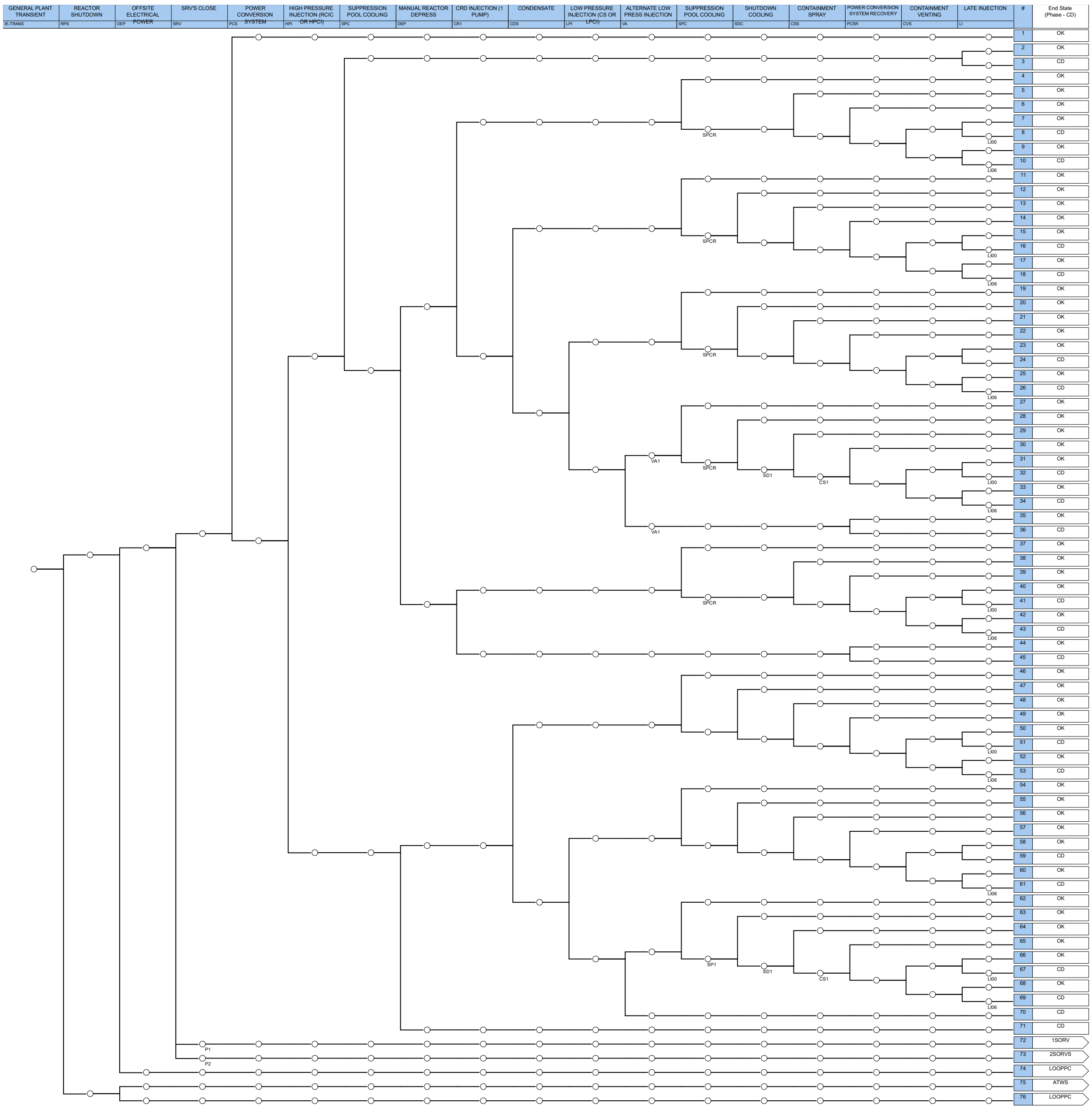

Figure 6-29. General Transient ET (IE-TRANS).

As with the PWR plant, the presence of the hydrogen facility near the BWR plant may cause a hydrogen leakage that leads to an explosion. This event may create a blast pressure that damages the switchyard components. When it happens, a LOOP event may occur. The mitigation procedure due to a switchyard-related LOOP IE is shown in Figure 6-30. Upon a LOOP event, the reactor is shut down and emergency power is activated. If safety relief valves remain closed while the HPI system and suppression pool cooling actuate, the reactor will be in a safe shutdown state. The tree logic is quite similar to the general transient tree. Redundant safety measures are incorporated in the tree, including manual depressurization followed by an LPI, an alternate LPI, shutdown cooling, containment spray, and containment venting to prevent an overpressure event.

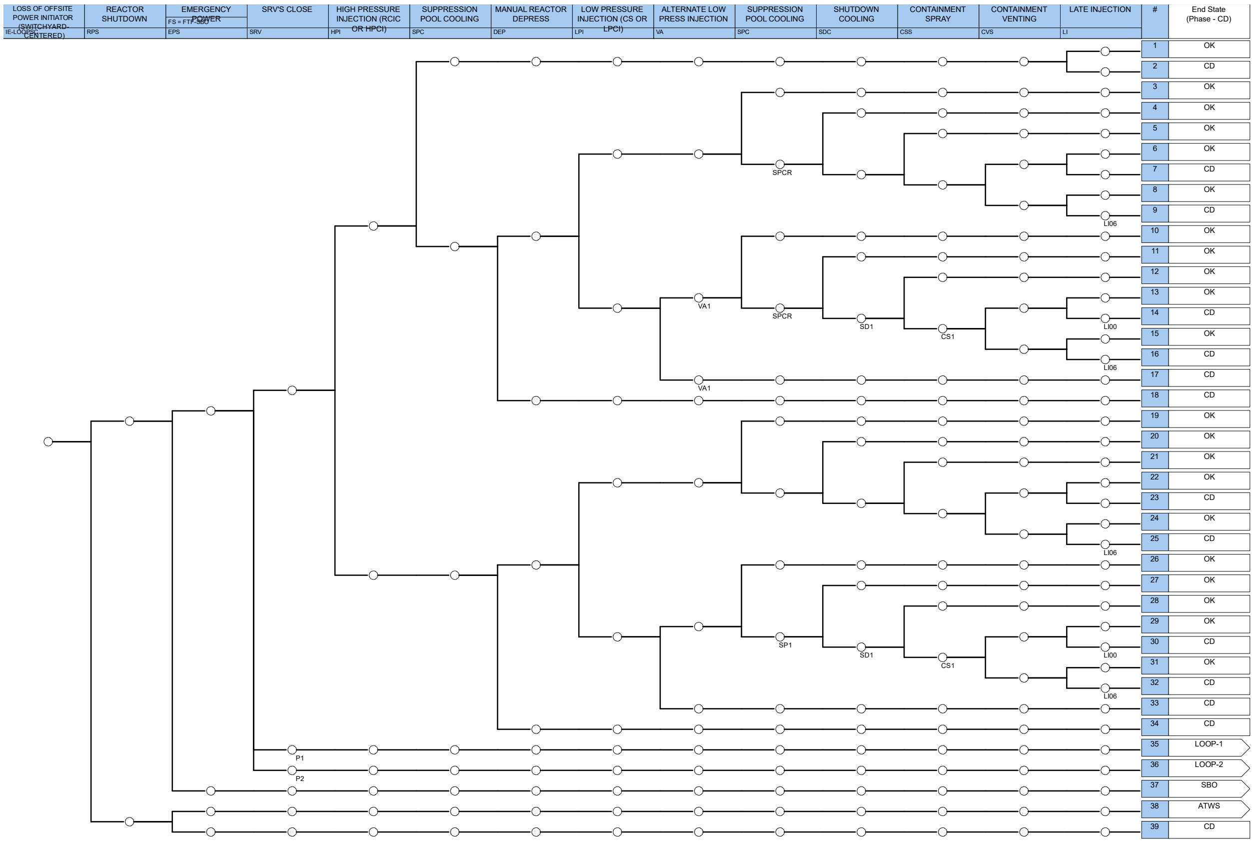

Figure 6-30. LOOP (Switchyard-centered) ET (LOOPSC).

6.4.1 HES Linkage into the BWR Model

The mitigation procedure for a steam line break in the HES is shown in Figure 6-31. When the event occurs, the core will be damaged if the RPS fails or if the MSIVs fail to close. If both systems function properly, the mitigation tree transfers to the General Transient event tree as shown in Figure 6-29. However, since the General Transient tree is used as is, there needs to be a set of linkage rules to customize the tree based on the initiator (i.e., a steam line break in the HES). This linkage rules are set as pictured in Figure 6-32. It instructs SAPHIRE to activate the LSSB-HES Flag Set when the initiator is IE-LSSB-HES. This instruction is also carried over to the transfer ET, i.e. General Transient. The LSSB-HES Flag set is set up as shown in Figure 6-33. It activates the HE-SLB-TOT House event and changes its state from False to True. The same logic is used for HES Design 1 and 3.

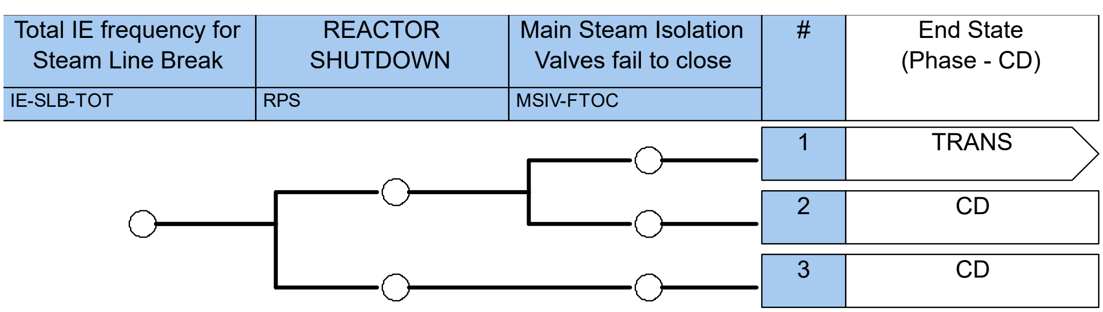

Figure 6-31. Initiating Event for Steam Line Break in the HES (IE-SLB-TOT).

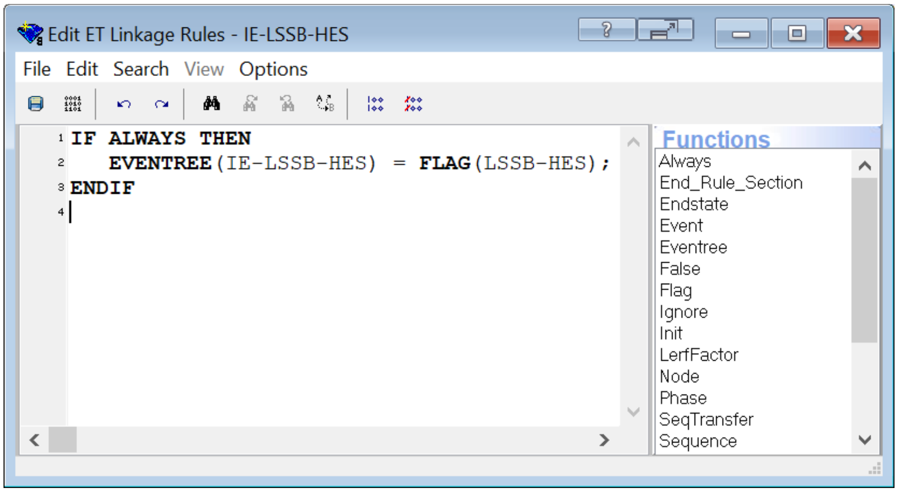

Figure 6-32. Linkage rules for the IE-LSSB-HES ET

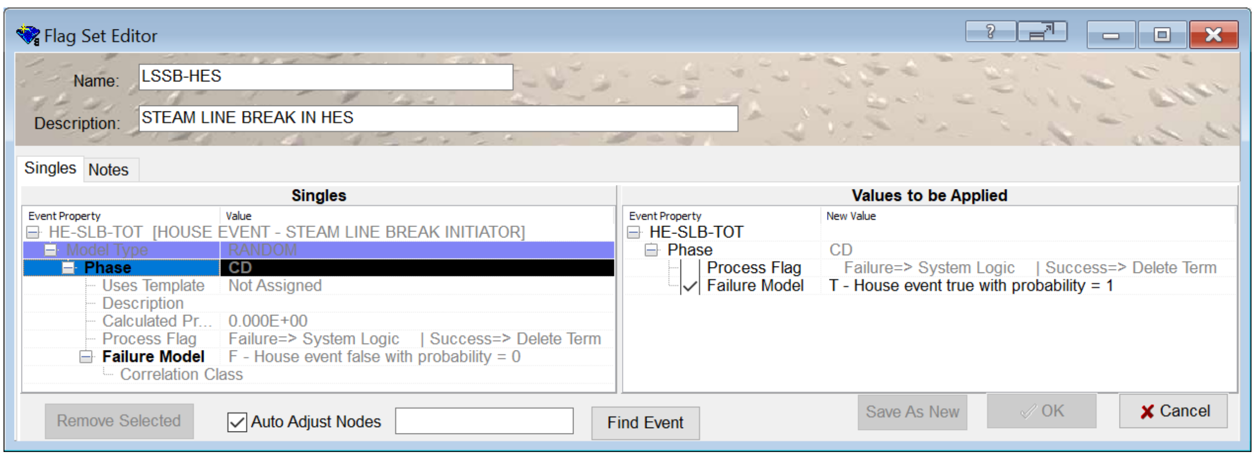

Figure 6-33. LSSB-HES flag editor.

As indicated in Figure 6-31, the IE-SLB-TOT ET transitions to the TRANS tree only when RPS functions successfully. For that reason, the RPS top event in the TRANS tree should not be evaluated again when the sequence originates from IE-SLB-TOT. This logic is made possible by adding a complement of HE-SLB-TOT as shown in Figure 6-34. This event is coupled in an AND gate with the other events that may cause RPS to fail. With this configuration, when the IE-SLB-TOT ET transitions to the TRANS tree, the LSSB-HES Flag is activated, and the HE-SLB-TOT House Event is set to true. Therefore, its complement becomes false, and the RPS failure top event does not occur. Meanwhile, when the TRANS tree is activated after the MSIV is closed, the Power Conversion System (PCS) is always off. This logic is implemented by adding the HE-SLB-TOT house event in an OR gate to the PCS and PCS recovery FT, as shown in Figure 6-35 and Figure 6-36 respectively.

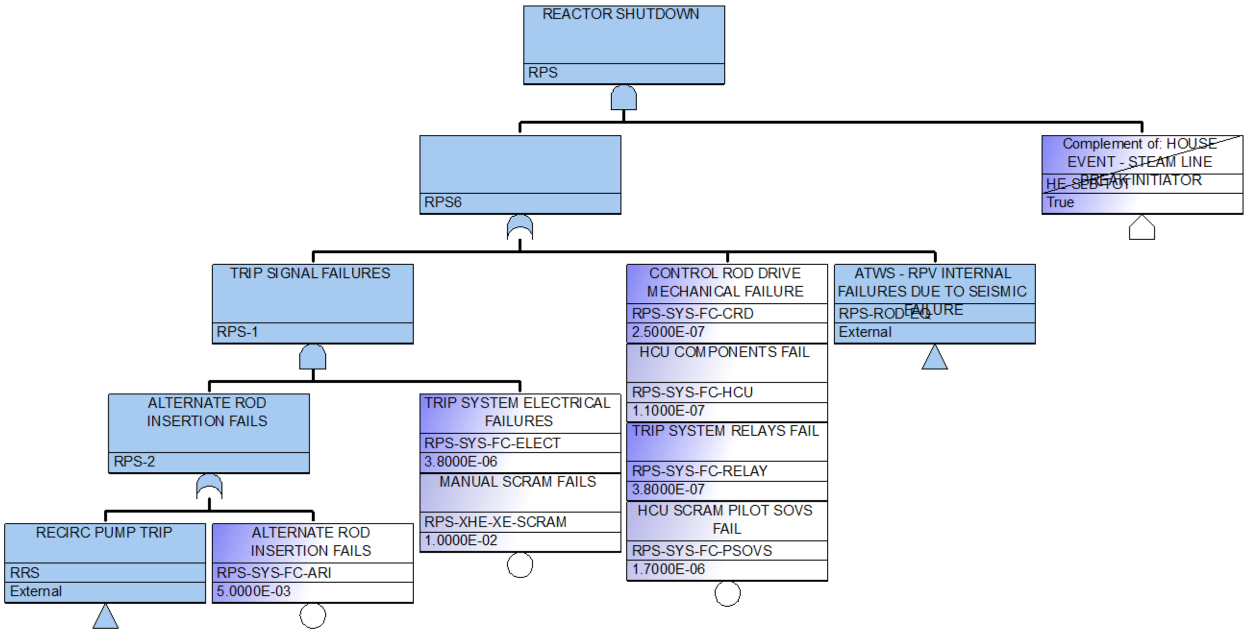

Figure 6-34. RPS FT.

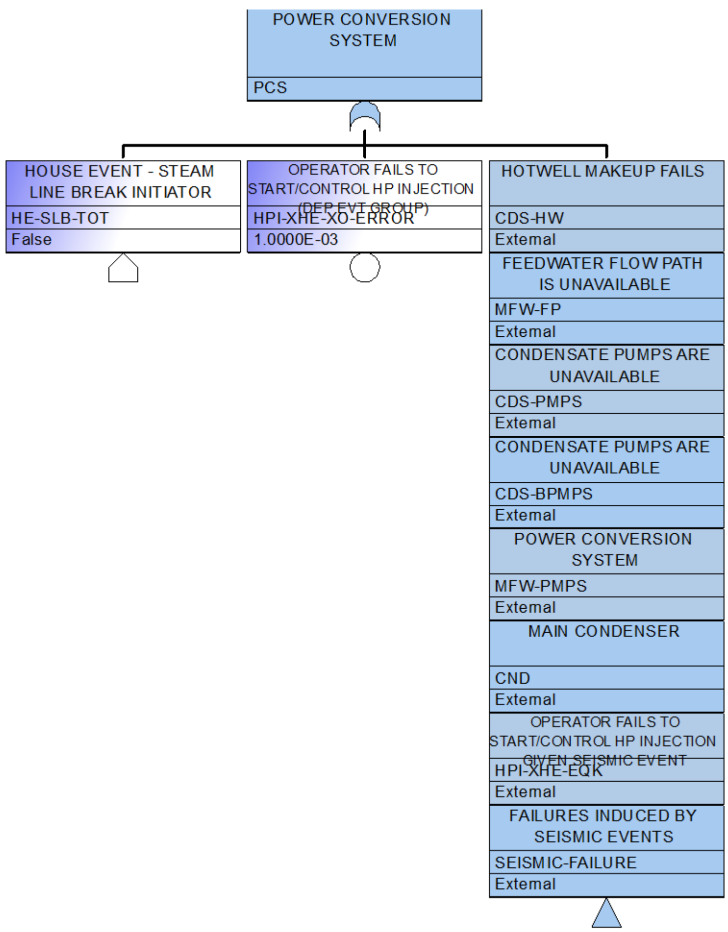

Figure 6-35. PCS FT.

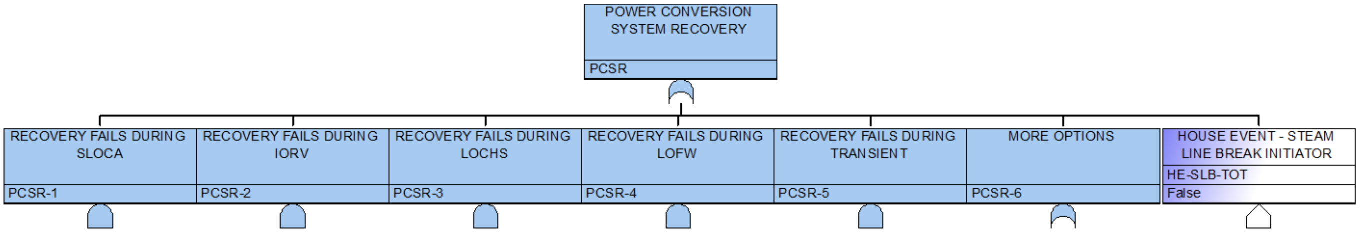

Figure 6-36. PCSR FT.

6.5 Sensitivity Studies

This section describes several sensitivity studies conducted in the risk analysis. The factors considered in the sensitivity analysis are:

1. Whether to use one or two isolation valves for the HES

2. Whether to use one, two or three bypass trains in the HES

3. Whether to equip a dedicated ceiling ventilation system at the hydrogen plant to vent leaked hydrogen to the atmosphere.

A Change Set is used to alter the HES design configuration from two isolation valves to only one. This Change Set is shown in Figure 6-37. When this change set is activated, the HES-ISOV-FLAG switches state from True to False, which affects the FTs associated with the HES isolation valves. Meanwhile, the change sets for Train number 2 and 3 of the HES steam bypass trains are shown in Figure 6-38 and Figure 6-39, respectively. These change sets alter the state of FLAG-SEL-TRA2 and FLAG-SEL-TRA3, respectively, from True to False. The initial configuration of the HES consists of two isolation valves and three trains.

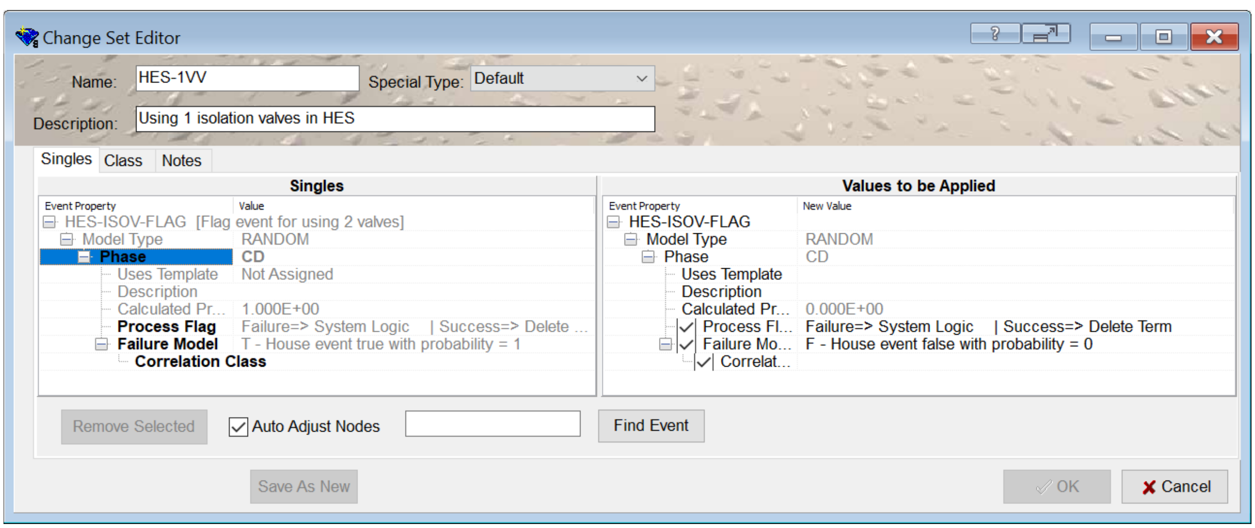

Figure 6-37. Change Set for HES isolation valves.

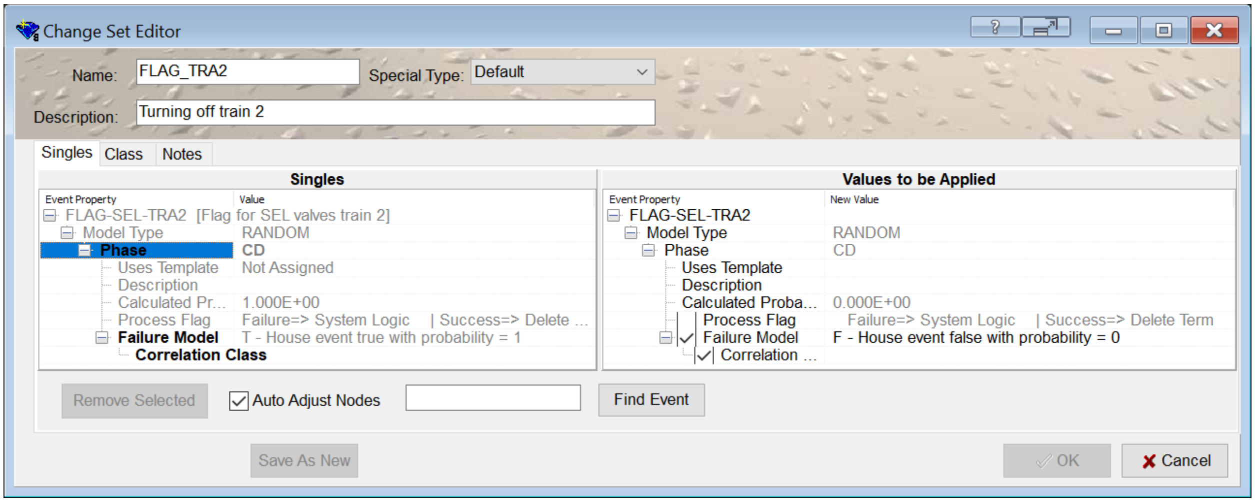

Figure 6-38. Change Set for Train 2 of HES bypass trains.

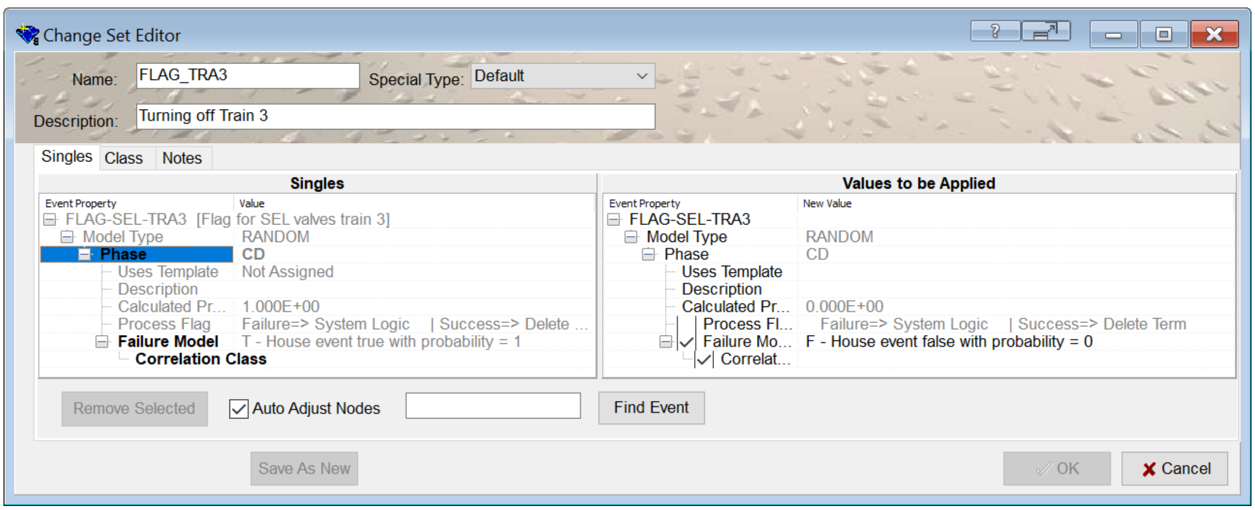

Figure 6-39. Change Set for Train 3 of HES bypass trains.

7. PRA RESULTS

7.1 Nominal PRA Results

7.1.1 Nominal PWR PRA Results

The initial frequency for the Main Steam Line Break, switchyard-related LOOP, and general transient IEs in the PWR model are 3.01E-4/year, 1.34E-2/year, and 6.76E-1/year, respectively. Meanwhile, the CDF values from these events are 2.54E-7/year, 2.75E-7/year, and 9.89E-7/year, respectively. These values are reported in Table 7-1.

Table 7-1. Summary of PRA nominal results for PWR.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency	Nominal	3.01E-4	—	1

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Switchyard-related LOOP frequency	Nominal	1.34E-2	—	1
General Transient frequency	Nominal	6.76E-1	—	1
CDF due to steam line break	Nominal	—	2.54E-7	1912
CDF due to switchyard-related LOOP	Nominal	—	2.75E-7	6183
CDF due to General Transient	Nominal	—	9.89E-7	2581

7.1.2 Nominal BWR PRA Results

The initial frequency for General Transient and the Switchyard-related LOOP IEs in the BWR model are 7.40E-1/year and 1.34E-2/year respectively. Meanwhile, the CDF of these events are 3.89E-6/year and 5.79E-7/year respectively. These values are reported in Table 7-2.

Table 7-2. Summary of PRA nominal results for BWR.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
General transient frequency (steam line break is modeled within general transient for the BWR)	Nominal	7.40E-01	—	1
Switchyard-related LOOP IE frequency	Nominal	1.34E-02	—	1
CDF due to general transient initiator	Nominal	—	3.89E-06	5200
CDF due to switchyard-related LOOP	Nominal	—	5.79E-7	5083

7.2 Heat Extraction System Design 1

7.2.1 HES Design 1 PWR PRA Results

With the installation of the HES Design 1 system, the resulting frequency for the Main Steam Line Break event is 3.18E-4/year, or an increase of 5.6% from the initial value. The new CDF becomes 2.67E-7/year, or an increase of 4.9% from its initial frequency. These values are reported in Table 7-3.

For the switchyard-related LOOP event, the initiator frequency is determined by the operator's performance to seal the leak within 2 hours as the bounding time for the MCA event. In this model, the SPAR-H human reliability model was utilized to estimate the operator's failure probability. If all the PSFs are set at their nominal values, the operator's failure to isolate the leakage in 2 hours is 1E-2. With this value, and without the presence of a dedicated ceiling ventilation system to vent out the hydrogen leakage, the IE frequency increases slightly by 1.3% from 1.34E-2 to 1.36E-2. Even so, this estimate may be rather conservative, because 2 hours is a reasonably ample time to actuate a valve isolating the leakage. Furthermore, it is informed in reference [13] that 2 hours is the longest time for the operator action in this scenario, which indicates that it is more than the average time required to perform such an action. With that consideration, a more realistic operator failure probability is estimated as 1E-4 by setting the available time PSFs as expansive. With this estimate, an increase in the IE frequency is not significantly observed. The variations on the dedicated ceiling ventilation system is performed to investigate the possible design options on the hydrogen plant. The highest risk increase of 1.4% rise from the initial CDF is observed when the SPAR-H timing is set at the nominal value and there is no dedicated ceiling ventilation system to vent the leaked hydrogen. These values are reported in Table 7-1 and Table 7-3.

Table 7-3. Summary of PRA results for PWR with HES Design 1 changes.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES	Base assumptions	3.18E-4 **(+5.5% - 5.6 %)**	—	10
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	1.36E-2 **(+1.3%)**	—	2
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
CDF due to steam line break with HES	Base assumptions	—	2.67E-7 **(+4.9 %)**	1931
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	—	2.79E-7 **(+1.4%)**	6243
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183

7.2.2 HES Design 1 BWR PRA Results

PRA results for the reference BWR reactor are summarized in Table 7-4. The addition of steam line break IE frequency to the existing general transient initiator's risk is trivial. Likewise, the additional CDF due to steam line break in HES is less than 1%. Meanwhile the IEs related to a switchyard-induced LOOP are the same with the PWR model because such events are indifferent to the reactor types, but are a function of the geographical region in which the reactor resides in. The increase in CDF due to switchyard-related LOOP resulting from the hydrogen MCA event is negligible. The highest risk increase of 1.17% CDF is observed when the SPAR-H timing of 2 hours is assumed nominal and there is no dedicated ceiling ventilation system to vent the leaked hydrogen to the atmosphere.

Table 7-4. Summary of PRA nominal results for BWR with HES Design 1 changes.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES	Base assumptions	1.66E-5 **(+0.002%)**	—	3
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	1.36E-2 **(+1.3%)**	—	2
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-02	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-02	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
CDF due to steam line break with HES	Base assumptions	—	8.00E-10 **(+0.02%)**	1931
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	—	5.86E-7 **(+1.17%)**	5133
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083

7.2.3 HES Design 1 Extended Sensitivity Analysis Results

Results of extended sensitivity analyses on the PWR risk of multiple HES design options are summarized in Table 7-5. These results are obtained with a 1E-15 cutoff value set in the PRA solver settings. The steam line break IE frequency does not change much between the various HES design options. This is because the IE-SLB41 intermediate event in Figure 6-1 is on the order of 1E-5 regardless of the selected design option. When this event is combined with the isolation failure event (IE-SLB-NEW1232), the resulting probability becomes an order of 1E-9. This value is insignificant compared to the event where isolation valves ruptures (IE-SLB-NEW1242) are of an order of 1E-5. With such trivial variations, the CDF due to steam line break is analyzed only for the two extreme design options (i.e., one with two isolation valves and three bypass trains and another with one isolation valve and one bypass train). Results show that there is no significant difference in CDF between these design options. The design options do not affect the IE frequency and CDF due to switchyard-centered LOOP event. For that reason, the design option with one isolation valve and one bypass train is deemed better due to having fewer components and, consequently, less cost.

Table 7-5. Sensitivity analyses for PWR.

Risk metric	IE Frequency (/y)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES (two isolation valves and three bypass trains)	3.18E-4	—	39
Steam line break IE frequency with HES (two isolation valves and two bypass trains)	3.18E-4	—	37
Steam line break IE frequency with HES (two isolation valves and one bypass trains)	3.18E-4	—	35
Steam line break IE frequency with HES (one isolation valves and three bypass trains)	3.18E-4	—	47
Steam line break IE frequency with HES (one isolation valves and two bypass trains)	3.18E-4	—	44
Steam line break IE frequency with HES (one isolation valves and one bypass trains)	3.18E-4	—	42
CDF due to steam line break, with two isolation valves and three bypass trains	—	2.69E-7	11228
CDF due to steam line break, with one isolation valves and one bypass train	—	2.69E-7	11228

Sensitivity analysis results for BWR reactor are summarized in Table 7-6. Similar to the PWR, the variations on IE frequency between the design options are trivial. The CDF due to steam line break is analyzed for the two extreme design options, just as with PWR. The change in CDF is found to be negligible. With these considerations, the HES with one isolation valve and one bypass train may be preferred in terms of risk analysis, system complexity and costs.

Table 7-6. Sensitivity analysis for BWR.

Risk metric	IE Frequency (/y)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES (two isolation valves and three bypass trains)	1.66E-5	—	37
Steam line break IE frequency with HES (two isolation valves and two bypass trains)	1.66E-5	—	35
Steam line break IE frequency with HES (two isolation valves and one bypass trains)	1.66E-5	—	33
Steam line break IE frequency with HES (one isolation valves and three bypass trains)	1.66E-5	—	46
Steam line break IE frequency with HES (one isolation valves and two bypass trains)	1.66E-5	—	44
Steam line break IE frequency with HES (one isolation valves and one bypass trains)	1.66E-5	—	41
CDF due to steam line break, with two isolation valves and three bypass trains	—	8.23E-10	624

Risk metric	IE Frequency (/y)	Core Damage Frequency (/y)	Cut Sets
CDF due to steam line break, with one isolation valves and one bypass train	—	8.23E-10	624

7.3 Heat Extraction System Design 3

7.3.1 HES Design 3 PWR PRA Results

With the installation of the new HES design (Design 3), the resulting frequency for the Main Steam Line Break and the Switchyard-related LOOP IEs are 3.18E-4/year and 1.34E-2/year respectively. Meanwhile, the CDF values for these events are calculated as 2.68E-7/year and 2.76E-7/year respectively. A sensitivity analysis for the switchyard-related LOOP event is conducted following the procedure described in Section 7.2. These values are reported in Table 7-7. HES Design 3 has a simpler design relative to HES Design 1, which causes its risk increase to be less than that of Design 1.

Table 7-7. Summary of PRA results for PWR with HES Design 3 changes.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES	Base assumptions	3.18E-4 **(+5.5%)**	—	10
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	1.34E-2 **(+0.15%)**	—	2
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
CDF due to steam line break with HES	Base assumptions	—	2.68E-7 **(+5.55%)**	1955
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	—	2.76E-7 **(+0.22%)**	6192
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	—	2.75E-7	6183

With the installation of the HES and necessary electrical tap from the main generator, the IE frequency for the General Transient in the PWR model rounds to 6.76E-1/year, with an increase of less than 1% from the initial value. The increase in CDF is 9.16E-6 per year range and thus insignificant compared to the original frequency of 6.76E-1/year range. The new CDF is 9.89E-7/year, also showing no significant increase from its initial frequency. These values are reported in Table 7-8. To ensure nothing significant was being lost, calculations were also performed at with a 1E-17 and 1E-20 truncation and no cut sets were added between the original and new case. Overall, the difference is negligible due to the high reliability of transmission components. This also means that addition of the direct electrical tap is insensitive to the HES design employed.

Table 7-8. Summary of PRA results for PWR with electric tap out to HTEF.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
General Transient frequency with tap in switchyard to HTEF	Base assumptions	6.76E-1**(+0.00136%)**	—	9
CDF due to General Transient with tap in switchyard to HTEF	Base assumptions	—	9.89E-7 **(<< 1.0%)**	2581

7.3.2 HES Design 3 BWR PRA Results

PRA results for BWR are summarized in Table 7-9. In general, the increase in risk metrics due to the addition of HES Design 3 system are trivial. The risk increase to the Steam Line Break IE frequency is similar with HES Design 1 in Table 7-4, because the steam pipe break frequency in the HES of both designs is negligible relative to the initial steam line break frequency in the NPP. Meanwhile, the Switchyard-related LOOP frequency of HES Design 3 is less than that of HES Design 1, because HES Design 3 uses a smaller H2 generation plant of 100 MW while HES Design 1 uses a plant with 1,150-MW capacity. This difference results in the fewer number of components and a smaller H2 leak frequency in the 100-MW H2 plant compared to the 1150 MW H2 plant.

Table 7-9. Summary of PRA nominal results for BWR with HES Design 3 changes.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Steam line break IE frequency with HES	Base assumptions	1.66E-5 **(+0.002%)**	—	9
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	1.34E-2 **(+0.11%)**	—	2

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
Switchyard-related LOOP frequency with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-02	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	1.34E-02	—	2
Switchyard-related LOOP frequency with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	1.34E-2	—	2
CDF due to steam line break with HES	Base assumptions	—	8.00E-10 **(+0.02%)**	22
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, without dedicated ceiling ventilation system	Base assumptions	—	5.79E-7 (< **1%**)	5092
CDF due to switchyard-related LOOP with HES, conservative SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, and dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083
CDF due to switchyard-related LOOP with HES, realistic SPAR-H timing, without dedicated ceiling ventilation system	Sensitivity	—	5.79E-7	5083

As for the General Transient event, the risk increase due to the necessary electrical tap from the main generator is trivial that the resulting frequency for this event is still the same to two significant digits at 7.40E-1/year, with an increase of 0.00124% from the initial value. The increase in CDF is 9.16E-6/year and thus insignificant compared to the original frequency of 7.40E-1/year. The new CDF is 3.89E-6/year, also showing no significant increase from its initial frequency. These values are reported in Table 7-10. To ensure nothing significant was being lost, calculations were also performed at with a 1E-17 and 1E-20 truncation and no cut sets were added between the original and new case. Overall, the difference is negligible due to the high reliability of transmission components. This also means that addition of the direct electrical tap is insensitive to the HES design employed.

Table 7-10. Summary of PRA results for BWR with electric tap out to HTEF.

Risk metric	Case	IE Frequency (/y) (Δ%)	Core Damage Frequency (/y)	Cut Sets
General transient frequency with tap in switchyard to HTEF	Base assumptions	7.40E-1 **(+0.00124%)**	—	9
CDF due to General Transient with tap in switchyard to HTEF	Base assumptions	—	3.90E-6 **(<<1.0%)**	5200

7.4 Separation Distance Analysis

This subsection applies for both HES Design 1 and 3. The distance from the hydrogen plant to the NPP is 1 km in this study, following the overpressure analysis conducted by Sandia National Laboratories [13]. The study suggested that 1 km is a safe separation distance based on a set of conservative assumptions. An additional sensitivity study analyze the effect of separation distance on the fragility of transmission towers, which may affect the switchyard-induced LOOP frequency. Figure 7-1 shows the overpressure and total fragility curves of switchyard components as a function of separation distance between the hydrogen and switchyard. Around 845 m marks the critical fragility for switchyard components, below which their fragility is 1.

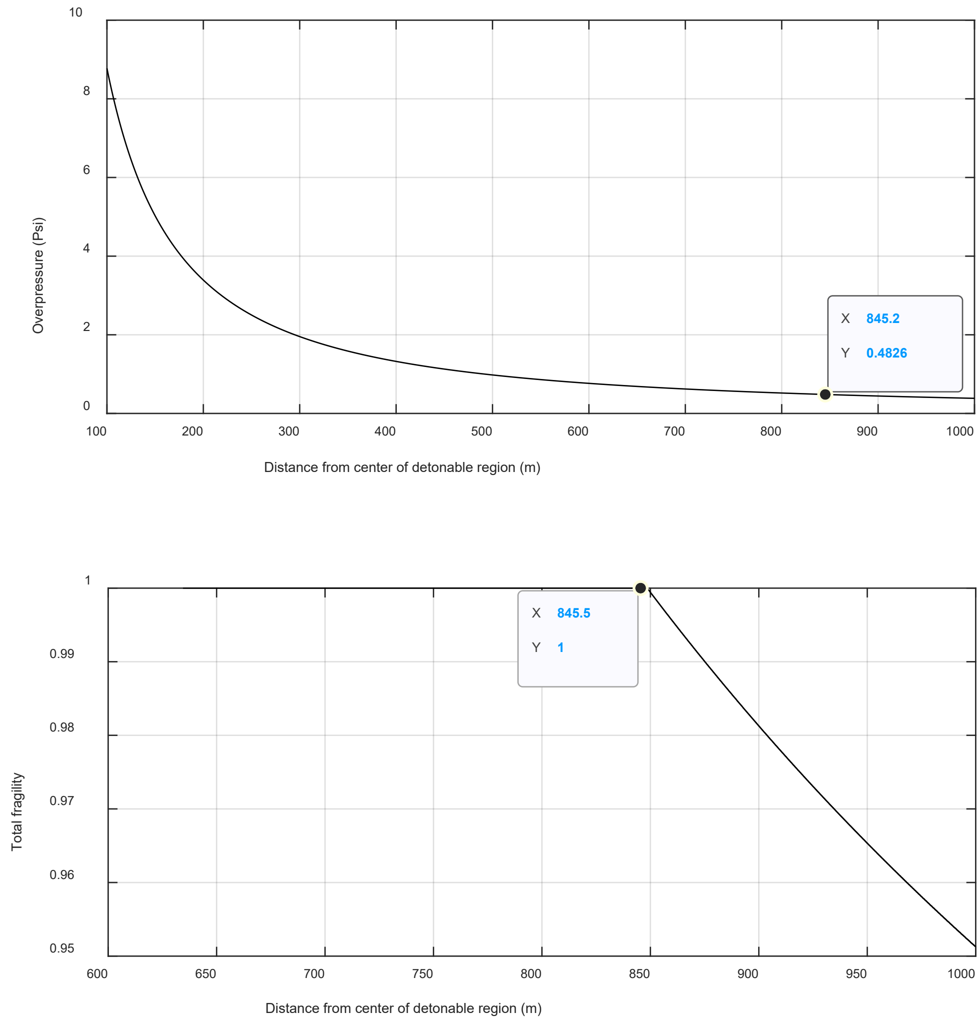

Figure 7-1. MCA overpressure (top) and total switchyard fragility (bottom) as a function of separation distance between the HTEF and NPP.

The hydrogen detonation event considered in Section 6 is the cloud detonation event, in which leaked hydrogen accumulates indoors for 2 hours before it finally ignites and detonates. There is another possibility of ignition immediately following leakage, which creates a high-pressure hydrogen jet detonation event. This event was excluded from the PRA model on the basis that it cannot create a significant overpressure to damage a transmission tower 1 km away, as shown in Figure 5-8. However, if the separation distance is reduced, the overpressure from the high-pressure hydrogen jet may damage the transmission tower and create a LOOP event. For that reason, a sensitivity analysis is conducted to find the minimum safe distance. The LOOP initiator FT in Figure 6-28 is modified to include the high-pressure jet event, as shown in Figure 7-2. The switchyard failure probability due to jet detonation (IE-LOOPSC-SC-JET-F) is initially set to 0 at a separation distance of 1 km. If a 15% increase in IE frequency is set as the safety limit with considerations discussed in Section 8.1, the IE-LOOPSC-SC-JET-F event should have a probability of 0.11. Meanwhile, if a 5% increase in IE frequency is used such that the change in IE-LOOPSC-HES frequency is comparable to the increase in Steam Line break frequency, the probability for IE-LOOPSC-SC-JET-F event is 0.037.

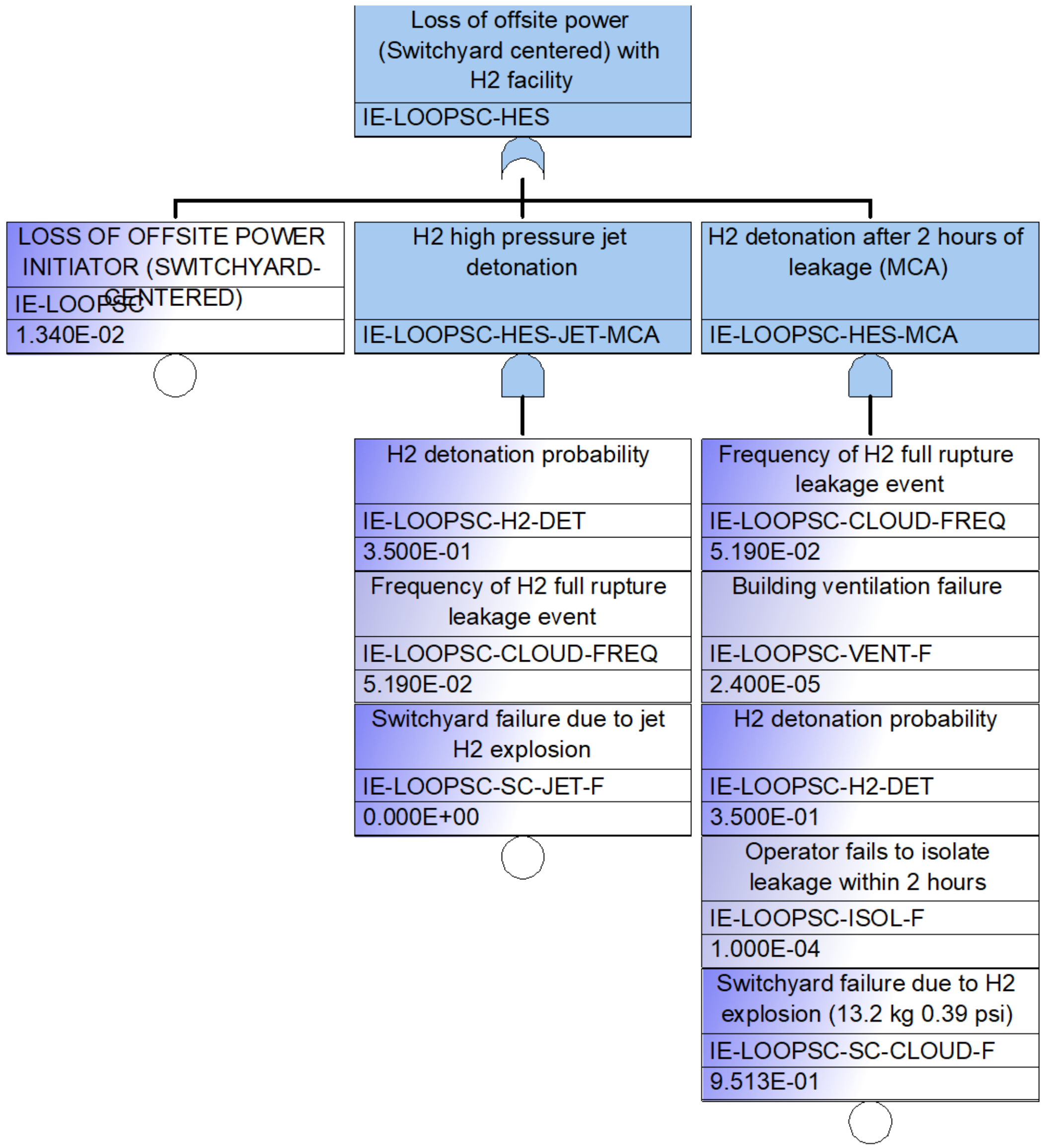

Figure 7-2. LOOP FT with high-pressure hydrogen jet event.

A reference study [13] has assessed various hydrogen jet detonation scenarios and identified the most conservative scenario of a 200-mm break at 50º C and 7 MPa. By combining data from this reference study and Figure 5-8, a graph of transmission tower fragility versus the separation distance between the hydrogen plant and transmission towers is plotted in Figure 7-3. The data points for IE-LOOPSC-SC-JET-F to fulfill the 5 and 15% IE increase are highlighted on the plot. The figure suggests that a minimum separation distance lies at around the 450-m mark to meet the safety criteria explained in the previous paragraph. When the transmission tower is spaced at least 500 m away from the hydrogen plant, the LOOP risk due to high-pressure hydrogen jet detonation is nullified.

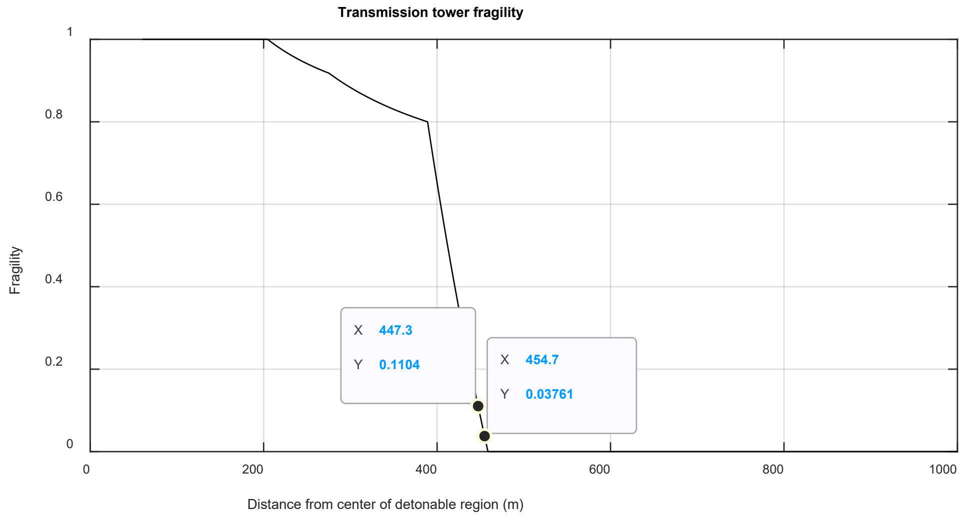

Figure 7-3. Fragility curve of transmission tower.

7.5 Final Risk Metric Results

7.5.1 Final Risk Metrics for PWR

Based on the results in the previous section, the plant total CDF and LERF are calculated using the conservative assumption. Those 2 hours are the nominal time to locate and seal hydrogen leakage (a conservative SPAR-H timing) and in which the hydrogen plant does not have a dedicated ceiling ventilation system. Furthermore, the HES base design is selected (i.e., an HES with two isolation valves and three bypass trains) and the base assumptions listed in Table 5-1 are followed. These results are shown in Table 7-11. The flexible NPP operation with an HES Design 1 increases CDF by 5.50E-7 (6.56%) and LERF by 1E-9 (0.12%), while the operation with an HES Design 3 increases CDF by 4.98E-7 (6.00%) and LERF by 6E-10 (0.07%).

Table 7-11. Risk metric for PWR.

	Total CDF (/y)	**Total LERF (/y)**
NPP without HES	8.33E-6	8.04E-7
NPP with HES Design 1	8.88E-6	8.05E-7
NPP with HES Design 3	8.83E-6	8.04E-7

The sensitivity analyses for possible configurations of a dedicated ceiling ventilation system and expansive time to isolate the hydrogen leak at the HTEF show that a 5.5% minimal increase in safety is achieved for both HES Design 1 and HES Design 3.

7.5.2 Final Risk Metrics for BWR

Similar to PWR, the BWR risk measures are calculated on the conservative assumption that 2 hours is the nominal time to locate and seal hydrogen leakage (a conservative SPAR-H timing) and that the hydrogen plant does not have a dedicated ceiling ventilation system. The base assumptions listed in Table 5-1 are also selected for this analysis, with the results shown in Table 7-12.

Both the total CDF and LERF increase by 1E-8 (0.03%) when a BWR NPP is coupled with a hydrogen production facility for HES Design 1 and HES Design 3.

Table 7-12. Risk metric for BWR.

	Total CDF (/y)	Total LERF (/y)
NPP without HES	2.84E-5	2.81E-5
NPP with HES Design 1	2.84E-5	2.81E-5
NPP with HES Design 3	2.84E-5	2.81E-5

The sensitivity analyses for possible configurations of a dedicated ceiling ventilation system and expansive time to isolate the hydrogen leak at the HTEF show that a minimal increase in safety is achieved of 1.3 and 0.11% for HES Design 1 and HES Design 3 respectively.

8. LICENSING PATHWAY SUPPORT FROM PRA

The NRC develops various regulatory guides to assist license applicants' implementation of NRC regulations by providing evaluation techniques and data used by the NRC staff. Two distinct pathways through guides and codes of federal regulations are used in the proposed LWR plant configuration change approval.

One pathway utilizes 10 CFR 50.59 [3], to review the effects on frequencies of design basis accidents (DBAs), amendment of the updated final safety analysis report, and determination of whether a licensing amendment review (LAR) is required. This pathway is dependent on the IE frequency, which is on the front end of the PRA.

A supporting pathway utilizes RG 1.174 [4] through the use of risk-informed metrics to approve a plant configuration change based on the effect on the overall CDF of an approved PRA. This pathway is dependent on the tail end of the analysis, the CDF-resulting metric of the PRA.

The final pathway is the LAR process, which would utilize PRA results as well; however, the process utilizes 10 CFR 50.90, "Application for amendment of license or construction permit at request of holder" [18] and should be avoided if possible due to lengthy review and monetary burden.

8.1 Licensing Process Through 10 CFR 50.59

The pathway that utilizes an evaluation of the change in DBA frequencies first uses 10 CFR 50.59 [3] to determine if an LAR would be required via 10 CFR 50.90 [18]. Changes that meet the 10 CFR 50.59 requirements do not require additional NRC review and approval. In a study commissioned by the LWRS [21], the effects on DBAs of a PWR with the addition of an HES were evaluated for adherence to the following eight criteria:

1. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the final safety analysis report (as updated)

4. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component important to safety previously evaluated in the final safety analysis report (as updated)

5. Result in more than a minimal increase in the consequences of an accident previously evaluated in the final safety analysis report (as updated)

6. Result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report (as updated)

7. Create a possibility for an accident of a different type than any previously evaluated in the final safety analysis report (as updated)

8. Create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the final safety analysis report (as updated)

9. Result in a design basis limit for a fission product barrier as described in the final safety analysis report (as updated) being exceeded or altered

10. Result in a departure from a method of evaluation described in the final safety analysis report (as updated) used in establishing the design bases or in the safety analyses.

If the above criteria are not met, the 10 CFR 50.59 process cannot be used to implement the plant modification and an LAR must be submitted to the NRC for review and approval.

As noted in Reference [21], nearly all criteria are readily met for a modification such as the HES, but there was not enough data available at the time to determine if item 1 (minimal increase in DBA frequency) is met when considering a minimal increase is traditionally understood to be ≤15%. This PRA found the largest increase in a DBA yearly IE frequency to be 5.6% (Large Steam Line Break for the PWR) from all considered HES Designs, thus meeting the criteria for 10 CFR 50.59.

8.2 Licensing Support Through RG 1.174

RG 1.174 [4] provides general guidance concerning analysis of the risk associated with proposed changes in plant design and operation. Specifically, thresholds and guidelines are provided for comparison with Level 1 PRA results for CDF and LERF.

As seen in Figure 8-1, CDF should be below 1E-5 overall and the change in overall CDF should be below a magnitude of 1E-5. Any plant that starts at a 1E-4 or more CDF requires less than 1E-6 increase in CDF to be considered. If these metrics are met, the NRC most likely considers this a small change consistent with the intent of the Commission's Safety Goal Policy Statement and a detailed quantitative assessment of the base values of CDF is not necessary for the license review.

If the above criteria for CDF are not met, an LAR must be submitted to the NRC for review and approval.

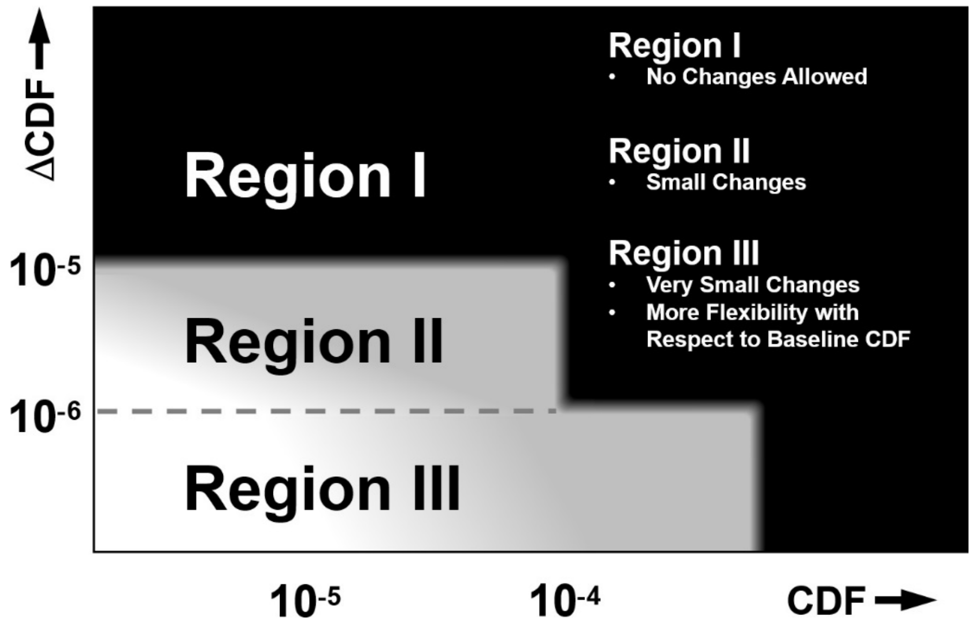

Figure 8-1. Acceptance guidelines for CDF.

As seen in Figure 8-2, LERF should be below 1E-6 overall and the change in overall LERF should be below a magnitude of 1E-6. If these metrics are met, the NRC most likely considers this a small change consistent with the intent of the Commission's Safety Goal Policy Statement and a detailed quantitative assessment of the base values of CDF is not necessary for the license review.

If the above criteria for LERF are not met, an LAR must be submitted to the NRC for review and approval.

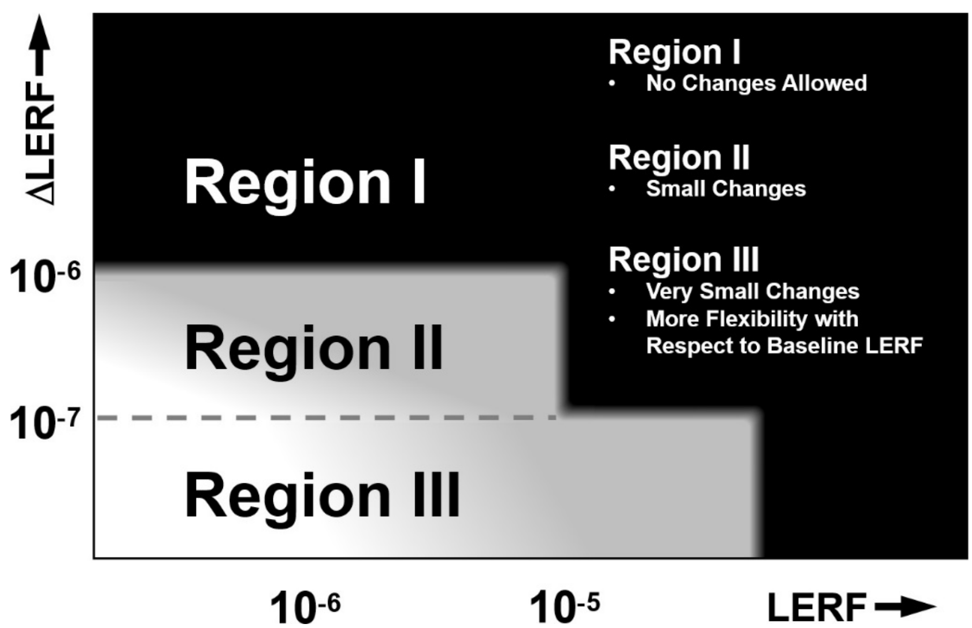

Figure 8-2. Acceptance guidelines for LERF.

8.2.1 HES Design 1 Results

As noted in Table 7-11, the generic PWR considered for this study has a nominal CDF of 8.33E-06 /y and a maximum increase after the addition of the HES Design 1 and HTEF to 8.88E-06/y for ΔCDF of 5.47E-07/y, which is well within Region III of the acceptance guidelines shown in Figure 8-1. The nominal LERF frequency for the PWR is 8.04E-07 /y and the maximum increase after adding the HES and HTEF is to 8.05E-07 /y for ΔLERF of 6.00E-010 /y, which is well within Region III of the acceptance guidelines shown in Figure 8-2.

As noted in Table 7-12, the generic BWR considered for this study has a nominal CDF of 2.84E-05/y, and the maximum increase after addition of the HES Design 1 and HTEF is to 2.84E-05/y for ΔCDF of 1.00E-07/y, which is well within Region III of the acceptance guidelines shown in Figure 8-1. The nominal LERF frequency for the BWR is 2.81E-05 /y, and the maximum increase after adding the HES and HTEF is to 2.81 E-05 /y for ΔLERF of 1.00E-08 /y, which is well within Region III of the acceptance guidelines shown in Figure 8-2.

8.2.2 HES Design 3 Results

As noted in Table 7-11, the generic PWR considered for this study has a nominal CDF of 8.33E-06/y and the maximum increase after the addition of the HES Design 3 and HTEF is to 8.83E-06/y for ΔCDF of 5.00E-07/y, which is well within Region III of the acceptance guidelines shown in Figure 8-1. The nominal LERF frequency for the PWR is 8.04E-07/y, and the maximum increase after addition of the HES and HTEF is to 8.04E-07/y for ΔLERF of 6.00E-10/y, which is well within Region III of the acceptance guidelines shown in Figure 8-2.

As noted in Table 7-12, the generic BWR being considered for this study has a nominal CDF of 2.84E-05/y, and the maximum increase after addition of the HES Design 1 and HTEF is to 2.84E-05/y for ΔCDF of 1.00E-07/y, which is well within Region III of the acceptance guidelines shown in Figure 8-1. The nominal LERF frequency for the BWR is 2.81E-05/y, and the maximum increase after addition of the HES and HTEF is to 2.81 E-05/y for ΔLERF of 1.00E-08/y, which is well within Region III of the acceptance guidelines shown in Figure 8-2.

8.2.3 Direct Electrical Connection Results

The direct electrical connection did not significantly change the overall CDF or LERF since there was only a 0.001% IE frequency increase on the transient ET for both PWR and BWR.

8.3 Licensing Amendment Review Process

Should the prior two processes fail to approve a change in the LWR, the last resort would be a detailed request for an LAR. As stated in Reference [21]:

> *10 CFR 50.90 is the governing regulation for the process undertaken by the licensee to develop and submit an LAR. This regulation states that the application fully describes the changes desired and is to follow the form prescribed for the original updated final safety analysis report submittal. An LAR is required when a change to the technical specifications is desired for whatever purpose. The LAR is developed by the licensee staff and is reviewed by internal committees and management to ensure that the technical content is correct and meets management approval.*

The NRC LAR review is extensive and typically involves meetings with the licensee and the opportunity for public meetings per 10 CFR 50.91, "Notice for Public Comment; State Consultation" [22]. The NRC issues requests for additional information to obtain responses from the licensee as a result of the NRC review. 19 CFR 50.92, "Issuance of Amendment" [23] includes a "no significant hazards" consideration to determine if any of the following conditions exist based on the NRC LAR review:

- Involves a significant increase in the probability or consequences of a previously evaluated accident
- Creates the possibility of a new of different kind of accident from any previously evaluated accident
- Involves a significant reduction in margin of safety.

Provided these regulatory requirements are met, the NRC issues, a safety evaluation that approves the LAR including the technical specification revisions.

9. CONCLUSIONS

Two generic PRAs for adding an HES to an LWR are performed, one for a PWR and one for a BWR. Two different HES designs, direct electrical connection from the NPP to the HES, and two sizes of HTEF (1,150 MWt and 100 MWt) are modeled. The results investigate the applicability of the potential licensing approaches which do not require a full NRC licensing review. The PRAs are generic, with some assumptions (see Table 5-1). Many conservative assumptions from the preliminary PWR PRA report [2] were eliminated through the use of design data for both the HES and HTEF. The results of the PRA indicate that the 10 CFR 50.59 licensing approach is justified due to the minimal increase in IE frequencies for all DBAs, with none exceeding 5.6%. The PRA results for CDF and LERF support the use of RG 1.174 as further risk information that supports a change without a full LAR.

This PRA investigation outlines a successful pathway to follow when moving to the site-specific case.

The hazard analysis performed to support the PRAs in this report provides insights that built the nominal case of safety and some economic and non-safety hazards:

- The HES should be placed in its own building to protect the turbine building SSCs and possible safety buses should there be a large steam line rupture.
- The high-pressure jet detonation hazard at the HTEF can be screened out as a hazard based on the low overpressures experienced at 1 km.
    - The high-pressure jet detonation hazard was the bounding hazard for safely decreasing the distance between the HTEF and NPP (switchyard transmission towers) to 455 meters.
- The low frequency of the hydrogen cloud detonation hazard effectively screens out this accident as a hazard even though the overpressures experienced are higher than the hig-pressure jet detonation.

Sensitivity studies performed on the nominal case provided the following insights:

- The addition of a dedicated ceiling ventilation at the HTEF and using a less conservative time allotment to isolate the hydrogen leak added approximately 1.3% to the safety margin for the LWR licensing case; however, the licensing case is strong without these additions
- The mitigation of the larger hydrogen cloud detonations with a dedicated ceiling ventilation in the HTEF makes the placement of the HTEF viable at much closer ranges than 1 km
- The safety case for using one isolation valve in the HES, rather than mimicking the NPP's MSIV paired configuration is a valid one, with a negligible increase in the CDF
- The safety case for using one bypass train, rather than three in the HES is a valid one, with a negligible increase in the CDF

This report confirms with high confidence that the safety case for licensing an HES addition and an HTEF sited 1.0 km from the NPP is strong and that 0.5 km is also a viable case. Site-specific information can alter these conclusions (e.g., using blast barriers and other modifications).

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Appendix A: Generic PWR PRA Model

This Appendix shows PWR ETs, which are transfers of the accident mitigation ETs described in the body of this report.

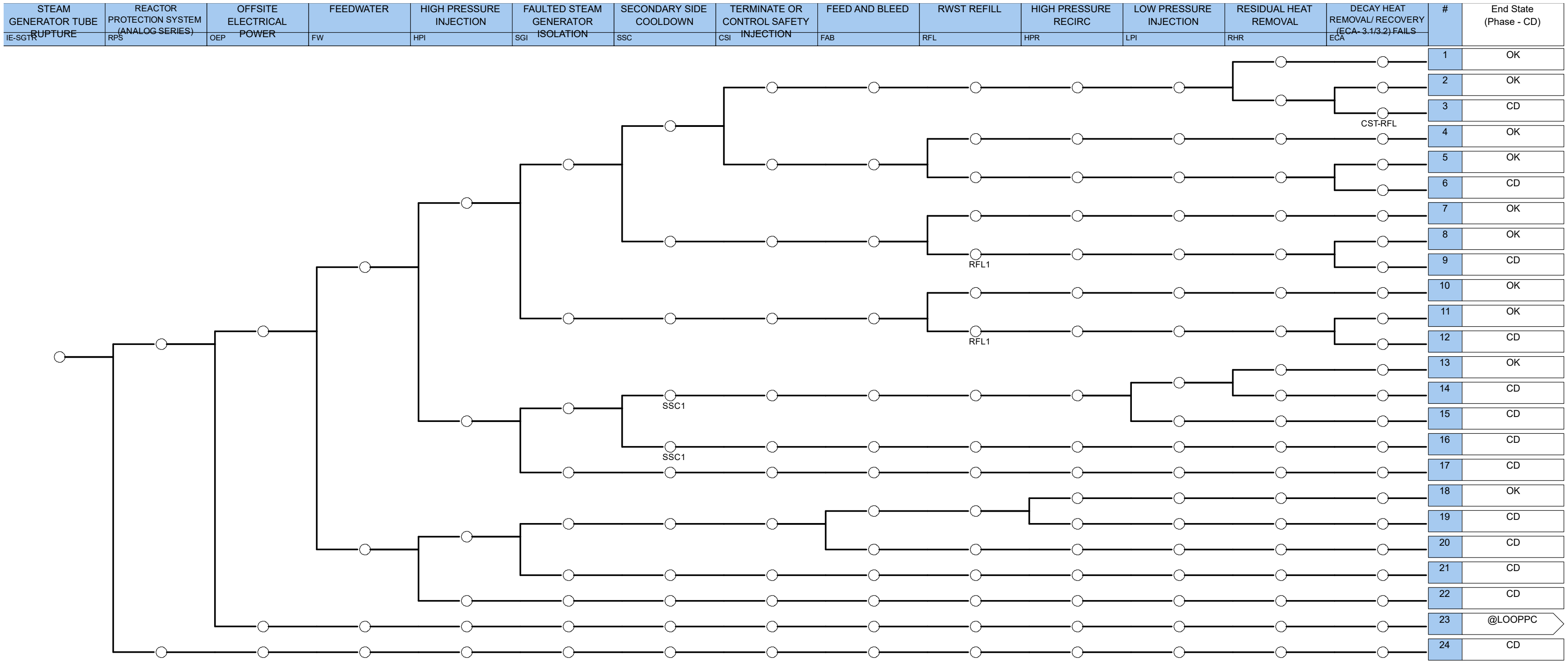

Figure A- 1. SGTR ET.

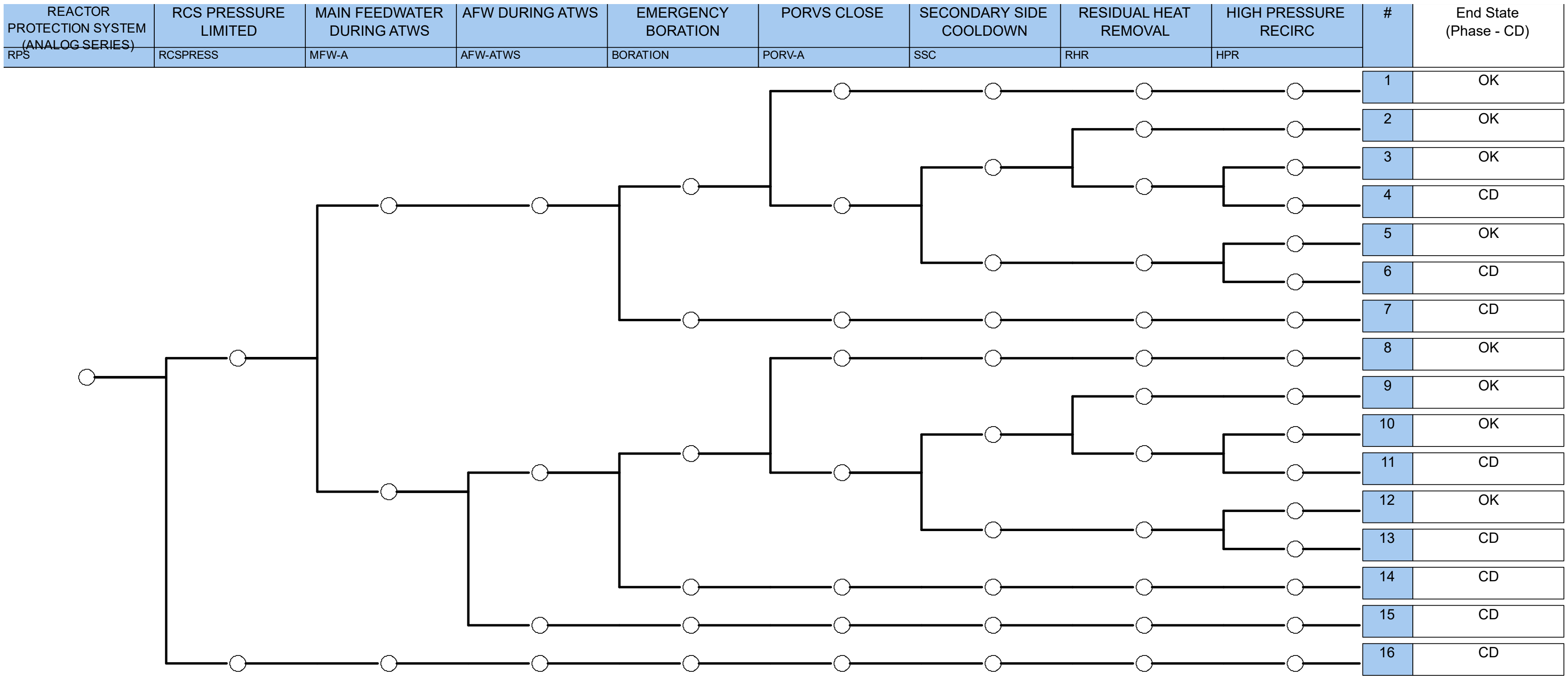

Figure A- 2. ATWS ET.

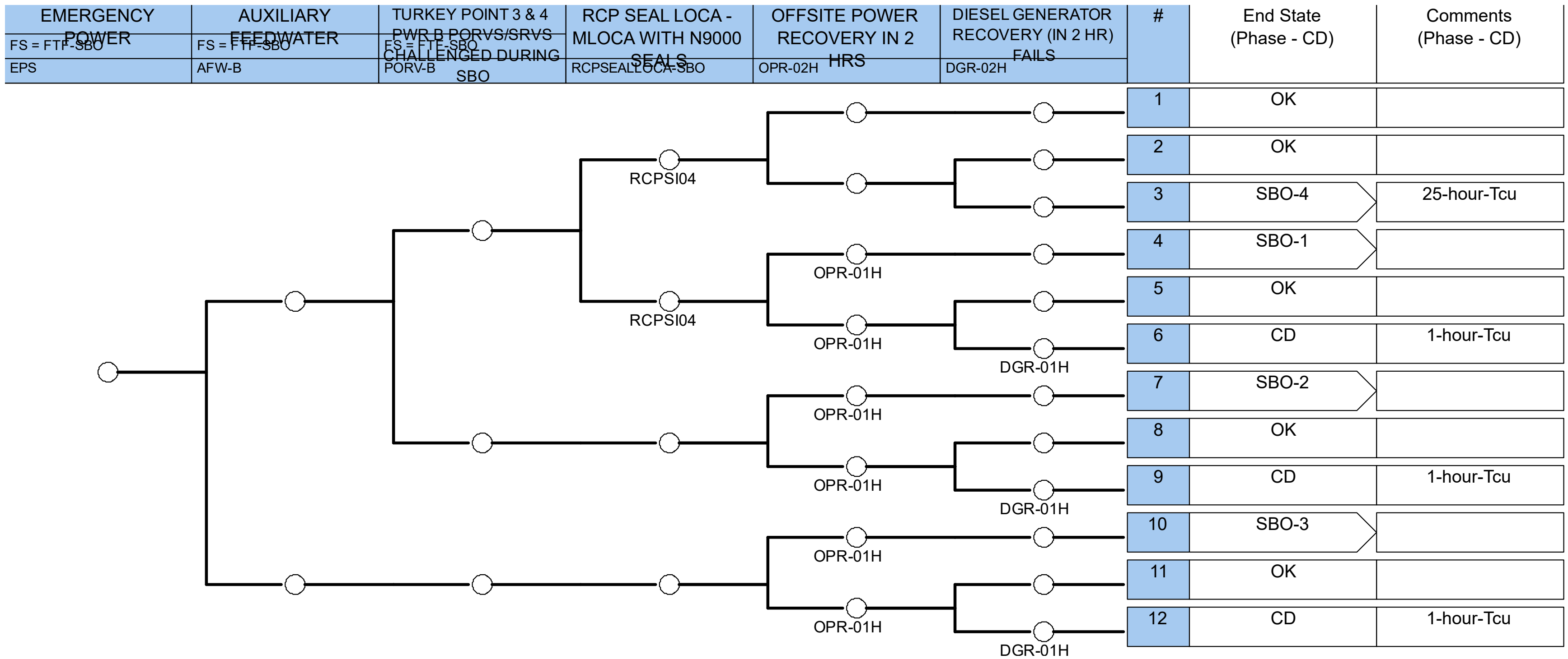

Figure A- 3. SBO ET.

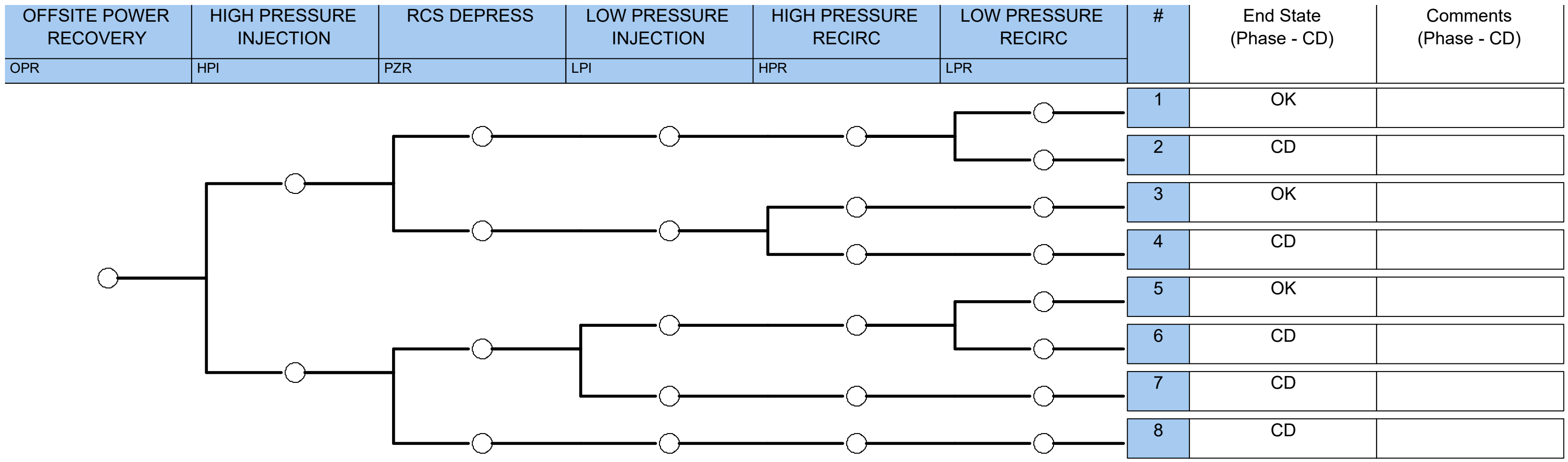

Figure A- 4. SBO-1 ET.

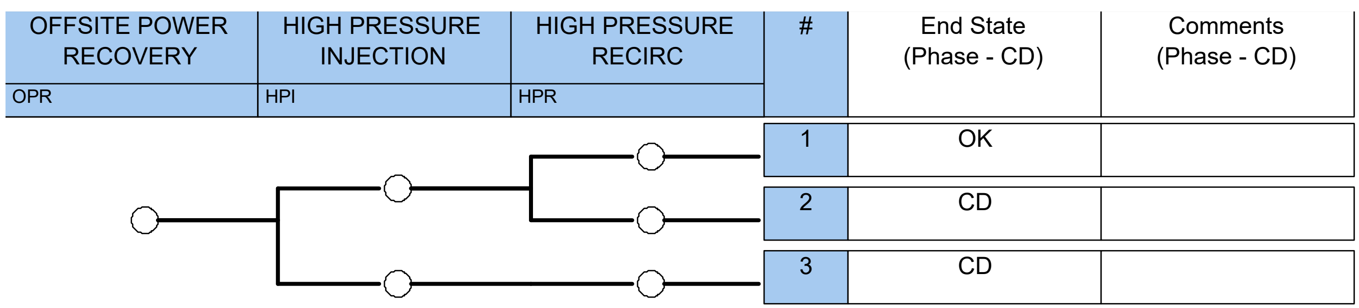

Figure A- 5. SBO-2 ET.

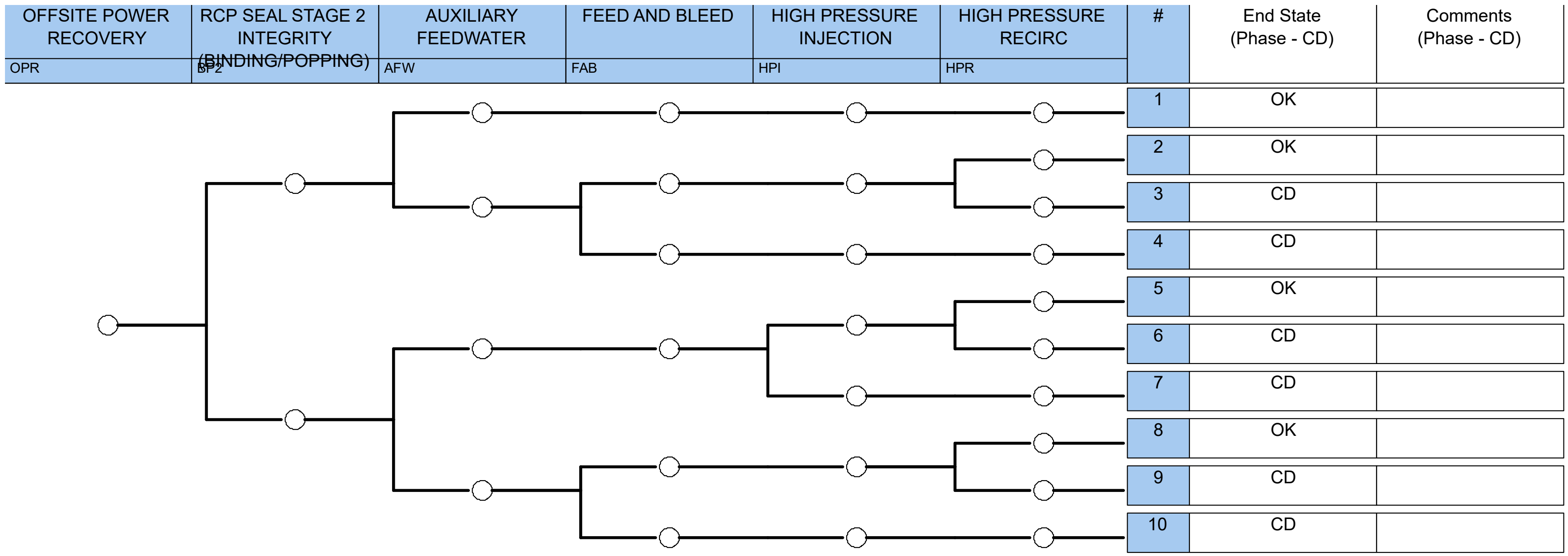

Figure A- 6. SBO-3 ET.

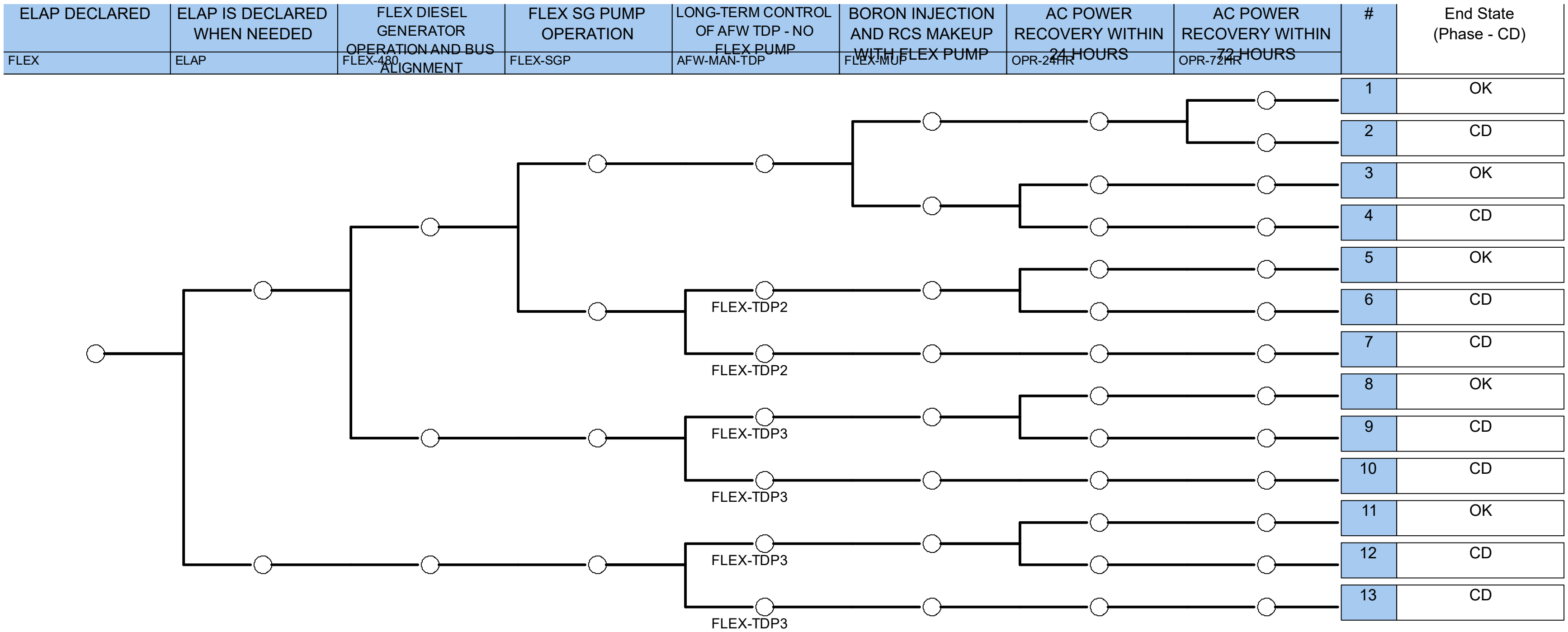

Figure A- 7. SBO-4 ET.

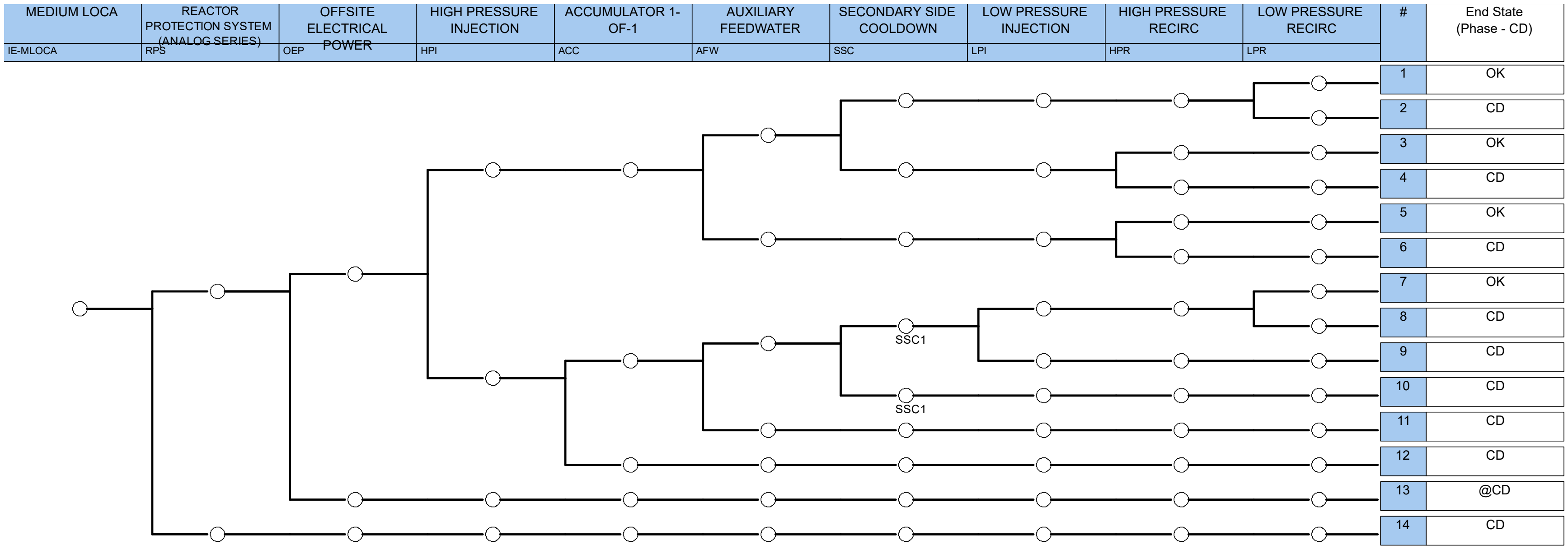

Figure A- 8. Medium loss-of-coolant accident ET.

Appendix B: Generic BWR PRA Model

This Appendix shows BWR ETs, which are transfers of the accident mitigation ETs described in the body of this report. The General plant transient ET previously shown in Section 6.4 is truncated and displayed in several parts here for better readability. The one stuck-open relief valve ET is shown in multiple parts for the same reason.

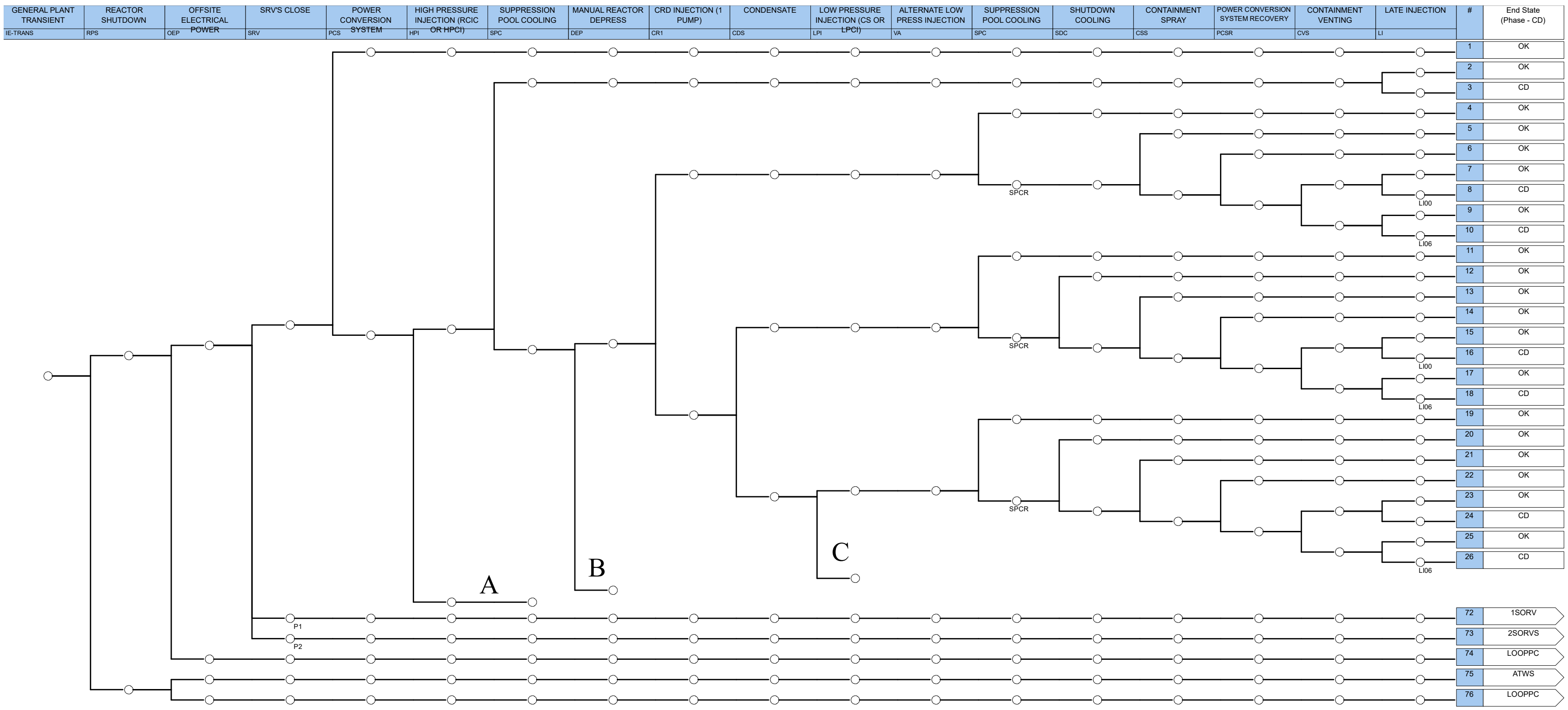

Figure B- 1. General plant transient ET (IE-TRANS) Part 1, showing three truncated branches (i.e., branch A, B, and C).

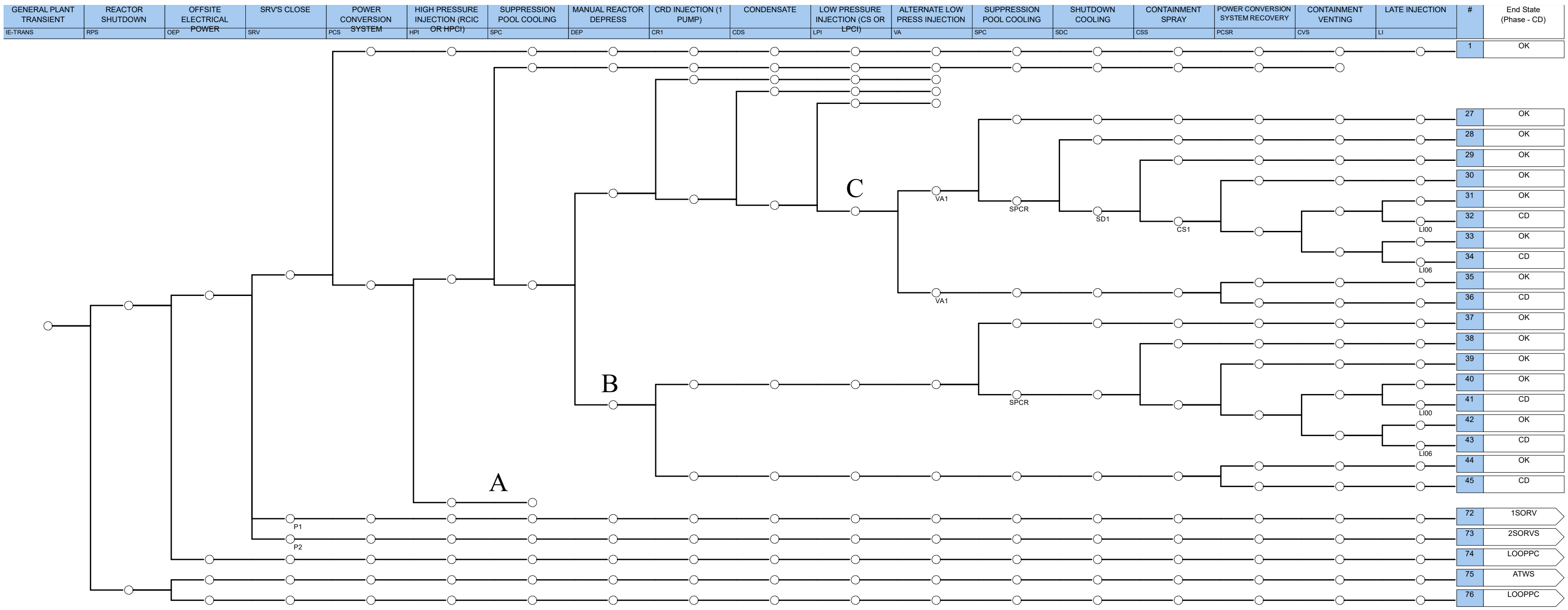

Figure B- 2. General plant transient ET (IE-TRANS) Part 2, revealing branch B and C.

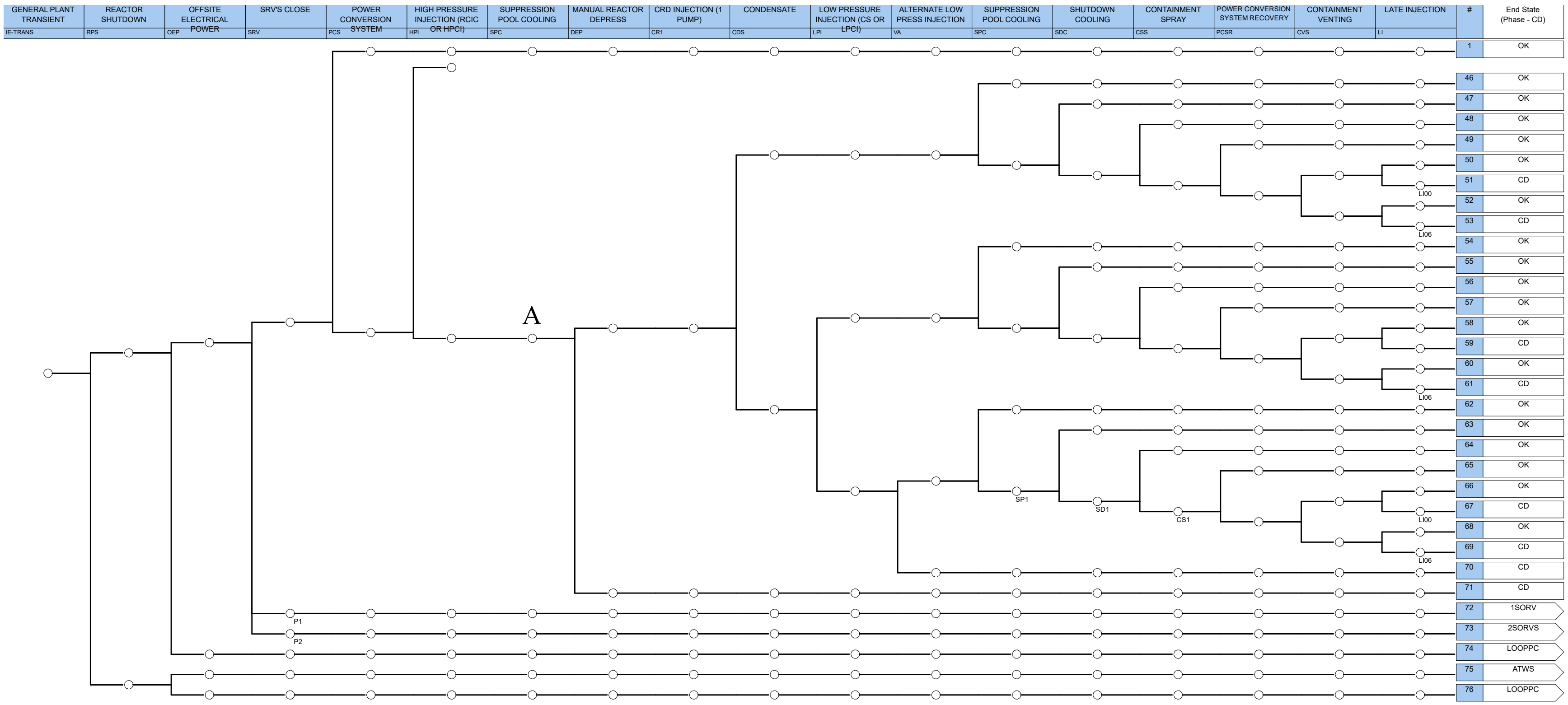

Figure B- 3. General plant transient ET (IE-TRANS) Part 3, revealing branch A.

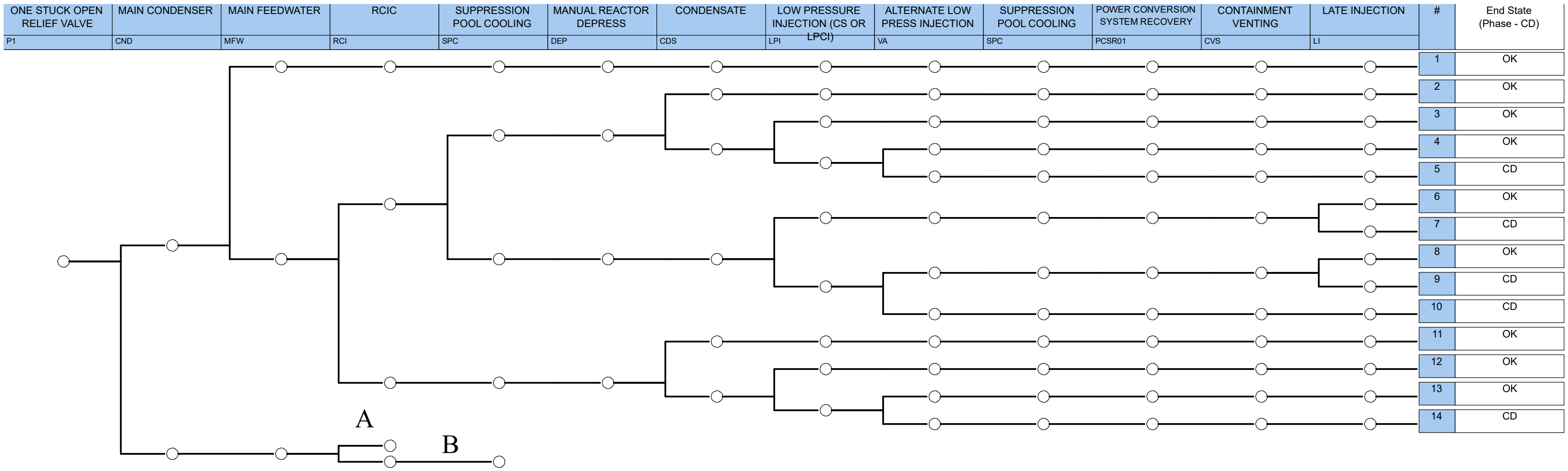

Figure B- 4. One stuck-open relief valve ET (P1) Part 1, showing a truncated branch.

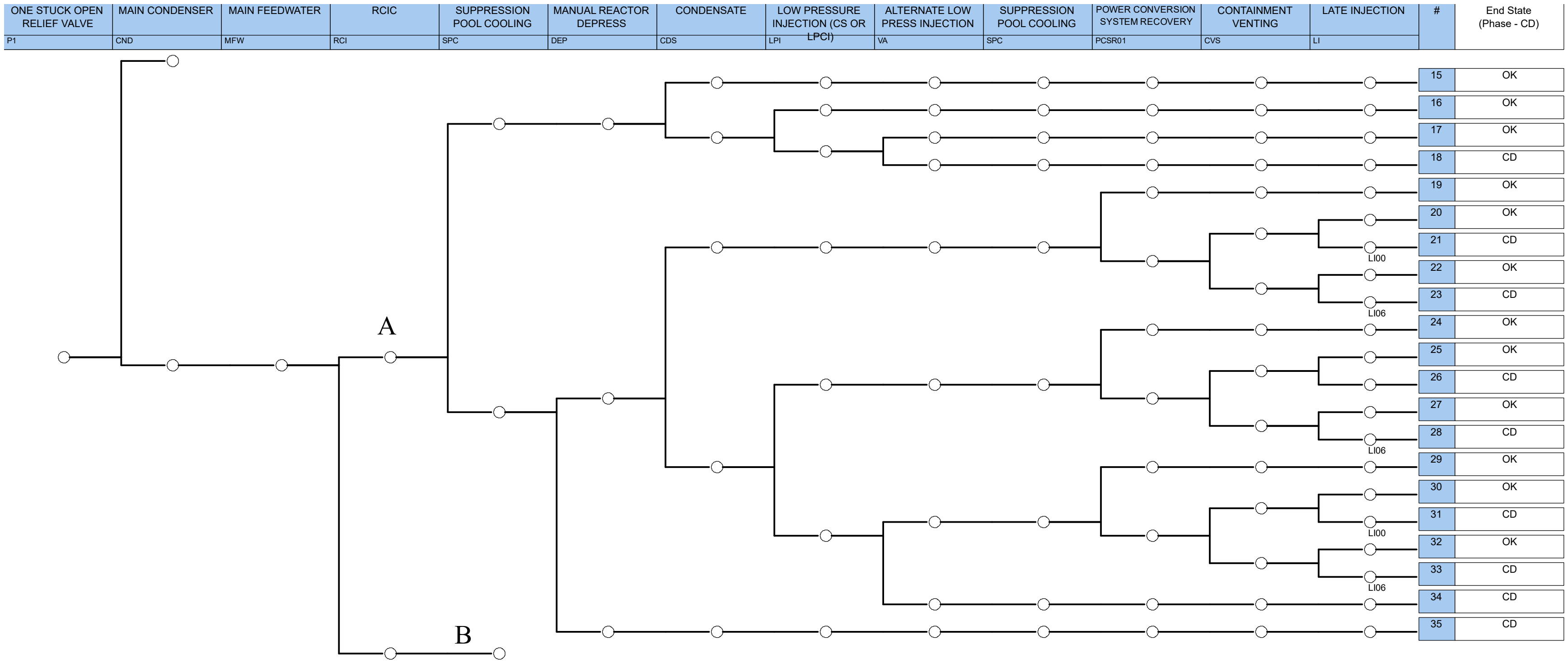

Figure B- 5. One stuck-open relief valve ET (P1) Part 2, revealing branch A.

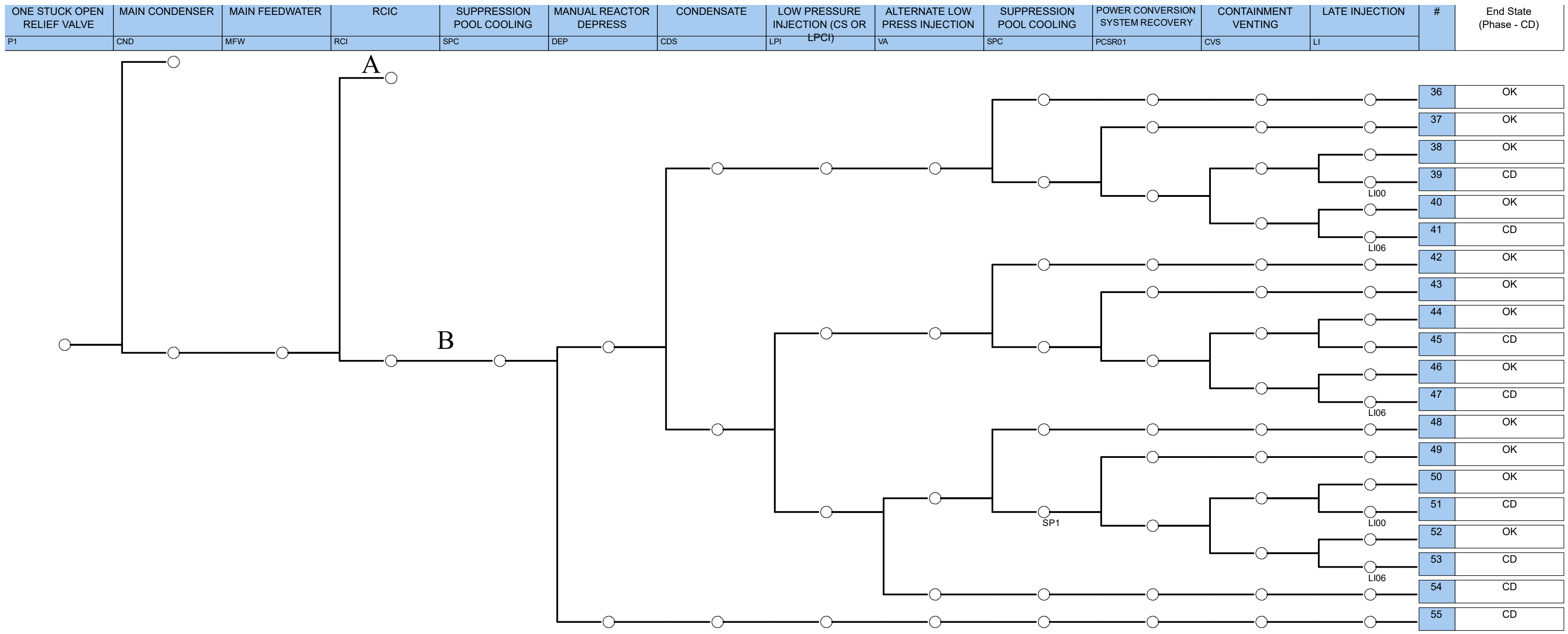

Figure B- 6. One stuck-open relief valve ET (P1) Part 3, revealing branch B.

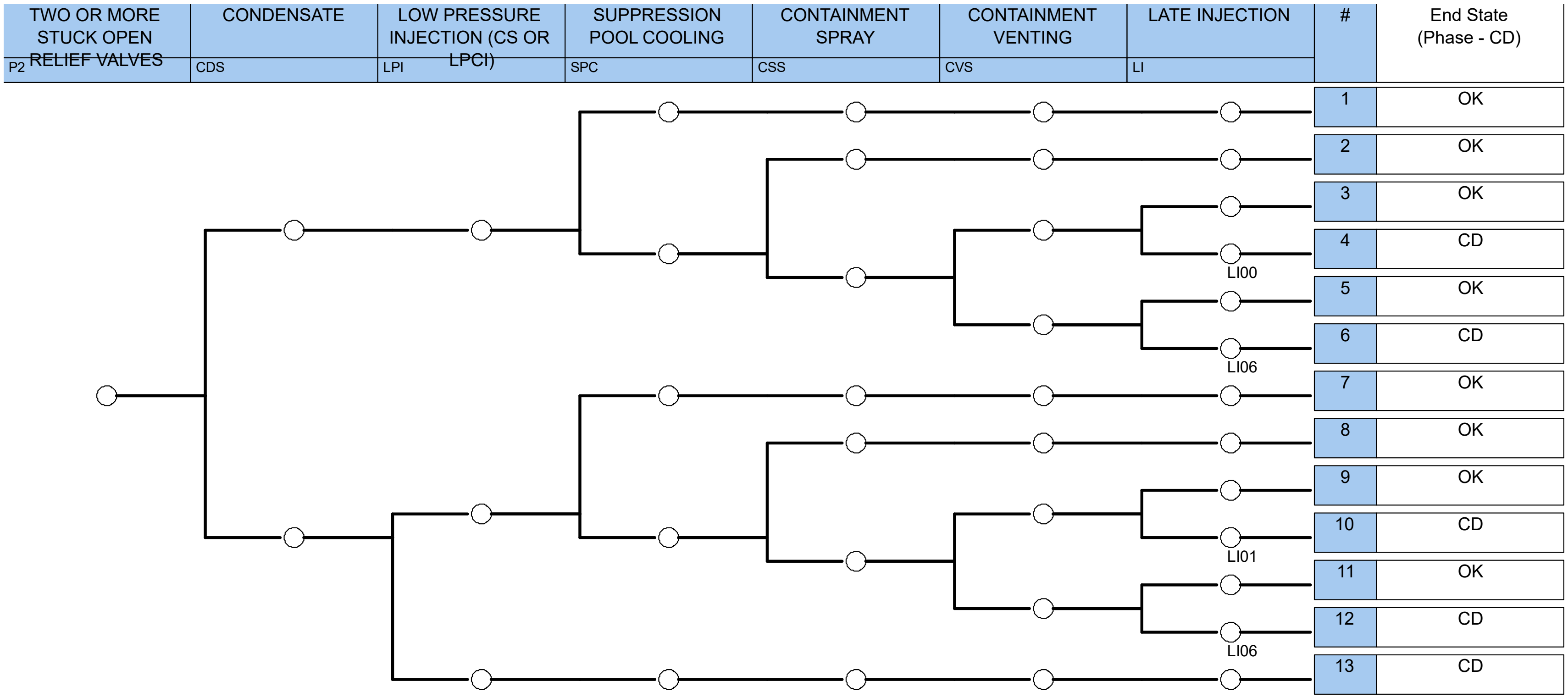

Figure B- 7. Two or more stuck-open relief valves (P2).

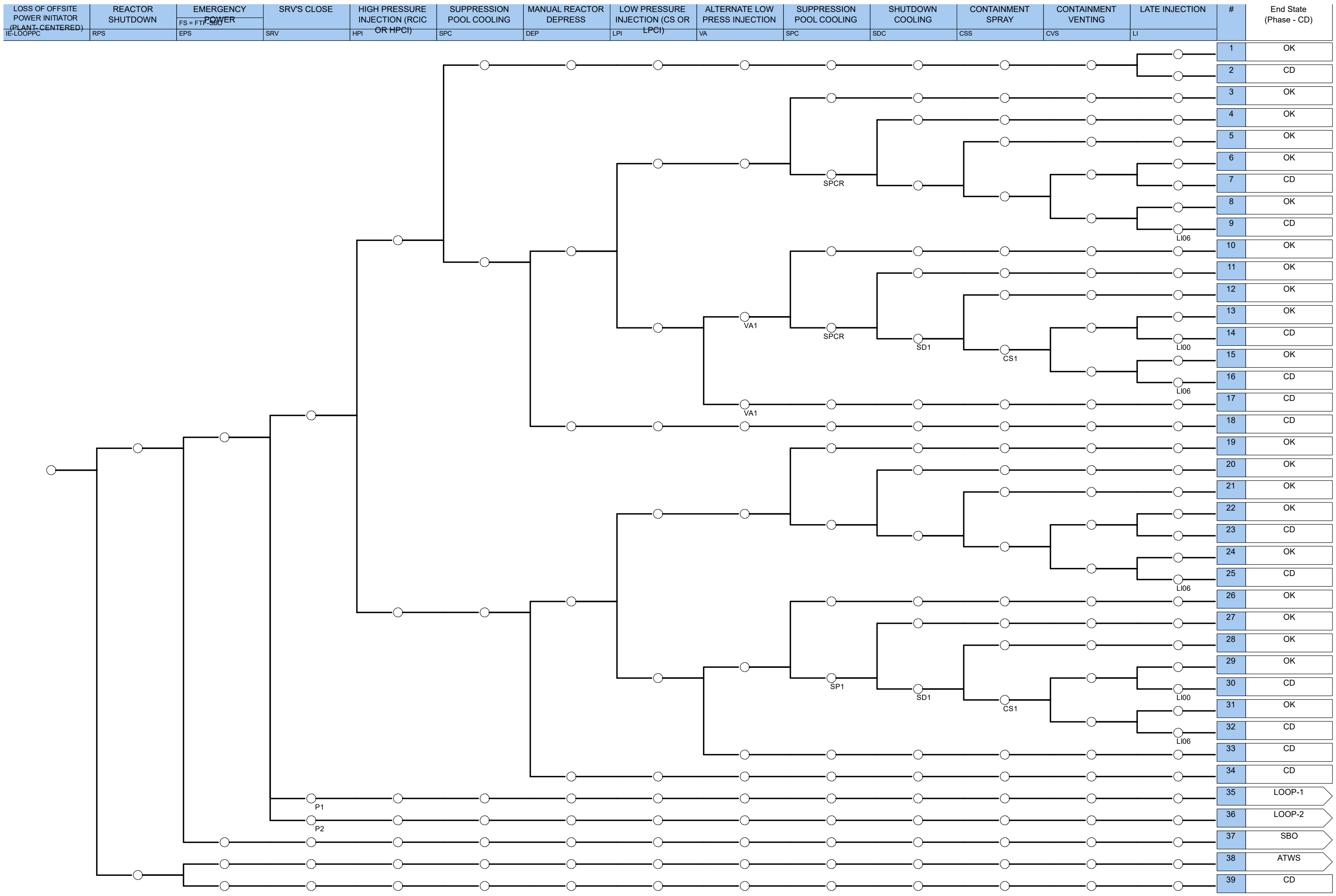

Figure B- 8. LOOP (plant-centered) ET (IE-LOOPPC).

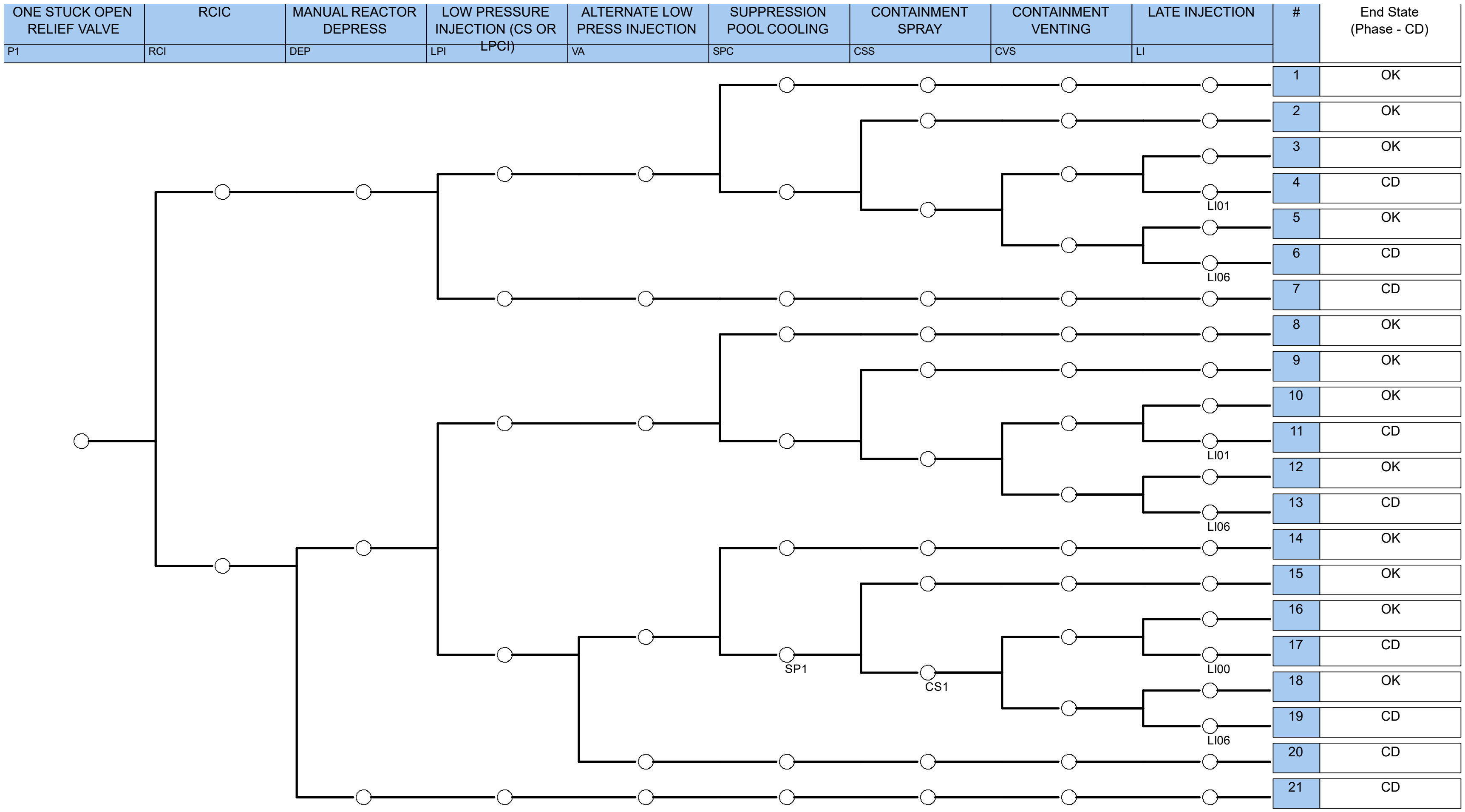

Figure B- 9. LOOP-1 ET (P1).

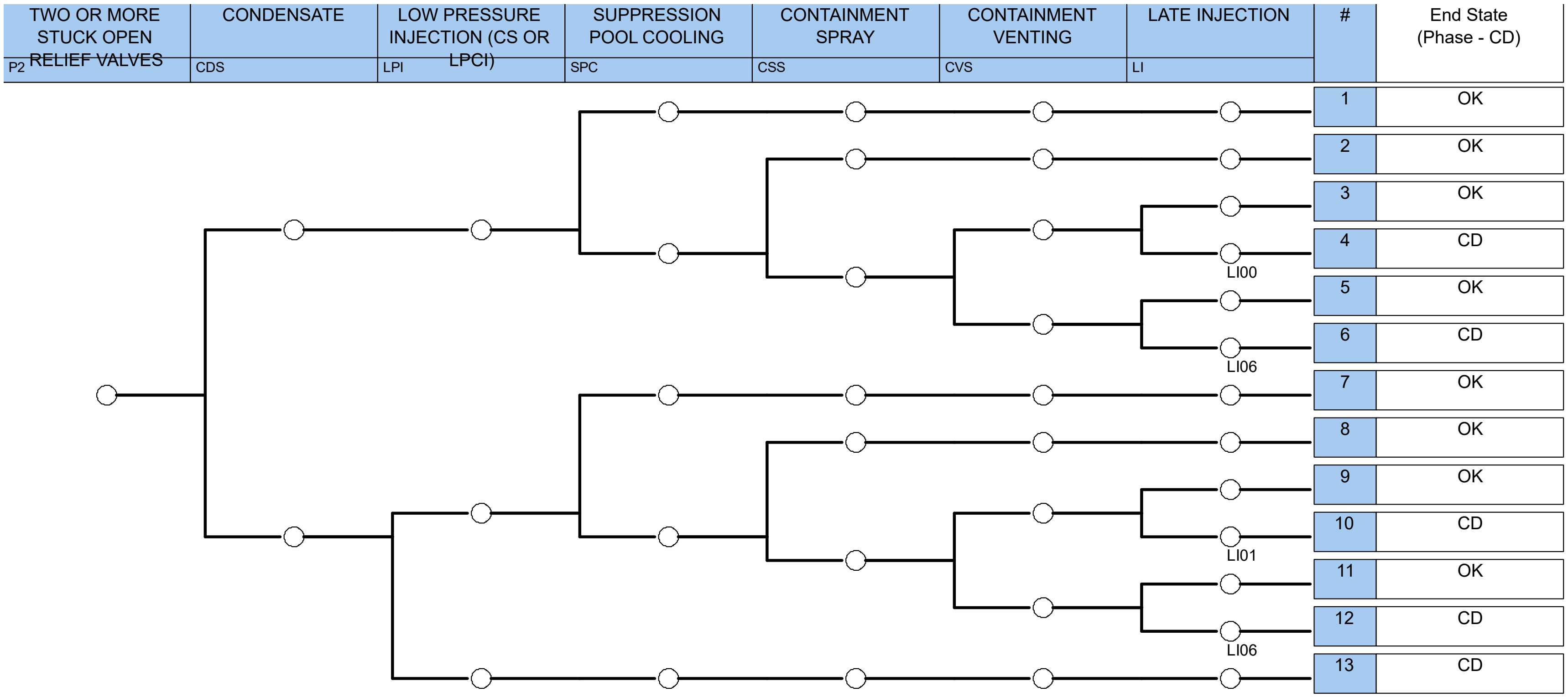

Figure B- 10. LOOP-2 ET (P2).

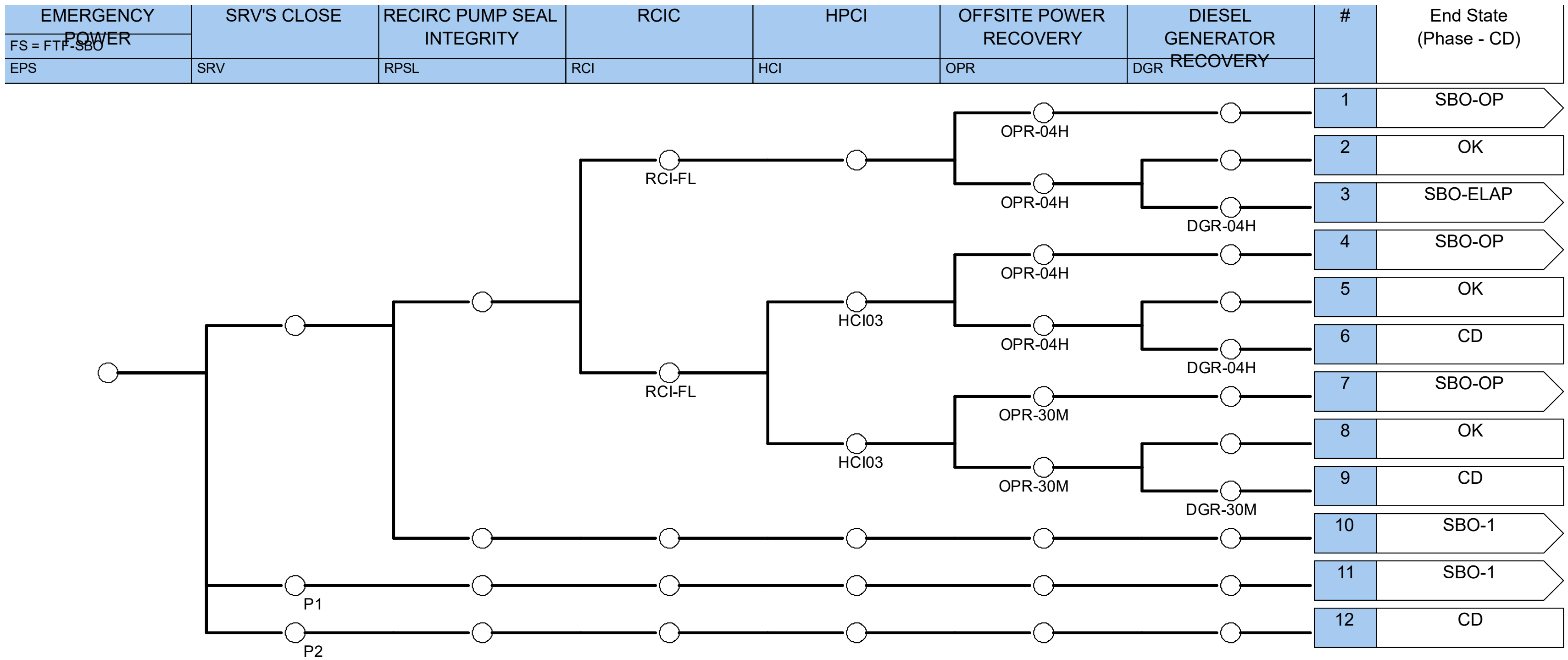

Figure B- 11. SBO ET.

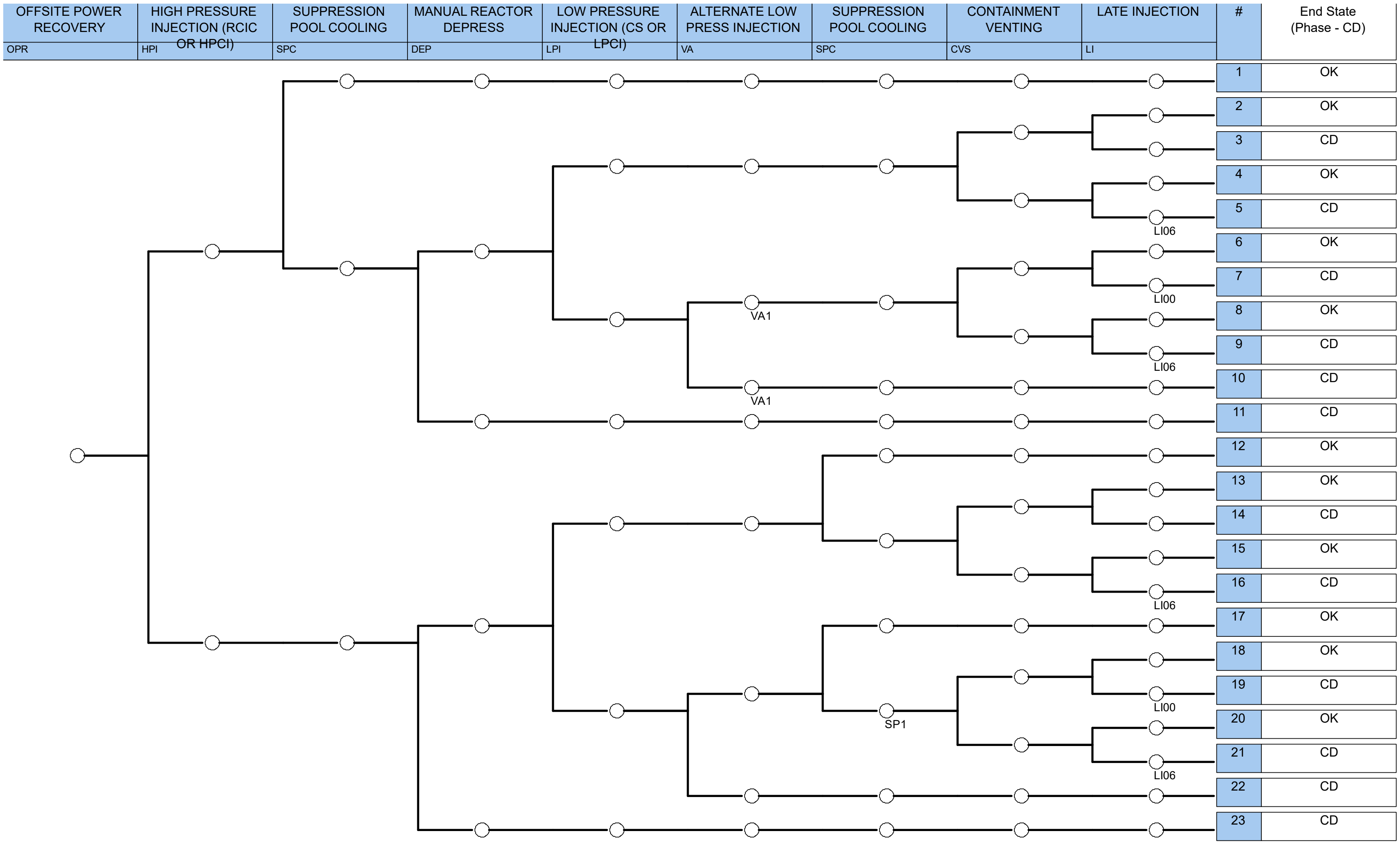

Figure B- 12. SBO-OP ET.

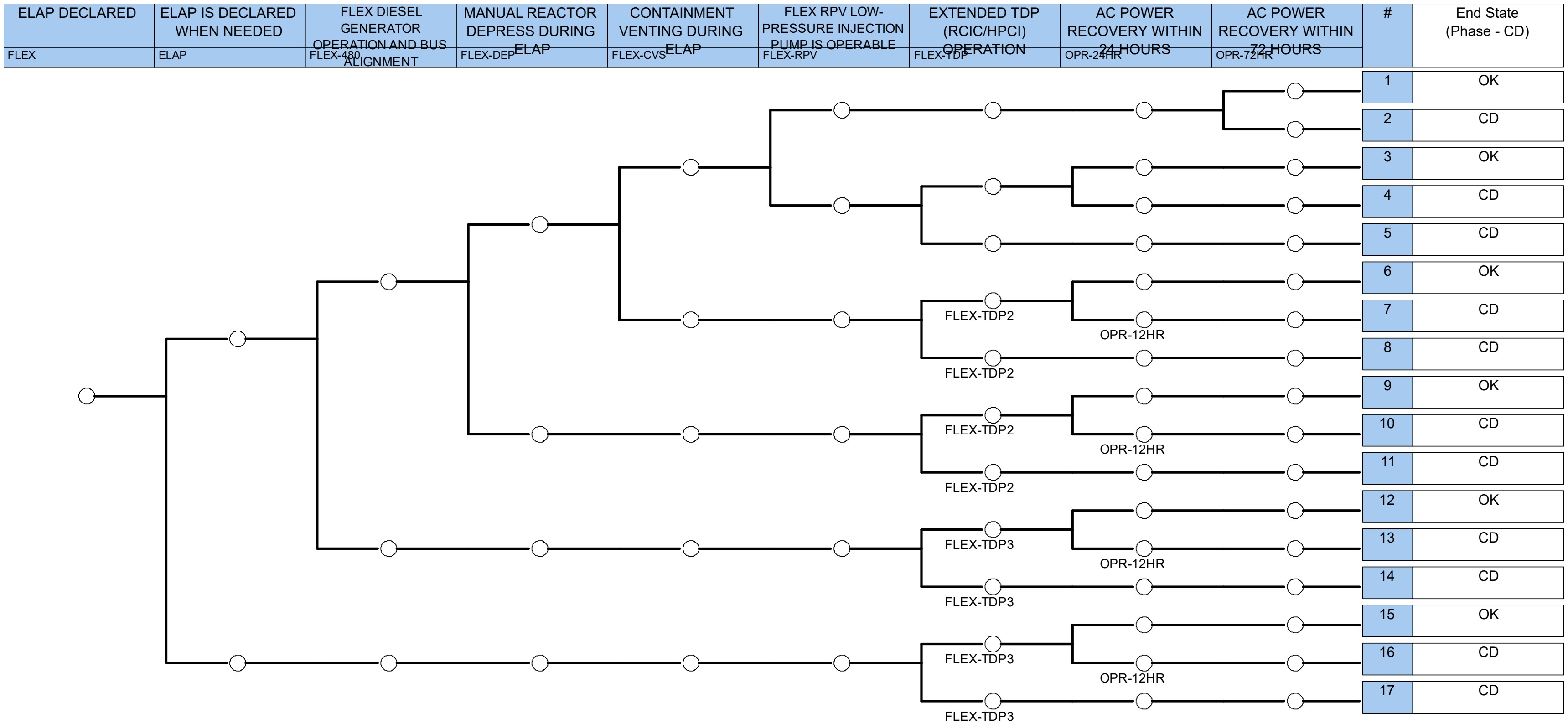

Figure B- 13. SBO-ELAP ET.

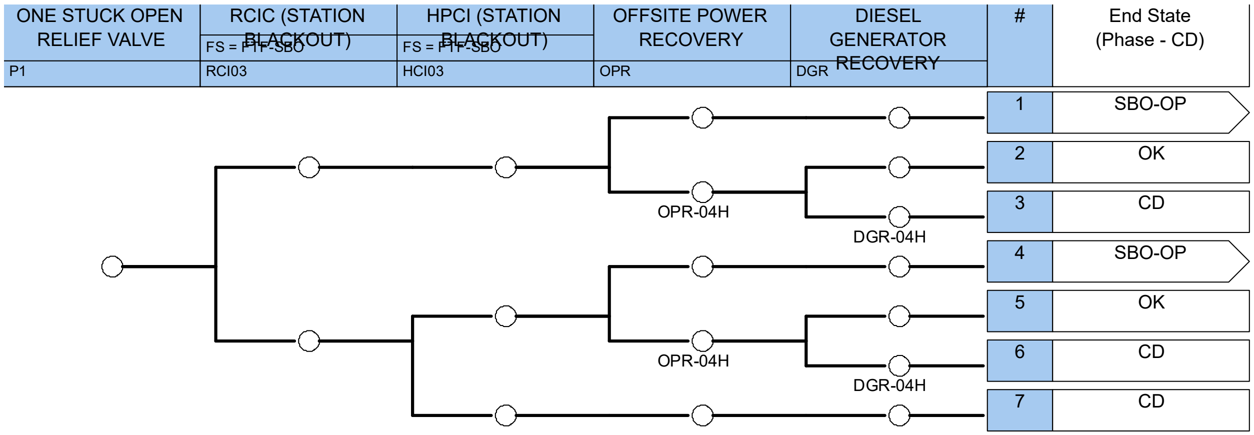

Figure B- 14. SBO-1 ET.

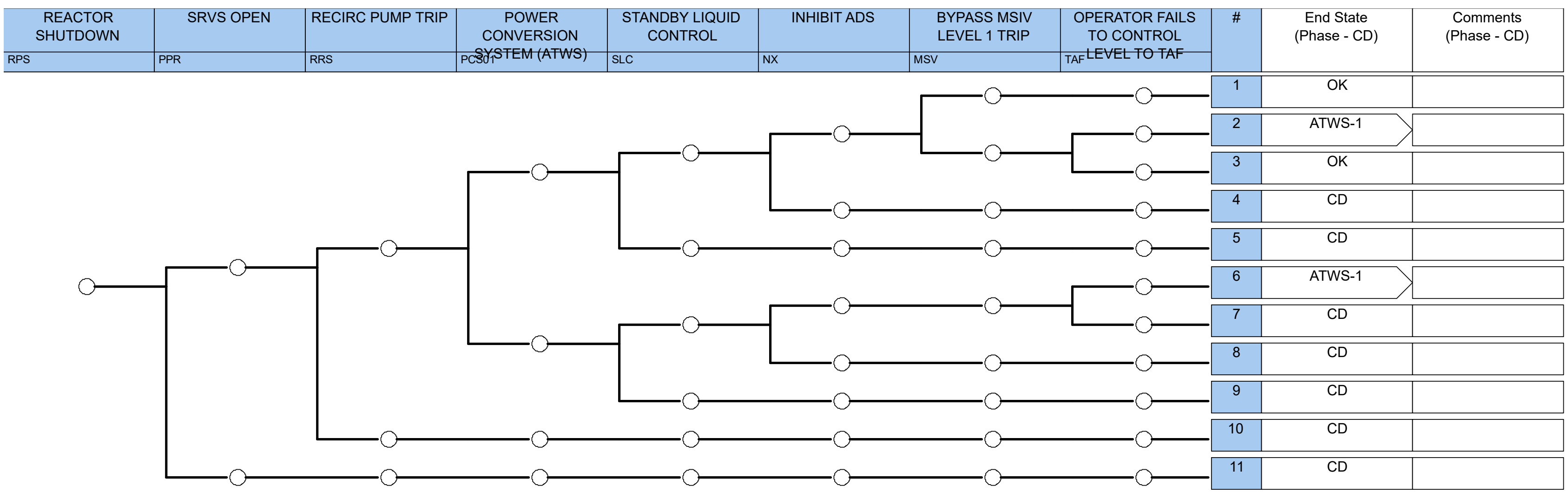

Figure B- 15. ATWS ET.

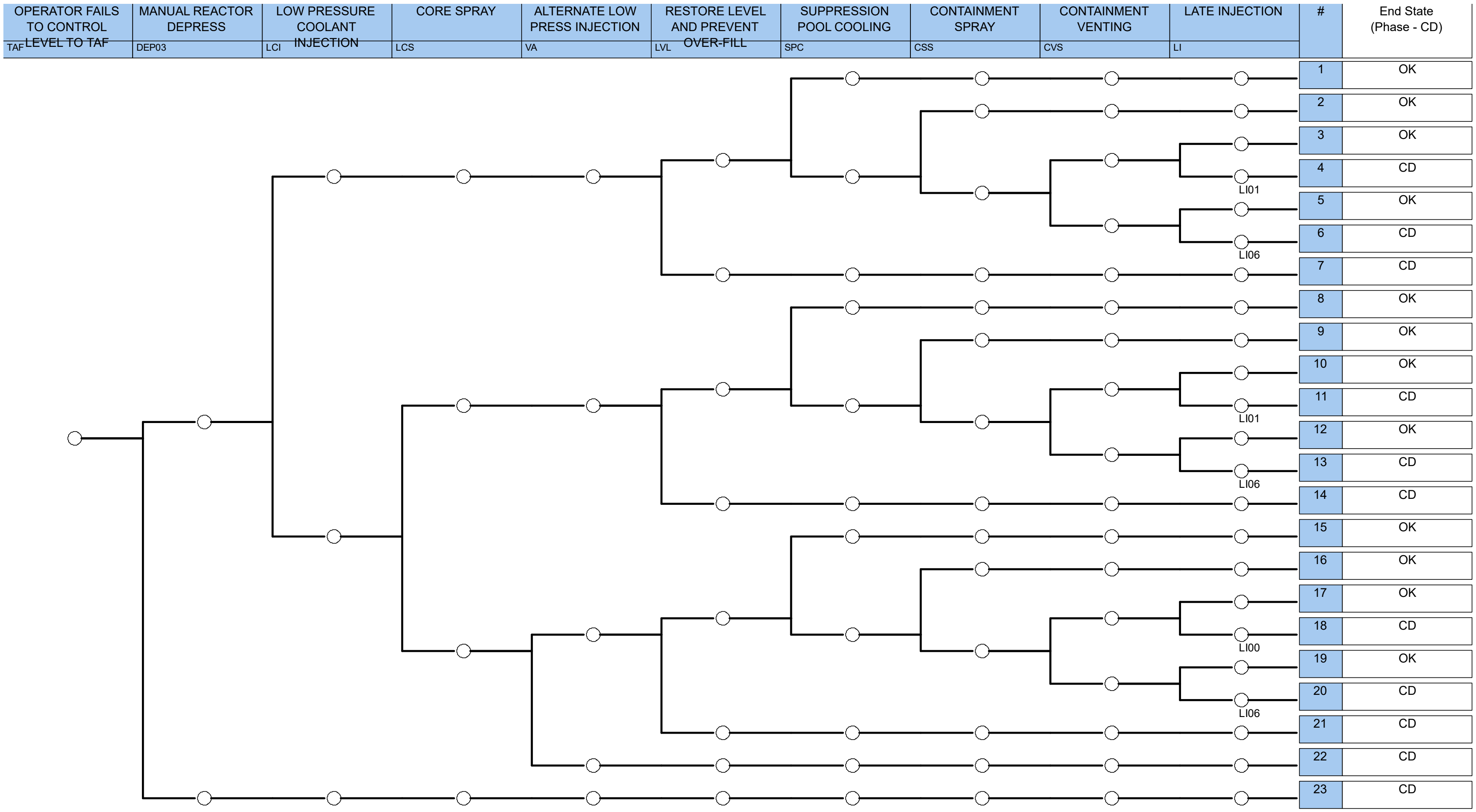

Figure B- 16. ATWS-1 ET.

Appendix C: FMEA Results

The FMEA results for BWR and PWR are presented on the following pages.

Table C- 1. BWR FMEA Results.

Process Function	Potential Failure Mode	Potential Causes/ Mechanisms of Failure	Existing ET?	Ranking Scale (1-10) Severity to CD	Frequency	Detection	RPN	Safety / Economic	General Notes	BWR Unique
External Power	LOOP	H2 detonation at HTEF	LOOP	3 - 9	3	1	9 - 27	S, E	Severity highly dependent on NPP. Number of plants where a LOOP is a really bad day. It depends on the configuration of Emergency Power	
Spray pond		H2 detonation at HTEF		3	3	3	27	S, E	Debris and above water spray mechanisms, ultimate heat sink	
Cooling Tower pond		H2 detonation at HTEF		3	3	3	27	S, E	Debris in ultimate heat sink	
Primary loop transport of process steam	Pipe Rupture after MSIV	Placement of HES in the turbine building: Damage to turbine building equipment, possibly safety power buses, depending on the plant	STM-LINE-BREAK	7	3	1	21	S, E	Recommend placement of HES in a dedicated building. This study will model PRA with that assumption.	Severity is higher for BWR, 7, Need to isolate in HES and dump steam to condenser
Primary loop transport of process steam	Pipe Rupture after MSIV	Operational vibration seismic, erosion,	STM-LINE-BREAK	4	3	1	12	S, E		
Service water pump house		H2 detonation at HTEF		3	3	1	9	E	As sited 1 km distance NPP to HTEF	

Process Function	Potential Failure Mode	Potential Causes/ Mechanisms of Failure	Existing ET?	Ranking Scale (1-10) Severity to CD	Frequency	Detection	RPN	Safety / Economic	General Notes	BWR Unique
	Heat Exchanger Leak	Contamination of the tertiary HTF loop with process steam	STM-LINE-BREAK	7	1	1	7	E	Steam in Therminol 66. Decrease lifetime through emulsion, cracking hydrocarbons. Talk with chemist. Ec severity: 5	Contamination of oil. Therminol will bind tritium. Mostly N-16 out of BWR steam. Possibly C-60, but little chance. Ec severity: 7
	Heat Exchanger Leak	Over pressurization of tertiary loop		2	3	1	6	E	Relief valve in tertiary loop	
External Supply Tanks integrity	Damage to CST, other supply tanks	H2 detonation at HTEF		2	3	1	6	S, E	As sited 1 km distance NPP to HTEF	
Forced air cooling		H2 detonation at HTEF		2	3	1	6	S, E		
Turbine load of up to 90%	Loss of 90% load immediately if used in following			2	2	1	4	S, E	Depends on the way power is placed on grid or to facility. Possibility of turbine trip. Need to quantify for PRA.	
H_2 in NPP process	H_2 piped back to NPP		TRANSIENT	1	1	2	2	S,E		BWR uses more H2. Already in risk model for local generation
	Flammability of HTF?			2	1	1	2	E	Data sheet shows minimal flammability	

Process Function	Potential Failure Mode	Potential Causes/ Mechanisms of Failure	Existing ET?	Ranking Scale (1-10) Severity to CD	Frequency	Detection	RPN	Safety / Economic	General Notes	BWR Unique
Steam diversion load roughly 5% thermal	Loss of 5% load immediately			0	2	2	0	S,E	NPP can handle up to 30% prompt load loss, so not a hazard	
Critical structure integrity	Damage to reactor building walls	H2 detonation at HTEF	No fragility	10	0	1	0	S, E	As sited 1 km distance NPP to HTEF	
H2 to transfer facility	pipeline failure leaks H_2 close to electrical lines			UNK	UNK	5	UNK	Potential S, E	Where would the tank farm be? How many tanks? Or only a pipeline to other facilities?	

Table C- 2. PWR FMEA Results.

Process Function	Potential Failure Mode	Potential Causes/ Mechanisms of Failure	Existing ET?	Ranking Scale (1-10) Severity to CD	Frequency	Detection	RPN	Safety / Economic	General Notes	PWR Unique
Spray pond		H2 detonation at HTEF		3	3	3	27	S, E	Debris and above water spray mechanisms, ultimate heat sink	
Cooling Tower pond		H2 detonation at HTEF		3	3	3	27	S, E	Debris in ultimate heat sink	
External Power	LOOP	H2 detonation at HTEF	LOOP	3 - 9	3	1	9 - 27	S, E	Severity highly dependent on NPP. Number of plants where a LOOP is a really bad day. It depends on the configuration of Emergency Power.	
Primary loop transport of process steam	Pipe Rupture after MSIV	Placement of HES in the turbine building: Damage to turbine building equipment, possibly safety power buses, depending on the plant	STM-LINE-BREAK	4	3	1	12	S, E	Recommend placement of HES in a dedicated building. This study will model PRA with that assumption.	Severity less in PWR
Primary loop transport of process steam	Pipe Rupture after MSIV	Operational vibration seismic, erosion,	STM-LINE-BREAK	4	3	1	12	S, E		
Service water pump house		H2 detonation at HTEF		3	3	1	9	E	As sited 1 km distance NPP to HTEF	
Forced air cooling		H2 detonation at HTEF		2	3	1	6	S, E		

				Ranking Scale (1-10)						
Process Function	**Potential Failure Mode**	**Potential Causes/ Mechanisms of Failure**	**Existing ET?**	**Severity to CD**	**Frequency**	**Detection**	**RPN**	**Safety / Economic**	**General Notes**	**PWR Unique**
	Heat Exchanger Leak	Overpressurization of tertiary loop		2	3	1	6	E	Relief valve in tertiary loop	
External Supply Tanks integrity	Damage to CST, other supply tanks	H2 detonation at HTEF		2	3	1	6	S, E	As sited 1 km distance NPP to HTEF	
	Heat Exchanger Leak	Contamination of the tertiary oil loop with process steam	STM-LINE-BREAK	5	1	1	5	E	Steam in Therminol 66. Decrease lifetime through emulsion, cracking hydrocarbons. Talk with chemist. Ec severity: 5	
Turbine load of up to 90%	Loss of 90% load immediately if used in following			2	2	1	4	S, E	Depends on the way power is placed on grid or to facility. Possibility of turbine trip. Need to quantify for PRA.	
H_2 in NPP process	H_2 piped back to NPP		TRANSIENT	1	1	2	2	S,E		PWR less of a hazard. H2 levels are low and are in risk models of applicable NPPs
	Flammability of heating oil?			2	1	1	2	E	Data sheet shows minimal flammability	
Steam diversion load roughly 5% thermal	Loss of 5% load immediately			0	2	2	0	S,E	NPP can handle up to 30% prompt steam load loss, so not a hazard	

Process Function	Potential Failure Mode	Potential Causes/ Mechanisms of Failure	Existing ET?	Ranking Scale (1-10) Severity to CD	Frequency	Detection	RPN	Safety / Economic	General Notes	PWR Unique
Critical structure integrity	Damage to reactor building walls	H_2 detonation at HTEF		10	0	1	0	S, E	As sited 1 km distance NPP to HTEF	
Primary loop transport of process steam	Heat Exchanger Leak	Erosion, vibration	STM-LINE-BREAK				0			
H_2 to transfer facility	pipeline failure leaks H_2 close to electrical lines			UNK	UNK	5	UNK	Potential S, E	Where would the tank farm be? How many tanks? Or only a pipeline to other facilities?	

Table C- 3. FMEA Results of HES Design 3

Function	Failure Modes	Causes	Effects	Existing ET?
Extraction steam piping: Providing steam to cogeneration boiler	No steam when demand comes / reduced steam flow	• Supply valve fails to open, or • Steam line break	To NPP: Slight adjustment of MSR power, or steam line break initiator To H_2 plant: Financial (loss of H_2 generation)	Main Steam Line Break (MSLB)
	Steam comes when no demand	Supply valve fails to close	To NPP: Trivial reduction in LP Turbine power generation. To H_2 plant: None. Direct steam to main condenser.	NA
Reboiler feed piping: Providing supply water to cogeneration boiler	No supply water when demand comes / reduced water flow	• Water supply pump fails, or • Water line break / leakage, or • Water supply tank failure, or • Water valve fails to open	To NPP: None	NA

Function	Failure Modes	Causes	Effects	Existing ET?
			To H_2 plant: Financial (Loss of H_2 generation)	
	Water comes when no demand	• Water supply pump spurious operation	To NPP: None To H_2: None	NA
Process steam piping: Providing steam to H_2 plant	No steam when demand comes	• No supply steam when demand comes, or • No water when demand comes, or • Cogeneration boiler failure	To NPP: None To H_2 plant: Financial, loss of H_2 generation	NA
	Steam comes when no demand	• Supply steam comes when no demand, and • Water comes when no demand	To NPP: Trivial reduction in LP Turbine power generation. To H_2 plant: None if atmospheric bypass valves exist.	NA
H_2 plant: H_2 generation	Hydrogen cloud detonation event (MCA)	• Detonation after 2 hours of undetected full rupture leakage	Switchyard failure: LOOP initiator (low probability)	LOOP
	Hydrogen high pressure jet detonation	• H_2 pipe break scenario of 200 mm line at 50 ºC and 7 MPa.	Switchyard failure	LOOP

Appendix D: Hydrogen Safety Analysis Supporting Information

This analysis documents the necessary modifications of SAND2020-10828 [13] to evaluate a 100MW HTEF. The previous report documented the HTEF system leak frequency and consequence of detonation from a range of different events. Note, the consequence evaluation utilized a deterministic methodology to evaluate the worst-case overpressure impact from a range of different impact conditions. The previous analysis was based on a preliminary design of an HTEF system that utilized steam from a NPP to produce hydrogen. This design was capable of producing a total of 300 U.S. tons of hydrogen daily at a power of 1,150 MW. The high temperature steam electrolysis process was comprised of forty-six 25-MWe modular units. The 100 MWe facility is comprised of four 25-MWe modular units.

System Leak Frequency

In the previous analysis, the leak frequency of the facility was calculated from the bottom-up component leak frequencies. A Bayesian statistical analysis combined leak events from non-hydrogen sources that are representative of hydrogen components with the limited data for leak events from hydrogen-specific components. The resulting component leak frequencies are documented as a function of normalized leak size below in Table D- 1.

Table D- 1. Component Leak Frequencies

Component	Leak Size	Generic Leak Frequencies				Hydrogen Leak Frequencies			
		Mean	5th	Median	95th	Mean	5th	Median	95th
Compressor	0.0001	6.0E+00	2.5E-01	2.2E+00	1.9E+01	1.0E-01	5.9E-02	1.0E-01	1.6E-01
	0.001	1.8E-01	2.1E-02	1.1E-01	5.4E-01	1.9E-02	6.8E-03	1.7E-02	3.8E-02
	0.01	9.2E-03	1.0E-03	5.2E-03	2.7E-02	6.3E-03	1.2E-03	4.6E-03	1.7E-02
	0.1	3.4E-04	8.2E-05	2.6E-04	8.0E-04	2.0E-04	4.6E-05	1.5E-04	4.9E-04
	1	3.3E-05	1.7E-06	1.2E-05	9.3E-05	3.2E-05	2.0E-06	1.5E-05	1.0E-04
Cylinder	0.0001	1.5E+00	6.6E-02	6.6E-01	5.3E+00	1.6E-06	3.5E-07	1.4E-06	3.4E-06
	0.001	3.4E-02	3.4E-03	2.0E-02	1.0E-01	1.3E-06	3.7E-07	1.2E-06	2.8E-06
	0.01	8.4E-04	1.6E-04	6.4E-04	2.1E-03	9.0E-07	2.6E-07	7.9E-07	1.9E-06
	0.1	2.5E-05	6.6E-06	1.9E-05	5.9E-05	5.2E-07	1.6E-07	4.5E-07	1.1E-06
	1	7.6E-07	1.9E-07	6.1E-07	1.8E-06	2.7E-07	8.1E-08	2.3E-07	6.0E-07
Filter	0.0001	6.9E-02	3.4E-04	5.3E-03	8.4E-02	NA	NA	NA	NA
	0.001	1.4E-02	6.2E-04	5.1E-03	4.1E-02	NA	NA	NA	NA
	0.01	1.6E-02	6.0E-04	4.8E-03	3.9E-02	NA	NA	NA	NA
	0.1	6.1E-03	1.4E-03	4.6E-03	1.5E-02	NA	NA	NA	NA
	1	6.4E-03	1.2E-03	4.4E-03	1.6E-02	NA	NA	NA	NA
Flange	0.0001	6.5E-02	1.7E-03	2.0E-02	2.3E-01	NA	NA	NA	NA
	0.001	4.3E-03	3.4E-04	2.2E-03	1.4E-02	NA	NA	NA	NA

Component	Leak Size	Generic Leak Frequencies				Hydrogen Leak Frequencies			
		Mean	5th	Median	95th	Mean	5th	Median	95th
	0.01	3.5E-03	8.4E-06	2.4E-04	7.0E-03	NA	NA	NA	NA
	0.1	3.5E-05	8.3E-06	2.7E-05	8.6E-05	NA	NA	NA	NA
	1	1.9E-05	1.9E-07	2.9E-06	4.6E-05	NA	NA	NA	NA
Hose	0.0001	2.8E+01	1.6E+00	1.3E+01	9.4E+01	6.1E-04	2.9E-04	5.8E-04	1.0E-03
	0.001	2.2E+00	2.9E-01	1.4E+00	6.4E+00	2.2E-04	6.6E-05	2.0E-04	4.5E-04
	0.01	2.1E-01	4.3E-02	1.6E-01	5.2E-01	1.8E-04	5.3E-05	1.6E-04	3.8E-04
	0.1	2.2E-02	6.0E-03	1.7E-02	5.3E-02	1.7E-04	5.1E-05	1.5E-04	3.4E-04
	1	5.6E-03	1.9E-04	2.0E-03	1.8E-02	8.2E-05	9.6E-06	6.2E-05	2.2E-04
Joint	0.0001	1.3E+00	7.0E-02	5.3E-01	4.6E+00	3.6E-05	2.3E-05	3.5E-05	5.1E-05
	0.001	1.7E-01	2.1E-02	1.0E-01	5.2E-01	5.4E-06	8.4E-07	4.7E-06	1.2E-05
	0.01	3.3E-02	4.2E-03	1.8E-02	9.3E-02	8.5E-06	2.9E-06	7.9E-06	1.6E-05
	0.1	4.1E-03	1.3E-03	3.5E-03	8.6E-03	8.3E-06	2.4E-06	7.5E-06	1.7E-05
	1	8.2E-04	2.3E-04	6.3E-04	1.9E-03	7.2E-06	1.8E-06	6.4E-06	1.5E-05
Pipe	0.0001	5.9E-04	7.1E-05	3.6E-04	1.8E-03	9.5E-06	2.1E-06	8.0E-06	2.2E-05
	0.001	8.6E-05	1.7E-05	6.2E-05	2.2E-04	4.5E-06	1.1E-06	3.7E-06	1.1E-05
	0.01	3.5E-05	9.1E-07	1.1E-05	1.3E-04	1.7E-06	9.9E-08	9.6E-07	5.9E-06
	0.1	4.7E-06	2.3E-07	1.9E-06	1.6E-05	8.4E-07	5.8E-08	4.6E-07	2.9E-06
	1	3.7E-06	1.0E-08	3.2E-07	1.0E-05	5.3E-07	5.5E-09	1.5E-07	2.3E-06
Pump	0.0001	3.9E-02	2.4E-03	1.8E-02	1.3E-01	NA	NA	NA	NA
	0.001	6.5E-03	8.5E-04	4.2E-03	1.9E-02	NA	NA	NA	NA
	0.01	2.5E-03	9.9E-05	9.5E-04	8.3E-03	NA	NA	NA	NA
	0.1	2.8E-04	7.2E-05	2.1E-04	6.7E-04	NA	NA	NA	NA
	1	1.2E-04	5.4E-06	4.9E-05	4.1E-04	NA	NA	NA	NA
Valve	0.0001	2.0E-02	2.2E-03	1.2E-02	6.4E-02	2.9E-03	1.9E-03	2.9E-03	4.2E-03
	0.001	2.8E-03	5.0E-04	1.9E-03	7.5E-03	6.3E-04	2.7E-04	5.9E-04	1.1E-03
	0.01	1.2E-03	2.6E-05	3.1E-04	4.0E-03	8.5E-05	6.6E-06	5.4E-05	2.7E-04
	0.1	6.4E-05	1.8E-05	5.3E-05	1.5E-04	3.0E-05	8.7E-06	2.5E-05	6.7E-05
	1	2.6E-05	8.3E-07	8.5E-06	9.1E-05	1.1E-05	4.7E-07	4.8E-06	4.2E-05

Table D- 2. HTEF Component Quantities Summary

Component	Quantity for 1150 MW HTEF	Quantity for Modular 25 MW unit	Quantity for 100 MW HTEF
Compressor	92	2	8
Cylinder (Vessel, intercooler, Separator, Heat Exchanger)	874	19	76
Joint (Tee, Elbow, Reducer, Expander)*	150	3	24
Pipe	7,360	160	640
Pump/Blower	276	6	24
Valve	966	21	84

* There are a total of 12 joints in the system that are independent of the modules